California Public Utilities Commission

Staff Recommendations on Capacity Market Structure:

A Report on the August 2007 Workshops in Collaboration with the CAISO

R.05-12-013

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Executive Summary

This report provides background on the long term elements of the California Public Utilities Commission's Resource Adequacy (RA) proceeding (R.05-12-013, Phase Two, Track Two), summarizes the workshops which were a part of that proceeding, describes and evaluates the various Resource Adequacy (RA) proposals before the Commission, and culminates in the recommendation of the CPUC Energy Division staff on the best forward course of action for the Commission's RA program. Decision makers may find this report most informative in the recommendations section which runs from page 95 through page 110.

In this report the Energy Division staff does not find that any individual proposal put forth by parties satisfies enough of the Commission's goals to be recommended without modification. This does not mean the proposals before the Commission do not have merit, in fact they were generally well thought out and grounded in reasonable economic theory; but the complications of California's power industry and its history do not lend themselves to blanket application of abstract market theories alone.

The recommendations of the Energy Division staff reflect this need for balance between strong economic theory and on the ground application. To that end proposals that include detailed scenarios designed and vetted by diverse interests fare better than those that are strong on theory or flexibility, but weaker on details. Notably, the two proposals which staff considered strongest, the Bilateral Trade Group's (BTG) proposal and the Centralized Forward Capacity Market (CFCM), advocated by the consortium of Investor Owned Utilities (IOUs) and generators known by the acronym CFCMA, represent markedly different views of the future RA program.

The differences between those programs highlight what are ultimately different strategies for approaching RA in California. Each proposal addresses the balance of risk and reward differently. Perhaps precisely because these proposals represent the relatively diverse interests of California's power market participants, the Energy Division staff utilizes these two proposals as foundations for the two recommendations contained in this report. Ultimately, the recommendations of staff attempt to mitigate the potential downsides of each proposal in developing the recommendations. Were the proposals more similar in their foundations, staff may have recommended a single, unified proposal; instead staff recommends either of the following with qualifications detailed below. Staff’s position is that the Commission is presented with two staff-approved alternatives which represent distinct policy directions that are best made at the Commissioner level.

Recommendation 1: The Modified Centralized Market

The Modified Centralized Market (MCM) incorporates aspects of the CFCM proposal, The CAISO’s Centralized Capacity Market (CCM) recommendation, and PG&E’s Composite proposal. The MCM is a bifurcated capacity market that recognizes there are multiple goals for a RA program that utilizes capacity as an element in determining and ensuring the adequacy of resources. The first element of the MCM is the Preliminary Capacity Showing (PCS) which occurs in a more than four year forward environment. The PCS requires IOUs to bilaterally procure a percentage of their forecast peak load in advance of the centralized market. New Generation is incorporated in the PCS only as directed by the CPUC for Renewable Portfolio Standard (RPS) and other Long Term Procurement Planning (LTPP) purposes unless it is determined to be less expensive than existing capacity. The showing is generally consistent with the current RA program except that the capacity product is standardized under a CAISO tariff and the product is seasonal rather than monthly.

The second element of the MCM, the Centralized Forward Reliability Market (CFRM), is a multi-year forward CCM for the remaining forecast load as well as planning and operating reserves. Load Serving Entities (LSEs) with significantly large purchasing power are required to remain exposed to the market clearing price for five percent of their forecast load. All capacity that participates in the CFRM is responsible for a Peak Energy Rent (PER) deduction that is calculated on an ex post basis based on a marginal inefficient unit. The CFRM also includes reconfiguration auctions that enable adjustments to capacity positions to accommodate load migration or other market changes.

Recommendation 2: Modifications to the Existing RA Program

The modifications proposed in the second staff recommendation are consistent with those put forward by the Bilateral Trade Group. These proposals include an Electronic Bulletin Board to increase pricing transparency, a standardized capacity product and an opt-out mechanism from backstop procurement. The remainder of the program is indistinguishable from the current RA program. It consists of LSE-based bilateral procurement of capacity in a short term environment and new capacity entering the market via IOU procurement with a cost allocation mechanism.

Energy Division staff recommends several changes from the current RA program regardless of the ultimate RA program adopted by the Commission. These changes include a seasonal capacity product, an ex post calculation of PER deduction that is locally variable and participation by DR when applicable.

List of Acronyms

BTG – Bilateral Trade Group

Cal-CIM – California Capacity Infrastructure Model

CAM – Centralized Availability Market

CFA – Comprehensive Forward Assessment

CCM – Centralized Capacity Market

CFCM – Centralized Forward Capacity Market

CFRM – Centralized Forward Reliability Mechanism

CONE – Cost of New Entry

CRAM – Central Resource Adequacy Market

CRFO – Centralized Request for Offers

CT – Combustion Turbine

DA – Direct Access

DR – Demand Response

EFOR – Equivalent Forced Outage Rate

ESP – Electric Service Provider

FCA – Forward Capacity Assessment

GHG – Greenhouse Gas

HSC – Houston Ship Channel

ICAP – Installed Capacity

ICPM – Interim Capacity Procurement Mechanism

ICR – Installed Capacity Requirement

IOU – Investor Owned Utility

ISO – Independent System Operator

LICAP – Locational Installed Capacity

LMP – Locational Marginal Pricing

LOLP – Loss of Load Probability

LSE – Load Serving Entity

LTPP – Long Term Procurement Planning

MCM – Modified Central Market

MRTU – Market Redesign and Technology Upgrade

MW – Megawatt

MWh – Megawatt-hour

NQC – Net Qualifying Capacity

PCOM – Physical Call Option Model

PCS – Preliminary Capacity Showing

PER – Peak Energy Rent

POU – Publicly Owned Utility

QC – Qualifying Capacity

QF – Qualifying Facility

RA-MOO – Resource Adequacy Must Offer Obligation

RA – Resource Adequacy

RAR – Resource Adequacy Requirement

RCST – Reliability Capacity Service Tariff

RFO – Request for Offer

RFP – Request for Proposals

RMR – Reliability Must Run

RPM – Reliability Pricing Model

RPS – Renewable Portfolio Standard

RUC – Residual Unit Commitment

TAC – Transmission Access Charge

UOG – Utility Owned Generation

VOLL – Value of Lost Load

WECC – Western Electricity Coordinating Council

Introduction

This report accomplishes two tasks assigned to the CPUC's Energy Division staff in track two of phase two of the R.05-12-013 proceeding. First, the report consists of a summary of the proceeding and a formal recommendation to the Commission by the Energy Division, in consultation with the CAISO of a RA program. Secondly, the report acts as a workshop report to summarize the workshops held during August of 2007 at the CPUC and the CAISO.

As directed by the December 22, 2006 and May 25, 2007 Assigned Commissioner Rulings, this report on Phase Two Track Two issues is written by CPUC Energy Division staff in consultation with CAISO. Consisting of both the Energy Division staff recommendation on the CPUC's RA program and a workshop report for the workshops in Phase Two, Track Two of R.05-12-013, the report will be included in the record of R.05-12-013 and parties will have an opportunity to comment on it as laid out in the Administrative Law Judge Ruling of July 20, 2007.

Consistent with the Assigned Commissioner's May 25, 2007 ruling, while the collaborative effort in the workshops and stakeholder meetings were extensive, the "Staff Recommendations" section of this report represents the recommendations of the CPUC's Energy Division alone. Input from the CAISO consisted of the CAISO Goals section as well as the CAISO Recommendations for the Design of a Central Capacity Market section on the limited subject area of CCMs offered in compliance with AB 380, as described below[1], and consistent with the May 25, 2007 ACR described above. There was also CAISO contribution to the Capacity Product section (pp. 39-44).

Questions or Comments should be directed, via email, to Robert Strauss at RLS@cpuc.ca.gov or Donald Brooks at DBR@cpuc.ca.gov.

Background

This section describes the current world of California's power market and the adequacy of resources as well as the RA program in place. This section is intended to describe the history and current power market in California including magnitude of the programs in question, and introduce key terms, as well as to better inform the reader of the context in which Energy Division staff makes its recommendations.

Overview of the Current Market

California's power market is estimated at greater than $11 billion per year – the current value of the three major electric IOUs Energy Resource Recovery Accounts. The Commission's decision in RA track 2 may have an important impact on this figure.

[1] See pages 21, 49-50 and Appendix 1 of this report.

Relationship between Various Entities and Jurisdictions

California is home to a variety of electric utilities. Of the approximately 68,000 peak hour Megawatts (MWs) in California, approximately 50,270 MWs of peak demand are in the CAISO service area, as measured on July, 24, 2006[2]. The CPUC regulates some but not all utilities in the CAISO service territory and also regulates some utilities outside of the CAISO service territory. Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric, California's largest, electricity IOUs are regulated by the CPUC, and account for approximately 68 percent of California's energy market measured in megawatt-hours (MWh)[3]. The CPUC also regulates competitive Electric Service Providers (ESPs) in the CAISO territory. Several Publicly Owned Utilities (POUs) and Munis are outside of the Jurisdiction of the CPUC but inside the service territory of the CAISO. As a group, both in and out of CAISO territory, POUs consist of approximately 22 percent of the state's energy consumption in MWh[4]. And finally there are two IOUs that span two jurisdictions, Sierra Pacific and PacifiCorp, that together account for a small share of California load near Lake Shasta and near Lake Tahoe.

California's generation industry is similarly diverse and interrelated. The IOUs sold large numbers of their fossil generating facilities in the late 1990s to merchant generating companies, but the IOUs retain a significant amount approximately one third of the state's generation of Utility Owned Generation (UOG) including large hydro holdings and nuclear units.[5] Merchant generators have built new generation in California in addition to purchasing existing or retired units. Under PURPA a significant number of Qualifying Facilities (QFs) entered the market selling power under long term contracts to IOUs and POUs. California also relies on imports from neighbors in the Western Electricity Coordinating Council (WECC) to the NW and the SW.

In addition to the diverse existing generation portfolio, California's generation industry is also significantly impacted by new generation coming online in the form of renewables introduced to ensure compliance with the Renewable Portfolio Standard (RPS) and LTPP for non-renewable generation procured by IOUs on behalf of the entire state.

The Hybrid Market

The large IOUs who have historically developed the majority of power generating stations throughout California were ordered to divest themselves pursuant to AB 1890 in 1996. Since then, there have been merchant generators owning and operating generating stations alongside generation still owned and operated by the IOUs. In fact, merchant generators and IOUs both have built additional generation in California. The state has endorsed the hybrid market approach that this represents in order to fill the upcoming need for additional generation investment in the state. Regardless of the capacity procurement structure adopted here, the

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2 March, 2007, Energy Division Staff, *2006 Resource Adequacy Report*, http://docs.cpuc.ca.gov/Published/REPORT/65960.htm

3 November, 2007, California Energy Commission, *2007 Integrated Energy Policy Report*, Publication # CEC-100-2007-008, http://www.energy.ca.gov/2007_energypolicy/index.html

4 Ibid.

5 Internal Energy Division staff records

decision should leave the opportunity for all market participants, either merchant or IOU, to invest in and operate generation for the service of California load.

Capacity, Energy, and Ancillary Services

It is important to realize that capacity and energy and are separate products. Energy, which is measured in MWh, has a separate value from capacity as well as a separate market for purposes of buying and selling it. Energy is the output from generators; it is nothing less than the actual electricity used every moment in California by homes and business statewide. While in sections below we more extensively address what capacity is, generally speaking it is the ability to be reliably dispatched when asked to produce electricity and is measured in MW.

Ancillary Services (AS) are grid reliability products other than capacity, which ensure the proper functioning of the grid including recovery from grid failure. The issue of AS and the market for them is separate from a RA focused capacity product.

Energy Issues

In order to fully understand the context in which this report and its recommendations are being made, it is useful to understand the energy market in California. Over the past dozen years California has experienced well documented and significant changes in its energy markets, transitioning from vertically integrated utilities to a hybrid market, incorporating both UOG and merchant generation. The Energy Crisis and the creation of the power exchange were also important developments. California created the California Independent System Operator (CAISO), which has managed the sale of electricity and the reliable operation of the grid including backstop mechanisms. The CAISO is currently developing the Market Redesign and Technology Upgrade (MRTU) for energy and Interim Capacity Procurement Mechanism (ICPM) for short term capacity need during the transition period to a final stable energy market.

MRTU

The sale of energy in California is being transitioned to MRTU effective March 31, 2008. MRTU incorporates significant changes in the way energy is bought and sold in California, including raising of the caps on energy and the introduction of nodal pricing to enable Locational Marginal Pricing (LMP), in recognition of the fact that certain constraints are more likely to be addressed by the market when the market can see variable prices for energy. Under MRTU, CAISO system wide energy price caps will rise from $350/MWh to $1000/MWh.

Backstop

The Reliability Capacity Service Tariff (RCST), the CAISO's current primary backstop mechanism, is set to expire on Jan 1, 2008. While a replacement backstop mechanism is still in the development stages, whatever backstop mechanism that comes to fruition potentially impacts the capacity market addressed in this report. Additional details on ICPM, which is intended to temporarily replace RCST, are expected in the coming months.

Obtaining New Resources

The current CPUC program has several methods that ensure new resources are added to the system. For example, some programs, such as parts of the Energy Efficiency and DR programs, are established in IOU tariffs. The California Solar Initiative provides subsidies to reduce the customer's payback period for new distributed solar installations. The RPS requires IOUs to enter contracts to procure renewable energy. The renewable program's focus is on new renewable resources, but it results in additions to system capacity.

The Commission's LTPP requires the three major IOUs to file ten year plans, updated every two years, to meet forecast load while complying with Commission policy goals. Through the LTPP, the CPUC authorizes the IOUs to build or buy new generation capacity for the system, allocating costs to all benefiting load. Further, the CPUC can specify the characteristics of new generation procured through the LTPP process to meet local capacity needs or AS requirements. In addition, the existence of the current energy and capacity markets, and/or the hope of future markets, has resulted in the construction of a limited number of new resources without IOU contracts. Some of these units are existing turbines moved from other locations, some are experimental plants trying new technologies in the California environment, and others are merchants, mostly small, taking advantage of a local resource or situation.

The Current CPUC Resource Adequacy Requirement

California's current RA program is based on a year ahead and month-ahead showing of compliance with a Resource Adequacy Requirement (RAR) by all CPUC jurisdictional LSEs. The CEC forecasts peak demand by month for each utility service area, as well as for each LSE for each month. Adjustments are made to each LSE forecast to account for plausible customer retention and coincidence. The LSEs are then required to demonstrate that they have procured sufficient capacity to meet their forecasted loads plus a Planning Reserve Margin (PRM) one a year ahead for the next summer, and then each month during the year. They do this by filing Advice Letters with the CPUC. The LSEs procure capacity resources from unit specific resources within the CAISO and imports into the CAISO that are both unit specific and non-unit specific. Liquidated Damages contracts are currently counted as RA with restrictions until 2009, and the Department of Water Resources contracts are counted for their life. There is also a Local RA obligation based on a deterministic analysis of transmission and generation contingencies within certain transmission constrained Local Areas. The analysis to determine Local RA obligations is performed annually by the CAISO.

There are 15 LSEs (3 IOUs and 12 ESPs) that each file 14 times each year, resulting in 210 filings annually. The CPUC, CAISO, and CEC perform allocations of capacity from DR and Reliability Must Run (RMR) resources, as well as conduct an allocation process for Import Capacity into the CAISO and across the internal Path 26. These three agencies also review the filings each month for compliance; the CEC reviews the LSE projections of customer retention and load migration, the CAISO receives and compiles generator supply plans, and the CPUC reviews resources procured versus supply plans and validates all other types of resources. The CPUC then notifies each LSE of acceptance or rejection of each filing.

The current program bases annual one year-ahead RA obligations on an annual forecast of peak demand conditions as well as Local RA needs, and requires compliance showings from one month to nine months ahead of time. An assessment of system needs occurs annually, including Local RA obligations. This is done in a transparent and cooperative process. Resources are revalidated annually, and the Net Qualifying Capacity (NQC) is held constant throughout the year. Credit for capacity from DR, RMR, and resources subject to the energy auction are performed annually, with quarterly true ups to account for load migration. The interaction between the agencies and between the agencies and the LSEs has created a cooperative atmosphere where continual development of the RA program is accomplished via stakeholder processes.

The current program is a one year-ahead program, and for that reason some parties have contended that the current program does not encourage resource planning and provide visibility into the future. Since it is a bilateral market it does not provide price and contracting transparency to the market. Since there are a number of agencies involved and compliance is done individually, administrative efficiency is a possible area for improvement both for each LSE and for the agencies involved in compliance review. On the other hand, the current program has provided for LSE based procurement that is overseen by the CPUC. The program has allowed for the participation of DR and RPS resources, as well as provided a vehicle for the CPUC to retain effective oversight of IOU procurement policies.

Assessment of System and Local Needs and PRM

Under the current program, the PRM is meant to cover projected load with some uncertainty, the impact of limited forced outages, and an operating reserve requirement. It is currently set by the CPUC at between 15 and 17 percent above peak load implemented beginning in 2006 adopted in D.04-10-035. There is the need under the current program to enhance the ability of the CPUC to analyze and revisit the determination of the PRM, and to develop a more analytical method for its determination

Parties in the August 22nd workshop addressed the development of an analytical approach to the PRM by explaining some of the key parameters underlying a forward assessment of capacity and infrastructure needs. These needs are directly linked to the timeframe under study, but the definition of proper study methodologies can be done under alternate market structures. All proposals for market structure rely on the CPUC to set the overall RA obligation for California by assessing the system and local needs within California and set a PRM to maintain overall system reliability, and for that reason the forward assessment of system conditions and needs that feed determination of the PRM can be completed outside of the debate concerning market structure. After the workshops Administrative Law Judge Mark Wetzel ruled that the PRM would be addressed in greater detail subsequent to the release of this report. With that change in schedule in mind, this report does not delve significantly into the subject beyond this background section.

Price and Contracting Transparency

The current RA program lacks a clear method of communicating prices and transactions to the larger market. Parties have expressed that price transparency is potentially useful for two reasons – to indicate locational and operational needs for forward investment and to indicate liquidity in the current market and facilitate transactions by removing the problem of asymmetric information. The current bilateral approach does however allow for price discrimination between different resources that provide different types of services, and between old and new resources for purposes of avoiding windfalls to current generators while also building new generation. This section seeks to discuss this issue in the context of the current program.

Parties have made the argument that with a more robust price signal, investors will know where to invest and how to guarantee returns. Parties have argued that if this price signal is to be the primary investment vehicle, then the price signal needs to be able to provide investment to promote reliability in the longer term as well as the immediate term. For this reason, there is a differentiation between a longer term price signal and shorter term price signal. Short term price capacity or energy price signals, if transparently given to the market, are in indication of immediate term scarcity. This is an indication of a problem that is delivered too late to be acted on by new entrants into the market. With a short term commitment and short term price signals, a developer will have no certainty that five years from now, when their development may be online, the price will still remain high enough to give a reasonable recovery of investment. In other words, the market needs to know not that there is scarcity today, but that there will be scarcity four years from now.

The current RA program does not provide resource commitment far enough in the future that new resources debating construction are able to make commitments, but this is not to say that the current program fails to deliver price signals; rather the current program does not contain a multi year requirement. The current bilateral approach and the centralized approach can both provide the multi year commitment horizons, even if the current approach does not currently provide the price signals and transparency that parties suggest in comments.

Short term price signals play a different role however in that they could increase the liquidity in the present market, and provide a means for LSEs to comply with the current RA program. LSEs and generator owners both currently encounter the possibility of asymmetric information. This could lead to inefficient procurement, both since it takes more time to locate buyers and sellers, and because buyers and sellers in some situations are unable to benchmark their bids against others. Unbalanced information between buyers and sellers exacerbates monopsony or monopoly power, where LSEs all have to go to one generator and do not know what prices other LSEs are agreeing to, or that some larger LSEs are able to take bids from a number of generators when the generators do not know what each other generator is bidding. It is very difficult to know what a reasonable bid would be for capacity to sell or buy, and if there is a general price differential between Local RA or System RA capacity, or between capacity in different Local Areas. It is compounded by the inclusion of RPS and energy attributes in a contract.

There are remedies for this problem specifically discussed in each of the market proposals, and remediation of this problem is in some senses independent of market structure. Prominent among suggested remedies is the creation of a bulletin board application that provides a public opportunity for interested parties to list capacity for sale and interest in purchasing capacity. Additional brokering and clearing functions could be added as well. If the current short term RA requirement were to evolve into a multi year requirement, this solution would need to be strengthened with additional features such as a clearing or credit mechanism. SCE presented a proposal to develop this sort of application at the August 28th workshop, and the workshop participants discussed the particulars of an application briefly. Parties have contended that the development of a centralized listing of buyers and sellers is essential for the maintenance of the current bilateral market, but it is also a first step towards a centralized market. Staff suggests that stakeholders convene a process to develop such an application.

Administrative Obligations

The current program imposes administrative obligations on both the LSEs and the agencies administering the program including the CEC and CAISO as well as the Energy Division. The incremental burden on the agencies involved related to the RA Program is hard to quantify, but a survey of the agency personnel administering the program finds that the agencies dedicate a substantial amount of time and resources to the program each month. The administrative obligations faced by the LSEs are unique to the LSE and type of contracting the LSE has with generators and customers. Energy Division lacks the data required to summarize the LSE burden here, so LSEs as well as other parties are encouraged as part of their comments on this report to include a breakdown of the administrative obligations they face derived from this program.

The burdens relating to the various agencies are different and unique to the roles the agencies play in the program; under the recently adopted capacity allocation mechanism in D.07-09-044 the Energy Division will be allocating capacity credit to LSEs at least quarterly and monthly in the future, in addition to the current reallocations upon change in condition of RMR contracts and the Local RA and DR allocations that are done annually. The Energy Division receives 210 Advice Letters each year, including 12 monthly filings for each of 15 LSEs, as well as the Preliminary and Final System and Local RA Filings. As knowledge in the market has increased, time and work requirements have decreased. However with the possible reopening of the DA market as well as the inclusion of the small and multi-jurisdictional LSEs in the RA program, there is the possibility of a growth in that burden as the Energy Division would need to educate new LSEs upon entrance into the program.

The CAISO receives annual and monthly supply plans from each generator under RA obligations pursuant to the CAISO Tariff Section 40. This includes all generators that are supplying RA capacity to CPUC jurisdictional LSEs as well as other generators supplying RA capacity to other LSEs within the CAISO. They also compile and issue the NQC list annually, and handle updates to account for data correction and new units coming online. In addition, the CAISO administers the annual import allocation process to allocate transfer capacity on interties.

The CEC reviews each individual LSE load forecast, and adjusts for the impacts of DR, EE, and coincidence. The CEC also adjusts forecasts for plausibility and manages monthly adjustments to account for the impacts of load migration.

Regardless of a decision regarding market structure, the current RA Program will likely continue with minor changes until the 2010 or 2011 compliance year, so the Energy Division is developing new methods and procedures to expedite processing and review of the RA Filings.

LSE-Based Procurement

The RA program has effectively maintained LSE compliance through the first two years of monthly filings and three years of year-ahead filings. This is accomplished by working with the LSEs and other stakeholders in a cooperative manner to establish and explain the rules of the current RA program, evaluating the filings completely in a timely manner, and effectively enforcing the rules when needed. Related to this is the cooperative relationship developed between agency staff and the LSEs, generators, and stakeholders. Compliance has been successful, as summarized for 2006 in the 2006 RA Report, and Energy Division has seen the same pattern of compliance in 2007. So far there has been only one enforcement case that has been settled, as well as five citations issued. In total, the settlement totaled $107,500 and the citations totaled $9,500[6].

This overall compliance and underlying cooperative relationship between agencies, and between agencies and LSEs, is a difficult to quantify factor that Energy Division staff view as a success of the current RA program.

Multiyear Resource Adequacy Obligation

A critical component of the current system is the IOUs' Long Term Procurement Plans. Every two years each IOU evaluates the resource needs in their service areas for the next ten year, using the CEC load forecasts as a guide. The primary focus of the long term procurement plans is to ensure that preferred resources, such as energy efficiency and renewables, are being used to their potential, but the remainder in the analysis is a residual need that is filled by traditional generation. Through a formal Commission proceeding the IOUs are authorized to contract for new generation to meet the residual need. IOUs that contract for the construction of new utility owned generation, or built it themselves, assign the costs to their customers. If the IOU contracts for a merchant generator to build the new plant, a Commission program allows, under certain conditions, for the costs of these contracts to be shared with all benefiting customers.

The strength of the current system is its use of the CEC Integrated Energy Policy Report process to evaluate system needs and plan ten years out. The weakness is the lack of clear price signals and market incentives to indicate appropriate investment. To the extent that IOUs are contracting for most or all new generation, the incentives of other LSEs and independent developers to invest in the new resources may be reduced. In addition, to the extent that other LSEs or developers plan to invest, those plans may not be coordinated with the IOUs long term procurement plans.

Summary of Phase Two, Track Two

While the Commission's RA program dates to early 2004, track two of phase two of the R.05-12-013 proceeding was created in the scoping ruling of March, 2006 and for purposes of this report did not begin in earnest until early 2007. The bulk of this report deals with the RA proposals put forth between March and August, 2007 as discussed in workshops during that time period, with particular focus on the workshops held during the second half of August (hereinafter "the August workshops").

This report is similarly informed by the 2006 RA Report written by Energy Division staff and formally released in March of 2007 and the August 2005 Capacity Market White Paper, both

[6] Citation and settlement amounts come from internal Energy Division staff records

of which represent initial positions of the Energy Division staff on the subjects addressed more completely in track two of phase two of the RA proceeding.

The schedule of Phase Two, Track Two of R.05-12-013 on a forward going basis is addressed in detail in the "Next Steps" section of this report. [p. 110]

Incorporation of Previous Reports

There have been two major reports related to RA programs at the CPUC that inform this report, the 2006 RA Report and 2005's Capacity Market White Paper, both prepared by the CPUC Energy Division staff. The 2006 RA Report (released in March, 2007) addresses Phase One and Phase Two, Track One issues related to current year compliance; in that regard it is outside the scope of this report. The Capacity Market White Paper is discussed below.

The 2005 Capacity Market White Paper

The Energy Division staff made eight recommendations on capacity markets in the 2005 Capacity Market White Paper. Those proposals were as follows:

Recommendation 1: Adopt a short-run capacity market approach with a downward sloping capacity-demand curve for the CAISO.

Recommendation 2: Further investigate alternative availability metrics (e.g. UCAP v. ISO-NE's proposed metric based on performance during shortage conditions) and ensure development of an availability metric that is applicable to hydro, wind, thermal and other generation technologies, and to appropriate demand response products.

Recommendation 3: Consider subtraction of peak energy rents from the capacity payment.

Recommendation 4: Adopt reasonable locational installed capacity requirements with locally varying demand curves.

Recommendation 5: Consider protecting against capacity exports during times of tight supply through the use of capacity prices that fluctuate seasonally.

Recommendation 7: Make the fixed-cost recovery curve explicit.

Recommendation 8: Strive for regulatory credibility.

This report revisits those recommendations in the context of the development of the record in R.05-12-013 and in particular the proposals before the Commission as discussed in the August workshops. While some of the recommendations are outside the scope of this report, the recommendations from the 2005 white paper serve as useful metric for key analysis of the proposals discussed below. In particular staff incorporates several of the recommendations from the 2005 Capacity Market White Paper in its recommendations on the proposals before the Commission in Phase Two, Track Two. The incorporated recommendations are addressed in greater detail below.

Summary of the CPUC Workshops and CAISO Stakeholder Meetings

The CPUC and the CAISO have collaborated to varying degrees on workshops and stakeholder meetings to inform this report as well as the respective proceedings at each organization. This section summarizes those meetings with the goal of both describing the process for informing this report and highlighting the key events in both venues.

CPUC Workshop Summary

The August workshops were held on the revised track two proposals as submitted on August 3, 2007. Workshops at the CPUC were held on August 15, 20-22, and 27-29. The agendas for the workshops are attached as appendix.

CAISO Stakeholder Meetings

In addition to the CPUC workshops, the CAISO held stakeholder meetings in Folsom or via telephone bridge during August 2007. The dates of those stakeholder meetings were August 13, August 15, August 20 – 23, and August 27-29, 2007. The CAISO's stakeholder process continued through October, resulting in the CAISO recommendation (included in pp. 83-96 of this report) on a CCM.

CAISO MSC Meeting

On October 1, 2007 the CAISO's Market Surveillance Committee (MSC) met at the CPUC to discuss the proposals before the CPUC and the Capacity Market proposals that the CAISO reviewed via their stakeholder process.

Goals

There are a variety of disparate goals which drive the participants in the RA proceeding. Parties include Generators, IOUs, POUs, ESPs, financial intermediaries, large and small consumers, governmental entities, grid operators, and consumer advocate organizations. Each party brings a unique set of goals to the proceedings and the proposals they put forth or their comments on the proposals of others reflect those perspectives. Similarly, regulatory entities such as the PUC, reliability organizations such as the CAISO and jurisdictional entities have unique perspectives on the proposals before the Commission in this proceeding. The CPUC's Energy Division staff views its obligation as including consideration of these various entities' goals in the formation of its recommendation, but ultimately its recommendations are made with the primary consideration to the laws that direct the CPUC's RA policy as well as the CPUC's governing decisions.

With regard to the subject of RA they generally fall into three categories – overarching state goals as codified in the governing legislation and policy pieces such as the Energy Action Plan (EAP), CPUC goals such as governing decisions and the scoping memo for the RA proceeding, and the CAISO's organizational goals related to grid operation. Also included in this section is a discussion on the metrics by which these goals can be measured.

Energy Division staff also recognizes the market and its participants have a certain temperament, and while maintaining the status quo solely for the purpose of maintaining the status quo is not the role of a regulator, neither is rocking the boat to see who falls out. Recognition of the interrelation of various elements of the current market is an important part of policy making, and consistent with that recognition, staff acknowledges that the health of the market may require recognition of factors beyond the directly assignable goals listed above. Put another way, staff has taken the perspective that attaining the optimal outcome of such a complicated subject cannot be done without broadly considering the market as a whole.

While goals are essential foundational elements to a policy recommendation, a list of goals does not a policy make. Based on the academic canon, real world examples of existing and past RA policies, party comments and replies, and the participation of a great many people in the workshops before this commission, staff has distilled these goals into metrics by which the proposals before the Commission can be effectively analyzed. Accordingly, this section includes a discussion on the metrics by which these goals can be measured.

State Goals

The state of California has certain goals for the energy industry, as well as environmental and economic goals, that often overlap. Since provision of energy is of such importance, it is impacted by a range of state policies. First, there are policies particular to the energy industry, such as reliable and affordable energy service, then there are the other state goals, such as environmental and consumer protection. The state has what is termed a hybrid market, wherein the generation of electricity is provided in a market based competitive fashion, and independent power producers or merchant generators compete with the large IOUs that have traditionally been under tight regulation. In tandem, the state encouraged competitive retail access, known as Direct Access (DA), where individual customers could choose their provider to get better rates and/or better environmental performance, among other reasons. This was suspended during the Energy Crisis, but parties filed a petition in December of 2006 to investigate reopening of DA. Community Choice Aggregation is also one of the energy related state policies.

The state passed AB 57 and AB 380 to ensure that IOUs planned for the purchase of sufficient energy resources to meet their projected demand and that all LSEs in California purchased sufficient capacity resources to meet projected peak load plus reasonable planning reserves. In addition, the state passed SB 1078 to create the RPS and recently passed AB 32 to create a program to eventually regulate all production of greenhouse gas (GHG) emissions in California. This will have special implications for the energy sector.

All these state goals as well as other goals outside of the energy sector create the framework within which the CPUC must develop a market structure. The market structure discussed in this report seeks to accommodate the full measure of California’s adopted policies; whatever is developed pursuant to this effort will also take time to implement, and the implementation of policy will also impact these goals.

AB 380 & Public Utilities Code §380

The state of California passed AB 380 in 2005 to require LSEs within the CPUC’s jurisdiction to procure sufficient capacity to meet their peak load plus reasonable planning reserves. AB 380 has become encoded into PU Code §380 and has been implemented by the CPUC through the CPUC's RA Program. AB 380 directed the CPUC to establish an RA Program that accomplishes the following:

(1) Facilitate development of new generating capacity and retention of existing generating capacity that is economic and needed.
(2) Equitably allocate the cost of generating capacity and prevent shifting of costs between customer classes.
(3) Minimize enforcement requirements and costs.

AB 380 specifically directs the Commission to consider a capacity market with input from the CAISO, a position reaffirmed by President Peevey in his March 25, 2007 Assigned Commissioner Ruling directing the creation of this report.

Other Legislation and the Public Utilities Code

In 2002, AB 57, as codified in PU Code §454.5 requires the PUC to adopt procurement plans for large electrical corporations, essentially the three major IOUs.

AB 1576, of 2005, as codified in PU Code §454.6 requires that repowering costs associated with a procurement plan are recoverable in rates.

In 2002, Senate Bill 1078 established the RPS program in PU Code §387, §390.1, and §399.25, requiring 20 percent renewable energy by 2017. In 2006, Senate Bill 107 codified, in §399, an accelerated deadline – 20 percent by 2010 – that had previously been established in the EAP I. The 2005 EAP II has examined a goal of 33 percent by 2020, but this goal has not been codified by the legislature.

Clean Water Act, Clean Air Act, and CEQA Review

The energy sector is directly and indirectly regulated by a panoply of state and federal agencies among them the State Department of Water Resources and the Air Resources Board. AB 32, which will regulate GHG emissions, is to be administered primarily by the Air Resources Board, for example. State and federal water agencies such as the State Department of Water Resources and the Bureau of Reclamation operate hydroelectric generating facilities in the state. Additionally, local jurisdictions regulate energy production via their Air Quality Management Districts. Siting of new generation is overseen by the California Energy Commission, siting of transmission lines is overseen by the CPUC, and generators must obtain air pollution permits and water pollution permits from the respective state agencies that implement the Clean Air Act and Clean Water Act respectively. Finally, the California Environmental Quality Act requires the state to undergo environmental review when debating the awarding of permits or construction of any new facilities.

Publicly Owned Utilities

There are still a number of POUs in the state which represent together approximately 22 percent of state electric load[7]; there are large ones such as the Los Angeles Department of Water

[7] November, 2007, California Energy Commission, *2007 Integrated Energy Policy Report*, Publication # CEC-100-2007-008, http://www.energy.ca.gov/2007_energypolicy/index.html

and Power (LADWP) and Sacramento Municipal Utility District (SMUD), but also a number of smaller ones such as Riverside and Gridley. Some smaller POUs are in the CAISO, but importantly LADWP and SMUD, Merced and Modesto are not within the CAISO. This means that whatever market structure is developed must be able to operate alongside alternative regulatory regimes. As the operator of the majority of the state's transmission infrastructure, the CAISO has a large hand in regulating the operation of the POUs, but the larger ones that are not in the CAISO also must coexist and operate within an increasingly integrated electricity market both in California and throughout WECC.

Energy Action Plan

As a result of SB 1389 enacted in 2002 the EAP I, a collaborative document created by the CPUC, the Consumer Power and Conservation Financing Authority (CPA), and the CEC, was first voted out in 2003. Subsequently, EAP II was voted out in 2005.

Law Minimizing Cost to Ratepayers

The CPUC has regulated the electricity industry for the State of California since 1911. Since that time the PUC and its predecessor entities have been directed by various pieces of legislation to minimize the cost of service to ratepayers, as described in Public Utilities Code §451 and 454.

Commission Goals

In addition to state law, the Commission's RA goals are guided by both the Public Utilities Code and a number of governing decisions. The Public Utilities Code that governs that most directly addresses RA is Public Utilities Code §380, addressed above in detail, but the overlap of a number of areas such as grid reliability, DR, Advanced Metering Infrastructure (AMI), and environmental goals as well as others that overlap tangentially.

R.05-12-013 and other Commission decisions directly related to RA

The comprehensive history of the PUC decisions that govern RA is beyond the scope of this report, but there are overarching elements which deserve mention. In addition to the RA proceeding[8] (R.05-12-013) the Commission also has open the ancillary LTPP Proceeding (R.06-02-013) to address related issues on a longer horizon than the current RA proceeding. The final decision in the 2006 LTPP was approved by the Commission on December 20, 2007.

Environmental Policies and Programs

In addition to the proceedings related to RA and LTPP the Commission has a number of open proceedings that impact or are impacted by the Phase Two issues in R.05-12-013. Two proceedings in particular, the RPS proceeding R.06-02-012 and the GHG proceeding R.06-04-009 directly relate to the procurement of resources and are potentially significantly interrelated with the RA proceeding.

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[8] R.05-12-013 is described in detail in the March, 2007, *2006 Resource Adequacy Report*, by Energy Division Staff, http://docs.cpuc.ca.gov/Published/REPORT/65960.htm

The RPS both directly and indirectly impacts the Commission's RA program as it relates to procurement of new generation for the IOUs and the state as a whole. New generation satisfying the RPS goals set forward in SB 1078 and SB 107 as implemented via R.01-10-024, R.04-04-003 and R.06-02-012 as well as Commission decisions, have varying levels of Qualifying Capacity (QC) and a complicated relationship to the existing and proposed RA programs. The specific role of new generation introduced specifically for meeting the RPS requirements varies depending on the RA program or proposal and the specific performance qualities of the generation on a unit by unit basis. Probably the most significant relationship between the RPS and the RA programs is to what extent new generation coming online to meet RPS obligations overlaps or eliminates the generation we would expect to come online via the RA program.

GHGs and the potential for a cap and trade system have the potential to be negatively impacted by capacity payments via both the existing and proposed RA programs. While the possibility exists that these programs will continue to function regardless of the RA program ultimately adopted, the costs and efficacy of the programs may be significantly impacted.

Advanced Metering Infrastructure

The Commission has invested heavily in AMI with the goal of enabling customers and utilities to efficiently manage their consumption. This efficient management includes the potential for both customers and utilities to respond to pricing signals and reliability needs. The three major electric IOUs have requested over $4.5 billion of AMI expenditures, approximately $2.4 billion of which has already been approved by the Commission in decisions including D. 06-07-027, D.07-07-042, and D.07-04-043. While price volatility itself can vary over time, the capability of AMI to enable response to it as well as system reliability needs, remains an important consideration for the Commission.

Direct Access

While DA was effectively suspended by AB 1X, the CPUC recognizes that those policies may be revisited in the future. Consistent with that possibility, RA programs must consider the implications for a DA-enabled market in the long term future of California. While LSEs currently serving customers may be uniquely positioned in the market for a variety of reasons, it is incumbent upon the CPUC to ensure that the market operates as efficiently as possible including both entry into and exit from the market by LSEs.

CAISO Goals

The CAISO believes that a long term RA framework must, in conjunction with the CAISO's core functions of providing a reliable transmission grid, non-discriminatory access to transmission service and efficient spot markets, serve the primary goal of providing electric service to CAISO control area consumers at the desired level of service reliability and at stable and reasonable prices.

In service to the above goal, the long term RA framework should be designed to (a) induce timely and efficient investment in new supply infrastructure (including DR and existing resource re-powering) to meet the needs of consumers within the CAISO control area, and (b) ensure sufficient and dependable availability of supply capacity on a day-to-day basis to support reliable operation of the transmission system.

In order to achieve those high-level goals, the CAISO supports the following specific objectives for the long term RA framework being developed in this proceeding.

1. The framework should provide for regular (yearly or at least biennially) multi-year forward assessments of capacity needs that contain sufficient information to guide RA procurement. Such assessments are needed irrespective of whether procurement is completely bilateral or conducted through a centralized process. They should include quantitative estimates of system-wide and local area needs and generator performance attributes (e.g., dispatchability, ramping, quick-start capability), and should be coordinated with transmission planning. The CAISO expects that it would collaborate with the CPUC and CEC in formulating such assessments.
2. The framework should provide for a multi-year forward review, or showing, of the capacity that is actually committed to serve CAISO control area needs for the target delivery year. The absence of a demonstration of actual capacity commitments would add unnecessary uncertainty to decision-making processes, both private and by central authorities, on the timing and optimal characteristics of investments in new infrastructure.
3. The framework should enable DR and imports to participate and compete effectively with internal generating resources to provide RA capacity.
4. The framework should provide for effective coordination with the transmission planning process.
5. The framework should provide well-defined criteria and mechanisms for supplementary RA procurement to backstop any shortfalls resulting from the primary (bilateral or central) RA procurement mechanisms. The criteria and mechanisms should be specified for different possible time frames in advance of the delivery period when backstop action might be needed and appropriate.
6. The framework should allow for effective market power mitigation, particularly with respect to capacity needed in constrained local areas of the grid where the threat of new entry may not be sufficiently feasible to ensure competitive prices.
7. The framework should be compatible with effective energy-hedging strategies by LSEs.

General Background and Theoretical Foundation

Capacity payments, as a mechanism for cost recovery and supply adequacy assurance, are an unusual component of the electric power industry. In most other industries, as capital intensive as they might be, suppliers assume investment risk and recover their cost and profits by selling the commodity or service at market based prices. The need for capacity remuneration in addition to payments for energy and reserve provision in the power industry is often rationalized on the grounds that electricity is a necessity and hence commodity prices must be controlled and supply adequacy must be ensured through regulatory intervention. It is also argued that reliability of supply which has public good characteristics similar to national security or fire protection is a distinct product from energy whose supply needs to be regulated and paid for through capacity remuneration.

The concept of capacity payments originated in the theory of marginal cost and peak load pricing of electricity in a regulated monopoly framework initially developed by the French economist Marcel Boiteaux in the 1950s. The basic idea is that consumption efficiency is achieved by pricing energy at marginal cost but such pricing will not recover investment cost. Hence, to achieve cost recovery with minimal distortion to consumption efficiency, a public utility should charge marginal cost for the energy and be remunerated separately for its capacity. Furthermore, the capacity cost should be recovered through a demand charge levied on peak loads which determine the capacity needs in the system. Further development in peak load pricing theory recognized that capacity contributes to reliability even during off-peak periods and introduced more sophisticated methods for allocating capacity cost based on loss of load probability (LOLP) and the value of lost load (VOLL).

On the supply side, total capacity in the system is optimal when the expected VOLL equals the incremental amortized cost of peaking capacity, usually a combustion turbine (CT). In other words; amortized cost of one MW CT per hour = VOLL per MWh * LOLP. Furthermore, the capacity mix is optimal when the difference in energy cost per MWh between any two adjacent technologies in the merit order exactly equals the difference between the amortized capacity costs (per MW per hour) of the two technologies. When the system is at its optimum in terms of total capacity and technology mix, and it is optimally dispatched (transmission constraints not withstanding) then paying for all the energy produced at each point in time at the marginal cost of the most expensive unit dispatched at that time will result in a revenue shortfall for all units which is exactly equal to the capacity cost of the peaking unit (i.e. the CT). This theoretical result underlines the idea that in an optimally configured system with energy remunerated at marginal system cost, all generators should receive a capacity payment supplement that equals the capacity cost of a peaking unit. The reason that all units should receive the same capacity payment that is based on the cost of a peaking unit is that the inframarginal energy revenues of shoulder and base load units which are paid marginal system cost (although their operating costs are lower), exactly covers the shortfall between the capacity payment they receive and their own capacity cost.

It is important to observe that the above calculation is based on the Cost of New Entry (CONE) for the respective technologies and does not account for the fact that some existing plants might have been depreciated or partially paid for through the rate base. The above calculation also assumes that if fuel cost changes then the technology mix will adjust within a short time period so as to track the relative fuel costs. For instance, if the price of natural gas rises then the capacity of CTs should go down (or the growth rate in CT capacity should decline) and the capacity of combined cycle gas turbines and base load technologies should increase. While the adjustment takes place shoulder and base load units that are paid during peak load periods marginal system cost base on the increased gas price will experience windfall profits. In theory such profits should attract new capacity in these technologies which will eventually reduce the number of hours during which the peaking units are setting the price and erode these windfall profits as the capacity mix gets back into equilibrium. In reality, however, capacity mix in the electric power industry adjusts very slowly as compared to the rapid changes in fuel costs. While such adjustment takes place windfall profits that accrue to existing generators represent a transfer from consumers to producers. Furthermore, in a deregulated system there is no assurance that such profits will be directed toward new investment that will expand needed new capacity.

The shorter construction time and lower risk tend to favor buildup of peaking units which may exacerbate the wealth transfer problem. These considerations support, to some degree, those who advocate differentiation in capacity remuneration between existing and new capacity or, alternatively, imposing some mechanisms such as cumulative caps (implemented in Texas) or PER adjustments (implemented in New England) that attempt to limit wealth transfers from consumers to producers.

The framework discussed above where generators receive energy payments based on marginal system cost plus capacity payments based on the CONE of peaking capacity has been implemented in several South American countries such as Chile and Peru, and in South Korea where the wholesale energy market is organized as a cost based power pool with generators required to submit cost based offers for energy. Capacity payments are also implemented in Italy, Spain and Argentina where energy prices are market based. A major criticism of such an approach is that when energy is priced at marginal cost or prices are suppressed by a capacity payment, there is no incentive for DR unless a mechanism is in place (e.g., interruptible service contract) that will allow demand side resources to avoid capacity payments. Consequently, such systems result in excess capacity. In some cases, such as in Argentina, capacity payments have become the primary source of income for generators who offer energy below marginal cost in order to qualify for the lucrative capacity payments. Another criticism of the capacity payment approach has been that it institutionalizes a payoff to existing generator but does very little to induce new investment in generation capacity.

An alternative approach to paying generators for capacity is to allow scarcity pricing that reflects the VOLL during shortage periods. If total capacity meets the optimality criteria mentioned above, then LOLP will equal the CONE of a peaking unit divided by the VOLL. If we use a one day in ten year criteria and assume CONE to be about $72,000 per MW-year, the implied VOLL is $30,000 per MWh. In this simple example the system will be short 2.4 hours per year. Allowing the wholesale price to rise to VOLL (i.e., $30,000 per MWh) during the shortage period will produce the same revenue for a generator as a capacity payment of $72,000 per MW-year. An advantage of the scarcity pricing approach is that generators must be operating at full capacity during the shortage period to collect the full payment. Furthermore, consumers exposed to such scarcity prices will have a strong incentive to curtail load and participate in DR programs, thus reducing capacity requirements and total cost of electricity. To the extent that parties are hedged through bilateral contracts, scarcity prices should be reflected in the bilateral prices, resulting in the same annual income to generators. In reality one would expect that demand will respond to prices much below $30,000 per MWh and such response would significantly mitigate the scarcity prices. Taking such response into consideration in setting the capacity targets will result in reduced capacity and more hours during which DR rather then marginal generation cost sets the price.

In Texas' energy only market an energy price cap of $3,000 per MWh is sufficient to allow accrual of sufficient scarcity rents to generators to cover their capacity costs. Similarly MISO allows scarcity prices for energy to rise to $3,500 per MWh (consisting of $1,000 per MWh for energy and $2,500 per MWh as a reserve shortage adder) while in Australia energy prices can rise to $8,000 per MWh.

The prevalence of market power and inelastic demand has motivated price caps and market mitigation procedures in many US electricity markets that are at odds with the possibility of an energy only market approach where scarcity pricing may provide an adequate mechanism for capacity cost recovery. Suppression of scarcity prices through market mitigation, along with further price suppression due to reliability motivated out of market procurement of resources by the ISO's, has resulted in what has become known as the missing money problem. In, other words energy revenues are not sufficient to cover the investment costs of a new entrant and often the fixed cost of existing generation plants, thus, endangering supply adequacy and system reliability. CCMs which are unique to the US have aimed over the past decade to remedy the missing money problem but have had limited success so far in solving the real problem of incentivizing new generation investment.

The idea of capacity markets originates in the North Eastern pre-restructuring power pools. In those power pools utilities were penalized if their generation capacity fell short of the peak load they were serving. The New England Electricity Pool (NEEPOOL), for instance had a $75 per kW annual penalty for capacity shortage relative to a weighted quantity based on the annual peak and the average monthly peak. To avoid such penalties utilities in NEEPOOL recruited interruptible customers whose interruptible load could be counted toward their capacity obligations. Subsequently members became involved in daily bilateral trading of capacity among themselves so that utilities that were short would effectively lease, on a daily basis, capacity from other utilities that had excess. Similar situations existed in the New York Pool and in PJM. The penalty systems and bilateral arrangement among utilities were intended primarily to provide some accountability that would assure sufficient resources in the system and reduce free riding among utilities. They were not designed to incent new investment in a competitive market setting.

When the Eastern pools were transformed into competitive wholesale markets run by ISOs, they established centralized installed capacity (ICAP) markets as a natural evolution of the capacity credits systems and bilateral trading of capacity under the pool regimes. Since consumers are only interested in energy and do not care about capacity, ICAP markets were based on trading an artificial product for which the demand is set administratively by holding LSEs accountable for enough capacity to match their peak load and a reserve margin. This approach preserved the power pool capacity accounting system with a deficiency penalty but supplemented the bilateral trading of capacity with a centralized auction that allowed supply and demand of installed capacity to determine the actual deficiency payment by those who are short to those who have excess. However, as discussed below, the ICAP markets failed miserably, triggering a series of reforms that are still regarded as work in progress. The failure was attributed to what has become known as bipolar prices in the capacity market due to the fact that within a short time period (a day or month) both the demand and supply of capacity are fixed. Thus, if the overall system is short of capacity ICAP prices will rise to the shortage penalty while if there is excess the price of ICAP will fall to zero. Furthermore, if some suppliers of capacity have market power and physical withholding is possible then the ICAP price can be maintained at the shortage penalty rendering the ICAP market moot.

Debates continue over whether capacity mechanisms separate from energy markets are needed in restructured electricity markets, whether such capacity markets need to be centralized, and if so how they should be designed. The academic and policy advocacy papers written on the subject, to say nothing of the regulatory and legal proceedings on the subject, are too numerous to list in this report. Proponents of capacity mechanisms argue that given the technical, political and social realities of electricity markets, energy markets need to be supplemented by some capacity mechanism that will ensure generation adequacy. The primary objective of such mechanisms is to create sufficient incentives for efficient levels of investment. In most cases, however, this goal is interpreted as inducing investment in generation that will meet prescribed reliability criteria based on technical rather than economic considerations. Stabilization of generators' income stream is also often viewed as a means toward achieving the efficient investment objective. The debate is by no means resolved, especially given the lack of evidence that capacity mechanisms have accomplished their stated goals and the perception that such mechanisms are merely a wealth transfer device from consumers to generators.

Currently there are three prevailing general approaches to assuring generation adequacy:

1) Adequacy mechanisms based on capacity products which takes two forms:
   a) Capacity payments to installed or operational capacity
   b) Capacity obligations imposed on LSEs which can be met in several ways:
      i) Bilateral contracting with regulatory verification
      ii) Centralized capacity market
      iii) Combinations of bilateral contracting with bulletin board trading of standardized contracts or a central capacity market
2) Energy only markets with limited mitigation (e.g. high offer cap) that rely on energy remuneration and scarcity pricing to guide investment
3) Central resource procurement that can take the form of:
   a) Competitive tendering through a Centralized Request for Offers
   b) Strategic reserve contracts between the ISO and the critical resources

In the following sections we review some specific instances of the first two approaches in the US and abroad. The competitive tendering approach common in some European countries (e.g. France and Germany) is similar to the long term procurement method used in California but there is no experience to asses its success. The Strategic reserves approach on the other hand which is common in Nord Pool, is incompatible with FERC restructuring policies since it effectively puts the system operator in a position of a market maker with discretion to affect market prices by dispatching resources it procures through long term contracts (in Finland the ISO is even allowed to own peaking units).

Capacity Obligation and Capacity Markets

Evolution of the early capacity markets in The North Eastern US markets

The PJM installed capacity market was the first of its type to become operational in 1999. Capacity owners were under obligation to offer their capacity at a given price ($/MW month). There was no distinction between old and new capacity and owners would be penalized if they could not meet certain performance standards. The ICAP payment did not take into account location or operational characteristics of a resource. The approach proved inadequate for assuring RA, as noted by FERC in its 2004 staff report. The PJM ICAP market suffered from several shortcomings that also emerged in the initial ICAP markets in New England and NYISO.

One deficiency was the characteristic bipolar price pattern mentioned above which PJM has attempted to rectify by gradually increasing the product duration. The first incarnation of an ICAP market was based on a daily product. This design de facto restricted participation to existing generators and left no room for participation by new entrants. The high price volatility and eventual collapse of the daily ICAP market at PJM led to the development of a more sustainable monthly capacity market and to a proposed seasonal obligation. Similar moves toward capacity products with longer duration have been implemented at ISO-NE and NYISO.

Another typical problem with the PJM ICAP market was deliverability of the installed capacity. In New England which faced a similar problem, new quick response units were built in Maine near the gas sources but energy from these resources could not be delivered to the Connecticut load center due to transmission constraints. Leaky performance standards have been another pervasive problem in ICAP markets. While generators that sold ICAP to a local LSE at PJM were subject to recall of energy sold for export, there was a loophole in the system that allowed generators to delist their capacity at PJM with a two day notice making it no longer available for recall. The penalty for such delisting was sufficiently low to make it economically attractive whenever exporting energy was lucrative. Finally, lack of contestability by new generation due to the short duration of the traded capacity product made it possible for existing generators to exercise market power in the capacity market in shortage situations. The reforms extending the duration of ICAP obligations did not go far enough in terms of creating capacity obligations that could enable response by new planned investments when ICAP prices increased due to capacity shortage.

The deficiencies in existing ICAP markets and problems arising from incompatibilities in these markets prompted the commissioning of a study to develop a proposal for a single integrated capacity market for PJM, ISO-NE and NYISO. The NERA 2003 report recognized the need for a forward looking capacity obligation to ensure adequate investment and proposed a Central Resource Adequacy Market (CRAM) for the three ISOs. While the CRAM proposal has been eventually shelved for a variety of reasons it laid out the foundation for the Reliability Pricing Model (RPM) adopted by PJM and for the Forward Capacity market (FCM) adopted by ISO-NE. The NERA report proposed that LSEs be subject to a capacity obligation with sufficient lead time for planning and construction of new capacity. According to the CRAM proposal "the ISO would determine the resource needs in advance of the planning period, would hold a central procurement through an auction, would pay the auction price to all resources provided during the period and would recover the cost from load during the performance period. The difficulties arising from uncertainty with respect to load obligations several years in the future would be eliminated and all LSEs would face a common charge for RA that would be passed on to consumers and would be competitively neutral at the retail level. Consumers will receive the benefits of adequacy and pay the cost of adequacy"[9]. A key aspect of the proposed scheme was that: "The planning horizon must be sufficiently long to enable the CRAM to be the deciding factor in the decision to construct. ……Only when the pool of competitors is expected to include entrants can the market power concerns be adequately addressed. Particularly, this means that a three year planning horizon is the minimum."[10] The proposal also recommended a commitment

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9 NERA "Central Resource Adequacy Market Report for PJM, NY-ISO, and NE-ISO" 2003, p.2

10 *Idem*, p.3

period from one to three years with preference for longer duration for new entrants to reduce generators' uncertainty and hence reduce risk premiums in their cost of capital. The CRAM proposal also recommended the use of a vertical demand function on the ground that new entry will provide the needed elasticity on the supply side to prevent the bipolar pricing phenomenon that was prevalent in short term capacity markets that excluded new entrants.

Current Capacity Markets

While there are a variety of capacity markets inside the United States, Energy Division staff considered capacity mechanisms outside of the United States as well during the formulation of this report. This section focuses on current capacity markets inside the United States, while more information regarding capacity mechanisms outside the United States is available in Appendix 2.

The ISO-NE Forward Capacity Market

The New England ICAP market has experienced bipolar pricing of its capacity deficiency auction like other ICAP markets. Prices were fluctuating between zero and the capacity deficiency penalty, but eventually collapsed down to zero after February 2004 due to system-wide excess capacity. The combination of suppressed energy prices due to market mitigation and out of market, reliability motivated actions by the ISO, and the low ICAP prices resulted in insufficient income to generators to sustain existing capacity and induce new investment in needed generation. Furthermore, because the capacity market in New England did not account for transmission constraints, system-wide excess capacity in the ISO-NE territory has masked local deficiency of capacity in congested areas such as Boston.

The reform of the capacity market in New England aimed at addressing the missing money problem for existing generators and induce new needed investment had a false start. The first design of a short term locational ICAP market, known as LICAP followed the New York demand function model with some minor modifications. Like the New York model LICAP used an administrative demand function capped at twice the CONE for a CT. The LICAP demand function consisted of two linear segments anchored at three points so that the price decreased from 2 times CONE at the minimum requirement to CONE at 104 percent of the minimum requirement and down to zero at 118 percent of the minimum requirement. These parameters could vary by location and were set through a stakeholder negotiation process.

In addition the LICAP design introduced the concept of PER whereby the LICAP clearing price was to be adjusted ex post on an annual basis by subtracting the inframarginal energy revenues per MW per year realized by a CT used as a benchmark. The ex-post PER adjustment provided a means for a true-up of the capacity payment to the actual missing money as well as an added instrument for deterring the exercise of market power in the energy market. Performance incentives were determined by a pro rata calculation of the capacity payments based on availability during a predetermined set of days when generation capacity is scarce. Eventually the LICAP proposal was scrapped due to strong opposition from different advocacy groups who objected to the projected mass wealth transfer from consumers to generator with no assurance of resolving the generation adequacy problem. The opposition to LICAP was supported by a strong lobby in the U.S. Congress and governors in five out of six states in the ISO-NE jurisdiction.

The FCM design emerged from the ashes of the failed LICAP proposal as a stakeholder compromise settlement. The FCM design adopted key features of the CRAM proposal that emphasized the participation of new entrants in the FCM and salvaged some of the attractive features of the LICAP proposal such as locational valuation of capacity, PER adjustments and performance penalties based on availability during critical hours.

The main elements of the FCM are as follows:

Three-year planning period.

The auction takes place about 42 months before the commitment period begins. However, to limit the length of the transition period the first auction will be held in the first-quarter of 2008 for delivery in June 2010. Subsequent auctions will gradually reach the 42-month commitment period. There is a one-year commitment period for existing capacity and up to five-year commitment period for new capacity.

Existing capacity participates in the auction each year and has a one-year commitment. New capacity can choose at the time of qualification a commitment period between one and five years. The price paid to new capacity with multiple year commitment after the first year is indexed. Both new and existing capacities are paid the same market-clearing price in the first year, provided there is sufficient competition and adequate supply. Capacity may be provided by both demand and supply resources.

Descending-clock auction.

A simultaneous descending-clock auction is used to determine the market clearing prices and the capacity suppliers for each zone. The descending-clock auction is an iterative auction procedure in which the auction manager announces prices, one for each of the locational products being procured. The bidders then indicate the quantities of each product they wish to supply at the current prices. Prices for products with excess supply then decrease, and the bidders again express quantities at the new prices. This process is repeated until, for each product, supply equals demand. A starting price for the auction specified before the auction begins is two times the CONE where CONE = $7.50/kW-month in the initial auction.

Capacity requirements and transfer limits.

Before the auction, the ISO determines for the first year of the commitment period the minimum capacity required in each zone and in the system, as well as the transfer limits between zones. The ISO determines zones before the auction based on an identification of transmission limits that may bind in the auction. Before the start of each auction, the capacities installed in a zone, less retirement and export bids, will be compared to the zone's local sourcing requirement in the first year of the commitment period. For an import-constrained zone, if the capacity in the zone is greater than its local sourcing requirement, the zone will not be a separate zone in the auction. Export constrained zones are modeled in the auction.

Qualification process.

Before the auction, potential bidders submit a predefined package of qualification materials to the ISO. Each bidder specifies the location and capacity of its existing resources.

Each bidder also specifies the location and capacity of its potential projects that could be completed by the beginning of the commitment period. This is the capacity that the bidder offers at the starting price. The qualification includes satisfying credit as well as other terms. The qualification deadline for existing capacity is approximately six weeks before the deadline for new capacity.

Reconfiguration auction.

Annual reconfiguration double auctions will be conducted to allow minor quantity adjustments due to changes in ISO forecasts, cancellation of new generation projects, de-listing (temporary and permanent), and to facilitate the trading of commitments made in the initial auction.

Obligation and settlement.

Listed unit have a must offer obligation in the day ahead energy market at prices subject to market mitigation rules and will receive the monthly capacity payment at the time of performance. The capacity payments will be recovered from the LSEs on a load share basis at the time of performance. During the transition period, until the first performance month covered by the FCM, generators will receive a fixed capacity payment starting at $3.05 per kW-Month and rising to $4.20 per kW-month.

Peak Energy Rents Adjustment and non performance penalties.

The monthly capacity payments at performance time will be decreased by a PER adjustment calculated based on the net energy profits of a generic peaking unit with a 22,000 heat rate, averaged over the preceding 12 month period. The PER deduction in any month is capped to two month worth of capacity payments and the annual PER deduction is capped at the annual capacity payment. Performance penalties are based on availability during a predestinated number of critical hours. Unavailability during these critical hours will be penalized by proportional reduction in the net capacity payment (after PER adjustment).

Demand side resources.

Demand resources will be prequalified for the FCM auction by derating them to account for expected availability. Their rating will be adjusted in subsequent years based on performance record. In addition demand resources are grossed up by 20 percent to account for avoided reserves and distribution losses. The prior derating of demand side resources is viewed as a prepaid performance penalties and hence they are not subject to performance penalties due to unavailability during critical hours, nor to PER deduction.

Self provision.

LSE can self-provide all or part of their capacity obligation by contracting forward with existing and new generation and with demand side capacity resource and submitting price taking offers into the FCM for their self-provided capacity, which de facto reduces the Installed Capacity Requirement (ICR). Self-provided capacity is not subject to PER adjustment but is subject to performance penalties like any other capacity resource. In other words, in case that capacity self-provided by an LSE is not available during critical hours, the LSE is liable for the capacity payment corresponding to the unavailable portion of the obligation.

Market power mitigation.

Market power on the supply side is mitigated by capping the FCM price at 2 times CONE and by enabling contestability by new entrants. Furthermore to address market power by existing suppliers, a quantity rule shifts some of the capacity purchased from the primary auction to a reconfiguration auction. In addition the Internal Market Monitoring Unit has broad authority to prevent physical withholding and market manipulation by scrutinizing Delist bids above 0.75 times CONE and combinations of Delist bids with new generation offers from the same entities. To mitigate market power on the buyers' side (monopsony power) new capacity that intends to bid below 0.75 times CONE must be submitted to the Internal Market Monitoring Unit before the bid qualification deadline to be considered in the Forward Capacity Assessment (FCA). If the Internal Market Monitoring Unit finds that the New Capacity bid is consistent with the unit's long run average costs (absent contractual considerations), then the bid can set the price. Otherwise, the New Capacity bid is entered into the FCA pursuant to the Alternative Price Rule which is designed to set a floor on capacity payments to existing generators. If an ISO Request for Proposals (RFP) covers any part of capacity costs, that capacity will be subject to the Alternative Price Rule.

Obligations of existing capacity and rules for delist bids.

At qualification, existing suppliers must enter all import/export, permanent delist, and delist bids that are above 0.8 times CONE. For transparency, these bids (price, quantity, and zone) are posted one day after the qualification bid deadline. If a unit's permanent pre-list bid is accepted in the auction, the unit is not eligible to receive capacity payments in this or any future commitment period. Permanent delist bids above 1.25 times CONE and de-list and export bids above 0.8 times CONE must be reviewed and qualified by the market monitor before they are entered into the FCA. Bids at qualification indicate the physical resource, the type of bid, the quantity, and the price.

The descending clock auction for the required new capacity recognizes bids from existing supply. The descending clock auction determines the clearing price paid to all capacity procured in the primary auction. Since the bids from existing supply are submitted at qualification, the quantity of new capacity required to reach the ICR is known as a function of price, recognizing any accepted bids from existing supply. De-list bids from existing supply at or below 0.8 times CONE can be directly entered into the descending clock. These bids do not require approval of the market monitor and are eligible to set the price. De-list bids at or below 0.8 times CONE may be rationed, if so designated by the supplier.

All Existing Capacity must submit appropriate information in the qualification process. All de-list bids above 0.8 times CONE from existing capacity, all Import/Export Bids, and all permanent de-list bids must be submitted to the ISO before the bid qualification deadline to be considered in the FCA. All permanent de-list bids above 1.25 times CONE and de-list bids from existing capacity, including exports, that are above 0.8 times CONE must also be submitted to the ISO's Market Monitor before the bid qualification deadline to be considered in the FCA.

The quantity, price and zone of each de-list bid including those above 0.8 times CONE will be posted one day after the qualification deadline; if approved by the Internal Market Monitoring Unit, full information will be posted. The state regulatory commissions will be provided confidential access to full information about posted de-list bids pursuant to the current Information Policy prior to monitoring review.

Obligations of new capacity.

All sellers of new capacity must submit appropriate information, designed to demonstrate that the project is viable, in the qualification process. The filing deadline for new capacity will be approximately six weeks after offers from existing capacity are posted. One hundred percent of the ICR, taking into account forecast error, as appropriate, not including permanent de-list bids and de-list bids, will be purchased in the FCA at prices up to 2 times CONE. The definition of new capacity will include appropriately eligible repowerings and reactivated reserves. New generation projects must post financial security starting with one month the capacity payment at the time of the initial auction and an additional month of capacity payment at the beginning of each of the two subsequent years before performance. In addition new generation projects will be subject to milestone verification by the ISO. In case of project cancellation the financial security will be forfeited. In case of delays in construction the holder of the new generation capacity contracts is liable for liquidation damage for the unsupplied energy and must replace its unfilled capacity obligation by procuring capacity from unlisted resources.

The PJM Reliability Pricing Model

The RPM design at PJM represents a stakeholder consensus that contains some of the key elements of the CRAM proposal but it includes a variable resource requirement feature (i.e., sloped demand function). The proposal was filed with FERC on August 31, 2005. RPM is based on an integrated resource planning model that looks four years out to determine generation resource needs in terms of location (up to 23 regions) and resource mix (the resource mix qualification was later eliminated). The needed resources are procured on a four year forward basis through a sealed bid uniform price (at each location) auction. The RPM accounts for existing and planned transmission and encompasses demand-side resources that can participate in the procurement auction.

The RPM auction features an administratively determined downward sloping demand curve that allows the procured quantity to vary with price. The use of a sloped demand curve has been rationalized on the ground that it reduces uncertainty of the capacity payment to generators and thus encourages more investment in generation capacity resulting in increased social welfare. However, this argument is debatable since it is based on the assumption that generation firms are risk averse while the benefits are measured in terms of expected social welfare gains. This scenario presumes that society as a whole and consumers in particular are risk neutral.

After the initial approval by FERC on April 20, 2006, the parties entered into four months of settlement discussion (ordered by FERC ALJ) that resulted in only slight modification to the original proposal. Specifically, the contracting lead time was reduced from four to three years and the demand function was shifted down so that it is capped at 1.5 the CONE which is estimated at $65,000/MW-Yr. The curve drops linearly from 1.5 times CONE at 98 percent of target capacity to 0.2 times CONE at 105 percent and then vertically down to zero. The RPM auction allows participation by DR and transmission alternatives, it allows an opt-out alternative for LSEs. Features such as seasonal pricing of capacity, operational price adders and load following requirements for portions of the capacity obligation, which were in the original proposal were eliminated.

The capacity contracts have an ex-ante PER adjustment feature that reduces capacity payments (at performance time) to account for excess energy rents, based on a six year moving average energy profits of a generic peaking unit. This deduction is capped at the capacity payment so that generators incur no down side risk (i.e., the capacity payment cannot be negative).

Performance incentives in the RPM are based on a system of peak-hour availability charges and credits that will induce generation resources to be available during stressed system conditions. The PJM tariff identifies 500 hours during the year that are potentially high load periods. The calculation of availability will be limited to the subset of these high load hours during which resources would have been economic to operate according to their cost-based offer price. Generators whose availability during these hours is less then their Equivalent Forced Outage Rate – Demand (EFORd) will have their capacity payment reduced proportionally (excluding unavailability for reasons outside management control). The peak hour incentives approach has the advantage of accommodating the needs of energy limited resources by allowing them to meet their capacity obligation while restricting their energy output to a limited number of peak hours. Gross capacity procurement is based on EFORd rating of offered capacity which is specified by the resource owners in the initial and first two incremental auctions. However, at the third incremental auction the EFORd rating of a resource is adjusted by PJM based on performance record. To prevent physical withholding through specification of excessive EFORd, existing resources cannot be offered at an EFORd higher then their actual EFORd over the last 12 months.

The RPM accounts for import supply by allowing resources located outside the PJM area to supply capacity into PJM if they have firm transmission service to PJM. In addition PJM takes account of the capacity assistance from other control area in determining its capacity requirement. However, the PJM capacity requirement is defined on an annual basis so it would not readily accommodate capacity available in other regions as a result of seasonal or other types of peak diversity.

Under the RPM, PJM contracts for capacity in the forward auction for an annual term, pays for the capacity during the delivery year and allocates the cost of this capacity to the LSE on a load share basis. By defining the obligation on an annual basis and allocating all the annual costs to LSEs on a daily basis, the RPM design avoids the potential for cost shifts arising from differences between daily, monthly or seasonal capacity prices or from load migration. LSEs can contract, however, forward for capacity outside the RPM forward auction and self provide their contracted capacity in the forward capacity auction to offset their obligation. In such a case they will incur higher or lower capacity cost reflecting their contracting choices. Because procurement is based on a down sloping demand function LSEs that fully cover their obligation (based on target capacity) through self-provision may still be liable for a prorate share of the cost associated with capacity procured in excess of the target under the demand function approach.

Market power mitigation in the forward capacity auction is dealt with in the RPM by enabling new entrants to compete with existing generation, by capping the forward capacity price at 1.5 times CONE and by PER adjustments to the capacity prices. In addition preliminary market structure screens are applied and offer prices are mitigated based on calculated avoided cost metrics and extensive provisions dealing with adjustments for required capital expenditures. With regard to buyer market power the RPM market rules contain provisions for minimum offer prices for new resources but these provisions appear to have limited practical significance given the ability of LSEs to self-provide their capacity obligation which is equivalent to offering that capacity at price zero.

The NYISO Demand Curve Model

In attempting to reduce the volatility of ICAP prices the NYISO was the first to introduce a variable resource requirement also known as the ICAP demand curve, in the New York capacity market. The demand curve was developed through a stakeholder process and went into effect in May 2003. Prior to introducing the demand function approach, the NYISO ran a semiannual auction for six-month capacity products and a monthly capacity auction for monthly capacity products for the remainder of the six-month capability period, as well as a centralized deficiency auction prior to each month.

Each LSE had to provide contracts to demonstrate to the NYISO that it was covering its capacity requirement for the upcoming month. Any shortfalls were covered through the centralized deficiency auction in which the NYISO bid for all the deficient capacity at a price equal to the deficiency penalty imposed on LSEs for each MW-month of capacity deficiency. LSEs exceeding their capacity obligation could offer their excess in the auction. The deficiency auction represented a vertical demand function where the ISO demanded a fixed quantity of capacity, and resource providers and LSEs with spare capacity offered supply schedules against it. The experience has been that prices in that auction were either at the deficiency price or close to zero.

Under the demand function approach, the six-month strips are auctioned off while monthly ICAP auctions continue to operate as double auctions in which LSEs and resource providers can adjust their seasonal strips. In the daily spot deficiency auction, however, the vertical demand function has been replaced with a downward sloping demand curve capped at the deficiency penalty. The downward sloping segment of the demand function is linear and is determined by two points bracketing the target capacity and the corresponding capacity price is set at some multiple of the estimated capacity cost of a CT. The parameters of the ICAP demand curve vary by location (specifically differentiating New York City (NYC) and Long Island from the rest of the state) and are subject to adjustment according to the NYISO Tariff 2004b (section article 5, section 5.14.1(b)). The demand curves corresponding to capability years 2008/2009, 2009/2010 and 2010/2011 are specified in a recent report dated August 31, 2007. Imports qualify as capacity only if backed by transmission contracts.

In the NYISO report to FERC it is stated that the ICAP demand curve has achieved the goal of stabilizing ICAP spot prices in the deficiency auction. Furthermore, purchased quantities in the deficiency auction have increased, while clearing prices have decreased. The deficiency auction has also provided a price floor for the six-month and monthly capacity markets.

According to that report the demand function approach seems to function well and it mitigates incentives for withholding capacity by rewarding available capacity in excess of the minimum requirement and by recognizing that such extra capacity has value in enhancing reliability and moderating energy and ancillary service prices. However, there is no evidence that the demand function approach has achieved its primary objective of attracting new generation resources and as a result of that the New York Public Service Commission has been exploring approaches such as imposing load hedging obligations on LSEs and resource procurement options.

In a recent press release dated April 18. 2007 the NY PSC stated "The New York Independent System Operator has determined that downstate will need 250-500 MWs of supply by the year 2011 to satisfy reliability needs and as the Commission noted the existing wholesale electricity market structure has not led to much merchant-driven supply nor shown much promise for new merchant-driven entry recently. There may be a growing need for a rational and comprehensive decision-making approach to guide the future of New York's electricity infrastructure."

Current Energy Only Markets

Energy only markets where generators get all their income from energy and AS sales at prevailing spot prices that may include scarcity rents currently exist in Australia, New Zealand, Alberta, and in the US in MISO and ERCOT. Following is a brief description of the Texas and MISO systems.

The Texas Energy Only Market

In 2006, the PUCT, which regulates both the wholesale and retail markets of ERCOT, adopted a combination of market power and RA rules that explicitly rejected capacity payments in favor of raising the system-wide offer cap to ensure RA. The PUCT explicitly stated that it adapted the Australian energy-only RA mechanism to the ERCOT market. The rule raises the offer cap in ERCOT-procured markets to allow generation and load resources the opportunity to recover their fixed costs, improve incentives for bilateral contracting, and increase the transparency of ERCOT-procured ancillary service and energy markets. Specifically, the offer cap is to be raised from the $1,000 level that prevailed when the rule was adopted in August 2006 to $3,000 in 2009 when the Texas Nodal market design is expected to be launched. In addition, the Commission ended a system-wide market mitigation measure, the Modified Competitive Solution Method, which changed market clearing prices ex post under certain market conditions that suggested economic or physical withholding might have occurred. The PUCT also expressed its intention to rely on increased market-based DR to meet its RA goals. Increased market-based DR also would weaken the potential for market power abuse during times when scarcity pricing was expected.

An important aspect of the ERCOT energy only market is the absence of a must offer obligation of any kind and the reliance on hockey stick offers to set scarcity rents. Unlike the MISO system discussed bellow ERCOT has no scarcity pricing mechanisms for operating reserves although a scarcity adder reflecting emergency deployment of reserves is being developed. In addition a temporary backstop program for procurement of 1000MW of

Emergency Interruptible Load Service has been adopted, which is intended to guard against rotating blackout events and will be deployed only when involuntary curtailment of load is imminent.

As part of this rulemaking project, the Commission developed a formal definition of market power, reduced mitigation on smaller market participants, and gave larger market participants the opportunity to apply for the Commission's approval of voluntary mitigation plans. The PUCT also views as a key component of the rule its requirement for prompt disclosure of market information that will increase market transparency and promote competition. The PUCT believes that market transparency will provide incentives for market participants to make offers into ISO-procured energy and AS markets that are consistent with the properly functioning competitive market and not the result of market power abuse or other market manipulation. The implementation schedule for disclosure is also being tied to the schedule for increases to the offer cap, thereby further emphasizing the PUCT's decision that these two issues are interrelated.

This approach is based on the experience of the Australian market and the belief that companies that have the potential of abusing their market power will be reluctant to expose themselves to public criticism resulting from actions they take in the market to raise prices . In its initial rule the PUCT ordered the full disclosure of all offer data within 30 day and of the price setting offers for balancing energy within 48 hours whenever the price exceeds a certain threshold (set to 50 times HSC gas price). However, the early disclosure provision was challenged in court and was recently amended by the PUCT lengthening the disclosure period to 60 days.

The PUCT rule exempts market participants with Portfolios under 5 percent of installed capacity from mitigation (consistent with a "small fish swim free" market structure). Furthermore, market participants with portfolios larger than 5 percent of the installed capacity are also allowed to earn scarcity rents on their units but may be scrutinized by the market monitor if their strategies impeded competition. If they are uncertain whether their offers would be considered an exercise of market power, they have the opportunity to apply for a voluntary mitigation plan with the PUCT. The PUCT would review the plan, and if approved, would provide the market participant immunity against charges of market power abuse as long as it adhered to the voluntary mitigation plan. As further measure to curb market power, which could undermine an energy only market, the Texas Legislature has put in statute a limitation on ownership of no more than 20 percent of installed capacity in the ERCOT market.

Market participants in ERCOT are provided short-term forecasts to assist them with their unit commitment decisions (quick-start generation and demand resources). This follows the Australian model where the market operator emphasizes the importance of Projected Assessments of System Adequacy in informing market participants of unit availability and load forecasts. In addition, the PUCT embarked on an aggressive program to facilitate load response through an advanced metering initiative.

The Texas energy only adequacy rule recognizes, however, that while competition and DR are the best means of market mitigation, there are inherent aspects of electricity markets such as long lags in investment response to high prices that requires mitigation of wealth transfers from consumers to producers while the investment community responds to price signals. To address this problem, the ERCOT wholesale market limits the amount a resource can capture on an annual basis to $175,000 per MW (slightly over twice the estimated annual fixed cost of a gas unit). When that limit is reached, the offer cap (which will reach $3000 per MWh by 2009) is lowered to $500 per MWh or to 50 times the HSC[11] gas price whichever is higher, for the remainder of the calendar year.

The MISO Energy Only Market

In February 2007, MISO filed with FERC a RA proposal that relies on energy-only remuneration and contracting obligations imposed on LSEs. The proposal retains the $1,000 per MWh energy offer caps during non-scarcity conditions (i.e. when reserves are not deployed for energy production). However, an administrative demand curve for reserves will be used to set reserve prices during scarcity conditions when operational reserves are deployed. These reserve prices will also be added to the energy clearing prices during such scarcity periods. The demand curve for reserves, which will be used in the day-ahead and real-time markets, will allow scarcity pricing to rise as high as $3,500 per MWh, which is MISO's estimate of VOLL. Real-time co-optimization of energy and reserves will be implemented to improve resource utilization during scarcity conditions.

According to this scheme when operating reserves fall short due to emergency deployment of operating reserves or procurement shortfall, the operating reserves price rises until it reaches VOLL when the reserve falls bellow a minimum level (determines by the system operator) at which load must be shed. The operating reserve scarcity price is paid to all spinning reserves and is added to the balancing energy price to reflect opportunity cost (since any MW producing energy has the opportunity to offer spinning reserves instead).

The state commissions within MISO would be expected to enforce a contracting requirement for all loads, both traditional cost-of service load and competitive retail loads, to ensure RA. At this point there is no must-offer availability requirement in day-ahead markets for contracted resources but the desirability of such a requirement in MISO is being considered.

Energy Only Markets with Load Hedging Obligations

Energy only markets with full strength spot prices and scarcity rents provide a solid foundation to a market where capacity remuneration is implemented through load hedging premiums. To the extent that political forces are averse to high spot prices approaching VOLL as in the Australian system, price protection to customers that has been traditionally provided through energy offer caps can be replicated by imposing a load hedging obligation with call options whose strike price is set to the price cap level or lower, for a quantity that covers the peak load plus a reserve margin. The call option premium will provides the capacity remuneration to generators while the strike price provides a price ceiling on wholesale energy prices and a deterrent to generators against exercising market power (since they will need to return any proceeds above the strike price). Because call option entails the right but not an obligation to purchase energy at the strike price, consumers covered by call options are protected

[11] The Houston Ship Channel spot market

against high prices but can still enjoy cheap energy when spot prices are low. Under such a system the unmitigated spot prices, as high as they may get, do not affect consumer's payment but only serve as a reference for penalties and liquidation damages paid by non performing generators. To facilitate new investment and mitigate market power in the contract market, call options would have to be at least four year forward looking. Furthermore, to assure system reliability and deliverability load hedging obligations can be physical and locational, i.e., must be covered by a physical resource in a specific location.

The hedging obligations can be met through bilateral procurement or through a centralized market. However, due to the long time horizon, a centralized market operated by an entity such as the ISO having tariff authority solves many of the credit issues associated with underwriting long term forward contracts since it can guarantee payment to generators at performance time which is allocated to load at consumption time. Such an arrangement also solves load migration problems since the cost of the hedging contracts can be allocated directly to the load wherever it happen to reside at performance time.

Generation adequacy mechanisms based on call options are gaining popularity either as direct capacity remuneration instruments or as conceptual models for capacity products. In Brazil and Colombia which are hydro rich countries, long term call option contracts auctions for firm energy have been implemented or being planned as a generation adequacy mechanism. In the US North Eastern ISOs, PER adjustments to capacity payments attempt to mimic call option contracts providing intrinsic value to customers in exchange for capacity payment in the form of price insurance. Whether as direct hedging obligation or as a framework for the design of capacity products, call options provide the economic rational that links capacity obligations to energy, which is the commodity that consumers are interested in and willing to pay for.

The Capacity Product

This section describes the general definition of a QC product, forward assessments to establish obligations, and the role of collaboration between the CAISO and CPUC. The determination of QC products is important in its role in the RA Program, and it is related to definitions in the CAISO tariff that enable the CAISO to rely on capacity products to operate the grid. A capacity product is meant to be tradable, and thus must be fungible and standardized. To determine the amount of capacity that the CAISO needs to operate the grid reliably, agencies and market participants must coordinate an assessment of resource needs to some granular detail in terms of product mix and locational diversity. There are alternative approaches to the procurement of capacity, including bilateral transactions that allow for resource and locational mix, including the alternative reliance on energy contracts. There must be close collaboration between the CAISO and the CPUC in order to define and quantify QC, and determine resource needs to allow for reliable and efficient operation of the system.

Overview

In the simplest terms, the capacity product is one MW of energy supply capability that is committed to participate in the CAISO spot markets and either generate energy or provide operating reserve capacity in each hour during a specified delivery period, in accordance with the CAISO tariff. Such energy supply capability can be in the form of (a) the qualified generating capacity of a specific generating facility, (b) a portfolio of generating facilities external to the CAISO control area that can deliver energy or reserve capacity to a specific import scheduling point (a system resource), or (c) qualified DR. The commitment to participate is also known as the Resource Adequacy Must Offer Obligation (RA-MOO). The RA-MOO, as specified in the CAISO tariff, provides the necessary linkage between, on the one hand, the forward procurement of the capacity product and commitment by the procuring entity to pay it a capacity payment and, on the other hand, the service that capacity product provides to the procuring entity toward the reliable supply of electricity to consumers within the CAISO control area.

It should be noted that the capacity product as defined above, which is based on the existing RA framework of physical generating capacity subject to an RA-MOO, is not the only possible way to define a meaningful and effective RA product. For example, some parties have proposed an RA product that is defined as a fixed-price energy contract. The last sub-section of this part of the report discusses the energy contract approach in a little more detail, but for the most part this report assumes that the existing RA framework based on physical capacity and RA-MOO will be fundamentally retained, albeit with some possible enhancements being considered.

Moving beyond the simple, generic definition of the RA capacity product stated above, there are numerous details of the capacity product itself and related rules and provisions that must be specified in designing and implementing a long term RA framework. The next few sub-sections identify and describe the main features required of a capacity product and review some of the alternative ways to address them.

Standardized Capacity Products

Each resource that can supply QC will have some distinct characteristics related to its fuel type, its location on (or outside of) the CAISO controlled grid, its emissions, and its operational performance characteristics such as ramp rates, start-up time, etc. Thus two MW of capacity from two different resources will rarely if ever be identical. At the same time, there are good reasons to simplify the definition of the capacity product and to establish a more standardized capacity RA Tag that can be traded by LSEs or by a CCM. The option of bilateral contracts, either in the current RA Program or in a CCM option means that there will sometimes be non-tradable non-fungible products that are part of the RA Program. For other types of transactions, where liquidity and tradability are valued, the development of a RA Tag can simplify procurement and compliance for both generators and LSEs/CAISO irrespective of final market structure. There are a number of justifications for this.

- A more generic RA Tag with more generic product specifications increases the pool of suppliers. This facilitates greater liquidity in the market.

- Generic RA Tags are more easily traded since they are fungible and qualification of the resource is done beforehand instead of in the context of individual contracting. A generic set of obligations, and a generic contract language referring to that set means less uncertainty and interchange of confidential information.

- Tradable RA Tags facilitate DA as ESPs are more able to meet changing load requirements with products that are more easily traded with lower transaction costs.
- Generators have less uncertainty as to their own RA-MOOs, as they are able to see the standard language in the CAISO Tariff instead of each individual contract. This simplifies contract negotiations, and leaves price, quantity, and term as key negotiating points, not performance obligations and damage/penalty provisions that are uniquely defined by each LSE or generator, and that often also require complex confidentiality provisions regarding interchange of data.
- The CAISO is more certain that they get precisely what they want in the product definition, and do not need to rely on bilateral contract provisions between LSEs and suppliers to enforce RA-MOOs.

On the other hand, the actual capacity needed to serve CAISO control area load and maintain reliable grid operation is not merely a total of generic RA Tags. The CAISO requires a mix of non-generic resources in non-generic places with non-generic operating constraints in order to reliably operate the grid. This proceeding is currently analyzing the benefits and costs of incorporating a more complex resource mix into each LSE's RA obligation, and analysis of this option follows in a later section. The elements of a standard RA Tag are as follows:

1. Qualifying Capacity

The QC of an individual supply resource is a rating in MW of the amount of RA capacity that resource is qualified to provide. Each resource that wishes to offer RA capacity must first participate in a registration process whereby it submits specific information to a central authority such as performance history or interconnection studies, to support its intention to offer a proposed MW quantity of system or local RA capacity. In the case of new capacity that has not yet begun commercial operation the required information would include demonstration that specific milestones toward commercial operation have been completed. The central authority then verifies the submitted information and performs the required analysis of performance and deliverability to determine the actual QC of the unit. The QC of each resource, as well as location, Scheduling Resource ID, or other information, is listed in advance of procurement so that the buyers are fully aware of the amount of capacity each resource is able to offer. For purposes of this report, all references to capacity bought and sold for RA imply these registration and listing conditions, unless specifically stated otherwise.

a. Performance

There are many generator types that as a result of their performance characteristics typically cannot sustain their nameplate output level. Wind and solar generators, for example, are only able to produce what their weather-determined fuel supports at any given moment. Thermal generators are often constrained by ambient air and cooling water temperature and humidity conditions that lower their output to a small degree. Finally, older generators are often subject to emissions limits that constrain their production above certain levels. Each type of generator technology is somewhat unique in the performance constraints faced, so in such cases the QC of a generator would be based on performance history over a predetermined delivery period during peak hours.

b. Deliverability

Deliverability refers to the amount of power a generator can inject into the transmission grid given a reference set of system conditions adopted for the deliverability study, including the level and distribution of load, the grid topology and ratings of transmission facilities, and the operating levels of other generators. When more generation exists in an area than the transmission system allows to flow simultaneously to the grid as a whole, the deliverability of all resources subject to that constraint is decreased. The matter of how the reduction in QC should be allocated between the two generators is typically addressed in the context of the grid interconnection rules and policies and is not a topic of the present paper. Suffice it to say that each generator's QC will be adjusted in for deliverability in accordance with rules that are in the CAISO tariff and approved by FERC.

2. Registration, tagging, and tradability of capacity tags

Registration and tagging are the formal procedures whereby a resource's QC is associated with specific MW quantity of a tangible RA capacity product that can be sold, bought and traded in advance of the delivery period. The resource is then eligible to sell a number of RA Tags equal to the QC of the unit each month. The RA Tag that is sold is a commitment from the buyer to be subject to the RA-MOO as described by the CAISO in the CAISO Tariff for the duration of the delivery period. Penalties may accompany non-compliance with the RA-MOO by a generator.

3. The nature of the RA-MOO

The RA-MOO is a set of CAISO tariff provisions that define the obligations of RA capacity resources to participate in the CAISO markets and respond to CAISO commitment and dispatch instructions. As such the RA-MOO defines the service which the supplier of RA capacity agrees to provide to the CAISO in exchange for payment from the buyer. The supplier's agreement to the terms of the RA-MOO is therefore a fundamental element of the capacity tag that is traded in RA capacity transactions, and hence a fundamental element of the definition of the standardized RA capacity product.

The RA-MOO provisions that exist for today's RA framework will likely need to be enhanced for the long term RA framework to provide complete coverage of a number of important areas. In the context of a standardized capacity product, the objective behind the RA-MOO design is to provide a single point of reference for the rules and responsibilities to which a supplier of RA capacity agrees to adhere, so that there is no need to specify any of these details in a bilateral contract for RA capacity or in the standardized capacity tag itself; all that is needed is to refer to the relevant CAISO tariff sections.

Ultimately the RA-MOO provisions of the CAISO tariff that will apply under the long term RA framework should include, among other things, the following topics:

- The requirement to offer the RA capacity to the CAISO's day-ahead market, including both the Integrated Forward Market, and the Residual Unit Commitment (RUC), to be committed and scheduled for energy or AS or scheduled to provide RUC capacity;
- The requirement to offer the RA capacity to the CAISO's real-time market where feasible (for example, depending on the start-up time of the resource);

- The requirement to generate energy or provide reserve capacity in real time, consistent with its CAISO schedule or any real-time CAISO dispatch instructions;
- The conditions under which specific RA capacity may substitute other capacity or be relieved of some of its RA-MOO requirements to offer the capacity and provide energy or reserves in real-time; and
- A schedule of penalties or sanctions related to non-compliance with the CAISO tariff with regard to performance and dispatch under the RA-MOO.

Forward Assessments

Underlying each of the CCM or non-CCM proposals is provision for a forward assessment of capacity (forward assessment) that is expected to be performed collaboratively by the CPUC, CEC and CAISO. The function of such a forward assessment is to inform LSE procurement activities, supplier offers of capacity, and decisions to invest in new capacity. Parties have suggested that a forward assessment should address the full range of resource needs that the CAISO relies on to meet demand and operate the grid reliably. The time frame for the forward assessment varies from proposal to proposal over periods of up to six years. Types of resources needed by the CAISO include the following:

1. System, zonal and local capacity.

Location is the first characteristic to be considered. As it is already an explicit feature of the current RA framework, it is expected that the locational parameter would be retained in any future elaboration of the capacity product, at least at the current level of granularity. Currently there are three main categories used to define capacity needs based on location.

- System capacity is simply the total MW quantity of capacity needed to meet system-wide requirements, prior to specifying any attributes required of that capacity. The total MW quantity required is generally calculated by multiplying a system-wide peak demand forecast for the delivery period in question by the factor (1 + PRM), where PRM is the Planning Reserve Margin that has been adopted by the CPUC or other Local Regulatory Authority that has jurisdiction over the LSE that has an RA requirement.
- Zonal capacity is the highest level locational criterion and is based on the three large congestion zones utilized in the current CAISO market design, i.e., NP15, SP15 and ZP26. In practice, however, the zonal capacity requirement tends to reduce to a two-zone criterion, namely northern California (NP26) and southern California (SP26). This is further simplified by focus on the transmission capacity between the two zones (NP26 and SP26). The zonal capacity requirement works by starting with the system capacity requirement and stipulating a minimum portion of the system requirement that must be physically located within each zone. The minimum amounts needed for each zone are determined by the CAISO based on engineering studies.
- Local capacity is at present the most granular locational criterion and is based on ten local areas of the CAISO grid, which are defined by transmission constraints that limit the amount of energy that can be imported into each area. Due to these constraints each local area has an associated minimum MW amount of RA capacity that must be located within the area to meet peak demand, accounting for contingencies. This minimum amount is the Local Capacity

Requirement (LCR) for that area. The definition of the local areas and the minimum amounts of capacity needed for each area are determined by the CAISO based on engineering studies.[12]

2. Environmental attributes.

Supply resources can differ in their environmental attributes, which may be described in a purely qualitative sense (e.g., renewable versus non-renewable) or in a quantitative sense (e.g., by the quantity emissions of NOx, SOx or GHGs per MWh of energy production). For some environmental attributes requirements are already in place that affect LSE procurement and new investment decisions; main examples are RPS and air quality regulations governing NOx and SOx emissions. For other attributes a regulatory framework is under development; the CPUC and CEC are involved in a joint proceeding to regulate GHG from the electricity sector, and both are assisting CARB to implement AB32. At the present time, although environmental attributes and the associated laws and regulations do affect procurement and investment decisions, they are not yet incorporated explicitly into the definition of the capacity product to be procured to meet RA requirements. The questions of whether and how environmental attributes should become part of the RA product definition is a topic of discussion in the current proceeding.

3. Performance attributes.

Performance attributes of supply resources have been identified by the CAISO because they are relevant to the operating needs of the grid. The main performance attributes the CAISO has identified are:

- Dispatchability – the ability of a resource to respond to 5-minute CAISO dispatch instructions;
- Quick-start capability – the ability of a resource to start up and reach a specified operating level within a specified amount of time (typically 10 minutes);
- Ramping capability – the ability of a resource to increase or decrease its operating level by a specified amount within a specified amount of time;
- Regulation capability – the ability of a resource to respond to Automatic Generation Control signals to follow instantaneous fluctuations in demand;
- Black start and voltage support capability.

At present the question of whether to incorporate any of these characteristics into the RA product definition or the LSE RA requirements is still under discussion.

There are some important ways that have been identified in which the different capacity attributes and needs interact. First, an increase in the amount of renewable generation as a result of environmental policy and regulations will increase the need for certain performance attributes, most notably dispatchability, quick-start and ramping capability. The reason is that the leading types of new renewable generation – wind and solar – can only produce what their local weather conditions allow. As a result they typically tend to deliver as much as is physically possible given the conditions of the moment, and as grid operating needs such as transmission constraints require any alteration in their output they can be dispatched down only and not up. From an operational perspective, then, the limited dispatchability of these resources combined with their inclination to deliver as much energy as possible when weather conditions allow creates increased need for resources that are dispatchable to manage grid operating needs. As the

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[12] April 3, 2007 CAISO staff, *2008 Locational Capacity Technical Analysis* posted at : http://www.caiso.com/1c44/1c44b8e0380a0.html

proportion of these non-dispatchable renewable resources increases, the need for the other dispatchable types increases as well. This issue has been discussed in much greater detail along with relevant engineering explanations in a recent CAISO renewable integration study.[13]

A second interaction to be noted is that certain performance attributes – most notably voltage support and black start capability – are fairly local in their impact and therefore the needs for them are defined locally. As a result, capacity procured to provide these attributes will also be able to count towards the more generic LCR in certain local areas.

Alternative Approaches

At a high level the principal types of mechanisms by which capacity needs may be met under long-term RA are:

a. Bilateral arrangements between LSEs and suppliers, for both new investment and existing capacity;
b. A bulletin board that allows posting of offers to buy and sell capacity, which provides an information resource to support bilateral arrangements;
c. A central auction market for trading capacity;
d. Backstop procurement by the CAISO to fill any identified procurement gaps left open by the previous mechanisms (mechanisms such as RMR, RCST, ICPM);
e. Possible forward ancillary service (AS) procurement mechanisms, with the potential for new AS product definitions (e.g., the Forward Reserve Market of ISO-NE);
f. The CAISO Day Ahead and Real Time energy and AS markets, also with the potential for new AS product definitions.

Under the current RA framework mechanisms (a) and (d) are in use. Mechanisms (b) and (c) have been proposed in parties' filings in the current proceeding, and (e) has been mentioned in the course of some of the public discussions.

One persistent theme in the filings and the discussions is that the central auction market for capacity (item (c)) would be well suited for trading capacity that meets a standardized product definition and is qualified as either system capacity (i.e., without a locational attribute) or local capacity for a specific local area of the grid, but not for capacity that is more narrowly defined by a performance or environmental attribute. To incorporate such attributes into an auction market would, it is argued, reduce the likelihood of having sufficient competition among the available supply in that market. Mechanisms (a), (b) and (d), however, could explicitly target such attributes. And of course, the AS markets of mechanisms (e) and (f) would explicitly target those attributes for which AS products were defined.

Collaboration between the CAISO and the CPUC

This section is a description of the collaboration between the CAISO and the PUC from the context of the ACR and the governing legal authorities. The section also includes a description of the collaboration with regard to the joint workshops and the matrix.

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[13] November, 2007 CAISO staff, *Integration of Renewable Resources Report* posted online at: http://www.caiso.com/1ca5/1ca5a7a026270.pdf

Overview of the Collaboration

The CAISO and the PUC have a collaborative role in the production of this report and certain elements of the Commission's R.05-12-013. AB 380 specifically directs the Commission to develop RA requirements for all LSEs in consultation with the CAISO. Consistent with that requirement, on March 25, 2007, the assigned Commissioner President Peevey issued a ruling directing the Energy Division staff to collaborate with CAISO in the generation of this report. The Assigned Commissioner's Ruling directed collaboration by the Energy Division staff with the CAISO specifically on the subject of Centralized Capacity Markets and did so without pre-judging the subject. The Assigned Commissioner's Ruling expressly states that the CAISO will not have a deliberative role in this collaboration.

Consistent with that ruling the CAISO and the Commission's Energy Division have undertaken significant effort during the course of the R.05-12-013 proceeding to collaborate extensively with each other on the subject of CCMs. Several days of workshops on the subject were jointly hosted both in San Francisco and Folsom and great care was taken to ensure events were noticed to all parties in both the Commission's proceeding and the CAISO's stakeholder process.

The CPUC staff worked with the CAISO staff and stakeholders in the development of the CAISO's CCM evaluative matrix, which was used to facilitate evaluation of both CCM and non-CCM proposals.

Joint Workshops

During the R.05-12-013 proceeding CPUC workshops and CAISO stakeholder meetings were held both separately and in a joint-host collaborative process. Dates and Agendas for the workshops and stakeholder meetings are included in Appendix 4. This report, in addition to providing the CAISO recommendation on CCMs and CPUC staff recommendation on the RA program, also reflects the collaborative workshops held in August, 2007 and the CPUC staff hosting of the CAISO MSC meeting on October 1, 2007.

The Matrix

The CAISO and CPUC collaborated to frame issues on the CAISO led stakeholder development of the CCM matrix (the Matrix) for the comparison of proposals that directly related to the CAISO's role in recommending a CCM. The stakeholders with CCM proposals filled out and filed the Matrix with the details of their proposals at the CAISO, similarly, non CCM proposals filled out the Matrix and filed their proposals with the CPUC's energy division staff to ensure all proposals were framed in a uniform way for comparison purposes. All Matrices were made available to stakeholders and parties at both agencies.

CAISO Language in this Report

In addition to the staff level collaboration between CPUC and CAISO staff, this report includes a CAISO recommendation on CCM structure which is wholly the work of the CAISO. That section, titled "CAISO Recommendations for a Centralized Capacity Market" (pp. 82-95 of this report) represents solely CAISO's position on CCM design and not those of the CPUC s Energy Division staff. In addition, the CAISO contributed the section titled "CAISO Goals" (pp. 23-24) and contributed to the Capacity Product section (pp. 39-44).

Metrics for Analysis

The Energy Division has developed seven metrics to guide its analysis of the proposals for trading RA capacity. The intent of these metric is to focus the analysis on the key decision points the Commissioners may use in determining the preferred approach.

Ensures Reliability

Reliability is most readily identified as the goal of RA programs. In fact reliability is directed in PU Code § 380 and elsewhere, including the CAISO tariff. Reliability is, simply put, the condition of adequate capacity to meet peak load and operating reserve requirements for California. Significantly, reliability can be viewed from both a long and short term perspective. In this analysis Energy Division staff considers short term reliability under this metric and considers long term reliability under Enable New Generation.

The subject of reliability is complicated by the relationship between transmission constraints and energy, and the existence of intermittent resources. A reliability metric must recognize these issues at the same time it answers the *primary* consideration of if there is sufficient capacity under contract to meet expected needs. Of special note is the need for mechanisms that ensure reliability if the primary markets fail to provide sufficient resources, generally called backstop procurement.

In examining backstop procurement there are several question to consider: What should be the trigger for backstop procurement? What kind of resources should be procured through a backstop mechanism? How far ahead should the need for backstop procurement be assessed? On one hand evaluating the need for backstop action far in advance allows for more efficient solutions that may require more time. On the other hand such early triggers tend to suppress market responses such as demand side solutions that might have avoided the anticipated problem. Another important question is whether backstop procurement should be used as a market power mitigation tool and if so, what is the best approach. Currently, the waiver approach that waives RAR obligations when resources cannot be contracted below a certain price amounts to the use of backstop procurement as a market power mitigation tool. Any resources that economically withhold their capacity from being procured for RAR may be procured by the ISO as RMR.

Enables New Generation

If the subject of reliability is fairly straightforward, the subject of new generation in California is more complicated. The subject of facilitating new generation in the context of RA is directly addressed in PU Code § 380 in subsections (a)(1) and (h)(2). But the issues is also addressed in PU Code § 454.5 and the corollary of repowering is addressed in § 454.6, both of which include UOG as a mechanism for obtaining new generation and attaining reliability. Similarly, the RPS directly impacts the subject of the enabling of new generation. The subject of new generation must consider this governing language as well as the steel in the ground reality of California's hybrid energy market today.

In order to meet the state's reliability goals, new generation needs to be constructed to replace old, inefficient and unreliable generation and to meet expected load growth. While California has relied on publicly owned dams for some power, PURPA began the process of creating a merchant sector of independent power producers. In the late 1990s, the IOUs divested most of their fossil fueled generation fleet and began relying on merchant generators to build new power plants.

Currently, there are a significant number of natural gas fired power plants that are nearing the end of their useful lives. Many of these plants are in local areas and are needed for grid reliability. Any regulatory program for capacity should send the proper incentives, so that existing power plant sites can leverage the value of existing infrastructure and cost effective new sites can be developed to serve local areas.

In order to justify building or repowering a power plant, a developer has to forecast a revenue stream sufficient to cover the cost, including return on capital invested (profit). This has two factors, the magnitude of the forecast revenue and the certainty of forecast. Short term commitments, such as revenues from daily energy markets, have far more variability than revenues from long term contracts where revenues and costs are fixed or hedged. Therefore, short term commitments have a greater potential forecast error. In addition, there is a risk that government will change the regulations in ways that affect costs and or revenues.

In an energy market, generators receive energy payments equal to the marginal cost of the least efficient unit that is currently operating. To the extent a generator is more efficient than the marginal unit it recovers some of its fixed costs. In periods of high demand, less efficient units are called into operation, thus increasing revenues for all generators receiving the market price. If high demand turns to shortage, prices and revenues rise dramatically. To prevent extremely high prices, some energy markets have price caps. In California the price cap is $350/MWHr and is set to rise to $1000/MWHr when the CAISO day-ahead energy market begins operation.

To the extent energy market prices are capped or energy market revenues are unreliable, capacity payments are needed to ensure generators recover the full costs of their units. In

California, large variation in demand between average load and system peak means that resources are needed to meet system peak, although they may operate less than 100 hours per year. These units require a capacity payment because they can recover only a limited amount of their costs through the capped energy market.

Adheres to Least Cost Principles

There are a variety of state goals and Commission directives that relate to least cost principles. For instance, PU Code § 451 states that all charges received by public utilities must be just and reasonable; since RA costs will ultimately be born by customers, least cost must be analyzed. Staff considers the proposals before the Commission with regard to least cost principles in light of total cost, competition and price transparency.

Total Cost

On a basic level, the Commission wants to accomplish its goals at the least cost to ratepayers. Overall costs to ratepayers include energy, capacity, AS, transmission services, and market administration costs.

Competition and Price Transparency

While it is widely accepted that competition in markets drives down costs, achieving true competition in the multiple markets in any RA program is not trivial. Staff is particularly attuned to structural problems that prevent competition from functioning properly in the proposals before the Commission. To that end transparency in pricing, full participation in markets by both buyers and sellers and the use of competitive market reference principles for markets that are not perfectly competitive play a large role in staff's analysis. Advanced Metering Initiative (AMI) aims to increase the information available to the end user about real time pricing. This increase in transparency has the potential to impact peak load by enabling price sensitivity by a variety of different classes of customers.

Enables Direct Access

Retail competition is a part of the overall policy framework for electric regulation. Currently ESPs and Community Choice Aggregators (CCAs) represent a small percentage of the total market in California, but the possibility of reopening DA and increasing its share of the overall market can not be ignored. The impacts of any RA program on ESPs and CCAs must be considered.

Recognizes Jurisdictional Constraints

The amount of control that can be exercised to protect ratepayers in case of market failure is of significant concern. To the extent that the CAISO is a FERC regulated entity, market functions under its control are subject to FERC rules and oversight. Commission ability to intervene in a FERC regulated activity, to remedy perceived dislocations and unreasonable results, is limited. Conversely, Commission jurisdiction currently does not include several California market participants. For that reason we must remain cognizant that any CPUC jurisdictional market will not be comprehensive in addressing the State's reliability needs.

Facilitates Environmental Policies

While there is significant potential for overlap on jurisdictional issues related to the state's environmental policies, the proposals themselves must be evaluated with regard to both their impact on the state's environmental policies and *vice versa*. Staff paid close attention to the issues of renewables and greenhouse gasses, but other environmental policy issues were also considered when applicable.

Possesses Fundamental Feasibility

In addition to metrics tied to the state goals, staff recognizes a separate and fundamental need for the program to operate with both internal and external structural compatibility. While a failure of a proposal to satisfy the internal structural feasibility goal or outward structural compatibility effect the proposal's ability to meet each of the goals above, these goals are more fundamentally addressed from the perspective of feasibility as a standalone metric. Staff considers the following sub-goals in its determination of fundamental feasibility of a RA proposal:

- Program Expense
- Administrative Burden
- Internal Structural Consistency
- Compatibility with California's Market

Proposal Descriptions and Analysis

Each of the proposals was analyzed on how well they satisfied the Commission's goals and metrics. This section focuses on the August 3, 2007 proposals or proposals that were revised or amplified for the August 3, 2007 filing. These proposals were the focus of the August workshops and were most extensively developed both by the proposal advocates and their critics via the CPUC workshop and CAISO stakeholder processes. The proposals that were filed in March and either withdrawn or not actively reintroduced by parties are discussed to a lesser degree in Appendix Three. The descriptions of the proposals in this section are not intended to be comprehensive; they merely are intended to outline the major components of the proposals for comparison purposes. Similarly, while all proposals were evaluated on the same criteria, the explanations provided for each proposal builds on the prior analyses. This means that analyses of similar situations are described in less detail as each proposal is reviewed in turn.

Bilateral Trade Group

Summary of the BTG Proposal

The Bilateral Trade Group proposal represents the most concrete continuation of the status quo with regard to the current RA program. The proposal discusses an energy only end state and the use of an electronic bulletin board to increase price transparency, but generally perpetuates the program that now exists.

The program that exists now is summarized above in greater detail but is fundamentally an LSE-based RA requirement showing in both a year ahead and month-ahead environment. The BTG proposal also utilizes a standardized and tradable capacity product and permits opt-out from backstop mechanisms by means of demonstrated self-provisioning of capacity.

Analysis

Ensures Reliability

The Bilateral Trade Group proposal ensures reliability. As a fundamental continuation of the existing RA program, an assessment of reliability associated with the Bilateral Trade Group proposal need only examine the current state of reliability. By most measures the state is resource adequate under the current program; where and when appropriate, reliability mechanisms have functioned as intended and resources have been available to ensure grid reliability.

The current RA program has provisions that encourage, but do not require LSEs to procure specific resources needed for grid operation. If the year-ahead system or the local showings do not procure sufficient resources, LSEs have an opportunity to fill the need before the CAISO performs backstop.

The CAISO backstop mechanisms exist in two distinct forms under the current program: RCST and RMR. RCST is used to meet short term needs when RA resources are not adequate. Discussions during the August workshops revealed that the use of Must Offer Obligations under RCST has declined significantly in the past year. RMR are year long contracts for specific need resources. The use of RMR has declined significantly since the advent of the RA program.

The current RCST program is scheduled to end on December 31, 2007. The CAISO is currently pursuing an ICPM. Failure to establish an adequate replacement for RCST would impair the reliability of this proposal.

Enables New Generation

The BTG proposal enables new generation. New generation comes online under the BTG proposal via LSE bilateral contracting or via a mechanism associated with the Commission’s LTPP proceeding. In the LTPP proceeding IOUs can be ordered to procure new generation and share the costs of that generation with all benefiting LSEs. There has been a limited amount of merchant generation that has entered the market under the current program, but that is generally limited to smaller resources. Merchant generation is not expected to enter the market absent long term contracting under the BTG proposal, though it is potentially more likely to do so than under the current program because of higher transparency associated with the Electronic Bulletin Board.

To the extent that MRTU provides a more efficient energy market, BTG supports believe merchant generation will be incented to invest based on energy pricing. It is unlikely that merchant generation would enter the market absent a IOU long term contract if the Commission continues to authorize IOUs to meet system need though long term contracts supported by all benefiting customers.

Adheres to Least Cost Principles

The BTG proposal is generally consistent with least cost principles but raises some concerns with regard to overall cost. In the current market existing generation is paid significantly less than new generation. The overall program cost associated with the BTG proposal is therefore less than a market where all generation is paid the same price. Some parties postulate that generation developers will/have adjusted their bids for long term contracts to capture generation lifetime costs since revenue after the initial long term contract expires is uncertain.

With better market information, provided by the bulletin board in the BTG proposal, the range of prices for existing generation within each market should narrow. To the extent that actual prices are different than what market clearing prices will be in a more transparent market, the costs to ratepayers may increase or decrease.

As a continuation of the current RA program, the BTG proposal is consistent with the Commission's least cost mechanisms including least cost dispatch.

Enables Direct Access

The BTG proposal generally enables DA. The BTG proposal is not in conflict with current DA program or the reopening of DA. The BTG proposal is supported by some, but not all, ESPs and their customers. ESPs in particular are concerned with cost allocation as it relates to the local RA requirements and the lack of any mechanism to adjust for load migration during the year. Some ESPs believe the problem is minor or can be resolved by adjusting the current program, while other ESPs prefer other proposals. Since it retains the current structure of the program, it does not create any more risk in customer migration than the current program, although even the current RA program has significantly impacted the business model of some ESPs that have begun to see risk related to migration in ensuring recovery of costs they have taken on to ensure compliance with the year ahead procurement obligation.

Recognizes Jurisdictional Constraints

The BTG proposal generally maintains Commission jurisdictional over the RA program. The BTG proposal does not significantly vary from the existing RA program with regard to jurisdictional entities, despite the changes proposed. The trading platform is effectively distributed, but under CPUC jurisdiction for CPUC jurisdictional entities. No changes in jurisdiction would apply to the setting of the PRM. CONE calculations are not explicitly applicable under the BTG proposal.

Facilitates Environmental Policies

The BTG proposal supports the Commission's environmental policies. By having the IOUs build generation for system needs, the Commission through the LTPP proceeding can ensure changes in environmental rules, such as GHG, are incorporated into the decision-making process.

Possesses Fundamental Feasibility

Because the Bilateral Trade Group's proposal is generally a continuation of the current program, it can be viewed as feasible[14]. However, there are elements to the proposal which do not currently exist and present potential problems. For example, it is unclear how an electronic bulletin board will be established, or how it will be financed. But, because the cost of an electronic bulletin board is relatively small compared to the overall cost of capacity, this should not affect the proposals feasibility. It is also noteworthy that not having a direct path to the end state (energy only market) does not prevent any element of the proposal from functioning in the interim, regardless of how long that interim state lasts.

On problem of note, in the workshops BTG proponents discussed an energy only market end state without any clear mechanism for getting there. Theoretically, as the energy market gets more efficient with the implementation of MRTU, as well as the increase in the price caps, the amount of revenue resource owners need to obtain from the capacity market will decrease. This should encourage merchant investment while at the same time competition is reducing capacity payments. Conversely, the existence of the IOU long term contracts backed by a regulatory guarantee could preclude any merchant from entering the market.

PG&E Composite

Summary of PG&E Composite Proposal

PG&E's proposal is a composite approach that includes a planning element to determine both the quantity and type of resources that are needed six years in the future. It is a six step process. The first step is called the Comprehensive Forward Assessment (CFA) and it would be performed by the CAISO, the CEC, and the CPUC. The assessment would entail a comprehensive review of the reliability, competitiveness, environmental performance needs of the system covering a five- to ten-year study period, taking into consideration load forecasts and anticipated resource retirement forecasts, MRTU identification of pivotal suppliers, and all energy policy objectives. The forecast would be conducted every three years.

[14] The current program has been summarized in greater detail in the Current CPUC RAR section starting page ten.

The second step, Self Supply, follows the CFA, and allows for LSEs to commit to self supplying capacity via bilateral contracts or other mechanisms to meet the needs identified in the Forward Assessment.

The third step involves a centralized procurement mechanism for targeted procurement, Centralized Requests for Offer (CRFO) via Requests for Offers (RFOs) for each separate Transmission Access Charge (TAC) area. The RFO process would be conducted by the IOU for the TAC area, or an agent, and long term contracts would be entered into by the supplier and the CAISO for capacity, energy, AS, and other products. An auction or other mechanism would sell energy, AS, and other product scheduling rights.

The fourth step would allow a second self-supply opportunity for LSEs to commit resources to the CAISO for availability, similar to today's RA.

The fifth step is a Centralized Availability Market (CAM), which would operate a year ahead of the operating year to procure all residual needs for the uniform product, availability of MWs of capacity to the grid operator, including local needs that were not self-supplied by LSEs.

Lastly, in the sixth step, costs would be assessed for the CRFO and CAM through the CAISO tariff, based on proportional load share of load in the TAC Area for which LSEs did not self-supply. Revenues from the CAM and from energy, AS and other products would offset the CRFO contract payment.

Analysis of the PG&E Composite Proposal

Ensures Reliability

The PG&E Composite proposal ensures reliability. The Composite proposal provides multiple mechanisms to meet the RAR, including both LSE requirements and centralized directed procurement. In particular the proposal includes LSE showing to the CAISO similar to today’s RAR, which occurs after a combination of self supply toward a centrally determined reliability target and targeted procurement via a centralized RFO.

In addition to the LSE based target and a centralized CAISO-involved RFO, the local reliability requirements would be addressed by the CAISO via the CAM if they were not met via self supply or the CRFO. In this sense the backstop mechanism is integrated into the design of the program and operates in the year-ahead time frame.

Enables New Generation

The PG&E Composite proposal enables new generation. New Generation enters the Composite market via several mechanisms; bilaterally either by merchants building on spec and offering capacity into bilateral arrangements , by means of an arrangement for an LSE to self supply or, alternatively, via the centrally administered RFO for targeted procurement. Although nothing in the proposal would prevent new generation from entering via this mechanism, Energy

Division staff does not believe the program will result in merchant generation entering without contracts given the likelihood of contracted generation as an alternative.

Adheres to Least Cost Principles

The PG&E Composite proposal raises concerns about overall cost which are not answered at this time. The question of program cost over time is difficult to assess in PG&E's Composite proposal. Energy Division staff believes the program's costs over time are similar to the current costs associated with the RA and LTPP programs plus the cost of the CAM, but recommends further investigation on this subject.

In as much as the Composite proposal relies on IOU procurement least cost procurement obligations are met via Commission direction in R.01-01-024, R.04-04-025 and related decisions. While this assessment would potentially apply to both IOU and RFO driven procurement, there is significant uncertainty how the Composite's use of IOUs as agents for CAISO will impact the Commission's control over least cost principles. Further examination of structural mechanisms that could ensure compliance with the Commission's rules related to least cost principles is necessary. Until such a time, Energy Division staff is reluctant to speculate on the applicability of least cost dispatch and other Commission procurement directives.

While nothing in the proposal directly addresses the existing LTPP proceeding, PG&E's Composite proposal appears compatible with either incorporation or elimination of or coordination with the LTTP proceeding. Many elements of procurement potentially overlap with the activities of the Commission's LTPP programs and additional review of the relationship between the proposal and the LTTP program would be necessary, especially with regard to existing legislative mandates.

The Composite proposal hints at but does not sufficiently detail the cost benefits associated with a CAISO run CAM. An area particular in need of additional detail is the reference to the CAM being based on fixed operation and maintenance costs. Also in need of greater detail is the cost allocation associated with the CRFO.

Enables Direct Access

The Composite proposal cannot be described as enabling DA. In particular the proposal's four or five year out RA showing by all LSEs presents a significant barrier for DA to participate in California's energy market. While the proposal does minimize problems associated with cost allocation, it does so in a way that is potentially harmful to ESPs. The PG&E Composite proposal creates a forward obligation on ESPs that potentially creates credit risk issues based on a number of factors. The tradeoffs between the problems alleviated via a more efficient cost allocation mechanism and the increased credit costs were raised as significant concerns by groups representing ESPs and their customers during the August workshops. In particular, the risk of lumpy customer load acquisition and loss in a DA environment coupled with a complete showing in a multi-year forward environment potentially creates large over or under procurement scenarios. These off target procurement scenarios directly impact balance sheets and impact credit. In a best case scenario, the Composite proposal places a high burden on DA that potentially causes them to revise their business model, in a worst case scenario, the proposal eliminates it.

Recognizes Jurisdictional Constraints

The Composite proposal generally recognizes jurisdictional constraints, but significant concerns exist in some areas. As the name implies, the Composite proposal consists of multiple mechanisms for trading capacity. With regard to the subject of jurisdiction, procurement can occur both under CPUC and FERC jurisdictions. The Composite proposal includes LSE-based procurement via self supply mechanisms which fall under CPUC jurisdiction. The CAISO’s role in the CAM falls under FERC jurisdiction by means of the governing tariff for the CAM. This particular element of the CAISO run portion of the market appears to function for existing generation given the year-ahead time frame.

While much of the Composite proposal maintains a bright line of jurisdictional issues related to RA, there are elements which are jurisdictionally challenging. Of particular concern are the issues related to the CAISO's role in the CRFO and the agent status of the IOUs on behalf of the CAISO. The use of agents that straddle multiple jurisdictions and the spreading of credit risk across jurisdictions present challenges which are likely to end up litigated in market failure situations. Similarly, the role of IOU or ESP acting as agents on behalf of the CAISO may complicate the assessment of adherence to least cost principles addressed above.

The subject of FERC jurisdiction remains unclear in light of both FERC assertions related to capacity and capacity markets and the ultimate governance of a CAISO tariff via the Centralized Availability Market. While procurement is generally regarded as within the purview of states, and mechanisms such as self supply would generally be considered jurisdictionally distinct. The relationship between the IOUs and CAISO in the CRFO creates a great deal of uncertainty although staff believes FERC could assert jurisdiction over activities under the CRFO.

Facilitates Environmental Policies

The Composite proposal generally facilitates the state's environmental policies. The state’s environmental policies are impacted by the Composite market in several ways. The RPS goals in particular are addressed directly via the determination of the Comprehensive Forward Assessment and met either via self supply or via targeted procurement in the CRFO. Repowering potentially enters the market via a similar mechanism.

The CFA also potentially provides an opportunity to minimize impact on the state’s GHG programs. Similarly, by targeting self supply or the metrics for the CRFO, the impact of a capacity payment on potentially environmentally undesirable units is minimized.

Possesses Fundamental Feasibility

It is not clear if the Composite proposal possesses fundamental feasibility. The primary concern is less will the Composite proposal work but rather will it work for all of the market. In addition, In particular, the proposal threatens to preclude the development or expansion of DA at some point in the future by forcing a showing of RA that is incompatible with the nature of businesses that do or may support DA customers. In addition, Legal challenges related to the role of agent are potentially threatening.

The Comprehensive Forward Assessment is not addressed in sufficient detail to determine the outcome of the process with regard to inter-agency collaboration. In multi-agency collaborations, procedural minutia has potentially large impacts on outcomes. Energy Division staff feels additional information on the development of the CFA from a process and substance perspective is necessary.

PG&E Bilateral with Multi-year Forward

Summary of the PG&E Multi-Year Forward Proposal

PG&E's proposal for a bilateral market with a multi-year forward obligation shares many similarities with the existing RA market and therefore the proposal of the BTG. Similar to the proposal of the BTG, the bilateral with multi-year forward proposal enables price transparency via an Electronic Bulletin Board system and a forward showing requirement for LSE.

The Bilateral with Multi-Year Forward proposal varies from the BTG proposal in that it extends the showing obligation for resources out to include an five, four and three year ahead showings in addition to the year and month ahead showings currently extant. In the proposal, each showing would be paired with a comprehensive load assessment including a broad-spectrum determination of all the resources required by the state for a fully functioning energy system. The initial showing would be no less than 80 percent of the load assessment for each LSE, reaching 100 percent by the three year-ahead showing. Subsequent showings are repeated each year with increased precision owing to less uncertainty over time related to expected load.

The Bilateral with Multi-year Forward proposal expressly incorporates the Calpine proposal for a standardized capacity product via the creation of a tradable capacity certificate.

Notably, the Bilateral with Multi-year Forward proposal includes legislative changes to address concerns that individual LSEs and non-CPUC jurisdictional entities may not meet the entirety of the comprehensive elements of their assessments.

Analysis

Ensures Reliability

The PG&E Multi-Year Forward proposal ensures reliability, but carries some risks related to timely procurement, although those risks are protected against via backstop mechanisms. The RAR is met under the PG&E multi-year forward proposal consistent with the existing LSE-based RA program’s design. The proposal provides an RA showing with sufficient time before delivery that ample mechanisms can ensure reliability including a variety of backstop mechanisms.

Enables New Generation

The PG&E Multi-Year Forward proposal enables new generation. Under the PG&E multi-year proposal new generation enters the market via bilateral contracting between LSEs and generators or via a merchant generator entering without a long term contract. Energy Division staff does not believe merchant generators are likely to enter the market without a long term contract under the PG&E multi-year proposal, despite being able to do so.

Adheres to Least Cost Principles

The PG&E Multi-Year Forward proposal raises minimal concerns over adherence to least cost principles. Energy Division staff does not believe the multi-year proposal will be significantly more expensive than the current RA program with one possible exception related to DA. Small ESPs are likely to experience significantly higher credit expenses which potentially increase the costs of the overall energy market. Additionally, lumpiness of new generation risks the occurrence of scenarios were more generation is procured in a manner that risks expensive procurement on a per-MW basis. In addition, forward contracting will result in transaction costs as LSEs adjust their capacity contracts to match load migration. This cost may be significant to small ESPs.

The Commission's existing least cost mechanisms would function as they do under the current program.

Enables Direct Access

The PG&E multi-year forward proposal is not compliant with DA and significantly jeopardizes both existing and potential DA service providers. The proposal can be characterized by the lack of compatibility with some ESP business models that do not facilitate long term contracting for resources. The primary source of this incompatibility, difficulty with long term forward contracting, is driven by the potential lack of a long term forward assessment on which to base RA contracting associated with some ESP business plans and lack of long term customer contracts.

Recognizes Jurisdictional Constraints

The PG&E multi-year bilateral proposal represents almost no changes to the current RA program from the perspective of jurisdiction, in other words the Commission retains jurisdiction over the procurement by jurisdictional entities. Left unaddressed is the subject of non-jurisdictional entities under this scenario. Energy Division staff believe more development of this point is necessary.

Facilitates Environmental Policies

As an extended version of the current RA program the multi-year forward proposal is generally consistent with the Commission's environmental policies. Significantly the Commission would retain a broad spectrum of control under most potential scenarios in the multi-year proposal.

Possesses Fundamental Feasibility

This proposal has the same basic feasibility as the current program or the BTG proposal with a few added issues. Multiple year forward forecasting presents some implementation issues. For example, forecasting load for small ESPs will have potentially high error rates, requiring a well developed adjustment mechanism. Forecasting QC of resources is also subject to error and the longer the forecast period the more the need for adjustment mechanisms. The current policy of not adjusting QC for forced outages would be unsustainable in a multiple year forward environment.

Aglet Physical Call Option Market

Summary of the Aglet PCOM Proposal

Aglet proposed what it described during workshops as a third way by addressing RA via a physical call option on IOUs. The proposal addresses the RA needs of the state by requiring LSEs to procure capacity in a three year-ahead showing, with no opt out options. Specifically, the Physical Call Option Model (PCOM) model clears capacity and dispatchable DR via a bid/ask mechanism, with either party capable of submitting an initial bid. The PCOM itself is administered by a third party who would be selected by the CPUC via an RFO process.

In the PCOM new generation is permitted to place bids of up to thirty years. However, where the expected output of a new or repowered generator is three percent or more of an LSE's annual sales, the LSE would be required to sign ten year contracts. It is not clear how the determination of output of a generator would translate into annual sales for an LSE. DR is permitted to place bids of up to five years into the PCOM.

Analysis

Ensures Reliability

The Aglet PCOM proposal does not sufficiently ensure reliability. Energy Division staff has serious concerns that the PCOM will not meet the RAR. The foundation of these concerns is the 90 percent showing of peak load for summer months three years forward is insufficient to ensure RAR targets for all load. Energy Division staff does not believe a showing of 90 percent of peak load is sufficient to ensure reliability in any scenario. While Aglet's proposal to not change the PRM implies that there is still an obligation to meet the full RAR, the proposal does not detail how or when the additional load and PRM is met or functions to ensure reliability. Even with a subsequent showing, the PCOM proposal's partial forward showing does not address the gap between 90 percent of forecast load and the PRM would be met if new generation is needed. Energy Division staff is particularly concerned that new generation procurement obligations will fall disproportionately on ESPs which may not be capable of meeting them. This situation is further exacerbated by the requirements on LSEs to procure new generation via long term contracts when the units are more than three percent of their load. This concern is addressed in greater detail below.

The PCOM proposal does not address backstop beyond indicating that Aglet proposed a backstop mechanism in Track 1 of Phase 2 in R.05-12-013. That proposal included three separate backstop mechanisms depending on the source of the shortage.

Enables New Generation

The PCOM risks shortcomings in the area of new generation. While Energy Division staff does not believe that a three year-ahead forward showing provides a tenable time frame for participation of new generation, it is still theoretically possible in the PCOM that existing generation will satisfy that portion of the demand. If the PCOM functions as planned, new generation would enter the market via the acceptance of merchant bids for capacity either without long term contracts or via long term contracts associated with the three percent rule discussed above.

Energy Division staff remains concerned that backstop mechanisms are likely devices for new generation procurement for RAR shortcomings. Additionally, staff is concerned that market disrupting intervention is a significant risk in this scenario. Such disruption will likely reduce or eliminate the likelihood of merchant entry based on market operation alone.

Adheres to Least Cost Principles

The Aglet proposal introduces significant uncertainty with regard to adherence to least cost principles. Energy Division has significant concerns with uncertainties related to cost of the administration of the program as well as the cost of new generation purchased via the program. With regard to the costs of administration of the program, the PCOM specifically addresses least cost principles with regard to market operation and oversight, but the proposed mechanism (a third party market administrator selected by an Energy Division run RFP) carries risks related to cost that the proposal does not address.

With regard to the cost of generation procured via the PCOM, staff is concerned that several requirements present likely cost increases. In particular, staff is concerned that the likely rushed bid scenarios to bring new generation online will result in high cost generation as well create inefficiencies in the market which exacerbate the problem over time. Staff also has significant concerns with the cost implications associated with new generation's 3 percent of load trigger for long term contracting requirement, which potentially enables market power on the buy side to avoid new generation cost obligations.

The PCOM proposal explicitly adheres to least cost principles with regard to dispatch. IOUs are required in the PCOM to adhere to least cost dispatch rules. What is not clear with regard to cost minimization is if the proposal result in an overall lower cost than other proposals based on the concerns detailed above

Enables Direct Access

The PCOM proposal generally does not enable DA. The PCOM presents significant challenges with regard to DA. The proposal specifically addresses LSE's new generation obligation via a 3 percent of load trigger for long term contracts with new or repowered generation. While not fully explored or explained in the proposal, Energy Division staff is concerned that both size and market power can be used to force small LSEs to disproportionately shoulder new generation costs in this scenario by procuring existing generation's available capacity to meet their 90 percent showing obligation before smaller LSEs. This scenario would leave smaller LSEs with an increased likelihood if not certainty that they would be required to sign long term contracts because of the lumpy nature of new generation. Energy Division also remains concerned that a 3 year forward showing for 90 percent of forecast load may be incompatible with DA.

Recognizes Jurisdictional Constraints

The jurisdictional issues related to the Aglet proposal are minimal owing to the PCOM's focus of jurisdiction on the CPUC. Both the trading platform and determinations on the PRM take place under CPUC jurisdiction. While Aglet states the PCOM does not depend on counting conventions, its failure to address them at all prevents further jurisdictional analysis in that area. The calculation of CONE is not applicable in the PCOM. Also the three proposed backstop mechanisms are all under Commission jurisdiction.

In one significant area of uncertainty, the Aglet proposal addresses jurisdictional issues related to non-CPUC jurisdictional entities only by reference to AB 380 without additional explanation or analysis. Energy Division staff is concerned that the proposal has not sufficiently considered non-CPUC jurisdictional entities that may impact overall grid reliability or cost allocation issues related to new generation in the California market.

Facilitates Environmental Policies

The PCOM does not address environmental policies in sufficient detail to make a determination. The Aglet proposal does not address impacts on or by the state's environmental policies except to say that the environmental policies are being addressed in R.06-02-013, the Commission's LTPP. No detail is provided on the coordination between the RA program and the LTPP program. While the possibility of environmental policy impacts on the RA program could in theory be addressed in the LTPP program under the PCOM proposal, Energy Division staff is concerned that the Aglet proposal may not sufficiently consider the potential impacts of the PCOM on programs such as the GHG requirements.

Possesses Fundamental Feasibility

Energy Division staff is concerned that the PCOM proposal is potentially lacking fundamental feasibility for several reasons. Primary among them is lack of detail on how portions of the proposal will be implemented and address various concerns. There appears to be a lack of coordination between a 90 percent forward showing where new generation may participate and the remaining obligation, where new generation may not be able to respond sufficiently. This scenario, as addressed above, is likely to result in a dependence on directed new generation rather than market induced new generation. Energy Division staff is also significantly concerned that insufficient consideration of the balance sheet impacts of call options on load-side market participants was included in the proposal. Finally, as addressed above, the PCOM is to be administered by a third party selected via an RFO process run by the CPUC and potentially generate revenue on a forward going basis from transaction fees. The short or long term cost of running or creating the market were not calculated. This market administration mechanism is inadequately addressed in the proposal for Energy Division staff to discount the potential risks and expenses not addressed in the proposal.

Additionally, Aglet did not have a representative present for significant portions of the August workshops to answer question or proffer insight into how the PCOM works in a variety of different scenarios. The workshops represented a significant mechanism for addressing details not explicitly addressed in proposals or potentially interpreted in multiple ways. The inability to ask Aglet representatives to address specific issues in the workshops further limits staff's ability to speak affirmatively to the fundamental feasibility of the PCOM.

Mirant

Summary of the Mirant Proposal

Mirant proposes annual assessments of capacity requirements, by Local Areas and system wide, with an annual capacity auction and short term LSE compliance showing, as is done in the NYISO. In addition, Mirant proposes retention of some parts of the current RA program. The CEC load forecasting, CAISO qualification of resources, and CPUC enforcement mechanism represent current parts of the current RA program that would be retained. The Mirant proposal includes changing from a monthly peak compliance showing to an annual peak showing and the refinement of some counting conventions for particular resources. Under the Mirant proposal the pricing of capacity is determined via a sloping demand curve that is established by a central clearing of a combination of LSE provided and centrally procured resources. In short, the LSEs provide resources they have procured to hedge their exposure to the central clearing prices and the CAISO clears all resources and procures any deficiencies to set a demand curve price for the next compliance period, either month, season, or year. Their proposal includes an ex-ante PER deduction based on historical data.

The CAISO will clear each Local Area individually to ensure that capacity is procured in sufficient quantities and paid respective to other capacity within Local Areas. All suppliers of capacity receive the final auction clearing price and all LSEs pay it. Under Mirant's proposal

LSEs and the CAISO would trade a standard UCAP product which has been de-rated for performance and outages. The System and Local RA obligations will continue to be based on a cooperative forward assessment that describes needed locational amounts of capacity, and necessary resource mixes to meet CAISO operational standards.

Mirant asserts that the continuation of ratepayer funded investment is fundamentally inconsistent with a market based investment approach, and that entities that are able to support investment through ratepayer funding or side payments can cause the market to clear artificially low by bidding the new generation into the market at $0. Additionally, Mirant asserts that bids supported by ratepayers will not reflect the true level of risk, since those costs are passed through to ratepayers, whereas merchant generation's risk exposure is included in their bids.

Analysis

Ensures Reliability

The Mirant proposal carries significant risk regarding reliability. Energy Division staff is concerned that a short term LSE-based capacity requirement will not work as proposed by Mirant. The requirement of a CAISO backstop in a short term timeframe in the event the primary LSE based market fails to deliver sufficient RA resources only ensures reliability if there is sufficient generation available in the market already. This scenario would likely only apply when an LSE was incapable of paying market clearing prices for capacity. What is not clear in the Mirant proposal is how reliability is ensured between the pricing signals of a nearly short market and the time when new generation responding to those signals actually comes online.

Mirant's proposal permits a bilateral approach to LSEs fulfilling their RA obligations, and a central CAISO clearing mechanism to determine a price which is paid to all capacity within Local Areas and outside Local Areas. Should the LSEs fail to procure sufficient capacity, the CAISO would use a non market distorting price to procure backstop capacity if it exists. It is not clear how the mechanism would operate. Regardless and as stated above, this promotes short term reliability only when there are sufficient resources available. This approach is distinct from the current RA program because procurement of new generation is not directed in a long term environment under the Mirant proposal. Energy Division staff is concerned that short term reliability is not secured between the time the market clears and the period when new generation responding to those signals comes online to actually meet reliability needs.

While Mirant's proposal does not include any backstop mechanism other than the RA program itself, during the August workshops Mirant acknowledged that some mechanism must ensure reliability should the RA program fail to do so. Those mechanisms were not sufficiently addressed in the workshop for Energy Division staff to comment on them formally beyond summarizing them as insisting on being minimally invasive on the unhindered functioning of the RA program.

Enables New Generation

While the Mirant proposal raises concerns over the timeliness of new generation, over time it would seem new generation would respond to high capacity and energy prices and enter the market. Mirant's proposal specifically envisions new generation entering the market via merchants' estimated revenue from a demand curve with a "gentle" slope[15] based on the price of new entry at market equilibrium or via bilateral contracts between generators and LSEs seeking to hedge the clearing price emerging from the CCM. Unfortunately, there is limited evidence that a year-ahead CCM will incent merchant generation to enter the market without a long term contract. The NYISO CCM has not been shown to incent new generation without long term contracts. The short time period between the market and the delivery period precludes new generation from competing in the market without significant merchant investment prior to the auction. If there was uncommitted capacity or demand resources that can be mobilized in a short time frame, they would represent the sole means of meeting deficiencies in the interim.

Adheres to Least Cost Principles

The Mirant proposal does not adhere to least cost principles. To the extent that there is overcapacity in a particular market, the downward sloping demand curve requires over procurement. In addition, all capacity is paid the same price. That price is determined by the administrative set demand curve and the CAISO's determination of CONE. To the extent that new capacity bids clear in the market, existing capacity receives the same capacity payment. Also to be considered is the cost of backstop or other out of market or regulatory procurement if the CCM does not incent sufficient generation to meet reliability needs.

An additional issue is market power. To the extent some of the local areas are closely held, the generation owners in those markets may be able to exert market power to increase the market clearing price.

Enables Direct Access

The Mirant proposal positively impacts DA. The CCM method of cost allocation to all LSEs based on actual load does not require small LSEs to forecast demand or contract for capacity to meet a forecast. Small LSEs have repeatedly noted the costs and risks related to load migration. This proposal would address those concerns.

Recognizes Jurisdictional Constraints

The Mirant proposal addresses jurisdictional issues only with regard to non-CPUC jurisdictional entities and imports without focusing on FERC/CPUC jurisdictional issues directly. However, as designed the proposal relies on a FERC jurisdiction trading platform and a FERC approved CONE calculation. The proposal includes a collaboratively determined PRM. Mirant proposes addressing the subject of non-CPUC jurisdictional entities via the CAISO's

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15 August 3, 2007 Mirant Track 2 Proposal, p.27.

tariff authority. The Mirant proposal also includes a shared multi-agency view of handling imports via adjustment of the QC calculations to ensure reliability. While there are minimal details on FERC/CPUC jurisdictional issues, the implication is clear: Mirant view a capacity market as a FERC jurisdictional mechanism. This view can create cross-jurisdictional complications (see the environmental policy section below). Mirant expressly states that the demand curve is set via a FERC process.

Facilitates Environmental Policies

The Mirant proposal's facilitation of environmental policies is unclear. Mirant's proposal minimally addresses the state's environmental policies. The only issue directly addressed is that DR should be able to participate based on its performance at peak. Aside from DR, the proposal does not consider its impact on the state's environmental policies nor does it consider the environmental policies on the program. During the workshops Mirant made repeated references to new generation entering the market without being tied to ratebase. Mirant also acknowledged that new generation will continue to come online to meet the RPS obligations as the Commission directs. The possible conflict between those positions was not addressed directly. Similarly, the potential cross-jurisdictional concerns related to a FERC jurisdictional program impacting or being impacted by CPUC environmental policies were not addressed.

Possesses Fundamental Feasibility

Energy Division staff believes Mirant's proposal is feasible. NYISO has implemented a similar proposal for several years.

Constellation

Summary of the Constellation Cal-CIM Proposal

Constellation's California Capacity Infrastructure Model (Cal CIM) proposal is similar to the CCM design in New York, with one key difference. That difference is that the Cal CIM model calls for the jurisdictional agencies (including the CAISO, CPUC, and CEC) to inform market participants of the state-wide and locational RA requirements, including the PRM, three to four years in advance of the delivery year. LSEs may enter into bilateral transactions to meet their capacity obligations at any time.

Prior to each supply month, LSEs may report their capacity purchases to the CAISO. The CAISO then conducts a spot auction. All capacity offered into the spot auction, including capacity reported by the LSEs, and any other capacity that is offered is paid, for that month, a clearing price that is determined by a demand curve that has been established at the time the resource obligation was announced. The demand curve pricing is based on the CONE less estimated PERs for a proxy unit. In each month, all LSEs pay the monthly spot clearing price for their share of the overall RA obligation. LSEs that have entered into bilateral capacity transactions in advance of the monthly spot auction are hedged against the spot auction clearing price. In addition, LSEs whose load has changed, due to load migration, for instance, may offer their excess capacity into the monthly spot auction, if they have not sold it bilaterally.

In its updated proposal, submitted on August 3, Constellation included a proposal for an additional backstop capacity procurement that would be triggered by a shrinking reserve margin and lack of new generation siting activity.

The Constellation proposal stresses that a CCM should provide (i) planning information, and (ii) a transparent price signal for the capacity product that together will facilitate and support bilateral contracting. The demand curve feature of the Constellation proposal also provides a means to limit the abuse of market power. Finally, Constellation emphasizes the importance of implementing a capacity market model that promotes bilateral transactions, so that the wholesale market structures will be able to support renewed merchant investment and thus replace the biennial regulatory authority for utility-backed investment in new generation.

Analysis

Ensures Reliability

The Constellation proposal carries significant risks regarding reliability. Constellation's proposal, the Cal-CIM, like the Mirant proposal, relies on price signals from the capacity market to signal new generation to enter the market. Energy Division staff remains concerned that this does not address short term reliability via non-market distorting mechanisms. While the Cal-CIM market is an LSE based RA requirement at its foundation via the forward obligation’s provision a target capacity level, there is a disjuncture with the pricing associated with that target. This disjuncture creates uncertainty in the market and may discourage market entry until it becomes clear that there is not enough capacity in the short term. As addressed below, it is not clear that the price of capacity set by an administrative target that has not been updated over time will match actual need.

Constellation indicated that some backstop mechanism is potentially necessary with the Cal-CIM proposal and that the proposal is compatible with such a mechanism as long as it is used minimally and does not interfere with market pricing signals. Energy Division staff emphasizes the backstop mechanism potentially interacts in a number of ways with the pricing expected in the Cal-CIM proposal in ways that are dependent on the exact backstop mechanism.

Enables New Generation

The Constellation proposal raises concerns about new generation. Similar to the Mirant proposal Constellation’s proposal envisions new generation entering the market via merchants’ estimated revenue from a demand curve based on the price of new entry at market equilibrium or, potentially via bilateral contracts between generators and load sufficient to meet load’s RA obligations. The Constellation proposal is structured to enable new generation to help meet RA obligations by being able to build based on the RA targets which are announced four years forward. Energy Division staff is concerned that the delay between the RA obligation signal and the LSE showing requirements does not provide stable pricing signals. In particular Energy Division staff is concerned that some LSEs will procure generation four years out to meet RA obligations but that other will not be able to or will elect not to and will create volatility for the reasons stated above in the analysis of Mirant's proposal.

Energy Division staff has two main concerns with the Constellation proposal as it related to new generation. First, there is a concern that, similar to the Mirant proposal, the Cal-CIM proposal does not adequately address the issue of lumpy generation not matching non-generating unit based RA targets for small LSE. While larger LSEs may be able to procure generation based on four year out signals, Energy Division staff is concerned that new generation is not particularly suited to address short term marginal needs from a wide base of small LSE. Additionally this proposal risks administratively directed new generation to meet the demand during short term periods of market disequilibrium that may prevent merchant generation from entering the market based on the price signals themselves.

Adheres to Least Cost Principles

The Constellation proposal does not adhere to least cost principles. As addressed in the section above on Mirant's proposal, least cost principles are neither a goal nor a guideline in the Constellation proposal. While Constellation's use of a four year forward RA target potentially reduces volatility in pricing by both providing opportunities for new generation to enter the market in competition with existing generation, the proposals fixed RA target is worrisome. In particular, errors in forecasting can create situations where real world demand is not matched to administratively determined demand. In such scenarios the market is sending the wrong pricing signal or under procuring capacity.

Similar to the concerns raised with the Mirant proposal, the energy market is effectively pushed into volatility in the capacity market with no apparent benefit to any party but existing generation. Also like the Mirant proposal, regardless of the efficiencies or inefficiencies associated with generation entering the market via the Constellation proposal, the Commission's least cost principles are for all intents and purposes minimized because there is no Commission review of procurement.

On total, Energy Division believes the volatility in this Cal-CIM proposal results in higher costs than proposals with less volatility or with volatility mitigating elements built into them. Staff is similarly concerned that price signal dependent capacity markets are flawed owing to the fact that the clearing price of capacity drops with the new entrant's participation in the market. The effect of this pricing disparity increases uncertainty in the market rather than decreases it with the increased amount of pricing information. Additionally the proposal ignores the fact that the inefficiencies in the signal risk distorting the pricing new entrants should expect from the energy markets.

Enables Direct Access

The Constellation proposal increases risks for the DA market. While the flexibility of a multi-year period to meet a RA can be generally considered as DA enabling, Energy Division staff has several concerns related to the compatibility of the Cal-CIM program with DA. As discussed above staff is concerned that the risk of volatile price swings during market disequilibria may prove difficult for higher customer volatility LSEs. Similarly, the concern that DA serving LSEs may be the most exposed to market disequilibria induced price swings in a manner that discourages the DA market by exposing only it prices that do not reflect the actual market. This forces ESPs to change their business model to assume the risk of market fluctuations that make it hard to offer rates competitive against the IOU ratemaking ability.

Recognizes Jurisdictional Constraints

The Constellation proposal risks increased exposure to disputes on jurisdictional issues. While the Constellation proposal does not address jurisdictional issues with regard to FERC/CPUC jurisdictional concerns, similar to the Mirant proposal, the implication with Cal-CIM is that a capacity market is a FERC jurisdictional mechanism.

The establishment of the PRM occurs under the Cal-CIM proposal via collaboration between the CAISO, CPUC, and CEC. The CONE calculations and the administratively determined elements of the demand curve would occur under FERC jurisdiction.

Facilitates Environmental Policies

The Cal-CIM risks complications with environmental policies. Constellation's proposal, similar to Mirant's proposal, only minimally addresses the state's environmental policies. DR is able to participate in the Ca;-CIM, but Constellation's discussion of the impact on and by environmental policies is minimal. The proposal does not consider in any detail impact on the state's environmental policies nor does it consider the environmental policies on the program beyond that the proposal would provide "strong incentives…to meet those goals". [Constellation proposal, March 30, 2007 p.33] While not directly addressing RPS, Constellation stated that the Cal-CIM proposal is incompatible with "the existing hybrid market that provides regulatory guarantees for utility investment" [Constellation proposal March 30, 2007 p. 27]. This potentially risks cross-jurisdictional concerns related to a FERC jurisdictional program impacting or being impacted by CPUC environmental policies similar to those discussed in Mirant's proposal.

Possesses Fundamental Feasibility

Although clearly distinct from the Mirant proposal Energy Division staff has both similar and distinct concerns with the fundamental feasibility of Constellation's Cal-CIM proposal. Energy Division's primary unique concern regarding the Cal-CIM proposal relates to the potential mismatch between the projected obligation and the actual obligation at the time of the one year showing or in the energy market itself. Energy Division staff is also concerned with the varied ability to procure capacity from a four year forward versus a one year forward perspective depending on the size and credit facilities of LSEs that may create pricing problems that discourage DA. Similar to the Mirant proposal, Energy Division staff is concerned with unrecoverable windfall to existing generators that may create market imbalances over time and the NYISO market as well as the NYPSC's concerns with the NYISO market.

CFCMA

Summary of CFCMA Proposal

The CFCM proposal is similar to New England's FCM approach, but also includes several modifications. The proposal includes a five year planning horizon, with a four year centralized forward, locational capacity auction, and includes reconfiguration auctions that are used to acquire capacity needs based on adjusted planning assumptions. The CFCM proposal includes a sealed bid auction to clear offers of capacity resources (including planned resources, imports, and DR) to secure the required quantity of resources, statewide and locational.

While not explicitly included in the CFCMA proposal, New England's FCM approach does include a PER deduction. During the August workshops several members of the CFCMA indicated they objected to a PER that is deducted from energy revenue or calculated on an ex post, as opposed to an ex ante, basis.

The CFCM proposal includes performance incentives similar to those in place in the PJM capacity market. Planned resources are eligible for a price and quantity commitment of up to ten years.

The CFCM proposal includes market monitoring, mitigation, and a price collar so that capacity clearing prices stay with a zone of reasonableness around a competitive level, especially in import-constrained areas in which there are relatively few buyers and sellers. The design also includes provisions for backstop procurement by the CAISO.

Analysis

Ensures Reliability

The CFCMA proposal ensures reliability. The CFCM proposal provides multiple mechanisms for meeting the RAR. LSEs are provided the opportunity to bilaterally contract for capacity, but this contracting is effectively a hedge against the clearing price delivered by primary mechanism for ensuring the RAR is met, the CAISO's operation of a centralized auction for the RAR in a four year forward environment. The CAISO can increase the RAR in the first of three subsequent reconfiguration auctions, during which parties can trade capacity based on hedging positions or changes in load.

Under the CFCM proposal the CAISO may also run a separate auction for additional capacity to secure additional capacity if necessary for backstop purposes. The details to do so are not included in the proposal, but such a supplemental market would need to be structured to prevent withholding from the primary auction. This supplemental auction is the primary backstop mechanism of the CFCM.

Enables New Generation

The CFCM proposal enables new generation. Under the CFCM proposal new generation enters the market via either bilateral contracting bid in as self supply or by merchants bidding capacity offers from potential facilities into the markets. When those prospective units' bids clear the market, the merchant has four years to bring the plant on-line. In addition, new generation that clears the market can choose to lock in the winning capacity payment for up to ten years, creating a guaranteed revenue stream.

Adheres to Least Cost Principles

There is significant exposure to lack of adherence to least cost principles with the CFCM proposal. Like other capacity markets, all capacity is paid the same price. To the extent that new capacity bids clear in the market, existing capacity receive the same capacity payment. This is potentially far in excess of the economic costs of the units.

The four year forward design of the CFCM proposal ensures that new generation bids against existing capacity that has not entered into bilateral contracting agreements. This mitigates market power to the extent that merchants find the market attractive their participation essentially caps the capacity price at the true CONE.

There is a great deal of uncertainty related to the cost of the operation of the CFCM proposal. Energy Division staff made efforts to determine costs associated with the operation of the NE ISO. Anecdotal information points toward significantly higher costs especially related to market monitoring and program establishment costs including software systems. During the August workshops CAISO market monitoring staff indicated they were not sufficiently staffed to handle those responsibilities at this time. Energy Division staff recommends additional information be gathered on this subject, but it was not available at the time of the release of this report.

Enables Direct Access

The CFCM proposal generally enables DA. The CFCM proposal is highly compatible with DA with a minor caveat. ESPs are provided with the opportunity to self supply at their own discretion. This flexibility allows ESPs to hedge against the clearing price of the CFCM to the extent they choose. The potentially DA discouraging element of the CFCM is related to the ability of large generation to hedge against the clearing price of the CFCM by obtaining capacity bilaterally in a manner that ESPs are not capable of replicating. Such a scenario has the effect of unevenly exposing ESPs to the CONE relative to the larger IOUs in the same market.

Recognizes Jurisdictional Constraints

The trading platform of the CFCM falls under FERC jurisdiction. All capacity, including capacity secured bilaterally bids in to the CAISO administered market and receives the clearing price. The market structure is established via a FERC approved tariff.

Based on discussions during the August workshops and the CFCMA filings, the determination of net CONE in the CFCM proposal is collaboratively set, apparently under FERC jurisdiction, initially in the CFCM. Over time CONE is set by the market itself. The floors and caps in the CFCM are set under FERC tariff.

The mechanism for establishing the PRM is described as "state approved" [p.8 appendix C, August 8, 2007 CFCMA filing]. During the August workshops CFCMA members indicated that the PRM could be established collaboratively by the CPUC, the CAISO and the CEC, but that such a determination is to be worked out in the subsequent phases of implementation. It is not clear if this nature of this determination is included in the FERC approved tariff or would exist elsewhere.

Facilitates Environmental Policies

The CFCM's facilitation of environmental policies is unclear, but the risk of negative impacts is significant. The CFCM proposal envisions self provided capacity from RPS related procurement as bidding into the centralized market as a price taker. In this regard the primary concern regarding environmental policies would be that a FERC tariff would potentially be the mechanism for placing qualified capacity values on the RPS generation in the FERC controlled market.

The potential impact on GHG programs is difficult to determine in the CFCM proposal. There is a risk that capacity payments in the CFCM may increase the effective costs associated with some GHG scenarios. This risk is difficult to quantify and Energy Division staff recommends further discussion on the subject before a final Commission decision.

Possesses Fundamental Feasibility

The CFCM proposal is a complex program that will take many years to implement. It has many interrelated issues that will require extensive proceedings to resolve. In addition, the NEISO model on which it is based is only now beginning implementation and it will be years before its success can be evaluated.

The costs associated with the administration of the CFCM proposal are potentially high and there has been little record development of the subject. As addressed above there is anecdotal information indicate that there would be a significant increase the market monitoring necessary to ensure the market functions properly compared to the existing RA program.

Additionally, Energy Division staff is concerned that a market that relies on an administratively set floor for capacity does not reflect the actual value of capacity. While the CFCMA members indicate the floor is necessary to prevent market manipulation of the capacity price, Energy Division staff does not believe the costs associated with a floor as well as the market distortions allow for a true market price to exist. During the August workshops some participants indicated the CFCM is likely to produce prices at the floor or the cap than between those administratively set values. Energy Division staff remains concerned that a third scenario is also likely, namely that the capacity market will clear just below the CONE resulting in no new generation but high capacity prices. To some extent this issue is mitigated by a PER deduction, which CFCMA members agreed is the mechanism in place in ISO New England, which serves as the model for the CFCM proposal. Energy Division staff remains concerned that a PER deduction does not sufficiently mitigate against market power unless it is calculated ex-post rather than the tacitly proposed ex-ante. A detailed discussion of this concern can be found below, but to summarize, Energy Division staff remains concerned that an ex-ante PER results in low capacity prices precisely at the time when shortages in supply should be resulting in high capacity prices to enable new generation to enter the market. While it has been argued that energy prices would then be signaling new generation, Energy Division staff remains concerned that the volatility of energy prices does not provide the pricing stability necessary to minimize the costs of new entry associated with credit risks. Additionally, staff is concerned that a program that pays capacity payments for only a few years before high energy prices drive new generation beg the question of why a capacity market is necessary at all as well as if such a program's start up costs can be spread over a sufficient period of time to minimize their impact on the market.

Finally, Energy Division staff remains concerned that the CFCM proposal provides no off-ramp in the event of market failure or significant market distortion. Staff has significant concerns with the potential costs associated with the failure of a program that the Commission has no direct ability to control.

Summary of Other Metrics

Regardless of the strengths and weakness of each model as a stand alone theoretical framework for the Commission's forward going RA program, the Energy Division staff is required to consider the proposals in the context of real world implementation in California's complex state and federal environment. Considerable effort was made in the August workshops and in comments to address some of these issues, many of which are addressed above, but many issues require further examination. While it is untenable to completely address all of the potential issues, there are several categories that merit further development.

QFs/UOG

The proposals do not explicitly address how QFs and UOG should be treated but that can be inferred from the other aspect of the proposals. In the BTG proposal QFs and UOG are treated as a special instance of a bilateral contract which can be applied toward meeting the RAR. The Aglet proposal does not differentiate QF and UOG from other resources since the main focus of that proposal is on establishing a supplemental market for call options that would meet part of the RAR. The proposal by Mirant, Constellation CFCMA and PG&E composite, all envision self-provision of capacity which can be cleared through the CCM either as price taking bids or be netted from the LSEs obligation. UOG and QFs contracted on a long term basis will qualify as auction tenders under either the short term or the forward capacity auctions and can therefore be accommodated without impacting the effectiveness of the CCM. Thus as far as handling of QFs and UOG, none of the proposals has a relative advantage or disadvantage.

Target Capacity and PRM

To varying degrees, each of the four CCM proposals as well as the BTW and Aglet proposals attempt to build or rely on the existing RA program targets. Each of the proposals recognizes the need for the specification of procurement targets at both the system level and the local level. In addition, each of the proposals contemplates a target procurement level based on some level of PRM. The main difference between the proposals lies in the forward visibility and lead time available to the CAISO and market participants to take corrective action when resources fall short of the need relative to a multi year forward assessment of capacity requirements.

The BTG proposal advocates the continuation of the annual RAR. While a substantial fraction of resources used in the RAR compliance are procured through multiyear contracts, the same year compliance verification, provides no information regarding planned retirement of plants or future resource availability, with sufficient lead time to procure new resources or adjust transmission expansion plans. The problem is partly addressed in the BTG proposal through the procurement of new generation resources on a multiyear basis based on multiyear assessment. The physical call options advocated by Aglet can provide forward visibility regarding future resources provided that the traded options have three or four year lead time.

Among the capacity market proposals, The Constellation short term Market proposal includes long term forward planning that will guide bilateral capacity procurement, however, the actual verification of available capacity takes place too late for the ISO or new entrants to respond. The argument that the bilateral market is sufficiently transparent to provide early warning signs in case of future resource shortage is not persuasive.

To the extent that the Mirant proposal tries to preserve the existing RAR process it has the same shortcoming with regard to visibility into meeting capacity targets. Furthermore, the Mirant pitch to take new generation investment away from the IOUs will further reduce forward visibility into future RA. However the latest amendment of the Mirant proposal indicated flexibility with regard to adopting a Forward Capacity approach rather than the short term capacity market. The Mirant proposal also suggested using annual capacity targets on the grounds that capacity is inherently an annual product. While the CAISO seems to favor this concept, the idea of an annual capacity target has been criticized by DRA arguing that an annual target results in over procurement and excess cost to consumers. Considering the variation in summer and winter ratings of resources, a seasonal target may be a reasonable compromise.

The PG&E composite proposal deals effectively with providing forward visibility with regard to new generation resource procurement. However, the short term capacity auction makes it difficult to verify RA in time to enable corrective action if targets are not met.

The CFCMA proposal explicitly addresses the forward visibility issue by imposing resource verification with sufficient lead-time to allow response by competing new resources. Subsequent reconfiguration double auctions guarantee that the updated targets are met through market mechanisms rather than backstop procedures.

All the proposals presume that the PRM will be set based on technical considerations and defer to the outcome of other proceedings that will address the criteria and methodology for PRM determination. The BTG proposal envisions future reduction in the PRM in an energy only market framework, as a result of increased DR to real time energy prices. However, given the ISO operating procedures and NERC reliability standards it is doubtful that the ISO will reduce reserve procurement counting on passive load response. The CFCMA proposal does not explicitly specify how demand can participate in the FCM, however, the ISO-NE FCM upon which the CFCMA is modeled, allows demand side participation in the primary and subsequent reconfiguration auction. Demand side offers accepted in the FCM effectively reduce the PRM since commitment by demands to reduce load replaces the need for new generation or imports. As the BTG proponents pointed out such DR is different than response to real time prices, however, in the foreseeable future only such advance commitment by demand will induce procurement of less reserves by the system operator.

Credit Issues

Whenever long term commitments are involved one must address the question of how to assure that commitments will be honored without placing unreasonable burdens on the parties. Risks should be placed on the parties best able to handle or mitigate them.

While none of the proposal specifically addresses the credit issue it is not too difficult to extrapolate the credit implications from what has been proposed. The BTG proposal advocates continuation of the status quo which seems workable as far as credit is concerned. The LSEs RAR obligation are sufficiently short term as to not to raise credit issue since the one year contracts can be easily backed by supply contracts with customers. On the other hand long term procurement from new generation facilities is underwritten by the IOUs which are in turn underwritten by the rate payers. However, the credit issue may present obstacle to extending the RAR forward visibility to four years since then LSEs may encounter credit obstacles that will make it difficult to enter into three or four year bilateral contracts, unless they are able to sign up customers for such extended periods. The Aglet proposal may also encounter credit problems in underwriting three or four year forward call options, unless such options can be secured by the tariff authority of the ISO which would be difficult to do if the market is being run by an independent third party as proposed.

The Constellation proposal and Mirant proposal places all the risks of new generation on the generation developers who recover it though the CCM. The Mirant proposal's strong pitch for taking long term procurement of new generation contracts out of the hands of the IOUs should be evaluated in light of the credit consequences of such a move. The PG&E composite proposal places the underwriting of credit risk, either on the customers or on the ISO who is envisioned in the proposal as the counterparty to the capacity portion of the long term contracts. With regard to existing capacity, the credit problem is addressed adequately whether the centralized capacity component of the PG&E proposal is a short term one or a forward looking one (as will be discussed hereafter). The CFCMA proposal provides forward visibility into RA without imposing a heavy credit burden on LSEs whose contracts with customers are shorter than four years in length and are not protected by ratepayers.

In the Constellation, Mirant, and CFCMA proposals the ISO procures the forward commitments and guarantees payments at performance time by virtue of its tariff authority. So at commitment time the ISO collects the capacity payments from the customers and pays the suppliers. This arrangement also automatically addresses load migration and load shrinkage since the payment follows the load wherever it ends up and any shortfalls are automatically prorated over the entire load.

The one area where the CFCMA proposal may face credit issues is with regard to financial assurances from new resources. Obtaining adequate financial guarantees from entities who commit to bring new resources online in four years will place a very high credit burden on such entities and consequently raise the cost of new capacity to the consumers. In order to avoid such higher cost the CFCMA proposal (following the ISO-NE FCM) has limited the financial guaranties which can be interpreted as having consumers share the risk of default with the new investors. However, in order to minimize such risk the proposal suggests close monitoring of new capacity construction to ensure adherence to predefined milestones and to provide early warning of possible delays in new capacity coming on line.

Opt-out from Cost Allocation Mechanism and Energy Auction

The current RA Program incorporates the Energy Auction and Capacity Allocation Mechanism from D.07-07-044. Under the adopted mechanism, the large IOUs procure capacity via Power Purchase Agreements that is meant to serve system needs, not bundled needs. IOU owned generation cannot participate in this mechanism. The IOUs then hold an auction to sell the electricity from these plants, and bill the remainder if there is remaining costs to all benefiting customers. Under the current Capacity Allocation Mechanism the LSE notifies the CPUC of their purchases of new generation multiple years forward and the CPUC determines that the LSE has contracted for the construction of new resources sufficient to cover their contribution towards overall system need. Then the CPUC notifies the IOU which bills customers for their new construction and the IOU via the distribution section of the company then removes that component of the distribution charge from the customers that are taking retail service from that LSE. The LSE has them opted out of the Capacity Allocation Mechanism and does not receive a share of the capacity credit for resources that their customers no longer pay for.

For a centralized market, an opt out mechanism is different since the CAISO or CPUC is the agent that authorizes new construction, and an LSE is not directly billed for the capacity until the time of actual delivery. In this environment, under an opt out mechanism an LSE that has procured sufficient resources to satisfy their needs for new construction would be able to notify the CPUC or the CAISO that they have met their forward obligations for both existing and new capacity out into the time horizon that the centralized market is clearing at the time of their showing, and once the CPUC has approved their showing to this effect, they either would not be billed for whatever the centralized market clears at, or what the CAISO bills others for any backstop that occurs.

The BTG proposal, in advocating continuation of the status quo, implicitly proposes continuation of the Capacity Allocation Mechanism, which means development of an opt out such as described above. The Aglet proposal does not address opt-out explicitly. The PG&E composite proposal also does not address opt out explicitly but one can infer that they would not object to continuation of the Capacity Allocation Mechanism so long as there are no free riders on the operational environmental and other attributes of the new resources procured by PG&E through the RFO process. The Constellation and Mirant proposals, while allowing self provision, do not provide a stable environment for an opt out mechanism due to the variable procurement imposed by the demand function they advocate. Specifically if an LSE self provides its share of the target capacity it may still find that the CAISO procured more than the target capacity level because the price was right and as a result the self-sufficient LSE will get a bill for its share of the excess capacity procured under the demand function approach. The CFCMA proposal does not create instability for a self providing LSE by using a fixed target capacity so that any entity can opt out by self-providing its obligation and bidding it at price zero into the capacity market. In the settlement process at performance time the payment obligation of the self-sufficient LSE will be expected to offset receipts for the capacity it sold.

Relationship to Energy Market

An energy market with marginal cost pricing for energy and scarcity pricing to reflect scarcity or DR is the economic gold standard for market signals that will induce efficient technology mix and supply adequacy. Furthermore, efficient allocation of risk among investors and consumers dictates that the price volatility resulting from such an energy only approach should be mitigated through long term contracting and financial hedges. From an economic perspective the primary difference between the different proposals lies in how they propose to collect the scarcity rents and the extent to which the collection and distribution method of such rents is done in a timely and effective way that will induce needed investment and maintain an efficient capacity mix.

In the BTG proposal scarcity rents are imbedded in the bilateral contract prices. However, the lack of transparency in that approach and the reality that at least in foreseeable future the residual energy markets will be capped (although the BTG proposal envisions an unmitigated energy only market in the long run) raises questions with regard to the efficiency of the bilateral market as the dominant mechanism for ensuring generation adequacy. Standardized product and bulleting board trading will partially address the price transparency issue but unless the traded product are sufficiently forward looking to enable participation by new merchant generation, the market signal provided by such a bulletin board will not provide adequate incentives for efficient new investment and updating of the generation fleet. Separate contracting with new generation attempts to rectify this problem but such separation is incompatible with a unified competitive energy market. The Aglet proposal recognizes that the only meaningful definition of a capacity product is a call option on energy which enables generators to collect scarcity rents in the form of an option premium. Al the other proposals that advocate a CCM including the PG&E composite proposal fail to recognize that capacity payments in any form can be only justified economically as a mechanism for collecting scarcity rents (otherwise known as missing money) that are needed to support fixed cost recovery by generators. It is therefore prudent that in exchange for collecting capacity payments generators should forgo scarcity rents in the energy market trough some form of ex-post PER adjustment. None of the CCM proposal including CFCMA supported an ex-post PER adjustment, although such an adjustment is paramount to the economic justification of capacity payment. An ex-post PER adjustment would not only support the economic rational of capacity payment as an alternative form of collecting scarcity rent but would also provide an additional tool for mitigation of market power in energy markets by neutralizing the incentives of generators for economic withholding.

The ex-ante adjustment to the estimated CONE based on expected energy revenues which is used implicitly or explicitly in all the capacity market proposal is a poor substitute to an ex-post PER adjustment. First of all, unlike a PER adjustment that is applied to the final capacity price resulting from the auction, the energy revenue deduction used in the calculation of Net-CONE may not carry into the final market price for capacity if bidders use a more conservative estimate of energy revenue than the expected value. Second the ex-ante deduction does not have the energy market power mitigation effect and third generators collecting only a portion of their fixed cost through a reduced capacity payment relying, on energy revenues to make up the difference are exposed to more risk than if they received a full CONE based capacity payment and in exchange had to return the scarcity rent portion of their energy revenues.

CAISO Recommendations for the Design of a Central Capacity Market

Introduction and Summary

This section of the report presents the CAISO's recommendations to the CPUC regarding the high level design principles and features that should be reflected in a CCM)). In this paper, the CAISO is not taking a position on whether the CPUC should adopt a CCM. Rather, the CAISO is offering its response to the much narrower hypothetical question, "If the CPUC decides that a CCM should be implemented for California, what would be the preferred conceptual design of such a CCM?" By responding to this question, the CAISO is complying with the CPUC's May 25, 2007 Assigned Commissioner's Ruling on Staff Report Regarding Track 2 Issues.

Four entities submitted CCM proposals to the CAISO, and the CAISO's recommendations herein are based on its assessment of these proposals: the California Forward Capacity Market Advocates (CFCMA, consisting of SCE, SDG&E, Reliant, FPL and NRG), Constellation, Mirant and PG&E. To further inform the CAISO's assessment of CCM design alternatives, the CAISO engaged the consulting firm LECG to provide detailed descriptions of the CCM designs recently adopted by the PJM ISO (the RPM) and ISO New England (the FCM). In addition, the CAISO conducted a stakeholder process between August and September of this year and received three rounds of written stakeholder comments on the topic of CCM design.

Based on the CAISO's preferred design principles and features as discussed in this paper, the CAISO believes that the CFCMA's proposed CCM framework is the most favorable design. A significant factor contributing to this conclusion is the fact that only the CFCMA proposal provides for a multi-year forward assessment of the capacity that is actually committed to serve the needs of the CAISO control area. The CAISO believes that such an assessment is necessary for making optimal RA procurement and investment decisions, particularly to facilitate effective coordination with the transmission planning process. A second significant factor supporting the CAISO's preference for the CFCMA proposal is CFCMA's approach to market power mitigation, which the CAISO believes will be critically important to support reasonably priced local capacity procurement in constrained local areas of the grid. Third, the CFCMA proposal includes effective current-period performance incentives for RA capacity (*i.e.* the EFORd and EFORp mechanisms), rather than utilizing a resource's current-period performance only to adjust its QC in subsequent periods.

The CAISO's preference for the CFCMA's CCM framework should not be read as a recommendation to adopt the entire CFCMA proposal as submitted, however, primarily because that proposal and the others address some design details that deserve further, and much greater, evaluation and discussion and therefore cannot and should not be resolved at this time. The CAISO's objective at this time is only to identify high-level design concepts and features that should be included in a CCM design if the CPUC decides to adopt a CCM, not to offer recommendations on all aspects and elements of a complete CCM design. This paper identifies areas where further discussion and issue resolution will be needed and which should be taken up in a later CCM design process if and when the decision is made to pursue a CCM.

This section is included in this joint report as a CAISO section and does not reflect the position of the CPUC Energy Division staff. Energy Division staff highlights that CAISO's position as well as the CAISO MSC's position and the CAISO management response to the MSC opinion are included in this report without being supported or disputed by the CPUC Energy Division staff.

Design Principles and Features of a Central Capacity Market

The rest of this document is organized in the following manner. First, the document identifies a series of topics in each of the numbered sub-sections, starting with the higher-level design concepts and principles, then moving into more detailed topics. Within each topic, the CAISO states its recommendations as a series of numbered propositions. The CAISO also provides additional discussion on each of the propositions in order to clarify and explain the rationale for the stated recommendations, and to identify topics that will need further assessment later in the CCM development process if a CCM is to be pursued.

Long Term Resource Adequacy Design Principles

Proposition 1. The long term RA framework should be designed to (a) induce timely and efficient investment in new supply infrastructure to serve the CAISO control area, and (b) ensure sufficient availability of supply capacity on a day-to-day basis to support reliable grid operation. Objectives (a) and (b) are the means to achieve the more basic goal of providing electric service to CAISO control area consumers at the desired level of service reliability and at reasonable and stable prices.

Proposition 2. Because a point of emphasis in the CCM discussions has been to provide a sufficient revenue stream to suppliers of RA capacity to induce both new investment and the

commitment of existing capacity, the evaluation of CCM design alternatives should take a big picture perspective and consider the full set of opportunities and mechanisms by which RA capacity resources will earn revenues.
In particular, the earnings of capacity resources from a CCM will be complemented by earnings in the CAISO spot energy and AS markets, as well as its earnings from any bilateral contracts it may enter.

Multi-year Forward Resource Adequacy Framework

The term multi-year forward (FMY) framework has commonly been used in the CAISO's CCM stakeholder process, but it does not have a commonly-understood meaning. This section starts by breaking the concept down into component activities that could comprise an MYF framework, depending on what such an MYF framework is intended to accomplish. Of the list of possible components stated below, an effective MYF framework for RA should include at least item (a), but may or may not include any or all of the other components.

(a) MYF assessment of capacity needs;

(b) MYF specification of the RA requirements of each LSE;

(c) MYF commitments by new resources to provide RA capacity;

(d) MYF commitments by existing resources to provide RA capacity;

(e) MYF review or showing of LSE and CCM RA procurement and capacity commitments (which requires some form of items (c) and (d)), and identification of any shortfall or gap between this and the needs assessed per item (a); and

(f) MYF backstop action to address any identified shortfall.

Proposition 3. The CAISO should collaborate with the CEC and CPUC to formulate a MYF assessment of capacity needs (item (a) above), including (i) system-wide capacity needs, (ii) local-area capacity needs, (iii) needed generator performance attributes such as ramping and quick-start capability, and (iv) needs that are responsive to other state policies such as environmental policies.
The CAISO agrees with the arguments of most of the participants that such an assessment will provide a needed body of information to guide LSE procurement activities, irrespective of the degree to which each LSE conducts its procurement bilaterally or through the CCM. The time frame being discussed is 5-6 years forward of the delivery period, but the specifics of the assessment time horizon and process remain to be worked out.

Proposition 4. A MYF review of the resources committed to provide RA capacity (item (e) above) is the most reliable and effective way to ensure that investment in new infrastructure is keeping pace with projected needs, including needs that may be created by the retirement decisions of existing resources, and to allow effective competition among existing resources and new investment in generation, DR and transmission upgrades.

The CAISO believes that a MYF demonstration of resource commitment is preferable to an approach of simply putting out the MYF assessment (item (a)) and then waiting to review actual capacity commitments only one year (or less) prior to the delivery period. In essence, the CAISO believes a complete assessment of the capacity committed to serve a control area load should be conducted sufficiently in advance of delivery to allow appropriate backstop action to be taken if needed. One concern with waiting too long to review actual capacity commitments is that MYF decisions regarding the adequacy of new investment and the possible need for backstop action would have to make strong assumptions about whether all existing resources would continue to be available or might retire or opt out of providing RA capacity (i.e. de-list – a topic covered later in this document).

The MYF commitment is also essential for enabling effective competition between existing capacity, new supply capacity, DR and transmission upgrades. Particularly in local constrained areas of the grid, the capacity price differentials in such areas can be dramatically reduced to the extent that forward commitments of new investment in DR or transmission upgrades reduce the share of overall capacity that must be located within each such area. Later in this document, the CAISO describes one potential approach to allow new generation investment in a local area to compete with a transmission upgrade in the context of the CCM.

In order to accomplish Proposition 4 (item (e)), there must be some rules and procedures for obtaining MYF commitments by new and existing resources (items (c)-(d)). This could be accomplished without specifying each LSE's RA requirements in the MYF time frame, however, because the CCM would clear based on the total demand for capacity at the system level and in each local area, irrespective of each LSE's eventual share of those requirements. As described further below, the LSEs would have the opportunity to self-provide into the CCM any RA capacity they had procured bilaterally, but such LSE self-provision is not a requirement for the CCM to work effectively.

The matter of backstop procurement (item (f)) is discussed in a separate section below.

Primary Reliance on Bilateral Procurement and Self-Supply

Proposition 5. The CAISO supports a long term RA framework that relies primarily on bilateral procurement by LSEs, and only secondarily on the CCM mechanism to procure commitments of RA capacity. Under such a framework, the RA capacity procured bilaterally by LSEs would be offered into the CCM as self-supply.

Primary reliance on LSE bilateral procurement has been part of the RA framework since the program began, and the CAISO sees no reason why a CCM needs to alter that approach. The existing RA and LTPP programs can easily be made compatible with a CCM by structuring their time frames to achieve multi-year forward capacity commitments, so that the capacity procured under these programs can be offered into the multi-year forward CCM as LSE self-supply.

Moreover, the establishment of a CCM would not preclude the CPUC from enhancing these programs, if it so desired, to establish a more centrally coordinated self-supply process for its regulated LSEs, as long as the results of such a process are available in time to be offered into the CCM as self-supplied capacity. Such enhancement may be desired, for example, as a vehicle to implement state environmental policy. PG&E's proposal is somewhat similar to this with its CRFO concept, although the PG&E concept would need to be modified to make it a fully CPUC-sponsored rather than one to which the CAISO would be a party as PG&E has proposed. Some parties have expressed the concern that a high degree of coordination of bilateral procurement, as with PG&E's CRFO proposal, could result in depressing the CCM clearing price by systematically procuring all needed new investment through the CRFO under regulated rate-base cost recovery, thereby preventing new investment from ever setting the price in the CCM. Establishing a positive floor on the CCM clearing price, as discussed later in this straw proposal, may or may not be sufficient or desirable as a way to address this concern. The CAISO believes such potential impacts and possible mitigations warrant further analysis and discussion if a CCM is to be pursued, so that the value of the CCM clearing price as a signal for needed investment is not undermined.

Product Procured Through a CCM

In defining the product to be procured through a CCM, the CAISO supports building upon the existing RA framework and incorporating possible enhancements if needed, rather than developing an entirely different product.

Proposition 6. The CCM should procure MW of supply capacity (including imports and DR) that will be subject to an RA Must Offer Obligation (RA-MOO) under the CAISO tariff. This is consistent with today's RA framework.

The CAISO recognizes that additional work needs to be done on the RA-MOO in the context of fully specifying the standard capacity product to be procured for RA, irrespective of the decision whether to pursue a CCM. For example, it will be necessary to specify additional details on the obligation to offer AS, the nature of the obligation for special types of resources such as DR resources and imports, and how the RA capacity supplier's compliance with the RA-MOO will be measured and enforced. The CAISO also acknowledges the March 22, 2007 proposal of Calpine and the other proponents for a standardized RA contract and associated generator obligations, and expects to address these matters through a stakeholder process starting after the start-up of MRTU irrespective of whether a CCM is adopted.

Proposition 7. The CCM should procure MW of System Capacity and MW of Local Capacity for predetermined local areas of the CAISO controlled grid.

The quantity of System Capacity needed would be determined based on the load forecast for the CAISO system (through appropriate state-led load forecasting process) and the PRM adopted by the CPUC and the Local Regulatory Authorities. The MW quantities of Local Capacity needed for each Local Capacity Area would be determined by the Planning and Infrastructure Development department of the CAISO as subsets of the total System Capacity required. This approach is consistent with today's RA framework.

The CAISO also notes, however, that within certain Local Capacity Areas all supply resources may not be equivalent with regard to their effectiveness on particular constraints. One approach to such situations could be simply to specify smaller Local Capacity Areas, but this approach would likely exacerbate any potential for exercise of local market power. Alternatively, treating all capacity within such a local area as if it were equivalent could lead to under-procurement in the bilateral and CCM processes, thereby requiring CAISO backstop procurement to compensate for the effectiveness gap.

Proposition 8. The CAISO supports adopting a capacity product definition that does not include additional resource performance attributes beyond the requirements of the RA-MOO, but stipulates that it may be necessary to develop additional mechanisms or products to ensure that any needed resource performance attributes not targeted explicitly by the CCM are adequately provided.

Several parties in the CCM process raised the question of whether the RA product should explicitly include requirements for generator performance attributes such as dispatchability, ramping and quick-start capability. The approach advocated by three of the four submitted CCM proposals (except for the PG&E proposal) is to keep such attributes out of the capacity product definition and rely on the spot AS markets in conjunction with the MYF assessment to provide sufficient information and incentives for investment in the types of capacity needed for efficient grid operation. Although in theory it is possible through optimal market design and pricing to induce timely and efficient provision of the needed quantities of supply capacity, as well as the needed types of supply capacity and capacity that is needed in specific locations, it would be risky to rely completely on that approach when the new LT-RA framework is first implemented. The CAISO's concern is that even if a shortfall in certain needed attributes is identified at the time of an MYF review of committed capacity, there would be no mechanism in place to induce the right kind of new investment short of a special, targeted backstop procedure. The CAISO therefore endorses the approach of keeping such attributes out of the RA product definition, but would not foreclose the possibility that additional provisions may be appropriate in order to incent forward commitment of supply resources with specific performance attributes.

The concern could be addressed through approaches that have already been mentioned in the current proceeding, such as the specification of new AS products, the adoption of inter-connection requirements for resource types that create needs for additional dispatchability, ramping or regulation, or the creation of another forward market for the needed attributes. The CAISO proposes to evaluate alternative approaches in the context of the 2008 CCM design process if the CCM approach is pursued.

Performance Incentives for RA Capacity

Proposition 9. The CAISO supports mechanisms that provide effective incentives for RA capacity to be available and perform as needed through adjustments to the current-period capacity prices paid to RA resources, such as EFORp (peak hour availability) and EFORd (average availability) measures.

Such mechanisms are superior to ones that utilize current-period performance metrics only to reduce a resource's QC in future periods, without any impact on the resource's current-period payments.

Pricing and Price Determination in the CCM

Proposition 10. The CAISO supports the use of the estimated CONE as the reference point for establishing the demand and hence the clearing price in the CCM.

The value of the CCM clearing price as a signal for needed new investment, and the usefulness of the CCM auction as a venue for effective competition between existing resources and new resources (including DR, as well as decisions to retire or re-power existing units), depend on the use of estimated CONE as the reference price in establishing demand. Further specificity on the process, methodology and responsibility for developing the estimated CONE for the CCM is not discussed here and would need to be addressed in the 2008 CCM design process if a CCM is pursued.

Proposition 11. The CAISO recommends that the issue of whether to apply a PER deduction to the CCM clearing price in determining the capacity payments to RA resources be addressed in the context of the subsequent CCM development process if a CCM is pursued.

The PER deduction was a controversial and much debated topic in the CAISO's CCM stakeholder process. In fact, it was such an important a topic that the CAISO requested and received an additional set of written stakeholder comments focused on this topic alone, in the hope of being able to arrive at a definitive recommendation to offer at this time. The additional comments led the CAISO to conclude, however, that the decision to apply or not to apply a PER deduction should not be taken lightly and should not be decided at this early, conceptual design stage of CCM development. Rather, this decision should be deferred to a later process in which the objectives of the PER deduction can be fully articulated and alternative ways to design and implement it can be fully fleshed-out and carefully analyzed and compared. The CAISO recognizes that many of the parties would like to have a more definitive answer at this time, but based on the complexities and potential unintended consequences that must be considered in formulating a PER deduction methodology, plus the polarity of opinion on this issue (including polarity on the issue of the benefits versus cost impacts of a PER deduction), the CAISO believes that it is more prudent not to decide the matter before initiating the in-depth CCM development process.

To illustrate some of the complexity involved in a PER deduction, the CAISO refers back to Proposition 2 stated earlier, *i.e.* that the design of the CCM should take into account the full range of opportunities for RA capacity, including new investment, to earn sufficient revenues to be viable. In a competitive market for the supply of RA capacity (which the MYF CCM would create by enabling new investment to compete with existing supply), a competitive supplier would incorporate in its capacity offer price its best estimate of expected earnings in the spot energy and AS markets. Absent a PER deduction that would reduce suppliers' capacity payments after the fact, whenever new investment clears the CCM the clearing price can be expected to approximate Net CONE, which is the CONE minus expected spot market earnings as calculated by marginal supply bidder. As the CFCMA proposal notes, these calculations are performed by and incorporated in the bids of each of the suppliers based on their own assessments of economic and financial factors, so there is no need for administrative calculations under this approach except for the very first time the CCM is run, which requires an estimated Net CONE for setting CFCMA's proposed price collar.

In contrast, the PER deduction discussed during the stakeholder process would be implemented through the CAISO settlement process, based on a methodology that would be aimed at limiting the spot market earnings of RA capacity when spot prices are high. Such a

PER methodology would likely designate a reference resource with a relatively high heat rate, to enable more efficient resources to retain more of their spot earnings and reinforce the incentives to build new or repower efficient units and allow inefficient ones to retire. Depending on how environmental costs are reflected in spot market prices, the choice of the reference unit for PER deduction can also be used to reinforce incentives to build new clean units (e.g. having low emissions of GHGs or other regulated pollutants) and allow dirtier ones to retire.

Parties who oppose the PER deduction argue that it would greatly increase uncertainty of the capacity payment stream and thereby raise the risk and the cost of financing investment in new capacity. Parties who support the PER deduction argue that it provides greater certainty of the total revenue stream of the RA capacity, *i.e.* capacity payments plus spot market earnings, provided the RA resource in question is fully operating during those high-price hours used for calculating the PER deduction. Another argument in favor of the PER deduction is that it creates strong disincentives for suppliers to try to raise spot prices, thereby mitigating potential exercise of market power in a manner similar to an energy hedge contract.

Proposition 12. The CAISO believes that a vertical demand curve at the target capacity quantity is preferable to a sloped demand curve in the context of a MYF CCM.
The vertical demand curve at the target quantity allows capacity offer prices to establish the CCM clearing price for the target quantity, rather than fixing the CCM clearing price at exactly the CONE or Net CONE estimate when the target quantity is cleared. Moreover, when there is sufficient capacity offered to the CCM, the CCM will always procure the target amount of capacity rather than procuring excess capacity as it would with a sloped demand curve. [16]

Regarding the upper bound on the CCM clearing price, clearly an upper bound is appropriate to reflect the maximum willingness to pay for capacity, as long as the upper bound is high enough not to create a disincentive for new investment. The CAISO believes that the exact level of the upper bound does not need to be specified at this time and can be addressed in the 2008 CCM design process if a CCM is adopted. Regarding the lower bound on the CCM clearing price as suggested by CFCMA, the CAISO is not convinced that there needs to be a positive price floor to prevent the clearing price from dropping to zero when there is excess capacity in the system, for example, if resources wishing to de-list from providing RA capacity are required to submit de-list bids into the CCM. As noted earlier, there may be a concern that the CCM clearing price could systematically be depressed if all or most new investment enters the CCM through bilateral procurement and self-supply, in which case the CCM price might never be set by new investment and thus fail to become the desired price signal for new investment. Therefore, if a CCM design is adopted under a LT-RA framework that includes a significant expansion of centrally coordinated self-supply, it should consider carefully the potential adverse impacts on the CCM price signal and the effectiveness of mitigating provisions such as a requirement to submit bids to de-list to the CCM or some parameters that bound the amount of the coordinated self-supply at appropriate levels, rather than having an administratively set price floor.

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[16] We note that PJM's RPM auction, which includes a sloped demand curve, only procures capacity above the capacity target when the total cost is equal to or less than the cost of procuring to the capacity target.

Timing of CCM Auction Relative to Delivery Period

Proposition 13. The CAISO supports four-years forward as the optimal time horizon for conducting the primary CCM auction, and also supports the concept of holding a series of reconfiguration auctions between the time of the primary CCM auction and the start of the delivery period.

This issue is closely related to Item 2(e) discussed above, because in all of the CCM proposals the auction serves the dual purpose of (i) clearing supply and demand for capacity and producing a transparent clearing price, and (ii) providing a forward assessment of the total RA capacity that is committed to serve the CAISO control area, thus to allow identification of any shortfall. As stated above in Proposed Position 4, the CAISO believes that a MYF review of the total committed RA capacity is a more reliable and effective way to ensure that investment in new infrastructure is keeping pace with projected needs, and to enable effective competition between existing and new resources to provide RA capacity.

There are several important additional details that need not be addressed now but would need to be worked out in the context of a subsequent CCM development process if a CCM is pursued, such as the specification of the target delivery period, and the exact timing of the various auctions during the procurement cycle. In addition, it will be necessary to specify the qualification requirements for new resources to participate in the CCM, so that new projects are sufficiently developed by the time of the CCM auction to have confidence in their on-time start of commercial operation. The CCM design will need to ensure compatibility between the timing of the CCM auctions and the typical development timelines and milestones of new projects.

Role of CAISO Backstop Procurement to Meet Shortfalls in RA Procurement

When considering the need for and possible approaches to backstop procurement, it is useful to consider the potential CAISO backstop role in terms of three possible time frames:

(a) Long-term or multi-year forward time frame, in which the backstop could consider and procure commitments to build new resources;

(b) Short-term, on the order of one month to a year prior to delivery, which would consider only existing resources;

(c) Operational time frame, on the order of week-to-week or even day-to-day via the Exceptional Dispatch or some other very short-duration procurement provisions.

Unlike most of the other design elements discussed in this paper, backstop procurement will be needed regardless of the final LT-RA design (i.e. whether or not a CCM is pursued). Recent efforts to design a mechanism to meet types (b) and (c) procurement under the current RA design (*i.e.* in the context of developing ICPM) to replace the existing RCST) have demonstrated that an efficient backstop mechanism must be well coordinated with the design of any forward capacity procurement mechanism. That is the case because any such backstop mechanism is likely to affect forward RA prices and incentives. Thus, even though the CAISO's ICPM proposal will include a predetermined sunset date, the CAISO has noted the need to revisit the subject prior to the ICPM sunset to determine what the needs are and the most appropriate ways to address them based on how the LT-RA and related provisions and market conditions have developed by that time.

Proposition 14. At a minimum, the CAISO needs backstop procurement capability to be able to manage significant events that alter system or operating conditions.
Such procurement could fall under time frames (b) or (c) depending on the nature of the event. For all practical intents and purposes, this need is consistent with the provisions for significant event procurement currently being discussed under ICPM. This type of procurement is not integrated with the forward RA mechanism, but rather is undertaken in response to real-time events that require CAISO to request available non-RA resources to accept designation as interim RA at some reasonable price. Hence, this type of backstop procurement and pricing is not expected to affect forward RA markets to any extent. However, there may be a need to review the pattern of significant events to determine whether they require a re-evaluation of RA locational needs.

Proposition 15. The CAISO supports the objective, as advocated by most of the parties to this process, of designing the CCM to maximize its ability to procure most if not all of the needed capacity so as to minimize the need to utilize CAISO backstop procurement mechanisms of types (a) and (b).

Proposition 16. The previous proposition notwithstanding, the CAISO expects that it will need to have backstop capacity procurement capability of type (b) to supplement LSE or CCM procurement in a time frame up to one year ahead of delivery, similar to the provisions that exist today under RCST and are included in the latest ICPM design proposal.

The details of this type of backstop do not need to be completely worked out now, however, but should be included in the 2008 CCM design process if the CCM approach is pursued. More generally, any adopted CCM design should contain clear provisions for addressing situations where insufficient capacity is offered to clear the CCM auction, because such shortfalls could form one basis for triggering backstop procurement.

Proposition 17. The CAISO does not expect to exercise backstop capacity procurement in a multi-year forward time frame, i.e. time frame (a) above.

The matter of multi-year forward backstop procurement is discussed further below in the context of transmission planning.

Proposition 18. The capacity product procured through a backstop mechanism should have the same performance requirements (RA-MOO, any applicable performance penalties, etc.) as the RA capacity procured through the primary bilateral and CCM mechanisms.

Many of the details of backstop procurement need not be specified now but will require further discussion in the 2008 CCM design process if a CCM is pursued, including:

- The specific circumstances and triggers under which it would be appropriate for the CAISO to engage in short-term backstop procurement;

- The timing at which such backstop procurement should occur;
- The preferred mechanism for procuring the backstop capacity;
- The appropriate duration of backstop capacity commitments; and
- Whether backstop procurement should target resource attributes not targeted by the CCM, such as generator performance (dispatchability, ramping and quick-start) and environmental characteristics. (Note the connection between this point and the earlier discussion, in the context of the capacity product definition, of the possible need for supplementary mechanisms to induce investment in needed generator performance attributes.)

Cost Allocation for Central Procurement

Proposition 19. Cost allocation for each LSE should be based upon the LSE's actual load for each delivery period (e.g. settlement month), rather than a forecast of the LSE's load, so as to accurately reflect any DA load migration.

This approach to cost allocation should apply to both CCM procurement and to any CAISO backstop procurement. It would also be equitable and fair, particularly for costs associated with backstop procurement, to allocate costs based on cost causation principles as far as possible. For example, if possible the costs of backstop procurement should be allocated to those LSEs whose own capacity procurement shortfalls necessitated the backstop procurement. In contrast to today's RA approach, however, the submitted CCM proposals effectively render the cost causation principle largely moot because the self-supply mechanism ensures that LSEs will pay for central procurement only as needed to supplement their self-supplied capacity.

Requirement to Participate in CCM and Ability of Resources to De-List

Proposition 20. Supply resources internal to the CAISO control area that do not explicitly de-list from the RA market should be required to offer their capacity to the CCM.

In the eastern ISOs de-listing is the vehicle for installed capacity to opt out of the capacity procurement mechanism and thereby be relieved of their obligation to offer their capacity to the market. This proposition presupposes well-specified listing and de-listing provisions, which have been discussed to some extent in the CCM proposals and workshops but are not yet ripe for detailed specification. The subsequent CCM design process will need to develop the details, including potential exemptions from the CCM offer requirement (e.g. MSS load-following resources and non-PGA QFs), the specifics of de-listing and how it would work, and how de-listed resources that continue to operate during the delivery period might count towards meeting local area capacity requirements even if they don't count towards system requirements. As noted later in this paper, the requirement either to participate in the CCM or de-list is important for mitigating local market power in the form of physical withholding.

Coordination of Long Term RA with Transmission Planning

Several questions have been raised in the workshops and stakeholder meetings regarding this important aspect of long term RA. Some of the major questions are:

1. Can transmission upgrade projects compete directly against new generation projects in the CCM? If so, many details must be spelled out, such as how a transmission upgrade project would pre-qualify for the CCM by having achieved certain milestones, and how it would figure into the CCM supply and/or demand functions.
2. If transmission upgrades cannot compete against new generation, then how would a MYF assessment of needs and a MYF procurement process be coordinated with grid planning to ensure efficient infrastructure investment?

The CAISO has given some consideration to these questions and offers the following approach for further discussion with stakeholders.

Proposition 21. In advance of the multi-year forward CCM, the CAISO transmission planning process will identify specific, viable transmission upgrades to relieve constrained local areas of the grid. Such upgrades will serve as multi-year forward backstop actions in the event that not enough supply capacity is offered in the CCM to meet the RA capacity needs of a local area.

The concept behind Proposition 21 is best explained by means of an example. Starting with the time frame of the transmission planning process and the MYF assessment of capacity needs, suppose that a certain constrained area of the grid is estimated to require 1000 MW of internal RA capacity for the delivery period 5-6 years in the future. The 1000 MW estimate is based on the existing topology and capacity of the grid plus any upgrades that have already been fully committed to and adopted in the transmission plan (i.e. will definitely be built with a high degree of certainty). In addition, the CAISO's planning process also identifies another potential upgrade that would reduce the local capacity requirement to 600 MW. Finally, suppose that the local area actually contains only 750 MW of installed, QC, including any new supply that has already been committed to and will become operational within the 5-6 year horizon. All of this information is made available to the market to help inform bilateral RA procurement and the running of the MYF CCM.

Now suppose that the CCM is run four years forward of delivery. The supply for the local area includes LSE self-supply that may include new investment, as well as other offers of new and existing capacity, and possibly bids to de-list by resources within the area that may want to retire. The demand quantity is 1000 MW to test the presumption that the potential upgrade is not needed. If the CCM clears at least 1000 MW then the supply capacity for the local area is found to be sufficient and the potential upgrade is not needed, at least for the targeted delivery period. If the CCM clears less than 1000 MW, however, then there is a backstop decision to be made. Further details of this concept need to be developed, such as what magnitude of shortfall should trigger what sort of backstop action, what opportunities should be provided to parties to fill the gap, etc. But ultimately, if the capacity shortfall is deemed significant and other actions do not adequately meet the local need, then the CCM outcome would effectively become the trigger to move forward with the identified potential transmission upgrade as a transmission backstop to meet a shortfall in local capacity.

The approach illustrated above provides at least one way that investment in new transmission can compete with new generation to meet the capacity needs of a local area of the grid. It also characterizes how the CAISO might view its backstop role in a multi-year forward framework, that is, to focus on a transmission upgrade as the backstop for insufficient capacity rather than an explicit role in inducing new generation investment.
Another important aspect of coordination between the CCM and transmission planning lies in the application of the Transmission Economic Assessment Methodology (TEAM). The TEAM is a detailed approach for quantifying the expected economic impacts of proposed transmission upgrades, focusing on the effects of each proposed upgrade on locational market prices for energy and AS and on the opportunities to exercise market power in the spot markets. With a CCM structure in place that produces transparent clearing prices for system and local capacity, the TEAM could be usefully enhanced to estimate the effects of a proposed upgrade on capacity price differentials between system and local areas, on the quantities of local capacity needed for each area, and on the potential for market power in the local capacity markets. This would be a valuable improvement in the economic assessment of transmission upgrades for transmission planning purposes.

Market Power Mitigation

Proposition 22. Because of the potential for the exercise of supplier market power in local capacity areas, any adopted CCM design must include explicit provisions to mitigate local market power – both economic and physical withholding – and avoid over-reliance on the potential entry of new capacity in local areas to drive competitive market outcomes.

Such mitigation provisions should be clearly specified in advance of the implementation of the CCM, should address both physical and economic withholding, and should not simply depend on the CAISO Department of Market Monitoring and the FERC to monitor and limit the exercise of local market power.

Although the exact specification of such provisions will depend on the ultimate design of the other features identified above, there are several important observations to be made regarding market power mitigation.

1. As noted earlier in this paper in the discussion of the capacity product, local market power can be exacerbated when the various resources within the local area have different effectiveness on critical transmission constraints within that area.
2. Direct bid mitigation, based on structural, conduct and impact tests, is the most effective approach for mitigating economic withholding, regardless of whether a sloped or vertical demand curve is adopted. Relying solely on the use of a sloped demand curve in the CCM is not likely to be effective against concentrated supply ownership in an area.
3. The obligation of internal resources either to offer into the CCM or formally de-list is essential for mitigating physical withholding.

Finally, as noted by previously by the Department of Market Monitoring, although the focus of the CCM proposals is on the procurement and pricing of capacity, the CPUC and the parties should not lose sight of the essential role that long-term energy contracting plays in mitigating market power in the short-term energy markets. The best designed long-term capacity procurement and pricing structure will not prevent another energy crisis (even with a 15 percent PRM) if not coupled with large amounts of long-term energy contracting. Ultimately consumers consume energy, not capacity, and if this energy is not adequately hedged through long-term contracts, the market will be ripe for significant market power abuse. With this in mind, the degree to which the CCM design facilitates or complements long-term energy contracting has a significant impact on the overall protection against market power afforded by the CCM and the entire long term RA framework.

Staff Recommendations

In compliance with Public Utilities Code Section 380, President Peevey's ACR and directions from Administrative Law Judge Mark Wetzel, the Energy Division staff recommends the Commission implement one of the two proposals detailed below for the ongoing RA program. Based on the record before the Commission and as a result of the input of parties and stakeholders at the CPUC and the CAISO, and consideration of the recommendations of the CAISO and the CAISO's MSC, Energy Division staff believes both options balance state goals with the necessary stability of a long term RA program. The proposals reach long term stability in significantly different ways and attain the goals of the program as well as the state's other needs to different degrees. The direction the Commission ultimately takes involves policy decisions that are the purview of the Commissioners, but staff feels strongly that none of the proposals satisfied all of the CPUC's goals on a standalone basis. Energy Division staff emphasizes its concern with the RA program's interaction with the CPUC, CEC, and ARB's GHG emission reductions in particular.

Staff recommends either minor modifications to the current RA program or the adoption of composite RA approach that incorporates IOU procurement and a multi-year forward CCM. The following section will describe the proposals in detail then address the tradeoffs associated with each proposal.

Application of the RA Metrics and Goals

Energy Division has utilized the RA Metric Matrix to inform its recommendations from the proposals put forth in R. 05-12-013. The recommendations incorporate the goals and their application to the proposal before the Commission to ensure adherence to the greatest extent possible. As is addressed in the comparative section below, no proposal, including the recommendations staff puts forward, perfectly addresses all goals. Staff's primary goal in putting forward these recommendations is to provide the Commission with two options which satisfying different but significant goals as laid out in the Goals section above.

Recommendation 1: The Modified Centralized Market

Staff recognizes that the potential benefits associated with a CCM are significant, particularly with regard to price transparency and cost allocation, but one thing that remained unclear during the workshops was the implication of California's hybrid market on the functioning of the capacity market and vice versa. Some parties raised specific concerns regarding the State's environmental and other policy goals, particularly the capacity market's impact on the GHG and RPS policies as well as concerns about both UOG and monopsony power driving down the value of capacity on the other. At the same time, staff recognizes that EE programs and some renewables may be structured in such a way that price is only one element of a complex range of incentives to ensure an appropriate level and mix of resources is achieved.

To address these concerns, staff recommends combining elements of both PG&E's composite approach and the CFCMA's Centralized Forward Capacity Market into a Modified Centralized Market (MCM). While the MCM proposal is based on a combination of both proposals, it modifies elements of each to suit both market structure and policy concerns.

In response to collaboration with and contributions from the CAISO, input provided during the workshops, and taking into account parties' proposals and comments, Energy Division staff recommends, in general terms, utilizing significant portions of the PG&E's composite proposal. In that framework, staff recommends the elimination of PG&E's proposed role for the CAISO in the RFO process and the replacement of the Centralized Allocation Mechanism by a modified Centralized Forward Capacity Market as put forward by the CFCMA. This structure provides price signals for new generation for all parts of the market via a centralized clearing mechanism, but retains CPUC jurisdiction over procurement related to environmental and other policy goals.

Overview of the Modified Centralized Market

California's MCM addresses California's RA needs via a bifurcated market mechanism. At its heart, the MCM satisfies RA requirements via two distinct mechanisms in two distinct markets, both of which include local RA requirements. The first mechanism, the Preliminary Capacity Showing (PCS), is a forward capacity showing required of IOUs only. The second mechanism, the Centralized Forward Reliability Market (CFRM), is essentially a call option on energy that takes place via procurement of a capacity product bundled with a PER deduction. The PER is based on fixed cost recovery of a designated reference unit's characteristics, likely a moderately inefficient (in terms of heat rate) unit. This bifurcated market is enabled by the CAISO's adoption of a standardized capacity product which underlies both markets.

The Preliminary Capacity Showing and Price Exposure

Six years before the delivery year, the CPUC in conjunction with the CEC will establish the projected load for each IOU for the delivery year. As discussed elsewhere, the RA program must be closely coordinated with the LTPP program and EE and renewable targets. Similarly retirements of less efficient fossil power plants must be fully integrated in a forward environment to ensure the whole of the state's goals are met. IOUs are required to make a showing to the Commission that they have procured capacity to meet 90 percent of their projected load for the delivery year six months before the CFRM is run. UOG and generation under contract would be part of this showing as would new generation that priced below existing capacity. The culmination of this showing is similar to the current RA program except that the capacity product in question would be standardized. While the remaining 25 percent[17] of IOU's total RA obligation would clear in the CFRM, IOUs are expressly required to stay exposed to the price that the CFRM produces with at least 5 percent of the forecast load and PRM. This exposure is designed, in concert with the restrictions in the PCS, to both limit the potential exertion of market power and to ensure appropriate alignment with the incentives of market participants and the proper functioning of the market. This procurement mechanism will require coordination with the Commission's LTPP proceeding and could be modified by changes in PRM requirements.

The Centralized Forward Reliability Market

The CFRM is a CCM operated under CAISO authority and subject to FERC tariff. There will be separate auctions for each local area and for control area wide needs. All LSEs participating in the CAISO will be required to purchase capacity through the CFRM, though a forward showing equivalent to the PCS for IOUs would enable all LSEs to limit their participation in the CFRM to levels similar to the IOUs as discussed above. On the supply side both new generation, existing generation uncommitted via the PCS, and DR can participate. There is a list/de-list obligation based on CONE, addressed below. Under the CFRM rules most LSEs are permitted to bilaterally contract for 100 percent of their PRM and self-provide. The exceptional restrictions on IOU participation in the CFRM can, and likely should, be applied to any market participant with the ability to exert monopsony power.

The CFRM consists of four separate auction periods spread over time. The Initial auction occurs four years out and provides all load the opportunity to bid in via self supply of capacity (including DR, discussed below). All load not provided for via self provision is cleared against bid capacity. The remaining auctions, called the Primary, Secondary and Tertiary Reconfiguration Auctions, allow for trading previously contracted capacity. Trading capacity will allow generation to buy out of the delivery year if a project is delayed or retired, and new generation to be added. The Reconfiguration Auctions also provides an opportunity for the CAISO to adjust the target capacity if necessary.

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[17] The 25 percent of IOU RA obligation that participates in the CFRM is derived by subtracting the 90 percent of forecast load in the PCS from the current RA obligation of 115 percent of forecast load. In practice that number can be 117 percent or could change with a different PRM obligation.

The Peak Energy Rent Deduction

PER deductions apply to all capacity that participates in the CFRM. . The PER is calculated based on the recovery of fixed costs for a reference unit of moderate inefficiency (including heat rate and variable costs), which is determined in advance of the auction. The amount of revenue the reference unit would earn from the energy market during the delivery year is calculated and deducted from capacity payments. The PER deduction has the effect of making capacity acquired in the CFRM function much like a call option on energy rather than capacity as a stand alone product. The PER is calculated ex post based on actual market prices during the delivery period.

Bids and List/De-list Obligations

In the CFRM all capacity, including new generation, participates via bid submission. The auction clears based with the price of the clearing bid going to all generation in the auction that priced at or below that price.

All generators are required to participate via a list/de-list option where generators may set a clearing price below which they will not participate in the CFRM. A lack of a bid functions as price taking in the CFRM. Generators with existing contracts for other markets (non-CAISO, out of state, etc.) may de-list without submitting a de-list bid. Similarly, generators may seek de-list permission from the CAISO based on mothballing, planned service, repowering, etc. All de-list bids are CAISO approved with regard to both market power and grid reliability. There is a cap on de-list bids for existing generation at 0.7 times CONE. Any de-list bid over 0.7 times CONE requires complete review of costs by the CAISO Department of Market Monitoring.

The primary purpose of the list/de-list obligation is to allow supply freedom to enter and exit the market based on the market's clearing price. However, the risk for withholding or impact on grid reliability is significant and requires close monitoring. For this reason de-list bids must be reviewed by the CAISO market monitor for market power mitigation and reliability purposes. Additionally, where market power exists, close consideration must be given to market power and withholding; in situations where de-list bids exceed 0.7 times CONE thorough review of cost-based justification must occur. The de-list bid also provides a useful signal for backstop prices should a unit be permitted to de-list but be determined in the future to be necessary for grid reliability.

Some existing capacity markets require a minimum de-list period to discourage withholding. Such a structure is worth consideration in the CFRM, but a case by case review of a de-list bid with regard to market power may be more optimal than a uniform requirement. Certainly the review by CAISO's market monitoring section of the justification for the de-list and re-entry discourages withholding to some extent. The market monitoring unit should also carefully scrutinize de-list bids coupled with new generation offers from the same entity in order to prevent market manipulation.

Caps and Floors in the CFRM

There is no floor in the CFRM. Market power mitigation on the demand side occurs via the 5 percent exposure requirement by IOUs as well as the 90 percent bilateral requirement on IOUs in the PCS and new generation's limited ability to enter via that mechanism, especially in light of existing generation's participation in that market. Generators that do not want to participate in the CFRM may state a de-list price in their bid. In order to prevent market power exertion on the supply side staff recommends a cap of 1.5 times CONE be placed on all bids.

New Generation Options in the CFRM

New Generation is entitled to bid for up to a 10 year contract based on the clearing price of the auction, marked to inflation. This election to lock in the market clearing price for multiple years must be made before the auction is run. However, should similar bids clear the CFRM at the same price, a shorter duration bid would win over a longer duration bid. Staff believes the record would benefit from a discussion of if a price range to be considered equivalent should exist and, if so, what range would be appropriate.

Settlement in the CFRM

After the CFRM Initial and Reconfiguration auctions occur, costs incurred by the CAISO's procurement of capacity in the CFRM as well as the costs of administering the CFRM are allocated based on load at time of delivery adjusted for self provisioned capacity. Settlement occurs after delivery immediately after the calculation of PER deductions, if applicable.

Additional Information on the IOU Restrictions

The restrictions on IOUs are designed with three goals in mind:

1) a structural hedge against exposure of bundled customers to a non-market price set by a floor or cap on capacity
2) minimization of risks predatory pricing by load that could drive generators out of business
3) ensures a more equitable distribution of costs associated with new generation procured via the CFRM

Significantly IOUs are required to be exposed to the CFRM via a minimum of 5 percent of their forecast load for the delivery year as determined by the CPUC and CEC. The purpose of this restriction goes beyond the reasons listed above; IOUs are also exposed to the same risks associated with exposure to loss of load by having to sell capacity back into the market should they have procured beyond their ultimate load level. This restriction further limits the likelihood that market power can be exerted owing to certain load shift scenarios.

To the extent that IOUs procure resource in excess of the limitation, the CPUC will identify the excess resources and prohibit recovery of all costs associated with those resources. In identifying resources, the most expensive resources in the IOU portfolio at the time of the Initial Auction will be excluded from rate recovery.

Additional Information on Demand Response

The complexities associated with DR bidding into the CFRM are not easily addressed in this format. DR is provided the opportunity to bid into the CFRM at any point in either the Initial or Reconfiguration Auction or to contract with load for self provisioning showings. Because DR is not providing energy there is no applicable PER deduction. There is, however a need to administratively determine a performance or compliance rate for DR via some qualification of capacity. That determination may be adjusted over time based on actual performance. DR participation in the CFRM may be further incented by crediting it for avoided distribution losses and avoided operation reserves cost (in the ISO-NE such credits amount to a 20 percent payment premium over the market clearing value for capacity).

Energy Division staff emphasizes the increased need for quantifying all forms of DR in the context of the recommendation to ensure that the CPUC's DR efforts perform optimally. The interaction between DR and the CFRM is characterized here in the context of dispatchable DR, but staff recognizes that DR is not limited only to the DR discussed in this context and that all forms of DR both impact and respond to market clearing prices, etc.

Additional Information on CFRM Auctions and Capacity

Nothing prevents self supply of capacity by any party into the CFCM other than the restrictions on IOUs, even if that capacity does not have a PER associated with it. The constraint is that all capacity in the CFRM will have be responsible for the PER deduction associated with the market. This freedom increases the hedging mechanism available to all parties.

The CFCM and subsequent reconfiguration auctions clear based on a capacity product subject to PER deduction. The PER deduction, however, could be hedged through bilateral energy contracts outside of the centralized market. Thus, capacity that does not have a PER deduction associated with it which was procured, for instance in the preliminary showing under the CPUC modified RAR, can also be traded in the CFCM and reconfiguration auctions. An LSE that wants to sell capacity not associated with a PER deduction in the ISO centralized auctions could either choose to assume the PER deduction risk or cover that risk by acquiring a financial energy hedge (in the form of a call option with strike price matching the PER strike price) in the bilateral market. This subject is addressed in greater detail below.

Additional Information on Capacity from the PCS bidding into the CFRM

Should a participant in the PCS procure capacity that it does not need or that by market design it is not permitted to have in the CFRM, there are two mechanisms for trading that capacity. A LSE has the option of bilaterally finding a trading partner for the capacity in whatever form it exists (including standalone capacity rather than a capacity and energy hedge bundle). Alternatively, an LSE can procure a hedge against the energy price associated with that capacity and offer the bundle into a reconfiguration auction, so long as that hedge matches the PER deduction. This obligation ensures that the reconfiguration auctions clear with a uniform product. Energy Division staff highlights that the 90 percent limit based on forecast load should prevent a need for an LSE to have to bundle capacity with a PER deduction equivalent hedge, but provides more than one recourse should they need to do so.

Recommendation 2: Modifications to the Current Bilateral RA Program

Staff recommends minor adjustments to the current RA program that would bring greater price transparency and contracting efficiency consistent with general party criticism of the current program and the general recommendations made in the BTG proposal. Many components of the current program are to be retained, including but not limited to the general compliance framework of filings and review of filings, the annual listing of resources and their NQC, and the annual reassessment of Local RA obligations. There are some concrete recommendations for augmentation of the current program, which arise from experience with implementation of the current program and are grounded in basic principles of risk aversion and increased pricing transparency. In particular, staff recommends improvements that include an electronic bulletin board to list and advertise capacity, adoption of a standard set of generator obligations in order to streamline LSE contracting, and a collaborative forward assessment of capacity need with a multi year time horizon. Staff makes no recommendation here regarding the length of the commitment horizon, whether to retain the one year out filing or enlarge it to a multi year commitment requirement. Staff recommends studying this decision after the basic structure of the market is determined.

Parties have recommended the creation of an electronic bulletin board to list buyers and sellers of capacity voluntarily so as to facilitate direct bilateral negotiations. Currently there is a lack of coordinated communication and centralized listing so each LSE and each generator must engage in a series of phone calls to match up buyer and seller. This is an efficiency improvement that would streamline making contact with potential counterparties. An electronic bulletin board can also add the functionality of providing a credit and clearing mechanism for each trade; a centralized tracking and tagging of bilateral capacity sales can also speed compliance review at the energy agencies and minimize inefficient reporting by a number of separate LSEs and suppliers, and instead have one application generator one timely report. Development and testing and final implementation of any such bulletin board would probably be part of any implementation proceeding should the CPUC choose to adopt this second recommendation in the RA Phase two Track two decision.

In addition to the electronic bulletin board, parties have generally supported the clarification of generator obligations, and their adoption as a program administered by the CAISO and dictated by the CAISO tariff. As discussed before, parties have developed a set of CAISO tariff amendments that would establish performance testing and further definition of an RA QC supplier's obligations to the CAISO, and the parties have filed them with the CPUC for review. Parties have projected that the benefits of such tariff amendments would be to significantly reduce the contracting burden on both suppliers and LSEs to adopt these tariff provisions the CAISO would need to undergo a stakeholder process before filing them with FERC.

The BTG's proposal for an LSE opt-out of the backstop mechanism would imply continuation of the CAM as currently constituted, and LSEs would be able to opt out of the charges under the CAM by demonstrating that they have fulfilled their RA obligation by filing with the CPUC. This would suggest that the CAM would become the avenue for development of new generation, and if someone other than the IOUs chooses to finance construction, an LSE could demonstrate that. Parties would need to agree that the CAM would not only continue in the context of LTPP but potentially could also grow in future years as new generation is needed. Greater definition of the mechanism would involve strong cooperation between the RA proceeding and the LTPP proceeding, and might also require the Commission to direct investment more specifically on the IOUs in order to meet long term needs for capacity improvements.

Finally, many parties in the course of workshops supported a more rigorous and systematic assessment of future capacity need as discussed in the section on forward assessments. To supplement the other facets of this proposal, which generally drew from the BTG proposal and the general recommendations for any RA program on a forward going basis, staff recommends establishment of a study process that involves a standardized and generally accepted methodology and occurs on a regular and predictable timeline that would establish the capacity needs including planning reserves in order to meet the state's goals in environmental, economic, and reliability arenas. Specifically staff recommends a coordination of the IOU determination of system needs in the LTPP proceeding and the forward assessment of system needs that go into determination of the PRM in the RA proceeding. The CEC currently prepares load forecasting many years forward as part of the biannual IEPR process. The CEC provides updates in the off years between major reports that inform the current RA obligations that the CPUC requires of the LSEs. Were the CPUC to determine capacity needs in California on a regular timeframe, all market participants in California would gain more certainty with regards to optimal fulfillment of California's goals through procurement of new and existing resources.

The primary difference between the staff recommendation for modifications to the existing RA program and the BTG proposal is that the staff leave undecided the length and duration of the procurement obligation. Where the BTG proposal retains a one year out RA procurement obligation, staff does not specifically retain this feature. It is left undecided whether this direction is pursued in the course of program implementation. Much more study is needed before this decision can be made. Staff also recommends modifications to the existing BTG proposal as detailed below in the Other Recommendations section.

Tradeoffs between the MCM and the Modified RA Program

Energy Division staff makes two recommendations in this report because there simply is no single proposal that satisfies all the goals of an RA program in California. Accordingly, staff has proposed two solutions which meet two overarching goals:

First, the proposals minimize the risk of market failure. Many of the proposals before the Commission operate with a theoretical market design worldview. Energy Division staff cannot recommend proposals that work in theory but not in practice.

Second, the proposals must balance both internal goals from a program design perspective, such as pricing efficiency and external goals such as harmony with the Commission's environmental policies and general risk tolerance.

The result of the balancing of these two overarching goals is ultimately a choice between proposals that meet different parts of the Commission's broad range of policies but not all of them. Staff's two recommendations allow the Commission to move forward based on its determination of which policies establish the framework around which to work toward meeting all of its goals.

Energy Division staff highlights the previously discussed metrics in the context of the two recommendations, which vary on how they meet the identified metrics of the report in several ways:

Ensures Reliability

Both recommendations meet basic reliability requirements and provide a means of backstop procurement in case the primary market fails.

Enables New Generation

Both recommended proposals enable new generation through the use of long term contracts backed by ratepayers. In both proposals LSEs can enter into bilateral contracts to construct new/repowered generation. In both proposals an entity enters 10 year contracts and spreads the cost to ratepayers if needed (the modified current RA program proposal uses the IOUs and MCM uses a CAISO centralized market). The MCM proposal is slightly more likely to incent new merchant generation without a long term contract; although the possibility of a long term contract makes it unlikely merchants would take the shorter contract path given the availability of the longer contract.

Adheres to Least Cost Principles

In the near term, the BTG proposal should have lower overall costs than the MCM proposal. By splitting new and old generation with separate procurement mechanisms, the BTG proposal is able to pay less overall than is possible in a centralized market. The impact of the lower cost for existing generation is that new generation will charge more in the ten year contracts in order to ensure cost recovery over the life of the asset. This means the BTG proposal's cost advantage may erode over time.

Enables Direct Access

Both recommended proposals are designed to support DA. The BTG proposal may leave the ESPs more exposed to market power concerns than the MCM proposal's centralized market. In addition, the MCM proposal should result in less administrative cost to ESPs, and provide a fairer method of cost allocation for capacity.

Recognizes Jurisdictional Constraints

The BTG proposal retains CPUC jurisdiction over the majority of RA mechanisms. Short term backstop procurement continues to be FERC jurisdictional. The MCM proposal shifts the primary RA mechanism for new generation to the FERC jurisdictional CAISO. Under the MCM proposal the CPUC limits ratepayer exposure to FERC jurisdictional markets by mandating forward procurement by IOUs. That forward procurement acts as a hedge against unreasonably high prices in those markets.

Facilitate Environmental Policies

Neither recommended proposal directly facilitates environmental policies, but both have components that could be used for that purpose. The IOU procurement in both proposals can be used to direct funding for new generation towards preferred resources. To the extent that some procurement in the MCM proposal is through a centralized market, it would be more difficult to ensure that procurement facilitates environmental policies.

Possesses Fundamental Feasibility

On a basic level neither recommended proposal has operated long enough to ensure it will not fail, but each appears to possess fundamental feasibility. The recommended proposals vary significantly in complexity and implementation issues. The BTG proposal requires only modest changes to the current program. That program is functioning and requires significantly less personnel to operate than the MCM proposal. The MCM proposal requires a multi-year implementation process and significant increases in staff and resources at the CAISO.

The two recommendations fundamentally differ with regard to their risk tolerance, jurisdictional purview, and reliance on the market for prices. With regard to the metrics set forth earlier in the report, the recommendations can be characterized via a simple comparison. The MCM improves the jurisdictional and environmental elements of the CFCM and the CAISO proposal, while better enabling DA than the PG&E Composite proposal would on a standalone basis. From the perspective of the metrics discussed above, the BTG proposal addresses cost issues less efficiently than the MCM proposal but with less volatility and jurisdictional risks. Below, Energy Division staff summarizes the two proposals with regard to the three considerations of risk tolerance, jurisdictional purview, and reliance on the market for prices.

The MCM

The MCM represents a mitigation of many of the risks associated with the individual CCM proposals before the Commission. However, Energy Division staff recognizes that any CCM has risks that cannot be mitigated.

The primary risk associated with the MCM is that pricing is subject to an imperfect market and that such a market risks exposure to non cost-based outcomes. Significant effort has been made to mitigate this risk, but, stated bluntly, the stakes are quite high. California's recent experience with non cost-based outcomes in the energy market remains a significant reminder of what can happen with pricing problems in markets. This risk is offset by the potential benefits associated with market based entry and exit on the supply side, in particular a true market price and efficient cost allocation mechanisms.

The strength of the MCM is that it is designed to provide market prices both inside the CCM element of the program and in the bilateral IOU-driven portion of the program. This system of checks and balances ensures that pricing is generally consistent with what the market produces rather than what the IOU administered process produces with Commission overview. Similarly, the centralized market prices can be judged against the prices produced via an IOU run RFO mechanism should one exist. This system of price references between markets should produce checks and balances on both markets and ensure rapid adjustments can be made should market distortions occur.

Modifications to the Existing RA Program Consistent with the BTG Proposal

The risks associated with the existing RA program are related to two different aspects of the current RA program. It has been argued that the directed procurement prevents new generation from entering the market without ratepayer subsidy. The risk can be generally characterized as long term risk should it exist. If the risk exists in a less extreme scenario, we essentially see a system that is more expensive than it otherwise might be rather than a market failure. Staff views the Modifications to the Existing RA Program recommendation as low risk low reward. Market failure or extreme prices are not a likely outcome but the likelihood of truly efficient pricing is significantly reduced. Similarly, the outcome of these recommendations may improve the current RA program, but it is unlikely to get a lot better.

The subject of reliance on market pricing is difficult to address in the Modifications to the Existing RA Program recommendations. As addressed above in the risk tolerance section, the concern with regard to pricing is that directed procurement and ratepayer exposure to inefficient cost allocation does not result in proper market prices. The concern with regard to market prices for new entry into the market is mitigated by the IOU RFO process to some extent, but the question of oversupply driving down prices remains a concern. The lack of transparent pricing may result in inefficient outcomes where the most efficient generators aren't being utilized.

Other Recommendations

While these subjects may be addressed in the proposals above, Energy Division staff recommends the following be incorporated into any RA program the Commission goes forward with.

Seasonal Peak Capacity Product

There are efficiencies associated with a less than annual RA product. Seasonal RA captures many of those efficiencies without the administrative burden of a monthly or quarterly capacity product. These efficiencies include the ability of capacity resources that are not capable of delivering a full year capacity product to participate for a peak season period, facilitating the ability of units to opt out of capacity provision for part of the year to ensure timely service of units, and facilitating alternate calibrations of availability requirements depending on the seasonal demand and availability of alternative capacity.

The net effects of a seasonal peak capacity product include a larger pool of resources capable of bidding into the market during peak demand, which increases the efficiency of the market and greater flexibility for both generators and LSEs.

Energy Division staff recommends a five month summer season, starting in May, consistent with other Commission summer season starts. Staff believes this will facilitate greater participation by hydro facilities and may potentially require revisiting the NQC calculations for hydro as well other classes of intermittent capacity units. Similarly, it may be reasonable to create a three season capacity year which includes a November-January season, a May-September season and a shoulder season which includes the remaining calendar months in order to maximize some interruptible participation by carving out a low interruptible season from the non-peak season in a two season capacity year. Energy Division staff believes this issue would benefit from additional comments by parties.

Participation by Demand Response

Participation by DR in the capacity market encourages maximum participation of Demand Responsive resources in the state. While DR may not be capable of participating in the capacity market in all situations, the benefits of DR participation are two fold, both by decreasing load and by reducing the price of capacity at peak times. Regardless of the Commissions ultimate decision with regard to RA, Energy Division staff recommends participation by DR be maximized to the greatest extent possible.

Peak Energy Rent with Ex-Post Calculation

While highly contentious, even among parties willing to accept them, PERs play an integral part to any capacity market driven RA program. Energy Division staff points to the CAISO's Market Surveillance Committee's recent draft opinion which points to the benefits of ex post calculation of PER as a market smoothing mechanism. [The MSC opinion is included in Appendix 3]

Locational CONE Calculation

Incorporation of locational CONE calculation is consistent with MRTU's LMP mechanism and serves to further signal the desirability for new generation in load pockets. Additionally, locational CONE calculations serve to ensure Peak Energy Rent Calculations do not perversely discourage construction of new generation in load pockets.

Next Steps

This section provides an overview of the remainder of the RA Track 2 proceeding at the CPUC. In addition to listing upcoming dates, it provides a summary of potential dates for the various proposals.

Procedural Next Steps

Date	**Description**	**Source**
Jan. 18, 2008	ED staff releases Track 2 Report	
Feb. 15, 2008	Comments on Track 2 Staff Report	1/11/08 ALJ Ruling
Feb. 29, 2008	Reply comments on Track 2 Staff Report	1/11/08 ALJ Ruling
Apr. 15, 2008	Proposed Decision on Track 2 issues	1/11/08 ALJ Ruling
May 5, 2008	Comments on Track 2 proposed decision filed	1/11/08 ALJ Ruling
May 12, 2008	Reply comments on Track 2 proposed decision filed	1/11/08 ALJ Ruling
May 15, 2008	Final Decision on Track 2 issues	1/11/08 ALJ Ruling

Staff Recommendation Implementation Timelines

The following tables present timelines that represent possible implementation scenarios for the staff recommendations. Many details may vary significantly depending on the ultimate market design and timing choices. Correspondingly, these timelines are only intended to provide a general idea of implementation and are non-binding and non-exhaustive.

Recommendation One – Modified Centralized Market

Modified Centralized Market

Date	Description
Spring-Summer 2008	CPUC implementation proceeding, standardized capacity product defined
Summer-Fall 2008 (repeated annually)	CPUC/CEC/CAISO forecast of state wide resource needs for delivery year 2015
Fall 2008 - Fall 2010 (repeated annually)	LSEs procure capacity to meet forward requirements, IOUs are constrained to 90% of forecast load for 2015 on, based on CPUC/CEC/CAISO forecast of resource need for delivery year 2015
Fall 2010	LSEs making showing to the CPUC of their obtained capacity for delivery year 2015
Spring 2011 (repeated annually)	CAISO conducts primary auction for delivery year 2015
Spring 2012 (repeated annually)	CAISO conducts first reconfiguration auction for delivery year 2015
Summer 2015 – Spring 2016 (repeated annually)	Capacity delivered; payments calculated based on performance and PER deductions if applicable

Recommendation Two – Modifications to Existing Bilateral Trading

Bilateral Trading with Bulletin Board

Date	Description
Spring-Summer 2008	CPUC implementation proceeding, standardized capacity product defined
Fall 2008	Bulletin board implemented, 2009 prices
Fall 2008	Further forward prices added to bulletin board
Fall 2008 (repeated annually)	Year ahead RA filings due

Conclusions

These staff recommendations and the proposals of the parties will be addressed during the Resource Adequacy Phase Two Track Two proceeding (R.05-12-013). As detailed in the section above parties will have the opportunity to comment on this report in that proceeding as well as make replies to comments received. This report as well as those comments and replies will be part of the record in R.05-12-013.Appendices

The following appendices come from a variety of sources and are intended as additional background information on a variety of subjects. They are as follows:

Appendix 1 - AB 380

THE PEOPLE OF THE STATE OF CALIFORNIA DO ENACT AS FOLLOWS:

SECTION 1. Section 380 is added to the Public Utilities Code, to read:

380. (a) The commission, in consultation with the Independent System Operator, shall establish resource adequacy requirements for all load-serving entities.

(b) In establishing resource adequacy requirements, the commission shall achieve all of the following objectives:

(1) Facilitate development of new generating capacity and retention of existing generating capacity that is economic and needed.

(2) Equitably allocate the cost of generating capacity and prevent shifting of costs between customer classes.

(3) Minimize enforcement requirements and costs.

(c) Each load-serving entity shall maintain physical generating capacity adequate to meet its load requirements, including, but not limited to, peak demand and planning and operating reserves. The generating capacity shall be deliverable to locations and at times as may be necessary to provide reliable electric service.

(d) Each load-serving entity shall, at a minimum, meet the most recent minimum planning reserve and reliability criteria approved by the Board of Trustees of the Western Systems Coordinating Council or the Western Electricity Coordinating Council.

(e) The commission shall implement and enforce the resource adequacy requirements established in accordance with this section in a nondiscriminatory manner. Each load-serving entity shall be subject to the same requirements for resource adequacy and the renewables portfolio standard program that are applicable to electrical corporations pursuant to this section, or otherwise required by law, or by order or decision of the commission. The commission shall exercise its enforcement powers to ensure compliance by all load-serving entities.

(f) The commission shall require sufficient information, including, but not limited to, anticipated load, actual load, and measures undertaken by a load-serving entity to ensure resource adequacy, to be reported to enable the commission to determine compliance with the resource adequacy requirements established by the commission.

(g) An electrical corporation's costs of meeting resource adequacy requirements, including, but not limited to, the costs associated with system reliability and local area reliability, that are determined to be reasonable by the commission, or are otherwise recoverable under a procurement plan approved by the commission pursuant to Section 454. 5, shall be fully recoverable from those customers on whose behalf the costs are incurred, as determined by the commission, at the time the commitment to incur the cost is made or thereafter, on a fully nonbypassable basis, as determined by the commission. The commission shall exclude any amounts authorized to be recovered pursuant to Section 366. 2 when authorizing the amount of costs to be recovered from customers of a community choice aggregator or from customers that purchase electricity through a direct transaction pursuant to this subdivision.

(h) The commission shall determine and authorize the most efficient and equitable means for achieving all of the following:

(1) Meeting the objectives of this section.

(2) Ensuring that investment is made in new generating capacity.

(3) Ensuring that existing generating capacity that is economic is retained.

(4) Ensuring that the cost of generating capacity is allocated equitably.

(i) In making the determination pursuant to subdivision (h), the commission may consider a centralized resource adequacy mechanism among other options.

(j) For purposes of this section, "load-serving entity" means an electrical corporation, electric service provider, or community choice aggregator. "Load-serving entity" does not include any of the following:

(1) A local publicly owned electric utility as defined in Section 9604.

(2) The State Water Resources Development System commonly known as the State Water Project.

(3) Customer generation located on the customer's site or providing electric service through arrangements authorized by Section 218, if the customer generation, or the load it serves, meets one of the following criteria:

(A) It takes standby service from the electrical corporation on a commission-approved rate schedule that provides for adequate backup planning and operating reserves for the standby customer class.

(B) It is not physically interconnected to the electric transmission or distribution grid, so that, if the customer generation fails, backup electricity is not supplied from the electricity grid.

(C) There is physical assurance that the load served by the customer generation will be curtailed concurrently and commensurately with an outage of the customer generation.

SEC. 2. Section 9620 is added to the Public Utilities Code, to read:

9620. (a) Each local publicly owned electric utility serving end-use customers, shall prudently plan for and procure resources that are adequate to meet its planning reserve margin and peak demand and operating reserves, sufficient to provide reliable electric service to its customers. Customer generation located on the customer's site or providing electric service through arrangements authorized by Section 218, shall not be subject to these requirements if the customer generation, or the load it serves, meets one of the following criteria:

(1) It takes standby service from the local publicly owned electric utility on a rate schedule that provides for adequate backup planning and operating reserves for the standby customer class.

(2) It is not physically interconnected to the electric transmission or distribution grid, so that, if the customer generation fails, backup power is not supplied from the electricity grid.

(3) There is physical assurance that the load served by the customer generation will be curtailed concurrently and commensurately with an outage of the customer generation.

(b) Each local publicly owned electric utility serving end-use customers shall, at a minimum, meet the most recent minimum planning reserve and reliability criteria approved by the Board of Trustees of the Western Systems Coordinating Council or the Western Electricity Coordinating Council.

(c) A local publicly owned electric utility serving end-use customers shall, upon request, provide the State Energy Resources Conservation and Development Commission with any information the State Energy Resources Conservation and Development Commission determines is necessary to evaluate the progress made by the local publicly owned electric utility in meeting the requirements of this section.

(d) The State Energy Resources Conservation and Development Commission shall report to the Legislature, to be included in each integrated energy policy report prepared pursuant to Section 25302 of the Public Resources Code, regarding the progress made by each local publicly owned electric utility serving end-use customers in meeting the requirements of this section.

SEC. 3. No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because certain costs that may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIII B of the California Constitution.

As to certain other costs, no reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because a local agency or school district has the authority to levy service charges, fees, or assessments sufficient to pay for the program or level of service mandated by this act, within the meaning of Section 17556 of the Government Code.

Appendix 2 - Capacity Mechanisms outside the United States

Capacity payments provide direct remuneration to generators for installed or active capacity. The determination of active capacity is often based on simulation models that asses the probability that a generation unit in the merit order will be needed given the load forecast for a certain time horizon. The capacity payment can be fixed annually or can be varied according to LOLP calculation. In the UK prior NETA the capacity payments to available generators were changed hourly based on available capacity and the implied LOLP. Arguably, fixed cost recovery through capacity payments would induce generators to offer energy at their true marginal cost, but in some systems with capacity payments (e. g. Peru and South Korea) marginal-cost offers are mandated.

Long-term (typically annual) capacity payment mechanisms are currently used in Spain, in several South American countries including Argentina, Chile, Peru and Colombia , and more recently it was implemented in Italy. In the Spanish system, capacity payments are commingled with stranded investment remuneration. The funds for capacity payments in the Spanish system, like the stranded cost recovery funds, are collected as an uplift and distributed among the generation companies based on their technology mix and the dispatch pattern. This allocation mechanism affects a significant portion of generators' revenues and influences the way generation companies dispatch their units, which distorts the short-term objective of efficient economic dispatch.

The capacity payment mechanisms implemented in Chile and Peru are similar and are based on the Chilean model that employs simulation to determine the annual LOLP estimates on the basis of "effective capacity" and hydrological forecasts. The capacity payments are calculated as LOLP*VOLL with VOLL set by the regulator, and the payments are awarded to generators in proportion to their "effective capacities. " In Peru, the scheme was overly successful in attracting new investment in generation and resulted in substantial excess capacity. The development of natural gas resources in the jungle region further increased the displacement of old generators with more efficient gas units, but since in Peru only owners of generation capacity can enter into bilateral contracts (even if their capacity is never dispatched) there is a market for old units that should have been retired. As a result the rule has been modified so that only units that are in the merit order for dispatch are awarded capacity payments for their effective capacities (which may be substantially greater than the economically dispatched capacities). To prevent generators from undercutting their offered prices for energy so as to get in the merit order and thereby collect capacity payments (as has been the case in Argentina), the Peruvian system mandates that generators' offered prices must be cost-based (no more and no less).

The Argentina wholesale electricity market includes two different capacity payments that are related. One is an hourly capacity payment paid to capacity that is generating or has been committed as reserve on the day ahead dispatch; and the second is a payment for long-term thermal backup capacity for extremely dry hydro years, which is evaluated annually before the start of the winter season. These payments were instituted after the Argentine system experienced two years of severe rationing that resulted from a combination of insufficient investment, technical problems with nuclear and hydro plants, and two dry years in succession. In 1992, through a presidential decree, a private company CAMMESEA was created and assigned responsibility, as defined in the law for load dispatch, coordination of grid operation, and commercial administration of the market. The capacity payments are based on generation (resulting from dispatch) and reserves on peak hours of working days. Since capacity payments are based on dispatch, and a plant displaced in the dispatch loses both energy revenue and the capacity remuneration, there is an incentive for generators to understate their marginal energy cost. This leads to distortions in the efficient use of generation capacity and creates incentives for inefficient over-investment that can lead to collapse of energy prices and to boom-and-bust investment cycles. The overall experience in the Argentine system has been that the original objectives of the capacity payments have been accomplished, but in excess.

The Colombian electricity system had excess hydro capacity but very little thermal capacity, which exposed it to hydro shortages that occur about every five years. Because of abundant hydro power, prices of electricity have been low for long time stretches, which made it impossible to attract investments in thermal generation that predictably would be idle most of the time. The Colombian regulator instituted capacity payments with the objectives of distributing the capacity income among generators according to their expected contribution in covering supply under hydrological shortage conditions, and to attract investment in thermal capacity. Under this scheme generators were paid based on their expected participation in covering load in the dry season of a dry hydro year, even if the plant does not generate, as long as it is available. The methodology for determining the remunerated capacity of each unit was based on an optimal production simulation model applied to stress scenarios. The specific price for capacity is set by the regulator based on the fixed cost of an efficient generation technology. The Colombian regulator CREG has recently adopted an alternative approach to capacity payment that is based on firm energy options. Under this scheme distribution companies will be required to buy firm energy options from generators through a descending clock auction. The options will have a strike price determined by the regulator.

In Italy, day-ahead and real-time balancing markets for energy are run by the market operator, while markets for system services (including congestion relief, reserves, and real time markets) are run by the Italian transmission system operator (GRTN). The widening gap between demand and local generation, along with an increased reliance on imports has drawn the attention of Italian legislators to the problem of generation adequacy. To address this adequacy problem the Italian legislators introduced a new law that establishes a capacity payment scheme that explicitly remunerates generation capacity. The temporary capacity payment scheme, started in 2004 (and still in force) identifies eligible units for capacity payments. Such units must be dispatchable in the day-ahead markets and must declare their availability in a set of "critical days. " Those units engaged in physical bilateral contracts, or receive other incentives (e.g. renewable energy sources), or are affected by production uncertainty (intermittent sources such as wind and run-of-river hydro) are not eligible. Eligible units receive a basic payment and a supplemental payment that is paid only when the average weighted energy price is below the regulated price, up to a maximum of 20 percent of the regulated price. The funds for capacity payments are collected through an uplift of 0. 5 Euro/MWh.

South Korea like Peru has a cost based power pool where generators are required to offer their energy at marginal cost and receive capacity remuneration to cover their fixed cost. Initially, the Korean system operator practiced price discrimination based on technology by running two separate procurement auctions for peaking and base load generation units and paying different capacity payments to generators in each group. As of January 2007, the two procurement auctions have been merged and a uniform capacity payment based on total amount of installed capacity in the system has been introduced. The capacity payment is set to about $7. 8/MWh when the total installed capacity is between 112 percent and 120 percent of peak demand. Beyond this range the capacity payment is increase if capacity falls below the 112 percent mark so that total capacity payout stays the same as at 112 percent. Likewise if installed capacity exceeds the 120 percent mark the capacity payment is reduced so that the total payment stays the same as at 120 percent. This scheme essentially creates a constant sum game for generation capacity outside the target range. It should also be noted that the above scheme is essentially similar to the NYISO demand function approach (except for the shape of the curve). This highlights the fact that the term “Demand Function” is a misnomer alluding to a non existent market when in fact it is an administrative capacity payment scheme where the payment is a descending function of available capacity.

Appendix 3 - Previous Filings

SCE

SCE's proposal most closely resembled the PJM RPM and included a primary forward auction with multiple backstops. The primary auction would be for locational capacity, corresponding to regions that have major transmission constraints and that have passed a competitiveness assessment.

SCE's proposal included locational demand curves that would clear the capacity market based on the CEC's forecast of load, and the CAISO's assessment of capacity needs four years in the future. The demand curves contained a vertical segment centered around CONE and were capped at 1.5 times CONE. The primary auction would be run approximately four years before delivery.

The SCE proposal included options for a backstop if insufficient generation was bid into the auction to meet demand or if generation with in "sub-competitive" local areas would otherwise be taken out-of-merit. The alternatives included: 1) enhancing the transmission system, 2) entering into cost-based contracts with existing generation needed for unique circumstances, and 3) holding a backstop auction in which the CAISO would award a long-term (10 to 15 years) capacity contract in order to secure capacity from new generation in the needed location(s). LSE's could "self-provide" new generation capacity to avoid and allocation of backstop procurement charges.

SCE stated that its design supported all levels of potential retail choice load migration. All LSEs would be responsible for their pro rata share of the costs necessary to meet total grid needs. Costs would be allocated based on each LSE's actual realized load, and there would not be a need for individual LSE load forecasts, individual LSE showings of compliance or LSE penalties for non-compliance. SCE also proposed a tagging system that will allow generators, LSEs and marketers to efficiently trade capacity.

SCE's proposal allowed all generation to participate in the primary 4-year ahead market. All generation would receive the same 1-year payment, all else being equal. However, new generation would have additional collateral requirements and milestone reporting. New generation purchased through the backstop would receive a fix capacity payment for 10-15 years. All capacity units would have a must-offer requirement to all CAISO markets for which they were capable of performing, including day-ahead energy and AS, RUC and real-time energy and A/S markets. Generation faced performance penalties if they did not perform during critical periods.

Reliant

Reliant's proposal, the California Forward Reliability Model (CFRM), included a four-year forward centralized capacity resource auction for a one year commitment of eligible capacity resources. Reliant's proposal involved the application of vertical demand curve of peak load forecast plus the Commission's planning reserve margin.

Under the Reliant proposal, payments by LSEs for RA capacity obligations would occur in the future target year. In addition, LSEs would be able to self-supply requirements within the CFRM auction. The CFRM proposal would permit bilateral contracting and would support bilateral trading in that it would permit those with self-supply to submit their capacity in the auction.

Reliant's proposal referenced a day-ahead market must-offer obligation for all CFRM committed resources. With regard to imports, the proposal stated that there should be a qualification of identified resources outside of the CAISO to ensure deliverability to load and firm transmission rights.

To mitigate local market power, Reliant stated that bids from local area resources could be capped at levels that allow the resource a reasonable return in coordination with review by an independent market power monitoring entity.

Reliant addressed the issue of load migration, and claimed that their CFRM proposal would provide a clear and transparent capacity charge that could be adjusted to accommodate the switching of customers from one LSE to another.

NRG

NRG Energy's March 30th proposal included a locational, forward capacity market cleared centrally and administered by the CAISO. The proposal included elements of the ISO New England's FCM design, including the descending clock auction, where the bid price of new generation sets the price for capacity.

Under NRG's proposal, the amount of capacity that would be procured through the auction process would be equal to that of the CAISO's installed capacity requirement, including reserves and the supply commitment made in each capacity auction would be for four years in the future. New generation that clears the market has the option of receiving the cleared price for up to four years (forward commitment year plus three extension years)

NRG's proposal also featured the implementation of locational delivery zones for import or export-constrained zones, and a separate auction/capacity price would be established for these delivery zones.

Under the NRG proposal, each LSE would be required to pay for a share of the installed capacity requirement proportionate to its share of peak load, with payment charged to LSEs in the delivery year. LSEs would be allowed to self-supply their projected capacity obligations by bidding capacity in the auction as a price taker. LSEs would be prohibited from "opting out" of the auction process.

NRG pointed out that their approach would reduce the mandate by CPUC for mandate of long term procurement in future.

SDG&E

SDG&E's proposal was similar to the New England FCM, using forward procurement to achieve specific quantity targets, both system-wide and in each relevant local area.

The market design included the Primary Residual Capacity Auction (PRCA) which was designed to procure firm physical commitments from new and existing resources, including generation, DR, and imports, sufficient to meet 100 percent of the forecast peak load plus the planning reserve margin four years forward. Bids could be seasonal, but the total capacity acquired was the same in each season.

SDG&E's design included a sealed-bid, first price auction, like the PJM's RPM. Under the proposal, the auction would clear by accepting the self-supplied resources and lowest-cost offers sufficient to cover the peak load plus planning reserve margin. The offer price of the last cleared resource would set the clearing price of capacity applicable to all cleared resources. New resources would be eligible for a 5 to 10 year contract at the clearing price. SDGE cited the benefits of the sealed-bid format in that it would provide: ease of administration, lower burden on participants, and enhanced ability of the market monitor to assess the impact of potentially non-competitive bidding

As in New England, the SDGE proposal included a series of annual incremental auctions to allow trading of positions among qualified resources, top-up or release of capacity if forecasts change, and supplementation of resources procured in the primary auction if insufficient offers were received initially. The proposal also included a backstop procurement for a 15 year contract if the primary auction failed to produce sufficient resources.

The costs of capacity would be allocated during the performance year based on actual load. The approach to market settlements under the SDGE proposal was most similar to that in New York. Loads in constrained areas would pay a blended price equal to the weighted average of the Local Area price and the lower system price.

SDG&E's proposal included a must offer requirement for energy and AS markets. External resources would be required to offer an energy schedule into the day-ahead markets and the reliability commitment for an amount at least equal to their Capacity Supply Obligations, but would be exempt from a real-time must-offer requirement. Internal resources located in a Local Area that scheduled itself for export would be required to be offered into all CAISO energy and AS markets up to its eligibility to participate in those markets unless the resource is fully dispatched to meet its export obligation. Accepted units would be subject to availability penalties during periods of reserve shortage and performance metrics that would be self-funding and which would reward units with above average availability and penalize those with sub-par performance. Finally, the SDGE proposal included rules for physical operating characteristics and bid cap values.

Appendix 4 – The MSC Opinion

Final Opinion on "Long-Term Resource Adequacy under MRTU"
by

Frank A. Wolak, Chairman
James Bushnell, Member
Benjamin F. Hobbs, Member
Market Surveillance Committee of the California ISO
November 5, 2007

1. Introduction

The California Public Utilities Commission (CPUC) is currently considering whether to implement a centralized capacity payment mechanism. It has asked the California ISO to provide a recommendation on the hypothetical question: If the CPUC adopts a CCM how should it be designed? The Market Surveillance Committee (MSC) has been involved in both the ISO process and the broader CPUC process, having participated in a number of stakeholder meetings and conference calls over the past year. On October 1, 2007 the MSC held a meeting at the CPUC to discuss centralized capacity payment mechanisms and other long-term resource adequacy (LT-RA) proposals with stakeholders, ISO staff, and CPUC staff. This opinion addresses a broader set of questions than the one posed by the CPUC to the ISO. We first comment on whether the CPUC should adopt a CCM at this time. Then we provide recommendations for necessary features of any LT-RA process, whether or not CPUC decides to implement a centralized capacity payment mechanism.

Although we have a number of concerns with the performance of California's electricity market, we do not believe that any of the current capacity market proposals effectively address them. In fact, given the wide range of uncertainty surrounding the future organization and structure of California's electricity market, as well as the performance of new capacity-market structures in eastern markets, it appears to us to be a singularly inappropriate time for California to commit to a new resource adequacy mechanism with potentially significant cost consequences. In short, we believe there is substantial value to deferring any major overhauls of the Resource Adequacy structure until California's specific needs for such a LT-RA product are known with greater clarity.

Under the current RA paradigm,[1] the California ISO has met significant reliability challenges over the past six years with little adverse economic consequences. Moreover, on July 24, 2006, the California ISO served a peak system load of 50,270 MW, a value that exceeded the ISO's one-in-fifty-year forecast for the summer of 2006. Of course, the lack of serious resource shortfalls in the recent past is not a guarantee that they could not arise in the future. [2] Further, many are concerned that the current RA paradigm is too dominated by the procurement plans of

[1] For the purposes of this opinion, we define the current RA paradigm to include more than just the current bilateral RA requirement imposed on load-serving entities. The current paradigm is also largely driven by the CPUC long-term procurement process, which has resulted in both substantial wholesale energy price hedging (typically in the form of long-term fixed price contracts or tolling arrangements) by the utilities and the investment in new capacity the cost of which is then allocated among non-utility load-serving entities in the investor-owned utility's service territory.

[2] For example, the Department of Market Monitoring in its 2006 Annual Report on Market Issues and Performance expressed concern that the increasing dependence of Southern California on imports and tight reserve margins in the current South of Path 15 (SP15) zone make it vulnerable to reliability problems if there is a major transmission outage into this region.

the regulated utilities. We share those concerns. However, given the status of several other policy initiatives currently underway in California, it is difficult to see how establishing a CCM would alter this in the near term. [3] As long as utilities continue to procure power for the vast majority of California consumers, and state mandates dominate those procurement plans, a change in market design will not reduce the central role of utilities and their regulators in this market. [4] Therefore, we believe that a CCM under these circumstances would not reduce the scope of regulatory oversight of the RA process, but it would rather shift its emphasis from the CPUC to the Federal Energy Regulatory Commission (FERC).

[3] In fact, a centralized market could intensify the interest in utility-backed investment, because this utility investment could drive down the price of capacity purchased from the centralized market. Such a phenomenon appears to be at play in regions such as western Connecticut.

[4] The only way to limit influence of regulated-utilities over the procurement process is to dilute the market shares of these firms, either through robust retail choice or through New Jersey-style Basic Generation Service (BGS) procurement auctions. Procurement auctions, by diluting the responsibility for default service amongst multiple firms, could also begin to address the current problem of cost-allocation risk that utilities now face.

There are several major policy initiatives currently underway or issues that are unsettled that contribute to the uncertainty about the need for, and preferred design of, a LT-RA product. These are the Market Redesign and Technology Update (MRTU), the uncertain future of retail choice, and the recently adopted aggressive renewable energy and GHG emissions goals.

In the first of these initiatives, the California ISO is currently implementing a LMP energy market with a day-ahead integrated forward market under the Market Redesign and Technology Upgrade (MRTU). There are many remaining market design challenges associated with successfully implementing MRTU that could be made more difficult by implementing a centralized capacity payment mechanism at approximately the same time. It is also important to remember that MRTU is very much a work in progress. Although first phase of the market will be implemented in 2008, important changes will follow in years to come. There is a significant likelihood that new AS products will be developed to better address the changing reliability needs of the California ISO control area. This means that when firms acquire capacity today, they are not well informed about what that capacity will actually have to do in a few years time.

A major uncertainty concerns retail choice, which is currently unavailable to most electricity consumers in California. This may change soon with the potential rise of community choice aggregation, as well as an ongoing proceeding at the CPUC to consider a return of DA. It is important to recognize that the existence and form of retail choice is an essential piece of information necessary to craft a satisfactory resource adequacy policy. Without retail choice, much of the rationale for FERC-based LT-RA policies goes away because the vast majority of load will continue to be served by CPUC-jurisdictional entities. Even if it is reinstated, the conditions of retail choice, such as the extent of eligibility, costs of “exit” and “conditions for return” are important factors in determining the need for and preferred attributes of an RA policy. None of these features are known with any kind of certainty today.

Finally, California’s significant energy efficiency and renewable energy goals imply that there is little need for additional energy from non-renewable generation to meet future load growth through 2020. Meanwhile, uncertainties concerning the design and costs of California’s GHG emission control policies further complicate the RA paradigm. While there will likely be a need for some fossil fuel generation unit investments to operate the California ISO control area with a significantly larger renewable energy share, we do not believe that the current capacity-market proposals would fill these focused needs.

Thus, in general, the long-run economic organization of the California market remains very much a moving target. Given the great degree of uncertainty and ongoing change currently at play in California, we feel that a far more prudent and cost-effective course of action at this point is to refine the current RA paradigm to correct known flaws rather than completely overhaul it, while preserving the option of a full redesign at a later date. Moreover, a number of potential problems with the current RA paradigm may be addressed by MRTU. As the MRTU implementation process identifies the need for new energy and ancillary service products, new RA needs may be identified. A number of the eastern ISOs are currently in the initial stages of implementing new long-term capacity payment mechanisms in response to perceived shortcomings in their former capacity payment mechanisms. Another market, Texas, is pursuing the so-called "energy only" path. By delaying significant changes in its RA paradigm, California can learn from the experience of these ISOs.

2. Resource Adequacy and MRTU

There are many features of MRTU that are new to California market participants. These include a day-ahead integrated forward market with LMP, a new local market power mitigation mechanism, obligation-type congestion revenue rights issued by the California ISO, and a residual unit commitment (RUC) process, to name a few. There are also plans to implement convergence bidding between the day-ahead and real-time markets under MTRU and number of other additional market design elements in future releases of MRTU. Many of these features have the potential to improve the effectiveness of the current RA paradigm in California.

An LMP market for energy with more granular pricing of AS can provide greater transparency to all parties about the economic and reliability benefits that a specific generation unit provides to electricity consumers. Each generation unit has the option to sell its energy in the day-ahead or real-time market at the LMP at its location as well as any AS the unit is able to provide at the relevant locational AS price. Under the current zonal market design, the opportunity cost of signing an RA-contract for generation unit owners needed for local reliability reasons is significantly less transparent because a significant fraction of the revenues this generation unit owner expects to receive from the ISO if it were not an RA resource would come in the form of uplift payments.

Under the MRTU market design, a generation unit owner that signs a fixed-price forward contract for energy, that clears against the price at the counterparty retailer's location, has a strong incentive to operate it's units to minimize the difference between the price at the retailer's location and the price where the generator injects energy. The existence of a short-term LMP market enables retailers to sign RA contracts and fixed-price forward contracts for energy that hedge virtually all of the locational price risk faced by the retailer. In contrast, the current zonal market design can often add significant uplift charges to the hourly real-time price paid by the retailer that increase both the mean and variance of its wholesale energy procurement costs.

If retailers sign fixed-price forward contracts for energy to hedge short-term locational price risks far enough in advance of delivery to allow new generation units to compete to supply this energy, MRTU can also provide strong incentives for suppliers to locate and operate their generation units to reduce the short-term cost of operating these generation units in the day-ahead and real-time markets.

Finally, as discussed below, the combination of new environmental mandates and the transition to MRTU cast a great deal of uncertainty over the questions of both *how much* capacity California needs and what this capacity must *do.* While the first phase of MRTU will be implemented this year, the next phases will carry important modifications that will further shape the role that resource adequacy products will play. A process to implement scarcity pricing for energy and AS is underway, and the CAISO continues to refine the role and definitions of various AS in the future market design. Perhaps most important, the addition of large amounts of intermittent renewable energy sources will change the California ISO's concept of reliability and operating reserve requirements in ways that are not yet clear. Because California does not know exactly what certain generation units will need to do in the future, it is tempting to procure and require this capacity to do everything and anything. This is one interpretation of what the must-offer requirement attempts to do—that is, to require units to make themselves available to provide any of a broad range of services depending upon the needs of the operators at the time. However, purchasing capacity and developing performance requirements after generation capacity has been purchased may be a costly approach to ensuring reliable system operation, because California will very likely have a much better sense of those requirements in a few years time.

3. California's Renewable Energy and Energy Efficiency Goals

California currently has a legislative requirement that investor-owned utilities (IOUs) and energy service providers (ESPs) satisfy 20 percent of their retail sales using renewable energy by 2010 and the energy agencies have established as a policy goal that this requirement increase to 33 percent renewable energy by 2020. Further, in 2006, the California legislature established a ten-year goal of 3,000 MW of roof top solar photovoltaic installations. California also has a number of energy efficiency goals to reduce overall energy consumption as well as peak energy demand. The CPUC recently adopted energy efficiency targets for 2009-2011 programs that authorize funding consistent with these long-term goals. According to the California Energy Commission (CEC) studies as part of the 2007 Integrated Energy Policy Report (IEPR) proceeding, these energy efficiency, rooftop solar PV, and supply-side renewable generating technology goals imply that they will be very little need in California for electricity from new non-renewable generation through 2020, except those required to meet local capacity requirements.

In light of these facts, it is important to recognize that the RA paradigm need not be focused on investment to meet load growth for more than a decade. Rather, the incremental generation investment needs for the system will be defined by these renewable energy and energy efficiency goals. Because any new fossil-fuel capacity likely to be constructed in California in the next ten years will be needed at specific locations in the network or to serve particular system reliability goals, it is not clear that a centralized capacity payment mechanism will be an improvement over the existing RA paradigm as a means to obtain this needed new generation capacity.

A central policy question that has yet to be confronted is the best way for the system to absorb the large amounts of intermittent energy sources coming as a result of California's RPS. One vision is that these resources will have to be paired with flexible thermal resources (e.g. CTs) on an almost MW for MW basis. Another vision would require much more flexibility in consumption patterns through active participation of final demand in the wholesale market and perhaps expanded storage options and better integration with current regional hydro resources.

The proper design elements of a resource adequacy regime depend upon which of the alternative visions described above is pursued. However, it is important to emphasize that *none* of the current resource adequacy proposals--including the current regime--would implement either of these visions. The capacity paradigm emphasizes the *potential* for energy production, rather than actual energy production. The focus on peak *energy* revenues in the pricing mechanisms may also prove to be a poor match for the much higher needs for nimble generation services and active participation by final consumers that a system with large intermittent resources would imply.

4. Learning from Other Markets

PJM and ISO-New England have recently implemented long-term capacity payment mechanisms. The New York ISO has also recently implemented a number of changes to its capacity payment mechanism. It is unclear whether these changes will achieve the desired goals. Only by careful study of the performance of these capacity payment mechanisms for several years will it be possible to determine which aspects were successful and which were not. There are many competing claims about the underlying conditions that make capacity markets necessary, and about the most effective design of capacity markets. To our knowledge, none of these claims have been rigorously tested, in part because the markets themselves are so new.

The Electricity Reliability Council of Texas (ERCOT) has decided to pursue what many refer to as an "energy-only" market with LMP where retailers and suppliers enter into long-term energy supply arrangements to fund new generation investments. If California were to adopt a capacity payment mechanism now, it would give up the opportunity to learn from the successes and failures of the recent reforms of the eastern markets and the experience of the ERCOT market.

The benefits from waiting are likely to be substantial given the enormous wholesale energy and capacity cost increases that the eastern markets have experienced with the implementation of these new capacity payment mechanisms. It may indeed not be possible for California to avoid these costs and still attract sufficient new investment to meet load growth in the distant future. However, because of California's ambitious renewable energy and efficiency goals, it is possible to have a few years of experience with MRTU and the eastern ISO capacity markets before deciding whether to implement a capacity payment mechanism.

5. Shortcoming of Current RA Paradigm and Recommended Changes

Several shortcomings of the current RA paradigm have been identified during our discussions with stakeholders and ISO staff. The first is the lack of standardized LT-RA contractual terms and conditions to facilitate secondary market trading. A second issue is the time horizon prior to delivery for procurement of capacity to be in compliance with the CPUC's RA requirements. A third issue is the role of the must-offer requirement for capacity resources given California's increasing dependence on renewable resources and imports. A final issue is the need for a clearly defined ISO backstop for the RA process.

Calpine has made a proposal for standardized contractual terms and conditions for RA products that seem to have met with significant stakeholder support. We see the value in a standardized RA product although we do not see a need for the ISO to adopt a formal standardized RA contract in its tariff. We are concerned that implementing the RA conditions in the ISO tariff will reduce the ability to make changes to these conditions in the future.

We could be supportive of a LT-RA compliance process that is somewhat further in advance of delivery than the current requirement. Clearly there are benefits to pushing the procurement of resources beyond more than one year in advance. This would increase the likelihood that transmission and generation projects requiring longer construction lead times can compete in a LT-RA process. A longer time lag between negotiation and delivery of the LT-RA product also implies that there will be less need to rely on administrative procedures to mitigate the local market power that existing RA suppliers might have in many local areas. With enough advance notice, new entrants can effectively compete with existing generation units in many parts of California.

However, it may not be necessary to *require* such forward commitments through the RA process, if firms are entering into longer term arrangements on their own anyway. Conversely, the farther into the future such a requirement is extended, the more problems arise with forecasting future needs and other sources of uncertainties. Despite the costs, such a requirement could nevertheless be justified if it can be demonstrated that firms were not taking on sufficient fixed-price forward obligations absent a regulatory mandate to do so.

We question the need to require a must-offer obligation to accompany all RA capacity. A must-offer obligation has very little meaning for renewable energy resource, because it can only be available to produce when the energy source is available. California depends on imports for close to 25 percent of its energy needs and a must-offer obligation for imports is fundamentally different from a must-offer obligation for an internal resource. It is impossible to identify the specific resource offering to supply energy at an intertie into California, whereas it is straightforward to determine whether a specific internal generation unit is offering energy or AS into the ISO's markets. For both of these reasons, we question the need to require all RA resources to have a must-offer obligation that only has meaning for a small subset of the generation resources serving California load. Instead, we believe that the ISO should consider procuring additional AS, such as replacement reserve, on a locational basis to ensure that the ISO have the necessary unloaded generation capacity at the necessary locations throughout the control area to operate the system in real time.

Purchasing a much smaller amount of a significantly higher quality product such as replacement reserve is likely to be much more cost-effective for California consumers and should enhance grid reliability relative to the case of purchasing a must-offer obligation from all RA generation units, despite the fact that the necessary service the ISO operators need is provided only by a small subset of the RA units. The higher prices paid to units providing the necessary replacement reserve in the locations that these units are needed will provide strong incentives for units that can provide this ancillary service to be constructed in the locations where these high prices are being paid.

The final issue concerns the need for a backstop. The purpose of a backstop is to ensure that if circumstances arise where the operators do not believe they will be able to maintain system reliability, then some entity must have the discretion to purchase, or order an LSE to purchase, the necessary energy or capacity to solve this reliability problem. Ideally, the ISO should have the ability to implement this backstop procurement process at any time horizon prior to delivery, if the ISO believes that real-time system reliability will be adversely impacted without it. For example, if two years out the ISO determines that the only way to meet load growth in a given area with a given level of reliability is if a new generation unit is constructed in a local area, the CPUC or ISO can run a procurement process to ensure that the unit is built. Because the ISO is the primary entity charged with maintaining system reliability, it must have the discretion to initiate the actions necessary to maintain system reliability at all time horizons prior to delivery. Such policies should also be cognizant of demand-side options for addressing any potential shortfalls, however. More progressive load-management could address many potential RA shortfalls and could likely be implemented in a much shorter time frame than new generation construction

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6. The Future LT-RA Process in California

Because we do not recommend an overhaul of the existing RA paradigm at this point, we do not have specific LT-RA design proposal. However, we do recommend that the ISO and CPUC monitor the performance of the RA paradigms in other markets and the implementation of MRTU. This information can be used to formulate a LT-RA process tailored to California's long-term resource adequacy needs that avoids any shortcomings of the RA paradigms in other markets. In addition, more careful study of the current Long-Term Procurement Process (LTPP) of the California utilities under MRTU will help inform stakeholders on any shortcomings of the current structure. Based our analysis of the existing RA paradigm, we believe there are certain features that should be a part of any LT-RA paradigm, whether or not a centralized capacity mechanism is implemented.

The first issue is the need to maintain a substantial coverage of final demand in California through long-term supply contracts that provide a hedge against short-term energy price risk. These contracts should be negotiated far enough in advance of delivery so that new entrants have an opportunity to compete to supply this energy, which is typically at least 2 years in advance of the delivery date[18]. Approximately 25 percent of the energy consumed in California is imported, and many of these imports come from hydroelectric sources. California also has a significant amount of internal hydroelectricity generation capacity. These facts emphasize that the fundamental resource adequacy challenge for California is not adequate generation capacity, but adequate energy to serve demand. We do not believe that a CCM of the form contained in any of the stakeholder proposals would have prevented the California electricity crisis of the period June 2000 to June 2001. The crisis was not caused by a shortfall of generation capacity, but by a lack of commitment of financial suppliers to provide energy to the California market. All of the rolling blackouts that occurred in California occurred during periods with system demands less than 35,000 MW, which is far below the peak demand of more than 44,000 MW that were served during the summers of 2000 and 2001.

The growing share of energy to serve California that is projected to come from renewable energy sources provided under contracts that have retailers and final consumers bearing all of the quantity risk associated with the provision of this energy significantly increases the risk of energy shortfalls. For this reason, we believe that any viable LT-RA paradigm must address the fundamental adequacy problem for California. This problem is the risk of inadequate *energy* available to meet demand, as well as the secondary problem that energy might be available to meet demand, but wholesale prices will be so high as to cause significant economic harm to final consumers. For this reason, we conclude that any LT-RA process must demonstrate how the substantial risk of energy shortfalls and the resulting very high short-term prices that are likely to occur will be hedged. We believe that this risk is sufficiently large that both price-hedging contract coverage of retail load obligations and active participation by final demand in the wholesale market are necessary to ensure a truly reliable market. California's commitment to universal interval metering for all IOU customers makes active participation of final demand technically feasible.

There are several potential pathways to maintaining substantial energy hedging. Under certain wholesale and retail regulatory structures, firms will have a strong incentive to hedge virtually all of their short-term price risk without a regulatory mandate that they do so. If the vast majority of load in California continues to be served by regulated load-serving entities (LSEs), then the CPUC procurement process should ensure an adequate level of hedging of short-term price risk. Another pathway to adequate hedging of short-term energy price risk is a

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[18] That is because each MW of capacity sold through this mechanism is promising a payment of max(0,P(spot)-P(contract)), where P(spot) is the hourly short-term price and P(contract) is the contract price for that hour. This provides a MW hedge against wholesale prices in excess of P(contract). It is important to note that this type contract can result in refunds greater than the capacity payment received by a generation unit owner if it fails meet its capacity obligations or the market experiences significant periods of very high short-term prices.

centralized capacity mechanism with an ex post PER refund that resembles a short-term energy price call option on the amount of capacity sold by the generation unit. [5]

The second issue is the need for robust forward procurement, and the recognition that some forward procurement will still be vulnerable to market power. In general, procurement of either energy or capacity will be more competitive if it occurs on a time horizon long enough to allow for new entrants to compete against incumbent suppliers. If the time horizon prior to delivery of the service is 3 to 4 years in advance, then it is likely that only the major coastal metropolitan areas of San Diego, Los Angeles and San Francisco would still require a local market power mitigation mechanism for energy and RA capacity. For these local areas, even forward markets 3 to 4 years in advance are simply not sufficiently competitive (because of the significant barriers to new entry in these areas) to be relied upon without mitigation. In these cases, the goal is to set an administrative mechanism that allows for the recovery of the total costs of these local units, yet does not allow them to exercise local market power in the forward energy or capacity market. The specific form of the administrative pricing process chosen is less important the further in advance the capacity procurement process takes place, because the more possibilities there are for new entry to discipline the price existing suppliers are allowed to charge.

The third issue concerns the question of how to incorporate retail choice into the LT-RA process. We believe that that California's adoption of universal interval metering provides a promising foundation for a well-formulated DA policy. When customers bear the consequence for the resource choices of their retailers, the cost of a retailer having inadequate resources can be placed squarely on that retailer's customers alone. This involves making the default wholesale price that DA retail customers pay equal the hourly real-time energy price. No DA customer would be *required* to pay this wholesale price for all of their consumption, as they would have the ability to sign any tariff they want with a retailer. Charging all customers the hourly real-time price for all of their consumption within the hour addresses a number of important issues. First, it levels of the retail competition playing field, because all retailers must offer a hedging product that the customer finds superior to this real-time price. Second, it provides strong incentives for final consumers to become active participants in the wholesale market, which enhances system reliability in an energy market served by an increasing amount of renewable sources. Third, it provides a mechanism for retailers to manage energy shortfalls in real-time by charging customers extremely high short-term prices for consumption beyond the levels in their fixed-quantity supply contracts or paying them these high prices for reductions in consumption below these fixed-quantity levels. Last, if a retailer does go bankrupt, its customers are not allowed to immediately return to a default service that includes valuable energy hedges and resources for which DA customers had not paid, instead these customers must face a default wholesale price equal to the hourly wholesale price.

We believe these elements are necessary to provide both economic and physical reliability to the system, particularly considering the current and future features of the California electricity market. As discussed above, the importance of imported energy, along with the advent on MRTU and the addition of substantial intermittent resources on to the system, will mean that future reliability needs will differ from today. For example, the benefits of a must-offer requirement on RA resources will decline, as the percentage of those resources drawn from imported, energy limited or intermittent sources increases. The increase in intermittent sources will likely increase the volatility of the energy spot market, raising the need for more nimble generation and demand resources that can follow these fluctuations on a regular basis. More frequent and pronounced price fluctuations in the market should make investments in quick-start and fast-ramping resources lucrative. Finally, the likely increase in the frequency of periods of high prices makes it imperative that the vast majority of California load that cannot respond to short-term price signals be hedged against fluctuations in short-term energy and AS prices. On the regulatory side, the CPUC long-term procurement process should be better integrated with backstop needs of the ISO. This discussion with the CPUC should also cover what AS products and requirements the ISO operators believe are necessary for reliable system operation.

7. Concluding Comments

Our recommendation against adopting a CCM at this time does not imply that we could not support its implementation at a later date. We can imagine future system conditions and features of a CCM that would fit the California market. We can also imagine conditions in which CCMs, as they are currently conceived, are not at all necessary. There is much about centralized markets that we do not yet know. The same can be said of the current California electricity supply industry. New investment is now funded primarily through the utility procurement process, which is also relatively new. If this process is in fact producing adequate resources, the role of the current RA requirement must be viewed in another light. If we accept that investment is provided through other procurement processes and regulations, the ISO's RA requirement is largely reduced to a mechanism for funding its must-offer requirement. As the system evolves over the next several years, we should re-evaluate the benefits of a system focused so strongly on must-offer arrangements, rather than the provision of specific services. As noted above, we believe any resource adequacy policy must address the fundamental resource adequacy challenge that California faces because of its dependence upon hydroelectric, intermittent, and imported energy. Finally, we do not believe that the cost allocation challenges associated with allowing retail choice are insurmountable if a default retail pricing mechanism is adopted that includes embedding the hourly real-time wholesale price in the default retail price.

Appendix 5 – The Workshop Agendas

August 15th: Review of 8/13 ISO Workshop, Discussion of Non-Centralized Capacity Market Proposals

Hearing Room E

10:00 – 10:20 Introduction and discussion of schedule by PUC staff
10:20 –11:20 ISO led review of 8/13 workshop at ISO
11:20 – 12:00 Bilateral Trade Group presentation
12:00 – 1:00 Break for lunch
1:00 – 1:40 Aglet presentation
1:40 – 1:50 Break
1:50 – 3:30 CPUC moderated panel Q&A of non-centralized capacity market proposals

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August 20th: Component Market Consideration

Training Room B

10:00 – 10:15 Introduction of component element discussion by CPUC staff
It is expected that parties with proposals will discuss how their proposal relates to each element below and that parties will have the opportunity to ask questions of the proponents of a particular proposal. Parties will also be expected to discuss the relevant jurisdictional entity where each element is planned and executed.
10:15 – 11:00 Planning mechanisms
PRM and other planning mechanisms
11:00 – 11:45 Capacity product
Uniform product, alternative products
11:45 – 12:30 Pricing mechanism
Bilateral, market clearing, adjustment factors, price taking etc.
12:30 – 1:30 Lunch
Eating
1:30 – 2:15 Transactions
Initial, Subsequent, Payment
2:15 – 2:30 Break
Not working
2:30 – 3:15 Backstop mechanisms
Centralized and non-centralized backstops
3:15 – 4:00 Compliance
Delivery metrics, load metrics, enforcement
(Are there non-monetary enforcement mechanisms? e.g. right to participate)
4:00 – 4:45 Triggers
Are there elements that can be triggered or called by the market that might not otherwise occur? (e.g. a subsequent auction-based transaction, the an initial auction itself, review of CONE, adjustment of the PRM)
4:45 – 5:00 Other Issues

August 21st: Market Power Mitigation, Least Cost Principles, Ease of Administration, and Compliance with Commission's Environmental and Other Policies
Training Room B

10:00 am – 10:15 am - Introduction of topics by CPUC staff

10:15 am – 11:15 am - Market power mitigation – generation side – panel

11:15 am – 12:15 pm - Market power mitigation – load side - panel

12:15 pm – 1:15 pm - Lunch

1:15 pm – 2:00 pm - Least cost principles
- Presentation by PG&E
- Panel discussion

2:00 pm – 2:50 pm - Ease of administration - panel

2:50 pm – 3:00 pm - Break

3:00 pm – 5:00 pm - Compliance with Commission's environmental and other policies - panel

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August 22nd: Multi-Year Forward Commitment Discussion
Hearing Room A

10:00 am – 10:15 am - Introductions and announcements
- Topics for today:
  - Planning Reserve Margin in the proposals – panel
  - PRM and multi-year RAR
  - Multi-year RAR obligation
  - Recap and discussion – commitments and consensus

10:15 am – 11:00 am – Summary of proposal presentations
- PG&E – PRM
- Others as requested by presenters
- Q + A

11:00 am – 12:30 pm - Planning Reserve Margin in the proposals – panel
- Role of PRM in the proposals
- Pieces of the PRM – data sets and studies
- Resource mix – PRM to account for intermittent resources
- Integration of Operating Reserves
- Q + A

12:30 pm - 1:30 pm – Lunch

1:30 pm – 2:15 pm - PRM and multi-year RAR - panel
- New piece to the PRM – retirements and construction risk
- Datasets and study
- Q + A

2:15 pm – 3:30 pm – Multi-year RAR obligation - panel
- Structure of obligation
- Adjustments/realignments
- Load Migration
- Q + A

3:30 pm – 4:00 pm – Recap and discussion – commitments and consensus
- Brief summary and key points from the discussion
- Comments and Questions

August 27th Resource Mix and Ancillary Services
Training Room B

10 am to 10:30 am
Introduction and Review of CAISO's March 30th Track 2 Filing

10:30 am to 12:30 pm
Overview of CAISO Operational Requirements
How Operational Requirements are Met Today
- Resource Adequacy Capacity
- Reliability Must Run
- Must Offer Waiver Denial Process and RCST
- CAISO Markets (DA & HA Balanced Schedules, Ancillary Services, Real Time Energy)
- Out-of-Market Transactions

1:30 pm - 2:30 pm
How Operational Requirements will be met under MRTU

2:30 pm - 3:30 pm
Renewables and Demand Response and their impact to operational requirements

3:30 pm - 5:00 pm
How the operational needs can be met via the proposals – panel

Workshop Agenda R.05-12-013
Resource Adequacy Track 2 Workshops
Hearing Room A, August 28, 2007
10:00 am – 5:00 pm

10:00 am – 10:15 am - Introduction of topics by CPUC staff

- Welcome and introductions
- Topics for today
  - Multi Year RA and PRM
  - Registration and Tagging of RA capacity
  - Uniform Capacity product
  - LSE opt-out from cost allocation mechanism

10:15 am – 12:00 pm – Multi – year RAR and the PRM

- Structure / timeframe of obligation
  - Single year PRM vs Multi Year PRM
- Adjustments/realignments
- Load Migration / IEPR Load Forecast
- Q + A

12:00 pm – 1:00 pm - Lunch

1:00 pm – 2:00 pm – Registration and tagging

- SCE presentation of March 30th proposal
- Q + A – CAISO response

2:00 pm – 3:15 pm – Standard RA Generator Obligations

- Calpine stakeholder process
- CAISO response
- Q + A

3:30 pm – 3:30 pm - Break

3:30 pm – 5:00 pm – LSE opt out from Cost Allocation Mechanism

- General Issues
  - SCE presentation of March 30th proposal
  - PG&E presentation
  - AReM presentation
- Panel discussion

Thank you for your participation

Workshop Agenda R.05-12-013

Resource Adequacy Track 2 Workshops

Hearing Room A, August 29, 2007

10:00 am – 5:00 pm

10:00 am – 10:15 am - Introduction of topics by CPUC staff

- Welcome and introductions
- Topics for today
  - Interaction between RA program and the Commission's environmental and other policies
  - Reading into the record of comments on 8/3 proposals

10:15 am – 12:00 pm – Compliance with Commission's environmental and other policies - panel

- Demand Response
- GHG
- RPS
- CSI and EE
- Q + A

12:00 pm – 1:00 pm - Lunch

1:00 pm – 3:00 pm – Commments on the 8/3 filings for the record

3:00 pm – 5:00 pm – Closing administrative items