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

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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 centralized capacity market 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 centralized capacity market 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 centralized capacity market 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 centralized capacity market 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).

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 greenhouse gas emissions goals.

In the first of these initiatives, the California ISO is currently implementing a locational marginal pricing (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 ancillary services 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 direct access. 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.

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[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.

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 greenhouse gas 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 ancillary services 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 ancillary services the unit is able to provide at the relevant locational ancillary services 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 ancillary services is underway, and the CAISO continues to refine the role and definitions of various ancillary services 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 renewable portfolio standard (RPS). One vision is that these resources will have to be paired with flexible thermal resources (e.g., combustion turbines) 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 ancillary services 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 ancillary services, 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. 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 centralized capacity market 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 centralized capacity mechanism with an ex post peak energy rent 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

[5] 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.

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 direct access 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 direct access retail customers pay equal the hourly real-time energy price. No direct access 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 direct access 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 ancillary services 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 ancillary services products and requirements the ISO operators believe are necessary for reliable system operation.

7. Concluding Comments

Our recommendation against adopting a centralized capacity market 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 centralized capacity market that would fit the California market. We can also imagine conditions in which centralized capacity markets, 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.