Designing the Market for Local Reliability Service

by

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Introduction

A key feature of the California ISO's Congestion Reform proposal is the Local Reliability Service (LRS) auction. This auction procures a commitment from generation units in Local Reliability Areas (LRAs) to provide: (1) a minimum amount of energy in a day-ahead schedule balanced against load in that LRA and (2) additional "contingency capacity" available to provide additional energy should certain real-time contingencies arise. This portion of LRS capacity can held as unloaded capacity on a day-ahead or hour-ahead basis, as capacity scheduled to provide energy on a day-ahead and hour-ahead basis, or as capacity providing ancillary services. The term "Contingency Capacity" (CC) will used to refer to the portion of LRS capacity that is not required to be scheduled in a forward market. "Minimum Reliability Energy" (MRE) will refer to the portion that is required to be scheduled, so MRE + CC = total LRS capacity purchased. The total amount of LRS capacity will be called "Minimum Reliability Capacity" (MRC). There are several issues that must addressed in order for the LRS auction to be the most effective means possible within the proposed California market design for managing intra-zonal congestion and mitigating local market power.

There are five major issues. The first concerns procuring a sufficient amount of LRS capacity and energy so that the intra-zonal congestion in real-time is infrequent, unpredictable and economically insignificant. The second issue concerns the role of the LRS auction in providing locational price signals. The third issue concerns minimizing the impact that the mitigation of local market power by the LRS auction has on the operation of the ISO's energy and ancillary services markets. The fourth issue addresses the determination of the appropriate level for the bid cap on the participants in the LRS auction, and the appropriate time frame for removal or escalation of the LRS bid caps. The final issue is the appropriate time horizon over which the LRS product is purchased.

LRS Procurement to Make Intra-zonal Congestion Economically Insignificant

The 2-day ahead LRS auction purchases MRE and CC in anticipation of local reliability energy and capacity needs in real-time. Specifically, the ISO purchases MRE to be able to withstand an N-1 contingency (relative to system conditions known at the time of LRS procurement), plus additional CC to be able to recover from the same N-1 contingency after it occurs. In other words, in the pre-contingency state, the system is operating with all pathways at their "normal" ratings. When an N-1 occurs, the MRE is sufficient so that the system can continue operating, but now with some pathways at "emergency" ratings, so there is limited time the ISO can operate at that level. By dispatching the CC, the ISO can return all pathways to their normal ratings. Because the best estimate of weather conditions (a major driver of the demand for energy and LRS capacity) on a two-day ahead basis can be very different from the weather that occurs when that day arrives. The same statement applies to available capacity on the transmission grid and available generating capacity in the ISO control area. As the ISO operators have emphasized, if the system conditions forecast at the time the LRS auction is run actually occur in real time, then there will be no real-time intra-zonal congestion in any LRA. However, the likelihood that system conditions will be exactly as forecast on a two-day ahead basis is virtually zero. Consequently, the ISO must have a way to adjust its LRS requirements to respond to changes in system conditions between the 2-day ahead auction and real-time market operation. In addition, the ISO must have the flexibility to specify the 2-day ahead LRS capacity requirement not just to satisfy the LRS requirements for its best guess of system conditions two days from now. The LRS capacity requirement must build in some comfort zone to handle reasonable increases in energy demand due to plausible changes in the system conditions. This process will certainly entail some learning on the part of the ISO operators, but the important point to emphasize is the necessity of the allowing the ISO operators this flexibility in specifying LRS requirements.

Some stakeholders have expressed concern that the LRS auction mechanism gives the ISO operators too much discretion in dispatching generators for local reliability energy and capacity. However, there is little difference between the LRS and any of the ancillary services. For this reason, the LRS capacity procurement process should match as closely as possible the ancillary services procurement process. The ISO should determine the MRE and CC requirements on a day-ahead basis, following the same procedure it uses to decide on the Regulation, Spinning, Non-Spinning and Replacement reserves requirements a day-ahead basis. Ancillary services requirements are not determined according to fixed rules, but all market participants are aware of the WSCC reserve requirements and know that the ISO must satisfy these requirements. Because the ISO plans to make available the nomograms used to guide the process of determining daily LRS requirements, market participants should have a general idea of the quantity of these services the ISO plans to procure. The ISO should operate 2-day ahead and within-day LRS markets the same way that it operates the day-ahead and hour-ahead ancillary services markets, with one exception. The ISO should purchase its best guess of its real-time MRE and CC needs in the 2-day ahead market. If anything, it should a purchase slightly more of both MRE and CC to guard against the possibility of intra-zonal congestion in real-time due to an unexpectedly large demand shock between the close of the 2-day ahead auction and the day of operation. The fact that system conditions can change dramatically between the time that the 2-day ahead auction takes place and real time system operation implies that the ISO should operate a within-day LRS auction. This auction should occur before the hour-ahead scheduling process to adjust the LRS requirements to the ISO's current best guess of real-time system conditions. For reliability reasons and reduce likelihood of intra-zonal congestion, the ISO should not delay any 2-day ahead LRS requirements to the within-day market. Consequently, the within-day market should only be used as an incremental market for those instances when the ISO did not set the 2-day ahead requirements high enough.

A second aspect of the LRS procurement process necessary to insure that real-time intra-zonal congestion is infrequent, unpredictable and economically insignificant is the allowed level of real-time energy bids associated with the LRS capacity not committed to supply energy on a day-ahead or hour-ahead basis. Allowing unloaded LRS capacity owners to submit real-time energy bids at any price level significantly increases the likelihood and economic magnitude of real-time intra-zonal congestion. If the contingency occurs which requires that the LRS contingency capacity provide energy, the unit owner must supply the CC as additional locational energy at the current real-time price. Consequently, all LRS capacity winners have a contingent bid at zero in the real-time energy bid stack that will be taken in the event that this "planned-for" contingency occurs. If the "planned for" contingency does not occur, then increment of capacity sold to provide CC should be able to compete with other energy sources to provide real-time energy by submitting bids into the real-time energy market. Because the contingency has not occurred, competition from other resources within the LPA and outside of the LPA should discipline the ability of this firm to exercise its market power. However, once the contingency occurs, this firm faces a completely inelastic demand for the CC to provide energy. For this reason, the firm must be a price-taker for this quantity of energy under these system conditions.

Another way to interpret this rule is that a winner in the LRS auction cannot be paid as bid to supply energy in real-time from unloaded LRS capacity. It can only set the market-clearing price or receive the market-clearing price. Under no circumstances (whether or not the contingency occurs) can bids in or outside of the LRS be skipped to accept one by this unit owner to supply energy from the contingent capacity portion of the LRS. So long as the contingency requiring this LRS capacity does not occur, the unit owner can submit a non-zero bid into the real-time energy market. Because the contingency has not occurred there will be available transmission capacity for units from outside the LRA to supply any additional energy required in real-time. However, if this contingency occurs, then competitors can no longer service incremental load within the LRA. Under these conditions, the unit owner is obligated to supply the entire unloaded LRS capacity at the current market-clearing price. This requirement on CC is valid for as long as the contingency affecting system operation is active. For example, if a transmission line goes out, then this obligation for CC remains in place until this transmission capacity is restored or the ISO is able to procure additional LRS capacity in a subsequent auction. This requirement insures that there is always effective competition from generation located outside of the LRA. The key feature is that non-zero bids from unloaded LRS capacity can only accepted if there is available transmission capacity to allow generators from outside of the LRA to compete with those located within the LRA. Without this requirement, local generators can bid extremely high prices to supply incremental energy from CC when they are the only suppliers available within a given LRA. These high-priced bids must then be accepted and paid as-bid, which implies significant intra-zonal congestion costs.

Locational Price Signals and the LRS Auction

The LRS auction can provide substantial locational price signals to generators located in LPAs that lack local generation sufficient to meet local load. However, it is important to bear in mind that the major cause of zonal price differences in the California electricity market is local market power. As shown in Figure 1 of "Diagnosing Market Power in California's Restructured

Electricity Market[1]," the in-state marginal cost curve for fossil units is extremely flat over a very wide range of output. Absent the exercise of local market power, a market with this marginal cost curve should not set locational prices that differ by more than $25/MWh, except in circumstances of system-wide scarcity of energy. Although the difference between the highest and lowest marginal cost of instate fossil units is approximately $25/MWh, there have been many hours when zonal price differences are more than $500/MWh, and this difference often approached $750/MWh during the $750/MWh adjustment bid and energy bid cap regime. Consequently, one goal of implementing the LRS auction is to provide locational price signals that do not reflect the exercise of local market power, and instead reflect the true willingness-to-pay of market participants to use the bulk transmission grid.

Because of the problem of local market power in the current California market design, one goal of the LRS service is to reduce the frequency and magnitude of inter-zonal congestion costs. However, this should not be viewed as a shortcoming of the LRS proposal, but as a measure of its success in mitigating the impact of local market power. Inter-zonal energy price differences can still occur under this proposal, but these cannot occur because a local generator withholds (economically or physically) a sufficient amount of capacity to enable it to set extremely high prices within its zone. Because the LRS auction procures sufficient capacity to prevent excessive withholding by local generators given the ISO's current best guess of real-time system conditions, capacity withholding to increase prices within a congestion zone is no longer a viable strategy for exercising local market power. However, locational price differences can still occur because generators located in zones with significantly more generation than local load would like to sell more energy than can be consumed locally and exported outside of the zone given the existing transmission capacity exiting this zone. Under these circumstances, these local generators will compete to supply energy outside of the zone and therefore set a lower price in this zone than in the surrounding zones. Clearly, these generation-rich zones would not have minimum generation requirements. However, because all of the LRAs have sufficient amounts of local generation committed so that generators located in each LRA faces competition from suppliers located outside of their LRA, the possibility of large inter-LPA price differences is reduced. Suppose that LRS capacity is procured to guarantee effective competition for local resources from external resources all times. Under these circumstances, the only way that inter-LPA price differences can occur in the day-ahead, hour-ahead or real-time markets is because collectively generators would like to supply more energy within a zone than can be consumed locally or exported given the amount of available export capacity out of the zone. With LRS capacity procured in this manner, generators will truly compete to use available transmission capacity rather than use the ISO's inter-zonal congestion management protocols to exercise their local market power.

The LRS service increases the average price of energy received by units located in generation deficient LPAs and in this way provides an additional signal for new generation units to locate in these LPA. Let Q(MRE) be the amount of MRE capacity a unit sells and P(LRS) the price it receives. Suppose the unit also supplies Q(E) of energy at a price of P(E) from this same unit. Therefore, the average price it receives for energy is equal to P(AVG) = (P(LRS)*Q(MRE) + P(E) *Q(E))/Q(E). To the extent that Q(MRE) is close to Q(E), the generator is paid P(LRS) +

[1] Borenstein, Severin, Bushnell, James, and Wolak, Frank A., "Diagnosing Market Power in California's Restructured Electricity Market, April 2000, available from http://www.stanford.edu/~wolak.

P(E). Recall that Q(MRE) must always be less than Q(E), because the LRS service is only procuring a commitment to schedule energy on a day-ahead basis and leave some capacity unloaded. The unit owner is free to sell the energy and unloaded capacity it expects to provide from this unit however it likes. The unit owner receives an additional payment Q(CC)*P(LRS) for providing unloaded capacity. This payment is necessary to compensate the local generator for supplying the additional energy out-of-merit order in real-time because the "planned-for" contingency actually occurred. Because this planned for contingency should only a occur a small fraction of the hours that the unit owner is paid to provide CC, this payment is additional compensation for the generator's local market power. It is important to note that the rules of the LRS auction allow this generator to sell this unloaded capacity as an ancillary service and refund the LRS payment for CC. Therefore, the payment Q(CC)*P(LRS) should not be construed as compensating the generator for any lost opportunities to sell CC into the ancillary services market. The fact that the CC portion of the LRS capacity can be sold as an ancillary services raises the following issue: What should be the real-time energy bid for the CC portion sold in the ancillary services auction? Consistent with the logic described above, any portion of this CC sold in an ancillary service must have a contingent zero bid which is activated if the "planned for" contingency occurs. Otherwise the CC capacity can bid however it would like, because it faces effective competition in real-time from outside of the LPA. However, if the planned for contingency occurs, then this zero bid is activated for entire CC, regardless of ancillary services it was providing. In these instances, the unit owner should also receive P(LRS) times the amount of energy provided from this CC, even if the entire CC was sold as an ancillary service, to compensate it for being a price-taker in the real-time energy market because the contingency occurred. This re-payment of the unloaded capacity payment on energy supplied in real-time because the planned for contingency occurred compensates the generator for the potential of being out-of-merit order in real-time. This contingent re-payment is the real-time equivalent to paying for the MRE portion in the 2-day ahead auction.

Several commentators on the LRS proposal have argued that the payment, P(LRS)*Q(LRS), represents an uplift payment to these generators unrelated to the provision of any service. This is an inaccurate characterization. The loads are purchasing a reliability service, because these unit owners would not voluntarily commit to provide the LRS energy and capacity without compensation and the grid could not be reliably operated in real-time without this service. It is certainly true that loads could sign forward contracts with these generators to supply the necessary amount of local energy in each hour and therefore render the LRS market unnecessary. However, the amount that loads would have to pay for these forward contracts would be excessive because of the significant local market power possessed by these generators. Consequently, under the current market design the LRS service is necessary to procure this necessary day-ahead commitment at a price that does not reflect the significant local market power possessed by these unit owners. The goal of the LRS auction mechanism is not to rely on this spot market to provide all or even a significant fraction of the LRS capacity. The purpose of this market is to provide a viable outside alternative for both loads and generators to use in striking long-term contracts for the provision of local energy, which should then result in significant self-provision of the LRS capacity by loads to the ISO.

Mitigate Local Market Power With Minimal Impact on Market Mechanisms

Generators participating in the LRS auction are free to hedge all energy and reserve capacity supplied from these units. A unit supplying LRS can sell its energy in the PX, sign a bilateral contract for the supply of this energy, or sell this energy in the real-time market. The winning LRS bidder can also sell the unloaded LRS capacity in any ancillary services markets that the unit is physically capable of providing. The LRS payment only guarantees that a minimum amount of energy and unloaded capacity or additional energy will be supplied in a LPA in a given hour and that the LRS energy will be balanced in the day-ahead energy schedule of each winning LRS bidder against load in that LPA. The LRS does not compensate the generation owner for energy that it supplies under its LRS obligation. This is left up to the generation unit owner. Designing the LRS service in this manner increases the opportunities for gains for trade between generators and loads in signing long-term contractual obligations for local energy and ancillary services capacity. Clearly, one straightforward way to self-provide LRS capacity is for load-serving entity to sign a forward contract with a local generator to provide hourly quantities of energy and ancillary services at least equal that load-serving entity's MRE and CC requirements.

It is important to note that the ISO needs this LRS energy and capacity to reliably operate the California grid. Under its current RMR contract provisions and intra-zonal congestion protocols, the ISO is meeting these current LRS needs. It is not a choice whether or not this amount of LRS energy and capacity should be made available. Currently, the ISO has over two years of experience operating the California grid. As a consequence, both it and the generation owners in California currently have very good estimates of the system conditions which lead to certain LRS requirements.[2] In fact, a major problem with the current intra-zonal congestion management protocols is that unit owners are able to forecast these system conditions very accurately. These unit owners then submit real-time energy bids which allow them to receive very large payments from the ISO's intra-zonal congestion management protocols. By forward purchasing these LRS requirements and requiring contingent zero-price real-time energy bids for the unloaded LRS capacity, the ISO can eliminate this opportunity to exercise local market power.

The requirement that unit owners supply LRS energy in a balanced day-ahead schedule within that LRA does not impose an economically significant burden on local generators. Clearly, there is more than enough load in this LPA to consume this LRS energy. In fact, the major factor driving the need for an LRS auction in a given LPA is a very large amount of local load relative to local generation capacity. Consequently, winners in the LRS auctions should have little difficulty finding load willing to schedule against this generation. Those areas that currently have RMR contracts, already supply similar levels of energy under the terms of their RMR contracts. The LRS obligation on the unloaded LRS capacity also does not impose any additional burden on the unit owner besides the contingent zero-price bid requirement which is necessary to mitigate the local market power that occurs when the contingency arises. For this contingent zero-price bid, the unit owner receives the LRS capacity payment, which should more

[2] Although the actual nomograms and operating procedures that would be used to determine LRS requirements are not public at this time, an important element of the current congestion management reform proposal is to release these nomograms to the market in a form that meets security and confidentiality concerns.

than compensate for the unlikely event that the unit may receive a market price less than its marginal cost of producing energy. Most instances when the contingency occurs which activates this zero-price bid requirement are times of high load conditions when market prices should be sufficiently high so that the sum of the real-time price and the LRS payment will exceed the unit owner's marginal cost. It is important to note that many of the instances of intra-zonal congestion this past spring were not due to high loads, but because much of the in-state capacity was down for scheduled maintenance. Nevertheless, we should recognize that the goal of the designing the LRS auction scheme is not to guarantee that the unit owner earns revenues in excess of variable operating costs during all hours in provides LRS service. Over the entire year the unit owner should receive total LRS payments that cover the annual incremental costs associated with providing its annual LRS obligations. This requirement implies that there may be a large number of hours when the hourly incremental LRS cost is in excess of the hourly LRS revenues, and vice versa.

Setting the Level of the LRS Bid Cap

In order to set the LRS auction bid cap, it is important to bear in mind what services the unit owner much be compensated for. LRS energy can be required during periods when the energy price in an LPA is less than the marginal cost of the units capable of providing it. To compensate for this hourly revenue shortfall relative to hourly production costs, the LRS bid cap for that hour should be set so that the sum of the LRS price and the energy price equals or exceeds the generator's marginal cost. This intuition implies that on an hourly basis a minimum level for the LRS bid cap is the maximum of 0 and (MC – PE), where PE is the relevant LPA energy price for that hour and MC is the generator's marginal cost. However, this hourly lower bound may over-compensate the generator for providing the LRS energy service because, as noted in Borenstein, Bushnell and Wolak (2000) [henceforth, BBW (2000)], there are many hours when the zonal PX price is below the marginal cost of the highest cost unit operating in California. Specifically, there are many hours when unit owners are willing to operate despite the fact that the zonal PX price is insufficient to compensate for the unit's operating costs during that hour. These unit owners are willing to operate because they are able to achieve prices significantly higher than the unit's marginal cost in other hours of the day. Setting the lower bound on the LRS bid cap at max(0,(MC-PE)) guarantees that all hours when the unit provides LRS energy it will at least recover its marginal costs. A similar guarantee against low-priced hours is not provided to other units in the ISO control area. This hourly price cap could therefore provide the supplier of LRS an additional payment that it not available to other market participants because of their location in the ISO grid. This logic underscores the statement that the relevant time horizon for a determination of whether the LRS price cap adequately compensates generators for the services they provide is not an hour, day, or even a month. The minimum time horizon for making this determination is a year, which allows for many hours when the unit owner may not even recover its variable production costs. In setting this time horizon for determining adequate compensation the ISO is not doing anything inconsistent with what occurs in every other competitive market. Retail outlets don't cover their variable costs every hour they operate. Airlines don't cover their variable costs on every flight they operate. There numerous examples from other industries to illustrate that relevant time horizon for determining profitability is longer than a single hour or day.

The lower bound on the LRS bid cap for a specific unit should at least allow the unit owner to recover any shortfall between annual market revenues earned by the unit and the annual variable operating costs and annual going forward fixed costs for the unit. Mathematically, this can be written in terms of annual magnitudes as:

[Energy revenues + Ancillary Service Revenues + LRS Revenues
– (Variable Operating Costs + Going Forward Fixed Costs)] > 0

Given the shape of the instate marginal cost curve given in Figure 1 of BBW (2000), the lower bound on the hourly LRS bid cap for virtually all units is likely to be extremely low, and in the majority of cases zero. Most in-state fossil units, do not need to be compensated in excess of their energy and ancillary services market revenues in order to cover their variable operating costs and going forward fixed costs. Market performance from May to July of 2000 provides significant evidence in favor this point. Wholesale prices throughout California more than adequately compensated these units for their variable costs and going-forward fixed costs. Therefore, any additional payment for LRS service would be largely unnecessary. The general scarcity of in-state generation resources is enough to adequately compensate the vast majority of existing in-state generators.

However, there are very small number of high-cost units in California that may not run often enough for the above criterion to be met. For these units, the ISO should offer the standard Condition 2 contract. This contract guarantees the unit full-cost recovery but should have the requirement that the unit have a default bid in the ISO's real-time energy market at it marginal operating cost, and a appropriately low default bid in all ancillary services markets that the unit can physically provide. This cost-recovery option should be available to all unit owners. However, they must elect this designation on an annual basis. With this option available, the ISO can set a bid cap on the LRS service that allows all but these few very expensive units to recover their going forward fixed costs.

Setting unit-specific bid caps will require extensive cost-of-service determinations for each unit owner in the ISO control area. If the RMR contract negotiations are any indication, this can be an extremely costly and time-consuming process for both the ISO and the unit owners. In addition, there is no guarantee that the costs that generation unit owner report to the ISO or FERC are for the minimum cost mode of production. Clearly, these production cost estimates can be verified, but it is still uncertain whether they represent the minimum cost mode to operate the plant. Consequently, a superior strategy is to set a uniform bid cap for the entire ISO control area. This bid cap may allow some unit owners to exercise a portion of their locational market power, but this exercise of market power will also provide incentives for new low-cost generators to locate in these areas. An additional reason for market-wide bid caps is that it will make it considerably easier to phase out these price caps.

A very important part of giving the appropriate locational price signals to generators and loads is to put in place a timetable for increasing these LRS price caps on a five year time horizon. At the end of five years, these price caps should be completely lifted. Generators would only be subject to a market-wide price cap on energy. As discussed above, forward contracting for energy between loads and generation should render the LRS market redundant, even if local market power has not been mitigated by sufficient new generation entry or transmission upgrades. In the future, we expect generators to purchase and sell incremental LRS capacity in this market. However, the vast majority of LRS requirements would most likely be met through self-provision or other long-term bilateral forward transactions.

Figure 1 in BBW (2000) provides useful guidance for setting the appropriate level of the LRS bid cap. Approximately 16,500 MW of instate fossil capacity has variable costs in the range of $25/MWh to $35/MWh at natural gas price of $2.50/MBTU. The remaining 1,000 MW of instate fossil capacity has variable costs in the range of $35/MWh to $50/MWh at this natural gas price. Consequently, at a $2.50/MBTU natural gas price, a reasonable value for the LRS price cap is $10/MW, which is the maximum amount that a unit in the low-cost 16,500 MW segment of instate fossil capacity could be out-of-merit. The market price of energy could be $25/MWh, yet the $35/MWh unit could be required to run to provide LRS service. By earning the $10/MW payment for this capacity the unit owner would effectively be receiving its marginal cost per unit of LRS energy provided. As additional compensation, the unit owner would also receive this LRS payment for the unloaded capacity that can participate in any of the ISO's energy and ancillary services markets.[3] This payment is for the contingency that the unit owner may be required to supply real-time energy from this capacity as a price-taker at a price below its marginal cost of production. The same logic for the price cap on the LRS capacity applies in this case as well. The real-time energy price could be $25/MWh but this unit is needed because the contingency it was purchased for occurred. Therefore the appropriate bid cap at this natural gas price is $10/MWh, because this will effectively pay the unit its marginal cost for producing energy. It is important to note that this $10 bid cap rewards more efficient units, because they can also receive this LRS price cap per unit of LRS capacity provided in addition to the relevant price of energy. To account for changes in the natural gas price, the LRS price can could be periodically re-adjusted quarterly or annually in the following manner:

PCAP(LRS) = (Highest Heat Rate - Lowest Heat Rate)*Natural Gas Price Index,

where Highest Heat Rate is the heat rate of the unit associated with $50/MWh in Figure 1 of BBW (2000) and Lowest Heat Rate is the heat rate of the unit associated with $25/MWh in this same figure. The Natural Gas Price Index would be a weighted average over time and geographic locations in and around California of spot natural gas prices over previous quarter or year.

Another issue that is important to bear in mind is that the level of the market wide energy bid cap will determine which units will elect to go on a Condition 2 contract. It is very unlikely that any additional units will go on this contract at levels for the ISO price cap greater than or equal to $500. Lower levels of the price caps may trigger more generators to elect the Condition 2 contract. Regardless, of the level of the overall energy price cap, the LRS price cap should be no more than PCAP(LRS) defined above, using current natural gas prices, or even smaller. The very similar levels of marginal costs for most instate fossil units illustrated in Figure 1 of BBW (2000), provides a graphic illustration of the point that the costs of calling LRS capacity out-of-

[3] It important to bear in mind that any unloaded LRS capacity sold in the ISO's ancillary services auction or self-provided as ancillary services capacity requires refunding all LRS payments made for this capacity unless the planned for contingency occurs.

merit order are likely to be extremely small. Therefore, the LRS bid cap for the vast majority of units should be very small. Paying generators any more than this amount is simply rewarding them for their locational market power. Given the events of May to July of 2000, there seems little reason to reward generators for their locational market power.

A final issue associated with setting the LRS price cap is how to compensate generators for start-up and no-load costs to provide LRS energy. Whether the LRS price cap covers these costs should be considered on an annual basis and not on a per-start-up basis. Similar to the case of the RMR contract reform, the generator should account for the risk of an LRS call when deciding whether to shut down their plant. The ISO should not pay for start-ups or no-load costs associated with providing LRS service. On an annual going-forward basis the unit owner should recover these costs from LRS auction sales, energy sales and ancillary services sales. If the unit owner would like the guarantee of covering all of their costs, the ISO offers this option in its Condition 2 contract. If the ISO elects to be in the market, then it accepts the risk that it may sometimes need to provide LRS services when it is shut down. As discussed above, the nomograms necessary to determine LRS requirements will be available to market participants. They can therefore may their own estimate as to when and in what quantity LRS capacity will be required. They can then schedule their maintenance outages accordingly.

In closing this section, it important to emphasize that the ISO should set the LRS price cap as low as possible, despite protests that this price cap is not just and reasonable to the generators. The ISO should satisfy the just and reasonable standard with FERC by offering all generators the option to select a Condition 2 contract each year for the entire year. Given the level of average prices during the past 2.5 years in the California market, it is doubtful that many generators will elect this option. Nevertheless, it must exist to satisfy FERC's just and reasonable standard. Any generator electing to sell in the LRS market and therefore all of the other markets that the ISO runs faces the risk that it may not cover its going forward fixed costs from these markets. However, that is precisely the goal of a competitive market, to cause generators to face the risk of being unable to recover their costs unless they efficiently operate their unit. Those unit owners that do not recover their variable cost and going-forward fixed costs have the option in subsequent years to elect Condition 2 or to exit the industry and sell their units to another firm that may be able to create more value from the same generating assets. It is important to bear in mind that the LRS capacity auction is only compensating for out-of-merit energy calls. Given the shape of the in-state marginal cost curve shown in BBW (2000), the magnitude of these payments on an annual basis is likely to be very small. In addition, given that many generators freely produce energy during hours with prices below their marginal cost in order to be on to obtain prices above their marginal cost in other hours, the level of required compensation for providing out-of-merit generation is likely to be even lower than sum of max(0,(MC-PE))*Q(MRE) over all hours of the year. It cannot be emphasized enough that the ISO must hold the line on the price cap for LRS capacity. After all, even if all in-state fossil units elect the Condition 2 cost-of-service option, California consumers will still be ahead of the game because the industry will once again be cost-of-service regulated, but they will no longer have a stranded assets obligation to re-pay.

Time Horizon for LRS Procurement

There are a variety of reasons for the hourly procurement of LRS capacity rather than the ISO signing a long-term contract, such as the RMR contract, for LRS service. The most obvious reason is that LRS demand varies on an hourly basis in a way that is somewhat, but not completely predictable. By the same token, the demand for energy varies on an hourly basis with approximately the same degree of predictability. For this reason, we would anticipate that most energy would be procured well in advance of the day-before or hour-before it is delivered through forward market transactions. The level of energy demanded and where it can be supplied from is uncertain up to the hour that the energy is consumed because of both weather and other system conditions (generation unit outages and transmission line outages). Therefore, the ISO must run a real-time energy market to insure that it is able to meet the actual amount of electricity demanded in that hour. This real time market will not trade all of the energy consumed in that hour. In fact, it usually trades between 5% and 10% of the total energy consumed. A real-time energy market is necessary make any changes from the contractual positions that suppliers and loads enter into for that hour as result of unforeseen weather changes or system conditions since the long-term contract was signed. For this reason, the ISO must run a real-time energy market. Market participants are free to make forward market commitments based on this real-time market, but the real-time market is necessary for reliable operation of the ISO control area.

To see the necessity of a two-day ahead spot market for LRS take the above paragraph and substitute LRS for the word energy wherever it appears. The exact same logic implies the need for an LRS auction. The level of LRS demand can be forecasted, but it is not exactly known until two days before real-time operation. Many contingencies can arise between the time when a long-term RMR contract is signed and two days before energy is actually delivered. By running the 2-day ahead and within-day LRS auctions, the ISO is not precluding the vast majority of LRS capacity from being procured in the forward market and submitted to the ISO as self-provided LRS capacity. In fact, in many ways the LRS auction encourages this behavior, because of the cap on what the generator can bid each hour for providing the LRS service. This bid cap provides a viable but not excessive outside alternative for generators to use when they enter into the bilateral bargaining process with loads for the provision of LRS capacity in the forward market. For example, we could expect a generator that would like to operate its units in a cost-minimizing manner to want to sign a long-term contract to supply a constant quantity of energy over some time horizon. A load would therefore be willing to pay a little more in the periods expected to have low prices in exchange for a lower than expected price in periods expected to have high prices. The generator would be willing to accept this forward contract because this time path of plant output significantly reduces its operating costs. So long as this lower average revenue stream and lower production costs results in higher profits than the unit owner could obtain from selling in the LRS market and the day-ahead, hour-ahead and real-time energy markets, it will sign this long-term forward contract. The existence of the LRS spot market does not preclude the signing of long-term contracts between generators and loads for the LRS obligations of loads. In fact, the LRS market is design to facilitate the signing of long-term bilateral contracts for locational energy and ancillary services. A spot market for the LRS is the minimal market necessary for the ISO to run the grid reliably. Price-caps is necessary to mitigate the local market power possessed by these unit owners. However, given this spot market, the ISO should then allow the appropriate forward markets for LRS to develop in the same way that it allows forward markets for the provision of energy and ancillary services to develop. Once market participants are free to hedge outside of the PX in any manner they would like, these forward markets should develop. In addition, if the ISO unbundles it transmission access charge (TAC) to charge separately for day-ahead and hour-ahead ancillary services and real-time energy trades on a per-unit transacted basis, these forward market will develop. Market participants will face a non-zero marginal trading charge for each ancillary services or energy trade they make through the ISO. Because there is clearly a marginal cost associated with arranging trades outside of the ISO's markets, setting a cost-based marginal trading charge on trades in the ISO's markets will face market participants with the price signal necessary for forward markets to develop.

Another important reason for the ISO not to sign long-term contracts for the provision of the LRS services is that the ISO is not a participant in the energy and ancillary services markets. The ISO runs a spot market for ancillary services where loads can purchase their ancillary services needs. They have the option to enter into forward contracts for the provision of these ancillary services, and then provide these schedules to the ISO. The ISO also runs a market for real-time energy. Consistent with this view, the ISO should run a spot market for LRS service. Any argument for entering into a long-term contract with generators for the provision of LRS service would have to overcome the same arguments for why the ISO operates spot markets for ancillary services and energy. Some observers have argued that because there are bids caps on the LRS markets and these caps are likely to be hit very often, the LRS spot market is somehow different from the energy and ancillary services markets. However, this logic fails to recognize that there are also bid caps on the energy and ancillary services markets and, as the events of May to July 2000 have indicated, these caps are likely to be hit fairly often. However, as has been argued in various MSC opinions, this high frequency of hitting the price cap is due to an insufficient amount of forward contracting for energy.

The existence of an LRS auction also increases the ease with which new generators can enter by making the revenues earned from providing LRS service completely transparent to all potential entrants. Although the terms of the current RMR contracts are filed at FERC, it is unclear whether these terms are costlessly available to all market participants in the same manner that market prices are from the ISO's web-site. Rather than having to worry about how it might fare in a negotiation process with the ISO versus the existing RMR contract holder, the existence of an LRS auction implies that any potential entrants is always free to sell into the LRS market. If this new entrant is unsuccessful in the very costly process of negotiating an RMR contract with the ISO it can still enter the market and provide LRS service. In fact, given the existence of the LRS auction there is no need for any prospective new entrant to incurs the very high costs of negotiating an RMR contract with the ISO.

In short, the barriers to entry are significantly reduced because any potential new entrant can supply LRS capacity without incurring the sunk costs associated with initiating an RMR contract with the ISO. The existence of the LRS auction also does not preclude any new entrant from signing a long-term contract to provide LRS services with any load-serving entity in that LPA. For the reasons mentioned earlier, the existence of a liquid spot market for LRS will reduce the risk and transactions costs associated with entering into these long-term bilateral contracts. This will encourage the signing of long-term bilateral contract between generators and load-serving entitles for the provision of the energy and ancillary services necessary for loads to meet their LRS obligations. This forward contract market will develop because both sides of the bilateral bargain have a well-defined outside option that—the LRS auction and the PX and ISO spot energy and ancillary services markets. Gains from trade between loads and generation owners are possible because these contracts can specify longer-term operating commitments for generators, with less volatile energy and ancillary services prices, and may allow lower cost operation of the contracted generating capacity.

A final argument in favor of a 2-day LRS market versus long-term contracting for LRS service comes from the experience with RMR contracts over the past year. A major reason for FERC ordering the ISO to undergo a comprehensive reform of its congestion management process is the high levels of intra-zonal congestion costs. These high intra-zonal congestion costs occurred because there were an insufficient number of units in the California control area under RMR contracts. The ISO tariff allows calling RMR units to mitigate intra-zonal congestion and paying them under the terms of their RMR contract. The major expense in managing intra-zonal congestion is that many non-RMR units caused intra-zonal congestion and would submit very large negative decremental energy bids which had be taken. This often resulted in extremely large out-of-merit payments for intra-zonal congestion. Between the end of the Summer of 1998 and end of the Summer of 1999, RMR contracts for many units in California were eliminated. Many of these same units are now causing and relieving intra-zonal congestion as-bid under the FERC order. This experience put an enormous dollar value on the importance of a 2-day LRS service versus a long-term contract. The contingencies that arise between the beginning of the year and the end of the year are too difficult to predict. The ISO would have to sign RMR contracts with virtually all market participants to be completely insured against the events that led up to the most recent FERC order. By running a 2-day ahead and a within-day LRS market, the ISO has the freedom to react to system conditions that occur at the time and location they occur in it LRS procurement process. By having this spot market flexibility, the ISO stands the greatest chance on making good with its claim that the LRS auction will significantly reduce the magnitude, incidence and cost of intra-zonal congestion.