Preliminary Study of Reserve Margin Requirements Necessary to Promote Workable Competition

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Executive Summary

In response to a request from the California Legislature, the Department of Market Analysis of the California Independent System Operator (CAISO) performed a preliminary study to answer the following question: What is a sufficient level of capacity reserve margin[1] in California to ensure that the average price of energy is reasonably close to the average price that would result in a *competitive market?*

For purposes of this preliminary study, we defined a workably competitive market as one where the average annual market price of power was less than 10% above a competitive market benchmark cost,[2] i.e., the annual average price-cost mark-up is less than 10%.

We found the capacity reserve margin (based on "dependable"[3] rather than "nameplate" capacity) should be 14% to 19% of the annual peak load to promote workably competitive market outcome. To illustrate this result, the capacity reserve margin for year 2000 was only 2%, and the corresponding annual price-cost mark-up was at an unacceptable level of 58%. To achieve and maintain the annual price-cost mark-up of below 10%, additional, dependable capacity of about 5,050 to 7,500 MW must be added to the base year dependable capacity of 46,300 MW.[4] We assumed that the new resources would not be owned by the existing large or strategic suppliers, and would be obligated to offer their total capacity into the market through long-term contract or other mechanisms.

It is important to note this new capacity can be supplied from a variety of sources. It could *all* come from price responsive demand with real-time metering, or a resource mix including conservation, demand-side reductions, long-term contracts, or new generation additions. This report does not offer insight into the appropriate mix of resources to meet the reserve requirement. For example, in the summer of 2001, additional capacity reserves came from 3,000-5,000 MW of conservation by consumers, 2,000 MW of new generation additions, and long-term contracts to cause suppliers to be available to meet demand. Although there has not been enough data to determine whether the annual

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[1] Note the meaning of capacity reserve margin is closer to the conventional system planning reserve margin, which compares installed dependable capacity with annual peak load. This differs from the operating reserve requirement, which depends on hourly system load and generation condition.

[2] At this time there is no established standard for a workably competitive market by any federal or state regulatory agencies. However, while there is not a formally established regulatory standard, economists generally agree that suppliers in a competitive market have an incentive to bid close to their marginal cost. Thus, the ISO's Department of Market Analysis believes that use of a 10% annual price-cost mark-up is a reasonable assumption.

[3] In computing the reserve margin, a dependability ratio (ratio of dependable capacity to maximum or nameplate capacity) of 95% could be used for competitive new supply. See later sections for comparison of dependable capacity to nameplate capacity for the base year of this study.

[4] In this report, we considered 5,600 MW of net imports were available and considered as a component of dependable capacity.

average price-cost mark-up will be within 10% for 2001, *preliminary observations* indicate the real-time market conditions in summer 2001 were workably competitive.

The appropriate mix of resources necessary to meet the desired level of reserve margin is a separate question that should be answered using an integrated resource planning framework. As noted above, the sources of reserves should account for market driven new generation additions (currently under construction or in the siting process at the CEC), long-term contract commitments from new resources, overall conservation by consumers and savings from demand reduction programs and investment of real time meters. Additional dependable import will also increase capacity if transmission is available. Price-responsive demand and forward contracting are especially effective in promoting competition because they not only provide equivalent new capacity but also provide additional restraints on strategic bidding and further mitigation of market power.

Our findings on the level of reserve margin are consistent with the historical reliability requirement, which is typically 15% to 18% of planning reserves. These reserves were traditionally designed to meet a variety of operational and planning contingencies including outages of generation and transmission facilities, dry year hydrological conditions, unexpected load growth, and extreme weather patterns. Our findings show that this level of reserves will also help promote competitive market outcomes.

The location of the new resources is equally important, so that new capacity is available to ensure that adequate reserve margins are maintained in each region and sub-region of the State.[5] Moreover, any proposed installed reserve requirement or market must be coordinated and consistent with a proactive policy on transmission expansion. That is, under certain conditions, transmission upgrades can act as a suitable replacement for local generation and can ensure access to adequate supplies.

The methodological basis for the ISO's study is to use the relationship between market supply adequacy and market price to evaluate the competitive effects of new capacity. Specifically, the ISO determined the relationship between the residual supply index (RSI, a measure of hourly supply and demand balance considering the largest supplier's market share of available capacity) and the price-cost mark-up. Once this relationship was estimated based on historical base year data,[6] the ISO used it to simulate the effects of new capacity on prices in the market. The ISO found that new capacity from competitive suppliers would increase the RSI and lower price-cost mark-up, thus producing lower prices in the marketplace.

The results of the ISO's study are preliminary and are based on use of historical data and on conditions that may not exist in the future. For example, climatic conditions, consumer behavior and regulatory actions are important to consider when using historical data to make projections for the future. During summer of 2001, mild climatic conditions, substantial consumer conservation, the FERC's temporary (through September 2002) market power mitigation measures, and forward purchases by California Department of

[5] The study shows that based on this criterion, using the historical period November 1999-October 2000 as a reference, about half of new competitive generation capacity should be located in NP15 to ensure such geographical dispersion. Additional locational requirements for reserves are available from the CAISO Transmission Planning Dept.

[6] The study used historical data from November 1999 to October 2000.

Water Resources substantially reduced the ability of suppliers to exercise market power. Market conditions also benefited from 2,000 MW of new generating capacity coming on-line. In using the results of this study to determine future resource needs, it will be necessary to develop scenarios and forecasts based on differing climatic and hydro conditions, load growth, conservation measures and generation additions already planned or under construction by market participants. Any required reserves calculation also needs to account for the projections of substantial amounts on new generation in permitting and under construction throughout the West and expected to be on-line in the next two to five years.

Introduction

Experience in the deregulated energy market in general, and California's specific experience since the summer of 2000, indicates that a sufficient level of capacity reserve is a critical factor in reducing the possibility and extent to which electricity generators can exercise market power. The purpose of this study is to address the following question: What is a sufficient level of reserve margin in California to ensure a *workably competitive market*, i.e., to ensure that the average price of energy is reasonably close to the average price that would result in a *competitive market?*

Approach

To answer this question we must unambiguously define the terms " reserve margin" and "workably competitive market."

From a market outcome perspective, we define a standard for "workably competitive market" as one where the average annual mark-up of prices over the competitive benchmark does not exceed 10%. The average annual price-cost mark-up is calculated as the average annual cost of energy based on observed market performance over and above the annual average cost of energy in a competitive market, i.e., one where the prices reflect the highest cost unit needed to meet system demand, and suppliers would be bidding in all units at marginal cost. For example, in 1999, the total actual market cost was $7.7 billion in ISO/PX market. The competitive market cost for the same period was estimated at $7.2 billion. The average price-cost mark-up for 1999 was thus (7.7 – 7.2)/7.2 = 7%.

At this time there is no established standard for a workably competitive market by any federal or state regulatory agencies. A 10% annual price-cost mark-up is the working assumption used by ISO's Department of Market Analysis (DMA).[7]

To analyze the impact on prices from the exercise of market power and to project future impacts on market prices, the DMA has developed a market power indicator based on the structural characteristics of the wholesale power market. This indicator, the "Residual Supply Index" (RSI), is a measure that indicates whether the largest seller in a particular market is pivotal in the sense that total market demand could not be met absent that seller's supply:

RSI=(Total Supply -Largest Seller's Supply)/(Total Demand)

An RSI value less than 100% would indicate that the largest supply is pivotal and thus would have the ability to set the market clearing price. When RSI is marginally higher than 100%, the largest supplier, or a few of the large suppliers jointly, still have significant market power. Only when RSI is significantly above 100% (usually at 120% or more), the market will be fairly competitive.

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[7] This threshold was chosen in part by reviewing past FERC ruling in natural gas cases which had used a 10-15% above competitive market level standard. See Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, Docket No. RM95-6-000, and Regulation of Negotiated Transportation Services of Natural Gas Pipelines, Docket No. RM96-7-000, issued 1/31/96.

Using historical data from November 1999 to October 2000 (a full year), we determined that there was a close relationship between hourly RSI and hourly price-cost mark-up in the ISO/PX markets (see Appendix: Details of Regression Analysis). Based on this relationship, we then estimated the market power impact or price-cost mark-up under different market supply and demand conditions, including the effect of new capacity additions. We then translated the results into the traditional measure of reserve margin, which is reviewed below.

To define the generation reserve margin we rely on the "dependable supply" as follows:

Reserve margin = (dependable supply - peak demand)/(peak demand)

The ISO believes that it is highly misleading and inappropriate to use the nameplate generation capacity in computing the dependable supply and the reserve margin. For example, due to technical limitations and market incentives, total installed nameplate generation capacity of more than 50,000 MW could yield dependable supply of only 46,000 MW, providing opportunities for the exercise of market power and high price-cost mark-up, even when peak loads do not exceed 46,000 MW.

Technical factors may limit the level of dependable generation to varying degrees, based on the type of generation resource. For example, energy-limited and intermittent generation including run-of-river hydro, wind, renewable energy resources, cogeneration and other qualifying facilities may not be capable of generating at full capacity during the peak demand periods even if there are no mechanical outages. Moreover, the dependable generation from some of these resources depends on annual climatic conditions (e.g., hydrologic cycle) and short-term weather patterns. Generation outages are inevitable and also must be accounted for. Thus, the level of available or dependable capacity is highly dependent on the assumptions regarding environmental conditions, short-term weather patterns and other factors that limit the physical operation of resources.

In order to simplify this analysis, the ISO assumed that the dependable supply was equal to the historical net import and generation capacity actually participating in the market in summer 2000.

Study Methodology

The ISO's study used actual data from the California energy market between November 1999 to October 2000 to perform a regression analysis involving System Load, RSI, and price-cost mark-up.[8] The ISO then determined how much additional competitive generation must be added to the market to ensure a price-cost mark-up below 10%. To account for seasonal and time of day variations, the data is separated into four categories, namely, May to October (Peak & Off-Peak Hours) and November to April (Peak & Off-Peak Hours) and separate regressions are done for each period. Once this relationship was

[8] In our regression analysis we used the Lerner Index that is defined as *(market price-competitive marginal cost)/market price*. This simple transformation of the price cost mark-up into the Lerner Index allows us to estimate a linear relationship between the Lerner Index and the RSI, whereas the original relationship between RSI and price-cost mark-up is highly nonlinear. The transformation is simple since the price-cost mark-up is defined as *(market price-competitive marginal cost)/competitive marginal cost*, so we can use price-cost mark-up =Lerner index/(1-Lerner Index).

estimated based on historical base year data, the ISO used it to simulate the effects of new capacity on prices in the market. As explained above, any new capacity from **competitive** suppliers will increase the RSI and lower price-cost mark-up, thus producing lower prices in the marketplace.

Recognizing the importance of locational dispersion of reserve capacity in eliminating opportunities for the exercise of market power, the ISO first performed the analysis system-wide, then did additional analyses, by area, to determine if sufficient reserves exist in each area or sub-market. For example, if all, or a major part of the reserve capacity is located in SP15, it would not mitigate market power in NP15. To guard against this outcome, the ISO performed the above analysis for NP15, again using historical data from November 1, 1999 to October 31, 2000.[9]

Preliminary Results

For the period November 1999 to October 2000, the average annual price-cost mark-up is 58.6%, and the reserve margin at the peak hour (hour 16 of August 1, 2000) is 2%. To limit the average annual price-cost mark-up to 10%, we must have enough new competitive generation capacity (not owned by the existing generation owners). With the historical load and generation patterns observed during the study period, an additional amount in the range of 5,050 MW to 7,500 MW of new competitive dependable supply must enter into the market. With the added capacity, the reserve margin would be in the range of 14% to 19% for the peak load hour, and the average reserve margin for the top 100 hours of system peak load would be in the range 19% to 25%. This supply of reserves can come from a variety of sources including price responsive demand under real-time meters, interruptible load, or new generation with the necessary transmission upgrades necessary to make them available to the larger market.

The following table summarizes these findings.

[9] An analysis on smaller pockets, such as San Francisco is necessary to maximize the locational value of new reserves.

Load, Available Capacity and Reserve Margin at Summer Peak Hour
(Hour 16, August 1, 2000)

	Base Year	With 5,050 MW new capacity	With 7,500 MW new capacity	Note
Peak Load	45,208 MW	45,208 MW	45,208 MW	
Available Capacity	40,680 MW	45,730 MW	48,180 MW	In-state resources only
Available Net Import	5,615 MW	5,615 MW	5,615 MW	
Reserve Margin	2%	14%	19%	(Available Capacity + Available Net Import – Peak Load) / Peak Load
Average RSI*	128%	144%	152%	Average RSI is a poor indicator of the distribution of RSI which is the key in predicting the price/cost mark-up. See note below

* Note that average RSI is not an insightful indicator of market competitiveness. Behind a seemingly high average RSI value, there are many hours when RSI is below 120% or even 100% as shown in Figure 2 of the Technical Appendix. Price-cost mark-up can be very high in those hours below 120% and the loads are very high too, which contributes to above average share to the annual price-cost mark-up measure. A more appropriate measure is the distribution of RSI, and the number of hours below 120%. The average RSI statistic is only given to illustrate that RSI values increase with additional competitive capacity.

These results assume proper locational dispersion of the reserve capacity. Repeating the analysis for NP15 leads to the requirement that to limit the price-cost mark-up to 10%, about half of the new competitive supply must be located in NP15.[10] The corresponding minimum reserve margin in NP15 would then be 25% for the peak load hour and would have an average of 28% for the 100 hours with the largest NP15 load.

As stated above, it is highly important not to confuse the nameplate capacity or even the observed maximum capacity (Pmax) of a resource with its dependable capacity. In this study, we used actual historical market participation (capacity scheduled or bid into the market as energy or ancillary services) as dependable capacity. Other studies such as those carried out for Summer or Winter generation adequacy assessment, may use as dependable capacity the available capacity (taking into account outages, derates, environmental and climatic limitations, etc.) that could potentially participate in the market regardless of whether or not it actually did.[11] Finally, some studies, such as CEC's report on California Energy Outlook, may use the nameplate capacity of the units and

[10] More specifically, at least 2,900 MW out of the total of 5,050 MW (or at least 3,500 MW out of the total of 7,500 MW) of new competitive supply must be in NP15.

11 Depending on what capacity value is used, the required reserve margin to ensure a relatively competitive market can be different.

include units not in the ISO control area. The following table shows the relationship between these studies with a view to the data pertinent to the study period:

Comparison of Control Area Generation Capacity Values used in this study, CAISO's 2001 Summer Assessment Report, and CEC's California Energy Outlook Report

Study	Capacity Measure Used	MW	Comments
DMA Study	Available Capacity	40,679	Generation capacity made available to the market through schedules and bids. Based on historical data for Summer 2001 peak (August 1, 2000, Hour 16).
CAISO's Summer Assessment*	Net Dependable Capacity	42,113	Nameplate capacity less derates for QFs, but before accounting for potential forced outages; also excluding dynamic schedules and potential new generation. The 42,113 MW changes to 43,259 MW when all these factors are considered. Based on forecast made for peak of August 2001 in February 2001.
CEC's Energy Outlook**	Nameplate Capacity (For all units in California)	52,586	Based on the CEC's April 2001 data included in CEC's September 2001 Report. This report differ significantly from CAISO numbers because it included new capacity built after 2000 and it included all units in California, some of which are not inside CAISO control area.

*Maximum Net Dependable Capacity of CAISO Control Area Resources and Maximum CAISO Control Area Generating Capability (as of February 2001) are reported in "CAISO 2001 Summer Assessment." See that report on CAISO's website for various measures of generation capacity in CAISO control area.

** Breakdown of the Nameplate Capacity among different generation technologies is provided in California Energy Commission's California Energy Outlook Report, available on CEC's website.

Special care must be used when applying the capacity reserve ratios indicated by this study, since the value is very sensitive to what capacity value is used. When uncertain about dependable capacity, it might be more reliable to use the range of 5,050 to 7,500 MW of new competitive capacity relative to the resources in the base year of 2000.

We must emphasize that in this study we are only addressing the level of reserves, and not how best to procure the reserves. New generation proposed by the market, conservation efforts, long-term commitments, all contribute to the necessary reserves.

Also it is important to note that assumptions regarding the hydro year (wet, normal, or dry) and level of imports impact the needed internal generation capacity.

Conclusion

Assuming no substantial change in the pattern of load and existing generation supply, and assuming that all new generation is competitive, to ensure a relatively competitive market (price-cost mark-up less than 10%), the capacity reserve margin (as defined above) should be at least in the range 14% to 19% at the annual peak load. Due to the differences in dependable capacity values from different sources, it is more meaningful to use the new dependable capacity required in addition to the base year capacity. That is, about 5,050 to 7,500 MW must be added to the base year dependable capacity (46,300MW based on DMA data of 40,679 MW plus 5,600 MW of dependable net imports).

The geographical dispersion of the new capacity to be added to ensure the required reserve margin must ensure that these reserve margins are maintained in each region and sub-region. Specifically, about half of the new competitive supply needed to ensure a workably competitive market must be located in NP15. The corresponding minimum reserve margin in NP15 would then be 25% for the peak load hour.

The new reserve need not necessarily come from competitive new generation. Demand side resources can be considered towards meeting the reserve requirements. Reserves could *all* come from price responsive demand with real-time metering, or a resource mix including conservation, demand-side reductions, long-term contracts, or new generation additions. This report does not offer insight into the appropriate mix of resources to meet the reserve requirement.

The appropriate mix of resources necessary to meet the desired level of reserve margin is a separate question that should be answered using an integrated resource planning framework. As noted above, the sources of reserves should account for market driven new generation additions (currently under construction or in the siting process at the CEC), long-term contract commitments from new resources, overall conservation by consumers and savings from demand reduction programs and investment of real time meters. Additional dependable import will also increase capacity if transmission is available. Price-responsive demand and forward contracting are critical elements of promoting competition because they not only provide equivalent new capacity but also provide additional restraints on strategic bidding, further mitigating market power.

The analytical model used here represents a first cut analysis, and should be expanded to account for the market power mitigation effects of long term contracts. This cannot be done at this time due to the lack of statistical data. Such studies can be done after one full year of data is available. Thus the results of this analysis should be considered preliminary.

Climatic conditions, consumer behavior, and regulatory rules are important to consider in using the historical data to make projections for the future. During summer of 2001, mild climatic conditions along with FERC’s temporary approval (through September 2002) of market power mitigation, and forward purchases by CDWR substantially reduced the possibility of the exercise of market power. The situation was also helped by 2,000 MW of new generation capacity coming on-line expeditiously.

In using the results of this study for the future, it would be necessary to develop various scenarios based on different climatic and hydro conditions, load growth and price responsive demand.

Finally, we would like to point out that the RSI analysis on reserves should not be considered a total prescription to ensure competitive market results. As stated, a number of factors are critical including demand side response and conservation efforts, and availability of market power mitigation measures. Also there are underlying structural changes which may impact the reserve margin including long-term contracts covering a large portion of load, number of new suppliers in the market and their incentive to be available because they are covered with commitments to load, and other structural market conditions. All of these factors are critical in assuring competitive market outcomes.

Technical Appendix

Details of the Regression Analysis.

Given hourly load, imports, and operating reserve requirement data from November 1999 to October 2000, we first calculate the RSI and Lerner index for each hour for this period. The estimated hourly Lerner indexes are then regressed against estimated RSIs and actual system loads. To account for seasonal and time of day variations, the data is separated into four categories, namely, May-October (Peak & Off-Peak Hours) and November-April (Peak & Off-Peak Hours) and separate regressions are done for each period. RSIs and actual system loads are assumed to vary linearly with respect to Lerner Index. It is important to note that price-cost mark-ups will have a nonlinear relationship with RSIs and actual system loads and this will capture the nonlinear relationship between price-cost mark-ups and Lerner Index.[12]

Lerner index and RSI regression Results

Peak Season (May-Oct 2000)				
	Peak Hours		Off-Peak Hours	
Variables	Coefficient	t-stat	Coefficient	t-stat
Intercept	1.26	12.58	2.31	16.38
RSI	-1.54	-27.20	-2.24	-33.17
Actual Load	2.19E-05	15.85	2.01E-05	7.07
R-Squared	0.63		0.58	
Number of Observations	2,522		1,886	
Off-Peak Season (Nov-1999 - Apr 2000)				
	Peak Hours		Off-Peak Hours	
Variables	Coefficient	t-stat	Coefficient	t-stat
Intercept	1.48	10.96	1.59	4.25
RSI	-1.20	-21.74	-1.95	-12.77
Actual Load	1.93E-06	0.80	4.40E-05	6.03
R-Squared	0.42		0.34	
Number of Observations	2,494		1,840	

These results indicate that in all four periods there is a significant correlation between the Lerner index, RSI and actual system load. The Lerner indexes are then converted to price-cost mark-ups to provide a direct illustration of relationship between RSI and price-cost mark-up:

Price-cost mark-up =Lerner index/(1-Lerner Index)

Finally, we compute hourly annual average mark-up and supply ratio (for peak hour(s)) according to the following formulas:

[12] This nonlinear transformation is used to capture the fact that as RSIs decline or actual system loads increase market prices increase at an increasing rate.

Annual average mark-up = Sum of hourly market cost / Sum of hourly competitive cost

where *hourly competitive cost = Historical System Load * System Marginal Cost*

*hourly market cost = Historical System Load * System Marginal Cost*Price-cost mark-up*

and

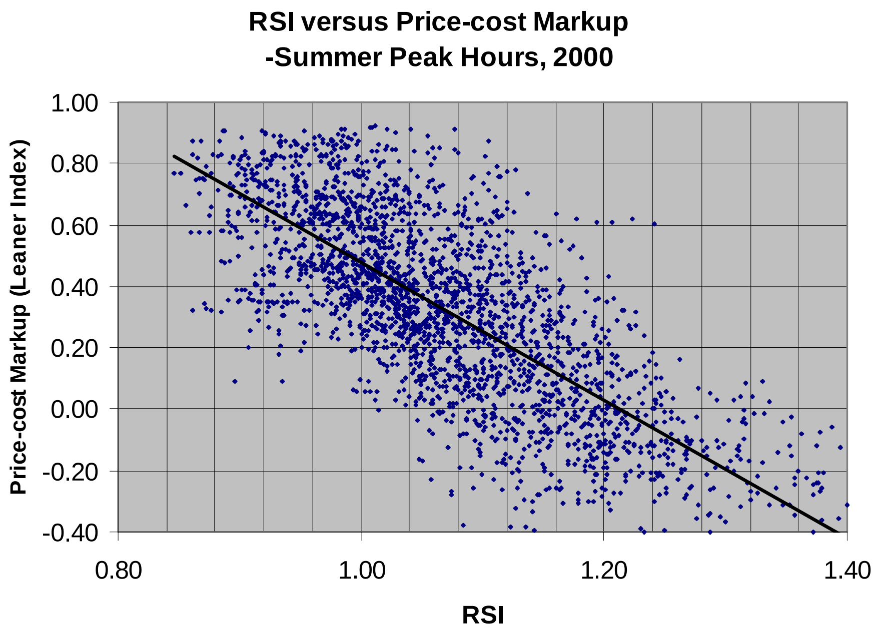
Supply Ratio = (Historical net import + Historical in-state generation)/Historical System Load

The reserve margin is:

Reserve Margin = 100*(Supply Ratio - 1)%

Using the summer peak hours, the following chart illustrates the relationship based on regression analysis:

Figure 1. Relationship between RSI and Price-cost mark-up



This figure illustrates the relationship between RSI and Price-cost mark-up measure in Lerner Index. It shows a clear negative correlation between the variables. The higher the RSI, the lower the price-cost mark-up. When the RSI is about 1.2, the average price-cost mark-up is about zero.

RSI Distribution in Base Year and with New Capacity

The following chart shows the RSI values across all the hours in a year from the lowest value to the highest value. Two cases are reported here: the base year statistics and the simulated case with 5,050 MW of additional capacity. As noted in the report, the average RSI is fairly high even for the base year (128%), although the price-cost mark-up was very high (58%). This chart can help to explain the outcome. For the base year, there were about 600 hours when the RSI was below 100%, which will result in very high price-cost mark-up. Furthermore, there were approximately another 2,600 hours when RSI is between 100% and 120%, which also results in significant price-cost mark-up. These hours also contribute larger than average to the annual average price-cost mark-up because these hours with low RSI are typically the hours with high system load and therefore higher share of annual cost.

Figure 2