GE Energy

Final Report to

California Independent System Operator

for

Planning Reserve Margin (PRM) Study - 2010

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Foreword

This document was prepared by General Electric International, Inc. It is submitted to the California Independent System Operator (CAISO). Technical and commercial questions and any correspondence concerning this document should be referred to:

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Executive Summary

The objective of this study is to provide guidance to CAISO and CPUC in establishing the Planning Reserve Margin (PRM). This is the reserve margin that is required to maintain the CAISO system at a given level of reliability as expressed in terms of a daily loss-of-load expectation (LOLE). The generation system reliability for CAISO was calculated at various levels of installed reserve margins in order to determine the reserves required to maintain the specified level of system reliability. The primary tool used for this study was GEII's Multi-Area Reliability Simulation program (MARS).

Starting from a set of original Base Case assumptions, a number of sensitivity cases were simulated in order to highlight the study assumptions that most affect the reliability results. For discussion purposes, the initial sensitivities were grouped into three categories. The first related to the general issue of how the reserve margins are computed. The second looked at including other resources such as imports and demand response in the reliability calculations. The third dealt with study data such as forced outage rates and interface transfer limits.

Following a review of the results from the initial sensitivity cases, additional sensitivities were simulated to determine the impact of the load scalars used for modeling load forecast uncertainty and the modeling of the energy limits on hydro units.

Using the knowledge gained from the original Base Case and all of the sensitivity cases, a Revised Base Case was developed to more closely model the way in which the CAISO system is operated. Figure ES - 1 plots daily LOLE for CAISO as a function of reserve margins computed on a monthly and annual basis. These results show the that the reserves required to maintain CAISO at a daily LOLE of 0.1 days/year are 13.4% on a monthly basis, and 9.2% on an annual basis, assuming imports not included in the reserve margins equal to about 14% of the annual peak load.

The impacts on PRM of the various sensitivity cases are summarized in Figure ES - 2, which are arranged to show the progression of the study. Except where noted to be otherwise, the reserve margins for all of the cases shown were calculated on a monthly basis.

Changing the way in which the reserve margins are calculated can reduce the PRM to about 20%. Taking the reliability benefits of the maximum possible level of imports from the outside (14,000 MW) would completely eliminate CAISO's reserve requirements. The impact of changes in some of the study data ranged from none (removing internal interface constraints) to almost 8% (drought hydro conditions).

Analysis of the Base Case and sensitivity cases indicates that the basic assumptions related to the way in which the reserve margins are calculated and the amount of reliability credit given to imports can have a greater impact on PRM than other assumptions related to unit characteristics and interface transfer limits.

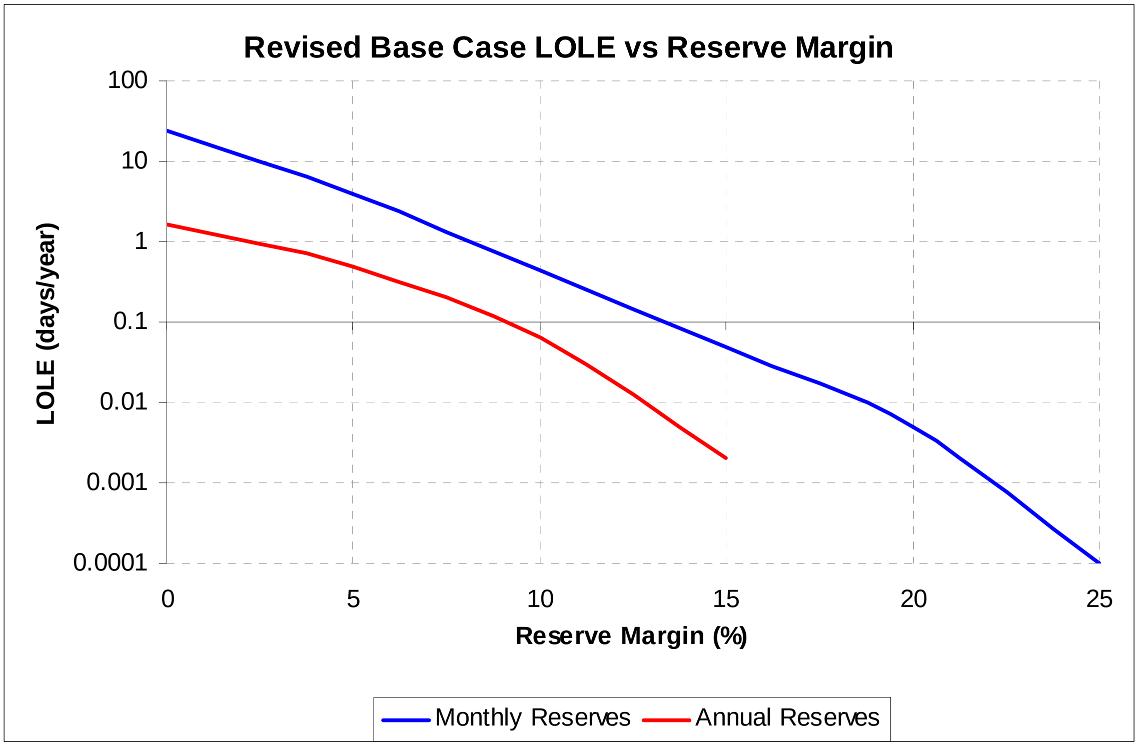

Figure ES - 1 - Base Case LOLE versus Reserve Margin

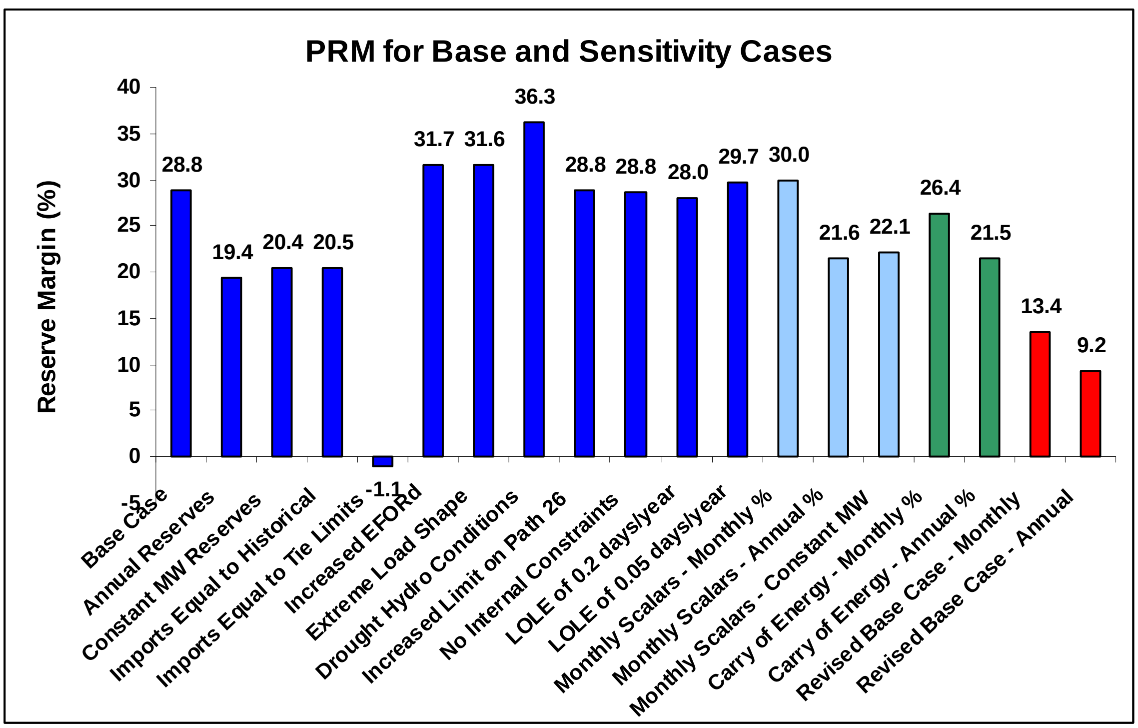

Figure ES - 2 - PRM for Base and Sensitivity Cases

1 Introduction

In late November 2007, the California Independent System Operator (CAISO) initiated a Planning Reserve Margin (PRM) stakeholder process, and held initial stakeholder meetings to review a preliminary study scope and proposals by potential vendors to perform a study. On April 10, 2008, the California Public Utilities Commission (Commission or CPUC) opened Rulemaking (R.) 08-04-012 "to review, and modify to the extent found to be appropriate, the Planning Reserve Margin (PRM) and the assumptions, methods, and procedures used for its determination."[1] The CAISO and the CPUC have merged their PRM stakeholder processes (although the CAISO will remain a party to the proceeding) and going forward will work on an integrated basis in R.08-04-012. In this report, the "PRM Study" refers to this joint stakeholder process unless otherwise noted.

On April 15, 2008, staff from the Commission's Energy Division, the CAISO, and the California Energy Commission (CEC) met with representatives from GE Energy and the California investor-owned utilities (IOUs)[2] to review the study scope and work schedule for the PRM Study, and to prepare for a future stakeholder workshop planned for June 2008.

The Commission's PRM preliminary scoping memo describes joint development of a PRM Study with the CAISO and describes a multi-phased proceeding, where the first phase will adopt the methodology, input assumptions, sources of data, and scenarios, and the second phase will determine the proper PRM for the Resource Adequacy (RA) program's 2010 and 2011 compliance years.[3]

Phases one and two of the PRM Study will determine the PRM that meets specified Loss-of-Load Expectation (LOLE) levels considering load and resource uncertainties, including the availability and performance of intermittent and energy-limited resources, transmission interface constraints, relationships between transmission and generation facilities, and analysis of various case scenarios that examine impacts of changes due to present and future generation, load growth, and potential transmission development. These phases are currently intended to include performance of both the Preliminary Study and the Final Study. The Preliminary Study, which will focus on the year 2010, is intended to highlight the data sources to which the PRM Study is most sensitive and the areas where more work in refining data can yield the greatest impact. The Final Study is intended to analyze the PRM requirements for the years 2010, 2014 and 2019.

This report presents the results of the Phase 1A Preliminary Study for 2010.

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[1] *Order Instituting Rulemaking* (OIR), issued April 16, 2008 in R 08-04-012 at 17-18.

[2] The IOUs are Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).

[3] OIR at 10-11.

2 Methodology

MULTI-AREA RELIABILITY SIMULATION (MARS)

The objective of this study is to provide guidance to CAISO and CPUC in establishing the Planning Reserve Margin (PRM). This is the reserve margin that is required to maintain the CAISO system at a given level of reliability as expressed in terms of a daily loss-of-load expectation (LOLE). The generation system reliability for CAISO was calculated at various levels of installed reserve margins in order to determine the reserves required to maintain the specified level of system reliability. The primary tool used for this study was GEII's Multi-Area Reliability Simulation program (MARS).

MARS was used to calculate the CAISO system reliability in terms of daily loss-of-load expectation (LOLE). Also available from the calculations was the hourly loss-of-load expectation (HLOLE) and the expected unserved energy (EUE, also termed loss-of-energy expectation, LOEE) at various levels of installed reserves.

The daily LOLE is often defined as the expected number of days of insufficient capacity at the time of the daily peak load. Under this definition, the system conditions during just a single hour of the day would be used to compute the index. For this study, the daily LOLE was based on all of the hours in the day**.** If the system were short of capacity at any time during the day, whether it was a peak or off-peak hour, it would be counted as a day of outage. If the system were short for several hours during the day, it would still count as a single day of outage.

MARS uses a sequential Monte Carlo simulation to calculate the reliability of a generation system that is made up of a number of interconnected areas. The areas are defined based on the limiting interfaces within the transmission system. Generating units and an hourly load profile are assigned to each area. MARS performs a chronological hourly simulation of the system, comparing the hourly load in each area to the total available generation in the area, which has been adjusted for planned maintenance and randomly occurring forced outages.

If an area's available generation is less than its load, the program will attempt to deliver assistance from areas that have a surplus that hour, subject to the transfer limits between the areas. If the assistance is not available or it cannot be delivered to the deficient area, the area will be considered to be in a loss-of-load state for that hour, and the statistics required to compute the reliability indices will be collected. This process is repeated for all of the hours in the year. The year is then simulated with different random forced outages on the generating units and transmission interfaces until the simulation has converged. For this study, each study year was simulated 1,000 times.

The reliability calculations in MARS are done at the area level – the generating units are assigned to areas, the hourly load profiles are defined by area, and the interface transfer limits are modeled between areas. The pool indices in MARS are computed from the area results: if one or more of the areas in a given pool are deficient in an hour, then the pool is considered as being deficient. In the 1A Preliminary Study, CAISO was modeled as three interconnected areas, so if at least one of the CAISO areas were deficient in an hour, then CAISO was counted as being deficient.

A detailed description of the MARS program can be found in Appendix A.

WHAT IS A RESERVE MARGIN?

The purpose of this study is to provide guidance in establishing a Planning Reserve Margin, (PRM) for the CAISO. One very basic question that needs to be addressed is "What is a Reserve Margin?" This is one of those questions that nearly everyone in the industry knows the answer to, even though there are multiple "acceptable" answers. The basic definition is straightforward:

Reserve Margin = (Available Capacity / Peak Load) –1

This is generally expressed as a percentage, so a system with 12,000 MW of Capacity and a Peak Load of 10,000 MW would have a Reserve Margin of 20%. (= (12,000/10,000) - 1)

The confusion comes when applying this concept across the year. There are three basic variations that are applied in the utility industry:

1. **Annual Reserves**. The reserve margin is measured at the time of the annual peak load and this total capacity is maintained throughout the year.
2. **Monthly Reserves**. The reserve margin is measured at the time of each monthly peak. The capacity required to maintain a specified percent reserve margin will vary each month.
3. **Constant MW Reserves**. The reserve margin is determined at the time of the annual peak load and that amount of MW of reserve is maintained each month. The capacity required each month will vary but the "cushion" between the available capacity and the monthly peak will remain constant.

All three of these methods are valid techniques, but, as will be shown, result in significantly different values of system risk for a given "reserve margin". First we will examine the logic behind, and the pros and cons of each methodology.

Annual Reserves

The first method is the most widespread application. It grew out of the time when utilities were vertically integrated entities with minimal interconnection to their neighbors. A utility with a 10,000 MW annual peak load wanting to maintain a 20% margin over their peak would install 12,000 MW of capacity. It wasn't so much a matter that the capacity needed to be there year round, but rather, having built the generation, it was there year round.

The "Available Capacity" in the above calculation was synonymous with "Installed Capacity". Having sufficient reserve to cover the peak load meant that there was generally more than enough capacity in the off-peak months to provide a secure margin even after accounting for maintenance requirements. This often resulted in all of the system risk being concentrated in a few peak months with virtually zero risk in the remaining months. The systems were “overbuilt” in the off-peak months but that was an unavoidable outcome of installing sufficient capacity to cover the annual peak.

Monthly Reserves

The second method comes from the idea that if a given percent reserve is required to cover the peak month of the year then why not maintain the same percent reserve over the peak of every month. The calculation is changed slightly in that the “Available Capacity” now represents only that capacity that is not on maintenance for the month. This method is applicable for a well-interconnected system that can purchase resources from its neighbors on a monthly basis. The advantage of this method is that it minimizes the amount of capacity that needs to be purchased in most of the months of the year. However, there are two disadvantages.

First, the risk tends to be higher in the off-peak months than it is in the peak period. Consider a system with a 50,000 MW peak load maintaining a 20% reserve on a monthly basis. In the peak month it will have a 10,000 MW reserve to cover operating margins, load uncertainty, and unforeseen outages of its generating units. But if another month has a peak load of 30,000 MW, then during that period there will only be a 6,000 MW cushion. With several large units on the system, the probability of insufficient capacity could be significantly higher. This logic is reflected in the fact that historically smaller systems have had to maintain a higher reserve margin than large systems.

This leads to the second disadvantage of this method. Because the risk is higher in the off-peak months, this method would require the system to maintain a higher reserve margin overall in order to meet a given reliability criteria, requiring them to purchase significantly more capacity during the peak months when capacity is scarce and prices are higher. This may not be fully offset by the reduced purchases in the other months since there will be surplus capacity available and prices will be relatively low.

Constant MW Reserves

The third method falls between the other two. This method maintains a constant MW reserve each month based on the requirements at the time of the annual peak. Let’s again consider a system with a 50,000 MW peak load maintaining a 20% reserve margin.

In all three methods, the system needs 10,000 MW of reserves in the peak month. In the first method, this would result in 60,000 MW of installed capacity maintained year round. If an off-peak month had a 30,000 MW peak load, it would have a 100% reserve margin (= (60,000/30,000) – 1). Even if we assumed that there was 10,000 MW of maintenance during that month, there would still be a 20,000 MW cushion resulting in a 67% reserve margin (= ((60,000 – 10,000)/30,000) – 1).

The second method, as described above, would maintain the 20% reserve margin, resulting in only a 6,000 MW reserve that would likely lead to higher risks. The third method would maintain the 10,000 MW reserve every month. In this example, the off-peak month would have a 33% reserve margin (= ((30,000 + 10,000) /30,000) –1). While this might be slightly conservative it is significantly lower than the first method, yet should result in lower risk in the off-peak months than the second method. This should reduce the amount of additional capacity required when capacity prices are high.

The PRM as applied in the CPUC's current Resource Adequacy (RA) Program is based on the monthly reserve approach. **Unless noted otherwise, all PRM values in this report have been calculated using the monthly reserves method to mirror the current practice of the CPUC's RA Program.** The impact that the definition of the reserve margin has on the results is significant as will be shown in Section 4.

Resources Included "In the Margin"

Also related to the calculation of reserve margins is the question as to what resources should be included "in the margin". The reserve margin typically includes all of the generating resources that provide reliability service to the system and can be used to mitigate outage events. The inclusion of other types of resources such as imports and demand response varies between ISOs.

The treatment of imports is a particularly important issue. Neighboring systems can be an important source of firm capacity. They can "bid in" to provide resources to meet reserve requirements just as the local generation can. As long as there is sufficient transmission, this will provide a broader market for capacity and should help to hold prices down. But in addition to the firm resources that neighboring systems can provide, there are also "emergency resources" available. When outages occur and available reserves start dropping, the system marginal costs will rise. At these times in particular, neighboring systems are generally more than willing to sell any available resources even if no capacity agreements are in place. These energy purchases can help the system to avoid outages, but do not count towards the reserve margin. In fact, they help reduce the overall reserve margin that needs to be maintained.

As an example, the NYISO has over 9,000 MW of ties to its neighbors. It typically allows about a third of that to count as firm capacity and bid into the New York capacity market. The remaining tie capability is available to provide emergency support, depending on the availability of the generation resources behind it, and may reduce in-state reserve requirements by as much as 5%.

For this study, the initial Base Case assumption is that **imports and demand response were not included in the reserve margin or reliability calculations.** Rather, these resources could be used to satisfy a portion of the PRM requirements, thus reducing the reserves that must be met with other sources of generation. The Revised Base Case includes in the reserve margin calculations the demand response and the imports associated with the out-of-state generation. It also includes additional imports in only the reliability calculations.

3 Data Assumptions

To identify and develop the data sources to be used for the preliminary study, several Working Groups were formed, comprised of representatives for the Commission's Energy Division, the CAISO, the California Energy Commission (CEC), the investor-owned utilities (IOUs), and other stakeholders. The Working Groups have issued a separate report detailing their recommendations.

Following the recommendations of the Working Groups, a MARS Base Case for this study was developed from data primarily provided by CAISO staff, with assistance from the IOUs and the State agencies. This section describes the data required by MARS, the sources of the data used in this study, and any assumptions that were made relative to the data.

UNIT DATA

The generating unit data for the CAISO system was developed from data submitted by the CAISO staff. The data provided for each thermal unit included:

- Name
- Area location
- Unit type
- Installation and retirement dates (all units assumed to retire after the study period)
- Planned outage rate
- Forced outage rate (EFORd) and number of forced outages per year
- Monthly unit capacities in MW

The forced outage data was taken from the NERC GADS 2002-2006 Generating Unit Statistical Brochure – All Units Reporting by unit type and size. MARS uses state transition rates, rather than forced outage rates, in its reliability calculations. The program can calculate the state transition rate from the forced outage rate and the number of forced outages per year.

For the hydro units, the same data was provided as for the thermal units with the exception of the forced outage rates that are not modeled for hydro units in MARS. Additionally, the amount of energy available from each unit each month was specified based on average monthly output using CEC/EIA 906 data from 1994-2005. MARS also allows input of a minimum rating which was assumed to be 10% of the maximum rating based on data from historical FERC Form 12 filings for California utilities. For about twenty units with insufficient monthly energy to support a minimum rating equal to 10% of the maximum, the minimum was set to 0 MW.

Wind, solar, biomass, geothermal, and small hydro were modeled in the Base Case with hourly profiles for all of the hours in the year based on actual operation for 2007, and scaled as needed for expected penetration levels and operation in 2010.

Table 1 through 4 on the following pages show the installed capacity and peak load that are projected for 2010, along with the reserve margin by month, for each of the three areas and for CAISO. The reserve margins shown do not include the Other Resources listed at the bottom of the tables.

The monthly values reflect any seasonal variations in unit output being modeled along with mid-year unit installations. For hourly resources such as wind and solar, the capacity shown is the maximum of the hourly values for the month.

Also shown are other resources such as demand response, out-of-state generation that was assumed for each area, and the average historical imports. These resources were not included in the Base Case but were considered in some of the sensitivity cases.

Demand response was modeled as energy limited units with a maximum rating and monthly or annual available energy calculated from the number of hours per month or year that the action can be implemented.

The historical imports, which include the out-of-state generation, were based on the imports at time of monthly peaks for January 2006 through June 2008. The out-of-state generation was not modeled as actual generating units but rather as a fixed MW value for all of the hours in the year. For the cases in which the total imports from out of state were modeled based on historical levels, the out-of-state generation was not modeled since they were included in the historical imports.

Table 1 - "As Found" Installed Capacity and Peak Load for Northern California Area (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Nuclear	2,300.00	2,300.00	2,300.00	2,300.00	2,300.00	2,300.00	2,300.00	2,300.00	2,300.00	2,300.00	2,300.00	2,300.00
Fossil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fossil-Gas	2,691.94	2,691.94	2,686.93	2,681.93	2,676.93	2,671.93	2,666.93	2,666.93	2,671.93	2,676.93	2,686.93	2,691.94
GT-Oil	156.00	156.00	156.00	156.00	156.00	156.00	156.00	156.00	156.00	156.00	156.00	156.00
GT-Gas	5,394.37	5,394.37	5,387.07	5,385.07	5,383.07	5,381.07	5,381.07	5,381.07	5,382.07	5,388.07	5,394.37	5,394.37
C.C.	1,799.40	1,799.40	1,799.40	1,799.40	1,799.40	1,799.40	1,799.40	1,799.40	1,799.40	1,799.40	1,799.40	1,799.40
I.C.	211.72	211.72	211.72	211.72	211.72	211.72	211.72	211.72	211.72	211.72	211.72	211.72
Diesel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steam	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ST-Gas	6,080.09	6,080.09	6,080.09	6,080.09	6,080.09	6,080.09	6,080.09	6,080.09	6,080.09	6,080.09	6,080.09	6,080.09
ST-Other	1,395.65	1,395.65	1,395.65	1,395.65	1,395.65	1,395.65	1,382.65	1,382.65	1,382.65	1,395.65	1,395.65	1,395.65
ST-Coal	128.70	128.70	128.70	128.70	128.70	128.70	128.70	128.70	128.70	128.70	128.70	128.70
Other	16.34	16.34	16.34	16.34	16.34	16.34	16.34	16.34	16.34	16.34	16.34	16.34
Refuse	599.93	599.93	599.93	599.93	599.93	599.93	599.93	599.93	599.93	599.93	599.93	599.93
Hydro	6,650.44	6,650.44	6,650.44	6,650.44	6,650.44	6,650.44	6,650.44	6,650.44	6,650.44	6,650.44	6,650.44	6,650.44
Hydro-RR	645.99	645.99	645.99	645.99	645.99	645.99	645.99	645.99	645.99	645.99	645.99	645.99
Hydro-Small	88.60	106.60	107.70	87.70	107.30	62.30	65.90	50.80	36.80	35.20	38.70	50.00
Non-RPS	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00
Biomass	401.20	377.60	364.10	347.40	370.00	443.50	438.70	434.20	432.80	400.40	391.80	377.60
Geothemal	124.20	124.00	124.50	130.90	127.40	125.30	124.50	125.80	126.00	123.90	122.70	123.50
Solar	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	198.12	171.63	378.93	372.85	413.34	388.72	386.22	392.60	371.67	322.63	98.08	59.05
Cogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Adjust	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	**30,686.69**	**30,654.40**	**30,837.49**	**30,794.11**	**30,866.30**	**30,861.08**	**30,838.58**	**30,826.66**	**30,796.53**	**30,735.39**	**30,520.84**	**30,484.72**
Peak	15,576.70	14,622.90	15,205.80	15,282.60	17,180.00	20,455.40	22,008.60	20,705.40	**22,236.00**	14,638.20	14,817.50	15,836.90
Reserve Margin (%)	97.00	109.63	102.80	101.50	79.66	50.87	40.12	48.88	38.50	109.97	105.98	92.49
Other Resources												
Demand Response	0.00	0.00	0.00	0.00	830.15	1,063.80	1,069.70	1,074.03	1,070.49	836.44	0.00	0.00
Out-of-State	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Avg. Historical Imports	242.00	346.00	1,125.00	1,265.00	1,856.00	1,739.00	1,446.00	739.00	936.00	75.00	286.00	666.00

Table 2 - "As Found" Installed Capacity and Peak Load for Southern California Area (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Nuclear	2,250.00	2,250.00	2,250.00	2,250.00	2,250.00	2,250.00	2,250.00	2,250.00	2,250.00	2,250.00	2,250.00	2,250.00
Fossil	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Fossil-Gas	470.22	470.22	470.22	470.22	470.22	470.22	470.22	470.22	470.22	470.22	470.22	470.22
GT-Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GT-Gas	4,796.52	4,796.52	4,796.52	4,796.52	4,796.52	4,796.52	4,796.52	5,146.52	5,146.52	5,146.52	5,146.52	5,146.52
C.C.	1,440.91	1,440.91	1,440.91	1,440.91	1,440.91	1,440.91	1,440.91	1,440.91	1,440.91	1,440.91	1,440.91	1,440.91
I.C.	11.30	11.30	11.30	11.30	11.30	11.30	11.30	11.30	11.30	11.30	11.30	11.30
Diesel	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00
Steam	581.91	604.27	662.61	721.09	771.86	861.34	862.54	862.58	867.46	671.58	599.02	566.20
ST-Gas	8,592.26	8,592.26	8,592.26	8,592.26	8,592.26	8,592.26	8,592.26	8,777.26	8,777.26	8,777.26	8,777.26	8,777.26
ST-Other	484.26	484.26	484.26	484.26	484.26	484.26	484.26	484.26	484.26	484.26	484.26	484.26
ST-Coal	126.00	126.00	126.00	126.00	126.00	126.00	126.00	126.00	126.00	126.00	126.00	126.00
Other	198.41	198.41	198.41	198.41	198.41	198.41	198.41	198.41	198.41	198.41	198.41	198.41
Refuse	263.20	263.20	263.20	263.20	263.20	263.20	263.20	263.20	263.20	263.20	263.20	263.20
Hydro	1,446.99	1,446.99	1,446.99	1,446.99	1,446.99	1,446.99	1,446.99	1,446.99	1,446.99	1,446.99	1,446.99	1,446.99
Hydro-RR	154.23	154.23	154.23	154.23	154.23	154.23	154.23	154.23	154.23	154.23	154.23	154.23
Hydro-Small	73.02	52.53	58.30	83.98	102.16	101.20	55.89	47.04	42.52	20.88	13.08	9.62
Non-RPS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	196.87	195.89	193.46	193.21	189.07	192.85	194.55	195.04	193.21	193.33	193.21	193.09
Geothemal	983.58	974.48	964.30	981.63	970.80	1,004.05	979.03	984.34	986.61	996.14	982.61	1,013.15
Solar	129.16	210.99	274.95	302.86	329.82	377.62	370.07	366.82	367.87	234.51	181.16	329.15
Wind	859.49	888.38	888.38	884.69	862.06	847.62	841.79	804.50	883.46	912.69	890.29	810.21
Cogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Adjust	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	**23,086.49**	**23,189.00**	**23,304.46**	**23,429.92**	**23,488.23**	**23,647.14**	**23,566.33**	**24,057.78**	**24,138.59**	**23,826.59**	**23,656.83**	**23,718.88**
Peak	16,347.50	15,572.90	16,346.50	16,369.00	19,078.90	19,129.10	22,566.40	23,293.90	**24,845.00**	17,474.50	15,994.00	16,024.80
Reserve Margin (%)	41.22	48.91	42.57	43.14	23.11	23.62	4.43	3.28	-2.84	36.35	47.91	48.01
Other Resources												
Demand Response	0.00	0.00	0.00	0.00	1,035.61	1,587.16	1,701.83	1,531.84	1,614.52	996.37	0.00	0.00
Out-of-State	1,488.00	1,488.00	1,488.00	1,488.00	1,488.00	1,488.00	1,488.00	1,488.00	1,488.00	1,488.00	1,488.00	1,488.00
Avg. Historical Imports	7,006.00	6,921.00	7,333.00	7,619.00	6,580.00	7,642.00	8,503.00	8,087.00	6,233.00	8,057.00	7,788.00	7,717.00

Table 3 - "As Found" Installed Capacity and Peak Load for San Diego Area (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fossil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fossil-Gas	40.41	40.41	40.41	40.41	40.41	40.41	40.41	40.41	40.41	40.41	40.41	40.41
GT-Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GT-Gas	1,669.47	1,669.47	1,669.47	1,669.47	1,669.47	1,669.47	1,669.47	1,669.47	1,669.47	1,669.47	1,669.47	1,669.47
C.C.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
I.C.	4.10	4.10	4.10	4.10	4.10	4.10	4.10	4.10	4.10	4.10	4.10	4.10
Diesel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steam	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ST-Gas	2,214.08	2,214.08	2,214.08	2,214.08	2,214.08	2,214.08	2,214.08	2,214.08	2,214.08	2,214.08	2,214.08	2,214.08
ST-Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ST-Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refuse	40.85	40.85	40.85	40.85	40.85	40.85	40.85	40.85	40.85	40.85	40.85	40.85
Hydro	3.59	3.59	3.59	3.59	3.59	3.59	3.59	3.59	3.59	3.59	3.59	3.59
Hydro-RR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro-Small	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Non-RPS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	68.80	65.00	64.70	65.20	41.40	67.70	69.50	65.10	75.40	133.40	126.90	47.00
Geothemal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cogen	172.40	174.50	168.60	170.30	176.20	169.20	171.20	169.80	170.40	167.90	168.30	167.00
Adjust	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	**4,213.70**	**4,212.00**	**4,205.80**	**4,208.00**	**4,190.10**	**4,209.40**	**4,213.20**	**4,207.40**	**4,218.30**	**4,273.80**	**4,267.70**	**4,186.50**
Peak	3,415.90	3,391.30	3,143.40	2,946.70	3,410.80	3,248.90	3,998.90	4,361.60	**4,712.00**	3,416.90	3,354.40	3,481.50
Reserve Margin (%)	23.36	24.20	33.80	42.80	22.85	29.56	5.36	-3.54	-10.48	25.08	27.23	20.25
Other Resources												
Demand Response	81.30	81.30	81.30	81.30	235.60	235.60	235.60	235.60	235.60	126.70	81.30	81.30
Out-of-State	702.00	702.00	702.00	702.00	702.00	702.00	702.00	702.00	702.00	702.00	702.00	702.00
Avg. Historical Imports	1,828.00	2,052.00	2,159.00	1,995.00	2,263.00	2,234.00	2,280.00	2,347.00	2,246.00	2,387.00	1,827.00	1,608.00

Table 4 - "As Found" Installed Capacity and Peak Load for CAISO System (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Nuclear	4,550.00	4,550.00	4,550.00	4,550.00	4,550.00	4,550.00	4,550.00	4,550.00	4,550.00	4,550.00	4,550.00	4,550.00
Fossil	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Fossil-Gas	3,202.57	3,202.57	3,197.56	3,192.56	3,187.56	3,182.56	3,177.56	3,177.56	3,182.56	3,187.56	3,197.56	3,202.57
GT-Oil	156.00	156.00	156.00	156.00	156.00	156.00	156.00	156.00	156.00	156.00	156.00	156.00
GT-Gas	11,860.36	11,860.36	11,853.06	11,851.06	11,849.06	11,847.06	11,847.06	12,197.06	12,198.06	12,204.06	12,210.36	12,210.36
C.C.	3,240.31	3,240.31	3,240.31	3,240.31	3,240.31	3,240.31	3,240.31	3,240.31	3,240.31	3,240.31	3,240.31	3,240.31
I.C.	227.12	227.12	227.12	227.12	227.12	227.12	227.12	227.12	227.12	227.12	227.12	227.12
Diesel	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00
Steam	581.91	604.27	662.61	721.09	771.86	861.34	862.54	862.58	867.46	671.58	599.02	566.20
ST-Gas	16,886.43	16,886.43	16,886.43	16,886.43	16,886.43	16,886.43	16,886.43	17,071.43	17,071.43	17,071.43	17,071.43	17,071.43
ST-Other	1,879.91	1,879.91	1,879.91	1,879.91	1,879.91	1,879.91	1,866.91	1,866.91	1,866.91	1,879.91	1,879.91	1,879.91
ST-Coal	254.70	254.70	254.70	254.70	254.70	254.70	254.70	254.70	254.70	254.70	254.70	254.70
Other	214.75	214.75	214.75	214.75	214.75	214.75	214.75	214.75	214.75	214.75	214.75	214.75
Refuse	903.98	903.98	903.98	903.98	903.98	903.98	903.98	903.98	903.98	903.98	903.98	903.98
Hydro	8,101.02	8,101.02	8,101.02	8,101.02	8,101.02	8,101.02	8,101.02	8,101.02	8,101.02	8,101.02	8,101.02	8,101.02
Hydro-RR	800.22	800.22	800.22	800.22	800.22	800.22	800.22	800.22	800.22	800.22	800.22	800.22
Hydro-Small	161.62	159.13	166.00	171.68	209.46	163.50	121.79	97.84	79.32	56.08	51.78	59.62
Non-RPS	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00	1,804.00
Biomass	666.87	638.49	622.26	605.81	600.47	704.05	702.75	694.34	701.41	727.13	711.91	617.69
Geothemal	1,107.78	1,098.48	1,088.80	1,112.53	1,098.20	1,129.35	1,103.53	1,110.14	1,112.61	1,120.04	1,105.31	1,136.65
Solar	129.16	210.99	274.95	302.86	329.82	377.62	370.07	366.82	367.87	234.51	181.16	329.15
Wind	1,057.61	1,060.01	1,267.31	1,257.54	1,275.40	1,236.34	1,228.01	1,197.10	1,255.13	1,235.32	988.37	869.26
Cogen	172.40	174.50	168.60	170.30	176.20	169.20	171.20	169.80	170.40	167.90	168.30	167.00
Adjust	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	**57,986.88**	**58,055.40**	**58,347.75**	**58,432.03**	**58,544.63**	**58,717.62**	**58,618.11**	**59,091.84**	**59,153.42**	**58,835.78**	**58,445.37**	**58,390.10**
Peak	35,247.90	33,168.10	33,957.00	34,456.90	39,669.70	42,331.40	46,495.10	47,470.50	**50,710.10**	34,765.30	33,740.80	35,306.30
Reserve Margin (%)	64.51	75.03	71.83	69.58	47.58	38.71	26.07	24.48	16.65	69.24	73.22	65.38
Other Resources												
Demand Response	81.30	81.30	81.30	81.30	2,101.36	2,886.56	3,007.13	2,841.47	2,920.61	1,959.51	81.30	81.30
Out-of-State	2,190.00	2,190.00	2,190.00	2,190.00	2,190.00	2,190.00	2,190.00	2,190.00	2,190.00	2,190.00	2,190.00	2,190.00
Avg. Historical Imports	9,076.00	9,319.00	10,617.00	10,879.00	10,699.00	11,615.00	12,229.00	11,173.00	9,415.00	10,519.00	9,901.00	9,991.00

Outage Rates

Table 5 shows the MW-weighted average planned and forced outage rates (EFORd) by area and unit type for the thermal units.

Table 5 - MW-Weighted Average Outage Rates (%)

	No. Cal.		So. Cal.		San Diego		CAISO	
	P.O.R.	F.O.R.	P.O.R.	F.O.R.	P.O.R.	F.O.R.	P.O.R.	F.O.R.
Nuclear	4.25	2.87	6.66	2.87			5.44	2.87
Fossil				7.95				7.95
Fossil-Gas	3.25	8.46	2.93	8.64	3.00	8.39	3.20	8.49
GT-Oil	1.09	10.30					1.09	10.30
GT-Gas	2.32	8.39	2.42	8.63	2.27	11.55	2.36	8.92
C.C.	4.89	6.33	4.89	6.33			4.89	6.33
I.C.	2.70	16.70	3.04	8.39	3.07	8.39	2.72	16.13
Diesel			1.09	10.30			1.09	10.30
Steam			4.06	6.91			4.06	6.91
ST-Gas	7.96	7.22	7.74	6.95	6.93	6.91	7.71	7.04
ST-Other	2.21	3.36	3.12	5.49			2.45	3.91
ST-Coal	5.39	6.96	5.39	6.96			5.39	6.96
Other	4.72	7.95	4.51	7.55			4.52	7.58
Refuse	4.55	8.08	3.36	11.95	2.73	15.52	4.12	9.54

As a way of reviewing the forced outage rate data, Figure 1 plots the unit forced outage rates (EFORd) as a function of the unit size for the 760 thermal units being modeled. As would be expected when using class-average data rather than unit-specific data, there is significant clustering of the data, but the plot does show the range of values being assumed. There are a number of units with very high and very low forced outage rates, but for the most part these units are fairly small. The vast majority of the units have forced outage rates in the 6% to 8% range.

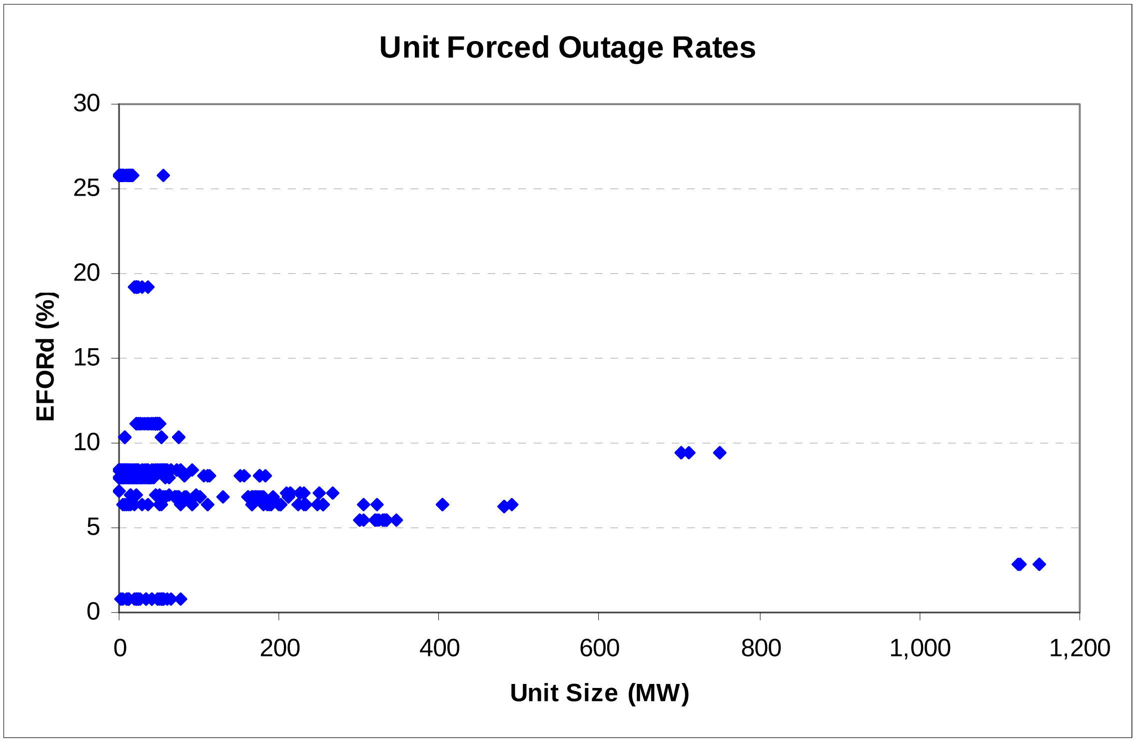

Figure 1 - Unit Forced Outage Rates versus Size

Hydro Capacity Factors

Figure 2 shows the range of monthly capacity factors for the hydro units modeled. Most of the units fall within the expect range of 20% to 80% while there are some outliers.

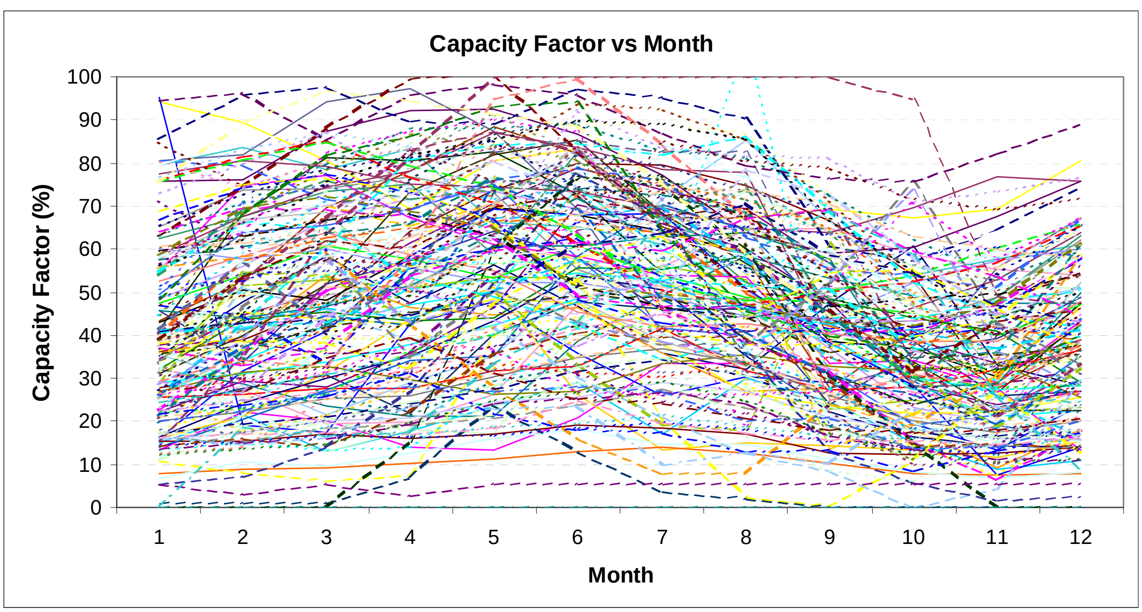

Figure 2 - Hydro Unit Monthly Capacity Factors

Planned Maintenance Schedule

For these cases, the planned maintenance was scheduled by the program for all units except one nuclear unit for which its maintenance schedule had been specified. The program scheduled the maintenance on an area basis so as to levelize, as much as possible given the discrete sizes of the units, the weekly MW margins, calculated as the installed capacity minus the peak load minus the capacity on maintenance. The total capacity on scheduled maintenance each week for the CAISO system along with the remaining margins are shown in Figure 3.

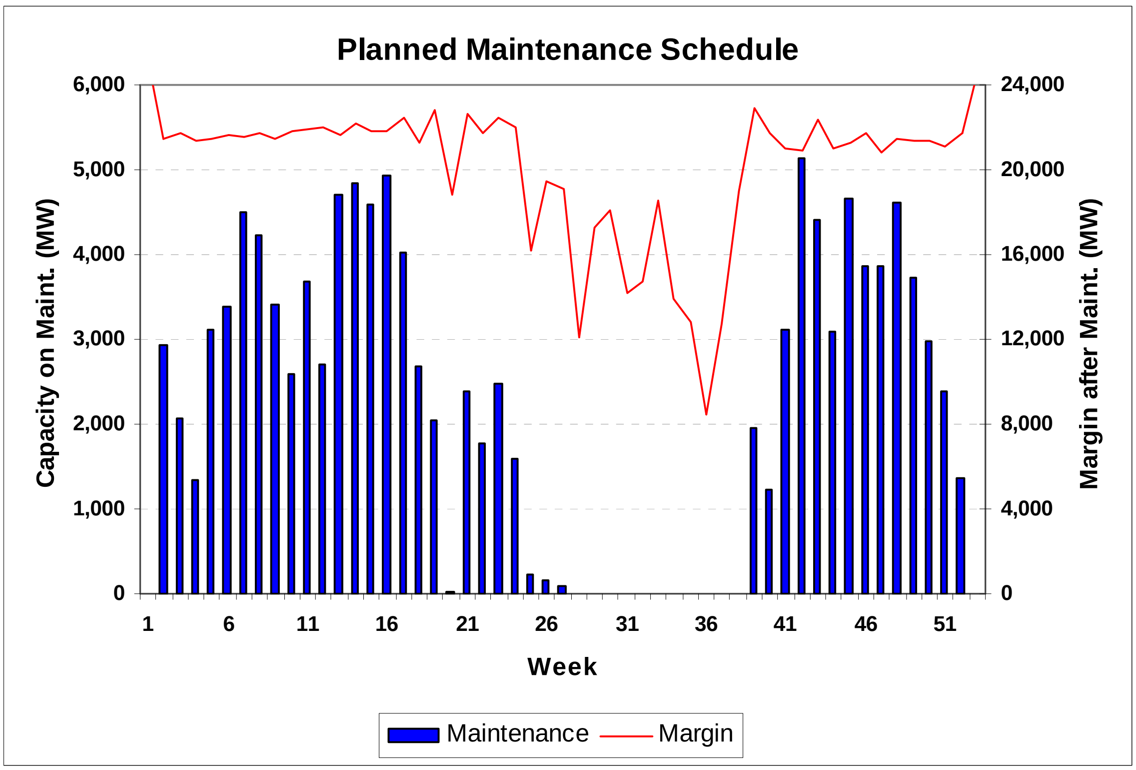

Figure 3 - CAISO Capacity on Scheduled Maintenance

The maintenance schedule for the CAISO generating units developed by the program resulted in weekly margins that were fairly constant between 21,000 MW and 22,000 MW except during the peak weeks when, even with no maintenance scheduled, the margins dropped to a low of about 8,000 MW. The program scheduled little maintenance during week 20 because of a 6,000 MW increase in the peak load for that week compared to adjoining weeks.

INTERFACE TRANSFER LIMITS

The CAISO system was modeled as three interconnected areas. The interface between the Northern California and Southern California areas had a rating of 3,750 MW from north to south, and a rating of 2,902 MW going from south to north. The rating of the interface between Southern California and San Diego was modeled as a function of the availability of the two SONGS units. This relationship is shown in Table 6.

Table 6 - Southern California to San Diego Interface Rating

Status of SONGS Units		Interface Flow Limit (MW)	
Unit 1	**Unit 2**	**North - South**	**South - North**
Available	Available	2,200	236
Unavailable	Available	2,200	1,314
Available	Unavailable	2,200	1,316
Unavailable	Unavailable	2,200	2,440

LOADS

Load Shape

MARS requires a chronological hourly load shape for each area being modeled. This data is often developed from historical hourly load data from a year with weather, economic, and other characteristics similar to the year to be studied. In other words, the hourly shape from a year with "normal" weather conditions would typically be used as a base case load model, while a shape from a year with "extreme" weather conditions may be used for a sensitivity case.

MARS will then adjust the input hourly load profile to generate a load model with the specified forecasted peaks and energies, on a monthly or annual basis.

The historical hourly load profile for the CAISO areas for the year 2007 was selected as being representative of a year with normal hot summer weather, and was used in developing the Base Case load model. These shapes were adjusted to meet the peak projections for 2010 as adopted by CEC in November 2007 as part of the 2007 Integrated Energy Policy Report (IEPR) proceeding.

Load Forecast Uncertainty

To model the uncertainty associated with the peak load projections through time, MARS computes the reliability indices at multiple levels of assumed monthly peak loads. It then calculates a weighted-average value for each index based on the probabilities corresponding to the load levels. For this study, the peak loads for the 1-in-2, 1-in-5, 1-in-10, and 1-in-20 load forecasts were used. The per-unit load multipliers relative to the 1-in-2 forecast and the associated probabilities are shown in Table 7.

Table 7 - Load Forecast Uncertainty Assumptions

	Load Forecast			
	1-in-2	**1-in-5**	**1-in-10**	**1-in-20**
No. California	1.0000	1.0264	1.0367	1.0777
So. California	1.0000	1.0663	1.0773	1.1070
San Diego	1.0000	1.0680	1.0880	1.1490
Probability	0.5	0.3	0.1	0.1

DATA QUALITY

A study such as this requires a significant amount of data that is often derived from multiple sources. With the use of multiple data sources comes the possibility for inconsistencies in the data from the different sources. With data related to generating units, another problem is the way in which a specific unit may be identified in the different sources. Such was the case with some of the hydro and unit outage data.

The ratings of the hydro units were taken from the CAISO master list of units, while the available energy came from a CEC source. There was no way to directly link the units between the two sources. Additionally, different levels of aggregation of the units at a plant were done in the two sources, further complicating the merging of the data. A review of the monthly capacity factors indicated problems with the data that were ultimately resolved by CAISO staff. Even after the CAISO review, there were still some units with capacity factors greater than 100%. The energy on these units was reset to give a capacity factor of 100%.

One of the sensitivity cases that had been agreed to involved using the actual 2007 planned outages for the units rather than having the planned outages scheduled by MARS. Once again, the lack of unique unit identifiers prevented the CAISO staff from matching most of the units in the outage database with the units in the study data. In addition, reporting of the outages was inconsistent, with some units showing 0 MW derate and being reported as having outages in the CAISO Scheduling and Logging for the ISO of California (SLIC) database. As a result, this sensitivity was delayed until more complete data is available.

For this study, historical hourly data for wind and other renewables were scaled for use in modeling 2010. For the Phase 1A Preliminary Study for 2010, the scale factors for the units in the PG&E area were not submitted in time to be included in the simulations. They will be included in the Phase 1B analysis.

4 Results

ORIGINAL BASE CASE

For this study, the Base Case PRM was defined as the **monthly reserves, excluding imports and demand response**, required to maintain **CAISO** at a daily LOLE of **0.1 days/year**. To determine this level of reserves, the reliability of the CAISO system was computed over a range of reserve margins. To model CAISO at the different levels of installed reserves, "perfect" capacity (capacity without planned or forced outages) was added to or removed from each of the three areas so that the reserves in each of the areas was equal to the CAISO reserve margin.

As shown in Figure 4, the daily LOLE was then plotted as a function of installed reserves, and the reserve margin at the point at which CAISO was at the target LOLE was determined from the graph. For the Base Case, the PRM using monthly reserves was 28.8%. The impact on PRM of using monthly reserves as opposed to annual reserve or constant MW reserves will be examined during the discussion of those sensitivity cases.

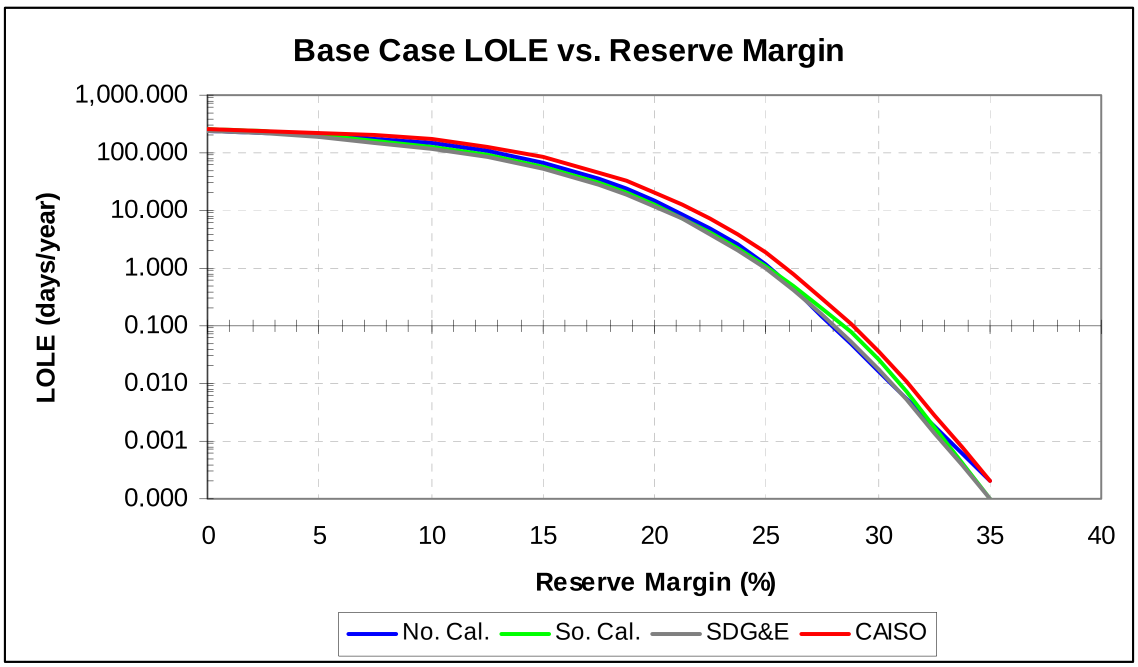

Figure 4 - Base Case LOLE versus Reserve Margin

Figure 4 shows the risk in the three areas to be fairly balanced. As would be expected, the risk for CAISO was slightly higher than that of the least reliable area, reflecting the fact that most of the time, the outages in the three areas were overlapping and occurred on the same days. However, there were occasions during which one of the areas would be short but the others were not, which would contribute a few additional days of outage to the CAISO total.

Impact of Load Forecast Uncertainty

A significant consideration in the reliability analysis is load forecast uncertainty. All of the cases examined considered a range of load forecasts from a 1-in-2 probability to a 1-in-20 probability. The results shown are an annual expected value that combines the LOLE calculated for each load forecast, weighted by their probabilities of occurring. In this section we show the impact on a monthly and hourly basis for a single case. This data is from the Base Case with a 25% reserve margin on a monthly basis.

Figure 5 is a plot of the expected number of outages occurring at the 1-in-2 forecast level. The results are displayed in a surface plot showing the results by hour of the day and by month. The plot reflects zero values for all periods except hours 18 and 19 in February and March. This case assumed a constant percent reserve each month and therefore the highest risks occurred in the off-peak months.

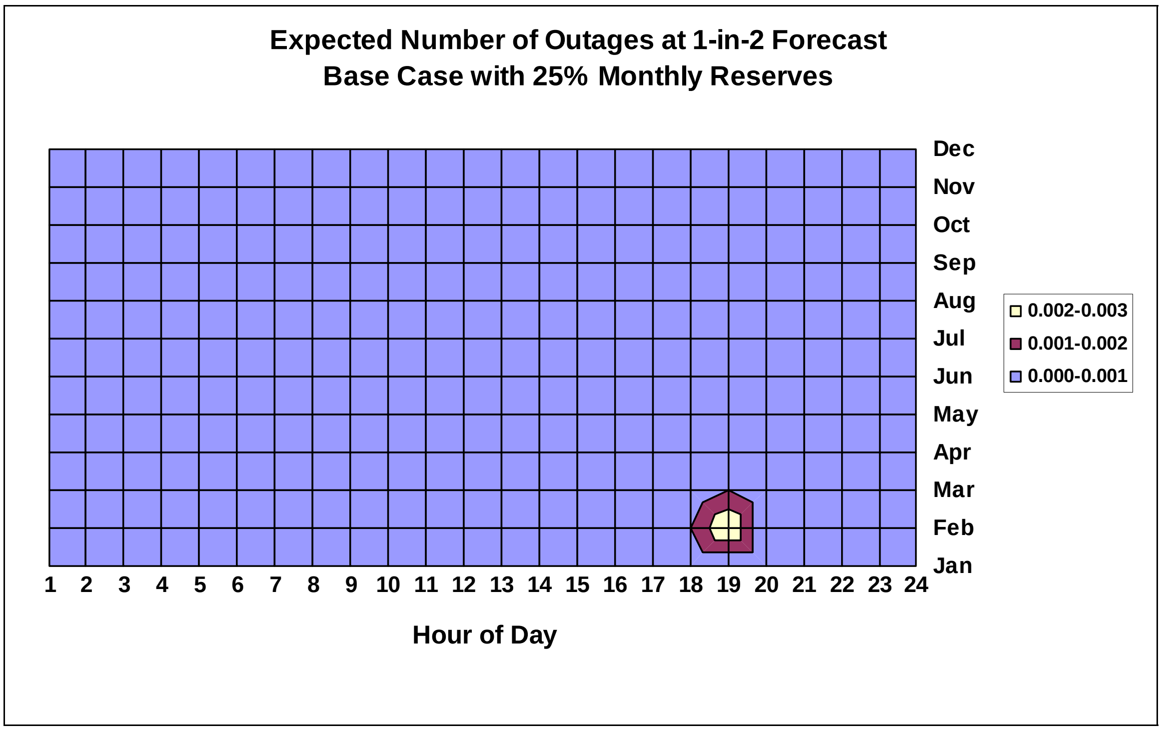

Figure 5 - Hourly Results for a 1-in-2 Forecast

Figure 6 shows a similar result for the 1-in-5 forecast levels. Now the outages have spread out to include both the first three and last three months of the year. In fact, the highest value is in December although the risk occurs throughout more of the day in October. As the loads increase in Figure 7 and Figure 8, this trend continues. At the 1-in-20 load forecast, the monthly reserves have dropped from 25% to about 14% and the possibility of outage extends through most of the day.

Figure 9 shows the expected values for all load forecasts by month and time of day.

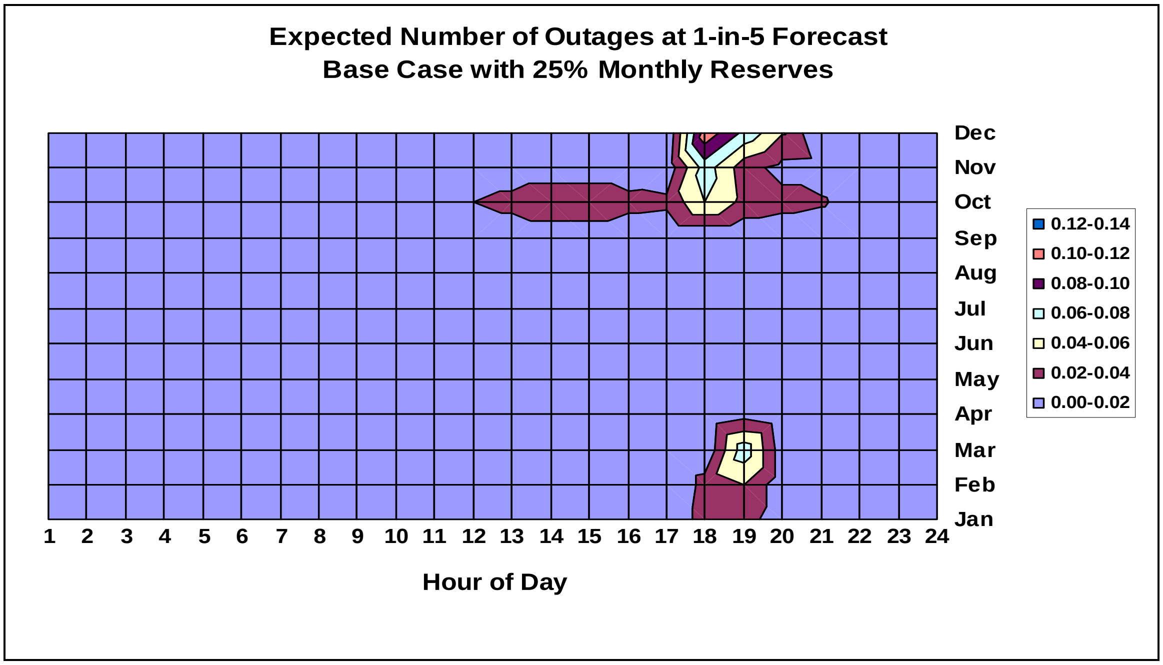

Figure 6 - Hourly Results for a 1-in-5 Forecast

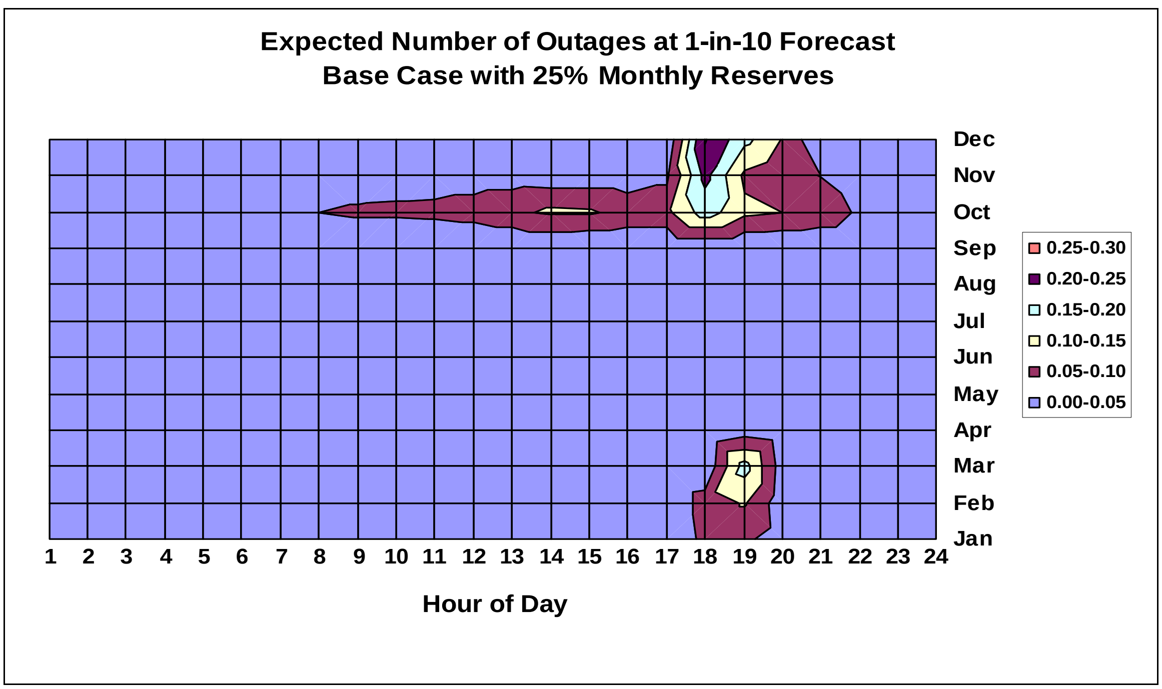

Figure 7 - Hourly Results for a 1-in-10 Forecast

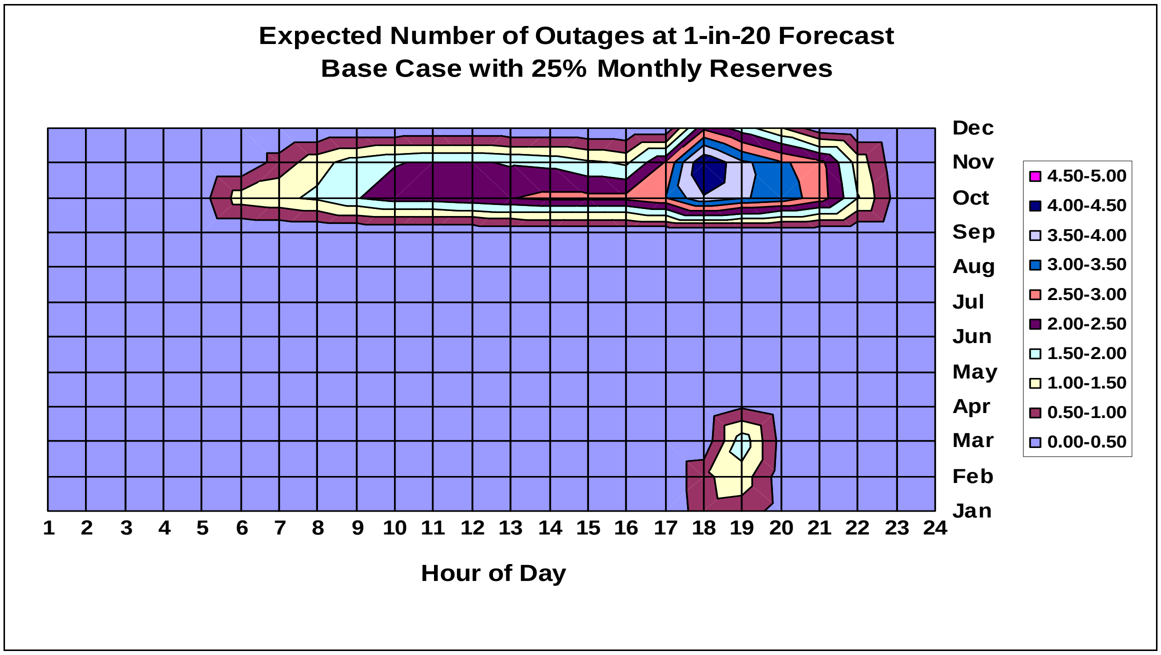

Figure 8 - Hourly Results for a 1-in-20 Forecast

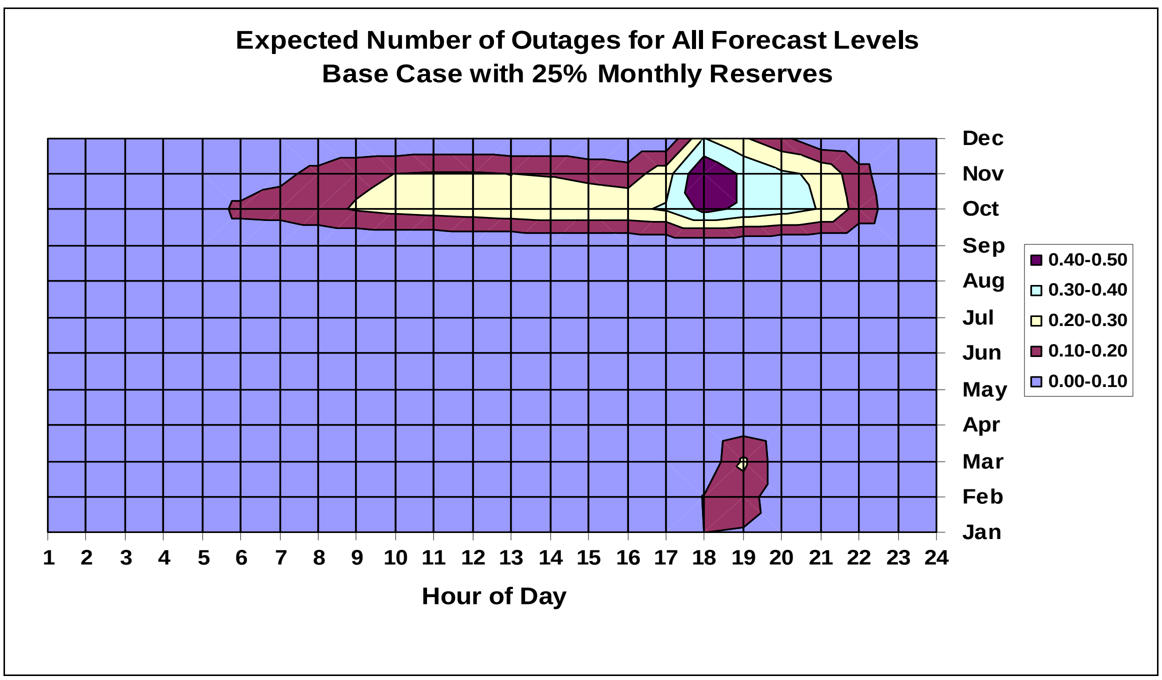

Figure 9 - Expected Hourly Results for All Forecast Levels

Hourly LOLE and Loss-of-Expected Unserved Energy

Although this study is focusing on the daily LOLE, the hourly LOLE and expected unserved energy (EUE), also referred to as loss-of-energy expectation (LOEE), were also computed and are shown in Figure 10 and Figure 11.

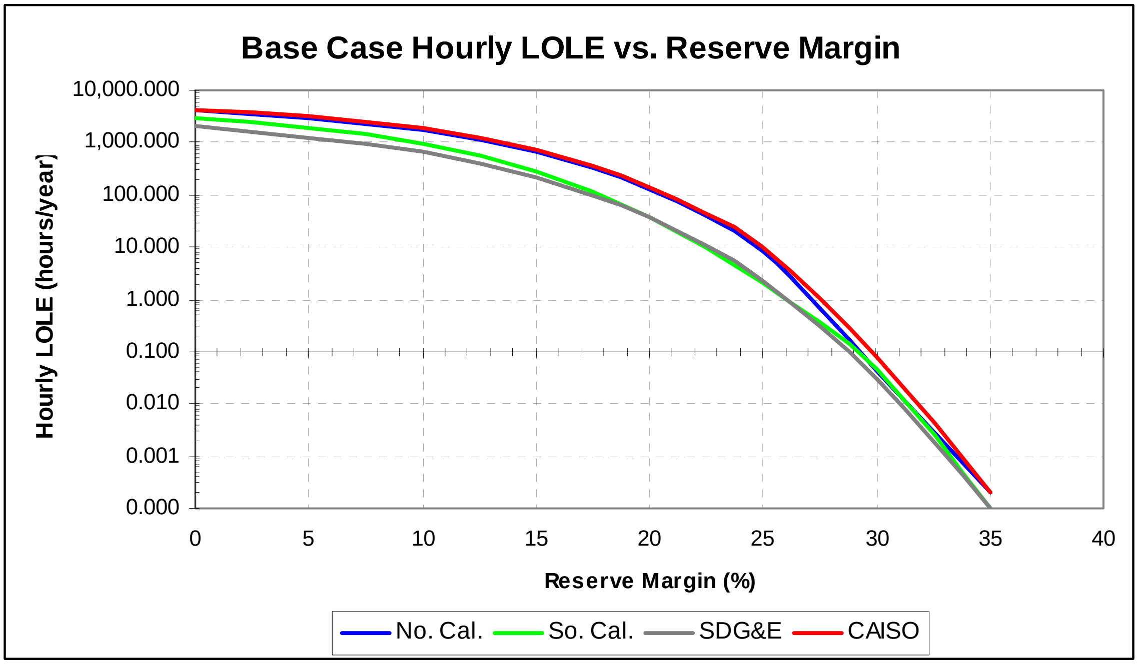

Figure 10 - Base Case Hourly LOLE versus Reserve Margin

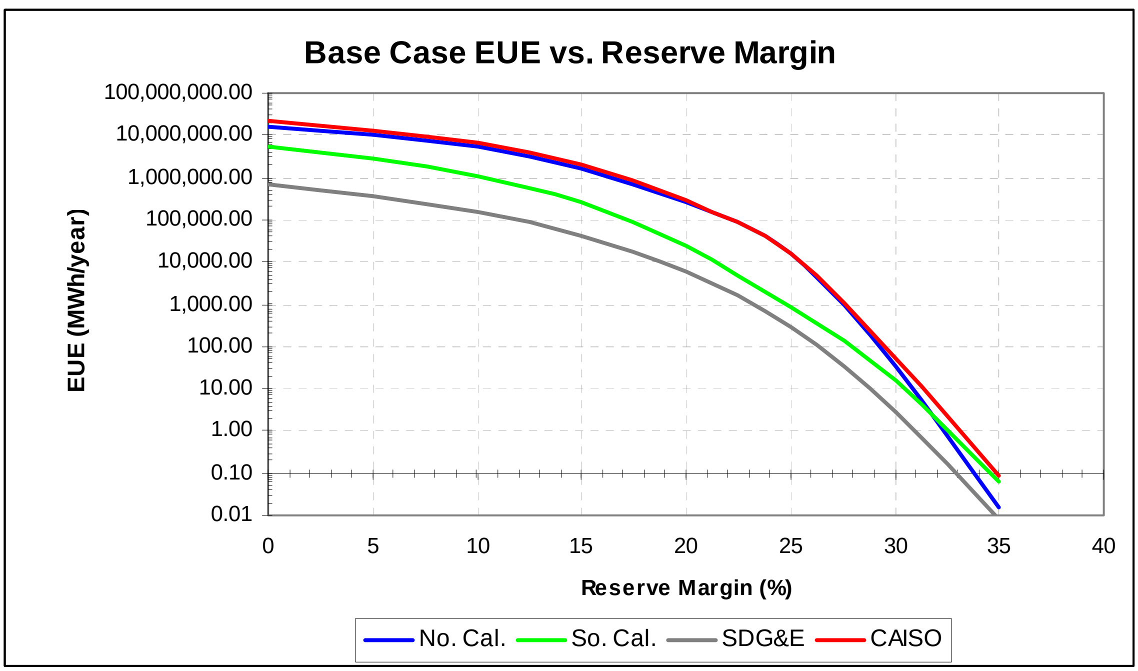

Figure 11 - Base Case Expected Unserved Energy (EUE) versus Reserve Margin

The daily LOLE is the expected number of days per year that there is not sufficient generation available to meet the load at sometime during the day. The hourly LOLE is the expected number of hours per year of insufficient generation. The ratio of the hourly LOLE to the daily LOLE is the average duration of the outage on those days that had an outage.

Both the daily and hourly LOLE count just the number of outages with no consideration given to the magnitude of the outage. The EUE accumulates the MW of outage for each hour, producing the expected amount of unserved energy in MWh/year. The ratio of the EUE and the hourly LOLE would give you the average magnitude of outage for those hours during which an outage occurred.

Unlike the daily and hourly LOLE, whose range of possible values is limited to the number of days or hours in the year, the EUE will reflect the size of the system being modeled. Also unlike the other two indices, the CAISO EUE is always the sum of the EUE for the three areas. This is more readily seen in Figure 12

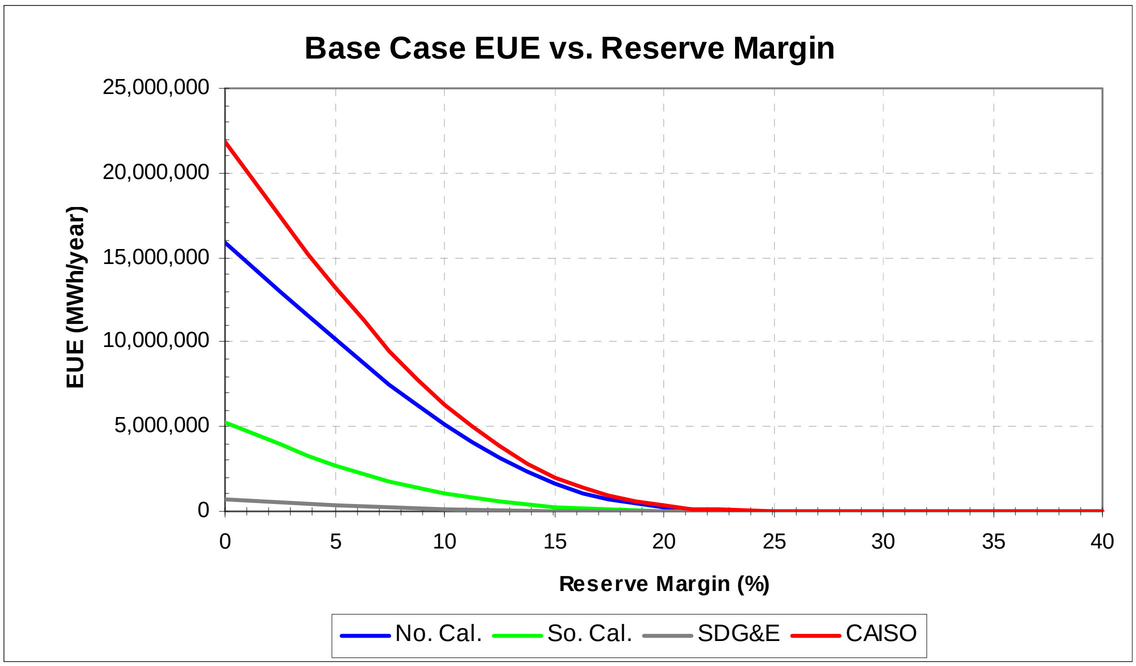

Figure 12 - Base Case Expected Unserved Energy (EUE) versus Reserve Margin

Simulation Convergence

One of the questions regarding Monte Carlo simulation techniques such as those used in MARS involves the number of replications, or simulations of the year, that are required for the index of interest to converge. Figure 13 shows the cumulative average of the CAISO LOLE as a function of the number of replications for three different levels of monthly reserves for the Base Case. Early on in the simulation, the cumulative average varies, sometimes significantly, in response to the results of each additional replication. As the number of replications increases, each additional replication has less of an impact and the cumulative average begins to settle out. With these cases, the results settled out after about 200 replications with only slight variations occurring after that.

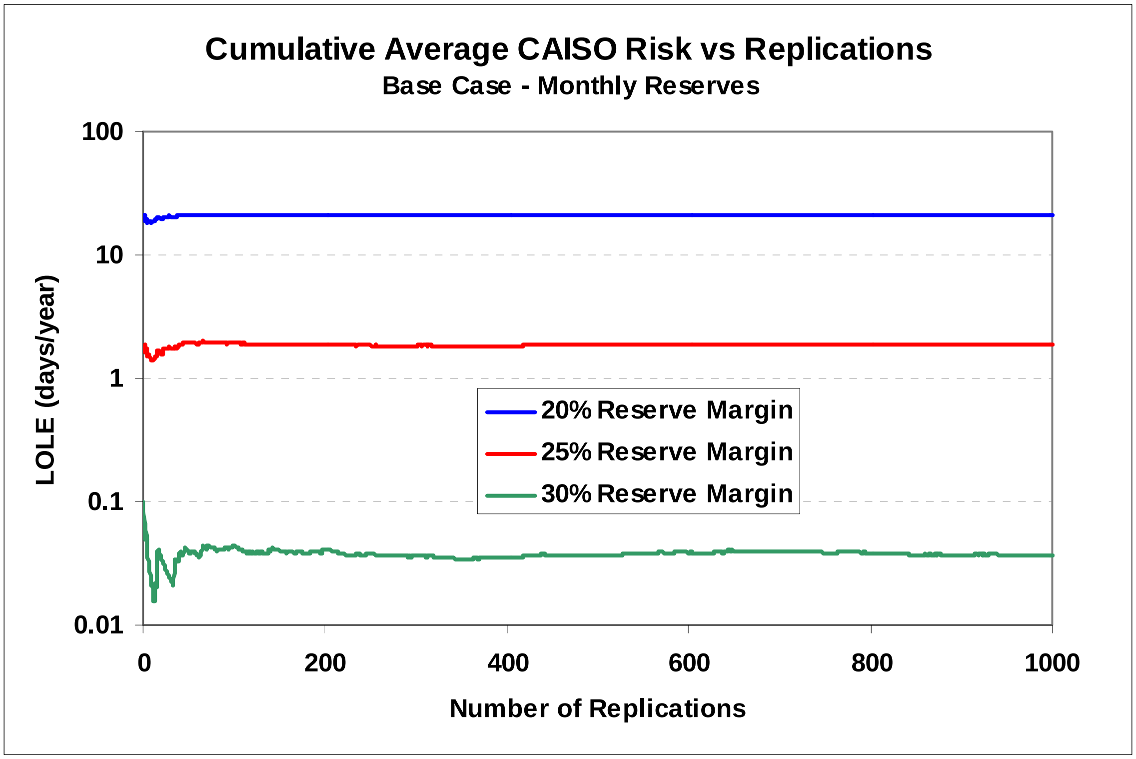

Figure 13 - Cumulative Average CAISO Risk versus Number of Replications

Distribution of Calculated Indices

Although we are usually interested primarily in the expected values of the calculated indices, Figure 14 shows a distribution of the results of the individual replications for the 25% monthly reserve margin simulation of the Base Case. The distribution shows the amount of variation that could be expected in the CAISO LOLE depending on how the random forced outages occurred.

Of the 1,000 times that the system was modeled, the CAISO risk fell in the range from 0 to 1 days/year approximately 170 times. More than 480 times it was between 1 and 2 days/year, and there were times when it was greater than 5 days/year. The expected value for all 1,000 replications was 1.88 days/year.

Risk by Load Forecast Uncertainty Load Level

MARS calculates the reliability indices at each of the load forecast uncertainty load levels being modeled, then computes the weighted-average value based on the probabilities of occurrence for each load level. Figure 15 shows the Base Case CAISO risk as a function of monthly reserve margin for each of the four load forecasts modeled (1-in-2, 1-in-5, 1-in-10, and 1-in-20).

For the 1-in-2 forecast, the CAISO system would be at 0.1 days/year with a monthly reserve margin of approximately 22%. Including the effects of uncertainty, the reserve margin increased to about 29% as was seen in Figure 4.

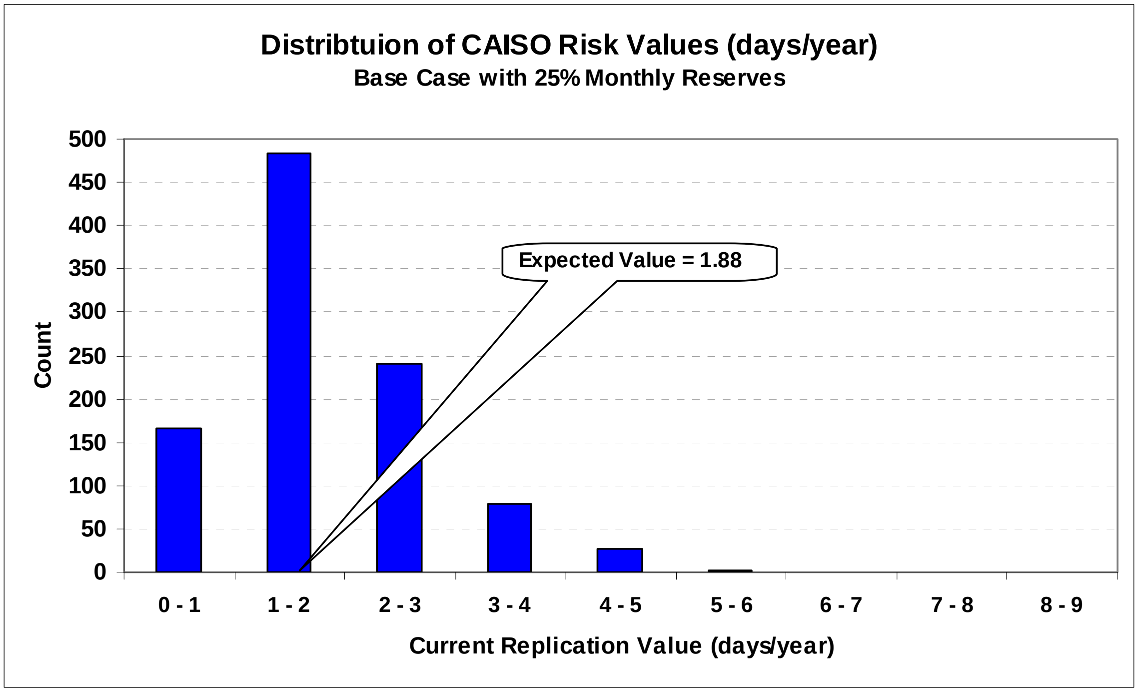

Figure 14 - Distribution of Base Case Replication Results with 25% Monthly Reserves

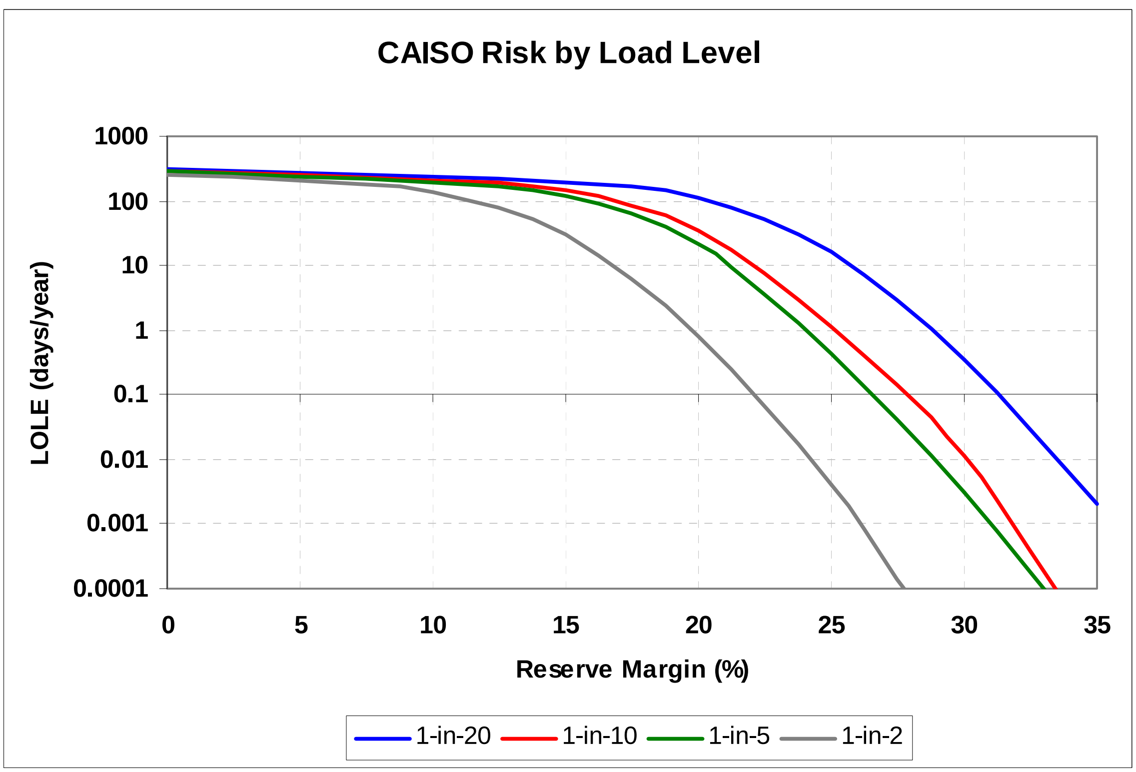

Figure 15 - CAISO Risk as Function of Load Forecast

INITIAL SENSITIVITY CASES

To highlight the study assumptions that most affect the reliability results, a number of sensitivity cases were simulated. For discussion purposes, the sensitivities were grouped into three categories. The first related to the general issue of how the reserve margins are computed. The second looked at including other resources such as imports and demand response in the reliability calculations. The third dealt with study data such as forced outage rates and interface transfer limits.

As noted previously, except for where it was one of the parameters being varied for a specific case, all of the PRM values shown have been calculated using the **monthly reserves** method and assume that **imports and demand response have not been included in the reserve margin or reliability calculations**.

Figure 16, Figure 17, and Figure 18 show the CAISO LOLE as a function of reserve margin for the three groups of sensitivity cases. In Figure 18, increasing the limits from south to north on Path 26 and removing all of the internal constraints had almost no impact on the results, so those two curves along with Base Case are essentially the same curve.

The PRM for the sensitivity cases are summarized in Figure 19. The results of the sensitivity cases will be discussed in the sections that follow.

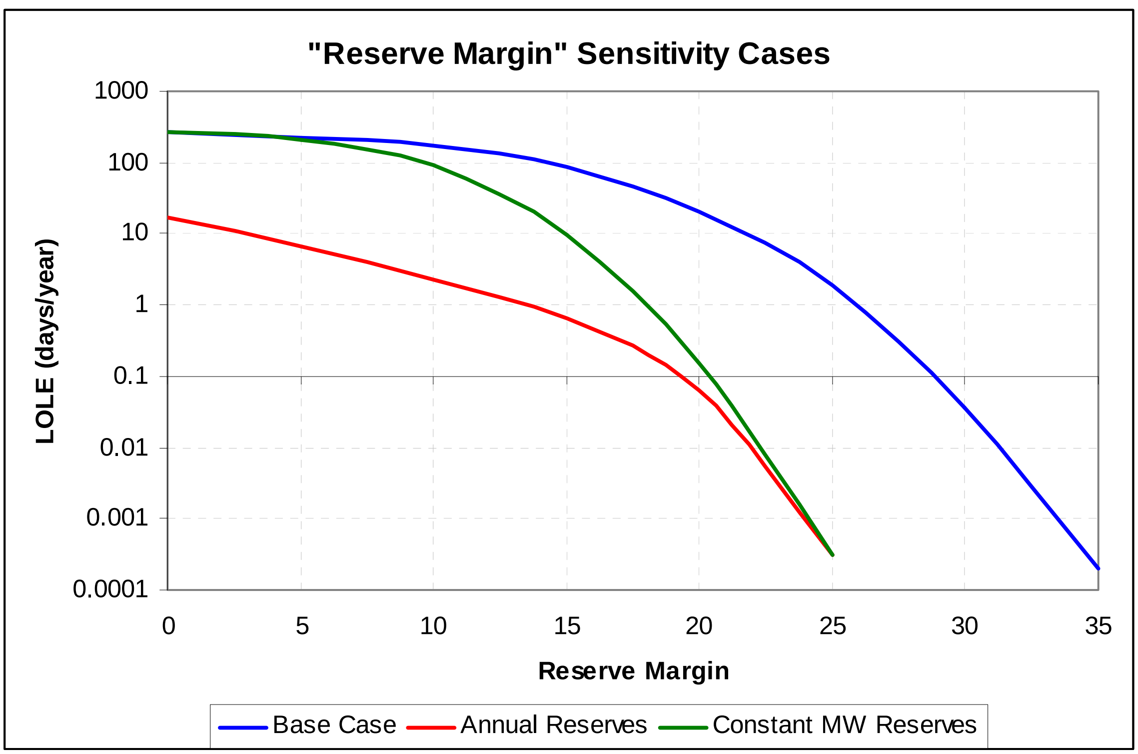

Figure 16 - "Reserve Margin" Sensitivity Case Results

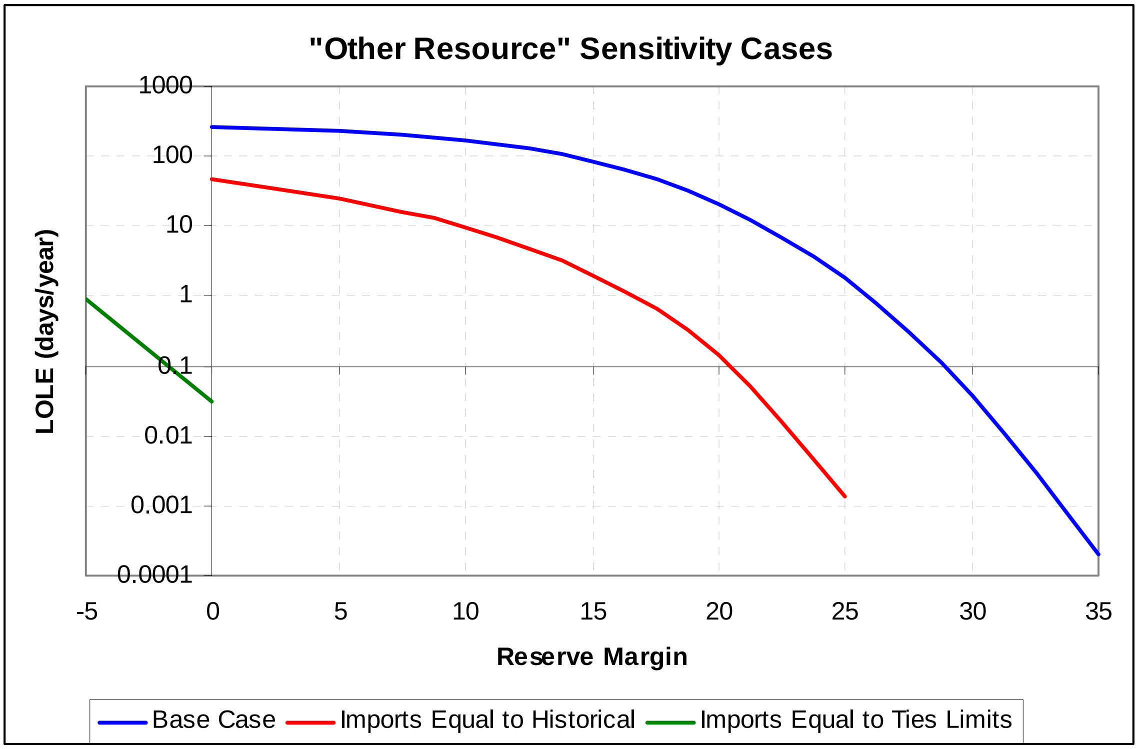

Figure 17 - "Other Resource" Sensitivity Case Results

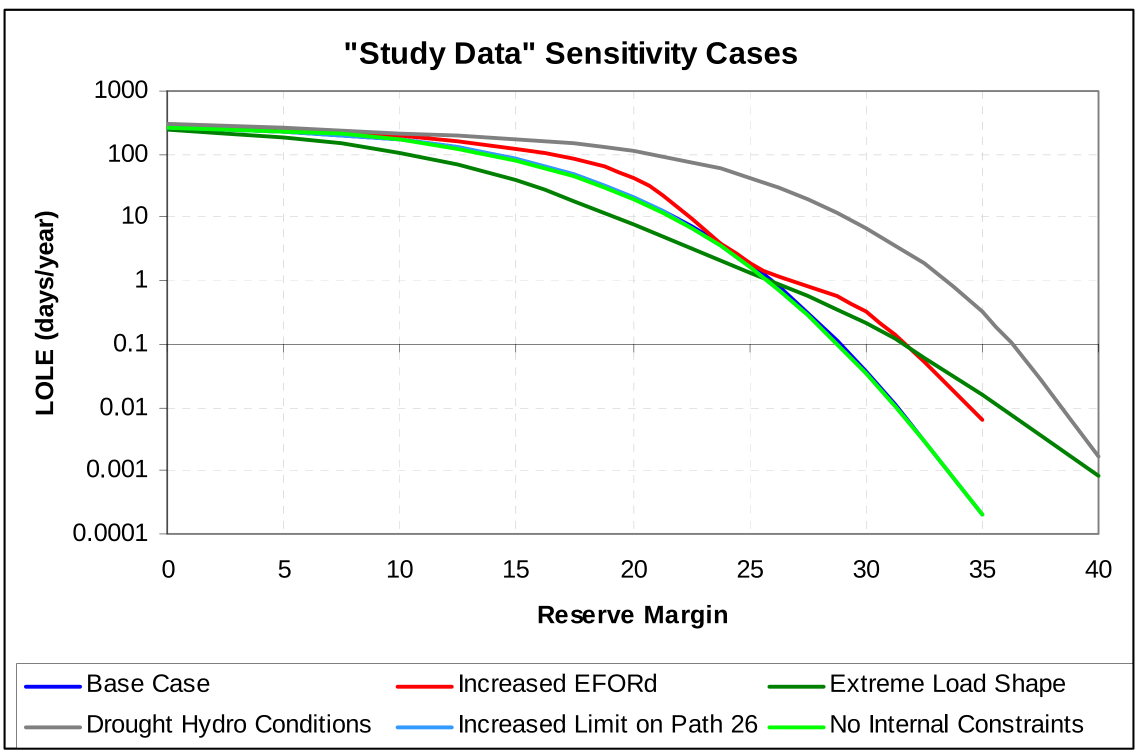

Figure 18 - "Study Data" Sensitivity Case Results

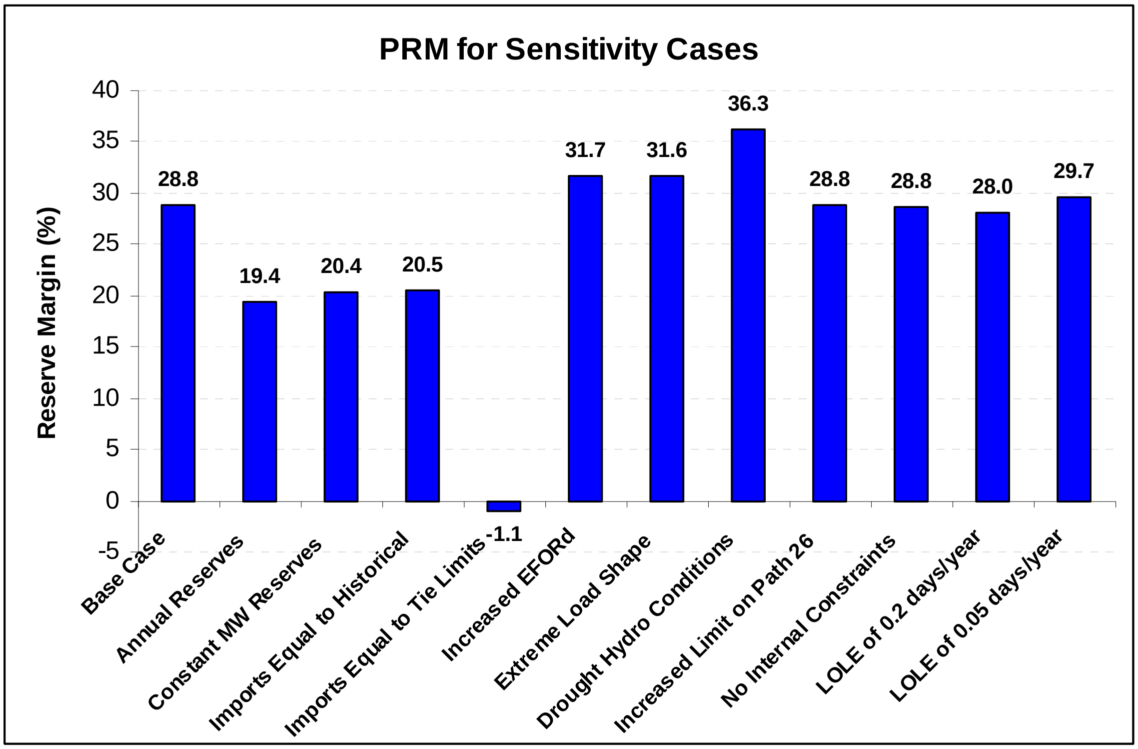

Figure 19 - PRM for Initial Sensitivity Cases

Annual and Constant MW Reserves

The first two sensitivities addressed the issue as to the way in which the reserve margins are calculated. As was discussed in Section 2, there are three (and possibly more) ways in which reserve margins are stated in the utility industry. The Base Case assumption for this study was to use the monthly reserves, which resulted in a constant monthly PRM of 28.8%. With an annual reserve margin measured at the time of the annual peak, which resulted in significantly higher reserves in the off-peak months, the PRM dropped to 19.4%. With the reserve margin set to a constant MW value for all months, the PRM was equal to 20.4%. To better understand these results, we focused on the 20% reserve margin case for the three methods.

With reserves of 20%, the annual risk for the three cases was calculated as:

Monthly Reserves	21.099 days/year
Annual Reserves	0.065 days/year
Constant MW Reserves	0.154 days/year

So saying that CAISO has 20% reserves could describe a system with an LOLE ranging from less that 0.1 days/year to one in excess of 21 days/year, depending on how you defined the reserve margin. Using monthly reserves, which resulted in the least reliable system at reserves of 20%, required the highest reserve margin to meet an LOLE of 0.1 days/year. With annual reserves, the system was most reliable with 20% reserves and needed the lowest PRM.

The monthly risks are shown in Figure 20 for each case. As would be expected, given that the reserves in the peak month were the same for all methodologies, the risk in the peak month was the same for all three cases. The LOLE in the off-peak months, however, varied significantly, resulting in the wide range of annual LOLE.

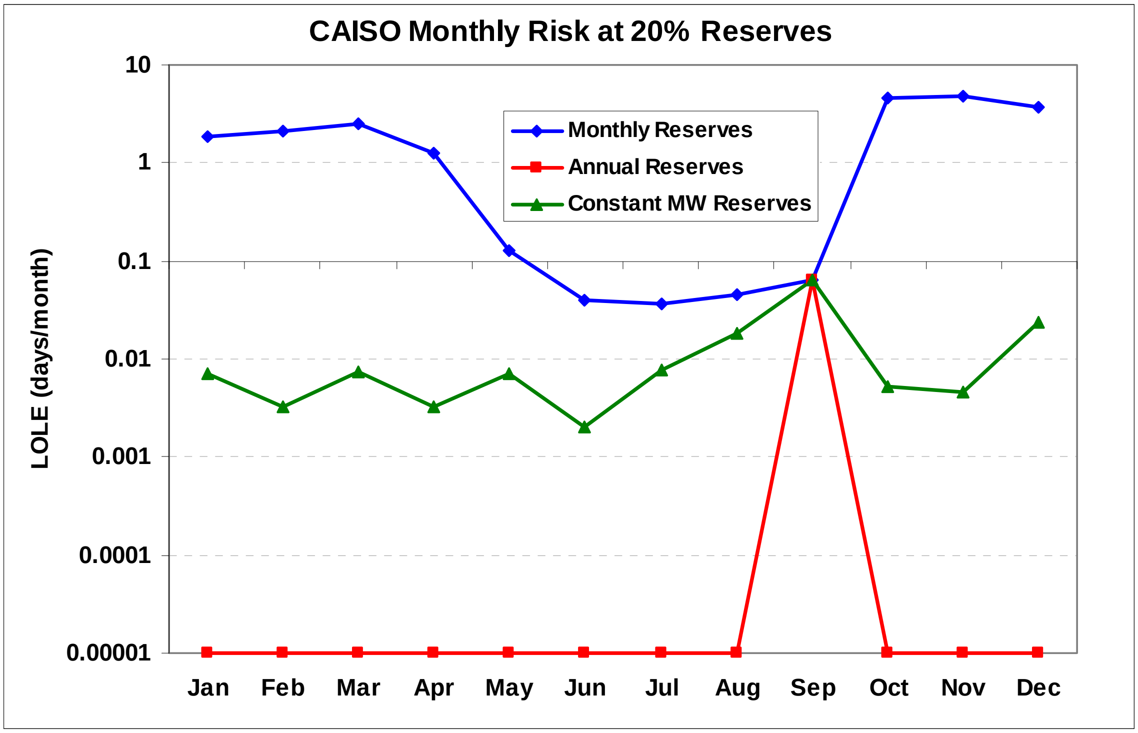

Figure 20 - CAISO Monthly Risk for Various Methodologies at "20% Reserves"

With the annual reserves set to 20% at the time of the annual peak, the MW reserves in the remaining months increase dramatically as the loads drop off, as shown in Figure 21. As a result, all of the risk occurs in the peak month and none in the other eleven months. With the monthly reserves held at a constant percent of peak load, the MW reserves follow the load and decrease in the off-peak months, leading to the increased risk in those months. With the constant MW reserves, the risk is fairly well balanced between the months. The corresponding monthly percent reserves are shown in Figure 22.

The decision of which methodology should be applied, or possibly some other variation, is a policy issue and rather than a technical issue. These examples are shown to illustrate the impact of that decision.

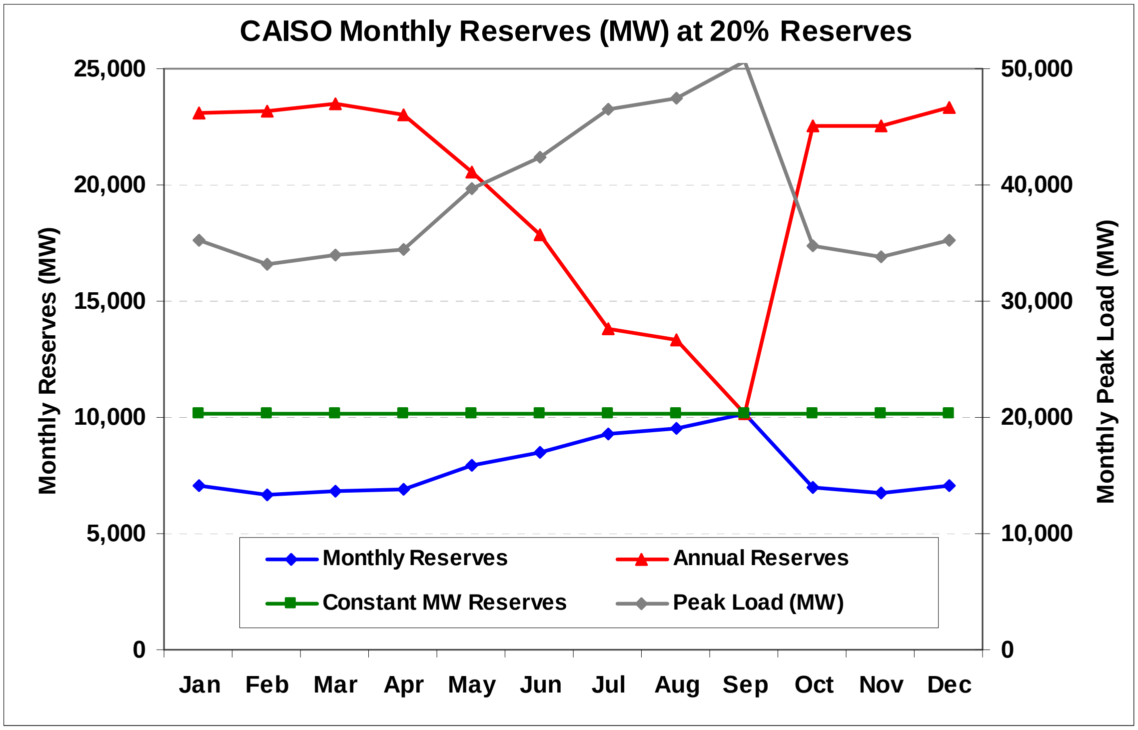

Figure 21 - CAISO Monthly Reserves in MW at "20% Reserves"

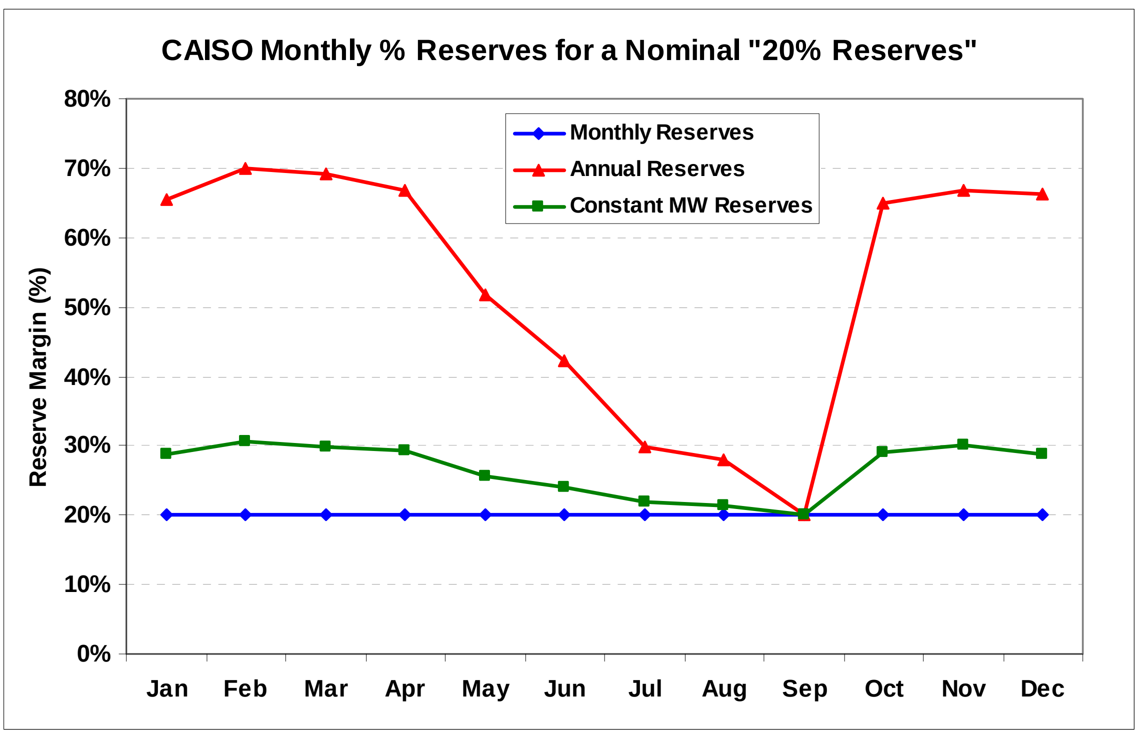

Figure 22 - CAISO Monthly % Reserves for Various Methodologies at "20% Reserves"

Inclusion of Other Resources

The Base Case considered only the generating resources that are part of the CAISO system and did not include other resources such as imports from outside areas and demand response programs. In this set of sensitivity cases, we included imports and demand response in the reliability calculations, although we continued to not include them in the reserve margins calculations. The system was, in effect, getting the reliability benefit of these resources while not counting them in the reserves.

The first case modeled the demand response and average historical flows as shown in Table 1 through Table 4. The results of this case are shown in Figure 17. Unlike previous cases in which the risk was balanced between the three areas, all of the CAISO risk in this case came from the Northern California area. Most of the imports modeled were into the Southern California and SDG&E areas, with the Northern California imports dropping to as little as 75 MW in October compared to over 10,000 MW in the other areas. As a result, all of the outages in the Southern California and SDG&E areas were eliminated. With the availability of the additional resources south of Path 26, the flows going from south to north on Path 26 were limiting for a significant portion of the year. Including the demand response and average historical flows reduced the PRM by more than 8% to 20.5%.

The second case in this group assumed the maximum imports possible, equal to the transfer capabilities into each of the areas. The following values were assumed:

Northern California	3,200 MW
Southern California	8,253 MW
SDG&E	2,850 MW

The derivation of these values is shown in the Working Group Report. These values are somewhat higher than the average historical imports for Southern California and SDG&E, but are significantly higher for Northern California. Figure 17 shows that the modeling of more than 14,000 MW of imports year-round along with the demand response programs reduced the CAISO PRM to –1.1%. In other words, with these additional resources available, which exceed 28% of the CAISO annual peak, CAISO could maintain the system at 0.1 days/year without any generation reserves of its own. This case illustrates the maximum impact that imports could have on the PRM.

Increased Forced Outage Rates

One of the key assumptions in determining the reserve requirements is the forced outage rate data for the generating units. The forced outage rate data assumed in the Base Case is summarized in Table 5. For this scenario, we assumed that the forced outage rates (EFORd) for all of the generating units were increased by 25%. The impact on the CAISO LOLE is shown in Figure 18 and increased the reserve requirements by about 3% for a PRM of 31.7%.

Extreme Load Shape

The historical hourly load profile for CAISO for the year 2007 was selected as representative of a year with normal hot summer weather and was used in developing the load shape used in this study. The impact on reserve requirements of extreme hot summer weather was measured through a set of simulations based on the 2006 hourly load shape. In order to maintain the correlation between the load shape and the intermittent resources, hourly data for the intermittent resources from 2006 and adjusted for the levels of penetration expected for 2010 was also used.

MARS automatically schedules the planned maintenance of the generating units. The maintenance was scheduled on an area basis against the weekly peak loads so as to levelize the available reserves (available reserves = installed capacity – capacity on schedule maintenance – peak load). Changes in the hourly load shape, such as using the 2006 shape, could result in a different maintenance schedule. However, for this sensitivity, we used the maintenance schedule that was developed from the 2007 shape, assuming that the actual maintenance schedule would be developed based on assumed normal weather conditions. With the appearance of extreme hot weather as in the 2006 load shape, there may be some flexibility for rescheduling maintenance, depending on how far in advance the extreme weather was predicted, but for the most part, the original maintenance schedule would remain.

As shown in Figure 18, use of the extreme load shape and corresponding intermittent data added slightly less than 3% to the reserve requirements, increasing the PRM to 31.6%.

Drought Hydro Conditions

The Base Case assumed hydro energy production based on the average for 1994 through 2005. To measure the impact of hydro energy production on PRM, this sensitivity assumed drought conditions based on CEC/EIA 906 data from 1992. Under the drought conditions, the total monthly energy available from the hydro units modeled was 53% of the Base Case energy.

As can be seen from Figure 18, this sensitivity had the greatest impact on PRM, increasing it from 28.8% in the Base Case to 36.3%.

Increased Transfer Limits

The next two sensitivities focused on the impact of the internal transfer limits. The first increased the south-to-north limit on Path 26 by 1,000 MW from 2,902 MW to 3,902 MW. The curves in Figure 18 show that these changes almost had no impact on the CAISO LOLE. Removing all of the internal constraints reduced the PRM by less than 0.1%.

If an area is short of capacity and thus experiences an outage, there is either an overall shortage of capacity in the entire system, or the system has enough capacity but the transfer limits into the area with the shortage are constraining. When you model the system without internal constraints, all of the risk is then a result of insufficient capacity. Since the risk improved only slightly when the constraints were removed, this would indicate that nearly all of the risk in the Base Case was due to overall system capacity shortages, rather than internal transfer limits.

This is consistent with the Base Case results that showed the risk in the three areas to be nearly the same. If the risk is the result of system capacity shortages, all of the areas will share in that shortage and experience roughly the same number of outages. If there is sufficient capacity but the interfaces are limiting, then there is a tendency for the import-constrained areas to experience more risk than the other areas.

Variation in LOLE Design Criterion

For the Base Case and all of the other sensitivity cases, the PRM was calculated as the reserves required to bring CAISO to an LOLE of 0.1 days/year, which is the target level typically used in the utility industry. The purpose of this sensitivity was to see the impact on the PRM of designing the system to a different criterion, one twice as reliable and one half as reliable as the typical 0.1 days/year. Figure 4 plots the LOLE over a range of reserve margins. From this curve we can see that an LOLE of 0.2 days/year could be maintained with a PRM of 28.0%, while an LOLE of 0.05 days/year would require reserves of 29.7%, a change of slightly less than 1% in either direction from the Base Case PRM of 28.8%.

Separate Area PRMs

The Base Case determined the PRM required for CAISO to maintain an LOLE of 0.1 days/year. Because CAISO would be considered to have a day of outage if at least one of its areas had an outage, the CAISO risk will always be greater than the risk of its least reliable area. So for CAISO to be at 0.1 days/year, each of its three areas would have to be at or below that level of risk.

An alternative way of interpreting PRM is to determine a separate value for each area so that each area is at 0.1 days/year. Depending on the extent to which the area outages overlapped, CAISO could then be anywhere from 0.1 days/year (complete overlap of outages) to 0.3 days/year (the area outages never overlap). Because the areas are interconnected and changes to reserves in one area can change the risk in the other areas, this usually involves an iterative process in which the reserves in all of the areas are adjusted to bring then all to criterion simultaneously.

In the Base Case, the results in Figure 4 showed all three areas approaching 0.1 days/year with nearly identical reserve margins between 28% and 29%. Because of this, it was not necessary to iterate on the areas, and the PRMs to bring the areas to 0.1 days/year would be nearly equal to the Base Case value of 28.8%.

Levelized Monthly Risk

As indicated by Figure 20, the monthly risk can vary significantly from month to month, especially in the case with constant monthly percent reserves. The objective of this sensitivity was to determine the PRM values for each month that would result in the annual risk of 0.1 days/year being evenly spread throughout the year.

The monthly LOLE for the Base Case is plotted as a function of reserve margin in Figure 23. Also plotted as the horizontal black line is the monthly target risk of 0.0083 days/month. From this plot we can see that June through September would require a PRM of about 22%, May would require 25%, and the remaining months are clustered between 28% and 30%. The monthly PRM and CAISO monthly peak loads are shown in Figure 24.

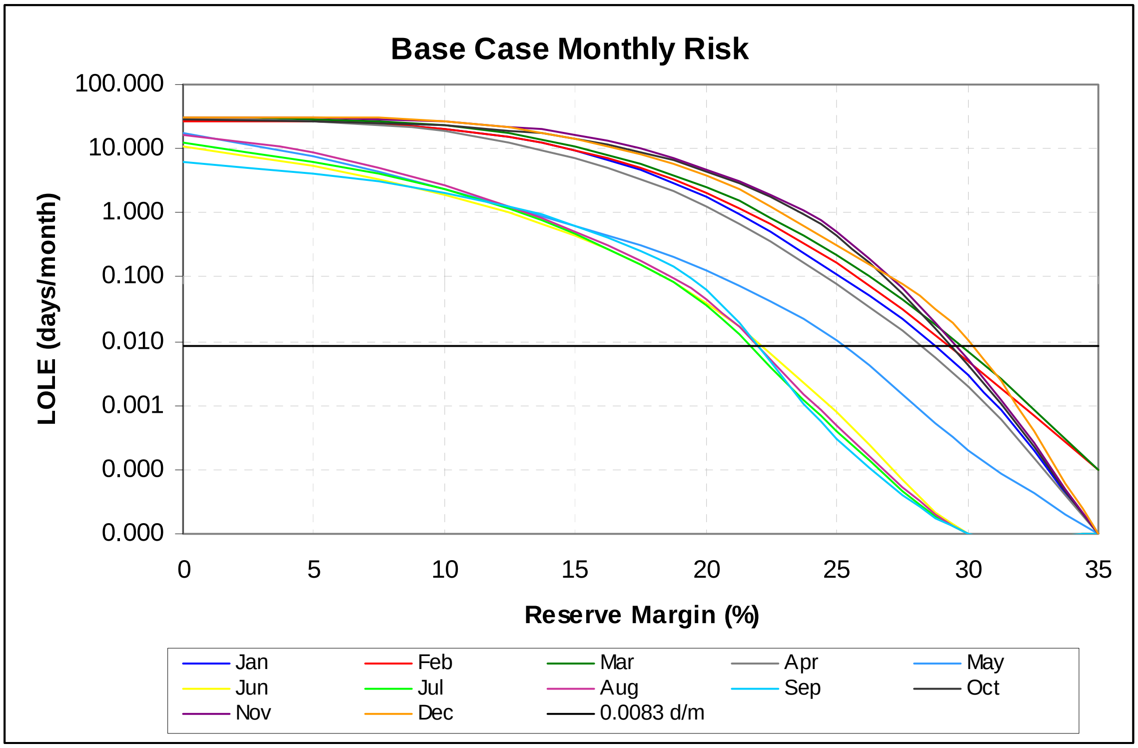

Figure 23 - Base Case Monthly LOLE versus Reserve Margin

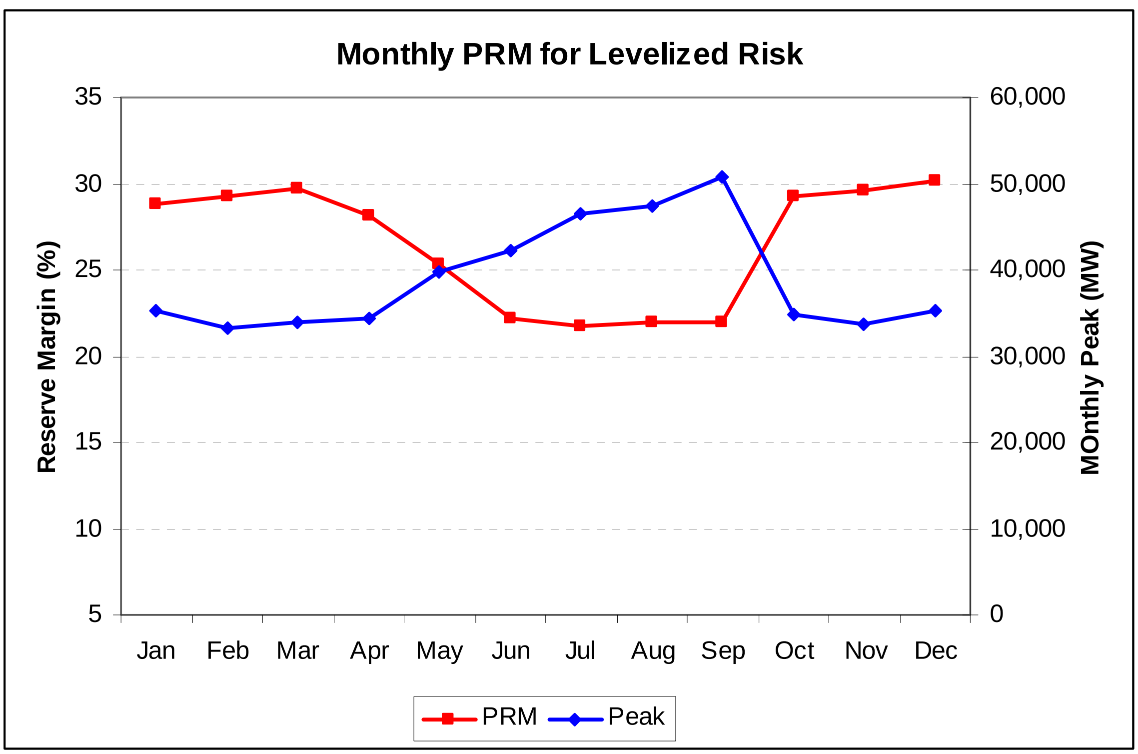

Figure 24 - Monthly PRM for Levelized Risk and Peak Load

There are two factors that help explain the inverse relationship between the monthly peak loads and the monthly PRM. The first is the general observation that larger systems can maintain a given level of reliability with lower reserves than smaller systems. Although the reserve margins account for the capacity on maintenance, Figure 3 shows that there is little if any planned maintenance scheduled during those months. As a result, there is a larger pool of units available to serve the load during the higher load months and the random forced outages are more even distributed.

The second factor are the loads themselves. The monthly load factors for May through September are less than 71%, while they are greater than 77% for the remaining months. With the higher load factors, there were more loads closer to the monthly peak that increased the risk and thus required greater reserves to maintain a given level of LOLE.

Maintaining Operating Reserves

The Base Case and all of the sensitivity cases assumed that a loss-of-load event would occur when there was insufficient resources, including assistance from other areas, to meet the load. If you wished to plan the system such that you maintained a level of operating reserves equal to some percentage of the load, then the PRM would increase by the same percentage.

ADDITIONAL SENSITIVITY CASES

The purpose of the initial sensitivity cases was to identify data and other study assumptions to which the CAISO PRM would be most sensitive. When the results were reviewed at the workshop in October, the load scalars used for modeling load forecast uncertainty and the modeling of the energy limits on the hydro units were identified as two areas that warranted further investigation. This section discusses the results of the additional sensitivity cases run dealing with these assumptions.

Load Scalars for Load Forecast Uncertainty

To model the uncertainty associated with the peak load projections through time, MARS computes the reliability indices at multiple levels of assumed monthly peak loads. It then calculates a weighted-average value for each index based on the probabilities corresponding to the load levels. For this study, the peak loads for the 1-in-2, 1-in-5, 1-in-10, and 1-in-20 load forecasts were used.

For the Base Case and initial sensitivity cases, a single scalar that applied for the entire year was assumed for each of the three study areas. For the first set of additional sensitivity cases, the scalars were specified on a monthly basis. The annual and monthly scalars for the forecasts for the three areas are shown in Figure 25, Figure 26, and Figure 27. The uncertainty was greatest during the shoulder months of May and October in Northern California and June and September in Southern California. In most cases, the monthly scalars were somewhat higher during the summer months than the constant annual values that were originally assumed.

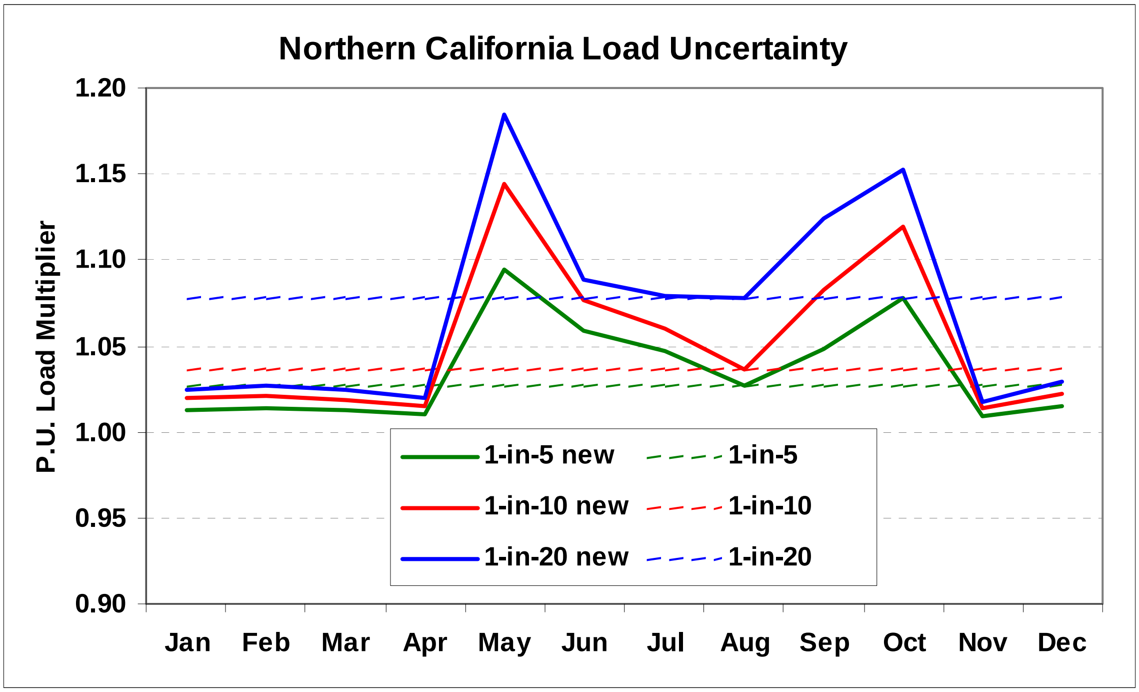

Figure 25 - Load Scalars for Northern California Area

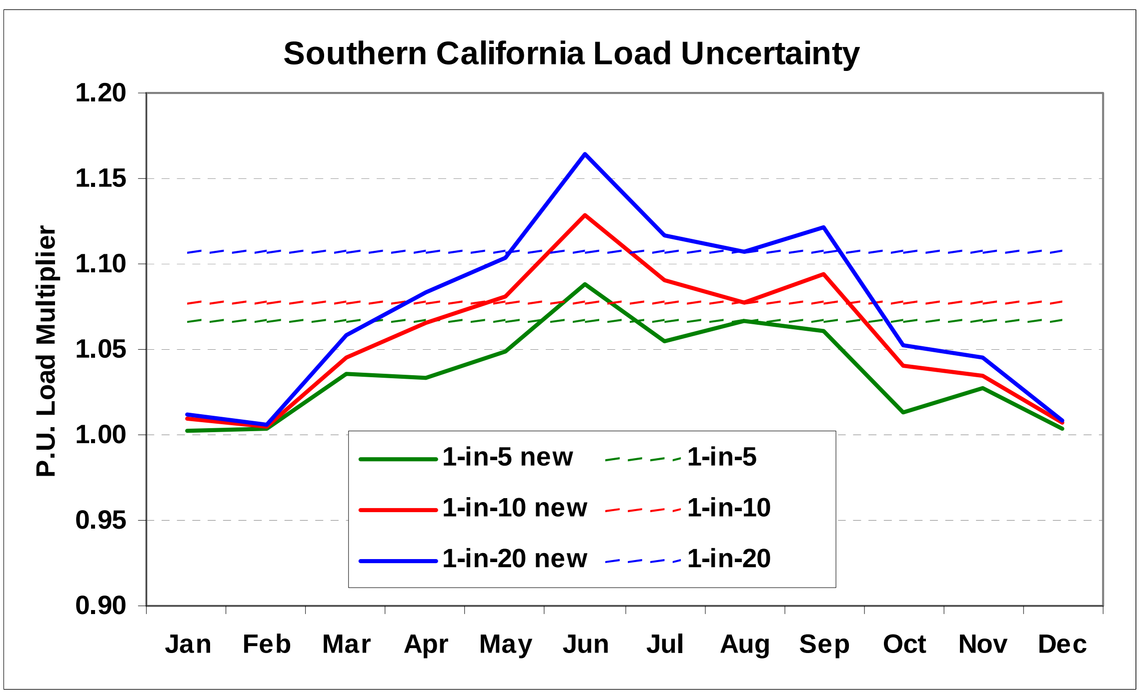

Figure 26 - Load Scalars for Southern California Area

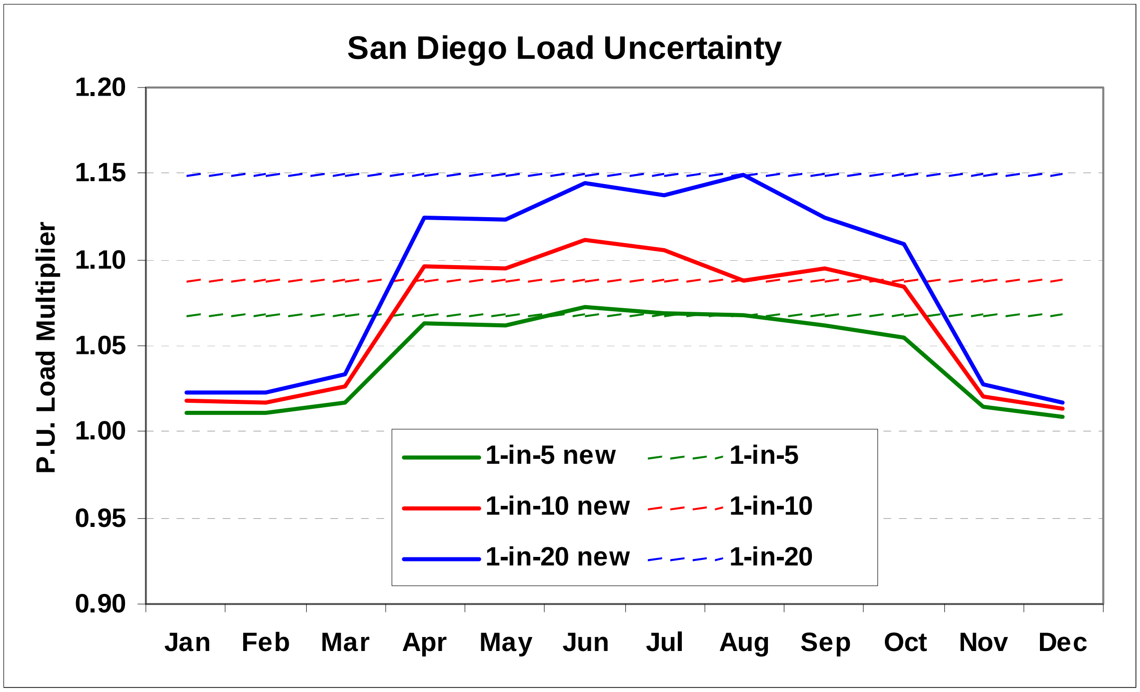

Figure 27 - Load Scalars for San Diego Area

The impact on the PRM of the monthly load scalars is shown in Figure 28. The three colors represent the three assumptions as to how the reserve margins are calculated: on a monthly basis, annual basis, or constant monthly MW of reserves based on the reserves at the time of the annual peak. The solid lines plot the daily LOLE versus reserve margin assuming the monthly load scalars. The dotted lines are the results previously seen based on constant annual load scalars.

As we had seen in the previous results, all of the risk occurred in the peak month when using annual reserve margins. For Northern California, the new scalars for September were significantly greater than the previous values; they were somewhat higher for the other two areas. As a result, the risk with the monthly scalars was always greater than in the previous cases, resulting in an increase in the PRM from 19.4% to 21.6% with annual reserves.

With the monthly and constant MW reserves, the risk occurred in all of the months. At the lower reserve margins, the risk was present for even the 1-in-2 forecast, so the change in scalars for the other forecast levels had no impact; if an outage occurred at the 1-in-2 load level, it would also have occurred at the other three load levels. As the reserve margins were increased up to a point, the risk was actually better with the monthly scalars. As the reserves continued to increase, though, the curves eventually cross, resulting in an increase in the PRM from 28.8% to 30.0% with monthly reserves, and from 20.4% to 22.1% with constant MW reserves.

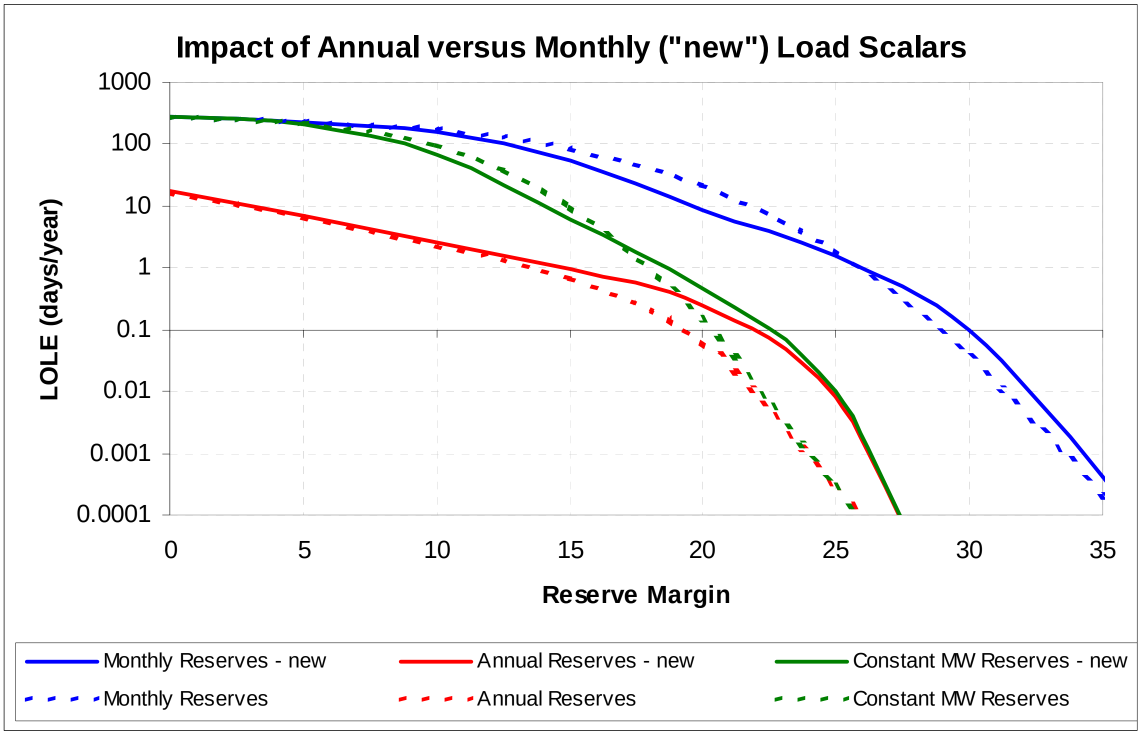

Figure 28 - Impact on PRM of Monthly Load Scalars

The LOLE with annual and monthly scalars for the 20% reserve case are shown in Table 8. At this level of reserves, the reliability of the system was better with the monthly scalars when using a monthly reserve calculation, while it was worse with the annual and constant MW reserves.

Table 8 - Annual LOLE (days/year) at 20% Reserve Margin

	Annual Scalars	Monthly Scalars
Monthly Reserves	21.099	8.744
Annual Reserves	0.065	0.247
Constant MW Reserves	0.154	0.461

The monthly risk for CAISO with 20% reserves is shown in Figure 29. The solid lines are for the cases with the monthly load scalars, while the dotted lines are the results, previously shown in Figure 20, with the annual scalars. For the annual reserves, the risk was slightly higher in September due to the increase in the September scalars. For the monthly and constant MW reserves, the risk in the summer months increased while the risk in the remaining months was reduced or eliminated, consistent with the change in the monthly scalars relative to the previous constant scalars.

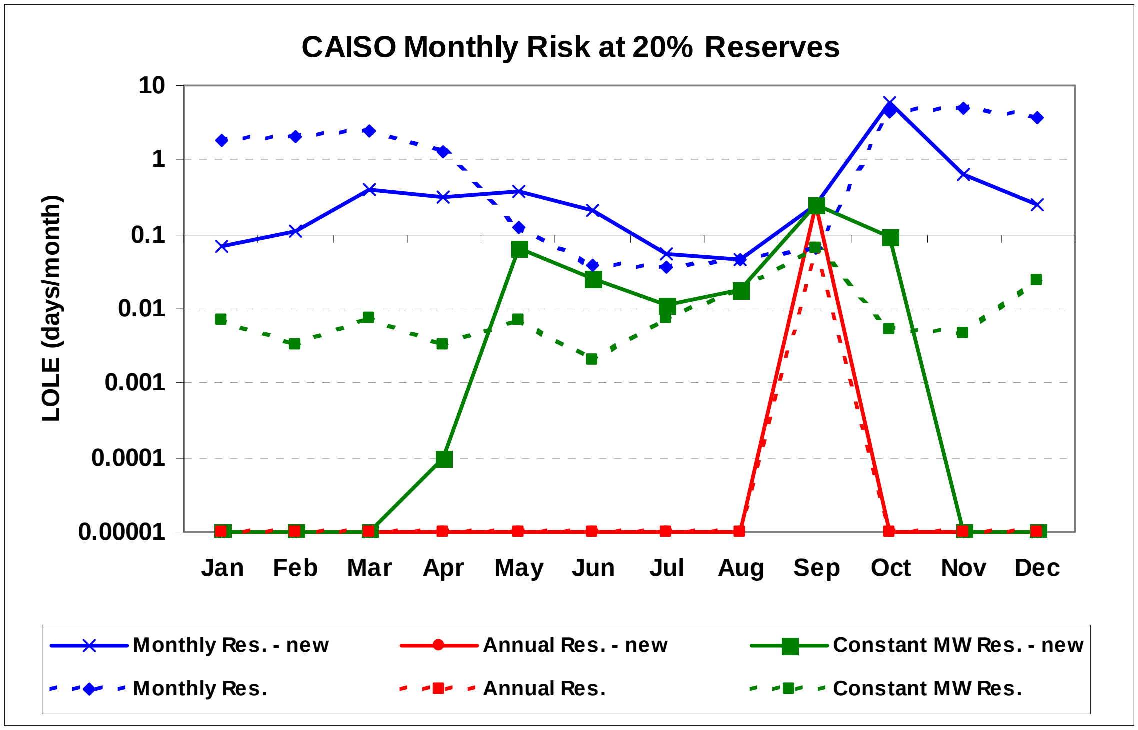

Figure 29 - CAISO Monthly Risk at 20% Reserves

The monthly risk for the three areas with 20% monthly reserve margins are shown in Figure 30 for the original case with annual scalars, and Figure 31 for the case with monthly scalars. With the annual scalars, the CAISO risk was mainly set by the Southern California and San Diego areas, except for October and November when Northern California was the main driver.

With the monthly scalars, there was more variation from month to month, with the Northern California area driving the CAISO risk in May and September through November, consistent the relationship of the area monthly scalars with the annual scalars: the monthly scalars for May, September, and October for Northern California were much higher than the annual scalar, while the November values for the other two areas were much lower than their annual scalars.

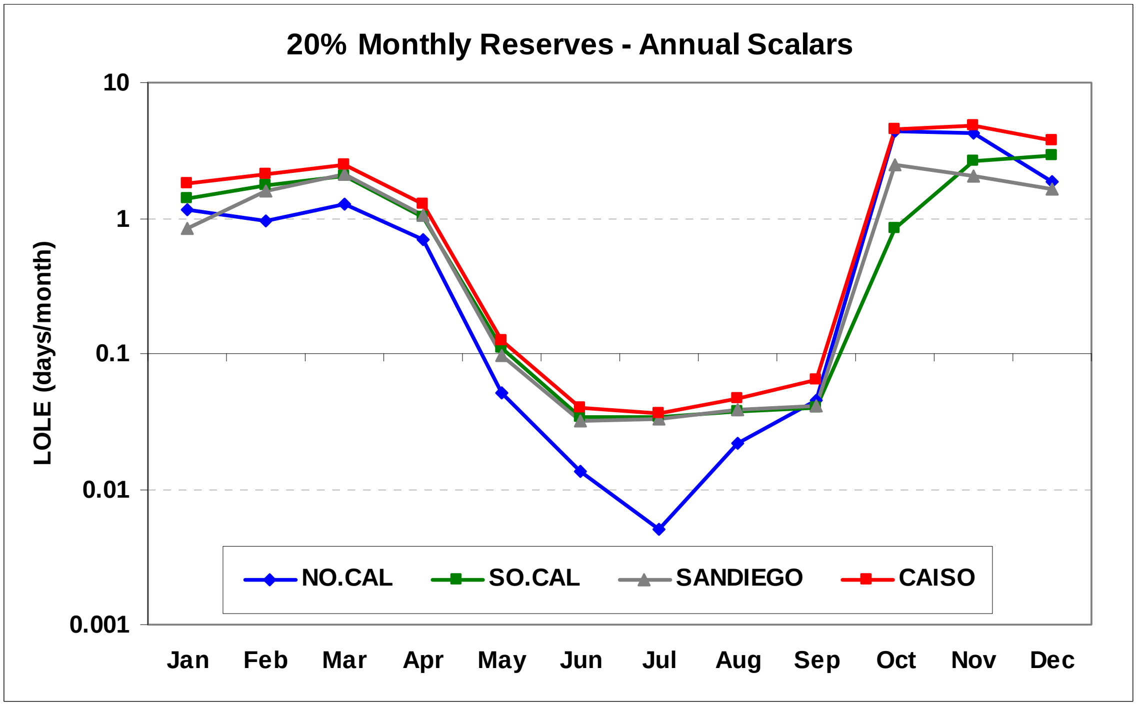

Figure 30 - Monthly Area Risk for 20% Monthly Reserves with Annual Scalars

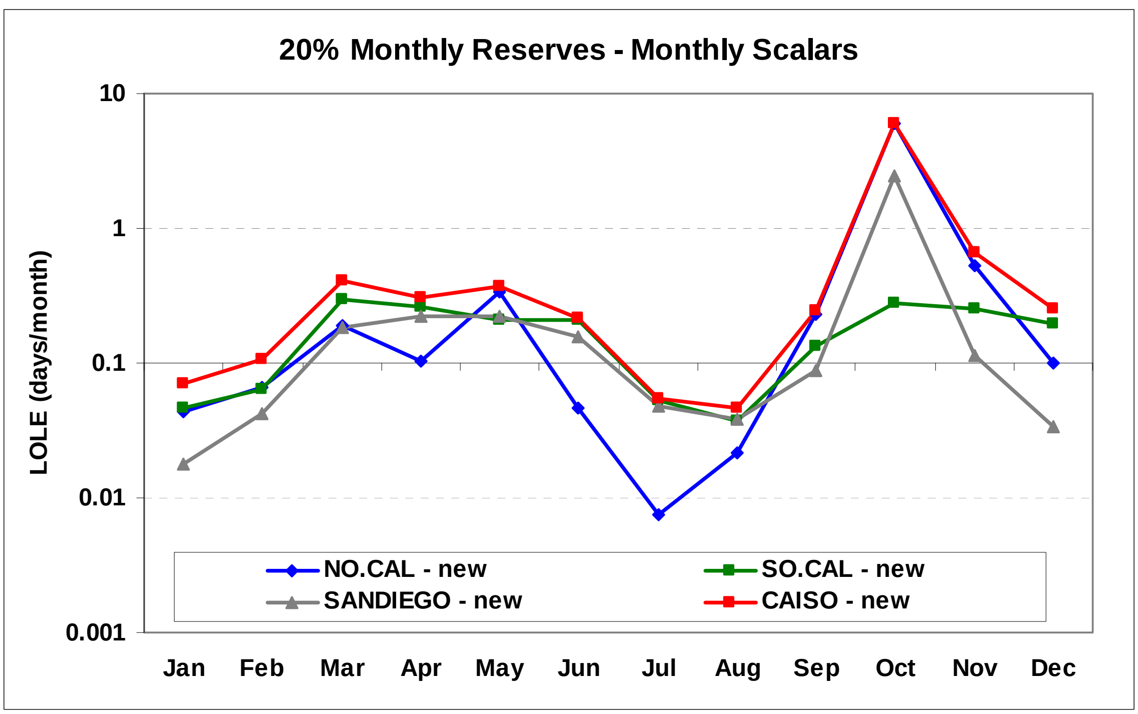

Figure 31 - Monthly Area Risk for 20% Monthly Reserves with Monthly Scalars

Energy Limits on Hydro Units

In MARS, each hydro unit is specified in terms of a minimum rating, maximum rating, and monthly available energy. The minimum rating, which would represent the run-of-river portion of the unit, is scheduled for all of the hours in the month. The remaining capacity and energy are then scheduled as needed to meet load that cannot be met by other resources in the area or by assistance from other areas. An option within the program allows energy that was not used in one month to be carried forward to subsequent months, up to a specified limit.

Starting from the case with the monthly load scalars for load forecast uncertainty, several sensitivities were run in which the modeling of the energy limits was varied. In the first case, the monthly limits were modeled without carryforward, which is how the energy limits have been modeled in previous simulations. To bracket the impact of the energy limits, the next case assumed no energy limits at all. The third case assumed that all of the energy for the quarter would be available at the start of the quarter, with unused energy carried forward within the quarter. The final case went back to the monthly limits, but allowed carryforward limited to the available energy for the month. This would prevent unused energy from early in the year from being accumulated for use later in the year. In all of these cases, the reserve margins were computed on a monthly basis. The LOLE for these cases are shown in Figure 32.

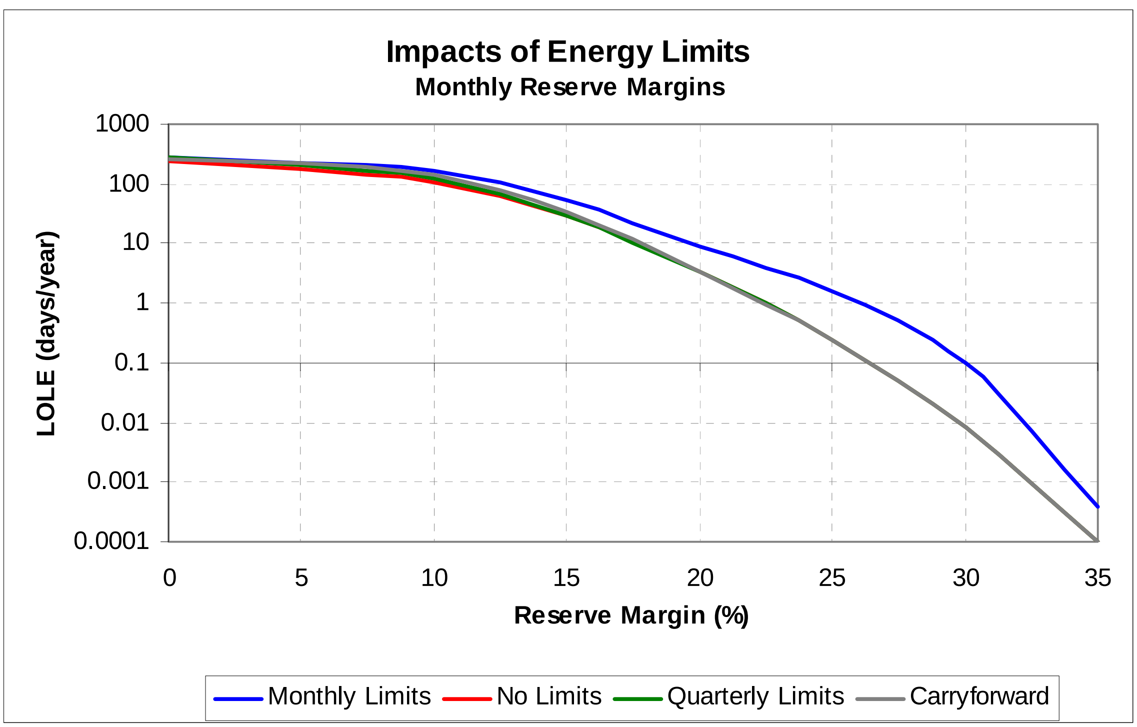

Figure 32 - Impact of Energy Limits on PRM

With the monthly limits and no carryforward, the PRM was 30%. For the other three cases, there was a very slight difference in risk at the lower reserve margins but above 20% monthly reserves, the risk was nearly identical, resulting in a PRM of 26.4%.

Though not shown here, the carryforward of hydro energy had a negligible impact on the annual PRM

To better understand the impact of the energy limits, Figure 33 shows the monthly LOLE by area for the 25% monthly reserve margin case. Comparing the case with monthly limits and no carryforward with the case with unlimited energy, nearly all of the change occurred in October, with little if any change in the other months. Since the results in Figure 32 showed that monthly limits with carryforward produced nearly the same results as no energy limits at all, it appears that the timing of the availability of the energy, rather than the amount available, resulted in the increase in risk in October. Being able to carry the unused energy from September into October was sufficient to cover most of the shortages in October.

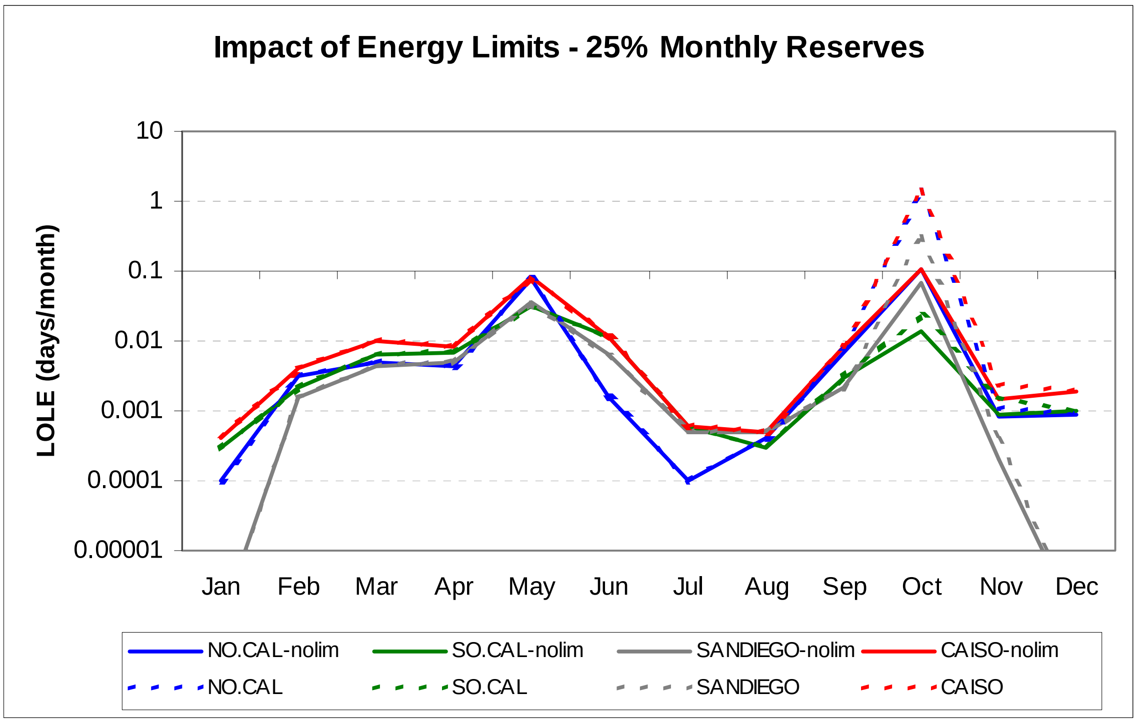

Figure 33 - Impact of Energy Limits on Monthly Risk – 25% Monthly Reserves

For the three cases with energy limits, the amount of energy available, after accounting for that used for the run-of-river, was 25,909,620 MWh for the year. The amount actually used during the year and the resulting PRM are shown in Table 9.

Table 9 - Hydro Energy Usage – 25% Monthly Reserve

Case	MWh Used	PRM (%)
Monthly Limits	4,040,568	30.00
Monthly Limits with Carryforward	4,088,252	26.42
Quarterly Limits with Carryforward	4,087,949	26.40
No Limits	4,092,071	26.40

With the monthly limits, allowing the unused monthly energy to be carried forward increased the energy available in October, reducing the PRM to 26.42%. Although the annual hydro energy usage was slightly less when the limits were specified quarterly, October had more energy available (with the energy from November and December as opposed to just the carryforward from September), slightly reducing the PRM further. Removing all of the energy limits increased the annual usage but had no further impact on the PRM. For the extreme of going from monthly limits with no carryforward to no energy limits at all, the annual hydro energy usage increased by 51,503 MWh, or 1.3%.

Figure 34 shows the expected number of outages by hour of the day and by month for the four different load forecasts modeled for the case with 25% monthly reserves, monthly load scalars, and monthly energy limits with carryforward. (Note that the plots use different scales.) In Figure 35, the results of the four load forecasts have been combined with their corresponding probabilities of occurrence.

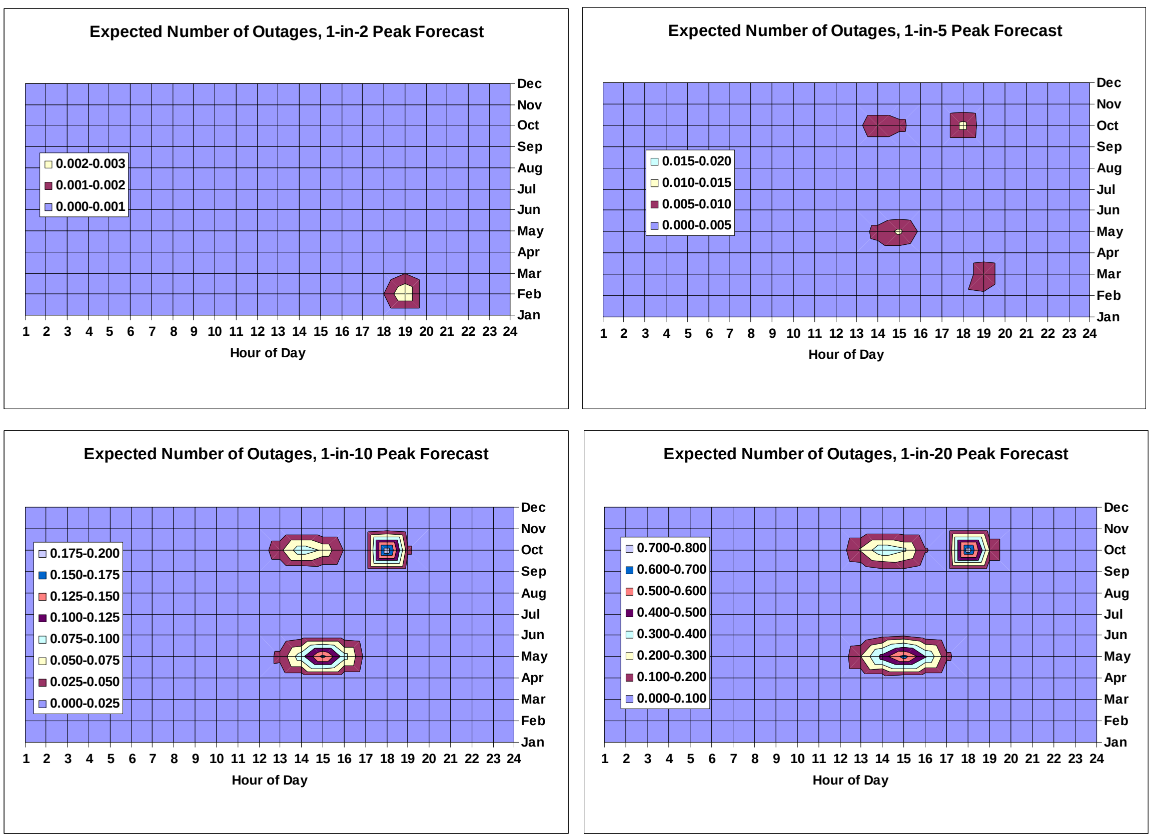

Figure 34 - Expected Hourly Results for Individual Load Forecasts

The two periods of outage during the day in October are consistent with the daily load shapes for that month. During the week of the monthly peak (Figure 36), the loads peak early in the afternoon, drop off somewhat, and then peak sharply during the early evening.

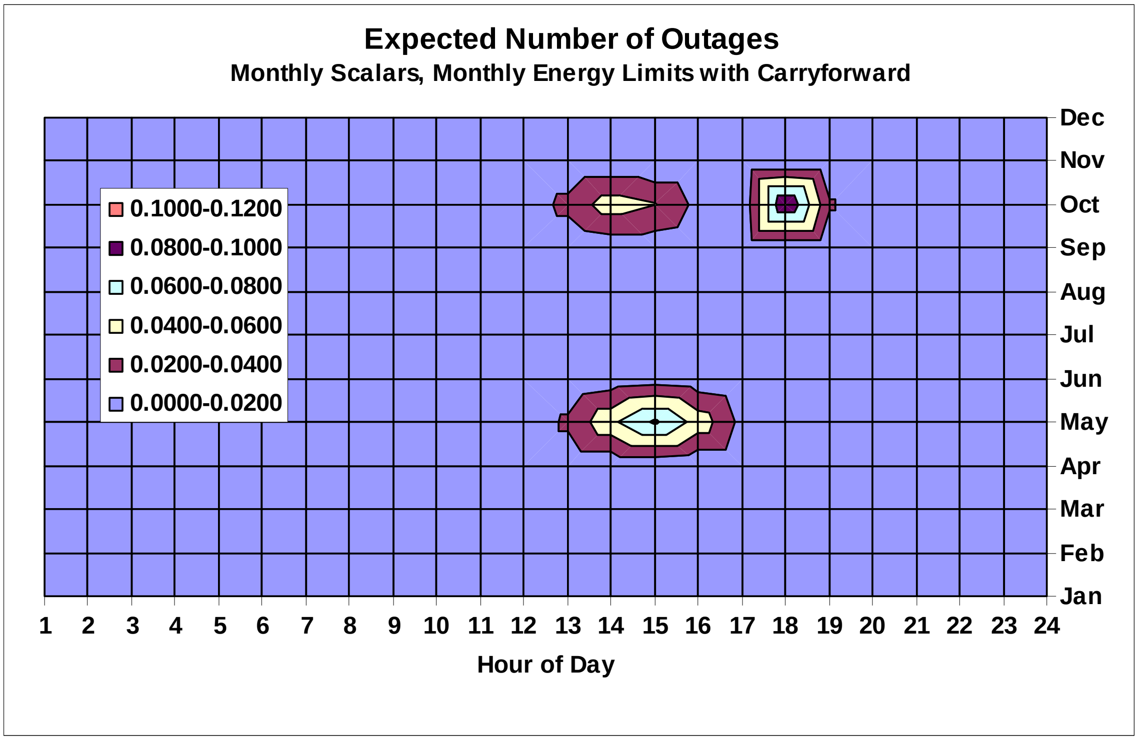

Figure 35 - Expected Hourly Results for All Load Forecasts

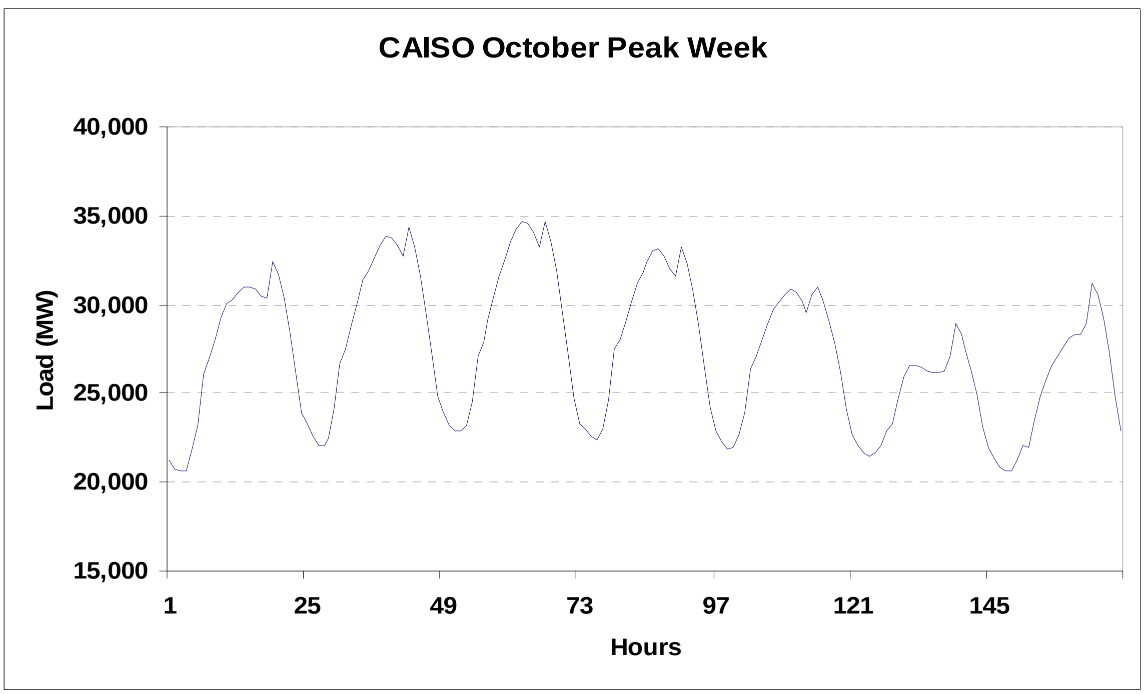

Figure 36 - CAISO Hourly Loads for Peak Week in October

REVISED BASE CASE

Using the knowledge gained from the original Base Case and all of the sensitivity cases, a Revised Base Case was developed to more closely model the way in which the CAISO system is operated.

The original Base Case did not include any reliability benefit from non-firm emergency assistance that could be provided by neighboring systems. In fact, one of the original sensitivity cases showed that assuming imports equal to the transfer limits of the ties into CAISO could eliminate all of the in-state reserve requirements.

Also not included in the original Base Case were the generators owned by or contracted to CAISO members but located out-of-state and the impact of demand response programs. Unlike the non-firm emergency assistance, which affects the reliability but not the reserve margin, the out-of-state generation and demand response would affect both the reliability and reserve margins.

The Revised Base Case included the monthly load scalars and carryforward of unused hydro energy that were described in the discussion on the additional sensitivity cases. It also included the out-of-state generation and demand response shown in Table 1 through Table 3, which were included in the reserve margin calculations. Also included in the Revised Base Case were the non-firm emergency imports shown in Table 10, which provided reliability benefit but were not included in the reserve margins. These were not included. Total imports into CAISO were equal to 9,500 MW, which is approximately two-thirds of the total import capability into CAISO.

Table 10 - Imports Modeled in the Revised Base Case (MW)

	Out-of-State Generation Included in the Reserve Margins	Non-Firm Emergency Assistance Not Included in the Reserve Margins	Total Imports
Northern California	0	1,000	1,000
Southern California	1,488	4,712	6,200
San Diego	702	1,598	2,300
CAISO	2,190	7,310	9,500

The Revised Base Case was simulated over a range of monthly and annual reserve margins. The resulting daily LOLE for CAISO are shown in Figure 37. Also shown are with the dotted lines are the correspond results from the cases without the demand response or imports.

For the Revised Base Case, the PRM was 13.4% with monthly reserves, and 9.2% with annual. Without the demand response and imports, the PRM was 26.4% monthly and 21.5% annual.

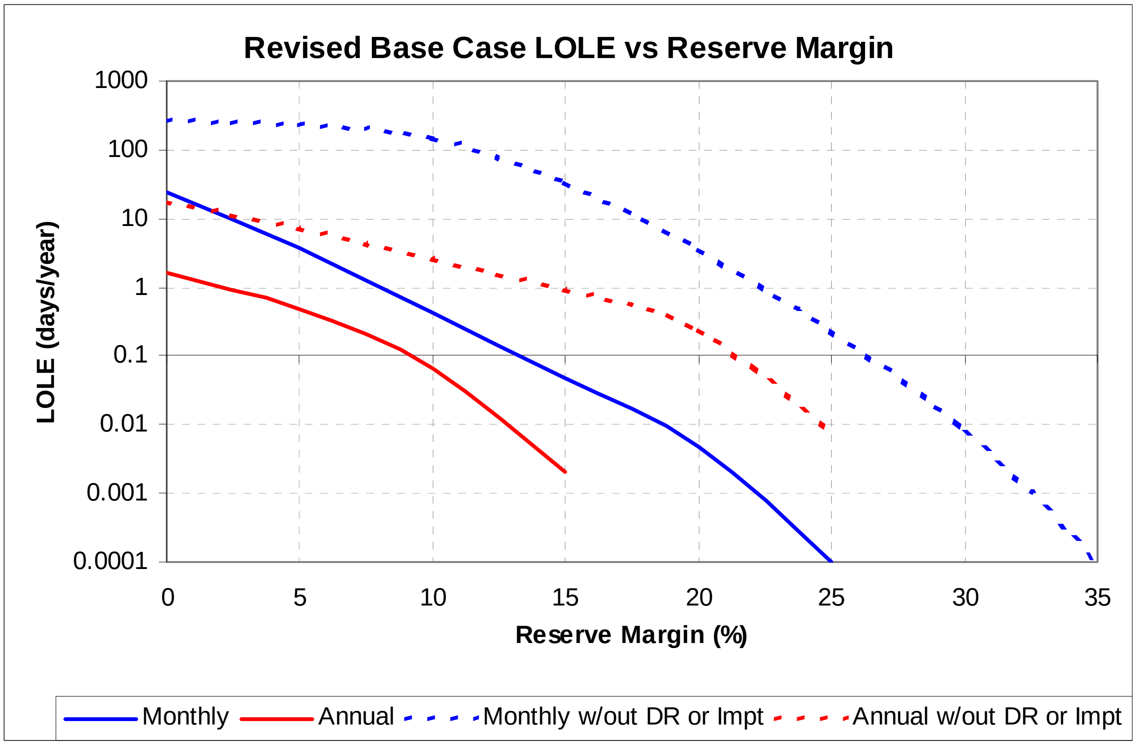

Figure 37 - Revised Base Case Results

In the Revised Base Case, the demand response was included in the reserve margins calculations at its monthly or annual maximum value. However, for the reliability calculations, it was worth somewhat less since there were limits on the number of hours per month that the different programs could be implemented.

When using annual reserve margins, the reliability benefit of the imports not included in the reserve margin would decrease the PRM by the percentage of annual peak load that they represent, in this case slightly more than 14%. Including demand response and imports decreased the annual PRM by 12.3%, slightly less than the 14% due to the greater impact that demand response has on reserve margins than reliability.

For the monthly reserve margins, the impact of demand response and import was slightly more at 13.0%, due to the fact that imports that are equivalent to 14% at time of peak are worth slightly more during the off-peak months.

The monthly risk for CAISO at 10% reserve margins is shown in Figure 38. With the annual reserves, most of the risk occurs in the peak month of September, with a small amount occurring in July. With the monthly reserve margins, most of the risk occurs in May and October, with less amounts occurring in all but the winter months. As would be expected, the risk in September is the same in both cases.

In July, the risk is slightly higher with the annual reserves than with the monthly reserves. All of the July risk in the monthly case occurs in the Northern California area. The capacity adjustment that is used to model a given level of installed reserves is based on the coincident peak loads in the areas. In Northern California, the coincident peak load in July is almost 800 MW more than in September, resulting in a smaller capacity adjustment for July in the monthly reserve case. This gives rise to the slightly improvement in the Northern California, and thus CAISO, risk.

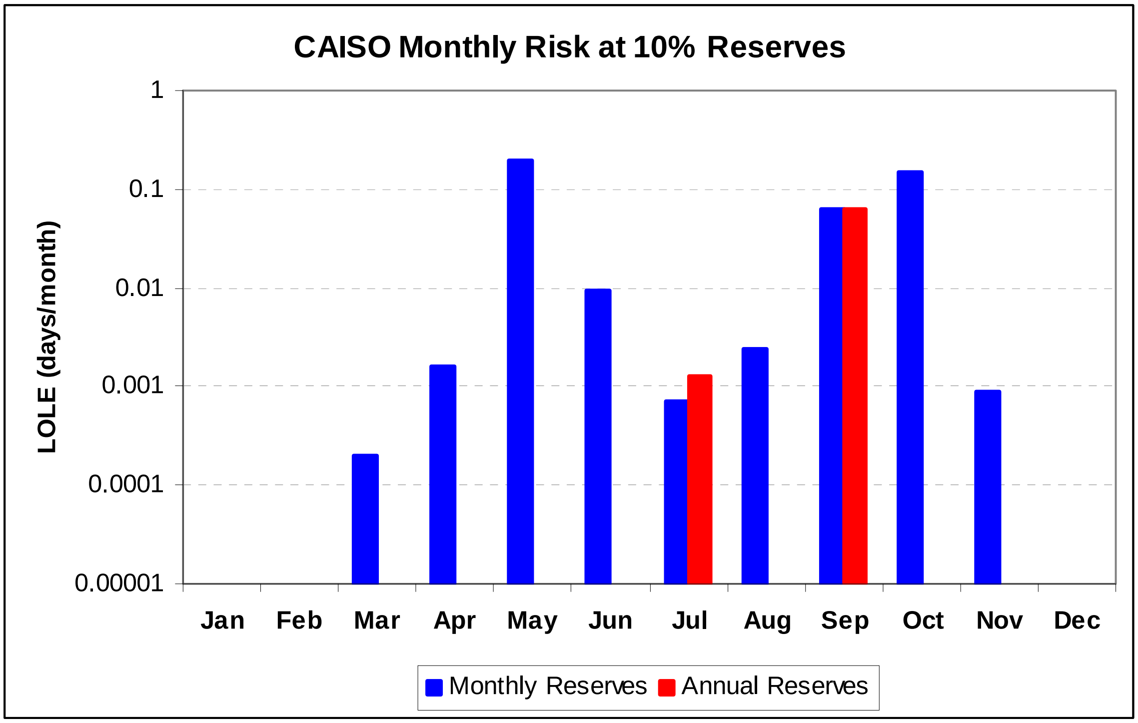

Figure 38 - CASIO Monthly Risk at "10% Reserves"

5 Conclusions

The primary objective of the Phase 1A Preliminary Study was to highlight the system data and other study assumptions to which the CAISO PRM would be most sensitive. Analysis of the original Base Case and initial sensitivity cases indicated that the basic assumptions related to the way in which the reserve margins were calculated and the amount of reliability credit given to imports could have a greater impact on PRM than other assumptions related to unit characteristics and interface transfer limits.

When the results were reviewed at the workshop in October, the load scalars used for modeling load forecast uncertainty and the modeling of the energy limits on the hydro units were identified as two areas that warranted further investigation.

Using the knowledge gained from the original Base Case and all of the sensitivity cases, a Revised Base Case was developed to more closely model the way in which the CAISO system is operated. The case showed the reserves required to maintain the system at a daily LOLE of 0.1 days/year to be 13.4% on a monthly basis, and 9.2% on an annual basis, assuming imports not included in the reserve margins equal to about 14% of the annual peak load.

Appendix A – MARS Program Description

The Multi-Area Reliability Simulation software program (MARS) enables the electric utility planner to quickly and accurately assess the reliability of a generation system comprised of any number of interconnected areas.

MARS MODELING TECHNIQUE

A sequential Monte Carlo simulation forms the basis for MARS. The Monte Carlo method provides a fast, versatile, and easily-expandable program that can be used to fully model many different types of generation and demand-side options.

In the sequential Monte Carlo simulation, chronological system histories are developed by combining randomly-generated operating histories of the generating units with the inter-area transfer limits and the hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules and policies which govern system operation, without the simplifying or idealizing assumptions often required in analytical methods.

RELIABILITY INDICES AVAILABLE FROM MARS

The following reliability indices are available on both an isolated (zero ties between areas) and interconnected (using the input tie ratings between areas) basis:

- Daily LOLE (days/year)
- Hourly LOLE (hours/year)
- LOEE (MWh/year)
- Frequency of outage (outages/year)
- Duration of outage (hours/outage)
- Need for initiating emergency operating procedures (days/year)

The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for all of the reliability indices. These values can be calculated both with and without load forecast uncertainty.

DESCRIPTION OF PROGRAM MODELS

Loads

The loads in MARS are modeled on an hourly, chronological basis for each area being studied. The program has the option to modify the input hourly loads through time to meet specified annual or monthly peaks and energies. Uncertainty on the annual peak load forecast can also be modeled, and can vary by area on a monthly basis.

GENERATION

MARS has the capability to model the following different types of resources:

- Thermal
- Energy-limited
- Cogeneration
- Energy-storage
- Demand-side management

An energy-limited unit can be modeled stochastically as a thermal unit with an energy probability distribution (Type 1 energy-limited unit), or deterministically as a load modifier (Type 2 energy-limited unit). Cogeneration units are modeled as thermal units with an associated hourly load demand. Energy-storage and demand-side management are modeled as load modifiers.

For each unit modeled, the user specifies the installation and retirement dates and planned maintenance requirements. Other data such as maximum rating, available capacity states, state transition rates, and net modification of the hourly loads are input depending on the unit type.

The planned outages for all types of units in MARS can be specified by the user or automatically scheduled by the program on a weekly basis. The program schedules planned maintenance to levelize reserves on either an area, pool, or system basis. MARS also has the option of reading a maintenance schedule developed by a previous run and modifying it as specified by the user through any of the maintenance input data. This schedule can then be saved for use by subsequent runs.

Thermal Units. In addition to the data described previously, thermal units (including Type 1 energy-limited units and cogeneration) require data describing the available capacity states in which the unit can operate. This is input by specifying the maximum rating of each unit and the rating of each capacity state as a per unit of the unit's maximum rating. A maximum of eleven capacity states are allowed for each unit, representing decreasing amounts of available capacity as a result of the outages of various unit components.

Because MARS is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time, and can be used if you assume that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in a given hour is dependent on its state in previous hours and influences its state in future hours. It thus requires the additional information that is contained in the transition rate data.

For each unit, a transition rate matrix is input that shows the transition rates to go from each capacity state to each other capacity state. The transition rate from state A to state B is defined as the number of transitions from A to B per unit of time in state A:

$$\text{TR (A to B)} = \frac{\text{Number of Transitions from A to B}}{\text{Total Time in State A}}$$

If detailed transition rate data for the units is not available, MARS can approximate the transitions rates from the partial forced outage rates and an assumed number of transitions between pairs of capacity states. Transition rates calculated in this manner will give accurate results for LOLE and LOEE, but it is important to remember that the assumed number of transitions between states will have an impact on the time-correlated indices such as frequency and duration.

Energy-Limited Units. Type 1 energy-limited units are modeled as thermal units whose capacity is limited on a random basis for reasons other than the forced outages on the unit. This unit type can be used to model a thermal unit whose operation may be restricted due to the unavailability of fuel, or a hydro unit with limited water availability. It can also be used to model technologies such as wind or solar; the capacity may be available but the energy output is limited by weather conditions.

Type 2 energy-limited units are modeled as deterministic load modifiers. They are typically used to model conventional hydro units for which the available water is assumed to be known with little or no uncertainty. This type can also be used to model certain types of contracts. A Type 2 energy-limited unit is described by specifying a maximum rating, a minimum rating, and a monthly available energy. This data can be changed on a monthly basis. The unit is scheduled on a monthly basis with the unit's minimum rating dispatched for all of the hours in the month. The remaining capacity and energy can be scheduled in one of two ways. In the first method, it is scheduled deterministically so as to reduce the peak loads as much as possible. In the second approach, the peak-shaving portion of the unit is scheduled only in those hours in which the available thermal capacity is not sufficient to meet the load; if there is sufficient thermal capacity, the energy of the Type 2 energy-limited units will be saved for use in some future hour when it is needed.

Cogeneration. MARS models cogeneration as a thermal unit with an associated load demand. The difference between the unit's available capacity and its load requirements represents the amount of capacity that the unit can contribute to the system. The load demand is input by specifying the hourly loads for a typical week (168 hourly loads for Monday through Sunday). This load profile can be changed on a monthly basis. Two types of cogeneration are modeled in the program, the difference being whether or not the system provides back-up generation when the unit is unable to meet its native load demand.

Energy-Storage and DSM. Energy-storage units and demand-side management are both modeled as deterministic load modifiers. For each such unit, the user specifies a net hourly load modification for a typical week, which is subtracted from the hourly loads for the unit's area.

TRANSMISSION SYSTEM

The transmission system between interconnected areas is modeled through transfer limits on the interfaces between pairs of areas. Simultaneous transfer limits can also be modeled in which the total flow on user-defined groups of interfaces is limited. Random forced outages on the interfaces are modeled in the same manner as the outages on thermal units, through the use of state transition rates.

The transfer limits are specified for each direction of the interface or interface group and can be input on a monthly basis. The transfer limits can also vary hourly according to the availability of specified units and the value of area loads.

CONTRACTS

Contracts are used to model scheduled interchanges of capacity between areas in the system. These interchanges are separate from those that are scheduled by the program as one area with excess capacity in a given hour provides emergency assistance to a deficient area.

Each contract can be identified as either firm or curtailable. Firm contracts will be scheduled regardless of whether or not the sending area has sufficient resources on an isolated basis, but they can be curtailed because of interface transfer limits. Curtailable contracts will be scheduled only to the extent that the sending area has the necessary resources on its own or can obtain them as emergency assistance from other areas.

EMERGENCY OPERATING PROCEDURES

Emergency operating procedures are steps undertaken by a utility system as the reserve conditions on the system approach critical levels. They consist of load control and generation supplements, which can be implemented before load has to be actually disconnected. Load control measures could include disconnecting interruptible loads, public appeals to reduce demand, and voltage reductions. Generation supplements could include overloading units, emergency purchases, and reduced operating reserves.

The need for a utility to begin emergency operating procedures is modeled in MARS by evaluating the daily LOLE at specified margin states. The user specifies these margin states for each area in terms of the benefits realized from each emergency measure, which can be expressed in MW, as a per unit of the original or modified load, and as a per unit of the available capacity for the hour.

The user can also specify monthly limits on the number of times that each emergency procedure is initiated, and whether each EOP benefits only the area itself, other areas in the same pool, or areas throughout the system. Staggered implementation of EOPs, in which the deficient area must initiate a specified number of EOPs before non-deficient areas begin implementation, can also be modeled.

RESOURCE ALLOCATION AMONG AREAS

The first step in calculating the reliability indices is to compute the area margins on an isolated basis, for each hour. This is done by subtracting from the total available capacity in the area for the hour the load demand for the hour. If an area has a positive or zero margin, then it has sufficient capacity to meet its load. If the area margin is negative, the load exceeds the capacity available to serve it, and the area is in a loss-of-load situation.

If there are any areas that have a negative margin after the isolated area margins have been adjusted for curtailable contracts, the program will attempt to satisfy those deficiencies with capacity from areas that have positive margins. Two methods are available for determining how the reserves from areas with excess capacity are allocated among the areas that are deficient. In the first approach, the user specifies the order in which an area with excess resources provides assistance to areas that are deficient. The second method shares the available excess reserves among the deficient areas in proportion to the size of their shortfalls.

The user can also specify that areas within a pool will have priority over outside areas. In this case, an area must assist all deficient areas within the same pool, regardless of the order of areas in the priority list, before assisting areas outside of the pool. Pool-sharing agreements can also be modeled in which pools provide assistance to other pools according to a specified order.

OUTPUT REPORTS

The following output reports are available from MARS. Most of the summaries of calculated quantities are available for each load forecast uncertainty load level and as a weighted-average based on the input probabilities.

- Summary of the thermal unit data.
- Summary of installed capacity by month by user-defined unit type.
- Summary of load data, showing monthly peaks, energies, and load factors.
- Unit outage summary showing the weeks during the year that each unit was on planned outage.
- Summary of weekly reserves by area, pool, and system.
- Annual, monthly, and weekly reliability indices - by area and pool, isolated and interconnected.
- Expected number of days per year at specified margin states on an annual, monthly, and weekly basis.
- Annual and monthly summaries of the flows, showing for each interface the maximum and average flow for the year, the number of hours at the tie limit, and the number of hours of flow during the year.
- Annual summary of energy and hours of curtailment for each contract.
- Annual summary of energy usage for the peaking portion of Type 2 energy-limited units.
- Replication year output, by area and pool, isolated and interconnected, showing the daily and hourly LOLE and LOEE for each time that the study year was simulated. This information can be used to plot distributions of the indices, which show the year-to-year variation that actually occurs.

- Annual summary of the minimum and maximum values of the replication year indices.
- Detailed hourly output showing, for each hour that any of the areas has a negative margin on an isolated basis, the margin for each area on an isolated and interconnected basis.
- Detailed hourly output showing the flows on each interface.

PROGRAM DIMENSIONS

All of the program dimensions in MARS can be changed at the time of installation to size the program to the system being studied. Among the key parameters that can be changed are the number of units, areas, pool, and interfaces.