Energy Division Proceeding Status Update and PRM Modeling Manual
R.08-04-012

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Energy Division Proceeding Status Update and PRM Modeling Manual (R.08-04-012)

1. Summary

The Commission opened Rulemaking R.08-04-012 on April 10, 2008 to develop greater analytical rigor to the establishment of reserve margins sufficient to protect reliability across the California ISO (CAISO) system. Through working groups, workshops, and staff reports, the proceeding served to inform stakeholders and staff and to enable refinements to a study methodology that focuses on probabilistic methods in use in other states. Energy Division provides this report to reinitiate the proceeding, give status up until this point, and to recommend a set of minimum analytical requirements. These minimum analytical requirements include a proposed set of specific modeling methodologies drawing from the discussion in the working groups and subsequent analysis.

Previous reports and workshops have utilized the CAISO and the CAISO's vendor, General Electric (GE), to provide modeling expertise and to complete analysis via GE's software package called Multi Area Reliability Simulation (MARS). This PRM report builds off of earlier analysis with GE as the vendor, and develops methodologies further aimed towards achieving the Commission's goals of a more analytical method of establishing reserve levels.

The PRM Modeling Manual in Section 4 is divided into five subsections that correspond to Working Groups that helped to develop the methodologies: (1) general scope and policy issues, (2) intermittent generation modeling (wind/solar/cogeneration/hydro resources), (3) load and demand response inputs to MARS simulation, (4) modeling of non-intermittent generation and classification of all generation, and (5) modeling of transmission limitations and imports. These sections deal with the major inputs that were identified in earlier workshops and study reports, and includes proposed methodologies in detail that constitute the recommended minimum analytical requirements. These proposed methodologies represent the analysis of Energy Division and an attempt to specifically outline means of providing adequate analysis to Commission decisionmakers.

Outside of specific methodologies that affect the conduct of the modeling, there are several results of the analysis that have policy implications. Section 5 describes specific items and presents recommendations. These policy implications relate to how the study results are used to establish the PRM, but have limited effect on how the model is actually run. .

Much of the material presented here has been discussed in working groups and workshops, but some new proposals are made with regards to intermittent generation and load forecast uncertainty. The proposed methodologies envision complete analysis for the near term (1 year out), midterm (5 years out) and long term (10 years out) timeframes.

Attached to this report is a summary of working groups, their membership, and a list of meeting dates.

2. Background

The Commission opened Rulemaking R.08-04-012 on April 10, 2008 and Energy Division convened working groups to study the means to increase the analytical rigor used in setting the PRM sufficient to protect reliability across the CAISO system. During April and May of 2008, five working groups were formed to develop recommendations for an initial demonstration of the MARS model (Preliminary 1A), which was to inform the proceeding as to which data inputs are the most critical to the determination of the PRM. Pursuant to workshops held on June 25 and 26, those working groups reconvened with new members to deliver data to the CAISO for the Preliminary 1A run, and to develop recommendations for a set of modeling assumptions and data sources for more advanced study. No new working groups were proposed or developed after the June workshops, and existing groups were not reorganized or redefined; groups 2, 3, and 4 met regularly over the summer, while two working groups in particular (1 and 5) did not meet more than once each. No working group meetings have occurred since October 2008. Listings of working group membership, meeting dates, and brief summary of discussions is included in Appendix 1.

Energy Division published a Draft Energy Division Proposal for PRM Inputs to the service list on October 17, 2008 which framed discussion for the October 22 and 23 2008 workshops to prepare for a final study of PRM levels. The October workshops and subsequent stakeholder conference calls in December and January provided the opportunity to assist Energy Division in developing this PRM Modeling Manual that will inform the PRM proceeding. This Modeling Manual lists Energy Division's set of minimum analytical requirements and proposed set of methodologies that flesh out the minimum analytical requirements so as to provide decision makers with sufficient information to evaluate the appropriate PRM. Energy Division's draft recommendations made for the October workshops as well as other study results and working group proposals were published to the service list and are now posted on the PRM reports page of the CPUC website.[1]

At the October 2008 workshops, stakeholders reviewed the study results and Energy Division's draft recommendations, and requested additional study runs from GE to answer questions at the workshop. Supplemental results were sent to the service list in December 2008, and a subsequent conference call explored these results.

Specifically, this Modeling Manual presents:

- Background information regarding base cases and sensitivities run for Preliminary 1A
- Energy Division's minimum analytical requirements for study of the PRM for the near term, mid-term, and long term study years;
- Methodologies to fulfill the recommended minimum analytical requirements.

[1] http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/PRM_reports_documents.htm

- Detail regarding the study of near term, midterm, and long term study years.

3. SCOPE AND STATUS

The analytical requirements in this report have been developed pursuant to Energy Division's participation in working groups and discussion with staff at other agencies, and represent an attempt to present a complete modeling manual to stakeholders and to the proceeding in order to streamline the conduct of the current study. These recommendations were developed within the constraints and responding to the needs of the current GE MARS modeling approach, which is documented in earlier postings on the PRM page of the CPUC website. With that said, Energy Division does not anticipate that these methodologies would be difficult to adapt to another vendor's Monte Carlo LOLE type model or future versions of GE's MARS model. Additionally, Energy Division will continue to review methodologies and best practices in the event that new advances in the field enable more robust and accurate modeling. The Modeling Manual is organized by type of input, including recommendations to complete analysis in all study years. Energy Division seeks to gauge the effects of the large changes California is making to the electricity system to accommodate such factors as 33% Renewable Portfolio Standard, retirement of Once Through Cooling (OTC) plants, and the greater penetration and functionality of demand side alternatives. The Modeling Manual includes near term (1 year out) recommendations, mid-term (5 year out) recommendations, and long term (10 year out) recommendations; this is to provide analytical support for the RA proceeding and the LTPP proceeding which are to be the main users of the PRM results.

Potential funding sources and funding processes are not discussed in this report, although the general structure of the project requires specific delegation of certain tasks. These tasks are discussed later in this section.

3.1. Minimum Analytical Requirements

The minimum analytical requirements to inform a robust level of PRM:

1. Study of near term, midterm, and long term study years.
2. Study of the penetration of renewable generation at installed capacity levels different enough that study results at different capacity levels can be differentiated and are indicative of projected renewable resource buildouts.
3. Study of CAISO as whole, not just individual service territories.
4. Standardized data delivery drawn from CAISO operations and planning data to the extent possible.
5. Data vetted and validated by Energy Division and stakeholders including generation classification and load shapes, and posting of all non- confidential data on the CPUC website for review by parties.
6. Modeling of load forecast uncertainty without the use of simple scalars by the assembly of "typical" and "extreme" load shapes for all base cases.
7. Commitment to study external areas as "bubbles" consistent with TEPCC database.

8. Study of extra cases to establish reserve levels on a non-annual basis in addition to an annual peak basis.
9. Minimum of two cases that illustrate the reliability affects of the load shapes resulting from future policy developments related to AMI and plug in hybrids. Energy Division recognizes the difficulty in gathering these data inputs.
10. Modeling of hydro and demand response resources in a monthly chart, instead of just totaling their contributions annually.
11. Modeling of intermittent generation (wind, solar, cogeneration) stochastically pursuant to GE Energy's refined and updated stochastic modeling functionality.

Energy Division's proposed modeling methodologies to implement and fulfill the minimum analytical requirements outlined above are discussed in greater detail in Section 4 of this report.

3.2. Cases and Sensitivities – Near Term, Midterm, and Long Term:

Minimum analytical requirements cannot be sufficiently fulfilled without specific description of how the study modeled the inputs and from where the data was compiled. That specific description of methodologies and specification of data sources is provided in this PRM Modeling Manual. Suggestions for data sources include the following: the base case should be constructed assuming the current state of the system, with current generation and loads, modeling the hourly LOLE of meeting annual peak load using the annual methodology. Studies should be done of three future years, near term, Midterm, and long term so as to see the current system, the effects of California's energy policy transformations, and a snapshot of the midpoint in the system's transition. The performance of intermittent (wind, solar, cogeneration) generation should be drawn from recent CAISO settlement data which provides the basis for the MARS model to stochastically insert actual performance history randomly within certain constraints. Load inputs should be drawn from the most recent IEPR forecasts and observed historical load shapes, and four probabilistic load shapes scaled to future peak and energy forecasts, but are assembled from actual data, without uncertainty scalars. Non-intermittent generation should be modeled with NERC California class average EFORd statistics, and generator information and classification is done based on the CAISO Generating Capability List.

Energy Division recommends sensitivities on top of the general base case to test particular factors such as the effect of 33% RPS, policy influenced future load shapes, and removal of once through cooling plants, and to further inform the proceeding as to the effects of a monthly peak reserve margin or a reserve margin that levelizes risk across all months of the year.

3.3. Additional tasks outside of running cases

In addition to running cases, the entity performing the study should be prepared to provide other services including expert witness testimony, compilation and editing of output reporting, and sufficient workshop time to inform the proceeding.

Programming Modifications to the GE MARS program to enable Energy Division Proposed inputs

The entity performing the analysis may need to make specific modifications to their existing program to enable refinement of several key input assumptions that have been highlighted in recent stakeholder discussion. Inclusion of discussion related to these modifications in the various methodology sections enables a broader evaluation of the most effective way to model certain factors.

Data delivery

In areas where data is to be provided by outside parties, data should be provided to the CPUC, which may engage a limited number of stakeholders to error check and format the data into clear and concise inputs. The CPUC intends to post all data inputs received as part of the Preliminary 1A study as well as data specified as being useful for continuing analysis in this proceeding, on the CPUC website.[2]

3.4. MARS Treatment of Multiple Areas

The MARS model was developed to address reliability assessments in which multiple areas exist, but which are closely coupled for any of several reasons. In the original CAISO PRRS proposal, two phases of analysis were suggested: (1) an initial phase with three areas, and (2) a second phase with ten areas. It was generally understood that the three areas corresponded to the three IOUs, and the ten areas corresponded to the CAISO LCR load pockets. As the CAISO stand alone effort morphed into the CPUC PRM effort, the focus has been on an analysis focusing on the three IOU regions. This PRM study is not currently meant to replace the CAISO LCR process, which will continue for 2010 and until further notice.

MARS runs each of the three areas simultaneously, matching resources with loads within each area first, and then drawing upon resources in a second or third area to the extent needed, but constrained in two ways. First, the "surplus" areas must have generating resources available for export; second the transmission path limit between the two areas cannot be exceeded. Thus, it is explicit in the MARS construct that the areas be defined in ways that correspond to inter area transmission limitations. In the implementation chosen for this PRM study, the three transmission access charge (TAC) areas were selected because they are separated by significant transmission limitations. The PG&E TAC area has constraints with the other two areas at Path 26. The SDG&E TAC area has constraints with the SCE TAC area at the South of SONGS path. WECC has accepted the path ratings on these constraints, and these transmission constraints are well documented by WECC studies.

Utilities included within TAC Areas

Two of the three TAC areas include multiple utilities as part of loads and resources. The PG&E TAC Area includes the PG&E service area and participating

[2] http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/PRM_reports_documents.htm

publicly owned utilities (POUs) located in the NP 26 region serviced by the CAISO. Geographically this covers all of Northern California except the SMUD/Western balancing authority and the TID balancing authority, as well as the Pacificorp and Sierra Pacific service areas which are outside the CAISO. The SCE TAC area includes numerous municipal utilities utilizing the SCE bulk transmission system to deliver power to service area point of demarcation for these municipalities. The SDG&E TAC area includes only SDG&E loads and resources. In all cases, the analysis is conducted on a physical basis, so IOU TAC area loads and resources reflect all IOU distribution system customers, whether bundled customers of the IOU, the ESPs in the IOU service territory, or the POUs that are within the CAISO.

In using data defined by TAC area, it is important to recognize that the entities included within the CAISO and the TAC areas have changed through time. For 2006 and 2007 data series, all data are consistent with the current (2008) definitions of these areas. However, going back into 2003-2005, as proposed in later sections of this report, requires a few adjustments to historic data to be consistent with the current CAISO and TAC area definitions. For example, SMUD left the CAISO (and PG&E TAC area) in 2002, but Western did not leave the CAISO until later years. MID and TID left in 2005. Data from the 2003-2005 periods would require consideration of whether the specific data series in question is defined consistently, and if not, making appropriate adjustments. Generally, the data are available to make such adjustments, but preparation of data for use in MARS requires conscious consideration of this potential issue, and timelines to allow the analytic work to be completed.

3.5. Classification of Resources and Dispatch Order of Resources in MARS

The MARS model uses an internal algorithm to forecast the dispatch of certain resources in the order needed to preserve reliability. Many steps are taken to prevent loss of firm load, including dispatch of resources within areas with shortages and areas that share resources. Types of resources are ordered as to their available energy and dispatchability. Resources are generally classified into one of three groups, with the associated information provided so that the MARS model can treat them appropriately. The three classes are summarized below:

Type 1 Dispatchable resources without energy constraints: they are modeled stochastically, and iterations are performed with probabilistic outage rates ascribed to each resource. This category includes most conventional dispatchable resources that are commonly referred to as thermal resources.

Type 2 Energy-limited deterministic load-modifying resources: non dispatchable resources with intermittent capabilities can be modeled deterministically. Hourly production profiles are specified for these resources, including an energy quantity for each hour of the year. This energy amount is deducted from the load amount for each corresponding hour, and directly modify load. This category includes the intermittent resources that are modeled as described in section 4.2 below.

Type 2 Energy limited resources – peak shaving: Users would specify a max capacity and available energy for each resource for each month, season, or year. These

resources are used when other resources are unable to meet load, and are used to avoid outage events. These include demand response and hydro units.

Although there can be adjustments made to this order, in general the MARS model dispatches resources and records data in the following order:

a. Type 2 deterministic load modifiers such as wind, solar, hydro, cogeneration hourly production profiles are deducted from load on a hour by hour basis

b. Type 1 conventional resources are either randomly assigned forced outage based on the rates assigned to the applicable classes of resources or are deemed available; the generation available is totaled and compared to the modified load in each hour produced by Step a.

c. If there is insufficient Type 1 generation in an area to meet load, extra type 1 generation from other Areas is dispatched and transferred to the Area with the outage event, subject to tie line constraints

d. If Type 1 generation from all other Areas is still insufficient to meet load in an Area, Type 2 Peak Shaving resources are "dispatched" subject to capacity limits and until available energy is expended. First hydro in this class is used then demand response is used.

e. If resources still do not satisfy load at this step, an outage event is registered in the affected Area. If at any time in the order above, if load is met, then MARS considers load met and moves on to the next hour.

f. This order is run each of 8760 hours of the year chronologically.

g. The year is begun again for additional iterations until the model converges within an acceptable confidence interval and all iterations are totaled and averaged to create an expected total of outage events per year.

h. Summary information is gathered and reported as required

3.6. Preliminary 1A Inputs and Sensitivities

To provide parties with an understanding of the impact of various input elements on the PRM Study results and note differences between this Modeling Manual and the Preliminary 1A study, Table 2 below describes in general detail the base case and sensitivity assumptions built into the Preliminary 1A results. During the October 2008 workshops, the stakeholder group reviewed the initial results of the Preliminary 1A Study and sensitivities run by GE. Additional cases were run subsequently to provide additional information and the results were presented to stakeholders. This manual proposes significant modifications to the Preliminary 1A methodologies and proposes additional sensitivities to inform Energy Division and the Commission.

Table 1 Preliminary 1A Study Base Case and Sensitivity Cases

	Sensitivity	Base Case assumption	Sensitivity assumption	GE analysis and expected output reporting
1	**Scheduled outages**	All planned maintenance outages optimized for each area at off peak months, none during summer	Plant specific planned outage schedules from 2007 for each unit	Input to the model the unit-specific planned outage schedule provided by CAISO and run the model over a range of reserve margins to determine the PRM for this sensitivity. The new maintenance schedule will be summarized on a chart. The reliability impact will be shown on a chart, from which the PRM will be determined. It will also show how the CAISO risk would have changed if the PRM had been held constant at the Base Case value.
2	**Generator performance**	EFORd based on national class average as specified by WG4	Class average EFORd increased by 25%	Increase the EFORd of each unit by 25% and run the model over a range of reserve margins to determine the PRM for this sensitivity. The reliability impact will be shown on a chart, from which the PRM will be determined. It will also show how the CAISO risk would have changed if the PRM had been held constant at the Base Case value.
3	**Imports**	Historical imports at peak as requested by WG5	Maximum simultaneous path ratings of import lines, factoring transmission allocations to the IOUs	Two results were provided, one that modeled imports into each area as being equal to the sum of the maximum path rating limits of the interfaces from outside the CAISO and one corresponding to the recommendation of WG5 which used historical flows in the reserve margin calculations. The reliability impact will be shown on a chart, from which the PRM will be determined. It will also show how the CAISO risk would have changed if the PRM had been held constant at the Base Case value.
4	**Typical and extreme load profile**	2007 load/intermittent pairing for typical year	2006 load/intermittent paring for extreme load year	Using the load and intermittent data for 2006 and 2007, run the model over a range of reserve margins to determine the PRM for this sensitivity. The reliability impact will be shown on a chart, from which the PRM will be determined. It will also show how the CAISO risk would have changed if the PRM had been held

				constant at the Base Case value.
5	**Hydro production**	Available energy from EIA docs 1994-2005	Available energy EIA data from 1992	Using the drought hydro conditions as contained in the EIA data from 1992, run the model over a range of reserve margins to determine the PRM for this sensitivity. A chart will be used to summarize the data. The reliability impact will be shown on a chart, from which the PRM will be determined. It will also show how the CAISO risk would have changed if the PRM had been held constant at the Base Case value.
6	**Variation in LOLE level**	Installed Capacity for LOLE of 0.1 days/year for CAISO	Installed Capacity for LOLE of 0.2 and 0.05 days per year for CAISO	The PRM associated with a CAISO LOLE of 0.2 days/year and 0.05 days/year can be readily determined from the Base Case results reported by GE.
7	**Variation in Trigger for Loss of Load Event**	Loss of load event is triggered when available resources fall below load.	Loss of load event is triggered when load rises above 97% of available resources	The Base Case assumes that the loss of load begins when the load is greater than the available resources. If you wish to maintain a level of operating reserves equal to a percentage of the load, then the PRM would increase by the same percentage.
8	**Month Specific LOLE or annual LOLE**	PRM required for LOLE of 0.1 days/year across CAISO	PRM required for LOLE of 0.1/12 days/month across CAISO	From the Base Case results, the LOLE for each month will be plotted as a function of reserve margin. From these plots, the monthly reserve margin required for a monthly LOLE of 0.0083 days/month will be determined.
9	**Path 26 + 1000 MW**	3,750 MW N-S, 2,902 MW S-N	3,750 MW N-S, 3,902 MW S-N	Increase the S-N rating of Path 26 by 1,000 MW and run the model over a range of reserve margins to determine the PRM for this sensitivity. The reliability impact will be shown on a chart, from which the PRM will be determined. It will also show how the CAISO risk would have changed if the PRM had been held constant at the Base Case value.

10	**CAISO vs. Area PRM**	Single PRM applied to all areas to bring CAISO to LOLE of 0.1 days/year	Different PRM for each area to bring each area to LOLE of 0.1 days/year	Separately adjust the PRM of each area so that each area is at LOLE of 0.1 days/year. Because there are now three variables being adjusted (the PRM in each area) and the PRM in each area affects the LOLE in the other areas, the solution of this sensitivity is an iterative process. The result will be a table showing the PRM for each area and resulting LOLE for each iteration as the LOLE for each area is driven to 0.1 days/year.
11	**Monthly vs. annual PRM**	Static PRM percentage applied to the monthly peak loads needed to bring CAISO to LOLE of 0.1 days per year	Static percentage of PRM applied to static annual peak load needed to bring CAISO to LOLE of 0.1 days per year	Run the model over a range of annual, rather than monthly, reserve margins to determine the PRM for this sensitivity. The reliability impact will be shown on a chart, from which the PRM will be determined. It will also show how the CAISO risk would have changed if the PRM had been held constant at the Base Case value.
12	**Monthly load scalars**	One annual load forecast uncertainty scalar was applied to all hours of all months of the year that was meant to capture the uncertainty around peak hours of the peak month.	Each month was scaled using an independent load forecast uncertainty scalar meant to focus on the uncertainty in that month only	A revised change case was developed that incorporated the changed assumptions from a sensitivities 12 through 14
13	**Hydro Energy Carry forward**	Hydro available energy would be used or discarded at the end of each month, and would not be available in other months	Available energy unused from one month could be carried over to the next month, allowing some flexibility in dispatch of hydro resources	A revised change case was developed that incorporated the changed assumptions from a sensitivities 12 through 14
14	**Revised Imports Assumptio ns**	Original Base Case had assumptions on Imports as in Item # 3 above	Revised Base Case had assumptions of: (a) out of state generation owned by IOUs included in the margin; (b) non-firm historical imports NOT included in the reserve margins, but available when needed. The total imports assumptions for this run do not exceed 9,500 MW for CAISO.	A revised change case was developed that incorporated the changed assumptions from a sensitivities 12 through 14

4. PRM Modeling Manual

This section explains the methodology that Energy Division recommends to use in order to ensure fulfillment of Energy Division's minimum analytical requirements, including methodology and data sources for the near term, midterm, and long term study years. The PRM Modeling Manual is divided into five subsections that roughly correspond to Working Groups that helped to develop the methodologies: (1) general scope and policy issues, (2) intermittent generation modeling (wind / solar / cogeneration / hydro resources), (3) load and demand response inputs to MARS simulation, (4) modeling of non-intermittent generation and classification of all generation, and (5) modeling of transmission limitations and imports. The discussion notes specific parties that agree or disagree, and in some places includes some discussion surrounding particular methodologies to inform readers of the background behind this Modeling Manual. Recommendations that are revised since the October 2008 Energy Division Proposal are labeled as Revised Recommendations, while those recommendations that remained essentially the same are just labeled as Recommendations.

4.1. General Policy Issues

The proposal below is designed to develop policy choices that inform the Commission related to near term, midterm, and long term reliability needs. The issues include: the definition of the base on which the PRM will be applied (annual procurement targets or monthly procurement targets), process of data validation, the choice of the proper reliability metric from which to derive the procurement targets and PRM, and the definition of outage events. There are also issues of future buildout scenarios for the near term, midterm, and long term time frame and whether the metric that is used will reflect conditions in each service territory or all of the CAISO.

4.1.1. Annual, Monthly, and Levelized Risk Methods

LOLE studies such as MARS model the amount of capacity needed to maintain reliability under certain stochastic and deterministic conditions. The Preliminary 1A study provided results based on several separate definitions of PRM – the Annual Method, Monthly Method, Constant MW Reserve, and Levelized Risk Methods. The base case was developed using a Monthly Approach and several sensitivities were developed that tested the PRM levels for the other three methods mentioned above. Due to changes made in other methodologies, Energy Division recommends further analysis of some of these definitions of PRM so as to gauge the effects of revised methodologies on reliability levels.

Generally, LOLE studies used to set PRM levels within the electricity industry ask the question of how much capacity would be needed and available year round in order to meet reliability conditions caused by the annual peak load. Little attention is given to reliability conditions in offpeak periods, or in the amount of capacity not needed in offpeak months due to lower loads. The Annual Method results in an assessment of physical installed capacity, while not determining individual monthly resource portfolios. As a general rule, this is an approach compatible with the installed capacity requirements of the Eastern ISOs. Alternatively, the methodology used for the annual method can be deployed for each month on a stand alone basis, and is referred to as the Monthly

Method. The characteristics of load uncertainty and resource performance for each month determine the PRM value established for that month. Alternative versions of the Monthly Approach are the Leveled Risk approach, which requires a static reliability level each month relative to month specific loads, and the Constant MW Reserve Method, which holds a constant MW amount of reserves over month specific peak loads. Each of these methods significantly impacts the final level of reliability measured, and are discussed in greater detail below.

The Commission's current system RA program sets a procurement obligation that requires individual LSEs to procure a certain level of capacity in excess of their own monthly peak loads in order to share costs of maintaining reliability each month. Added together, these peaks and the sum of the resources represent the entire system. The CPUC allows LSEs to choose different resources to satisfy their monthly peak plus reserves obligation. Due the prominence of renewable and demand response in California - resources with vastly different monthly performance characteristics – matching a reliability method to the RA framework seems important, both to understand what the monthly flexibility currently provided means and whether there are implications not foreseen that motivate changes.

While reserve levels are computed often based on an annual peak (i.e. NYISO and PJM Installed Capacity Requirements studies) California's current RA program implements a fixed percentage reserve level above each monthly forecast peak. Application of a PRM derived from a study of peak load conditions using the Annual method to the month specific RA program would potentially create a disconnect as the PRM that is applied was really the answer to a different question than the RA program asks. The disconnect created by use of a PRM value based on the Annual Method in the current RA program would occur in months where the month's peak load is less than the year's annual peak load, and the LSEs present the CAISO with capacity amounting to their month specific loads plus reserves. If the percentage load uncertainty in such a month and the resource performance in such a month collectively stress the system more than it would be stressed under annual peak conditions, then the reserves provided to the CAISO may be insufficient. If so, this might require the CAISO to procure backstop capacity amounting to the difference between the month specific loads that are the basis for the RA program and LSE procurement obligation and the annual peak plus reserves that the study assumed to be available.

Due to the fact that both the RA proceeding and the LTPP proceeding seek to use the reserves implied by a PRM value as additive to peak load forecasts in order to satisfy grid reliability requirements, the difference in procurement structure becomes important[3]. Given the dual purpose of the adopted PRM, this choice in the LOLE modeling represents an important policy choice within this proceeding. If the Commission decides to use the same PRM level for both programs, the results of the PRM study will interact

[3] The LTPP uses the peak load and PRM to set the residual net short that the IOUs need to construct seven to ten years in advance, while the RA program uses the PRM to set procurement targets for LSEs to purchase one year in advance.

with the RA and LTPP proceedings, and the study should provide sufficient guidance to inform the decisions[4].

The Levelized Risk approach is not currently implemented in either the LTPP or RA proceedings, and Energy Division is not aware of its use in other ISOs. This alternative can be useful for decision makers however given the changing nature of the energy system in California.

The Preliminary 1A study results provide the following chart to illustrate the differences between the sensitivities run. The results provided in the chart below are for the Annual Method, the Monthly Method, and the Constant MW Reserve Method.

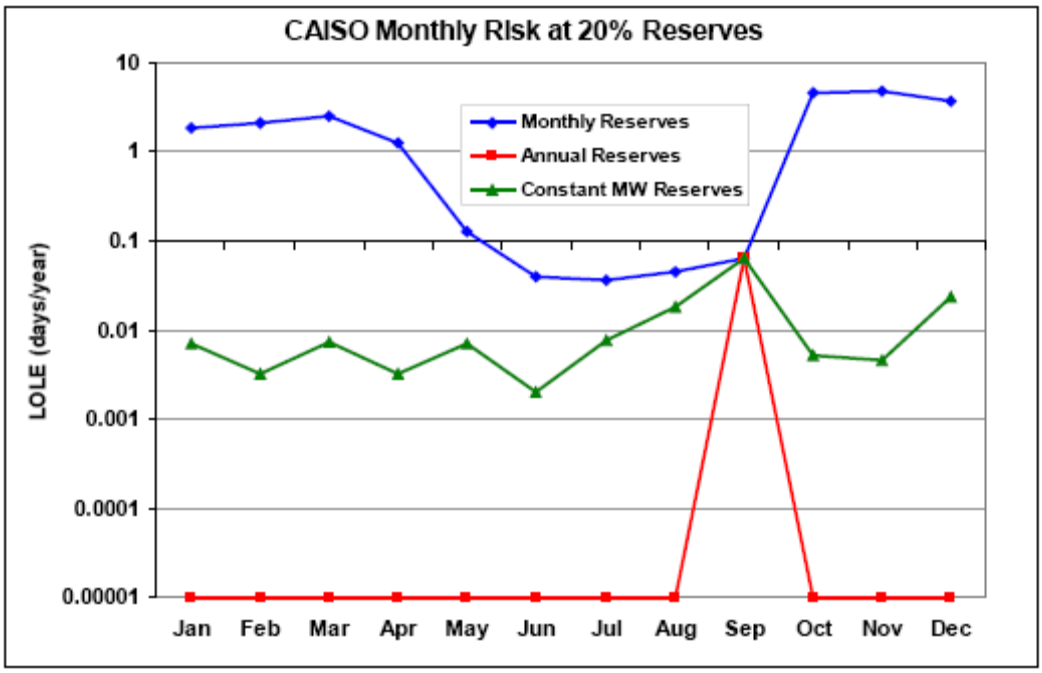

Figure 20 - CAISO Monthly Risk for Various Methodologies at "20% Reserves"

Source: GE Preliminary 1A Results, page 28. Published to the service list on October 15, 2008. This report is posted on the CPUC website at the following link: http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/97876.PDF

Annual Method: The Annual Method applies a fixed PRM percentage to the annual peak load and considers that amount of capacity available year round. This addresses physical needs of the system to ensure that sufficient capacity is constructed to meet reliability needs caused by peak load conditions. The surplus amount of capacity provided to the CAISO in off-peak months would focus CAISO risk in peak hours of peak months, and the amount of capacity provided by LSEs may be higher than otherwise needed for the off-peak months due to this reduced risk in those months. For this reason,

[4] The July 1, 2009 CPUC/ED LTPP straw proposal is much more clearly suggesting a difference between the system study perspective and IOU procurement, so the variability in performance implied by the policy-preferred resources might well be better taken into account in future LTPP proceedings than it has in previous ones.

the Annual Method for the study may produce results indicating a lower overall adopted PRM over the annual peak, but imply a higher amount of reserves procured over each month's individual peak demand, resulting in higher procurement costs. The Annual Method relies on minimally meeting summer peak requirements but focusing risk in the peak load period by providing an amount of resources available that substantially exceeds off-season peak loads.

The Annual Method implies surplus capacity is available so that resources can schedule outages systematically during the year, certain that they will continue to receive capacity revenues for the time they are under maintenance. When not on outage, these resources are part of the surplus capacity that is procured and made available to the CAISO relative to annual peak and made available in all months including offpeak months.

Monthly Method – The monthly method applies a fixed PRM percentage to variable month specific peak loads, and implies that units on scheduled outage are not included in the amount available to the CAISO each month. This is broadly consistent with the current RA program. The Monthly Method implies system conditions that potentially allow for lower procurement targets for capacity in off-peak months, although this implication could potentially spread risk throughout the year as resources available in the model to meet reliability are closer to monthly peaks and providing less "insurance".

Although the percentage of margin each month would remain steady, the actual amount in MW capacity would not; since the load levels vary each month, the percentage of load that results in a MW amount of reserves would be reduced, since percentages vary with the base the percentage is applied to. Therefore, the month to month variation in reserves may not track risk factors and may in fact result in more risk in off-peak months than during the summer peak season.

Alternative approaches include the Constant MW Reserve Method or a Levelized Risk Method that holds reliability constant across each month (or season) and allows the PRM to fluctuate in order to maintain that reliability level.

The Constant MW Reserve Method, a variation on the monthly method, would maintain a constant amount of reserves over the year rather than a fixed percentage of monthly load. For example, 15% of 30,000 MW is 4500 MW, while 15% of 50,000 MW is 7500 MW. This method would establish, for example, 7500 MW of reserves in all months. In off-peak months, the PRM would need to be 25% of load, while at peak the PRM would effectively be 15%. The above example reduces the total capacity procurement relative to the annual method, since load plus reserves would equal 37,500 MW in off-peak months instead of 57,500 MW.

Levelized Risk Method – The Levelized Risk Method is an alternative to the Monthly Approach; the PRM fluctuates as a percentage of load each month, but the reliability risk is held constant across the year at $1/12^{th}$ of the annual risk metric. As opposed to the Monthly Approach which allows the reliability level to fluctuate and averages the number of outage events across the year, the Levelized Risk Approach holds that constant and evaluates each month separately when setting a PRM level. The chart below illustrates the Levelized Risk Approach and is taken from the Preliminary 1A study report. As a percentage of load, the PRM is lowest in the summer months, when

peak load is highest; expressed as a steady MW value, the fluctuation would be of smaller magnitude. The effect of this is that in offpeak months a higher PRM is needed to keep CAISO at or below the LOLE metric.

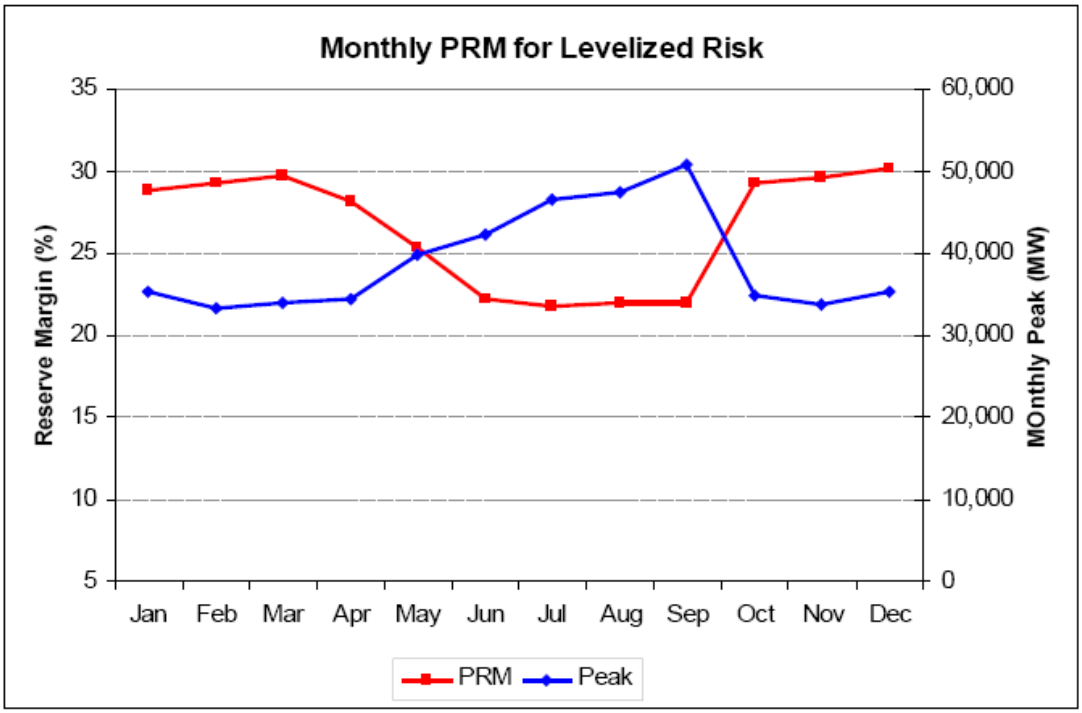

Figure 24 - Monthly PRM for Levelized Risk and Peak Load

Source: GE Preliminary 1A Results, page 33, published to the service list on October 15, 2008. This report is posted on the CPUC website at the following link: http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/97876.PDF

PG&E and SCE strongly contend that the final PRM resulting from the modeling ought to be based on the Annual Approach, and recommended that no further study of the Monthly Approach is warranted. Working Group and stakeholder feedback recommends that the final PRM be based on the Annual Approach as it ought to represent an installed capacity requirement, particularly in the midterm and long term LTPP horizons.

Policy Choices Inherent in This Decision:

The capacity need assessment and authorization component of the LTPP proceeding has focused on annual peak load and requires the construction of physical resources to meet annual peaks plus a PRM. Since the current capacity need assessment is meant to ensure capacity is built to meet peak demand, it does not consider the variability of load forecasts and reserve levels in off-peak months. Generating capacity built for system reliability pursuant to the needs assessment is typically still available to the CAISO to reliably operate the grid in an emergency or as the need arises. In a centralized capacity market, focusing on installed capacity some years into the future, this is the prevalent policy construct. Part of the rationale for a bilateral contract multi-year forward RA construct is that the evolving mix of resources required by policy preferences

can be much more readily accommodated than it can via a centralized capacity market with undifferentiated resource characteristics.

The current one-year ahead RA framework more closely resembles an approach where LSEs procure resources sufficient to meet month specific loads plus a fixed percentage of reserves. Under the RA framework, system risk is spread throughout the year by requiring procurement closer to actual load levels in off-peak months. Under current policy, resources on scheduled outage are not included in the capacity presented to the CAISO, and are thus replaced as RA resources during their outage. No significant change is needed in the PRM methodology to extend this construct further forward in time to 5-6 years in advance of the operational year.

A key policy choice represented in this analysis is the prioritization of the PRM to determine the amount of resources that need to be installed over the amount of resources that may need to be bought. This decision, in the context of the RA program, means that there is some risk of CAISO backstop procurement in offpeak months, particularly related to certain extreme events. In the alternative, applying the monthly PRM to the LTPP would result in capacity constructed in future years that is likely to be excessive, or at least not well suited to the actual needs of the system taking into account the variable performance of the policy preferences that would presumably be accomplished through other procurement mandates on LSEs. Although the annual PRM is applied to the RA obligation there has been limited and decreasing backstop actually initiated by CAISO (even during the 2006 heat storm).[5] There would certainly be added costs, however, if ratepayers finance the construction of additional percentages of resources in the future in order to meet a monthly peak based reserve target, just to have any portion of those resources unused in offpeak months. The current market is already well represented by low capacity factor plants that function as capacity resources.

This policy difficulty is caused by the need to use the same identical PRM value for both the LTPP and RA Programs, and by the current practice of maintaining a stable PRM percentage throughout the individual months of the RA compliance year. A decision to use a different PRM for the short term RA proceeding and a long term PTM for LTPP would alleviate this need, and allow the short term PRM to be based on the Monthly Approach while the LTPP long term PRM is based on the Annual Approach.

An alternative approach could be to fix the reliability level for each month or season and study the level of reserves needed to maintain reliability for each month of the year. Instead of 0.1 outage events per year, the study would model the PRM each month needed to maintain reliability at 0.0083 days with outage event per year on average (equal to 0.1 days per year / 12 months). The Commission could adopt a set of seasonal or monthly PRMs applicable to the RA proceeding and a fixed annual PRM for the LTPP. With this information decision makers would be more able to understand the dispersion of outage events across the year related to maintenance or outage events cause by events outside of peak heat days. Results for all these methods are provided in the

[5] 2008 RA Report, Chapter 4, linked here: http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/98960.PDF

Preliminary 1A Results report, but further study is needed before these results can be finalized.

Revised Recommendation: Pursuant to stakeholder feedback at recent PRM workshops and follow up calls, Energy Division has revised their earlier proposal. Energy Division recommends that the base case ought to be developed based on the Annual Approach, although Energy Division requests additional information regarding the effect that the methodological refinements in this report have on the results presented in Preliminary 1A. Energy Division recommends that a total of four additional cases be run for each study year (4 additional cases by 3 study years equals 12 total), with two using the Monthly Approach and two using the Levelized Risk Approach. The four sensitivity cases will be run to test the 2 load levels from the base case corresponding to the greatest amount of risk, 2 for each study year that test the Monthly Approach and 2 for each study year that test the Levelized Risk Approach.

The most important reason for these additional cases involves the future study years and the specification of the policy-preferred scenarios for those years. The more the resource mix leans toward intermittents or other resource additions with highly variable performance from month to month, the greater is the need for analysis of such cases.[6] Energy Division does not believe at this time that additional study of the Constant MW Reserve Method is needed. The information generated by these modeling runs will quantify the actual difference in system risk created by variations in resource mix and highlight the reliability differences of the current LTPP and RA program structures.

The results of this analysis and this proceeding will set the PRM for use in other proceedings, but will not alter the structure of the LTPP or RA proceedings. The results of this study will however establish a stronger basis of evidence to make future policy decisions, and to enable more thoughtful establishment of program structures.

4.1.2. Study Years – Near Term, Midterm, and Long Term

There are a number of changes that are underway in California's electricity market, including transformations that will have significant and unstudied effects on system reliability. They include such developments as 33% RPS, retirement of OTC plants, AB 32 GHG compliance, and the implementation of demand response initiatives like AMI or plug in hybrids. Energy Division is concerned that in the process of transformation, the electricity system may undergo changes that are hard to predict without analysis; both the end state effects and the Midterm transition effects may be clarified with additional analysis. Energy Division seeks to benchmark the reliability of the current system against the potential reliability levels of future system configurations. The methodologies and analysis that is possible with the PRM study allow Energy Division to investigate how these changes can be quantified and entered as a study case, but also how these new types of study cases are different than the more routine study cases the PRM studies are commonly used for. Scenarios can be run that illustrate the effects of the transformations on reliability.

[6] Clearly this observation suggests recommendations for method, number of study years, and characteristics of resource mixes in future years cannot be easily separated from one another.

It is less important which year is chosen to illustrate the current system, although the PRM study originally envisioned 2010 as the current system. The current PRM was established based on studies of conditions in 2003, so 2010 is at a minimum more current. It is also more certain, both for the RPS and GHG reasons, that 2020 be the long term year, given the renewable resources projected to be built for RPS, as well as the energy efficiency and demand response goals of the CARB scoping plan. There are also other Commission initiatives and California policy goals that could benefit from a more inclusive approach to the system PRM study, that otherwise may not be studied concurrent with the general system studies. It is also important to benchmark each study year against another, so as to verify that trends are consistent and to interface with other types of system studies that are underway (e.g. 5 year LCR, 10 year LTPP, 10 year RPS analysis).

The drawbacks of multiple study years include expense, staffing commitments, and the potential increase in time requirements.

Recommendation: In order to more accurately study the incremental effects of renewable resource development, and to study the effects of phased OTC retirement, Energy Division recommends study of the current system (Near Term), the transformed system (Long term) and the midpoint of the transformation (Midterm). The Long Term study year should be 2020 given the RPS goals that the Commission has adopted and the renewable generation or non-supply alternatives projected to be built to meet that obligation. The Midterm study year is reasonably set at equally in between, 2015.

4.1.3. Quality check on data inputs:

Throughout the course of the Preliminary 1A study process, there have been occasions where data inputs from various sources were delivered to GE via the CAISO that were either incomplete or misunderstood, and there were errors that were located after the data was delivered. As assumptions and conclusions are made regarding data provided, quality control of data is essential. This quality control function creates issues relating to confidentiality, as the team assembled needs legal access to data inputs in order to verify and check the data.

Recommendation: A small group of people should be designated from each agency or stakeholder group to verify data inputs, and given at least two weeks in order to do so. This means that data is delivered two weeks prior to the commencement of modeling runs, and this group can work with CAISO, CPUC, CEC, and the entity performing the analysis in order to facilitate the normal data cleaning functions. The team can be made up of general stakeholders, Energy Division, CEC, or CAISO staff, or modeling staff. To resolve the confidentiality issues, participants could stress the use of public and non-confidential data inputs whenever possible, but there may still be occasions where staff of an individual agency must validate data without outside help.

4.1.4. Future scenarios of intermittent and conventional resource buildout

Future buildout scenarios are most needed for intermittent resources because the sizable growth in intermittent resources will have the greatest effect on LOLE or EUE.

Potential modifications or retirements of plants that utilize once through cooling are also a possible scenario as we approach 2015 or 2020. Conventional resource buildout scenarios are significant to the extent that incremental conventional buildout affects general reliability of the CAISO by effecting general generator outage rates; if incremental conventional generator additions have this effect, then conventional resource buildout scenarios are important to examine. If not, then generic generator additions (or retirements) performed via MARS are sufficient, while being far easier and less contentious. This effect will likely be small for the 2010 run as only limited new generation will come online that is not currently in operation.[7] This effect could be more significant if a number of new conventional thermal plants with new technologies that are significantly more reliable are projected to be developed before 2015 and 2020.

There are a number of possible sources for projections of possible future buildouts of intermittent resources, especially as the state considers fulfillment of a 33% renewable portfolio standard (RPS) goal. Fulfillment of that goal by 2020 would require construction of not only new generation facilities, but also of new transmission facilities. The RPS staff in Energy Division have released their analysis of 33% implementation, with accompanying scenarios of potential renewable resource buildout to satisfy a 33% RPS requirement[8] and the CAISO has augmented the data used for that report (both confidential and non-confidential) with additional data to be used for certain other modeling efforts.

Recommendation: For conventional resources, GE MARS is able to add generic capacity to locations where there is insufficient capacity to support reliability, as specified in one of the sensitivities that GE was tasked with for Preliminary 1A. Energy Division recommends that, for conventional resources, the same function, or a similar function in alternate software, could be used to locate and quantify new generation needs within service areas and inform the stakeholders of this information. Generator information, such as outage rates, should be assigned from the applicable NERC class averages.

As to intermittent generation, Energy Division recommends that the results of the 33% staff analysis (along with CAISO augmented forecast production data) be used to indicate the MW amount of intermittent capacity installed by the midterm and long term years, and use the augmented CAISO data in order to create resource performance profiles for the intermittent generation for in those years located in the TAC areas and determined by resource type. The LTPP 33% analysis grouped buildout into several scenarios loosely called the Trajectory case, the High Distributed Generation case, High Wind case, and the High out of State case. The CAISO created forecast production profiles for the Trajectory case and the High Wind case, which would be necessary to model these scenarios via the MARS model. Energy Division recommends using these scenarios as a means to harmonize planning assumptions across studies, and due to the data's availability.

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[7] http://www.energy.ca.gov/sitingcases/all_projects.html

[8] Linked here: http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf

4.1.5. LOLE for CAISO or LOLE for each service territory

Because of transmission constraints and differences in load and resource characteristics between areas modeled within the CAISO, the individual TAC areas may have different levels of reserves in any given month if the same LOLE level is maintained for each area. Conversely, it is possible that each area, if holding the same level of reserves, may have different corresponding reliability levels or LOLEs.

An issue the Commission may wish to address is whether the model should either: (a) maintain the target reliability level across the CAISO or (b) maintain the target reliability level in each service territory. For Preliminary 1A, the working group supported approaching this issue by modeling both alternatives.

In order to determine the single PRM for the entire CAISO area (Option a), generic capacity could be added to areas that pose the most reliability risk first so that the overall system risk is minimized and overall CAISO reliability is at or below the target LOLE metric. Once the CAISO reaches the target LOLE, each of the sub-areas may be at different levels of reliability, but they will all be at or below the target LOLE. For example, Area A could be at 0.05 days per year, Area B at 0.03 days per year, and Area C at 0.02 days per year. If these outages do not overlap at all, then the CAISO would have an LOLE of 0.1 days per year (0.05 + 0.03 + 0.02), or, 0.05 outage events per year if all outages overlapped. The LOLE across the CAISO would equal the worst area (but Area A would be the major contributor to the overall CAISO risk). In general, the CAISO LOLE will not be lower than that of its least reliable sub-area (which indicates complete overlap of the sub-area outages), and will not be greater than the sum of the sub-area LOLEs (which indicates no overlap between the sub-area outages.)

In the second alternative (Option b), resources are added to or removed from each sub-area until each sub-area achieves the target LOLE. In this scenario, the CAISO will have a lower reliability (or higher LOLE) than option a, with all service areas meeting the specified LOLE of 0.1 days per year. To use an illustrative example, if each sub-area is at 0.1 days/year and the individual hours of outage events recorded by the model do not overlap, then the CAISO could be at 0.3 days/year reliability; if the outage events overlapped completely, the CAISO would be at 0.1.

Recommendation: Energy Division recommends option ‘A’, that the capacity procurement target that is reflected in the load and PRM should reflect the level that is necessary to maintain the CAISO system at the required reliability level of 0.1 days per year. This is consistent with the standard industry target for other balancing authorities. Working group participants broadly agreed with this recommendation.

Table 2 below summarizes Energy Division recommendations to resolve the policy concerns in this section.

Table 2 Revised Matrix of Energy Division Recommendations:

Primary Data Needs	HOW DATA IS USED	DESCRIPTION OF PROPOSED DATA INPUTS
1.1 – Annual vs. Monthly procurement targets; Translation of study results into PRM for RA and LTPP	Reserves are measured as a percentage over each month's peak (Monthly method) or a percentage over the annual peak (Annual method).	Focus on the Annual method case for purposes of base case and sensitivity studies, but produce two sensitivity cases based on the Monthly Method and two based on Levelized Risk method to gauge the effect of changes to other base case assumptions.
1.2 – Quality Control	Quality control of data inputs is an important function, and inaccurate data can lead to misleading results. A group of stakeholders can supplement the data cleaning effort of Joint Agency staff.	Members of working groups could volunteer to do quality control while data is being delivered to the entity performing the analysis for the Near Term, Midterm, and Long Term study runs. People designated from the pool of volunteers will be chosen by Energy Division based on confidentiality concerns and experience with the relevant data.
1.3 – Choice of Metric (LOLE, LOEE, HLOLE, other)	Choice of desired reliability level forms the basis on which reliability studies optimize the studied system.	Industry standard is 1 day in 10 years daily LOLE, although there are other metrics that can be used. Energy Division proposes to use an Hourly LOLE (to be specified in hours LOLE in a year), due to modeling of off-peak periods, and similarity to daily LOLE which is industry standard.
1.4 – Future Buildout scenarios	Future buildouts of intermittent resources are used to measure the effect of increased intermittents on system reliability. Buildouts of conventional resources are needed to the extent that new resources built significantly affect the overall outage rates of the system	Intermittent resource nameplate amounts, technology, and location should be taken from the CPUC 33% RPS analysis, while the analysis should add generic thermal capacity to areas where existing thermal generation is not sufficient to meet reliability, applying the applicable outage rates to the new capacity. No specific build out scenario is planned for additional thermal capacity in years past 2010.
1.5 – CAISO PRM or service territory PRM	Either the CAISO as a whole is driven to the desired reliability metric, or each area is individually driven to that metric. Maintaining CAISO in general at a desired reliability metric is the more conservative option.	Energy Division proposes to maintain CAISO at the desired reliability metric and let the service territories be different from each other

4.2. Intermittent, Cogeneration, and Hydro Resources

This section details Energy Division's approach to satisfy the minimum analytical needs related to intermittent and hydro resource capability. Because of the large role that intermittent resources are likely to play in meeting the State's Renewable Portfolio Standard (RPS) goals, it is important to represent these resources accurately in the PRM Study. Moreover, the qualifying capacity counting rules for wind and solar resources have been significantly altered in a recent RA decision[9]. In addition, cogeneration and hydro resources are a key to maintaining grid reliability in California by meeting peak

[9] D.09-06-028

demand and providing ancillary services. Further discussion of what was used in Preliminary 1A, recommendations for the near term, Midterm, and long term study years and issues associated with the data inputs are provided below. At the end of this section, Table 4 identifies the data inputs, describes their use in the model, and describes the proposed source of data to model that input.

4.2.1. Intermittent and Cogeneration Resources – Preliminary 1A Inputs

For the Preliminary 1A run of the study, 2006 and 2007 hourly intermittent and cogeneration generation profiles were aggregated by resource type and IOU service area and given to GE in order to serve as a Type 2 load modifier that correlated to the contemporaneous hourly loads. There was a tight linkage between load and intermittent generation profiles in the Preliminary 1A run of the model.

Actual historical load shapes from 2006 and 2007 were used in the model, so actual historical 2006 and 2007 intermittent generation profiles were used. This was to maintain the relationship between the weather and load and intermittent resource output. Thus, the historic 2006 hourly load was used as the profile for a future year's load; MARS used the historic 2006 wind, solar, cogeneration, and run-of-river hydro generation profiles.[10]

The working group intended that, for the Preliminary 1A study, wind data should reflect "what would have been" produced in the relevant future years given expected increases in wind capacity. Such estimates have been made in the past as part of a CEC study (Intermittency Analysis Project) that also included GE and AWS TrueWind as consultants. However, no estimates of this type have been produced for more recent years.

In the Preliminary 1A study, 2006 and 2007 hourly generation profiles for intermittent resources were scaled up to account for expected new generation. The primary method discussed in the working group was that these escalation factors could be calculated as a ratio of installed MWs (nameplate) in the historic year compared to the installed MWs expected in 2010. The IOUs agreed to calculate the escalation factors based on their expectations for new resource additions because no public data source was deemed sufficiently accurate. For wind resources, these escalation factors were calculated on a wind zone basis, and the wind zone scaling factors were aggregated to IOU service areas for incorporation in the MARS model. Other resource types' scaling factors were directly calculated at the IOU service area level.

Escalation factors for wind in Preliminary 1A were problematic. PG&E calculated their factors based on the ratio of nameplate capacity to projected future

[10] Analyses presented in the spring 2008 workshops of CPUC RA rulemaking R.08-01-025 support the contention that there is considerable negative correlation between load and wind generation in California, especially in the periods around summer monthly peak demand. This correlation is not pronounced in spring and winter months. Thus strict chronology between load and wind generation is important for a few system peak conditions, but may not be in most hours of the year.

capacity, as discussed by the working group; however their escalation factors were not used in the MARS model due to a miscommunication with GE. SCE calculated the escalation factors using a different method based on the ratio of annual energy production in the base year to the expected energy production in the 2010 year. SDG&E expects no new wind capacity in the service territory by 2010, so the escalation factor is 1.0.

Both the nameplate methodology and SCE's capacity factor methodology are imperfect approximations of an unknown future. The use of scale up factors based on nameplate capacity implicitly assumes the capacity factor, power curve, and wind regimes for new additions are the same as the existing portfolio. The use of energy (SCE's approach) takes into account that new projects may have a different capacity factor than older, existing units. This approach is an attempt to represent technology change (in terms of different capacity factors), but does not fully capture that the power curve of newer wind turbines may have a different shape than for older turbines. New turbines are expected to perform better at lower wind speeds, but may not produce more energy at higher wind speeds; neither scaling methodology can represent this expected change. Similarly, neither approach can model that the locations of new turbines may have different wind patterns from the location of existing turbines. SCE's approach may dampen variation between historical years in total wind energy produced for a constant amount of installed capacity by assuming that expected new capacity produces the same amount of energy in each past year. CEC data suggests that variation between years in terms of annual energy may be larger in PG&E territory than SCE. Most wind units in SCE show a small variation in annual energy between 2005 and 2007. Wind escalation factors and their use in Preliminary 1A are summarized in Table 3 below.

Table 3 Wind Escalation Factors for 1A

IOU/IOU Service Area	2010/2006 Factor	2010/2007 Factor	Method
PG&E - calculated	1.45	1.37	Projected 2010 nameplate capacity divided by nameplate in historic year used for wind production profile
PG&E – applied in MARS	1.0	1.0	Data transmission error
SCE	1.19	1.12	Projected annual 2010 wind energy divided by annual wind energy in year used for wind production profile
SDG&E	1.0	1.0	Assumed no growth in wind

4.2.2. Intermittent and Cogeneration Resources – Near Term Modeling Inputs

Due to concerns related to the limited freedom MARS affords to stochastically model the output and performance of intermittent resources, Energy Division and GE discussed potential refinements to the existing MARS methodology in order to better facilitate stochastic representations of intermittent generation and to disconnect the link

between historical loads and historical intermittent generation. The revised methods are described below. It is intended that these methodologies will be applied to all base and sensitivity cases. Energy Division describes the parameters below. Energy Division recommends that data be sourced from CAISO settlement quality meter data instead of IOU purchase data, due to standardization and access concerns. This data is currently compiled and will be posted on the CPUC PRM site shortly after release of this Modeling Manual for possible use in future PRM studies.

A step by step description of the process follows:

1. CAISO Scheduled Resource IDs are broadly categorized according to generation type. Source information is the CAISO generating capability list. All resources termed intermittent in this list are modeled according to this procedure. All settlement data from the four intermittent resource types (wind, solar, cogeneration, and run of river hydro) are aggregated together by service territory and scaled or summed with the forecast production of future renewable construction. The result is one 8760 hourly profile per resource type per service territory This process results in 12 columns of 8760 data based on settlement data ((4 resource types, 3 service territories equals 12 columns) which are to be published on the CPUC PRM website. To the extent that any of these 12 columns is not aggregated sufficiently to be publicly posted, the data will be transferred to the entity performing the study by Energy Division but will not be posted.
2. The model should incorporate a random choosing feature that chooses a single day of production (24 out of the 8760 hours of the year) for each resource type and each service territory from the days in the month that is being modeled. In short, for each "day" of March during the modeled year, a contiguous 24 hour "day" of historical performance from March will be chosen for each of the 12 columns referenced above. This "day" will be input into the model, and be deducted from load as a Type 2 load modifying resource.
3. During modeling runs, the beginning of each simulated day would trigger the random number generator to select an actual historical 24 hour "day" for each resource type in CAISO and input that day into the model.
4. Due to the observed correlation between load and wind performance at periods of superpeak temperature, Energy Division recommends an adjustment to wind performance (the 3 columns that include wind generation) when loads in any of the three Areas reaches within 95% of peak. MARS currently is able to model Type 1 conventional generation with an ambient derate that would automatically apply upon load conditions that occur that are within a certain percentage of peak. A generic generator would be input into each Area that is triggered when load reaches a certain percentage of peak, and the "capacity" input would be added to load to offset a portion of the wind generation to account for

this correlation between low wind generation and superpeak load conditions in certain hours.

As to specific details of this proposal, all data is drawn from historical settlement quality meter data of a single year. This prevents inconsistencies related to vintage of turbines and avoids the need to scale the profiles for each project and each year individually. As such, actual generation allows for 31 January profiles, 28 February profiles, and so on.

It is imagined that for purposes of near term analysis, historical generation for all types of intermittent resources (all 12 columns) would be scaled by the scale up factors IOUs proposed for Preliminary 1A. Midterm and Long Term analysis will be accomplished differently, according to scenarios developed for the 33% integration analysis released by the CPUC in June, 2009.

4.2.3. Production Profiles of Intermittent Resources – Midterm and Long Term Analysis

For midterm and long term analysis, with large additions of wind capacity, simply scaling up the historical profile may not be appropriate as new wind resources will be located in different areas and new technology is expected to have improved performance. There will need to be a reevaluation of the performance of new resources that are installed in future study years; to ensure that studies covering the same time periods are done in comparable fashion, it is important to coordinate study inputs.

Recommendation: Energy Division proposes to base the performance profile of future resources on the information developed for the 33% integration analysis and for the CAISO intermittent integration study. The location and overall size of new resources in development are included as part of the RETI proposal[11] and in preparation for conducting the 33% integration analysis, the CAISO has developed detailed production profiles for resources under the 33% Trajectory and High Wind scenarios. These production profiles can fill in the 8760 information that is needed for the MARS analysis. Since the CAISO is already conducting a study with these scenarios, and since the LTPP is poised to utilize that analysis, it is important for consistency to model those scenarios.

Once an 8760 performance profile is developed for each type of intermittent generation, then the entity performing the study will be able to use the stochastic methodology to model the variation in performance as described in 4.2.2 above. It is expected that current intermittent generation profiles (used for the Near Term Study Year) can be combined with the CAISO production profiles for the 33% integration analysis to represent the total production of new and existing generation in future study years. Once a single performance year is created by resource type and by year, then the entity performing the study can complete the analysis as done for the Near Term study year.

[11] http://www.energy.ca.gov/reti/documents/2008-08-16_PHASE_1B_DRAFT_RESOURCE_REPORT.PDF

4.2.4. Hydro Generation – Phase 1A Inputs

For the Preliminary 1A study, the Working Group considered hydro generation in two categories: (1) dispatchable, energy-limited resources, and (2) non-dispatchable, run of the river resources.

Dispatchable resources were modeled as energy-limited resources with monthly maximum and minimum capacities and an amount of energy available to the model to meet load. The minimum and maximum capacities for the Preliminary 1A Study were based on a 1 in 2 dry hydro year using values from the CAISO's Generating Capability List. PG&E also provided capacity figures based on a 1 in 5 dry year, consistent with qualifying capacity counting rules. However, these values were not applied in the GE MARS model. The working group notes that there is very little difference in minimum and maximum capacities between a 1 in 2 year and a 1 in 5 or drier year. The monthly energy available was the average monthly output using CEC/EIA 906 data from 1994-2005. This data required significant cleaning by the CAISO to match multiple data sources. Initially, the Preliminary 1A study assumed no carryover of hydro available energy (if there was extra not used in a month, it was not maintained for use the next month). Subsequent study runs demonstrated that carryover was a very sensitive study assumption, and after demonstrating the effect of this assumption, and via workshop discussion and stakeholder input, additional runs were conducted removing this constraint. Stakeholders were satisfied that enabling carryover of hydro available energy was a realistic assumption, and it was retained.

For run-of-the-river resources, the historic profile of actual generation from the same sample years (2006 and 2007) corresponding to the base years for load and intermittent pairing were used. PG&E and SCE provided the hourly generation for those years to the CAISO for these units.

The working group has previously recommended that a drought sensitivity case be run based on 1992 monthly available energy. The CEC uses 1992 for its modeling efforts because this is the driest hydro year on record for CA, although it is not the driest for WECC.

The working group also analyzed the role of the City and County of San Francisco's Hetch-Hetchy water system. This analysis shows that most sales of power from Hetch-Hetchy are generally to entities outside of the CAISO and that the Hetch-Hetchy system itself has very little interconnection with the CAISO-controlled grid. City and County of San Francisco typically meets its RA commitments using its Hetch-Hetchy system. The working group recommends that no further capacity (beyond this self-supply) should be modeled in this study because other components of CCSF loads and resources are outside of CAISO.

4.2.5. Hydro Generation - Near Term Analysis

Recommendation: Energy Division proposes to retain the methodology used in the Preliminary 1A run and subsequent modeling, and model dispatchable hydro resources as energy-limited resources with monthly maximum and minimum capacities and an amount of energy available to the model to meet load. The data used would be the

same as for Preliminary 1A. Available energy would be carried over to the next month in the event of unused energy from past months.

4.2.6. Hydro Generation – Midterm and Long Term Analysis

The PRM Study performed a sensitivity analysis that illustrated the effect of drought on monthly available energy, and reported the findings.

Recommendation: Energy Division proposes to retain the methodology used in the Preliminary 1A run and subsequent modeling, and model dispatchable hydro resources as energy-limited resources with monthly maximum and minimum capacities and an amount of energy available to the model to meet load. Available energy would be carried over to the next month in the event of unused energy from past months.

Table 4 below summarizes the revised recommendations by identifying each input, describing its use in the MARS model, and listing the recommended source of that data.

Table 4 Intermittent, Cogeneration, and Hydro Data Sources

Primary Data Needs	How Data is Used	Description of Proposed Input
Intermittent and Cogeneration Production Profiles – Near Term Inputs	Yearly (8760 hours) profiles are created for each resource type (wind, solar, cogeneration) and given to the entity performing the study. The model will pick a random 24 hour period of historical data for each resource type and from the month that the model is currently simulating, in order to illustrate the variability within a month of generation from these resource types. This is to reflect the minimal correlation of load and resource performance.	The CAISO settlement quality meter data is aggregated by resource type and by service area to create 12 resource profiles (4 service territories, three resource types) based on 2008 settlement data. Existing 2008 performance profiles will be scaled up by the same factors as was done for the Preliminary 1A model to represent additional construction between 2008 and 2010.
Intermittent and Cogeneration Production Profiles – Midterm and Long Term Inputs	Same as Near Term input above	The hourly 8760 production profiles created for the 33% renewable integration analysis performed by the CAISO should be used to simulate the future production of intermittent resources.
Dispatchable hydro – min/max capacity	MARS can dispatch units as needed within this range, subject to a monthly energy constraint	From CAISO Generating Capability List, based on 1 in 2 year hydro conditions
Dispatchable hydro – monthly available energy	Hydro units cannot produce more than this quantity of energy in a month, although unused energy from previous months can carry over as available.	Based on EIA data provided by CEC, average of 1994-2005 values
Hetch-Hetchy Hydro System		Not included beyond the CCSF loads
Helms Pumped Hydro		Model as a thermal generator with a forced outage rate
Other Pumped Hydro	Fixed monthly schedule provided by IOUs	Typical daily schedule based on historical data

4.3. Load and Demand Response Inputs to MARS Simulation

The purpose of this section is to describe the data inputs that were prepared and delivered to GE for use in the MARS Phase 1A analysis of 2010, and proposals for improved versions of these data for the Near Term, Midterm, and Long Term study years. These recommendations implement Energy Division's recommendation to model load

forecast uncertainty in a more realistic way and respond to working group disagreement with the current method of using scalars that multiply every hour of the month by a scalar to determine an extreme load shape. The proposal below was originally developed by CEC staff and is adapted from a proposal Dr. Mike Jaske of the CEC forwarded to the working group on September 25, 2008. That proposal was discussed in working group conference calls and through suggested edits to a draft of this section. Helpful changes and editorial clarifications were included.

4.3.1. Overview of Phase 1A Data Inputs for 2010

Preliminary 1A was designed to provide a quick set of inputs to the entity performing the study for use in developing a CAISO dataset for MARS and in evaluating some limited sensitivities to discern where greater efforts would be productive, e.g. the MARS results were sensitive to the variable in question. The original goal was to deliver data to the CAISO by June 15 2008. Some final input values were not actually delivered to the CAISO until July 23 2008. Some confusion about how MARS actually runs through the iterations (the three IOU service areas simultaneously, but independently unless resources are short in one area and long in another), were clarified and reviewed in working group combined conference calls during August 2008.

This is a brief summary of what was delivered to the CAISO:

- Two versions of 8760 hourly shapes for year 2010 scaled from 2007 actual and 2006 actual for each IOU service area. 2007 was considered the reference to be used in the base case, while 2006 was considered as an extreme used in the sensitivity testing. Each hourly shape was scaled to the 2010 annual peak adopted by the CEC in the 2007 IEPR proceeding for each IOU service area, meaning that both 2006 and 2007 load shapes were scaled to have the same 1:2 annual peak.
- For both years 2006 and 2007, the IOUs adjusted their previous historical loads to "add back" the impacts of demand response and distribution outages to reflect a "what would have been" historical load. Since the "add back" values were developed specifically for the Phase 1A analysis by the three IOUs, it would appear that such adjustments have not been done in earlier studies.
- Load uncertainty values for each IOU service area reflecting the increment by which hourly load would increase due to 1:5, 1:10, 1:20 weather conditions, rather than 1:2 weather conditions. These annual load uncertainty values for each IOU service area were obtained from the CEC 2007 IEPR proceeding.[12]
- Monthly demand response capability in terms of monthly expected load drop and maximum number of hours of availability per program were provided by the IOUs from their respective DR applications.

The CAISO released preliminary results of the base case to representatives of the CAISO, CEC, and CPUC on September 5 2008 for review. Staff of these agencies

[12] Incremental loads beyond 1:2 annual peak corresponding to 1:5, 1:10, and 1:20 weather conditions are reported by CEC Staff as part of the IEPR demand forecasting process.

reviewed preliminary Phase 1A results from the CAISO, and a few minor corrections were made to the base case. The final set of sensitivities to be investigated was decided, the entity performing the study ran these sensitivities and reported the results to the service list on October 15 2008.

Some data inputs provided to GE Energy for use in Phase 1A seem unusual (for example, the DR pattern for SCE), and should be reviewed, but have been left as provided by participants so as to preserve the integrity of the working group process.

4.3.2. Data Inputs for the Near Term Study Year

Energy Division intends to improve upon the data provided to the CAISO in the Preliminary 1A. Final results are expected to be the beginning point for a policy decision about how PRM analytics map into the CPUC RA framework. The OIR and the Scoping Memo outline various topics that are not themselves technical, but involve how technical information from the PRM analytics will be used to modify RA requirements going forward.

4.3.3. Reference Load Shape/Alternative Load Shape

The CEC has completed their development of load shapes that are meant to represent the different confidence intervals of load shapes. This is meant to depart from the methodology of load uncertainty scalars for establishing load shapes based on proxy years, and to decouple load shapes from wind performance shapes. A substantial defect of the scalar method is that by applying the same scalar to all hours of the day a very unusual load shape would be developed that is not realistic. The model might locate reliability problems in using such a load shape when this load pattern would never be expected in the real world. Instead, extreme weather is most likely to affect the peak and near peak hours and to have diminishing effect in “middle of the night” hours. The methodology to develop these load shapes is explained below. These load shapes are meant to be inclusive of the “added back” amounts of demand response and distribution outages.

Revised Recommendation pursuant to workshop discussion:

This proposal was originally slated for development for the Midterm and Long Term study years, but due to significant stakeholder opposition to the uncertainty scalar approach used in the Preliminary 1A run of the model, Energy Division decided to pursue this approach for the Near Term study. This is taken from a CEC staff proposal presented to stakeholders on a conference call on December 9, 2008. The 1 in 40 load forecast uncertainty case has been removed due to workshop input and Energy Division has determined not to run that case.

Step 1: Define temperature statistics for each weather case

Generally, a 3-day moving average maximum temperature is used for shoulder and summer months, while a heating degree day or minimum daily temperature is used for winter months. The specific statistic used can vary by month and utility. For brevity, this discussion presents the methodology in terms of a summer month. A later version of this document will present the specific temperature statistics used for each month and IOU service area. Also, the methods use by Energy Commission staff to assess summer

peak demand temperature response are documented in Staff Forecast of 2007 Peak Demand (June 2006, CEC-400-2006-008-SF).

For each month and year, identify the day with the maximum or minimum weekday CAISO-wide weighted average temperature for the CAISO from the sample period of 1950 to 2007. From these data, calculate the mean and sample standard deviation of the monthly and annual temperature statistics for each IOU service area. Calculating the IOU service area distributions from the set of CAISO peak temperature events ensures that the demand forecasts for IOU service area extreme events take into account the historical correlation of regional temperature patterns. Use the distribution of annual maximums in place of the monthly maximums for summer months to ensure that at least one month of the PRM study captures the annual peak forecast.

Construct a 1-tailed confidence interval for 1 in 5, 1 in 10 and 1 in 20 probabilities:

AvgMax631+ StDevMax631* 0.842 = Max631for 1 in 5 occurrence.

AvgMax631+ StDevMax631* 1.282 = Max631for 1 in 10 occurrence.

AvgMax631+ StDevMax631* 1.645 = Max631for 1 in 20 occurrence.

(Intervals based on a T distribution and >30 observations; Max631 represents a 3 day moving average of maximum temperatures weighted 60-30-10. For winter months a minimum temperature is used.)

An alternative method for calculating the temperature values for each case is to select the selected percentile points from the distribution of 57 years of monthly or annual peak temperatures. This is the method that has been used by Energy Commission staff.

Step 2: Estimate temperature-response function for each month or season:

Estimate the daily system peak load and temperature regression relationship for weekdays and non-holidays for the sample period 2005, 2006 and 2007. For example, summer months can be estimated as:

Predicted MW = Intercept + ß *Max631(75) + B2005 + B2006

where B2006 and B2006 represent dummy variables for 2005 and 2006.

Step 3: Derive 1-x monthly peak demand forecasts

Calculate 1 in 5, 1 in 10, and 1 in 20 system peaks for each month by applying the estimated coefficients from Step 2 to the temperature statistics calculated in Step 1 for each 1-x case, and scaling up to account for forecasted growth between 2010 and the historic year used to estimate demand. For example, the June 1 in 2 system peak in 2010 is:

MW(June)1in2 =(Intercept + ß(Max631(75) · (Max631(June)1in2 -75))

*(forecasted growth 2010/2007)

Step 4: Construct load shapes that correspond to monthly peaks from Step 3

4.1 Select the historic month that is the best fit for each weather case

Compare the monthly temperature statistics from 2003-2007 to the temperature statistics defined in Step 1. In addition, compare cumulative monthly heating or cooling degree days from 2003-2007 with the historical data.

For each weather case (1-2 included), select the actual hourly loads from the month from the pool of hourly load data whose temperature has the minimum deviation from the 1-x temperature for the CAISO as a whole.[13] This choice can take into account both peak and cumulative temperatures, and also consider the IOU service area deviation. Where there are competing choices (for example, one year is a better fit for SCE, another for PGE), that may provide an additional case to run.

4.2 Scale the hourly loads to the forecasted 1-2 peak demand

Scale all hours to reflect weather-normalized load growth between the historic year and the monthly 1- 2 forecast. For example, assume July 2006 is the 1-20 case. Use the estimation function from Step 2 and the 1-2 temperatures from Step 1 to calculate the hypothetical July 2006 1-2 demand. Scale all hours of July 2006 by the proportion (July 2010 1-2 MW Forecast/July 2006 estimated 1-2 MW). By using a constant for all hours, the desired correlation with historic wind load shapes is preserved in the 1-2 case.

4.3 Scale the peak periods of the extreme case hourly loads to the forecasted 2010 1-x peak demand

For the 1-5, 1-10, and 1-20 cases, scale the peak period only so that the peak hour corresponds to the 2010 monthly peak forecast. The duration of the extreme event for each weather case, and the proportionate increase for peak versus off-peak hours, can be developed based on examination of historic patterns.

4.4 Compile months to create 8760 loads

Splice together the 12 months for each 1-x case, adjusting to a consistent set of dates and day-types.

Load Uncertainty Scalars

Together with the load shapes created for the future years, there is still the need to establish the scalar for the peaks observed historically and the peaks likely to occur in the Near Term, Midterm, and Long Term study years.

The CEC has created a set of scalars that will be used to scale peak and energy actuals observed in the synthetic load shapes to the projected peak and energy used in the study years. These values will be posted on the CPUC website.

[13] Due to a variety of issues the number of years with hourly load data that is available for this purpose is limited. Some constraints limiting these data include: (1) current geographic definitions for the areas, (2) degree to which POUs are embedded in the area definitions, (3) access to adjustment data, and (4) mix of end-use customers provided electricity from grid-connected resources.

4.3.4. Demand Response Characterizations

The DR program capabilities provided by PG&E and SDG&E to GE Energy for the Preliminary 1A analysis included capabilities for all twelve months, but SCE only reported capabilities for May – October. For Phase 1A, SCE used the demand response impacts provided in the IOU's Demand Response application for 2009-2011 funding cycle which only included May through October as those are the months DR is likely to be utilized. Since the Preliminary 1A study results, the IOU funding applications for 2009-2011 have been adopted by the Commission, and the DR program load impacts for purposes of RA have been posted to the Commission website. These values represent the expected load drop of the programs when an event is called, and they are month specific. Energy Division is also preparing DR inputs for the LTPP proceeding that will take these projections out to 2020.

Revised Recommendation: Energy Division proposes to take the IOU forecasts of expected load drop from the recently adopted 2009-2011 DR funding decision and the long term DR forecasts to be used for LTPP and use these forecasts as the base for maximum capacity and number of event inputs that MARS uses for purposes of LOLE for the applicable Midterm and Long Term Study years.

4.3.5. Policy Preferred Load Level/Shape

In Preliminary 1A, only short term load uncertainty through weather fluctuation from monthly peak average weather was assessed. Long-term load uncertainty includes non-weather factors that are so small in the near-term 2010 load forecast that they were not included. As one looks further forward, the impact of these uncertainties on overall load levels/shapes grow larger, and such uncertainties should not be ignored[14]. There is the potential for a distinctly different set of typical load levels/shapes resulting from the changing energy markets contemplated in Commission policies. Distinct and persistent changes in load levels/shapes result in distinct and persistent changes to the quantity and distribution of any outage events observed via LOLE modeling, and could compound with other variables in heretofore unobserved ways. In addition, models may fail to reflect some real world phenomenon and this source of error could grow through time. Thus, long-term input and modeling uncertainties could include:

(1) econ/demo variation from trend

(2) increased Energy Efficiency incremental to the IEPR forecast

(3) electric vehicles

(4) incremental on-site generation (solar photovoltaic, combined heat and power and other cogeneration) reducing utility retail sales and perhaps shifting the shape of the net load provided by the utility.

[14] LTPP straw proposal (July 2009) in R. 08-02-007 recommends a set of alternate study scenarios, including scenarios that could potentially alter the load levels and load shapes currently under study.

Some of these uncertainties would merely shift the level of the load up or down compared to a base case. Broadly targeted energy efficiency might have this effect. Others have the potential to substantial change the shape of the net load served by the LSE through the distribution system and/or add to the volatility of net loads to be served via grid resources. Solar could easily have this effect. So there is uncertainty about both the level of the load and the shape of the load for any given level.

Recommendation: Energy Division proposes that these factors be modeled via the development of Policy Preferred load levels/shapes constructed such that the modeling results derived from them would be sufficiently different from the Base Case load levels/shape so as to present significantly different results. These Policy Preferred load levels/shapes would incorporate forecasted impacts from factors such as those listed above. Such Policy Preferred load levels/shapes omit the uncertainty from alternative economic or demographic factors affecting demand, but would encompass alternative factors affecting load levels/shapes due to the nature and extent of the policies that the Commission chooses to pursue through time. Incremental impacts from additional energy efficiency, CSI and other solar photovoltaic, as well as other distributed generation located on the customer side of the meter are likely to significantly impact the load levels and shapes both in peak and offpeak periods, so it is important to model the possible effects of these policies so as to understand their impact.

Energy Division recommends two versions of this load level/shape be developed similar to the synthetic load levels/shapes developed for the base case, such that the load levels/shapes could be evaluated comparably to the base case, and in the context of all the other input assumptions used to develop the base case. The two Policy Preferred load levels/shapes should be constructed so as to represent 1 in 2 and 1 in 10 temperature recurrence intervals that are evaluated for the Annual, Monthly, and the Levelized Risk Methods. Energy Division proposes to guide the development of load levels/shapes that correspond to the intervals that create the greatest risk of outage events as seen in the base case results for each of the study years. Energy Division proposes that in order to do this, 6 additional cases should be run (2 load levels/shapes for each of three study years) and evaluated alongside the Base Case so as to determine whether this will change the PRM required to maintain reliability within the required LOLE level.

4.3.6. Summary

Table 5 summarizes the overall pattern of successive development of Preliminary 1A, Near Term, Midterm, and Long Term demand forecasts and related input assumptions to MARS. The purpose of the Phase 1A Preliminary Study was to understand the sensitivity of the model to alternative inputs. The Preliminary 1A report revealed that the results are highly sensitive to changes in load forecast uncertainty assumptions, and different load shapes that are tested. Both methodological and assumption changes are proposed compared to the Preliminary 1A results.

Table 5 Revised Energy Division Proposals for Load Forecast Inputs

VERSION OF DATA DEVELOPED	FORECAST METHODOLOGY FOR SHAPE AND LEVEL	EXTREME/ALTERNATIVE SHAPE METHODOLOGY	LOAD UNCERTAINTY FROM WEATHER	NON-WEATHER UNCERTAINTIES AROUND CEC 1:2 FORECAST
Phase 1A 2010 (7/23)	Choose 2007 as typical shape. Scale the typical shape to force to fit CEC 2010 **annual** demand forecast	Select 2006 as extreme shape	Annual scalar for each IOU service area August peak from CEC staff 2007 IEPR results Model 1:2, 1:5, 1:10, 1:20	None
Near Term study year	Agency staff propose to splice together a typical year by selecting "typical" months or weeks from the set 2003 to 2007 after scaling them to eliminate econ/demo differences	Use "non-typical" shapes from the weeks or months of 2003 to 2007 in conjunction with scalars developed by CEC staff to develop 1:5, 1:10, and 1:20 alternative shapes	Folded together with alternative load shapes so that peak/off-peak differentials follow actual historic data rather than all hours scaling uniformly	Econ/Demo Growth and other components of long-term uncertainty would be quantified, but the inherent uncertainty limited to reflect a self-correcting annual or biennial planning process
Midterm and Long Term study years	Same as Near Term except scale each shape to force to fit CEC 2015 and 2020 **monthly** peak demand forecast from IEPR	Same as Near Term	Same as Near Term	Create a Policy Preferred hourly load shape corresponding to the load shapes used for the Base Case, for each study year, that incorporate likely effects of policy changes in future years

4.4. Modeling of Current Generation

In running a chronological simulation such as the MARS model, a fundamental input is a listing of existing generation and their associated properties (location, MW size, fuel, technology type, and performance characteristics). Within LOLE models, generator performance is modeled stochastically using a forced outage rate to demonstrate frequency of outage. In order to model non-intermittent generation, certain data inputs are needed: a) a forced outage rate such as the EFORd metric, b) mean time to repair once a unit is on outage, and c) a partial outage state in between 0 and 100% if the unit is modeled as a three or more state unit. Major inputs which were used for the Preliminary 1A run (already completed) and the Near Term, Midterm, and Long Term study years are discussed in the narrative detail below, and summarized in the matrix at the end of this section.

Methodology used for Preliminary 1A:

Equivalent Demand Forced Outage Rate (EFORd): The CAISO used the CAISO Generating Capability List to identify units within locations and by fuel type. The applicable NERC Generator Availability Data System (GADS) National Class average EFORd values were then applied to non-intermittent and non-hydro units. From this data, GE created a mean time to repair and other needed statistics to model all thermal non-hydro and non-intermittent resources as two state units. The class averages supplied by the GADS generator operating reports covered the years 2002 through 2006. At the time of the Preliminary 1A run, 2007 information was not available and computed. Identification of classes from the CAISO Generating Capability List proved difficult in the time frame required, and some inconsistencies resulted from the way QF units and CCGTs were placed into categories. Since the Preliminary 1A run of the study, stakeholders and joint agency staff have reviewed and corrected the generator classification to remove these errors and provide clearer identification of how generators fit into NERC classes. In addition, NERC has updated their National Class Averages. The GADS reports are linked to the NERC website.[15]

Generator scheduled maintenance – The CAISO attempted to make use of the actual 2007 planned outage schedules from the SLIC database, but found that the reports generated in SLIC were not complete and not reliable for this purpose. In the place of this data, GE used the scheduled maintenance optimization feature of the GE MARS program to schedule outages according to when the outages would fall for system reliability. The results of that optimization are included in the Preliminary 1A report produced by GE. The workshop will reserve time to discuss the proper approach to respond to the data inadequacy issue.

4.4.1. Compilation of Generator Listing

In revising the generator classification list and improving upon work done for Preliminary 1A, a number of methodological and logistical concerns arose. Energy Division developed an initial listing based on the CAISO's Generator Generating Capability List[16] and performed the following steps to transform the listing into the required input for MARS. Note that generator size is give as NDC, not NQC. Also generators were classified into NERC classes based first on technology type, not fuel type. For example, a reciprocating engine that burned natural gas was classified as a diesel generator, since that is the generator technology type most similar to reciprocating engines. Likewise, a gas turbine that was made to burn gasified diesel fuel was classified as a gas turbine, since that is the proper characterization of the generator technology type.

1. Nuclear units and geothermal units were placed into their corresponding NERC class
2. Combustion turbine generator type units were all classified as Gas Turbine NERC class regardless of fuel (except for cogeneration, which was classified as intermittent)

[15] http://www.nerc.com/page.php?cid=4|43|47

[16] http://www.caiso.com/14d4/14d4c4ff59780.html, downloaded as of mid January 2009

3. Steam types that are fed by gas of any kind (Natural gas, sewage gas, landfill gas) are Fossil Gas NERC class except for cogeneration.
4. Steam type that are fed by other fuels (including diesel fuel) are Fossil All Fuel Types except for cogeneration, nuclear and geothermal
5. Internal Combustion and Reciprocating engine types were classified as Diesel NERC class except for Cogeneration units
6. All child resources attached to Combined Cycle plants were removed, leaving just the Combined Cycle resource which was classified as a Combined Cycle NERC class.
7. All aggregate resources listed above were disaggregated and decomposed into a listing for each unit in the plant. This was done regardless of whether they have CAISO IDs. In splitting up aggregate IDs, some issues were encountered which are explained below:
8. The NDC is left as the measure of the unit size. When the aggregate ID had NDC and the child unit did not, the aggregate NDC was split among child IDs according to the ratio of nameplate of child divided by nameplate of aggregate ID. For example, if the aggregate ID was made up of 2 units with equal nameplate ratings of 6 MW each, then the 5 MW NDC of the aggregate ID would be split equally among the 2 child IDs
9. Aggregate ID lines were removed from the listing. Combined Cycle units were left aggregated so they could fit into the NERC class average for CCGTs, and intermittent classes (Solar, wind, cogeneration, hydro), were left aggregated since they would not be modeled with EFORd attached, but instead would be modeled as load modifying resources using historical production profiles
10. New resources added to the listing (such as Gateway or Starwood Midway) were disaggregated into individual units, and the NDC was apportioned according to Step 8. They were placed into the appropriate NERC class and an outage rate was assigned to them.
11. For the Aggregate IDs that aggregate various types of non-traditional resources (cogeneration and wind under one aggregate ID for example) these aggregate IDs were left classified just as intermittent; it is expected that the necessary performance history would be provided so they can be modeled as load modifiers
12. Non-traditional resource types such as biomass were classified according to technology type either as Gas Turbine or Fossil All Fuel types
13. Several resources that are indicated as not exporting to the grid or being for self-gen only were removed from the listing and will not be modeled

Energy Division will post the generator classification resulting from the steps above on the CPUC website and stakeholders may review it for error checking and to understand the mechanism of generator classification.

4.4.2. Equivalent Demand Forced Outage Rate (EFORd)

EFORd is a metric of outage frequency that is developed and calculated by NERC within the set of GADS data applications. Although unit specific performance indices can be generated from the NERC GADS application, NERC publishes a set of national class averages on their website. A number of reliability organizations use EFORd as a measure of generation availability in LOLE modeling.

Options for how EFORd could be modeled for generators in this study include: a) the use of NERC national class averages, b) the use of California class averages modeled after NERC classes with California specific generator data, or c) undertaking a benchmarking study using generator statistics for all generators that report to NERC, and classifying generators according to more relevant classes than just fuel type and size, and in so doing create classes that provide more statistically significant class averages for performance statistics including EFORd. The benchmarking study would be performed by NERC and would produce class averages that are driven to 95% confidence interval by grouping resources according to EFORd as an independent statistic and grouping resources into classes to lessen the standard deviation of EFORd within the class.

Recommendation: To complete data delivery for continuation of the MARS study for the Near Term, Midterm, and Long Term study years, Energy Division recommends each individual unit should be assigned the following data: the current CA class average EFORd value for the applicable generation class based on GADS reporting from 2003-2007, and the mean time repair calculated by MARS from the EFORd data as if the unit were modeled as 2 states. The CPUC may at a later time attempt to conduct a benchmarking study based on national generating units in GADS in order to group generators into more illustrative groupings that are more statistically significant than just size and technology type,

4.4.3. Generator Scheduled Maintenance

Working group members recommended the use of planned outage historical schedules, in order to ensure that MARS did not schedule maintenance during the summer, and to account for maintenance that occurs less often than annually (nuclear refueling). Due to data adequacy issues however, the CAISO was unable to provide deterministic outage schedules via SLIC that could be used for the Preliminary 1A run of the MARS model last October, 2008. Thus the CAISO used the MARS program to optimize scheduled outages and the results of the optimization were included in the Preliminary 1A report. Workshop discussion and the 1A report demonstrated that stakeholders were overall satisfied with the pattern of scheduled outages, the optimization was not inconsistent with actual history, and the potential significance of the actual outage histories was limited.

Recommendation: Due to continuing data problems and the difficulties of confidential data treatment, Energy Division recommends that the MARS program continue to optimize all generators.

4.4.4. Identification of Generator States

Data provided must either support the modeling of all non-intermittent generating units as two state units, or provide a means for certain units to be modeled as three state units. Phase 1A modeled outage data based on a simple two-state model, meaning that a unit is either 100% on or 100% off. For Near Term, Midterm, and Long Term study years, it is expected that an appropriate middle deration state (between 0 and 100% derate) can be developed for three-state models, which may differ depending on the generator class or type. Participants have suggested that classes of resources be separated into those that are modeled as two stated versus three stated by criteria other than size. Some have suggested for example that combustion turbines continue to be modeled as two state units, while combined cycle units are modeled as three state units given their performance abilities. More clarity is needed as to how a third state is determined using available data. Alternatively, workshop participants especially the CAISO noted that with the large pool of available resources within the CAISO, there is sufficient diversity and pool size that all units could be modeled as two state units without compromising the results. This approach would streamline data gathering significantly, and not overly hinder the quantity of resources available, especially as plants were disaggregated into units in creating the generator listing.

Revised Recommendation pursuant to workshop discussion:

Workshop discussion revealed significant support for modeling all generators as two state units. The reason for this is that the diversity of generation fleets that is possible when units are modeled as three or more state units would be most important in a system with a limited number of generators. Workshop participants understood that the work load and uncertainty associated with the modeling of a third state would not be worth the effort. To this end, Energy Division recommends that all units be modeled as two state units (simply on or off).

4.4.5. Identification of new generation additions

Recommendation: The Preliminary 1A run of the MARS model included some plants that were then under construction in the list of generator units, including the Humboldt repower, Inland Empire, Panoche, Otay Mesa, and Gateway. Several of these plants have now reached commercial operation, as have Starwood Midway and several smaller plants. Energy Division recommends amending the generator listing to include these new plants, disaggregated by unit and grouped into the applicable NERC class. For example the Humboldt Bay Repower is 10 small reciprocating engines classified as diesel. Table 6 below summarizes Energy Division's recommendations for the PRM study by identifying each data input, describing the input's use in the MARS model, and describing the proposed source of the input data.

Table 6 Revised Energy Division Draft Proposal for Generator Modeling

Primary Data Needs	HOW DATA IS USED	DESCRIPTION OF PROPOSED DATA INPUTS
4.1 - Location of generating units	This information will be used to determine location of resources as within TAC Areas.	The location of each generator is derived from the CAISO Generating Capability List, which lists generators within each service territory. New generic generators used to adjust the LOLE up or down will be located within the study areas where they are needed. Other new additions from 4.5 below will be placed according to location.
4.2 - Equivalent Demand Forced Outage rate, EFORd (in %)	Generator performance data is used to simulate probable system conditions in iterative modeling runs.	NERC has computed and delivered CA class average data based on 2003-2007 actual GADS forced outage data.
4.3 - Generator scheduled maintenance	The model will include or remove generation from availability depending on scheduled outages and will determine capacity margins accordingly. Generation that is on scheduled maintenance will not be included as available capacity in the determination of the PRM.	All units optimized in GE's MARS application
4.4 – Identification of generator states	This data is used to probabilistically model generators and "draw" a profile of available generation. Generators can be modeled in a multiple states	All units are modeled as 2 state units to save time and reduce complexity.
4.5 – Identification of New Generator Additions (Known Additions) by 2010	The model will assume a set of plants that come online and are able to provide reliability, and will apply the NERC class average data applicable to size and fuel/technology of the plant to arrive at an outage rate, and will model each new unit as a 2 state unit pursuant to 4.4 above	New plants added to the generator listing are those that are on the CEC siting website as planned to come online before June 1, 2010 and where significant construction has occurred. As many of these plants are now online, the new plants included in the dataset are Inland Empire unit 2 and the Humboldt Bay Repower.

4.5. Modeling of Transmission Limitations and Imports

Working group five did not meet regularly during the summer of 2008. The recommendations that follow were rewritten by Energy Division pursuant to workshop discussion.

4.5.1. Modeling of Transfers between Sub-Areas within CAISO

The working group looked at ways to model transfers between CAISO sub-areas that correspond roughly to NP 26 and SP 26, and south of SONGS (path 43). Annual transfer capabilities were provided. They could have been decomposed, if necessary, by month or peak/non-peak periods. In discussions with the Working Group, GE Energy indicated that the transfer limits can be varied as a function of area load and availability or unavailability of specific generation units. Furthermore, the IOUs having generation and/or contracts outside the CAISO area could be moved as if they are located within the CAISO.

Recommendation: Energy Division recommends that the following transfer capabilities should be modeled based upon the directional limit of the constrained Path 26 from the RA accounting.[17]

- PG&E to SCE (North to South) of 3750 MW is based upon maximum WECC rating minus the allocation Existing Transmission Contracts (ETCs) for municipal utilities in Southern California and loop flow.
- SCE to PG&E (South to North) of 2902 MW is based upon the maximum rating minus the allocation of Existing Transmission Contracts (ETCs) for municipal utilities in Northern California and loop flow.
- SCE to SDG&E is South of Songs Path 44, with a interface limit of 2200 MW
- SDG&E to SCE is based on the transfer capability allowed under the SDG&E Simultaneous Import Limit (SIL) on North of SONGS Path 43; this limit is dependent on the operation of the two units at San Onofre Nuclear Generating Station (SONGS).
    - SONGS 2 & 3 operational: 290 MW
    - SONGS 2 out & 3 operational: 1360 MW
    - SONGS 2 operational & 3 out: 1370 MW
    - SONGS 2 & 3 unavailable: 2440 MW

[17] D.07-06-029 (June 21, 2007), section 3.2.1, Path 26 Counting Constraint (Joint Parties).

4.5.2. Modeling of imports

In preparation for Preliminary 1A, Working Group 5 recommended that imports would be quantified using an average import amount into each service territory at hour of peak for each month averaged over the previous three years. For refinement of this assumption, the impact can be determined post GE-MARS simulation by assuming an additional amount of resources are available when calculating EUE. An additional sensitivity was completed that studied the effects of assuming imports equal to maximum WECC interface limits for paths into the CAISO. GE Energy's approach in post-processing is to add import capacity up to an import limitation when calculating the EUE, and then adding additional generation resources to achieve the desired PRM. The alternative is to model loads and resources located in balancing authorities outside the CAISO, including generation resources and interface limits to those areas. Additional data gathering would be in order, and this data may not be available to the participants or the CAISO. Proxy data can be created, but accuracy would be an issue. A hybrid approach is to include an amount of imports that are available as a resource for each intertie with a transmission forced outage rate and mean time to repair to represent the probability of a transmission line outage before adding additional new generation to achieve the desired PRM.

The working group discussed different approaches to represent the amount of imports in MARS LOLE calculations. The alternatives included: (1) assuming imports are available up to the import interface limits; (2) using historical import availability; (3) estimating import availability based on WECC production simulations; and (4) running the GE-MARS model without imports, and later estimating how much imports, up to the import limit, are required to meet a target of the load and PRM level.

The impact of imports is important because they are resources that can contribute to meeting load and each of the approaches listed above have trade-offs. Using an import assumption of maximum interface limits may overestimate the amount of resources that are available to the CAISO during a Stage 3 event. The use of historical import availability does not fully account for actual availability in an emergency, and thus may not be appropriate for 2010; additionally this assumption may not forecast typical import patterns or transmission system configuration in 2014 or 2019. Using a WECC production simulation would require the scope of the PRM study to be revised, along with the approved budget.

Revised Recommendation: Energy Division has revised their recommendation to accurately characterize this data input. While seeking to balance realism with conservatism, Energy Division notes that there are other processes particularly for RA that currently quantify the impact of import resources. Energy Division recommends following a three step approach as follows:

1. List all ownership and contractual arrangements with generators outside the CAISO. Currently the list includes plants such as Four Corners, Palo Verde Nuclear Generating Station, and El Dorado. Listing all contractual arrangements outside the CAISO that are set to last into the Near Term, Midterm, and Long Term Study years will enable the entity performing the study to metaphorically "relocate" these plants into the CAISO, as the

CAISO will potentially enjoy full dispatch of them as unit specific resources. These resources could also be listed via the LSE submissions and Import Capability requests in the Import Allocation process.

2. List the Maximum Available Import Capability on each Branch Group that the CAISO calculates for the annual Import Allocation process. From this amount, net the outside ownership or contractual arrangements listed from Step 1, and list the netted Maximum Available Import Capability in a spreadsheet that is posted publicly. This spreadsheet will give total import capability on each Branch Group, and will not reveal counterparties or terms of various arrangements. The adjustments will be on a Branch Group specific basis.
3. The resulting arrangements listed from Step 1 will be assigned a transmission outage rate and a NERC average EFORd pursuant to section 4.4 above, and these arrangements will be modeled as if they were Type 1 in area generation.
4. The adjusted import capability calculated in Step 2 above will be counted as Type 1 capacity available outside the Service Areas modeled, and be "dispatched" after all in area generation is dispatched, but before hydro or demand response Type 2 resources.
5. In addition to information already required for the EFORd averages of generators, this proposal recommends the calculation of outage rates on transmission Branch Groups. Energy Division suggests calculating these Branch Group outage rates by running a report from SLIC data over the previous five years of data, and as much as possible calculating an average similar to EFORd for each Branch Group. It is not known whether the resulting EFORd rates on individual Branch Groups would be confidential or not.

4.5.3. Implications for Midterm and Long Term study years

Transmission limits and import assumptions proposed for 2010 may change as new transmission is built and becomes operational. In particular the RETI work that the CAISO is participating in will highlight and prioritize the transmission upgrades needed to meet the 20% RPS goal and the proposed 33% RPS goal within the study period of 2010-2010. The transmission upgrades performed will significantly impact the geography of the CAISO, and thus the PRM model would need to take projected system improvements into consideration to the extent that new transmission provides additional interface between IOU service areas or between IOU service territories and other control areas. Working group discussion is needed to properly quantify these possible impacts.

5. Post Processing Steps Subsequent To Modeling Results that may factor into Commission Action

In addition to modeling inputs that are directly related to the base case and sensitivity cases run by the modeler, there are some modeling inputs that may factor as post processing steps that the Commission can take to modify the study results. These modifications may not require additional modeling work, but instead are mathematical additions or subtractions that are reflective of policy decisions. They include counting of certain existing resources, and measure of outage event, where the impacts of these choices are clear and the Commission is given sufficient information to understand the tradeoffs being made. They are discussed below, and are expected to be part of party comments after the study results are provided to parties.

5.1. Proper metric by which to measure reliability and choose a capacity requirement:

The Commission's choice of the proper statistical metric or metrics is fundamental to ensure the modeling program optimizes reliability. In order to do so, the Commission must develop criteria by which to decide both an agreed standard reliability level and the correct metric. A variety of metrics measure the correlation between reliability impact and planning reserve levels (summarized below). The chosen metric should account for the reliability of the generating system and certain electrical elements such as transmission interfaces to determine the capacity needed to maintain reliability across the system. The reliability level will translate into a required reserve level by which to target procurement. GE MARS is capable of delivering all of the following metrics simultaneously

Daily Loss of Load Expectation (Daily LOLE) – The expected number of days in which the load exceeds resource capacity; the traditional calculation of Daily LOLE considers whether there is sufficient capacity to serve the load at the time of the daily peak hour. The Daily LOLE of 1 day in 10 years is considered the industry standard of system reliability and it simplifies computing and model runs. The Daily LOLE does not reflect the variability within the peak periods and off peak periods of a day, particularly for load and intermittent resources.

Hourly Loss of Load Expectation (Hourly LOLE) – The expected number of days on which loads exceed resources on any hour of the day; 1 day in 10 years Daily LOLE does not mean the same as 24 hours of Hourly LOLE in 10 years . Hourly LOLE allows examination of load and intermittent variability during any hours of the day. This metric requires a larger quantity of data for both load conditions and intermittent performance, requiring 8760 hours instead of solely 365 peak hours of data. This data is available and has been provided to the CAISO for Preliminary 1A.

Expected Unserved Energy (EUE): The expected amount of energy (in MWh) unserved over the course of a year. EUE considers the variability of load and intermittent resources in off-peak periods. It also accounts for the duration and the magnitude of outage more precisely than by the expected number of days with an outage event, as that is a measure of frequency. There are limited examples of approved reliability metrics that use EUE as the measure. Participants have pointed out that EUE may be a useful

metric, in that it quantifies the expected magnitude of outage events. This enables a comparison between marginal MWh lost and an economic valuation such as Value of Loss Load (VOLL) which gauges the economic impact to customers of the marginal MWh lost. This comparison is currently planned for a future phase of the PRM OIR, where more data would be needed.

Recommendation: Energy Division proposes the proceeding take comment on the use of a capacity obligation that is sufficient to support an Hourly LOLE and/or EUE. Hourly LOLE attempts to account for the variability in load and intermittent resources over the day. Since there are limited examples of conversion from 1 day in 10 year Daily LOLE to an equivalent Hourly LOLE, and there are limited industry standard uses of the Hourly LOLE metric, modeling staff can be requested to provide a survey of current balancing authorities that use the Hourly LOLE to set and measure reliability of their system. EUE is an intriguing metric, but also of limited industry use currently, Energy Division recommends the entity performing the analysis present results that illustrate the magnitude of EUE in the current system.

5.2. Measure of "outage event"

CAISO alerts are called at various levels of operating reserve. For example, Stage 1 alerts are called when CAISO has less than 7% reserves, Stage 2 at 5% reserves, and Stage 3 at about 1 ½ % to 3% reserves. All of these alert levels illustrate conditions within CAISO operations. However, in defining the appropriate level of reliability to protect with capacity procurement, emphasis should be placed on the point at which firm load is lost. While other reserve levels designate certain emergency conditions, CAISO operations protect firm load until a Stage 3 emergency. Although the study can be performed to illustrate these conditions, other ISOs and reliability organizations typically measure outage events as the time when reserves are equal to 0%.

While the output report details capacity required at various reserve levels, the PRM will be set at what capacity is required to prevent "outage events", which are defined as when demand equals or exceeds resources and 0% reserves are available to the CAISO. This is consistent with the practice in other states and jurisdictions that conduct these types of study.

In California, firm load may be lost when the CAISO invokes Stage 3 events (when operating reserves available fall below 3%). Therefore, PG&E's recommendation is that the simulated LOLE calculated by GE-MARS when operating reserves fall below 3% be benchmarked against the 1 day in 10 year LOLE standard. SCE also questions this approach, and suggests that if the 0% reserves value is used, it would be appropriate to adjust any study result upwards by the margin between 0% and the point when CAISO would trigger firm load curtailment. Other working group members also disagree with this recommendation.

Recommendation: In general LOLE type studies reflect outages at 0% reserve levels, and therefore Energy Division recommends following this approach. Further, Energy Division encourages parties to comment on this issue when study results are presented.

5.3. Use of Net Qualifying Capacity (NQC) to Measure Available and Required PRM:

As the RA program requires LSEs to procure resources to meet RA obligations, and generators are quantified in size according to the generator's listing on the CAISO NQC list, coordination of the NQC tabulation with the generator modeling inputs is necessary. To be useful as a procurement obligation, the capacity target must be assumed to be met with NQC, and the reliability level met must be quantified in terms of NQC. A second issue is the application of MARS with regards generic capacity.

In order to determine the PRM level that meets a given reliability standard, such as a 1 day in 10 year LOLE, GE-MARS adds installed capacity until the calculated LOLE is less than or equal to the required LOLE standard. In measuring procurement responsibilities in terms of NQC, there is the question of how to quantify the capacity of generators that are added or subtracted from areas to bring the area up to or down to the desired reliability level. Would MARS remove a generic generator, or would MARS actually remove a real generator. In adding generators, would MARS add a generic generator or a proxy for a real generator to an area?

Lastly for purposes of completing the listing of generator inputs to feed into the MARS model, what capacity level is assumed for each plant? Assume a plant with a Net Dependable Capacity (NDC) of 600 MW and an NQC of 550 MW. Which is used as the size of the plant? It is possible that there is a good reason why the 600 was reduced to 550, such as application of an ambient derate or derate related to forced outage rates to determine an unforced capacity value. In addition intermittent resources would be modeled as being available up to their NDC, but in terms of procurement responsibility, the LSEs must be actually able to procure their totals. More explanation of this issue is presented in the generator information recommendations in section 4.4.

Revised Recommendation: Since LSEs are required to procure sufficient NQC MWs to cover their monthly forecasted peak demand plus the required PRM, capacity required to be procured must be a total of NQC.

To address the second issue above, Energy Division recommends adding or removing actual generators with forced outage rates applied, not the perfect capacity that GE has used for Preliminary 1A. This would facilitate making the link between NQC and the generator inputs to MARS. In specific, PG&E has developed an example of how resources would be added or subtracted to an area. PG&E's approach requires MARS to first remove units which have equal NDC and NQC (this is the case for many peakers or CCGT facilities) so that the resulting mix needed still can be expressed in NQC. In short, additions and subtractions would be done with actual units where the NDC equals the NQC, so as not to create an imbalance since 1 MW of NDC equals I MW of NQC for the generation discussed. Generation added would be peakers, and a forced outage rate would be applied to them equal to the NERC class in which they fit. The new generators would then be easily comparable to existing generation.

Finally, in compiling generator listings, the NDC from the CAISO Generating Capability List will be taken as the measure of the size of a plant. This enables all units in CAISO to be modeled in this study, not just those plants with CAISO IDs or NQC

values. It is expected that there will be little difference between NDC and NQC for the plants being modeled with EFORd.

5.4. Inclusion of all resources that provide reliability service to the CAISO

There are a variety of resources that provide reliability service to the CAISO and can help to mitigate outage events. Resources can be procured to maintain reliability, and could be considered "in the margin" meaning that imports, demand response, and all emergency assistance are part of the total amount that LSEs are required to procure. The Commission's current RA Program requires LSEs to present the CAISO with the totality of resources that are meant to provide reliability services, and the CAISO is required to quantify the required amount clearly for the LSEs. In other words, there could be no amount of "free" capacity that offsets system risk while not factoring into the procurement obligation. SCE sought greater clarity regarding this issue, and sought to explain that traditionally, there is some amount of emergency reserves that are available as an agreement between balancing authorities that is usually counted as capacity to provide reliability to the system, but is not generally included in a procurement obligation that LSEs are required to meet. SCE historically specifies some amount of assistance that other balancing authorities can provide, such as an amount of emergency imports that decrease the capacity needed for absolute reliability need. This practice is also consistent with several other states that use the LOLE method to set procurement obligations.

PG&E counters that the current RA program is intended to ensure LSE based procurement of all resources that are needed to meet reliability needs, and thus the PRM should not be reduced due to the presence of uncounted resources.

Recommendation: While the RA Program requires LSEs to present the CAISO with the totality of resources that are meant to provide reliability services, and the CAISO is required to quantify the required amount clearly for the LSEs, this expected interchange represents historical precedent and is acknowledged; other ISOs, even those using MARS in other parts of the country, accept some amount of energy operating reserves that are in addition to required reserves. There is a lack of consensus on this subject, but due to the impact (around 2-3%) this factor could have on the adopted reserve margin, Energy Division recommends that although the modeling result should reflect no amount of unspecified emergency reserves. Stakeholders are encouraged to discuss this recommendation in comments following both the issuance of this Modeling Manual and any subsequent Commission action.