BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development.	Rulemaking 01-10-024 (Filed October 25, 2001)
Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning.	Rulemaking 04-04-003 (Filed April 1, 2004)

WORKSHOP REPORT ON RESOURCE ADEQUACY ISSUES

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1 Procedural Background

This Workshop Report is submitted consistent with the February 13, 2004 ALJ Ruling in R.01-10-024. Administrative Law Judge Michelle Cooke facilitated a series of workshops that were held on March 16, April 6, April 7, April 12, April 13, April 14, April 26, May 5, May 17, May 18, and May 26.

The workshops focused on how compliance by load-serving entities (LSEs) with the 90% year-ahead forward commitment requirement adopted in D.04-01-050 will be assessed. Topics covered included protocols for counting supply and demand resources, deliverability of resources to load, and load forecasting.

The purpose of this report is to identify consensus agreements reached by the workshop participants, identify issues where agreement does not exist and set forth options to resolve those issues whenever possible.[1]

Some issues that are very important to establishing clear rules for assessing resource adequacy were not tackled, for example, penalties in the event of non-compliance and rules for transitioning from year-ahead resource adequacy compliance to operations. These issues still require additional work by the parties and guidance by the Commission, but the Commission must make certain threshold decisions regarding the scope and structure of the year-ahead 90% forward commitment requirement and showing to make discussion of the topics that were set aside fruitful.

[1] Throughout the course of the workshops, many parties prepared straw proposals for discussion purposes. Some, but not all, of these materials are included in the workshop report when the document provides a helpful summary of the issues, reflects consensus discussions, or is fairly technical in nature. Inclusion or exclusion of a particular document should not be taken as any indication of approval of any position expressed in the document, but rather a judgment by the workshop moderator on whether inclusion of the document in the workshop report added additional information necessary for the Commission to decide the issues before it.

2 Timing and Reporting Issues

At the workshops parties continually raised concerns about how the 90% year-ahead forward commitment requirement will interact with actual procurement of resources and the need to meet 100% (including reserve margin) of an LSE's load in real time.

Although there was not agreement on specific language, at the May 5, 2004 workshop, parties discussed timing and interaction issues extensively and appeared to reach general agreement on the elements that are necessary to successfully make the 90% year-ahead forward commitment showing. Parties envision that prior to making such a showing, (1) the rules regarding forecasting of load and eligibility of resources to "count" towards meeting that load will have been established, and (2) procurement of actual resources will have occurred and been "approved" in some manner, consistent with the policy guidance provided in an adopted long-term procurement plan. If these two elements are in place, the actual showing that an LSE is resource adequate becomes a fairly mechanical and non-controversial demonstration that the forward commitments add up to 90% of the associated load the LSE is responsible for.[2]

The remainder of the workshop report focuses on establishing the rules regarding forecasting of load and eligibility of resources to "count" towards meeting that load. However, providing clarity about the process by which procurement decisions by LSEs are "approved" is crucial to establishing a logical reporting process for resource adequacy. **The parties strongly urged that the**

[2] At the May 18 workshop, the parties discussed two capacity "tagging" proposals. Tagging is a way of identifying resources that have met all the requirements of the counting and deliverability protocols the Commission adopts and

90% year-ahead forward commitment showing NOT include the assessment of the reasonableness of actual procurement decisions by LSEs but that determination of reasonableness should be known in advance of making the year-ahead showing.

The implication of this general agreement is that the amount of load an LSE is responsible for serving must be known early on so that study work relating to deliverability (especially of imports) can be completed in advance of procurement and the year-ahead showing. The work group focusing on load forecasting issues recommended that:

> Each LSE should provide a forecast of its hourly loads for each of the five summer months early each year (somewhere between January and April) for the period May-September of the next year (e.g submission in 2005 for loads during May-September 2006). If there were to be review and/or reconciliation adjustments of a draft load forecast before it was finalized … the draft would come early in each calendar year, and adjustments would take place through the end of March with a goal of load forecasts finalized by April (e.g by April 2005 for the projected loads May-September 2006).

Finalization of each LSE's allocation of load is a necessary precursor to analysis of deliverability and procurement.[3] At the workshops, the California Independent System Operator (CAISO) stated that it would be able to perform its deliverability analysis in two months.[4] Following the deliverability assessment, sufficient time would be required for LSEs to procure resources (and potentially receive approval of them) to meet their load obligations, prior to making the year-ahead resource adequacy showing.

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thus facilitates the demonstration of compliance with resource adequacy requirements. Capacity tagging is discussed in more detail in Section 7.3.

[3] At the workshop, the discussion appeared to assume that the CEC would review forecasts and perform any necessary reconciliation or allocation, although no statement of agreement occurred regarding this responsibility. (See Section 4 below.)

[4] This projection is for the second year the analysis is performed. The CAISO assumes that the first year analysis and development of baseline assumptions will take at least six months to complete. See discussion of Deliverability (Section 6 below) for more discussion of the analysis and data requirements.

Three options were identified regarding the timing of the resource adequacy showing to meet the Commission's 90% year in advance forward commitment requirement:

- 12 months prior to May for the full season (May-September) for which resource adequacy must be demonstrated, i.e., May 2007 for May through September 2008
- 12 months before each month (May-September) for which resource adequacy must be demonstrated, i.e., May 2007 for May 2008, June 2007 for June 2008, etc.
- December 31 the year prior to the year in which resource adequacy must be demonstrated, i.e., by December 31, 2007 for season beginning May 1, 2008.

Parties supporting the 12-month options believe that this interpretation is most consistent with the Commission's intent. Of the two 12 month options, certain parties prefer the showing be made each month because better data (in terms of customer megawatts under contract) will be known each month.

Parties supporting the December 31 date argue that the 12 month options would require use of load forecast data that is at least 18 months old, and would not incorporate updated hydro conditions, recent contract performance, Reliability Must Run (RMR) contracts, status of projects under construction. In addition, the December 31 option would provide additional flexibility for LSEs to meet their resource adequacy requirement. The position of these parties is summarized in the position paper prepared by Southern California Edison Company (SCE) that is attached as Appendix A. Those who do not support the December 31 date are concerned that the later date of the showing will result in additional risk that LSEs are not resource adequate, with very little time to fix the problem, however, this concern is minimized to some extent if approval of procurement is separated from the resource adequacy showing.

Because of the uncertainty of the procurement approval process, it was not possible for parties to reach agreement on the timing of filings and the workshop moderator decided that discussion of reporting requirements related to resource adequacy should not occur until further guidance was provided.

The Commission must decide whether the resource adequacy showing follows the procurement approval process or incorporates an assessment of the reasonableness of procurement decisions into the resource adequacy showing. Given that decision, *the Commission must decide when an LSE must demonstrate that it has met the 90% year-ahead resource adequacy requirement.* At that point, it could be useful to have a working session to discuss the elements of the resource adequacy showing.

3 Phase-In

D.04-01-050 adopted a planning reserve margin (PRM) of 15-17% to be achieved no later than January 1, 2008. The planning reserve margin incorporates a 7% operating reserve margin required by Western Electricity Coordinating Council (WECC). The phase-in of the adopted planning reserve margin was not decided and instead was reserved to the workshops. The year-ahead 90% forward commitment requirement is applied to the load forecast plus planning reserve margin so the phase in affects the amount of reserves and forward commitment an LSE must make. Consistent with Finding of Fact 19 of D.04-01-050, this year-ahead requirement is to be implemented in 2007. For example:

90% applies for 2008 load plus applicable reserves, showing in 2007
90% applies for 2009 load plus applicable reserves, showing in 2008

Parties generally agreed that LSEs should make a year-ahead 90% forward commitment showing beginning in 2005 for the May through September 2006 load forecast but parties were unwilling to agree that the year-ahead 90%

forward commitment requirement is truly a "requirement" earlier than 2007 until the implications of not meeting the forward commitment requirement (i.e., penalties, etc.) are known, as well as decisions on phase-in, counting protocols, cost recovery, and contracting authority.

At the workshops, parties discussed 3 possible phase-in options: equal increments, fast phase-in, and slow early then larger increments. Each is discussed in turn. Parties suggested that the Commission should consider near term expected load growth, forecast uncertainty, market power, the available qualified resource pool[5], and costs in helping it to decide how quickly a phase-in to 15-17% should be accomplished. *The Commission must decide what phase-in of the 15-17% planning reserve margin is appropriate and whether to modify the 2007 timing of implementation of the year-ahead 90% forward commitment showing.*

3.1 Equal Increments

Under the equal increment approach, a formula is used that calculates the incremental annual change in planning reserve margin. The formula can accommodate an acceleration of the target year of compliance or modification of the planning reserve margin itself.[6] The formula is:

$$\text{Annual Increment} = \frac{\text{Target PRM \% - Current Year PRM \%}}{\text{Target Year – Current Year}}$$

[5] A concern generic to all phase-in options identified is that without knowing which existing resources will "count" for meeting the year-ahead 90% resource adequacy requirement, there is a significant amount of uncertainty about the pool of resources that will be available to satisfy the 15-17% reserve requirement. The criteria for "counting" are discussed in Section 5 below. The workshop moderator notes that resources that do not meet these criteria for the year-ahead 90%forward commitment requirement may still be eligible to meet the 15-17% reserve requirement by filling in the remaining reserve requirement after the 90% forward commitment is met.

[6] This topic was discussed at the May 17, 2004 workshop. On May 14, 2004, the Western Power Trading Forum filed a petition to modify the January 1, 2008 date for meeting the 15-17% planning reserve requirement. A draft interim opinion issued on June 8, 2004 dismisses the petition without prejudice. The issue is before the Commission for consideration in Rulemaking 04-04-003.

The parties discussed the pros and cons of this approach. The approach is simple to implement, fits with any target date for compliance, and assuming the January 1, 2008 compliance date remains, the resulting phase-in allows building new generation to be an option for meeting the requirement, which can mitigate market power. On the other hand, at least one party is concerned that the current year planning reserve margin component of the formula is not clear.[7]

3.2 Fast Phase-In

The fast phase-in is not so much a phase-in recommendation as a recommendation to modify the target compliance date. This approach is recommended by parties who want LSEs to meet the 15-17% target sooner rather than later. These parties recommend that LSEs be required to acquire a reserve margin of no less than 10-12% in 2005 and 15-17% in 2006. The CAISO, in particular, advocates this approach because of its concern that the May through September period typically has a 3-12% generation forced outage rate and with a longer phase-in, this forced outage rate could result in insufficient reserves to maintain the required 7% operating reserve margin. Some parties argue that the record in R.01-10-024 found that there was a generation surplus, therefore meeting this higher standard should not be problematic. Others believe that a faster phase-in is most consistent with the administration's policies and will encourage implementation of demand response programs. Some parties believe that adoption of a faster phase-in will encourage building of new resources and existing unit staying online; others believe that building new resources is eliminated as an option with this phase-in and existing units will hold significant

[7] The workshop moderator believes that this lack of clarity stems from the fact that LSE's have identified their short-term reserve requirement goals in other procurement filings, but no goal is adopted for 2004 or 2005 for the required reserve margin.

market power, which has serious cost implications. Another generic problem, exacerbated by a rapid phase-in, is the current limitation on LSEs' ability to contract in advance for multi-year products (i.e., multi-year contracts). A rapid phase-in also presents more cost issues to LSEs while the retail market remains ill defined due to uncertainty.

3.3 Slow Early then Larger Increments

The phase-in recommendation here is to adopt the following reserve requirements:

Year 2005: 8%
Year 2006: 9%
Year 2007: 12%
Year 2008: 15%

Some parties believe that a slower phase-in is most consistent with building new generation as a market power mitigation measure and provides LSEs with the most flexibility to meet their reserve requirement. On the other hand, some are concerned that the slower early approach simply defers potential trouble and results in problems meeting the operating reserve requirement.

4 Load Forecasting

There are many technical elements associated with load forecasting but for purposes of the workshops and this report, there are a few primary issues that require Commission guidance. Appendix B is a straw proposal developed by a self-selected load-forecasting working group. **The parties agree that there must be some entity that assigns responsibility for loads to LSEs**, especially in the event that forecasts made by each LSE result in a gap between expected system peak and the total forecasted peak load reported by each LSE. Therefore, this section of the report assumes that some type of assignment of load responsibility or reconciliation occurs[8] so that an LSE will know clearly what its resource adequacy requirements will be in advance of the resource adequacy showing.

The parties did not reach agreement on whether load reductions associated with demand response programs are to be removed from the load forecast or treated as a resource. This issue is discussed in Section 5.6.2 below.

4.1 Load Information Each LSE Must Submit

The load forecasting working group reached agreement that each LSE must submit hourly loads for each of the specified five summer months (May-September). This level of data is necessary to allow for adjustment for coincidence should the Commission decide such an adjustment is appropriate (see below). The parties support this recommendation.

Load forecasts need to include sufficient documentation to permit the reviewing entity to assess the results and basic forecasting approach. The load forecasting working group recommended that the following items be required:

- Historic hourly load for the previous year as used in CAISO settlement processes, adjusted for weather using an agreed-upon adjustment methodology
- Hourly values of the Load Forecast
- Basic documentation of customer counts[9], methodology, program impacts included (energy efficiency, distributed generation, price responsive demand, etc.)
- Narrative explanation of any significant factors

[8] The parties did not agree upon who should perform this assignment, but the CEC and CAISO were both mentioned as potential independent entities who could perform this assignment/reconciliation.
[9] Energy Service Providers (ESP) believe aggregate counts of customers should be sufficient to satisfy this requirement.

The expectation is that the proposed documentation level is consistent with that required in the California Energy Commission (CEC) biennial planning process, with which the utilities have experience, but non-utility LSEs do not. *The Commission needs to determine what level of confidentiality the forecast documentation will be afforded.*[10]

4.2 Adjustment of Peak Load Forecasts for Coincidence

Each LSE must forecast its hourly loads for each of the specified five summer months (May-September). An individual LSE's peak load most likely will not coincide in time with the system peak load due to the individual LSE's customer, geographic, and energy use make up. If each LSE is required to procure resources for its own peak load (including planning reserve margin), without adjustment, the result will be that LSEs with non-coincident peaks will procure more resources than are truly needed to meet the overall system peak load (including reserves), which has a real cost. At the workshop, parties estimated that adjusting loads for non-coincidence would reduce by approximately 1000-2000 megawatts (MW) the amount of resources required to meet system peak load.

There are two issues associated with the analysis of coincidence. First, what methodology to use to assess coincidence and second, whether to adjust LSE resource adequacy requirements based on the analysis. Each of these topics is taken in turn.

[10] The load forecasting working group recommends that all LSE-specific hourly load forecasts are confidential and access to such data will follow the usual non-disclosure agreement practices. At some level of aggregation, loads are no longer confidential and such "higher level" results can be prepared and released by the reviewing entity(s). No discussion of at what level of load aggregation shifts from confidential to public has yet taken place.

4.2.1 Coincidence Analysis

The load forecasting working group proposed two methods for assessing coincidence: LSE submitted forecast and historical loads (adjusted to average weather). Both are described in detail in Appendix B, with pros and cons of each method identified.[11] At the workshop the parties discussed both methodologies, but did not reach agreement on which way was preferred. Under the LSE submitted forecast approach, the designated load for the 90% forward commitment requirement is based on each LSE's share of total load during the CAISO's coincident peak hours, rather than LSE loads on their individual peak days. Under the historical loads approach, a coincidence adjustment is derived from the LSE's load at the time of the monthly CAISO peak, relative to the LSE's own monthly peak. Parties pointed out that if LSE submitted forecasts are used, all LSEs need to use the same modeling approach. One party was concerned that it is unclear whether hourly summer loads can be weather normalized.

The Commission need not adopt the specific implementation method laid out in Appendix , but *must decide whether coincidence analysis should utilize LSE submitted forecasts or historical loads.* In addition, *the Commission must decide whether any supplemental analysis needs to be performed for purposes of identifying the forward obligation for resource adequacy purposes.*

4.2.2 Should Forecasts (and Resource Adequacy Obligations) be Adjusted for Non-Coincidence?

The parties estimate that if no adjustment for non-coincidence occurs, approximately 1000-2000 MW of additional resources, above that needed to meet system peak load (including reserves), will be acquired. There are two options:

[11] Appendix B also describes a supplemental analysis that could provide additional information to assist in interpreting the results of the analysis. Some parties supported performing the supplemental analysis but others believe it is a very difficult analysis to perform.

adjust for non-coincidence or ignore non-coincidence. The Commission must decide whether to adjust for non-coincidence.

If the Commission decides to adjust for non-coincidence each LSE's forward obligations would be explicitly reduced by adjusting the original LSE load forecast for a monthly coincidence factor so that the "final" LSE load forecast used for compliance determination is lower than the original, non-coincident one. Prior to the existence of the CAISO, this type of adjustment occurred. Parties agree that adjusting for non-coincidence minimizes costs, but it is not clear exactly how load forecast reductions would be assigned to LSEs. Parties agree that adjusting for non-coincidence will be difficult. One party is concerned that if an adjustment for non-coincidence is made, there needs to be pooling of resources or resource adequacy will not be assured.[12] Another party countered that the market allows exchange among parties, and there is no need to tie the decision on adjustments for coincidence to any determination on pooling.

If the Commission decides not to adjust for coincidence, the forward commitment obligation would be based on the forecast by the LSE (consistent with the approach adopted for assignment of load to LSEs). The coincidence analyses would provide an understanding of the "cushion" provided by non-coincidence of individual LSE load forecasts and the benefits this has to further assure reliable system operation. One argument presented in favor of no adjustment for coincidence is that if there is a transmission constraint north-south or south-north at peak, it would be important for each LSE to carry full reserves for their load, rather than relying on system coverage for peak loads.

[12] Pooling is discussed in Section ? below.

The Commission must decide whether the load forecasts that set the resource adequacy 90% forward commitment obligation should be modified based on coincidence analysis. In addition, *it would be useful for the Commission to identify whether it is willing to have another entity, and if so, which one, perform the coincidence analysis and modification to load forecasts based on the coincidence analysis.*

4.3 Assignment of Load Responsibility to LSEs

The most crucial load forecasting concern is that the load of EVERY customer (including new customer growth) is assigned to be the responsibility of some load serving entity, otherwise resource adequacy objectives will not be met. The question is what customer base establishes the amount of load each LSE is responsible for procuring resources for, to meet its 90% forward commitment requirement. The fundamental problem that the choice of customer base raises is the relationship between the forecast and the financial obligation that comes with being resource adequate and the fact that load can move between LSEs between when the forecast occurs, the resource adequacy showing is made, and real time.

Two primary methodologies were proposed to assign load responsibility to LSEs: Current Customer and Best Estimate. These two methodologies are described in detail (along with pros and cons) in Appendix B, the Load Forecasting Strawperson. At the workshop, three other methodologies were also discussed: rolling 12-month forecast, IOU total service territory with allocation by a non-LSE, and only contracted amounts for non-IOU LSE.

Several parties expressed significant concerns that if methods other than the current customer methodology are used, there is a significant problem with gaming the forecast and under procurement of resources. Other parties believe that if penalties for gaming forecasts exist, this concern will be mitigated. Others expressed concerns that using the current customer base causes a problem due to the time lag associated with the resource adequacy showing and the time of delivery, resulting in procurement of resources for load that an LSE may no longer serves. At least one party was concerned that using only currently contracted for customer capacity to assign load will motivate LSEs to enter into shorter contracts with customers to reduce their resource adequacy obligation. At least one party believes that having a non-LSE perform the forecast and allocate load is inconsistent with the requirement that LSEs self forecast their loads.

If the current customer base is used to establish load responsibility then the concern about over-procurement of resources could be addressed contractually by requiring customer load to "settle" the capacity obligation if it moves to a new LSE between the time when the resource adequacy showing is made and actual delivery of supply. This "settlement" would effectively allow capacity commitments entered into by the first LSE to move with the load to its new provider. This potential solution appears to work for direct access customers but might have certain implementation problems for community choice aggregation (CCA) customers because of the smaller customer size and sophistication, but it is possible that this issue could be addressed in the CCA proceeding (R.03-10-003). Because this potential solution was first identified at the workshop, one party noted that it is possible that the potential solution to the load-shifting problem could introduce other billing and tariff implementation issues that have not yet been identified.

The Commission must decide which approach to forecasting customer base and assignment of load to LSEs it prefers. In addition, *it would be useful for the Commission* *to identify whether it is willing to have another entity, and if so, which one, perform this assignment and reconciliation of load.*

4.4 Inclusion of Losses in Load Forecasts

At the workshop parties discussed how to reflect transmission losses and unaccounted for energy (UFE) for purposes of determining the amount of load that establishes the resource adequacy requirement. The CAISO estimates that system-wide transmission losses could be in the range of 2000 MW, so accounting for these losses has important cost implications for LSEs. The CEC estimates that UFE could be in the range of -1 to +2% of metered load. The point on the electric system at which load is defined for purposes of establishing each LSE's load forecast impacts whether transmission losses or UFE are included in the forecast and thus whether an LSE must carry reserves for that load. Two different points of measurement were identified: CAISO interface and generation busbar.

Conceptually, load at the generation busbar is greater than the load measured at the CAISO interface by the amount of physical transmission losses between the generators and the CAISO interface, which is commonly referred to as a "transmission loss factor". SCE has found that, in practice, this "transmission loss factor" has to account for more than just the physical losses, for example UFE and metering discrepancies between real-time energy management systems and billing meters used for settlement.

For CAISO settlement purposes, LSEs currently use end-use metered usage plus losses up to the CAISO-interface. This measure represents hourly load at the customer meter (either from hourly meters or load profiled) plus distribution losses. The utilities publish distribution loss factors by voltage level for all ESPs within their service area to use for CAISO settlement purposes, so distribution losses used under this approach are calculated in a compatible manner. This definition point for LSE load does not adjust for transmission losses or UFE. The CAISO currently does not allow LSEs to schedule load associated with UFE, therefore this point of definition did not include UFE. Some parties believe that UFE could be incorporated into this definition point by assigning a percentage to all LSEs. Parties that support using load at the CAISO interface believe it is most consistent with the CAISO settlement process. They also point out that LSEs do not have access to transmission loss data in order to gross up their load forecast to the generation busbar, but generator loss data to load centers is known and therefore the counting protocols (discussed in Section 5 below) more appropriately will reflect losses in generator qualifying capacity.

If the measurement point for the load forecast is at the generation busbar, instead of the CAISO interface, transmission losses, UFE, and other adjustments are reflected in the differences between system control and data acquisition (SCADA) real-time metered loads and end-use customer loads. Measuring at the generation busbar requires “grossing up” load at the CAISO-interface for transmission losses. This load is defined as the sum of all generation within the control area (net of self generation serving customer load on the customer side of the meter) plus the net of imports minus exports to the control area. It is a “top down” measure of load, as compared to the “bottom up” definition of customer load as reported by LSEs to the CAISO for settlement, and it is real time. According to at least one party, this is the way that load forecasting is typically done. At least one party is concerned that if load forecasts are determined at generation busbar, the assignment of responsibility to procure to cover transmission losses to non- CPUC jurisdictional LSEs (i.e., municipal utilities) is necessary but problematic.

Some parties believe that transmission losses will already be accounted for in the determination of "qualifying capacity" for counting (see Section 5 below), and thus inclusion of losses by determining load generation busbar will result in double procurement of capacity representing losses. Parties appeared to agree that if the qualifying capacity of generating resources reflects a reduction for transmission losses, then transmission losses do not also need to be reflected in the load forecast. Parties also appeared to agree that UFE associated with energy theft is load that LSEs need to acquire resources (including reserves) to cover.

The Commission needs to decide whether transmission losses should be reflected in the load forecast by defining an LSE's load at the generation busbar or whether transmission losses should be reflected in the generation counting protocols. If the Commission decides instead that load should be defined at the CAISO interface then it should direct LSEs to adjust their load forecast for UFE and reduce generation qualifying capacity to reflect transmission losses.

4.5 Inclusion of Energy Efficiency Savings in Load Forecast

Parties agree that committed energy efficiency savings should be forecast and documented by each LSE in their load forecasts. For an energy efficiency program to be considered committed, **parties agreed that it must either have authorized funding (by a regulatory body) or a customer contract or commitment to the program. Parties agreed that a minimum level of documentation of energy efficiency savings includes time period (i.e., hourly) impacts, program design, and rollout (in order to determine when during**

course of the year savings will be realized). Utility operated energy efficiency programs have measurement and evaluation protocols associated with them that should facilitate straightforward integration into load forecasts. Because non-utility LSE operated energy efficiency programs do not fall under a regulatory authority or have approved measurement protocols associated with them, **parties agreed that the entity responsible for review and reconciliation of forecasts will assess the reasonableness of the forecasted savings for non-utility operated programs.**

4.6 Inclusion of Customer Side Distributed Generation in Load Forecast

Parties agreed that customer side distributed generation should be deducted from LSE load forecasts. In some cases, incentives for distributed generation are available to both utility bundled customers and direct access customers. Therefore, it may be necessary for some allocation of forecasted load reductions associated with installation of customer side distributed generation will need to be made between utility and non-utility load forecasts. The entity responsible for review and reconciliation of forecasts could assess the reasonableness of each LSE’s forecasted reductions associated with customer side distributed generation and make adjustments if appropriate.

5 Calculation of Qualifying Capacity

This set of agreements reached by workshop participants revolves around how to calculate qualifying capacity (QC) of various types of resources for resource adequacy purposes. <u>Qualifying Capacity is the maximum capacity eligible to be counted for meeting the resource adequacy requirement, prior to assessing deliverability of the resource.</u> Establishing qualifying capacity is the first step in determining a given resource's contribution towards meeting the year-ahead resource adequacy requirement of a load-serving entity.

The parties agreed on formulas for calculating qualifying capacity for numerous types of resources as described below. However, parties could not agree on whether qualifying capacity for unit specific resources owned or controlled by load-serving entities should be reduced for unit specific forced outage (FO) rates. *The parties agree that the Commission should decide whether a unit specific forced outage rate should be included in the qualifying capacity formula and therefore included a placeholder in the formula in the event that the Commission decides such an adjustment is appropriate.* More discussion on the forced outage adjustment follows the qualifying capacity formulas/protocols table.

The parties agreed that the North American Electric Reliability Council (NERC) Generating Availability Data System (GADS) definitions of industry terms should be relied upon in determining qualifying capacity. This set of definitions is attached as Appendix C. The following terms from the NERC GADS definitions are used in the formulas:

NDC= Net Dependable Capacity

SO= Scheduled Outages

Once a term is defined, it is not redefined each time it is used in a formula.

Resource Type	Agreed upon Formulas/Protocols
Group A: Load-Serving Entity owned/ controlled	
Hydroelectric: Pondage and Pumped Storage	QC= NDC- SO- [FO*]- VHD
NDC	Includes licensing and permit constraints
VHD	Variable head derate based on average dry year reservoir levels (essentially a look-up table that relates reservoir levels to capacity)
Average Dry Year	1-in-5 dry hydro scenario (e.g., use the 4^{th} worst year from the last 20 years on record)
FO*	Generic placeholder for forced outage factor if Commission decides to include
Hydroelectric: Run of River	QC= NDC- SO- [FO*]- CFD
CFD	Stream flow/conveyance flow/canal head derate based on average dry year stream flow/conveyance flow/canal head
Nuclear	QC= NDC- SO- [FO*]
Thermal: coal, combined cycle, combustion turbine, conventional	QC= NDC- SO- [FO*]
Geothermal	QC= NDC- SO- [FO*]- SFD
SFD	Derate for steam field degradation- several parties believe that steam field degradation is already factored into the NDC, this term just makes that expectation explicit.
Energy Limited Units	See Energy Limited Units below

Resource Type	Agreed upon Formulas/Protocols (continued)
Group B: Existing Qualifying Facility Contracts- See Qualifying Capacity Formulas for Existing Qualifying Facility Contracts below	
Group C: Contracts[13] - See Contracts discussion below	
Unit Specific Contracts	
Contract tied to physical plant characteristics	QC defined as specified for Group A
Contract for specific output	QC defined as specified for Group B
DWR Contracts: No Agreement- See DWR Contracts below	
System Contracts	
Imports[14]	QC= Contract Amount provided the contract: 1. Is an Import Energy Product with operating reserves 2. Cannot be curtailed for economic reasons 3a. Is delivered on transmission that cannot be curtailed in operating hours for economic reasons or bumped by higher priority transmission OR 3b. Specifies firm delivery point (not seller's choice)
System	No agreement- See Intra-Control Area System Sales below
Reliability Must Run Contracts, Condition 2	QC defined as specified for Group A and allocated to Participating Transmission Owners/LSE's based on their paid share of uplift costs.
Curtailable	QC = zero[15]

[13] Parties agreed that inclusion of a provision in the contract that allows for interruption to serve the seller's native load, in the context of a force majeure situation, does not automatically exclude the contract for counting towards the resource adequacy requirement.

[14] The CAISO expressed concern that this requirement would still allow for the seller to curtail its deliveries to meet native load requirements. The CAISO stated that it needs to research what triggers the right to curtail to meet native load, and depending on the outcome of that research, they could agree to the definition for import contracts to count. In addition, the CAISO indicated that it is concerned that WSPP Schedule C has an element that allows substitution of financial payment for failure to deliver. The CAISO indicated it needed to do more research on whether WSPP Schedule C would meet the definition of "economic reasons" before agreeing to this definition for import contracts to count.

[15] Parties agree that contracts that are curtailable for economic reasons (e.g., spot energy and capacity) should not count towards meeting the 90% forward contracting requirement. For this reason, the workshops did not address the availability of spot market energy and capacity. The workshop moderator believes that the issue of availability of spot market energy and capacity could better be addressed in the context of long term planning objectives and evaluation of whether the 90% forward contracting requirement is too high or too low given the availability of spot market energy and capacity.

Resource Type	Agreed upon Formulas/Protocols (continued)
Group D: Demand Programs	
Direct load control; non-firm interruptible; new programs (price responsive demand) - see Estimating Load Reductions from Demand Response Programs below	
Energy Efficiency	Reduces the load forecast as described in Section 4.5
Group E: Customer Side Generation (e.g., Photovoltaics, Distributed Generation)	
Serving onsite load	Serves to reduce load forecast[16]
Net metered sales/market sales	QC= historical performance over peak hours
Group F: New Generation Resources	
Projects under construction[17]	QC defined as specified for Group A as of: OPTIONS[18] Option 1: the scheduled commercial operation date Option 2: 30 days after scheduled commercial operation date Option 3: 90-120 days after scheduled commercial operation date
Projects currently in siting process	QC= zero

The Commission must decide whether to accept the agreements that parties reached on defining qualifying capacity for the various resource types.

5.1 Incorporation of Forced Outage Factor into Qualifying Capacity of LSE Owned/Controlled Resources

The issue of whether a forced outage rate should be reflected in the qualifying capacity of resources owned or controlled by a load-serving entity

[16] The ISO expressed a general concern about generation resources reducing the load forecast but did not further elaborate with respect to customer side generation.
[17] For new resources less than 50 MW in size, it is incumbent on the owner/developer to provide the requisite information to the appropriate regulatory body to assess whether the resource's output constitutes qualifying capacity for purposes of the year-ahead resource adequacy showing. See Section 5.7 for more discussion.
[18] Parties agreed in concept that projects under construction should be counted but did not reach agreement on when they should begin to count. The issues surrounding the timing of counting resources under construction is discussed below.

arises out of concern for equitable treatment between qualifying (QF) contracts and other resources. Some parties argue that the adopted 115% planning reserve margin reflects historical forced outage rates for LSE owned/controlled resources. These parties believe that incorporating a forced outage factor into the QC formula would result in over-procurement of resources and higher costs to ratepayers. These parties believe that if a forced outage factor is reflected in the QC for LSE owned/controlled resources, then the 115% planning reserve margin should be revisited. These parties believe that the nature of QF contracts ("put" contracts as opposed to "call" contracts of LSE owned/controlled resources) requires incorporation of historical performance in the QF contract QC, rather than just relying on contract capacity to set QC.

Other parties believe that if historical performance is reflected for some resources, it should be reflected for all resources. These parties believe that incorporating historical performance and forced outage factors on a unit specific basis would result in stronger incentives for unit owners to ensure performance on peak, reward units that do perform consistently on peak, and reflect the true availability of units that fail to perform on peak. This approach would require some entity to collect forced outage data.

Parties agree that QF historical performance data does capture forced outages, unlike the calculation of QC for LSE owned/controlled resources if no forced outage factor is incorporated. Parties agree that a potential solution to this situation is to "gross-up" the QF historical performance rate by 1/(1-FO). However, it is unclear whether forced outage rates for QF units would be readily available. An alternative approach would be to extract the system forced outage rate from the adopted 115% planning reserve margin to develop a new "unforced outage" planning reserve margin and then utilize historical performance on a unit specific basis to determine qualifying capacity.

The Commission must decide whether to adopt the formulas set forth for LSE owned/controlled resources with or without including a forced outage factor. If it decides forced outage factors should be reflected in qualifying capacity calculations for LSE owned/controlled resources, then it must decide whether to subtract the unit specific forced outage factor (the placeholder in the Group A formulas), gross-up QF historical performance to establish qualifying capacity, or whether to extract the system forced outage rate from the 115% planning reserve margin and then rely on historical performance by QF and LSE owned/controlled resources to set qualifying capacity. If it decides that forced outage factors need not be included, the forced outage factor placeholder may simply be deleted from the formulas.

5.2 Energy Limited Units

There was significant discussion about how energy limited units should be counted for purposes of the year-ahead resource adequacy showing. Parties agreed that individual units must be available 4 hours per day for 3 consecutive days to be counted. In addition, an energy limited resource must be available a certain number of hours per month to be counted for that month. Parties agreed that the number of hours per month a unit must be available to be counted should be based on the 1998-2003 average monthly number of hours that system load exceeded 90% of the monthly system peak, rounded to the nearest ten. The CAISO agreed to perform this calculation, which is set forth below.

Number Hours ISO Load Greater than 90% of the Monthly Peak

	May	June	July	August	September	Total

1998	**-**	**78**	**39**	**52**	**29**	**198**
1999	**21**	**11**	**20**	**36**	**38**	**126**
2000	**20**	**80**	**25**	**67**	**23**	**215**
2001	**50**	**46**	**27**	**62**	**43**	**228**
2002	**27**	**28**	**45**	**56**	**38**	**194**
2003	**10**	**18**	**106**	**75**	**56**	**265**
Avg. Hours	**26**	**44**	**44**	**58**	**38**	**210**
RA Obligation	**30**	**40**	**40**	**60**	**40**	**210**

The parties also agreed that individual energy limited units that meet the hours/days requirement can add together to meet the monthly hours obligation so that they may be counted for that number of hours in the resource adequacy showing. In addition, the parties agreed that each monthly hours requirement is independent from other months. This means that an LSE may designate an energy-limited resource to count for the month of August, but not May (for example).[19] *The Commission must decide whether this minimum hours requirement agreed upon by the parties for energy limited resources is acceptable.*

5.3 Qualifying Capacity Formulas for Existing Qualifying Facility Contracts

Parties at the workshop generally agreed that historical performance at peak should be considered in determining QF qualifying capacity, however, one party raised equity concerns because historical performance data captures forced outages for QFs, which is not captured by the formulas agreed upon for Group A resources if the forced outage rate is excluded. *It is the workshop moderator's belief that the formulas described under Existing Qualifying Facility Contracts (Group B) can be considered agreements once the forced outage issue is resolved,* although the Commission will still need to decide which of the two options to adopt for solar (without gas backup) and wind resources.

[19] These requirements are only for supply resources, demand response programs with limitations on their use are addressed in Section 5.6.1 below.

Resource Type	Formulas
Group B: Existing Qualifying Facility Contracts	
Cogeneration, biomass, geothermal, gas assisted solar	QC= Contract Capacity * historical performance[20] at peak[21]
Hydroelectric: Run of River	QC= historical portfolio[22] performance in average dry year
Hydroelectric: Pipeline	QC= historical performance[23]
Solar without gas backup, wind[24]	TWO OPTIONS Option 1: QC= average production during peak hours[25] Option 2: QC= NDC * ELCC
Average production	Average existing portfolio production over several years, unit specific rating for new wind resources
ELCC	Effective Load Carrying Capability

The parties did not agree upon a formula for calculating the capacity from solar (without gas backup) and wind contracts but instead presented two options. In large part, the inability to reach agreement relates to the very different performance of old and new wind projects and differences in performance between geographic regions. Those who support Option 1 believe that looking at past production best captures these performance differences. These parties also point out that we would need to understand how the ELCC is

[20] San Diego Gas & Electric Company (SDG&E) would reflect this factor on an individual QF basis, SCE and Pacific Gas and Electric Company (PG&E) would reflect it on a portfolio basis.
[21] The peak period for which historical QF performance would be measured was not defined or discussed at the workshop. QF Standard Offer 1 contracts define the on-peak period as “noon to 6:00 p.m. summer weekdays except holidays.” To arrive at a measure of “historical performance at peak” you would also need to decide the number of years over which to average historical performance and whether to use performance data for a single annual peak day or five monthly peak days (May-September). For example, if you used 5 years of monthly peak day data to determine the historical performance at peak, average performance would be measured over 150 hours (6 hour on-peak period * 5 years * 5 peak days per year).
[22] Portfolio basis was recommended for administrative ease, but this could also be calculated on an individual unit basis in the same way as Group A resources.
[23] The time period for measuring historical performance was not defined.
[24] Parties generally agreed that new and future wind contracts (including non-QF contracts) should be counted the same way as existing QF contracts for purposes of assessing resource adequacy.
[25] Peak hours were not defined.

calculated to ensure that it assesses load-carrying capability for the time period that is relevant for resource adequacy purposes, not for some other time period. Those who support Option 2 fear that Option 1 will undervalue capacity of new wind resources.

The Commission must decide which of the options for solar (without gas backup) and wind resources to adopt, and whether to adopt the formulas proposed for Existing Qualifying Facility Contracts in light of its decision on forced outages.

5.4 DWR Contracts

Finding of Fact 22 of D.04-01-050 states: "California should receive full credit and value for the long-term contracts entered into by the DWR to help California meet its energy needs during the crisis." The term "full credit and value" was not defined in the decision and the issue of how to count these contracts was referred to workshop. The parties did not reach agreement on how to ensure that full credit and value for these contracts is given.

The 9670 MW of DWR contracts consist of 3 types of contracts: unit specific resources (4095 MW); portfolio of resources (2600 MW)[26]; and market resources (2975 MW).[27] There are two parts to assessing whether (and how much of) a contract can be relied by an LSE in meeting its year-ahead 90% forward commitment requirement. First you must look at how much qualifying capacity the contract has, and then, whether it is deliverable. Some parties are concerned that some of the DWR contracts (market contracts primarily) would not result in qualifying capacity under the rules and protocols discussed for contracts generically. In addition, some of the DWR contracts may have deliverability

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[26] Portfolio of resources contracts have multiple generation units identified that the contract holder can use to meet its contract obligations.
[27] These figures are for contracted capacity in 2008.

issues that could result in derating of capacity that can be relied for the forward commitment requirement under the rules and protocols discussed for contracts generically. Parties identified several ways that the term full credit and value could be interpreted.

- Establish the qualifying capacity based on DWR contract amount even if the contract would not otherwise have a qualifying capacity, but then require the DWR contract to pass the generic deliverability screen to arrive at the contract's value for the year-ahead showing.
- Utilize the contract capacity for the contract's value for the year-ahead showing regardless of whether the contract would have any qualifying capacity or be deliverable under generic protocols.
- Apply generic protocols for calculating qualifying capacity and deliverability to establish the contract's value for the year-ahead showing, the same as any other contract.

Some parties believe that for unit specific contracts and portfolio contracts, using the protocols for calculating qualifying capacity should result in the same value that was contracted for, with the possible exception of wind contracts. However, this is a belief, no analysis was performed to support it. Most of the DWR contracts that rely on market resources will expire by 2012.

The Commission must provide its definition of full credit and value of DWR contracts so that LSEs know how they can rely on the DWR contracts in the year-ahead showing.

5.5 Contracts

Parties agreed that to evaluate contracts there are several threshold questions that need to be addressed, and the answers affect how a given contract should count towards meeting the year-ahead resource adequacy requirements. At the April 7, 2004 workshop parties developed a set of yes/no questions that depending on the answers, could result in a contract qualifying for inclusion in an LSE's portfolio for year-ahead resource adequacy purposes. In essence, contracts were divided into two types: those backed by physical capacity or demonstrable rights to physical capacity, and financial products not backed by physical capacity or demonstrable rights to physical capacity. Parties were able to agree on definitions of qualifying capacity for contracts backed by physical capacity (as reflected in the protocol table) but were unable to agree on what constitutes "demonstrable rights to physical capacity" and thus were unable to clearly identify whether certain types of contracts meet this test and constitute qualifying capacity.

The contracts that raise the most questions about whether they can be considered to hold demonstrable rights to physical capacity are system import contracts (primarily from the Pacific Northwest) and intra-control area system sales. **The parties discussed the import contracts and were able to reach an agreement on the elements that a contract must have to constitute qualifying capacity, subject to additional research by the CAISO.** That agreement is reflected in the protocol table. The parties discussed intra-control area system sales, but did not reach agreement about the elements those contracts must contain to constitute qualifying capacity.

5.5.1 Intra-Control Area System Sales

Based on discussion at the workshop, it appears that one of the primary products in the market is a contract known as a "Firm LD Contract", a system sales contract without physical resources identified that provides for liquidated damages in the event of non-performance. Without knowing all the details of the contract, it appears to have similar elements to those required for system import contracts to count except that it specifies a firm delivery point within the CAISO control area and does not provide reserves (because it is within the CAISO control area).[28]

One party was concerned that without specific physical resources identified, there is the possibility of more than one contract holder relying on the same physical resources to serve their load, which would not assure resource adequacy.[29] In addition, without identification of a physical resource for these contracts, performing a deliverability analysis becomes difficult. Most parties however, believe that intra-control area system sales should be considered qualifying capacity for year-ahead resource adequacy purposes. These parties point out that this is the product that currently trades in the market and that at a minimum, if the Commission wants to move to contracts that contain a unit specific requirement in the future, it needs to provide for a transition period to get there. As a potential short-term solution, one party suggested that the Commission consider allowing some limited percentage of the year-ahead portfolio to be this type of contract, until a more tradable product backed by physical resources is available in the market. Workshop participants indicated that they would continue to work to find common ground on the issue after the workshops concluded.

[28] At the workshop, Constellation Energy agreed to provide contract language of this type of contract, but as of today's date, the workshop moderator has not received this language.
[29] Although this issue was initially a concern for system imports, it appears to be less of a concern with respect to system imports than intra-control area system sales because of fact that the Pacific Northwest is a winter peaking system.

The Commission must decide whether intra-control area system sales constitute qualifying capacity for purposes of the year-ahead resource adequacy showing.

5.6 Estimating Load Reductions from Demand Response Programs

There are several types of demand response programs:

- Reliability/Emergency Programs: air-conditioner cycling programs; Interruptible tariffs
    - Utility cycling programs include direct control by the utility over whether customer interrupts
    - Utility interruptible tariffs all have different eligibility, triggering conditions, curtailment provisions, penalty provisions, operational history and do not include direct control by the utility over whether customer interrupts
- Price Responsive Demand Programs: Dispatchable programs; non-dispatchable programs
    - Dispatchable program provisions include a trigger price/event which alerts the customer the program is being "called" or dispatched
    - Non-dispatchable programs allow the customer to make the economic choice whether to modify its usage in response to price signals

The parties agreed on a methodology for determining the amount of load reduction that should be attributed to each program. For interruptible programs, the parties recommend that the amount of load reduction associated with this program should be calculated based on historical performance over the times the program was called or tested. For all other demand response programs, the parties recommended that adopted measurement protocols (a combination of historical performance and statistical sampling for each month (May-September)) should be used to calculate the load reduction associated with the program. This approach will allow the reliance on new demand response programs to grow as more experience is gained with the programs. One party noted that use of historical performance data is controversial for establishing qualifying capacity (see Section 5.1 above) and that the Commission should consider whether this approach remains appropriate given its decision on the forced outage factor.

Although there was agreement on how to estimate the load reduction attributable to demand response programs, no agreement was reached on two other issues related to how demand response programs will count in the year-ahead resource adequacy showing. These issues are discussed below.

5.6.1 Must Demand Response Programs Meet a Minimum Hours Requirement to Have Value in the Resource Adequacy Showing?

For generation resources, parties agreed that resources must be available a minimum of four hours each day, for three consecutive days, and a specified number of hours over the course of a month for that resource to be able to have value in the year-ahead 90% forward commitment showing. Several of the existing demand response programs can be triggered for periods of time less than four hours a day and have limitations on the number of hours they can be called in a month (or days in a row) that do not meet the criteria established for energy limited generation resources. **Parties agree that demand response programs need to be available for 48 hours over the May-September season to be able to be relied on in the year-ahead showing**.

The parties discussed two options for how demand resources could be relied on in the year-ahead showing:

1. All MW signed up for demand response programs with at least two hours/day availability count, provided that they meet the 48 hour/season criteria.
2. MWs signed up for two hour demand response programs need to sum to four hours per day to count (i.e., 200 MWs of 2 hour/day load reduction = 100 MW for resource adequacy counting) plus sum to monthly requirement described for energy limited resources and 48 hours/season.

Parties that support the first option argue that the load duration curve is needle-like at its peak and that programs with two-hour limits on availability should be able to meet that needle peak and count without being discounted because they cannot meet a four-hour peak or meet the monthly requirement set for energy limited generation resources. These parties are concerned that if programs that are available only for two hours cannot be utilized for resource adequacy requirements, programs may need to be redesigned because additional resources will be needed to satisfy resource adequacy requirements and the economics of the demand response programs will be impacted. Those who support Option 2 stated that the grid operator needs to know that a resource is available for more than two hours to be able to effectively utilize it in serving a high load situation.

After discussion at the workshop, **parties agreed**, pending receipt of data from the CAISO, **that demand response resources that are available for only two hours should be able to be utilized in an LSE's year-ahead showing but**

can only make up a limited percentage of the LSE's portfolio for the year-ahead showing. The limited percentage would be derived by developing a MW limit by calculating the difference between the annual peak load minus the third highest hourly load on the same day and then translating this MW limit into a percentage by dividing the MW limit by the peak load MW. The CAISO agreed to also perform this calculation for the fifth highest hour and the seventh highest hour. These calculations will allow assessment of how "needle-like" the highest peak hours are or whether some duration longer than two hours is required for a demand response resource to have value for resource adequacy purposes. Parties decided to hold off on making a recommendation on whether demand response resources that have a greater than two hour commitment need to meet the monthly minimum hours requirement recommended for energy limited generation resources until the results of the CAISO analysis was available.[30]

Upon receipt of the CAISO data, *the Commission must decide whether demand response resources may be relied upon in an LSE's year-ahead forward commitment showing without meeting the minimum hourly and monthly availability requirements recommended for energy limited generation resources.* If the Commission decides that demand response resources must be available for more than two hours to be used in the year-ahead showing, *the Commission must decide what minimum hourly and/or monthly availability requirements must be met.*

5.6.2 Should Demand Response Programs Be Treated as Demand Reduction or Supply for the Resource Adequacy Showing?

The Commission must decide whether demand response programs (interruptibles, direct load control, and price responsive demand) are treated as a demand reduction or

[30] On June 11, 2004 the workshop moderator received the results of the CAISO calculations. The table is included as Appendix G.

supply resource for purposes of assessing resource adequacy. The primary implication of this decision is whether an LSE must carry (and procure) reserves for the capacity associated with demand response programs. The utilities argue that they do not now, and never have, carried reserves for the load signed up under interruptible programs, precisely because customers on these programs can be interrupted. Those who advocate for treating these programs as supply resources are not so concerned with the reserves question, but rather with the difficulty of how you might model interruptible programs as a demand reduction and the fact that interruptibles are called in a manner more like a supply resource.

Parties discussed three options for how to treat demand response programs: (1) treat dispatchable programs as supply resources, non-dispatchable programs as load reductions; (2) remove all demand response programs from the load forecast; (3) treat all demand response programs as supply resources.

Parties that support handling programs based on their dispatchability argue that dispatchable programs operate much more like an energy limited product and because of these operating characteristics, it is hard to consider it a load forecast reduction comparable to an energy efficiency investment. At least one party felt that it was worth discussing eliminating the need to carry reserves on dispatchable load reductions if that was the impediment to treating dispatchable demand response programs as a resource.

Parties that support removing all demand response programs from the load forecast argue that demand response programs should be treated consistently with energy efficiency programs because they are both valued high in the loading order and that treating all demand response programs as load reductions promotes state policy consistency. These parties argue that these loads are not planned to be served because they are interrupted prior to firm loads. No party advocated treating all demand response programs as resources, thus **the parties do appear to agree that load impacts associated with non-dispatchable demand response programs should be removed from the LSE's load forecast, consistent with the protocols discussed above in Sections 5.6 and 5.6.1.**

Parties discussed whether treating dispatchable demand response programs as load versus supply impacts any other resource adequacy issues besides the need to carry reserves, for example, deliverability. The CAISO does not think there would be any issues, except perhaps for deliverability in a load pocket, however parties remain concerned about potential flow-through affects that are unclear. It appears that removing the need to carry reserves for the amount of load reduction associated with dispatchable demand response programs could solve the issues raised by advocates for Option 2.

The Commission must decide whether load reduction impacts from all demand response programs should be removed from the load forecast or if impacts from dispatchable programs should instead be treated as supply resources. If the Commission decides dispatchable programs should be treated as supply, *it must decide whether reserves must be carried on that amount of load reduction.*

5.7 Timing of When to Count Resources Under Construction

The issue of when you can count resources under construction is driven by the fact that the resource adequacy showing is made the year-ahead and there is considerable uncertainty as to whether projected online dates of projects are realistic. The CEC website shows an expected online date and a percentage constructed for all projects sited by the CEC at http://energy.ca.gov/sitingcases/all_projects.html. The parties discussed the calculation approach and reliability of the data included in that list and decided that at this point in time, it should not be relied upon for counting purposes. Instead, the parties discussed, but did not agree upon, three options for when a resource should be able to be counted:

Option 1: the scheduled commercial operation date
Option 2: 30 days after scheduled commercial operation date
Option 3: 90-120 days after scheduled commercial operation date

Some parties are concerned that the scheduled commercial operation date that would be known a year in advance is not sufficiently robust to ensure that an LSE will be resource adequate in real time. Parties that advocate for Option 1 believe that the scheduled commercial operation date can be used if there are penalties for an LSE that is not resource adequate in real time. These parties believe that if penalties are in place, LSEs will incorporate provisions into contracts with new generators to make the online date more reliable. Parties that advocate for Option 3 believe that many new projects do not actually come online until a few months after the scheduled commercial operation date known a year-ahead and therefore, to ensure that a new project can be relied on a year-ahead, one should not assume the project is available until 90-120 days after it is scheduled to be commercially operable.[31]

The Commission must decide when a project under construction is eligible to be counted for purposes of the year-ahead resource adequacy showing.

[31] This belief is based on anecdotal information, not a systematic study of online date projections a year-ahead and actual online dates.

6 Deliverability

After the qualifying capacity of a resource is determined, an analysis of whether the resource can be delivered to (1) the aggregate of load and (2) the CAISO control area (for imports) must still be conducted. **The parties agree that these two deliverability screens must be passed for a resource to have value in meeting the 90% year-ahead forward commitment requirement.** The parties have assumed that if an LSE contracts with a resource whose capacity is deliverable to the aggregate of load (rather than necessarily the specific location of that LSE's load) the resource will meet the deliverability requirements. In other words, most capacity used to meet resource adequacy requirements is effectively "pooled" and will be used to meet the needs of the entire system.[32] *The parties seek the Commission's confirmation that this assumption is accurate.*[33]

Several parties propose a third test: deliverability of resources to transmission constrained areas. Other parties vigorously oppose this requirement. This topic is addressed in Section 6.4 below.

6.1 Baseline Analysis of Deliverability of Resources to CAISO Control Area and Aggregate of Load

The parties agree that the CAISO should conduct the baseline deliverability analysis that establishes the deliverability of imports to the CAISO control area and deliverability of resources to the aggregate of load.

Appendix D was prepared for discussion purposes at the April 12 and 13, 2004 workshops and contains more technical details about the CAISO's proposed

[32] The exceptions appear to be existing transmission contracts and self-scheduled resources.

[33] The CAISO states that resources relied on for the resource adequacy showing need to be turned over to its control in order to operate the system closer to real time. This request by the CAISO highlights once again that year-ahead resource adequacy requirements may have potential interactions with system operation. The interaction issue was not addressed in workshops.

evaluation methodology than described herein; it was used to identify concerns that parties had about specific methodologies.[34] At the April 12 and 13, 2004 workshops, the parties concluded that additional technical work related to assessing import capacity would be useful. Appendix E describes a baseline analysis that the CAISO would perform to establish an amount of total import capacity available at each intertie.[35]

In a nutshell, the CAISO would establish an initial level of total import capacity available at each intertie based on historical 2003 on-peak summer import levels. The CAISO would then review the impact of that level of imports on the deliverability of generation internal to the CAISO control area (deliverability to aggregate of load) and adjust the import capacity level down if the deliverability of internal generation is impaired by the initial import assumption, no upward adjustment to the capacity import level would be made above historic levels.

This analysis would set the baseline for total import capacity as well as a baseline deliverability assessment for internal generation and would be updated annually to reflect additional generation coming online and changes to the transmission system. This approach has a preference for existing internal generation and does not assume additional import capacity above the historical usage would be available for a resource to use to meet its resource adequacy requirement.

The Commission must decide whether the baseline deliverability analysis should contain a preference for existing internal generation and limit import capacity at the

[34] The subjects in Attachments 1 and 2 of Appendix D were discussed at the workshops, the merits of Attachment 3 were not discussed because parties could not agree whether it was necessary to test deliverability of resources to transmission constrained areas, see Section 6.4.

historical usage level, for purposes of the year-ahead 90% forward commitment requirements. The workshop report next discusses issues that arise during the deliverability assessment.

In order for the CAISO to perform the baseline deliverability analysis, the parties agree that the following data requirements exist:

- counting rules finalized (see Section 5 above)
- firm import/export contracts known
  - export contracts to be modeled at contract level
- existing transmission contracts
- LSE peak load forecast (in order to develop simultaneous load forecast)
- Latest transmission plans reflected in model

Parties do not agree whether the next items are needed for the deliverability assessment, however, if they are needed, the information should be included consistent with protocols adopted in Section 5 above.

- QF contract capacity limits on interconnection basis
- Dry hydro vs. normal hydro assumptions

Despite the lack of agreement over whether certain information is needed, the workshop moderator does not believe that the Commission needs to resolve any issues with respect to data at this time. Instead, the parties should work with the CAISO during the first baseline analysis to refine the data requirements and information that each LSE must provide to the CAISO.

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[35] The approach described in Appendix E was discussed at the May 5, 2004 workshop.

6.2 How Should "Deliverability" be Allocated to Existing Resources if Deliverability to Aggregate of Load is Constrained?

In assessing the deliverability of a generation resource to aggregate load, the intent is that the deliverability assessment will be consistent with the deliverability finding and requirements that stem from the interconnection process.[36] The result is that as generators come online, their deliverability to the aggregate of load is assessed and, if there are deliverability issues, the generator is offered upgrade options to make their resource fully deliverable. **Parties agreed that it makes sense for a generator to be pre-certified as to their deliverability**. **Parties agreed that new generation coming online would not result in a change to an existing generator's rating for deliverability**. **Parties agreed that a generator that commits, through the interconnection process, to pay for upgrades to make it deliverable would pass the deliverability screen up to that level**. **Parties also agreed that deliverability is a sliding scale**, in other words, a generator with a 100 MW QC may only be able to deliver 80 MW to the aggregate of load under the baseline deliverability scenario. Under this example, unless the generator pays to upgrade the transmission system, the generator would only be certified deliverable at 80 MW. This 80 MW would be available for an LSE to use to meet its 90% year-ahead forward commitment requirement.

It is possible that there will be constraints on the transmission system that limit the deliverability of generation resources to load. In that case, some method of prioritizing the deliverability of resources must be adopted. The straw proposal in Appendix D assumes that generators will be allocated capacity if constraints exist, on a pro-rata basis. Equity concerns about the pro-rata allocation approach arose, so parties discussed two approaches to allocating deliverability to generation resources: allocation based on payment for firm transmission and an auction. *The Commission must decide how to allocate "deliverability" to existing resources if deliverability to the aggregate of load is constrained.*

The biggest concern parties identified with respect to the deliverability to aggregate of load is when general system conditions (as opposed to conditions caused by a specific new generator) result in less deliverability of existing resources than initially certified, what deliverability rating do affected resources have until upgrades occur? The reason this is a problem is that the duration of deliverability issues due to general system conditions is unclear because the determination to upgrade the transmission system is an economic decision, not a reliability decision. In this situation it is unclear whether to derate existing generators (although parties agree that this situation can truly affect deliverability) and which generator to derate is also unclear, an individual generator or some sort of pro rata deration on all generators. In addition, if the deliverability of a resource can change from year to year because of the need for system upgrades, planning to meet resource adequacy is made more difficult and impacts the willingness of developers to invest in California resources. This is why in the discussion above, parties agreed that a resource should be pre-certified as to its deliverability. *Any guidance the Commission can provide as to whether, and if so, how, deliverability of resources should be derated due to general system conditions will help provide certainty and investment direction.*

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[36] Parties agree that because the interconnection process is overseen by FERC, the entity that performs the

6.2.1 Allocation Based on Payment for Firm Transmission

Under this approach, rather than perform a pro-rata allocation to all generators if a constraint exists, capacity would first be allocated to generators who paid for firm transmission upgrades to make them deliverable[37] or who did not need to add transmission capacity to be deliverable as set forth in their interconnection study. At the time of interconnection a generator has the option to pay for upgrades to accommodate all or part of its output. The objective is that those generators that paid for deliverability for any or all of their output (or did not require upgrades at time of interconnection to be deliverable) would also be deliverable to that same extent for purposes of the resource adequacy showing. If additional transmission capacity is available, then it would be allocated to those generators for whom transmission needs were identified but who elected not to pay for upgrades at the time of interconnection.

Under this approach the amount of qualifying capacity of a generator who did not pay for firm transmission would be derated until those generators that had paid for firm transmission were deliverable. The percentage a particular generator's qualifying capacity was derated would set that generator's deliverability baseline. Parties believe that this approach would be consistent with FERC Order 2003, but could be cumbersome to implement. The CAISO would like to perform the analysis before committing to this approach, because it (as well as some other parties) is concerned that it may still be necessary to derate some generators that paid for firm transmission to ensure deliverability. However, this prioritization order appears to have general support.

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interconnection deliverability study will be decided by FERC.

[37]Historical utility resource plans on file with the Commission were suggested as a data source for determining firm resources prior to the existence of the CAISO. Once the CAISO came into existence, interconnection studies would be the data source for determining how firm a generator's transmission is.

6.2.2 Auction

At workshop parties also discussed an alternative approach to allocation constrained transmission capacity: conducting a one-time auction to allocate the transmission rights for purposes of the baseline analysis with revenues from the auction going to the entity who had historically paid for transmission. Parties expressed concerns about administration of the auction and equity concerns that this could still result in resources that paid for firm transmission not being deliverable, effectively stranding those resources for resource adequacy purposes.

6.3 Allocation of Total Import Capacity

After an assessment of the total import capacity on the intertie into the CAISO control area is performed, an allocation of the total import capacity to each LSE must be made. At workshops, parties discussed several possible approaches to allocation which are fully described in Appendix F, prepared by PG&E for purposes of discussion at the May 5, 2004 workshop. The hybrid approach and variants on it were discussed at some length and are summarized below in Section 6.3.1. *The Commission must decide which approach to allocating intertie capacity to adopt.*

Parties agree that the CAISO should identify the total capacity over each intertie and allocate it to each LSE (consistent with the approach adopted by the Commission) **approximately six months in advance of the year-ahead showing**. The parties agree that the LSE is limited to assuming that allocation in its resource adequacy showing, but it must have a contract utilizing its allocation for the capacity to have value in the resource adequacy showing. Parties point out that with the ability to trade the allocation of intertie capacity, there would be less unused capacity. *The Commission must decide if intertie capacity allocated to a particular LSE can be traded to another LSE and be able to count for resource adequacy purposes for the second LSE.*

Parties did not agree on the duration of the allocation of intertie capacity to LSEs, but discussed the possibility of using a one year allocation, a three year allocation, or the duration of the contract or resource that relies on the intertie to set the duration of the allocation of intertie capacity.[38] The duration of the allocation impacts the ease of determining transfer capability and predictability. There is a tension between updating allocations to LSEs and adopting a longer term predictable duration of the allocation. Those who support a one year allocation argue that it is inefficient to sign longer term contracts to use the allocation because of mobility of load and that LSEs without historical use of the intertie will not be able to get an allocation. Those supporting a duration longer than one year argue that it results in greater surety for resources that LSEs contract with that they will assist in the resource adequacy showing and that a longer duration promotes the ability to consider more resource options than a one year duration allows. *The Commission must decide whether to adopt specific duration of the allocation of intertie capacity for resource adequacy purposes, and if so, for how long that duration should last.*

6.3.1 Methods for Allocating Total Import Capacity

At the May 5 workshop parties discussed various approaches focusing on the hybrid approach described in Appendix F. Parties did not reach agreement on the correct allocation methodology to adopt.

[38] This discussion occurred at the April 12 and 13, 2004 workshops. At the May 5, 2004 workshop, the parties appeared to agree that once an allocation is made and is being utilized, that capacity does not need to be reallocated in subsequent years, as long as the contract using that path still exists. Because of the difference in discussion

The hybrid approach proposed in Appendix F suggests that first an allocation of import capacity be made on a pro-rata basis with adjustments made in subsequent steps to reflect existing commitments[39] on the various import paths. Other parties suggested that it would be more logical to make an initial allocation based on historical use of the tie line in order to respect existing commitments, and then if additional capacity remains, allocate it on a pro-rata basis. Under this second approach, an LSE's maximum allocation would be capped at the lesser of its historical allocation plus pro-rata allocation of remaining capacity or its pro-rata share of the total import capacity. Some parties believe that the two approaches, pro-rata first then allocate based on existing commitments, and existing commitments first then allocate remaining on pro-rata basis, are mathematically the same and will result in the same allocation to LSEs.

Another option discussed would assign the right to the import capacity to existing commitments, then assign rights to residual capacity on a pro-rata basis, and then put all capacity up for bid, with the revenue from the independently administered auction flowing back to LSEs based on the rights they hold under the initial allocation.

Parties did reach agreement that, if a pro-rata approach is used for the initial allocation or allocation of remaining capacity, then LSEs should receive an initial proportional allocation for the load they serve based on their contribution to revenue requirement rather than on access charges as described in Appendix F. The pro-rata allocation would use either historical or forecast load data,

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between the two workshops, the workshop report covers the discussion, assuming the dispute still exists, but parties should comment on whether the discussion at the May 5, 2004 workshop resolved this issue.

consistent with the approach adopted for determining the load forecast in Section 4.3 above.

The ability to trade rights to an import capacity allocation in a secondary market, whatever the initial allocation methodology adopted, should assist in addressing some of the concerns that assigning rights based on existing commitments or contracts limits the ability to enter into new contracts that require the use of the interties.

The Commission must decide how to allocate import capacity to LSEs for purposes of the year-ahead resource adequacy showing.

6.4 Is there a Resource Adequacy Requirement in Load Pockets?

The CAISO proposed that a third deliverability screen be adopted to assess a resource's deliverability to transmission-constrained areas, also called load pockets. A load pocket is a particular area of load with insufficient transmission to cover its load requirements, for example, the San Francisco Peninsula. Some parties support the concept of a load pocket deliverability requirement; other parties vigorously oppose this being a requirement for a resource to be utilized in the year-ahead resource adequacy showing.

The interest in load pocket deliverability appears to be driven by concerns by market participants and the CAISO that generators in local reliability areas are frequently called under the "must offer" provision of the CAISO tariff in order to support meeting load requirements in load pockets. However, some parties are concerned that the must offer provision will not be continued, leaving the CAISO with less tools to address local reliability problems. In addition,

[39] Existing commitments were not specifically defined but appear to mean firm resources using the import paths, not economy energy use of the line.

although parties point out that RMR units are supposed to address local reliability concerns, there are many non-RMR units that are being chronically called under the must offer provisions to support local load requirements. Consideration of whether, and if so, how, to adopt local procurement or load pocket deliverability requirements, appears to be an effort to respond to these issues.

This proposed test can be looked at in two ways, as a review of the capacity transfer limits into a load pocket, or as a requirement for procurement within a load pocket. Adopting a test that considers deliverability to a load pocket would effectively impose a reserve requirement, not just at a system level, but also on a load pocket basis. FERC indicated that the NY ISO phased-in a procurement requirement within load pockets that incorporates market power mitigation measures.

Parties who support adoption of this deliverability screen argue that load pocket deliverability is not currently addressed in the CAISO grid planning process, which can only look to transmission solutions to load pocket problems, whereas the resource adequacy process can look to generation and demand solutions as well. These parties argue that if a load pocket procurement requirement is adopted, reliance on reliability must run units and must offer calls should be reduced. One party specifically suggests that LSEs serving load in pre-defined load pockets must procure a percentage of their total capacity requirement from suppliers of qualified capacity electrically located within defined constrained areas. There was some discussion that the load pockets could be defined as the existing local reliability areas.

Parties who oppose adoption of this deliverability screen argue that deliverability to load pockets is more appropriately addressed in the CAISO's grid planning process than as a resource adequacy requirement. These parties worry about duplicative analysis of deliverability to load pockets being performed in the grid planning process and resource adequacy showing. One party suggests that one of the outcomes of the grid planning process should be a plan to identify units needed in load pockets, thus obviating the need for any local procurement or load pocket deliverability requirement in the resource adequacy showing. These parties argue that the Commission did not adopt a load pocket deliverability or procurement requirement and if a load pocket must also carry reserves at the same level as the system, the adopted planning reserve margin might need to be revisited. These parties are concerned that if a load pocket procurement requirement is adopted, the generators in that load pocket will be able to exercise market power and LSEs will end up procuring more reserves than required by the Commission's adopted planning reserve margin.

Another issue that arises in considering whether to adopt a load pocket deliverability or a local procurement requirement is how it would be applied to all LSEs within load pocket, given that some LSEs in a load pocket might be municipal utilities. In addition, distributing any constrained transfer capacity into a load pocket or the procurement requirement between LSEs, including community choice aggregators serving load in a load pocket raises difficult administrative and operational issues.

Some parties believe that additional data analysis is needed to better understand the scope of the problems that are trying to be solved in load pockets by the proposed establishment of a load pocket deliverability screen or a load pocket procurement requirement. For example, one party notes that it is unclear if the problems in load pockets relate to meeting peak load, base load, or emergency requirements and that different problems could argue for different solutions. At the May 5, 2004 workshop, parties discussed the type of information that would assist in analyzing the scope of the problem and the CAISO was asked to perform a review of historical data from must offer calls, specifically looking at why certain units (described as "chronic") are called, to facilitate further discussion of deliverability requirements for resource adequacy purposes for resources serving load pockets. The CAISO informed the workshop moderator that limitations on the disclosure of confidential market information and the overall accessibility of this data precluded production of the information in time for discussion at the workshop, so the topic was not discussed further.

Some parties suggested a short-term middle ground solution for dealing with this issue.[40] The proposal is that in existing local reliability areas, a local procurement requirement percentage be set based on the import limitation into the local reliability area divided by peak load in the local reliability area. This can be expressed formulaically as:

$$\text{Local Procurement \%} = \frac{\text{Import Limit MW}^{41}}{\text{Peak Load MW}}$$

Some parties expressed concern that several things must occur if a local procurement requirement is imposed in load pockets. For example, the CAISO must define load pockets specifically enough to establish procurement objectives in advance; dispatch requirements need to be defined (specific and in advance);

[40] All parties appear to agree that adopting a local procurement requirement could trigger market power concerns and suggest that market power mitigation measures must be concurrently pursued if a local procurement requirement is adopted. This solution was discussed briefly, but cannot be characterized as an agreement by all parties.

[41] This could be defined as the Capacity Transfer Limit which is described in Attachment 3 to Appendix D.

equity between LSEs must be addressed and distributed; and FERC must act on market power mitigation prior to contracts being negotiated by LSEs to meet local procurement requirements.

The Commission must decide whether deliverability should be assessed on aggregate basis or load pocket basis. In the event that the Commission decides that deliverability need only be addressed on aggregate, no additional decisions with respect to deliverability need to be made for an LSE to make its year-ahead resource adequacy showing. In the event that the Commission decides that a load pocket procurement requirement or deliverability into load pocket screen should be adopted, additional work is likely required as parties focused their discussion on whether or not this requirement was needed, not on how to accomplish it if it was adopted, although a potential short term solution was identified.

7 Other Topics Discussed at Workshop

7.1 Multi-Year Forward Contracting Requirement

At the workshop parties asked that we discuss and include in the workshop report the concept of requiring LSEs to demonstrate that they have entered into forward commitments more than a year in advance. At its core, this discussion evolved around adopting a new requirement that LSEs show long-term procurement 1-3 years in advance, by demonstrating that they have acquired sufficient resources:

one year in advance to meet 90% of load (including reserves)
two years in advance to meet 80% of load (including reserves)
three years in advance to meet 70% of load (including reserves)

If the Commission were to adopt such a requirement, the 2007 resources adequacy showing would demonstrate that the LSE has acquired sufficient resources to meet 90% of its 2008 load forecast (including reserves), 80% of its 2009 load forecast (including reserves), and 70% of its 2010 load forecast (including reserves).

Parties did not agree on whether such a requirement should be adopted but identified some pros and cons of adopting such a requirement. Some parties support this approach because it supports construction of new infrastructure and helps to ensure that commitments for the long-term resource plans are being implemented. Others were concerned about the potential cost implications of this idea and worried about over (or under) procurement of resources because of the ability of load to shift, especially over a longer time frame. In addition, many of the counting protocols (discussed in Section 5 above) are reliant on data that may only be available a year-ahead.

The Commission must decide whether it wishes to entertain this requirement at this time.

7.2 Allocation of DWR Contracts to All LSEs

Right now it appears that the utilities intend to rely on the DWR contracts consistent with the manner in which the contracts were allocated to them in D.02-09-053. At least one party asked that we discuss the possibility of allocating the capacity value associated with the DWR contracts (however the Commission decides they are to be given full credit and value) on a pro rata basis to LSEs based on their contribution to contract costs.[42] The advocates for an allocation of the capacity value to LSEs argue that this approach is consistent with the requirement that direct access customers pay a share of the contracts as

[42] Although it was not discussed in any detail at the workshop, this same issue applies to utility retained generation and QF capacity. It is the belief of the workshop moderator that, unless directed otherwise, the utilities plan to rely

determined in the cost responsibility surcharge proceeding, has the potential to assist with the load shifting problem by ensuring that the benefit stays with the customer. There was vigorous dispute between the parties about whether the costs allocated to direct access customers in the cost responsibility surcharge are only the above market portion of the DWR contracts costs and just what the "indifference" value used to assign cost responsibility represents. Opponents argue that (1) the Commission has been allocating stranded costs for years but has never tied the contracts to such allocation; (2) allocating DWR capacity value to non-utility LSEs would give LSEs credit for resources they don't actually use for serving load; (3) legislative history supports allocating the full value to utilities; and (4) allocation to non-utility LSEs raises operational concerns, and makes managing procurement more difficult because it is less clear what resources you can rely on until an allocation is made (and the timing of such allocation is unclear at this time). In addition, because the allocation of the cost responsibility surcharge to direct access customers has an after the fact true-up, it is unclear whether that allocation methodology would work for resource adequacy purposes. It is also an open question which contracts to allocate to which LSE and any allocation would result in administratively complex billing and remittance requirements.

Another option that was discussed was whether a portion of the DWR contracts could be allocated directly to direct access customers. The legality of such an allocation is not clear, but parties pointed out that performing a financial allocation, especially of block loaded contracts, does not mean that you need to have multiple operators of the contract.

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on retained generation based on their ownership share in the facility and QF contracts that they are parties to for

The Commission must decide whether any portion of the capacity value of the DWR contracts, QF contracts, and utility retained generation should be allocated to non-utility LSEs.

7.3 Capacity Tagging

The concept of capacity tagging allows identification of sufficient total committed capacity a year-ahead to meet resource adequacy requirements without specifying an energy procurement strategy for each LSE. The interest in the concept of capacity tagging is driven by the desire to ensure that meeting the year-ahead resource adequacy requirement does not result in stranded resources when customers move between LSEs that other customers then are required to pay for. By creating a standardized tradable capacity product and market, resources can be shared more effectively between LSEs because they know that the product will meet the Commission's resource adequacy requirements.[43]

At the May 18, 2004 workshop, two capacity tagging proposals were discussed, one sponsored by the Silicon Valley Manufacturing Group (SVMG) and one by SDG&E. The proposals contain specific recommendations about the definition of "capacity tags" and what a market to trade tagged resources should look like.[44] Although they were discussed at the workshop, agreement was not reached regarding the market component of the proposals. This report does not lay out the discussion about the market mechanisms in each proposal because of the exploratory nature of the discussion. However, parties appeared to reach general agreement about the minimum requirements a resource must satisfy to

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purposes of their year-ahead showing.

[43] Parties noted that right now, the electricity market is an energy product market, not a capacity market.

[44] The SVMG proposal was filed as an attachment to SVMG's pre-hearing conference statement in R.04-04-003. On and is not reproduced here. The SDG&E proposal was a summary of positions that SDG&E took in testimony during hearings in R.01-10-024 and is not reproduced here.

receive a capacity tag. Parties believe that the Commission must define what an acceptable product to receive a capacity tag is, but it is less important for the Commission to be involved in establishing or approving a trading mechanism.

A capacity tag would be for a specified amount of capacity (i.e., 1 MW) from a resource, based upon the definition of qualifying capacity for that type of resource, that also passes the deliverability screen. The parties refer to this part of the minimum requirements as being "certified". For example, a resource whose QC=30 MW and is fully deliverable would be eligible to receive 30 capacity tags if it also commits to offering its energy output to the CAISO spot market. The must offer obligation for energy provides a link between the advance capacity commitments and the need for those resources to offer energy in real time. Thus, **the parties agree that the minimum requirements to receive a capacity tag are that the capacity resource is certified and obligated to offer its energy into the CAISO spot market**. Receiving a capacity tag would mean that the amount of tagged capacity can be used by an LSE to meet its 90% forward commitment requirement. The parties believe that if the Commission adopts these minimum requirements, a market for tagged capacity can be developed which can assist in solving some of the load shifting, stranded resource, and cost issues described throughout this workshop report.

The Commission must decide whether a resource that has received a capacity tag, as defined above, is acceptable for purposes of the 90% year-ahead forward commitment showing. The parties also believe that *the Commission must decide in advance whether use of the resulting market is reasonable.*[45]

[45] The workshop moderator is not clear whether this recommendation addresses reasonableness in the context of the price that results from the capacity tag market or whether it is reasonable to utilize a capacity tag to meet resource adequacy requirements.

APPENDIX A

SCE's Comments to Question #4 Raised in the Counting Workshop, April 6-7, 2004

"When is a year in advance for purposes of assessing resource adequacy?"

The Resource Adequacy Workshops on Counting Issues held on April 6-7, 2004, identified five issues that were not fully discussed during these workshops due to time constraints. These issues were placed on the agenda for the added workshop scheduled on April 26, 2004. SCE was assigned one of these issues as stated above.

Decision D.04-01-050 "…establishes a requirement that utilities forward contract 90% of their summer (May through September) peaking needs (loads plus planning reserves) a year in advance…"[1] The issue is whether a "year in advance" is defined as: (1) twelve months in advance, (2) by the end of the previous calendar year, or (3) some other definition.

In SCE's Opening Comments on Resource Adequacy, dated March 4, 2004, SCE addressed the issue as follows[2]:

> SCE defines "a year in advance" to be a calendar year prior to the summer month in question. For example, to meet the resource requirement of May 2008, the LSE will forward contract 90% of its peak demand plus reserve margin prior to the end of 2007. Therefore, the appropriate coverage of the peak demand that LSEs must demonstrate for May 2008 will be (.90 * 1.15 * peak demand) or 103.5% of the May 2008 peak demand, and the LSE will forward contract this capacity prior to December 31, 2007.

Other parties, including the working group dealing with the load forecast issues, have suggested setting the "year in advance" definition to mean that the required resources need to be confirmed by April (or earlier) in the year prior to the summer in question. For example, under one proposal, 90% of the May – September 2008 resource adequacy requirement would be forward contracted by April 30, 2007.

SCE makes its recommendation for many reasons, but the primary reason being that Conclusion of Law #7 in D.04-01-050 states that "The utilities shall meet this 15-17% requirement by no later than January 1, 2008." Since this 15-17% requirement is designed to be the target reserve level in the summer of 2008 it appears that this language allows the utilities until December 31, 2007 to meet this requirement. This language seems to impute that by meeting this reserve margin target by the last day of the preceding year that this will meet the "year in advance" requirement.

SCE also has two other considerations in mind: (1) minimizing the costs to ratepayers of meeting these resource adequacy requirements, and (2) having sufficient information available which will allow informed and logical procurement decisions for the following summer.

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[1] D.04-01-050, page 11

[2] Footnote 6

SCE's recommendation would benefit ratepayers by providing LSEs greater flexibility to determine the optimum timing of their procurement activities in order to reflect more recent market conditions, economic conditions, regulatory changes, etc.

With a December 31 forward contracting deadline for the following summer's resource adequacy requirement, parties will have significantly more information with which to make procurement decisions. The following information will be more accurate in December prior to the summer in question (as opposed to April, 12 months prior to the summer) and will lead to improved estimates of resource adequacy requirements and supply availability:

1. Load forecasts can be finalized with a higher degree of certainty especially for smaller LSE's. The following information will be available to LSEs in December as opposed to April for the following year's summer peak:
    - Effectiveness of demand side and energy efficiency programs in reducing load during the peak hours.
    - More accurate forecasts of the following summer's peak
    - ESPs will have better knowledge of contracts that will expire or renew for the next year.
2. Better data regarding the online status of new generation projects.
3. Procuring by the end of Dec gives two benefits: 1) the primary one being more flexibility, and 2) the secondary one being more liquidity.
4. Determination of the Reliability Must Run (RMR) requirements. RMR studies by the ISO are completed by September of each year for the following year.
5. A better determination of the hydro availability for the next summer season. (October 1 is the start of the hydroelectric water year. At that time, the starting level of reservoirs for the hydro year is known, and projected hydro availability to meet the following summer's peak load can also be more accurately forecasted. Similarly, potential imports from hydroelectric resources in the Pacific Northwest can be better identified.)
6. The ISO's deliverability analysis integrating RMR, FTR, and other transmission planning studies should be completed.

For those who claim that the end of a prior calendar year is not a "year in advance," SCE responds that an April commitment date is no more in accordance with the Commission's decision. An April compliance date for the following year's resource adequacy requirement would effectively result in17 months in advance requirement for September, 16 months advance for August, and so on. The "year in advance" would be exceeded in all months except May. SCE's proposal makes the most sense, will ensure better planning, and will likely be more cost-effective for ratepayers.

LOAD FORECASTING STRAWPERSON[1]
Submitted 4/09/2004

Resource Adequacy Requirements Workshops in R.01-10-024

PREFACE

This report addresses several issues related to developing the load forecasts which D.04-01-050 requires LSEs to use in conjunction with a planning reserve margin to make forward commitments to resources. D.04-01-050 covers all LSEs under the jurisdiction of the CPUC, e.g. IOUs, ESPs, and CCAs.

This report has been prepared by a self-selected team of interested parties following the March 16, 2004 "kickoff" workshop in the resource adequacy workshops called by an ALJ Ruling dated February 13, 2004. This is final "strawperson" report, and the component sections have been discussed in two multi-party conference calls.

Pursuant to the direction of ALJ Cooke, this "strawperson" report has been scheduled to be discussed in an open public workshop on April 14, 2004.

I. WHO PREPARES LOAD FORECASTS FOR WHAT CUSTOMER BASE?

D.04-01-050 creates resource adequacy requirements for all LSEs under the jurisdiction of the CPUC, e.g. IOUs, ESPs, and CCAs. It is unclear who is to prepare load forecasts and what loads are to be included in these load forecasts.

The remainder of Section I discusses two options for preparation of load forecasts:

a. IOU for Its Current Customers and Expected Load Growth, and ESP for the Load of Its Current Customers and Their Expected Load Growth

The over-arching concern is that the load of EVERY customer is the responsibility of some load serving entity. One way to insure coverage is to agree on a methodology whereby the ESPs forecast of load during the forecast horizon is based on load projections of the current roster of ESP customers, including the growth in load of these customers as permitted by existing contracts as well as any reduction in load due to energy efficiency. The IOUs forecast, in contrast, will assume that all existing IOU bundled customers will remain on IOU bundled service **and** that all new customers will also take IOU bundled service. This methodology will insure that all customer loads, both existing and new customers, will be explicitly covered by an LSE.

Pros	Cons
The plus side of this methodology is that all customer loads, both existing and new customers are covered by an LSE forecast	This methodology will tend to overstate/understate the true load responsibility of ESP's /IOU's to the extent that customers change service providers during the forecast period.
This method does not require extensive "reconciliation" or "iteration" between the IOU forecast and the various ESP forecasts or among the ESP forecasts.	
This method allows for fairly straight-forward verification of IOU and ESP load forecasts as the recent historic loads of the current roster of each IOU's and each ESP's customer base is known.	

[1] As a collaborative effort to identify issues, this document does not have the endorsement of any party.

b. All LSEs Prepare "Best Estimate" Load Forecasts

In this option both IOUs and ESPs (and eventually CCAs) prepare load forecasts that are their best estimate of what loads will be in the months of May-September one year ahead. For the IOU, presumably this takes into account normal load growth expected through new customer movement into the service territory, but other factors could be attributed to expected load growth. For example, the load forecast of the utility will have to account for variables such as a significant number of customer turn-offs, a city in the service territory who opts for Community Choice Aggregation or if a core/non-core market is established. For ESPs, this option proposes that ESPs provide load forecasts for their best estimate of the aggregate load they intend to be serving for each of the summer months at the point the filing is submitted. Even though direct access is suspended, load growth can occur by load switching from one ESP to another, and by increases in loads for individual customers under contract.

Pros	Cons
Most accurate reflection of loads LSEs actually intend to procure resources for	Does not permit accounting for all customer IDs
Some parties interpret this to be consistent with D.04-01-050, while others disagree.	Creates additional uncertainty associated with DA/CCA customer loads switching back to IOUs or from one ESP to another. In practice, would not necessarily support explicit accounting for all DA customers.
	Could be open to considerable "gaming" resulting in a number of customers who's loads "fall through the cracks".

II. WHAT IS THE NATURE OF THE LOAD FORECAST?

There are several non-controversial elements of the load forecasts that each LSE is to prepare. These are:

- The basic unit of measurement that LSE's will be forecasting is hourly load in MWh. This means that variations in instantaneous load over an hour are ignored.[2]
- Each LSE is to prepare a load forecasts for each IOU service area in which it has customer loads. This means that an ESP serving customers across all three IOU service areas would prepare separate load forecasts for the grouping of its customers located in each IOU service area.

a. The Time Horizon of the Load Forecast

Each LSE should provide a forecast of its hourly loads for each of the five summer months early each year (somewhere between January and April) for the period May-September of the next year (e.g submission in 2005 for loads during May-September 2006). If there were to be review and/or reconciliation adjustments of a draft load forecast before it was finalized (see Section V.a) the draft would come early in each calendar year, and adjustments would take place through the end of March with a goal of load forecasts finalized by April (e.g by April 2005 for the projected loads May-September 2006).[3]

b. Inclusion of Losses in Load Forecasts

[2] There may be some discussion that peak demand should be expressed in MW rather than MWh. Historically, resource planning has centered on annual peak MW. In SCE's experience, for recent recorded data, the annual peak MW and peak MWH are so close as to be interchangeable, and resource adequacy planning can be done on the basis of the forecast highest annual or monthly MWh observation.

[3] See Section V.c for another option, which some parties prefer, but which other parties view as outside the scope of D.04-01-050.

There are two options which define alternative extents to which losses are included within the load forecasts submitted by each LSE. These are:

(1) End-use metered usage plus losses up to the ISO-interface

This would be the definition of load that LSEs send to the ISO for settlement purposes. It is hourly load at the customer meter (either from hourly meters, or load profiled) plus distribution losses. Distribution loss factors by voltage level are published by the IOU's for all ESP's within their service area to use for ISO settlement purposes, so under the current process we are all using distribution losses calculated in a compatible manner. This definition does not adjust LSE load for transmission losses, UFE or any other adjustments.

Pros	Cons
Uses CPUC-approved method for adjusting for distribution system losses	Excludes a portion of losses traditionally included in "peak" measurements
Consistent with current ISO settlement processes.	Reduces "peak" loads which LSEs would have to satisfy leaving these the responsibility of the system operator
Does not require development and approval of a new method for computing additional losses beyond the CAISO-interface	
Consistent with current contractual structure whereby energy is purchased at the ISO interface.	Does not include either transmission losses or UFE which would be required in order for forecasting volumes to be converted to a "generation" concept. UFE and transmission losses could sum to as much as 5% at time of peak.

(2) End-use metered usage plus losses to the generation busbar

This is Option 1 above plus transmission losses, UFE and other adjustments reflected in the differences between SCADA real-time metered loads and end-use customer loads. To implement this option requires that these "transmission" losses be added to the losses included in Option 1. The real-time loads monitored by the ISO and the IOUs on their EMS (energy management systems) for their respective control areas are measured at "generation". This load is defined as the sum of all generation within the control area (net of self generation serving customer load on the customer side of the meter) plus the net of imports minus exports to the control area. It is a "top down" measure of load, as compared to the "bottom up" definition of customer load as reported by LSEs to the ISO for settlement, and it is real time.

Conceptually, this load at generation is greater than the load as measured at the ISO interface by the amount of physical transmission losses between the generators and the ISO interface, which is commonly referred to as a "transmission loss factor". Edison has found that, in practice, this "transmission loss factor" has to account for more than just the physical losses. It also has to account for UFE and probably accounts for metering discrepancies between the real-time EMS systems and the billing meters (and distribution loss factors) used for settlement. IOUs or the CAISO should provide to the CEC the forecast transmission loss factor for their area, and the CEC should apply it equally to all LSE load to convert them from "at the ISO interface" to "at Generation".

Pros	Cons
Consistent with traditional definition of system peak measurements	The above approach does not use a GMM/TMM approach. There may be an entity who could identify its specific transmission path and transmission loss factor (which might be lower than what the IOU says is the system average transmission loss factor).
This method includes UFE and any other	Like the current CAISO settlement computations,

sources of losses, such as metering discrepancy.	makes all LSEs responsible for measurement errors that may be caused by a few entities
Creates an “all in” requirements forecast as it includes use, plus distribution losses, plus transmission losses, plus UFE.	Not consistent with current contracting practices in the industry where delivery is taken at the ISO interface, not at the generation busbar.
	Would require additional effort by IOUs and CAISO to identify “transmission” losses which should not be charged to CPUC-jurisdictional LSEs
	Because of the requirement for interval metering for DA customers >50 kW, ESPs generally have more accurate measurement of aggregate ESP hourly loads than do IOUs, thus non-IOU LSEs should be over-allocated UFE

c. Shape Information Characterizing the Load Forecast

This section discusses three alternatives and makes a recommendation. A recommendation is made because this is topic is such a central issue for the entire resource adequacy forward commitment obligation.

(1) 720/744 hourly loads for each of the five summer months

This option would require each LSE to submit in chronological sequence the hourly loads for the five summer months of May through September. Each month would have either 720 or 744 hourly values.

Pros	Cons
Consistent with D.04-01-050 and may facilitate counting options other than peak hour.	Does not contain as much information as Option 2 (the 8760 version), thus inhibiting use of the compliance filings for other evaluation purposes.

(2) 8760 hourly loads from which five monthly peak shapes can be extracted

This option would require each LSE to provide the full annual hourly load forecast in chronological sequence. From these data, the hourly loads for the summer months could be extracted.

Pros	Cons
Contains the most complete information about LSE loads across the entire year, thus facilitating other analyses	Only the months May-Sept are really going to be used per D.04-01-050
	By requiring 8760 hourly loads, this method goes beyond the analyses of peak loads for the five summer months included in D.04-01-050[4]

(3) Five monthly peak shapes

In this option, each LSE would report hourly loads for the highest 5, 10, or 20 hours in each of the five summer months. Using the load duration curve (LDC) as an analogy, the LSE would report the “top” of the LDC.

[4] The CEC participants suggested the CEC may end up requiring 8760 hourly loads to be filed by LSEs as part of the inputs which the industry will provide to the CEC’s 2005 IEPR proceeding.

Pros	Cons
consistent with D.04-01-050 and ALJ Ruling dated 2/13/2004	Contains much less information than either option 1 or 2
minimum amount of work involved	Limits options with respect to counting of resources.
	Inconsistent with Section IV.a of this report, since it would be impossible to determine true coincident loads for the CAISO control area if LSEs only submit a limited number of their own “high load” hours without time stamping

(4) Recommendation

The load forecasting team recommends that option (1) be implemented. Option (3) is not workable, because chronological hourly loads are essential to understanding coincidence of individual LSE loads to form the CAISO control area peak. The method of coincidence adjustment proposed in Section IV.a could not be implemented without hourly loads. Option (2) may be outside of the scope of the monthly analyses required by D.04-01-050.

d. Quantification of Energy Efficiency and Customer-Side of the Meter Distributed Generation Impacts

It is understood that LSEs account for “price induced” load responses as part of their base load forecasts. This section addresses the impacts from program impacts that are not motivated by prices. Expected “real” energy efficiency program impacts and the amount of distributed generation on the customer side of the meter are separately subtracted from the LSE’s “base” load forecast (e.g. the net forecast is lower with these effects included than the gross forecast without them).

(1) Energy Efficiency (EE) Program Impacts

Energy efficiency load reductions for the forecast period should be deducted from the base load forecast, irrespective of how these programs are funded or who is the program delivery agent. For these purposes, “committed” energy efficiency (EE) refers to CPUC approved PGC- and procurement-funded programs.

Energy efficiency load reductions for forecasts are conceptually developed in two stages. For some forecasting methodologies, these two stages can be subsumed into a single process. The first stage is to determine the historical impact of energy efficiency programs. This can be done directly, buy using the Commission adopted measurement protocols and procedures to determine program or measure-level savings. It can also be done indirectly, as through a forecasting model which captures the impact of historical load reductions. (This is the approach PG&E uses for PGC-funded EE.)

The next conceptual step is to extrapolate those load reductions into the future (in this case, for the next summer.) In the case of an explicit forecast, the measured program or measure-level impacts are extrapolated using CPUC approved budgets (“committed EE”) or budgets not yet approved by the CPUC (“uncommitted EE”). For year ahead forecasts, uncommitted EE will typically occur at the end of a funding cycle. For example, current EE budgets are approved through 2005, so forecasts for that year will be committed EE. When the forecast is not explicit, for example embedded in a forecasting approach, the forecasts made with the model will implicitly include historical levels of EE. A final step in most case is to provide the forecast in hourly detail. This generally utilizes historical load shape data at an appropriate level of desegregation.

As long as the steps of this process continue to be done under CPUC oversight, as for example, using the Commission’ adopted measurement studies or protocols, the resulting forecasts should be included without alteration in resource adequacy computations.

As long as *all* LSEs do not administer their own energy efficiency funds/programs the coordination of IOU energy efficiency program impact assessments will be necessary for ESPs and, in the future, CCA’s to include the appropriate amounts of energy efficiency savings in their load forecasts. Periodic re-evaluation of energy efficiency savings by all LSEs will be necessary to ensure proper quantification and application of this resource to load forecasts over time.

At this time, some EE may be applicable to ESP customers as well as IOU customers. In the future, the same may hold true for CCA customers. Since all LSEs are responsible for load forecasting and their own resource adequacy it is imperative that the real resource value of energy efficiency programs targeting their load be known. This may require unspecified information sharing in the future, perhaps using the CEC as an intermediary in their role of reconciling different LSE forecasts, and prorating EE impacts.

<u>(2) Distributed/Self-Generation Resources</u>

Incremental distributed/self generation (SG), which will serve customer load and will be located on the customer side of the meter, should also be deducted from the base load forecast.

As with committed EE, the IOU may be aware of SG installations that are fostered by IOU administered programs, which the ESP or the future CCA is not aware of. An IOU may have a forecast of the total amount of incremental SG but not know specifically whether units will be applied to bundled customers or DA customers. As with committed EE, the IOU could provide the CEC an annual allocation of incremental SG to DA customers based solely on the ratio of DA sales to total sales.

e. Treatment of Demand Response

The discussion of the treatment of demand response is separated into discussion of price responsive demand tariffs and programs versus treatment of interruptible / emergency load curtailment programs. Each of these two categories has two options.

<u>(1) Price Responsive Demand Tariffs and Programs</u>

There are two options for the treatment of price responsive demand tariffs and programs, which are intended to be implemented by the IOU when they are the "least cost" resource to be operated:

a) Distinguish Treatment on Dispatchability Characteristics

The impacts of PRD tariffs and programs which are not dispatchable by the LSE are subtracted from "base" load forecast. Dispatchable tariff and program impacts are carried as a supply resource.

In this option, price sensitive demand reduction are subtracted from the "base" load forecast only if the DR program is not dispatchable by the LSE. Under Alternative 1, demand reduction from dispatchable DR programs would be treated as a supply resource because this type of DR has the feel of a resource (ie., the demand reduction is dispatched like a resource), even though its effect is different than that of a supply in that it reduces demand rather than increases supply.

<u>Arguments in favor of Alternative 1 (against Alternative 2)</u>:

Dispatchable DR is treated as a supply resource because it operates as a supply-side option. Since the "strike price" and dispatch terms are known in advance, the LSE can integrate these resources within its supply portfolio (including market transactions) to implement a "least cost dispatch". Based on past experience, the LSE can estimate what if any of the non-dispatchable DR will be available coincident with the LSE's peak demand requirements.

b) All PRD tariff and program impacts are subtracted from "base" load forecasts.

In this option, all price sensitive demand reduction is subtracted from the "base" load forecast regardless of whether a program is dispatchable by the LSE or not. For dispatchable DR programs, the LSE has the right to trigger a demand reduction at a pre-set strike price. For a non-dispatchable DR, the customer chooses when and at what price to reduce demand, and the LSE estimates the demand reduction associated with different price levels when preparing its load forecast.

Arguments in favor of Alternative 2 (against Alternative 1)

Price sensitive DR programs are treated consistently. That is, both dispatchable and non-dispatchable DR are treated as demand reduction because both result in a demand reduction regardless of whether the LSE has dispatch rights. When the LSE exercises its dispatch rights, it will reduce its demand and the reserves associated with that load reduction. In both cases, the LSE would not carry reserves for load that is not projected to materialize at a given price.

(2) Interruptible/Curtailment Programs for Reliability

There are two options for the treatment of interruptible or emergency programs, which are intended only to be operated when the reliability of the system is threatened:

a) Treat Impacts as a Supply Option

In this option, the impacts of interruptible tariffs and programs are not to be subtracted from "base" load forecasts, but rather carried as resources.

Arguments in favor of Alternative 1 (against Alternative 2):

Dispatchable DR is treated as a supply resource because the demand reduction associated with these programs is already part of the LSE's reserves.

b) Treat Impacts as a Load Reduction

In this option, the impacts of interruptible tariffs and programs are subtracted from "base" load forecasts to the limit of each program.

Arguments in favor of Alternative 2 (against Alternative 1)

When the ISO calls for a Stage 2 curtailment, the LSE experiences a reduction in demand and associated reserves. The LSEs does not need to carry reserves on interruptible load since this is by definition non-firm load and the customer has been already been paid to curtail under prescribed rules. If treated as a "supply-side option", in order to achieve the same effect, the expected demand reduction would need to be grossed by the required reserves in order to capture the no-reserve need for interruptible load.

f. Weather and other Short-Term Variations

Values for weather variables and other factors inducing short term variation in loads should be chosen to represent expected (50:50) loads for each of the five summer months.

III. REPORTING AND COMPLIANCE

This section of the report addresses a number of topics which are essential to be resolved for reporting and compliance purposes. Understanding these reporting and compliance purposes helps to define the nature of the load forecasts.

a. Timing of Annual Compliance Submittals

There are two options which define when load forecasts are submitted as part of the annual process to determine compliance with resource adequacy requirements:

<u>(1) Load forecasts are submitted as part of the IOU's current short term filing each spring</u>

In 2002 and 2003 each IOU was required to submit short term procurement plans in the spring of the year and the CPUC issued a decision by the end of the year establishing procurement ground rules for the subsequent calendar year. This option presumes that this process is adapted to also address the resource adequacy commitment requirements as part of an annual short term filing. Thus, no later than April of each year all LSEs would file appropriate documentation to demonstrate that they had satisfied the year ahead commitment obligations for the months of May-September of the subsequent calendar year. A key portion of this documentation is their load forecast for at least these five summer months.

Pros	Cons
A single short term and compliance filing, which makes review of IOU filings more efficient	Non-IOU LSEs will be submitting compliance filings and no corresponding "going-forward" procurement filings are required for ESPs or CCAs
	Intermingling short term filings aimed at clarifying procurement rules for short term purchases with a compliance filing may be inappropriate

<u>(2) A two-stage process of developing load forecasts</u>

This option is designed to accommodate the coincidence evaluation/adjustment discussed in Section V.a of this report. Draft load forecasts would be submitted in January to the CEC, which processes them to adjust for coincidence and perhaps other factors beyond the knowledge of each LSE. These adjustments would be reported back to each LSE within a month. In stage two, final load forecasts are submitted as part of the compliance filing in April of each year (essentially the same as option (1) described above).

Pros	Cons
A specialized process for load forecast adjustments preceding actual compliance filings to demonstrate forward commitment obligations have been satisfied	Requires preparation of load forecasts without final versions of full calendar year data
The additional work of a two-stage process can result in reduced forward commitment obligations, thus saving money or identification of "cushion" represented by obligations based upon non-coincident peaks	Considerable additional analytic work
Factoring in "diversity" will lessen the tendency toward over-procurement of resources that will occur if diversity is ignored.	May result in additional proceedings regarding methodology of calculation and application of diversity factors.

b. Documentation of Load Forecast Reported by Each LSE

Load forecasts should be submitted with in-depth documentation sufficient to permit review of results and basic approach, including such items as:

a) Historic hourly load for the previous year as used in CAISO settlement processes, adjusted for weather using an agreed-upon adjustment methodology

b) Hourly values of the Load Forecast

c) Basic documentation of customer counts[5], methodology, program impacts included (EE, DG, PRD, etc.)
d) Narrative explanation of any significant factors

These elements of documentation are necessary for any of the analyses discussed in Section V.c. A documentation submission requirement would be new to non-IOU LSE that they are not used to satisfying. At least for utilities, no greater effort is implied by the proposed documentation than would be required by CEC's biennial planning requirements. Both ESPs and IOUs suggest that such filings could create confidentiality concerns that would have to be resolved.

c. Confidentiality of Load Forecast Submittals[6]

The following are aspects of the confidentiality issue yet to be fully discussed or resolved, but that both IOUs and ESPs have raised:

(1) All LSE-specific hourly load forecasts are confidential and will not be submitted to any reviewing entity except with that understanding. Access to such data will be limited and follow the usual non-disclosure agreement practices.

(2) At some level of aggregation, loads are no longer confidential and such "higher level" results can be prepared and released by the reviewing entity(s). No discussion of at what level of load aggregation shifts from confidential to public has yet taken place.

It is likely that these confidentiality concerns exist for other categories of data which are part of these resource adequacy compliance filings, and therefore the confidentiality issue should be resolved in a comprehensive manner.

IV. USE OF LOAD FORECAST AS A BASIS FOR FORWARD COMMITMENT OBLIGATIONS

The ALJ Ruling dated February 13, 2004 raised the issue of confidence adjustments among LSE forecasts. This section of the report addresses how coincidence would be assessed from among filings submitted by LSEs, and then discusses options for making use of the diversity information gained from such an analysis.

a. Coincidence Analysis

The CEC proposes two possible methods for adjusting for the coincident control area peak load on the basis of the hourly load forecasts of each LSE, and then using this information to identify the each LSE's load at the coincident peak.[7]

<u>(1) Computing Coincidence Directly from LSE Submitted Forecasts</u>

This method assumes all LSEs within the CAISO control area provide hourly forecasted load for the summer months.[8] The designated load for the forward obligation is based on each LSE's share of total load during the CAISO's coincident peak hours, rather than LSE loads on their individual peak days, using the following steps:

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[5] ESPs do not believe that individual customer by customer information should be provided. Aggregate counts of customers should be sufficient.
[6] This section was inserted after the 3/26/2004 conference call at the suggestion of Art Canning. No one has yet volunteered to write this section up.
[7] Note that these proposals require selection of either Option (1) or (2) in Section II.b for all LSEs.
[8] Since there are numerous publicly-owned utilities within the CAISO control area, this method requires that either the CEC or the CAISO require a comparable hourly load forecast from entities outside the CPUC's jurisdiction. The CEC has the legal authority to require such load forecasts for all "utilities" in California, and the CEC is currently evaluating whether it will resume such a requirement.

a) Calculate the times and amounts of CAISO forecasted peak hours by summing across all submitted LSE forecasts on an hour by hour basis, and finding the maximum five hours for the CAISO in each calendar month.
b) Extract LSE loads at the time of each of the monthly CAISO peak hours, and calculate each LSE's share of the CAISO peak for each hour. Take the average of the shares.
c) The individual LSE designated load is calculated as the product of the average share from (b) and either the CAISO monthly peak derived from either the aggregated forecasts, or the CAISO peak adjusted for transmission losses or other unaccounted for energy as described in Section II.b.
d) Compare the shares from (b) to shares calculated the same way from the most recent year's actual weather-adjusted hourly loads. If the shares calculated from the forecast differ significantly from these historic data, then further review and possible adjustment may be appropriate.

Pros	Cons
Can be derived directly from forecast.	Requires forecasts from all LSEs in CAISO. Could use CEC forecasts for non-CPUC jurisdictional LSEs.
Coincidence adjustments based on the same days of the year are likely to produce less error due to weather adjustments that vary across LSEs.	The aggregation of hourly forecasts produced by different entities and forecast techniques may not produce a valid CAISO forecast. Analysis and calibration of the aggregate forecast should be done before adjustment for coincidence.

<u>(2) Computing Coincidence Directly from Historic Adjusted Loads</u>

In this approach a coincidence adjustment is derived from the LSE's load at the time of the monthly CAISO peak, relative to the LSE's own monthly peak. (The "share of the peak day" approach in the first alternative could also be used with historic data, but it would require an additional step to adjust the peak day shares for differential growth across LSEs).

a) Calculate CAISO five monthly peak hours as in (1), using one year (or possibly more) of historic weather normalized hourly summer loads, to be provided by each LSE.
b) Extract LSE loads at the time of each of the five CAISO peak hours of the month, and the LSE's own monthly peak hours. Calculate a coincidence factor as the average of LSE's load at the CAISO peak hours, divided by the average of the LSE's five peak hours.
c) This coincidence factor is applied to the LSE's monthly peak forecast, adjusted for losses or other factors as needed.

Pros	Cons
Requires only historic adjusted hourly loads from non-CPUC jurisdictional LSEs. CEC could weather-adjust recorded data if needed.	Coincidence adjustment based on different days of the year may be more likely to produce erroneous measures of diversity due to differences in weather adjustment methods. (NYISO experience)
Coincidence analysis can be begun before forecasts are filed.	Averaging the coincidence factor over multiple years would be more reliable, but this may not be viable for ESPs with limited or highly variable history.

<u>(3) IOU Service Area Coincidence with ISO System Load Based on Analysis of Temperature Data</u>

As an aid to understanding of load diversity, a supplemental analysis in parallel to either of the above two options could be undertaken using temperature data for the three IOU service areas, which is available for 30 or 40 historical years. The CEC could take a weighted average temperature by service area and compare those service area temperatures to the weighted average for the ISO control area for the 40 historical years, and calculate a diversity of temperatures relative to the day of the ISO area hottest temperature. The CEC may have factors such as MW per degree Fahrenheit for each area, or could request and coordinate such analysis with the IOUs such that the temperature diversity could be converted to a peak hour MWh diversity. This would give a long term view of diversity and give insight as to frequency and probability of coincident high temperatures, but only looking at IOU total loads versus the ISO total load. This method gives no insight to diversity between bundled and DA load within an IOU service area. However, it does answer part of the diversity question with an analysis of long-term data, which is not available directly from LSE load data.

b. Use of Coincidence Results

To the extent that diversity among LSE hourly loads is found, what should be done with this information? The following are options:

(1) Adjust for Coincidence

In this option, each LSE's forward obligations would be explicitly reduced by adjusting the original LSE load forecast for a monthly coincidence factor so that the "final" LSE load forecast used for compliance determination is lower than the original, non-coincident one.

Pros	Cons
Forward obligations for a specific based upon that LSE's actual contribution to system peak	Implementation may require "finetuning" of language in D.04-01-050
If diversity is not taken into account then LSE's will be systematically over-procuring resources in "aggregate".	May result in additional proceedings regarding methodology of calculation and application of diversity factors.

(2) Ignore Coincidence

In this option the coincidence analysis described in Section V.a would not be used to adjust each LSE's load forecast or their forward commitment obligations relative to these load forecasts. Instead, the coincidence analyses would provide an understanding of the "cushion" provided by non-coincidence of individual LSE load forecasts and the benefits this has to further assure reliable system operation.

Pros	Cons
The diversity among individual LSE loads would create an additional "cushion" so that effective planning reserves were greater thsan the 15-17% of system peak adopted in D.04-01-050	LSE's obligated to acquire higher level of resources, perhaps 1-5% of there own peak loads, thus costing more money than if diversity were accounted for
Explicit coincidence analysis reveals the actual size of this "cushion"	Theoretically more correct to account for diversity directly than to use indirect means of "adjustment".
Avoid delays in approving compliance filings based on debates regarding calculation and application of diversity factors	

c. Analyses that could be Conducted for Each LSE's Submittal

The following are different analyses that could be conducted on each LSE's load forecast submittal once it has been filed. One or more of these analyses could be conducted, so there are elements of an evaluation process, not options. One or more different entities might be involved in such analyses.

(1) Summation of each LSE's load forecast and comparison to CEC's IEPR results at the IOU service area and/or the IOU's own IOU service area load forecast as a gross check on plausibility of LSE load forecasts

(2) Comparison of each LSE's load forecast to its previous resource adequacy compliance filings

(3) Feedback to be provided by CPUC, CEC, and CAISO to an LSE about possible errors within the load forecast submittal.

The CEC believes that a rationale for conducting some degree of evaluation can be made as follows:

(1) To evaluate the consistency and reasonableness of the aggregated load forecasts, each LSE provides the following:

a) An 8760 1-2 load forecast (year ahead)

b) Hourly loads for the previous year (or multiple years), adjusted for weather and other accounting protocols as needed.

c) Basic documentation

(2) Evaluate whether historic LSE loads sum to historic CAISO and utility totals. The purpose of this step is to verify that all existing loads and losses are accounted for, and that accounting protocols for program effects, etc, appear to be followed.

(3) Compare aggregated forecasts to UDC/IEPR/CAISO forecasts.

(4) Evaluate whether individual LSE growth rates within plausible bounds. Are they consistent with historic trends, forecasted economic conditions, and/or explained by expected customer actions?

(5) Attempt to resolve discrepancies with LSEs.

(6) Report on remaining discrepancies and make recommendations.

V. OTHER ISSUES

The discussions among the load forecasting team have raised a number of additional issues that appear to be important to record, even though they are outside of the scope of the load forecasting "strawperson" and are perhaps incompatible with the language of D.04-01-050. Nonetheless, implementation of an effective body of resource adequacy requirements may mean that these topics must be ultimately addressed.

a. Necessity of Acquiring Hourly Load Forecasts for Non-Jurisdictional Entities

Section IV.a proposes a method whereby the CEC obtains individual hourly load forecasts from each LSE and uses these, plus additional data, to determine the CAISO control area peak in each month. Hourly loads from the non-jurisdictional entities, including municipal utilities and other entities outside of the jurisdiction of the CPUC, are necessary to implement this proposed method. There are several sources of such information, but at least one of them must be implemented in order to develop an accurate forecast of each LSE's load at the time of the CAISO's monthly peak.

b. Some Loads Are Highly Variable, Which May Need to Be Explicitly Addressed in Load Forecasting Protocols

Load forecasting for entities that do not serve a traditional customer base (non-traditional LSEs) requires different approaches for determination of their planning reserve requirements. Their loads must be forecast with tools that account for the underlying source of the demand.

The water pumping loads of the State Water Project and its water contractors are a good example. SWP loads are based upon the amount of water moved through the SWP's system of pumps, which amount varies significantly from year to year. Since future SWP loads are subject to fluctuating hydrology conditions, they may not be closely aligned with recent load history. There are corresponding impacts on the state water contractors at the point of local water deliveries as these agencies use more of less ground water pumping depending upon availability of surface water deliveries.

Load forecasts for non-traditional LSEs such as the SWP should reflect, where appropriate, acceptable levels of service risks and flexible delivery times. Establishing a reserve requirement using forecasted loads for May through September a year in advance may not make sense for a non-traditional LSE such as the SWP whose water delivery requirements are not known until the end of the precipitation season, which is typically the end of April in a current year. A load forecast a year in advance could vary over the full range of historic hydrology. Since non-traditional LSEs such as SWP have direct control over the timing of their loads with flexibility during a month, and most of its load is served during the off-peak periods when resource adequacy for a control area is generally not a concern, they should enjoy greater flexibility in load forecasting and establishing reserve requirements.

Pros	Cons
More accurate load forecasts	Requires greater documentation to explain how fluctuations were built into the load forecast
	Greater complexity in reviewing LSE submittals

c. Load Forecasts Covering the Period One and More Years Ahead

As described in Section II.a of this report, each LSE will provide a forecast in the spring of the year for each of the five summer months of the following year. Most LSEs will prepare forecasts with longer time horizons in order to appropriately consider a portfolio of resources to cover expected loads. In order to facilitate planning, these forecasts could be provided for a five-year forecast horizon. Thus, in April of each year forecasts would be provided for the period May-September of the next five years, e.g. submissions made in April 2005 for May – September 2006
May – September 2007
May – September 2008
May – September 2009
May – September 2010

Pros	Cons
Lead time to build resources takes more than a one-year time frame.	One year ahead is the maximum commitment under the current rules, so no additional information needed for a compliance filing
A five-year ahead forecast would provide much better information for planning purposes.	ESP commercial contracts generally are not long-term in nature and, therefore, the ESP's ability to make long-term forecasts/commitments may be impacted.
A five-year ahead forecast would draw attention to the policy concern between directed planning and commercial feasibility.	

d. Rolling Twelve Month-Ahead Load Forecasts

Neither of the options described in Section I of this report provides a good method to address the expected load for ESPs. The first would require an estimate of the load under contract as of the point the forward planning process required a submittal, as though these were actually the expected load. As ESP's relationship with a customer is contractual, with a specified term, requiring an ESP to forecast load based on current customers may overstate ESP load and thereby require ESPs to secure, on a forward contract basis, reserves in excess of its requirements. Since an ESP does not have a base of customers from which to spread costs, but instead incurs costs commensurate with customer commitments, such a strategy could have a deleterious affect on ESPs and the service they can provide their customers. The second method is better, since it allows the ESP to make an accurate forecast, but by requiring one perhaps 13 months ahead (April 2005 to May 2006) and one 17 months ahead (April 2005 to September 2006), it cannot adjust for changes in ESPs loads as time passes and more information becomes available.

ESPs recommend that the ESPs forecast load based on contracts that will be in effect during the one-year forward peak summer period. The load projections can then be refreshed on a rolling one-year forward basis during the summer, to update the information to reflect new contracts or contract renewals. For example, in May 2004, ESPs would refresh their May 2005 forecast, in June 2004, ESPs would refresh their June 2005 forecast, etc. Additionally, as load is contracted for within the one-year forward window, ESPs can forward contract for the summer period to the forecast to reflect the load under contract. This allows the ESP to fulfill the intent of the order, which is to forward contract for reserves to meet summer peak requirements. We believe the order allows for, does not prevent, an interpretation that the load forecast for the summer period can be updated monthly on a one-year forward basis.

e. Updating Load Forecasts and Obligations After Initial Filings

Once an LSE has submitted its annual load forecast and accounting to demonstrate compliance for forward commitment obligations, how are subsequent updates of LSE internal load forecasts (different ideas about growth or unexpected terminations of contracts with end-users, etc.) tracked and forward commitment obligations revised for the period shorter than one year ahead?

The following are options:

<u>(1) Not tracked</u>

Once the “final” either year ahead or update compliance report is completed, load transfers are not tracked and any reconciliation is left to LSE’s (such reconciliation would be outside of the scope of compliance reporting)

<u>(2) For compliance reporting, a category of load shifts is established and reported</u>

Categories of LSE deficiencies and LSE overages due to load shifts reported, perhaps on a monthly basis.

<u>(3) Establish a daily capacity trading market (PJM), adjusting for LSE load shifts</u>

The concept is that LSEs must have a mechanism to true up the respective forecasts in order for it to match the actual load. One way to do this is through a secondary capacity market/auction (daily or monthly). Under this mechanism, a LSE could off load excess capacity or fulfill the additional capacity needs given changes in load. This capacity market would simply be a “reconciliation” market for “true-ups” and not a means by which LSEs would acquire all of their capacity needs. Another mechanism would be some sort of administrative reconciliation methodology that would capture load forecast differentials and somehow allocate penalties or overpayments appropriately amongst LSEs.

<u>(4) Establish a monthly true-up capacity trading market (NYISO) adjusting for LSE load shifts</u>

f. IOU Cooperation and Support to all Non-IOU LSEs (e.g., CCAs and ESPs)

If Non-IOU LSEs are required to meet the same resource adequacy and load forecasting requirements that IOUs are expected to meet, they will need a certain degree of cooperation and support from IOUs to be successful. R.03-10-003 is the forum in which most information exchange issues between future CCAs and IOUs are under discussions. Non load forecasting issues such as costs of information transfer between IOU's and CCA's should remain within R.03-10-003. However, specific information support issues to comply with resource adequacy requirements, such as those described below, should be addressed within this proceeding.

For new LSEs that do not have extensive historical load data on hand to calculate year- or more-ahead forecasts IOUs will need to be willing and able to provide sufficient historical load information to facilitate the best-informed LSE load forecasts. This may mean that for certain LSEs, CCAs for example, IOUs may need to provide up to 10 years of historical load data for a given city, county, or group of cities and counties (i.e., Joint Powers Authority). It will be imperative that this cooperation and coordination take place to ensure that accurate load forecasting occurs and resource adequacy requirements are met. Cooperation between IOUs and CCAs will also be required regarding economic forecasts that underpin load forecasts. Cooperation will also be required between IOU's and CCA's regarding load profiling data e.g. some CCA's may need to site more load profile meters to establish a statistically valid load profile sample for forecasting and other purposes.

Appendix C

NERC GADS Definitions

Operation and Outage States

Actual Unit Starts
Number of times the unit was actually synchronized

Attempted Unit Starts
Number of attempts to synchronize the unit after being shutdown. Repeated failures to start for the same cause, without attempting corrective action, are considered a single attempt.

Available
State in which a unit is capable of providing service, whether or not it is actually in service, regardless of the capacity level that can be provided.

Forced Derating (D1, D2, D3)
An unplanned component failure (immediate, delayed, postponed) or other condition that requires the load on the unit be reduced immediately or before the next weekend.

Forced Outage (U1, U2, U3, SF)
An unplanned component failure (immediate, delayed, postponed, startup failure) or other condition that requires the unit be removed from service immediately or before the next weekend.

Maintenance Derating (D4)
The removal of a component for scheduled repairs that can be deferred beyond the end of the next weekend, but requires a reduction of capacity before the next planned outage.

Maintenance Outage (MO)
The removal of a unit from service to perform work on specific components that can be deferred beyond the end of the next weekend, but requires the unit be removed from service before the next planned outage. Typically, a MO may occur anytime during the year, have flexible start dates, and may or may not have a predetermined duration.

Planned Derating (PD)
The removal of a component for repairs that is scheduled well in advance and has a predetermined duration.

Planned Outage (PO)
The removal of a unit from service to perform work on specific components that is scheduled well in advance and has a predetermined duration (e.g., annual overhaul, inspections, testing).

Reserve Shutdown (RS)
A state in which a unit is available but not in service for economic reasons.

APPENDIX C: NERC GADS Definitions

Scheduled Deratings (D4, PD)
Scheduled deratings are a combination of maintenance and planned deratings.

Scheduled Derating Extension (DE)
The extension of a maintenance or planned derating.

Scheduled Outages (MO, PO)
Scheduled outages are a combination of maintenance and planned outages.

Scheduled Outage Extension (SE)
The extension of a maintenance or planned outage.

Unavailable
State in which a unit is not capable of operation because of the failure of a component, external restriction, testing, work being performed, or some adverse condition.

Time

Available Hours (AH)
a. Sum of all Service Hours (SH), Reserve Shutdown Hours (RSH), Pumping Hours, and Synchronous Condensing Hours, or;
b. Period Hours (PH) less Planned Outage Hours (POH), Forced Outage Hours (FOH), and Maintenance Outage Hours (MOH).

Equivalent Forced Derated Hours (EFDH)*
The product of the Forced Derated Hours (FDH) and the Size of Reduction, divided by the Net Maximum Capacity (NMC).

Equivalent Forced Derated Hours During Reserve Shutdowns (EFDHRS)*
The product of the Forced Derated Hours (FDH) (during Reserve Shutdowns (RS) only) and the Size of Reduction, divided by the Net Maximum Capacity (NMC).

Equivalent Planned Derated Hours (EPDH)*
The product of the Planned Derated Hours (PDH) and the Size of Reduction, divided by the Net Maximum Capacity (NMC).

Equivalent Scheduled Derated Hours (ESDH)*
The product of the Scheduled Derated Hours (SDH) and the Size of Reduction, divided by the Net Maximum Capacity (NMC).

Equivalent Seasonal Derated Hours (ESEDH)*
Net Maximum Capacity (NMC) less the Net Dependable Capacity (NDC), multiplied by the Available Hours (AH) and divided by the Net Maximum Capacity (NMC).

APPENDIX C: NERC GADS Definitions

Equivalent Unplanned Derated Hours (EUDH)*
The product of the Unplanned Derated Hours (UDH) and the Size of Reduction, divided by the Net Maximum Capacity (NMC).

Forced Derated Hours (FDH)
Sum of all hours experienced during Forced Deratings (D1, D2, D3).

Forced Outage Hours (FOH)
Sum of all hours experienced during Forced Outages (U1, U2, U3, SF).

Maintenance Derated Hours (MDH)
Sum of all hours experienced during Maintenance Deratings (D4) and Scheduled Derating Extensions (DE) of any Maintenance Deratings (D4).

Maintenance Outage Hours (MOH)
Sum of all hours experienced during Maintenance Outages (MO) and Scheduled Outage Extensions (SE) of any Maintenance Outages (MO).

Period Hours (PH)
Number of hours a unit was in the active state.

Planned Derated Hours (PDH)
Sum of all hours experienced during Planned Deratings (PD) and Scheduled Derating Extensions (DE) of any Planned Deratings (PD).

Planned Outage Hours (POH)
Sum of all hours experienced during Planned Outages (PO) and Scheduled Outage Extensions (SE) of any Planned Outages (PO).

Pumping Hours
The total number of hours a turbine/generator unit was operated as a pump/motor set (for hydro and pumped storage units only).

Reserve Shutdown Hours (RSH)
Sum of all hours experienced during Reserve Shutdowns (RS). Some classes of units, such as gas turbines and jet engines, are not required to report Reserve Shutdown (RS) events. Reserve Shutdown Hours (RSH) for these units may be computed by subtracting the reported Service Hours (SH), Pumping Hours, Synchronous Condensing Hours, and all the outage hours from the Period Hours (PH).

Scheduled Derated Hours (SDH)
Sum of all hours experienced during Planned Deratings (PD), Maintenance Deratings (D4) and Scheduled Derating Extensions (DE) of any Maintenance Deratings (D4) and Planned Deratings (PD).

APPENDIX C: NERC GADS Definitions

Scheduled Outage Extension Hours (SOEH)
Sum of all hours experienced during Scheduled Outage Extensions (SE) of any Maintenance Outages (MO) and Planned Outages (PO).

Scheduled Outage Hours (SOH)
Sum of all hours experienced during Planned Outages (PO), Maintenance Outages (MO), and Scheduled Outage Extensions (SE) of any Maintenance Outages (MO) and Planned Outages (PO).

Service Hours (SH)
Total number of hours a unit was electrically connected to the system.

Synchronous Condensing Hours
Total number of hours a unit was operated in the synchronous condensing mode.

Unavailable Hours (UH)
Sum of all Forced Outage Hours (FOH), Maintenance Outage Hours (MOH), and Planned Outage Hours (POH).

Unplanned Derated Hours (UDH)
Sum of all hours experienced during Forced Deratings (D1, D2, D3), Maintenance Deratings (D4), and Scheduled Derating Extensions (DE) of any Maintenance Deratings (D4).

Unplanned Outage Hours (UOH)
Sum of all hours experienced during Forced Outages (U1, U2, U3, SF), Maintenance Outages (MO), and Scheduled Outage Extensions (SE) of any Maintenance Outages (MO).

Capacity and Energy

Gross Maximum Capacity (GMC)
Maximum capacity a unit can sustain over a specified period of time when not restricted by seasonal, or other deratings.

Gross Dependable Capacity (GDC)
GMC modified for seasonal limitations over a specified period of time. The GDC and MDC (Maximum Dependable Capacity) used in previous GADS reports are the same in intent and purpose.

Gross Available Capacity (GAC)
Greatest capacity at which a unit can operate with a reduction imposed by a derating.

Gross Actual Generation (MWh) (GAG)
Actual number of electrical megawatthours generated by the unit during the period being considered.

APPENDIX C: NERC GADS Definitions

Net Maximum Capacity (NMC)
GMC less the unit capacity utilized for that unit's station service or auxiliaries.

Net Dependable Capacity (NDC)
GDC less the unit capacity utilized for that unit's station service or auxiliaries.

Net Availability Capacity (NAC)
GAC less the unit capacity utilized for that unit's station service or auxiliaries.

Net Actual Generation (MWh) (NAG)
Actual number of electrical megawatthours generated by the unit during the period being considered less any generation (MWh) utilized for that unit's station service or auxiliaries.

***Notes:**

-- Equivalent hours are computed for each derating and then summed.
-- Size of reduction is determined by subtracting the Net Available Capacity (NAC) from the Net Dependable Capacity (NDC). In cases of multiple deratings, the Size of Reduction of each derating is the difference in the Net Available Capacity of the unit prior to the initiation of the derating and the reported Net Available Capacity as a result of the derating.

Equations

Availability Factor (AF)
[AH/PH] x 100 (%)

Equivalent Availability Factor (EAF)
[(AH - (EUDH + EPDH + ESEDH))/PH] x 100 (%)

Equivalent Forced Outage Rate (EFOR)
[(FOH + EFDH)/(FOH + SH + EFDHRS)] x 100 (%)

Forced Outage Factor (FOF)
[FOH/PH] x 100 (%)

Forced Outage Rate (FOR)
[FOH/(FOH + SH)] x 100 (%)

Gross Capacity Factor (GCF)
[Gross Actual Generation/(PH x GMC)] x 100 (%)

Gross Output Factor (GOF)
[Gross Actual Generation/(SH x GMC)] x 100 (%)

Net Capacity Factor (NCF)
[Net Actual Generation/(PH x NMC)] x 100 (%)

APPENDIX C: NERC GADS Definitions

Net Output Factor (NOF)
[Net Actual Generation/(SH x NMC)] x 100 (%)

Scheduled Outage Factor (SOF)
[SOH/PH] x 100 (%)

Service Factor (SF)
[SH/PH] x 100 (%)

Computation Method Discussion
Each of the statistics presented is computed from summaries of the basic data entries required in each equation The basic data entries are totaled and then divided by the number of unit-years in that data sample. This unit-year averaged basic data entry is then used in computing the statistics shown. Two examples.of these computations are shown below:

Example 1:

$$\text{FOF} = [\text{FOH/PH}] \text{ x } 100\ (\%)$$

Where:

$$\text{FOH} = \frac{\sum_{i=1}^{N} \text{FOH}_i}{N}$$

$$\text{PH} = \frac{\sum_{i=1}^{N} \text{PH}_i}{N}$$

i = individual unit in any individual year
j = individual derating occurrence
N = number of unit-years considered

Example 2:

$$\text{EFOR} = \frac{\text{FOH} + \text{EFDH}}{\text{FOH} + \text{SH} + \text{EFDHRS}} \times 100$$

Where:

$$\text{FOH} = \frac{\sum_{i=1}^{N} \text{FOH}_i}{N}$$

$$\text{SH} = \frac{\sum_{i=1}^{N} \text{SH}_i}{N}$$

$$\text{EFDH} = \frac{\sum_{i=1}^{N} \text{EFDH}_i}{N}$$

$$\text{EFDHRS} = \frac{\sum_{i=1}^{N} \text{EFDHRS}_i}{N}$$

Note: All computed values are rounded to the nearest hundredth. Entries of 0.00 signify the averaged values are less than 0.005.

Average Number of Occurrences Per Unit-Year

$$= \frac{\text{Number of Outage and/or Derating Occurrences}}{\text{Number of Unit-Years}}$$

Average MWh Per Unit-Year

$$= \frac{\text{Hours for Each Outage and/or Deratina Type x NMC (MWI}}{\text{Number of Unit-Years}}$$

Average Hours Per Unit-Year

$$= \frac{\text{Hours for Each Outage and/or Derating Type}}{\text{Number of Unit-Years}}$$

Average Equivalent MWh Per Unit-Year

Computed as shown in the equation for **Average MWh Per Unit-Year** above, except the deratings are converted to equivalent full outage hours. Equivalent hours are computed for each derating event experienced by each individual unit. These equivalent hours are then summarized and used in the numerator of the **Average MWh Per Unit-Year** equation. Each equivalent hour is computed as follows:

$$\text{EQUIVALENT OUTAGE HOURS} = \sum \frac{\text{Derating Hours x Size of Reduction}}{\text{NMC (MW)}}$$

Average Equivalent Hours Per Unit-Year

Computed as shown in the equation for **Average Hours Per Unit-Year** above, except the deratings are converted to equivalent full outage hours. Equivalent hours are computed for each derating event experienced by each individual unit. These equivalent hours are then summarized and used in the numerator of the **Average Hours Per Unit-Year** equation.

Notes:

--All computed values are rounded to the nearest hundredth. Entries of 0.00 signify the averaged values are less than 0.005.

APPENDIX C: NERC GADS Definitions

--Size of reduction is determined by subtracting the Net Available Capacity (NAC) from the Net Dependable Capacity (NDC). In cases of multiple deratings, the Size of Reduction of each derating is the difference in the Net Available Capacity of the unit prior to the initiation of the derating and the reported Net Available Capacity as a result of the derating.

APPENDIX D
Draft #2

"STRAW-PERSON" DELIVERABILITY PROPOSAL

Deliverability is an essential element of any resource adequacy requirement. Specifically, Load Serving Entities (LSEs) must be able to show that the supplies they intend to procure to meet their load requirements can be delivered to load when needed. Otherwise, such resources are of little, if any, value for the purposes of resource adequacy.

The California Public Utilities Commission (CPUC) is considering how to require the LSEs to demonstrate the deliverability of the resources they procure in both their annual resource plans and their long-term resource plans. This is essential so that the LSEs will be able to "count" their resources to determine whether they satisfy the planning reserve margin, and to ensure sufficient coordination between resource planning and transmission planning.

This paper and three attachments offer a "Straw-Person" proposal for deliverability with technical details on this proposed methodology. Draft 1 of this paper was the focus of a six-hour meeting and a two-hour conference call involving approximately 30 participants, as well as written comments from eight participants as of April 5th. **Additional written comments on this Draft 2 are encouraged as a way to facilitate the on-going debate at the April 12-13 workshops.**

The stakeholder discussions and written comments raised a number of general policy issues that go beyond the scope of this paper. A number of these issues were listed in a March 26, 2004 memo from the ISO's Phil Pettingill (on behalf of the Deliverability workgroup) to the entire Resource Adequacy service list. This paper carves out several other policy issues that could be separated from this proposed methodology and technical explanation for determining deliverability.

This proposed straw-person deliverability proposal consists of three assessments: Deliverability of Generation to the Aggregate of Load, Deliverability of Imports, and Deliverability to Load Within Transmission Constrained Areas. This third test involving deliverability to load pockets was debated extensively among stakeholders involved in this Deliverability test. As explained below, this third type of assessment may be an issue for the larger Resource Adequacy group to consider as a general Resource Adequacy requirement, rather than be subsumed as a third part of this technical Deliverability assessment.

Each of these assessments is discussed in greater detail below and in the Attachments.

A. Deliverability Of Generation To The Aggregate Of Load

As part of developing its proposal to comply with FERC's Order No. 2003 regarding the interconnection of new generating facilities, the ISO developed and proposed to FERC a "deliverability" test (but not a requirement). The purpose was to begin to assess the deliverability of new generation to serve load on the ISO's system. Recent experience indicates that while California has added needed new generating capacity to the system over the past few years, not all of that capacity is deliverable to load on the system because of the presence of transmission constraints. Therefore, although not requiring all new generation to be deliverable, the ISO proposed in its Order 2003 compliance filing to assess deliverability so that the sponsors of new generation projects can accurately assess their ability to deliver the output of the new plants to the aggregate of load for resource adequacy counting purposes. This first assessment reflects the deliverability test and the baseline analysis envisioned by the ISO to be conducted as part of this interconnection process.

The ISO recommends that a generating facility deliverability assessment be performed to determine the generating facility's ability to deliver its energy to load on the ISO Controlled Grid under peak load conditions. Such a deliverability assessment will provide necessary information regarding the level of deliverability of such resources with and without Network Upgrades (i.e., major transmission facilities), and thus provide information regarding the required Network Upgrades to enable the generating facility to deliver its full output to load on the ISO Controlled Grid based on specified study assumptions. That is, a generating facility's interconnection should be studied with the ISO Controlled Grid at peak load, under a variety of severely stressed conditions to determine whether, with the generating facility at full output, the aggregate of generation in the local area can be delivered to the aggregate of load on the ISO Controlled Grid, consistent with the ISO's reliability criteria and procedures. (This definition for deliverability comes the FERC interconnection order, and this methodology for assessing deliverability has been developed from consultation with PJM officials about their already-established practices.)

In addition, the ISO recommends, based on guidance in FERC Order 2003, that the deliverability of a new resource should be assessed on the same basis as all other existing resources interconnected to the ISO Controlled Grid.

Because a deliverability assessment will focus on the deliverability of generation capacity when the need for capacity is the greatest (*i.e.* peak load conditions), it will not ensure that a particular generation facility will not experience economic congestion during other operating periods. Therefore, other information (*i.e.* congestion cost analysis for all hours of the year) would be required in addition to the deliverability assessment to evaluate the congestion cost risk of a take-or-pay energy purchase contract with a particular generation facility.

Attachment 1, Generator Deliverability Assessment, contains the technical details of this proposed methodology.

B. Deliverability of Imports

California is now, and will likely remain, dependent on imports to satisfy its energy and resource requirements. Therefore, it is likely that as part of fulfilling their obligation to procure sufficient resources (reserves) in the forward market to serve their respective loads, the IOUs will contract with out-of-state resources. This is appropriate and necessary.

The ability to rely on imports to satisfy reserve requirements is entirely dependent on the *deliverability* of such out-of-state resources to and from the intertie points between the ISO's system and the neighboring systems. While the existing system may be able to satisfy the procurement plans of any one LSE, it likely will not be able to transmit the sum of LSEs' needs. Each LSE may well be utilizing the same potentially constrained transmission paths to deliver their out-of-state resources. Therefore, the transmission system should be checked to make sure that simultaneous imports can be accommodated.

When relying on imports to serve load, each LSE should be required to ensure that they have assessed the deliverability of such resources from the tie point to load on the ISO's system.

More specifically, this "Strawperson" proposes that each LSE, in conjunction with the ISO, be required to perform an integrated analysis on the annual procurement plans and the long-term procurement plans to ensure their identified resources are deliverable to load and that the necessary transmission capacity will exist on the system. Such an analysis should be performed using similar techniques used for operational transfer capability ("OTC") studies but would look at specific resource import scenarios expected in the future. Adverse internal generation availability and loop flow scenarios should be developed to adequately evaluate the capabilities of the transmission system to deliver imports to aggregate load.

Additionally, some kind of determination is needed regarding the ability of resources to be delivered to the tie point with California. Several stakeholders suggested a requirement for *firm* transmission rights over the neighboring system's transmission system would be too limiting, as some entities may want to optimize a portfolio of resources. This "Strawperson" proposal omits any deliverability requirement outside of California because it is beyond the scope of this technical explanation of a deliverability assessment. However, the ISO anticipates further discussion on the need for some kind of assurance that resources outside of California can deliver necessary MWs to the tie points.

In reviewing this paper several participants also questioned whether this Deliverability of Imports test is identical to the ISO's planned CRR simultaneous feasibility test (SFT). Both tests would use the same transmission network model for the same study year, and would consider the same contingencies. However, at this time the SFT models simultaneous flow limits in order to ensure that appropriate contingencies are covered, while the proposed Deliverability of Imports test has the ability to simulate each contingency that needs to be covered. The additional complexity and correspondingly improved accuracy would be a feature of the Deliverability of Imports test but not the SFT.

Attachment 2, Deliverability of Imports Assessment, contains the technical details of the deliverability of imports study methodology.

C. Deliverability To Load Within Transmission Constrained Areas

Load within transmission-constrained areas, known as "load pockets," present unique circumstances for the assessment of deliverability. A load pocket is an electrically cohesive area that is a sub-area of the ISO Control Area. (For example, the San Francisco Bay, San Diego, LA Basin, Fresno, NP15 and SP15 areas are examples of constrained transmission areas.) These load pockets can be defined by the impact of generators within the sub-area upon the contingencies known to limit operations in that sub-area. The boundaries of load pockets can be drawn to include generators that have calculated impacts beyond a certain percentage upon those contingencies. Load buses also can be similarly assigned and defined within these sub-areas based on their impact on the same contingencies.

Load pockets are highly dependent both on the availability of generation within the constrained area and the limited transfer capability of the transmission system. Because the transmission capability within a "load pocket" is so critical, this "Strawperson" proposes that special focus be placed on assessing the deliverability of the procured resources to serve load in such locally constrained areas of the transmission system. However, considerable discussion was held among stakeholders who believe the deliverability of resources outside these designated sub-areas to loads inside these "pockets" should be handled within the grid planning process, and not be part of this deliverability test. To inform further discussion, an understanding of the ISO's Grid Planning process and its similarity and differences to this proposed "Deliverability to Load" assessment may be useful.

The ISO Grid Planning process is designed to ensure the ISO Controlled Grid meets NERC/WECC Planning Standards, as well as some ISO-specific Grid Planning Standards. Currently the NERC/WECC Planning Standards do not address resource adequacy and deliverability issues (such as the deliverability of resources to load pockets,) while one of the more stringent standards that are specific to the ISO partly addresses the availability of resources in a particular area.

The San Francisco Greater Bay Area Generation Outage Standard effectively requires that three or four specific generation units are deemed out of service in the power system base case for analyzing transmission line contingencies. This Standard was developed after a June 14, 2000 localized resource shortage in the San Francisco Bay Area resulted in rolling blackouts that were necessary to ensure compliance with the WECC Minimum Operating Reliability Criteria (MORC.)

Because the San Francisco Greater Bay Area Generation Outage Standard specifically considers the availability of resources, this facet of the ISO Grid Planning Process falls into a category where both Transmission Adequacy and Resource Adequacy overlap. The ISO Grid Planning Standards Committee periodically reviews other areas of the ISO Grid to determine if additional specific standards are necessary upon review of generation availability data within those other areas. If other special Standards were approved for other transmission constrained areas, presumably the Transmission and Resource Adequacy assessment methodologies would overlap for the areas covered by these Standards.

To further underscore the distinction between grid planning and resource adequacy standards, it should be noted that the CPUC's rulemaking on transmission assessment practices anticipates a resource planning process that considers the economic trade-off between Load, Transmission, Generation and possibly RMR contracts. The ISO Grid Planning process would be limited to considering only transmission projects after the other alternatives have been considered. "Staff suggests that the Commission's transmission determination made as part of its review of the IOUs long-term procurement plans should be reflected in the CAISO's transmission planning process."[1]

In addition, a NERC taskforce recently issued a series of draft recommendations, including support for the eventual creation of deliverability assessment standards: "NERC shall develop assessment practices and reporting processes to verify that resources identified by load serving entities (LSEs) to meet resource adequacy requirements are simultaneously deliverable to the LSEs' loads. The assessment practices shall also determine whether the simultaneous import capabilities are sufficient to satisfy the import capability assumptions included in the resource adequacy assessments."[2] Although implementation of such proposed NERC standards is not likely in the immediate future, this task force recommendation does indicate that deliverability is a distinct feature from the existing NERC/WECC Planning Standards, and that some minimum national standards for deliverability assessment are needed.

Finally, some participants within this Deliverability workgroup raised questions related to RMR criteria. This "Strawperson" proposal assumes that RMR criteria would be an insufficient test for deliverability *in the long-term* because RMR is a year-ahead process. The options for providing local area reliability service are limited to signing RMR contracts or capital projects that can be completed within one year. Because of these limited options, the RMR criteria are typically less stringent than the ISO Grid Planning Standards or this proposed Deliverability to Load assessment. These latter two assessments are applicable for long-term planning purposes when long-lead time new

[1] Page 6, CPUC Rulemaking 04-01-026; Order Instituting Rulemaking on policies and practices for the Commission's transmission assessment process.
[2] Draft Resource and Transmission Adequacy Recommendations report, presented at the March 23-24, 2004 meeting of the NERC Resource and Transmission Adequacy Task Force.

transmission or generation projects are possible options. RMR criteria could, however, offer a test for deliverability to load pockets in the short-term.

The ISO initially proposed this "Deliverability to Load" standard to ensure that the CPUC and the ISO have a common methodology, from both a Transmission Adequacy and Resource Adequacy perspective, for assessing large load pockets like the San Francisco Bay area. It is possible this third "leg" of a deliverability assessment could be considered separately from the "Strawperson" proposal because there is some overlap among standards and a broader perspective may be needed. However, the ISO believes this a critical issue to be resolved in the context of the utilities' procurement activities, so that each load-serving entity can make a meaningful assessment of the trade-off between procuring local generation, building new transmission to serve load in the constrained area, or developing demand response. The details of this proposed methodology for Deliverability to Load in Transmission Constrained Areas are included for a fuller explanation.

In summary, the focus of this proposed assessment is to ensure the appropriate probability that severely constrained transmission areas will have sufficient transmission so that an adequate amount of generation from resources located outside the local area can be delivered to serve the local load. Specifically, the probability of load within the local area, exceeding the available capacity resources located in the local area and imported into the local area, should be equivalent to the probability of control area load exceeding the amount of capacity resources available to the overall control area. This methodology ensures a consistent level of resource adequacy across the ISO Controlled Grid.

The ISO anticipates further discussion on this proposed assessment and notes that the potential CPUC requirements upon LSEs – to address both deliverability and local reliability within their resource plans – could be determined in an integrated fashion through the suggested methodology in Attachment 3.

Attachment 3, Deliverability to Load in Transmission Constrained Areas, contains the technical details of this deliverability to load study methodology.

D. Summary

Several entities reviewing this "Strawperson" proposal questioned how the ISO might tie together these three suggested "buckets" of Deliverability, and when individual resources might be determined or categorized as "deliverable" based on these proposed tests.

The Generation Deliverability Assessment would be performed in the annual baseline analysis and in every new System Impact Study as part of the generation interconnection process. Resources that pass the deliverability assessment could be counted to meet reserve margin requirements and resources that don't pass could not.

The Deliverability of Imports assessment would be performed during the review of all LSE's long term and short term resource plans. Firm import information is an input to the generation deliverability assessments. Therefore, new firm import procurement plans would need to be tested using the generator deliverability methodology to ensure that the additional imports do not impact the deliverability of generation that has already passed the generation deliverability test. Once the resource plans are approved, the import assumptions for future generation deliverability assessment would be updated as needed.

The Deliverability to Load test would be performed during the development of the *long term* resource plans. Solutions for resolving resource deficient load pockets could include the construction of resources needed to meet reserve margin requirements but located in the deficient load pocket to mitigate the deliverability to load deficiency. The construction of resources within the load pocket could be by any developer of generation—a procurement contract with that new generator should ensure that it is actually built.

The Deliverability of Imports and the Deliverability to Load in Transmission-Constrained Areas would, generally, utilize common methods and terminology. However, the definition of the area to be analyzed for the Deliverability of Imports assessment is already defined as the ISO Control Area boundary. This boundary is determined almost exclusively by facility ownership and service areas rather than electrical characteristics. In contrast, the boundary for load pockets to be analyzed would be determined only by electrical characteristics. Operational Transfer Capability (OTC) is a term that applies to WECC paths that correspond to most of the ISO Control Area Boundary. OTCs are not calculated for most load pocket boundaries because power is not scheduled across these boundaries.

Because the ISO lacks critical data necessary to conduct a meaningful "test-run" of this methodology, preliminary study results would be misleading. One participant helpfully suggested that, should results be required quickly in time for LSEs summer 2005 resource procurement activities, then historical data could be utilized. The ISO appreciates this suggestion but is concerned that planned transmission upgrades and new generation would not be considered. In addition, a review of the day-ahead, hour-ahead, and real-time markets for both inter-zonal and intra-zonal congestion for the peak load day for each of the summer months could take considerable time. The ISO also emphasizes that continued stakeholder input and review is strongly encouraged if any of these procedures are undertaken. It is fully expected that this deliverability validation process would be tested and evaluated on existing resources to ensure that the results are reasonable, equitable and consistent with engineering judgment, and that refinements will be made as needed.

Generator Deliverability Assessment

1.0 Introduction

A generator deliverability test is applied to ensure that capacity is not "bottled" from a resource adequacy perspective. This would require that each electrical area be able to accommodate the full output of all of its capacity resources and export, at a minimum, whatever power is not consumed by local loads during periods of peak system load.

Export capabilities at lower load levels can affect the economics of both the system and area generation, but generally they do not affect resource adequacy. Therefore, export capabilities at lower system load levels are not assessed in this deliverability test procedure.

Deliverability, from the perspective of individual generator resources, ensures that, under normal transmission system conditions, if capacity resources are available and called on, their ability to provide energy to the system at peak load will not be limited by the dispatch of other capacity resources in the vicinity. This test does not guarantee that a given resource will be chosen to produce energy at any given system load condition. Rather, its purpose is to demonstrate that the installed capacity in any electrical area can be run simultaneously, at peak load, and that the excess energy above load in that electrical area can be exported to the remainder of the control area, subject to contingency testing.

In short, the test ensures that bottled capacity conditions will not exist at peak load, limiting the availability and usefulness of capacity resources for meeting resource adequacy requirements.

In actual operating conditions energy-only resources may displace capacity resources in the economic dispatch that serves load. This test would demonstrate that the existing and proposed certified capacity in any given electrical area could simultaneously deliver full energy output to the control area.

The electrical regions, from which generation must be deliverable, range from individual buses to all of the generation in the vicinity of the generator under study. The premise of the test is that all capacity in the vicinity of the generator under study is required, hence the remainder of the system is experiencing a significant reduction in available capacity. However, since localized capacity deficiencies should be tested when evaluating deliverability from the load perspective, the dispatch pattern in the remainder of the system is appropriately distributed as proposed in Table 1.

Failure of the generator deliverability test when evaluating a new resource in the System Impact Study brings about the following possible consequences. If the addition of the resource will cause a deliverability deficiency then the resource should not be fully counted towards resource adequacy reserve requirements until transmission system upgrades are completed to correct the deficiency.

A generator that meets this deliverability test may still experience substantial congestion in the local area. To adequately analyze the potential for congestion, various stressed conditions (i.e., besides the system peak load conditions) will be studied as part of the overall System Impact Study for the new generation project. Depending on the results of these other studies, a new generator may wish to fund transmission reinforcements beyond those needed to pass the deliverability test to further mitigate potential congestion—or relocate to a less congested location.

The procedure proposed for testing generator deliverability follows.

2.0 Study Objectives

The goal of the proposed ISO Generator deliverability study methodology is to determine if the aggregate of generators in a given area can be simultaneously transferred to the remainder of ISO Control Area. Any generators requesting interconnection to the ISO Controlled Grid will be analyzed for "deliverability" in order to establish the amount of deliverable capacity to be associated with the resource.

The ISO deliverability test methodology is designed to ensure that facility enhancements and cost responsibilities can be identified in a fair and nondiscriminatory manner.

3.0 Baseline analysis

Deliverability Test Validation: This procedure was derived from the deliverability test procedure currently used by PJM. Adaptations to the PJM procedure were necessary due to the considerable physical differences between the PJM system and the ISO-Controlled Grid. During the initial implementation of this procedure, it will be a tested, and evaluated on existing resources to ensure that the results are reasonable, equitable, and consistent with engineering judgment. Stakeholders will review the results of this validation process. The deliverability test procedure will be refined as needed.

In order to ensure that existing resources can pass this deliverability assessment, an annual baseline analysis, with the most up-to-date system parameters, must first be performed by applying the same methodology described below on the existing transmission system and existing resources. Identified deliverability problems associated with generation that exist prior to the implementation of this deliverability test may be mitigated by transmission expansion projects if the capacity is needed and/or the project is economically justifiable. Generation deliverability limitations on currently existing generation can be allocated among multiple generators contributing to the same problem based on the incremental flow impact that each generator contributes to the problem. The deliverability of both existing and new generators that are certified as deliverable will be maintained by the annual baseline analysis and the transmission expansion planning process.

4.0 General Procedures and Assumptions

Step 1: Build an initial powerflow base case modeling ISO resources at the levels specified in Table 1. This base case will be used for two purposes: (1) it will be analyzed using a DC transfer capability/contingency analysis tool to screen for potential deliverability problems, (2) it will be used to verify the problems identified during the screening test, using an AC power flow analysis tool. All new generation applicants in the interconnection queue ahead of the unit under study are set at 0 MW (but available to be turned on for the screening analysis but not for the AC power flow analysis). Then the capacity resource units in the queue electrically closest to the unit being studied are turned on in accordance with Table 1 until the net ISO Control Area interchange equals the interchange target, also described in Table 1. Generation applicants after the queue position under study are not modeled in the analysis.

Step 2: Using the screening tool, the ISO transmission system is essentially analyzed facility by facility to determine if normal or contingency overloads can occur. For each analyzed facility, an electrical circle is drawn which includes all units that have 5% or greater distribution factor (DFAX) on the facility being analyzed. (A 10% DFAX is used for 500 kV facilities.) Then load flow simulations are performed, which study the worst-case combination of generator output within each 5% DFAX circle. The 5% DFAX circle can also be referred to as the Study Area for the particular facility being analyzed.

The output of capacity units in the 5% circle are increased starting with units with the highest DFAX and proportionately displacing generation, outside the 5% circle, to maintain a load and resource balance. Any, several, or all the units within the 5% circle can be set at 100% output, up to a movement of 3000 MW or the twenty[1] units with the largest impact on the transmission facility.

Step 3: Using an AC power flow analysis tool, verify the overload scenarios identified in the screening analysis.

Step 4: Verified overloaded facilities with a DFAX from the new unit greater than 5% on lines 230 kV and below or 10% on 500 kV lines would need to be mitigated for the new unit to pass the deliverability test.

[1] The cumulative availability of twenty units with a 7.5% forced outage rate would be 21%--the ISO proposes that this is a reasonable cutoff that should be consistently applied in the analysis of large study areas with more than 20 units. Hydro units that are operated on a coordinated basis because of the hydrological dependencies should be moved together, even if some of the units are outside the study area, and could result in moving more than 20 units.

Draft Straw-Person Deliverability Proposal — Attachment 1

Table 1: Resource Dispatch Assumptions

Resource Type	**Base Case Dispatch**	**Available to Selectively Increase Output for Worst-Case Dispatch?**	**Available to Scale Down Output Proportionally with all Control Area Capacity Resources?**
Must-Take Capacity Resources			
• Nuclear	maximum dependable capacity	N	Y
• QF contracts	historical output	Y (up to contract limit)	Y
RMR	Dispatch as necessary to meet local area requirements	Y	Y
Energy Limited Capacity Resources			
• Hydro	Drought conditions, historical output, 90% confidence factor* for output during summer peak load hours** (An average hydro scenario will also be analyzed)	Y	Y
• Combustion Turbines with run-hour limitations	Approximately 50% of dependable capacity	Y	Y
Other Dispatchable Capacity Resources			
• Combined cycle gas, Steam turbine gas/coal, geothermal, biomass	Approximately 90% of dependable capacity	Y	Y
Intermittent Capacity Resources			
• Wind	90% confidence factor* for output during summer peak load hours** (An average wind scenario will also be analyzed)	Y	Y
• Solar	90% confidence factor* for output during summer peak load hours** (An average solar scenario will also be analyzed)	Y	Y
Energy Resources	Minimum commitment and dispatch to balance load and maintain expected imports	N	Y
Imports			
• Existing Transmission Contracts	Schedule/flow at contract capacity	N	N
• Dynamic Schedules	Schedule/flow at contract capacity	N	N
• Unit contingent LSE Import	Schedule/flow at contract capacity	N	Y

contracts for Capacity Resources			
• System resource LSE Import contracts	Schedule/flow at contract capacity	N	N
• Spot Market	Historical availability— analyze reasonable scenarios consistent with resource adequacy planning assumptions	N	Y (for unit contingent)
Load			
• Non-pump load	90% to 100% of maximum load.	N	N
• Pump load	Within expected range for Summer peak load hours**.	N	N

* 90% confidence factor means that the generation is expected to be dispatched, based on historical data, above the base case assumption during 90% of the Summer peak load hours.

** Summer peak load hours are the 50 to 100 hours in the months of August and September when Control Area load is between 90% and 100% of maximum annual load. August and September were chosen because that is when load is typically high and hydro availability tends to run short during drought conditions.

Distribution Factor (DFAX)
Percentage of a particular generation unit's incremental increase in output that flows on a particular transmission line or transformer when the displaced generation is spread proportionally, across all dispatched resources "available to scale down output proportionally with all control area capacity resources in the Control Area", shown in Table 1. Generation units are scaled down in proportion to the dispatch level of the unit.

G-1 Sensitivity
A single generator may be modeled off-line entirely to represent a forced outage of that unit. This is consistent with the ISO Grid Planning Standards that analyze a single transmission circuit outage with one generator already out of service and system adjusted as a NERC level B contingency. System adjustments could include increasing generation outside the study area. The number of generators increased outside the study area should not exceed the number of generators increased inside the study area.

Municipal Units
Treat like all other Capacity Resources unless existing system analysis identifies problems.

Energy Resources
If it is necessary to dispatch Energy Resources to balance load and maintain expected import levels, these units should not contribute to any facility overloads with a DFAX of greater than 5% for 230 kV lines or below, or 10% for 500 kV lines. Energy Resource units should also not mitigate any overloads with a DFAX of greater than 5% for 230 kV lines or below, or 10% for 500 kV lines.

WECC Path Ratings
All WECC Path ratings (e.g. Path 15 and Path 26) must be observed during the deliverability test.

Pmax* DFAX Impact
Generators that have a (DFAX*Generation Capacity) > 5% of applicable facility rating or OTC will also be included in the Study Area.

Deliverability of Imports Assessment

This deliverability assessment focuses on resources imported into the Control Area. WECC path ratings are established assuming favorable system conditions. Operational Transfer Capability (OTC) studies are performed seasonally for the upcoming season for operational purposes using expected and adverse system conditions, but are not regularly performed for planning purposes. A deliverability test is required to ensure that imports necessary for resource adequacy can be accommodated under expected and adverse system conditions such as resource shortages. These studies would be performed using similar techniques used for OTC studies but would look further into the future, and would test the simultaneous deliverability of Firm Imports needed to ensure resource adequacy. The basic steps are listed below.

1. Stability and Post-Transient Analysis

   a) Start from ISO Controlled-Grid summer peak base cases.
   b) ISO will model imports specified in the LSE resource plans, existing transmission contracts, and dynamic schedules.
   c) ISO in coordination with the PTOs will develop generation, and loop flow scenarios to stress transmission system
   d) ISO and/or PTOs will check for ISO Grid Planning Criteria violations
   e) ISO and/or PTOs will propose plans to mitigate criteria violations

2. Powerflow Analysis

The Generator Deliverability Assessment will incorporate imports specified in the LSE resource plans, existing transmission contracts, and dynamic schedules into the analysis. Proposed new import contracts that contribute to deliverability problems in that assessment will be identified, and mitigation alternatives will be suggested.

Deliverability to Load in Transmission Constrained Areas

This deliverability assessment focuses on the delivery of energy from the aggregate of capacity resources to an electrical area experiencing a capacity deficiency. It can be discussed in the context of demonstrating the "deliverability to the load" as opposed to the "deliverability of individual generation resources". This ensures that, within accepted probabilities, energy will be able to be delivered to Control Area load, regardless of cost, from the aggregate of capacity resources available to the Control Area.

The determination of the reserve requirement is based on the assumption that the delivery of energy from the aggregate of capacity resources to control area load will not be limited by transmission capability. This assumption depends on the existence of a balance between the distribution of generation throughout the control area and the ability of the transmission system to reliably deliver energy to portions of the control area experiencing capacity deficiencies.

The specific procedures utilized to test deliverability from the load perspective involve the calculation of a Capacity Emergency Transfer Objectives (CETO) and Capacity Transfer Limits (CTL) for various electrical sub-areas of the ISO Control Area. A CETO represents the amount of MWs that a given sub-area must be able to import in order to remain within the CPUC resource adequacy framework requiring that the probability of occurrence of load exceeding the available capacity resources is consistent across the Control Area.

To analyze the deliverability to load, electrically cohesive load areas must first be defined. These areas are sub-areas of the ISO Control Area (e.g. San Francisco Bay area, San Diego area, LA Basin area, Fresno area, NP15, SP15, etc). These sub-areas are defined based on the impact of generators, potentially within the sub-area, on the contingencies known to limit operations in the sub-area. Sub-area boundaries could be drawn to include generators based on the calculated impacts on those contingencies. Load buses are similarly assigned to these sub-areas based on their impact on the same contingencies.

Once a sub-area is defined, the CETO for that sub-area must be calculated using a reliability simulation tool such as Henwood RiskSym, or GE MARS. Using the simulation tool, determine the import capability of the load area necessary to ensure the LOLP inside the area is consistent with the rest of the control area—this value is the CETO for that sub-area.

The next step in the analysis is to calculate a generation forced outage target (GFOT). The GFOT will be equal to the internal area generation (G) plus the CETO minus the internal sub-area peak load and losses (L) or GFOT = G + CETO – L. An example of this concept is shown in Figure 1.

Once the GFOT is determined, specific unit forced outage scenarios need to be developed for modeling within a power flow base case model. Using the individual generator forced outage rates, develop a base generator outage scenario by selecting the units with highest outage rates until the GFOT is satisfied. Variations of the base generator outage scenario should also be developed by removing the most critical units from the model that result in adversely impacting the import capability of the sub-area. At least half of the generation in the outage scenario should be from the base outage scenario, and the amount of generation forced out in the scenario should not exceed the GFOT. Power flow base cases will be developed for each of the generation outage scenarios.

In general, all single element transmission contingencies should be tested on each of the power flow base cases developed. Multiple element contingencies that transmission system operators consider to have a sufficiently high likelihood of occurring should be treated as a single contingency and should also be tested. System performance for each of the contingencies should be measured against NERC Category B System Limits or Impacts for single transmission element outages and NERC Category C System Limits or Impacts for multiple transmission element outages, in the ISO Grid Planning Criteria. If any of the applicable performance limits are violated then the local area does not pass the deliverability to load assessment and should be mitigated as soon as practicable in the resource and transmission plans.

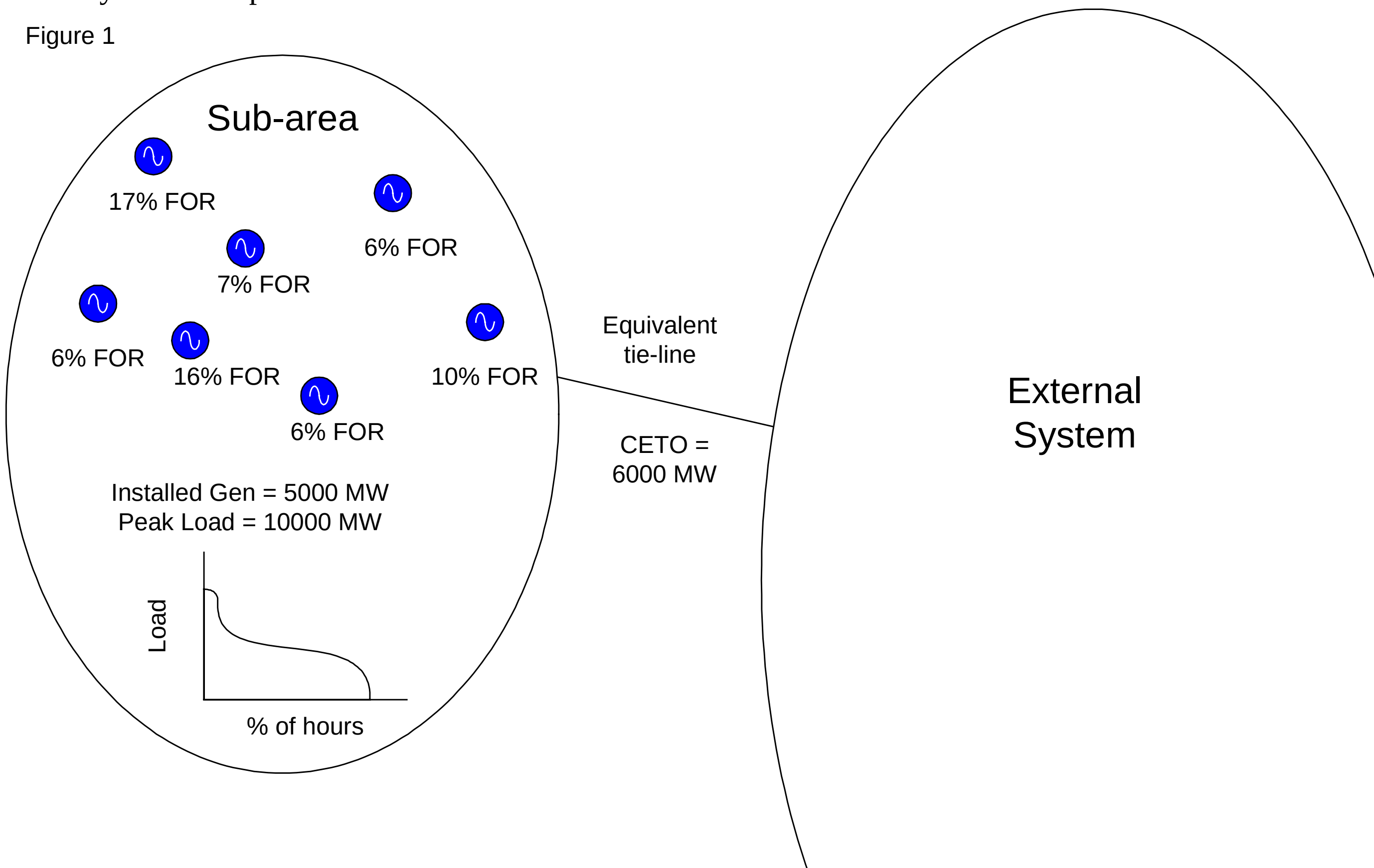
Once it is determined that the deliverability to load assessment of the area can be passed, a Capacity Transfer Limit is developed to establish target procurement levels for resources located in the local area. Economically procuring resources within the sub-area as part of the resource plan will tend to reduce RMR costs, and mitigate local market power. A Capacity Transfer Limit (CTL) for the area is developed by starting with the worst case generation scenario in the CETO test and then removing generators with the highest effectiveness factors that do not already have procurement contracts until a performance limit is violated. If the CETO test was not passed then the CTL should be set equal to the CETO.

Load serving entities with load in the sub-area should include resources, located in the sub-area, in their procurement plans so that a minimum of 90% of their load in the area minus their proportion of the CTL is served by resources in the local area. An LSEs proportion of the CTL should be calculated as a pro rata share in proportion to their percentage of the load in the area once existing transmission contractual obligations have been removed from the CTL.

APPENDIX D

Deliverability Straw Proposal

Figure 1



* The LOLP of the Sub-Area changes based on transfer capability of the equivalent tie-line to the External System. However, the transfer capability of the equivalent tie-line varies as a function of the generation pattern/availability inside the Sub-Area.
* The CETO is the minimum transfer capability of the equivalent tie-line that ensures that the LOLP target is satisfied.
* A full network powerflow model is then used to ensure that the CETO is achievable under reasonably expected generation outage scenarios.
* In this example 1000 MW of generation would need to be forced out in various combinations in order to test the CETO in the transmission analysis.

APPENDIX E

Assessment of Total Import Capacity

Deliverability Workshop Follow-Up: Assessment of Total Capacity into ISO Control Area

Background

At the CPUC's April 12-13, 2004 Deliverability Workshop, an action item was assigned to the California ISO. As requested, the ISO has been coordinating a detailed technical discussion and development of a proposal for establishing the total import capacity, for each import path, to be allocated to Load Serving Entities (LSEs) for resource adequacy planning purposes. This proposed approach will be presented at the next Deliverability Workshop scheduled for May 5, 2004.

Transmission constraints can impact the simultaneous deliverability of imports and internal generation. As a result, the interaction between the deliverability of imports and the deliverability of generation needs to be examined. The proposed generation deliverability assessment includes, as an input assumption, the amount of imports and existing transmission contract related encumbrances electrically flowing over the ISO Controlled Grid.

One of the observations from the Workshop was that LSEs needed to have results of the deliverability assessments in advance of submitting their resource plans to the CPUC for the year-ahead review. The generation deliverability assessment would provide results in advance. However, the deliverability of imports assessment initially described was an after-the-fact review of all of the LSE resource plans combined.

Because of the need for up-front information the ALJ assigned the ISO to lead a smaller group of Workshop participants to develop a methodology for determining the total amount of import capacity, by import path, which could be available to LSEs.[1] This document describes a proposal for a methodology developed by the subgroup.

Discussion of Proposed Approach

Whatever import capacity is available to LSEs for resource adequacy planning purposes should also be the basis for the import assumptions in the internal generation deliverability analysis. Because of the interaction between the deliverability of imports and the deliverability of internal generation, one should not simply determine the maximum import capability under favorable conditions and make that import capability available to LSEs for developing their resource plans. This approach assumes that all the import capability is needed and will be used for resource adequacy planning purposes, an assumption that could result in impairment of deliverability of

[1] Determining a methodology for allocating import capability to LSEs was not an assignment of this working group.

internal generation. (This would be inconsistent with the consensus from previous workshops that the deliverability of generation internal to the ISO grid should be preserved.) Furthermore, it is likely that, compared to a more reasonable import allocation, more of the allocated import capability might remain unused by an LSE to meet its resource adequacy requirement at the expense of more internal generation being available to meet an LSE's resource adequacy requirement.

Workshop participants proposed that historical import information should be the basis for determining the initial amount of import levels to be allocated to LSEs. Following this suggestion, the ISO reviewed actual import flows and schedules during peak load hours in 2003. After initial review of the data, it appears that 2003 saw the highest import levels in the last five years during peak load periods.

In addition to using historical data, existing transmission contract (ETCs) information should also be utilized. It is assumed that the entities that have contracted for the transmission capacity are already relying on this import capability in their resource plans, so this transmission should not be reallocated.

The impact of these total import levels would likely affect the deliverability of some existing generation, and the interplay between the deliverability of these existing generators and imports needs to be addressed. One of the key benefits of this proposed approach is that a clear deliverability benchmark would be established up front, it would be the starting point for future years, and LSEs would have some flexibility within this structure to adjust their resource adequacy plans to find an appropriate balance between imports and existing generation inside California.

Proposed Methodology

Initial Import Level

The proposed approach for combining both historical information and contractual information is to add final transmission import schedules (day-ahead, hour ahead, and real-time) not associated with ETCs, to ETC reservations on a path by path basis. One could then verify that this sum would not have exceeded the historical Operational Transfer Capabilities (OTCs) and make the appropriate adjustments. This methodology could be applied using several historical high load, high import hours and then taking the average total import as the initial import level.

Generation Deliverability Analysis

Using the initial import level as an input assumption, a baseline analysis of the deliverability of generation to the aggregate of load would be performed as described in the Strawperson Deliverability Proposal discussed in the Workshops. This benchmarking analysis would establish the deliverability of internal generation.

APPENDIX E

Assessment of Total Import Capacity

Per the ISO's Compliance filing for FERC Order 2003, the procedures for interconnection of new generators to the ISO controlled grid includes a Deliverability Assessment as part of the required technical studies. This assessment on new generators would be performed using the same methodology described in the Strawperson Proposal. The deliverability of existing generation already determined to be deliverable in the baseline deliverability analysis would be preserved. Once the new generator's deliverability level is established, its deliverability would be maintained as well.

The deliverability of new firm import contracts that utilize transmission import capacity allocated or acquired through trade by an LSE also would be maintained. These contracts would be modeled in future baseline deliverability studies. New firm import capacity could be identified in future baseline studies and allocated to LSEs for their use.

Generation retirements would be modeled and the deliverability impact on existing internal generators and imports would be included in the results of the baseline deliverability studies.

Deliverability Priority

If the baseline deliverability analysis for existing generation determines that the initial import level assumption is reducing the deliverability of internal ISO grid generation, then the initial import levels will be reduced and the baseline deliverability analysis will be re-run. Although it is not anticipated that import levels will have to be reduced significantly from their initial level, this issue may need to be reassessed after the analysis is completed, consistent with the "Review of Results" paragraph (below.)

New resources that are determined to be deliverable in the interconnection process, either because there is adequate existing capacity or through the construction of network upgrades, should have equal priority with pre-existing deliverable resources.

Make Results of Deliverability Assessment Available for Use

Once the deliverability assessment is completed the results will be provided for use in developing year-ahead LSE resource procurement plans for resource adequacy purposes.[2] The total import capacity, by path, determined to be deliverable would need to be allocated to LSEs using some allocation methodology that has yet to be defined.

(Optional Step) Modify Results of Deliverability Assessment based on Economic Tradeoff between Import Capacity and Internal Generation Capacity

[2] Operational requirements of the various local areas (i.e., RMR areas) would need to be addressed so LSEs have the necessary information to develop their resource procurement plans. This includes operational requirements such as the amounts and locations of generation needed to be on line and the potential generation retirements that could increase local area requirements. The deliverability to load methodology should focus on these requirements.

APPENDIX E

Assessment of Total Import Capacity
This step assumes that the deliverability of existing resources may not necessarily be preserved, and could be reduced as needed to increase the deliverability of imports, if it is determined that more economic capacity can be obtained from import levels that exceed the total import capability allocated to LSEs. Some sub-group participants had concerns regarding the logistics of implementing this step, and there is no consensus whether or not this step should be included in this general methodology.

Review of Results of Generation and Import Deliverability Assessment Methodology
As part of the initial implementation of this analysis, the test results for generation and import deliverability should be evaluated to ensure they are reasonable, equitable, and consistent with engineering judgment. Stakeholders would help review the reasonableness of these initial test results, and, if necessary, the deliverability test procedure could be refined.

Note: Assessing Deliverability and Transmission Planning
PG&E participated throughout this sub-group and reiterates its position that deliverability assessments, should be developed in the transmission planning process and the generation interconnection process.

DRAFT
April 30, 2004

Deliverability Workshop Follow-Up
Allocating Total Import Deliverability

Background

At the CPUC's April 12-13, 2004 Deliverability Workshop, the California ISO was requested to coordinate a detailed technical discussion and develop a proposal for establishing the total import capacity, for each import path, which would be allocated to Load Serving Entities (LSEs) for resource adequacy planning purposes. Three alternatives for allocating the total import deliverability were identified and discussed at the workshop:

1. Historical Rights Allocation Method
2. Pro Rata Allocation Method
3. Auction Method

The ISO's workshop assignment did not include coordinating the discussion on how to allocate the import deliverability. This document discusses the three allocation alternatives identified in the workshop and recommends adopting a hybrid of the Pro Rata Allocation Method and the Historical Rights Allocation Method--at least for the initial round of LSE resource procurement.

Historical Rights Allocation Method

The Historical Rights Allocation Method would allocate the deliverable capacity on each import path consistent with each LSE's historical rights to use that import path.

Some transmission ties were developed for the express purpose of importing specific resources, which the LSEs now depend on for their resource adequacy. The main advantage of the Historical Rights Allocation Method is that the resulting allocation would not conflict with any LSE's existing long-term commitment to an external resource.

Some of the disadvantages of the historical rights allocation method include the following:

- There may be disagreements on what constitutes a valid historical right, such as when an agreement that grants such rights terminates.
- It does not consider what import deliverability each LSE needs for its present resource procurement effort.
- It does not give LSEs with low historical import rights the chance to increase their rights, even if the other LSEs with historical rights no longer have a need for some of those rights.
- The resulting allocation has no relation to the size of an LSE's load or how much an LSE pays for transmission access.

In short, the Historical Rights Allocation Method is likely to unfairly endow a minority of the LSEs.

Pro Rata Allocation Method

The Pro Rata Allocation Method would allocate the deliverable capacity on each import path to each LSE that pays the applicable High Voltage Access Charge (HVAC) or Low Voltage Access Charge (LVAC) for that path in proportion to the LSE's load that is included in the billing determinant for that Access Charge. A pro rata share of the deliverable capacity of each High Voltage (i.e., above 200 kV) import tie would be allocated to each LSE that pays the HVAC. A pro rata share of the deliverable capacity of each Low Voltage tie would be allocated to each LSE that pays the Access Charge (which presently is the LVAC of the owning PTO) applicable to that tie.

Unlike the Historical Rights Allocation Method, the Pro Rata Allocation Method would consider the size of an LSE's load and how much an LSE pays for transmission access. However, this method also has some shortcomings, including the following:

- It does not recognize the commitments an LSE may already have to take external resources or the LSE's reliance on those resources for resource adequacy.
- It does not consider what import deliverability each LSE needs for its present resource procurement effort.
- It does not give LSEs the chance to increase their rights, even if the other LSEs do not have a need for all of their import deliverability allocation.

Auction Method

The Auction Method would allocate the deliverable capacity on each import path to the LSEs that bid the highest in an auction. An appropriately constructed auction method has the potential to equitably allocate import deliverability capacity. In theory, the LSE that has the greatest need would bid the most and receive the import deliverability allocation. And, if the auction proceeds were used to lower the Access Charge, similar to FTR auction proceeds today, all transmission users would benefit.

However, today's auction methods are only for annual rights. For longer term procurement, certainty in the cost of rights over a longer time frame would be necessary. Therefore, it would take a lot of time and effort to develop auction rules that would achieve the intended results and not be subject to gaming. It is not realistic to expect that such rules could be developed, tested and implemented in time for the LSEs resource procurement activities next year (2005).

Hybrid Method

The Hybrid Method contains the best features of the Historical Rights Allocation Method and the Pro Rata Allocation Method and adds a few other features to recognize each LSE's previous resource adequacy planning measures as well as allow for future planning needs and interests. In addition, the Hybrid Method facilitates the LSEs' efforts to achieve resource adequacy without the complexity and uncertainty that the Auction Method would involve. The Hybrid Method contains the following steps:

Step 1: Allocate the import deliverability on each import path to each LSE that pays the applicable High Voltage Access Charge (HVAC) or Low Voltage Access Charge (LVAC) for that path in proportion to the LSE's load that is included in the billing determinant for that Access Charge.

Step 2a: Adjust the allocations determined in step 1 so that each LSE that already owns or has contracts (including assigned CDWR contracts) for external resources, and counts those resources to meet its resource adequacy requirement, receives an allocation of the import deliverability on the relevant import tie(s) large enough to accommodate the countable capacity of those resource that cannot be accommodated on the LSE's Existing Transmission Contract (ETC) rights. If the sum of an LSE's allocation from Step 1 plus its ETC rights is larger than the total of its existing external resources being counted to meet resource adequacy requirements, then no adjustment would be necessary.

Step 2b: To compensate for an increased allocation on one tie in Step 2a, an LSE's allocation on the other import ties would be reduced by a like amount, and the allocations of the other LSEs would then be increased. The ties on which the allocations of the other LSEs will be increased would be at the option of those other LSEs.

Step 3: As soon as an LSE determines that it may not need all of its import deliverability allocation (e.g., after reviewing the bids received in the resource procurement process), it would notify the other LSEs of the potential availability of surplus import deliverability, and identify the affected import ties and the amounts. Any LSE potentially interested in a surplus import deliverability allocation would inform the offering LSE of its interest.

Step 4: Each LSE will use its allocation of import deliverability in conjunction with its resource portfolio to make the required demonstration of its resource adequacy. Any portion of the import deliverability allocation that is not needed for such demonstration would be released on a pro rata basis to the other LSEs that both requested it in Step 3 and then use it to make the required demonstration of its resource adequacy. To the extent no other LSE requests and uses the surplus import deliverability allocations in accordance with this Step 4, the LSE will retain its surplus import deliverability allocations and may use them to support resource procurement until the next import deliverability allocation cycle.

Step 5: In subsequent years, when import deliverability is allocated, an LSE will retain any portion of its previous import deliverability allocation as long as it is needed to count an external resource that it already owns or has under contract toward meeting its resource adequacy requirement. Such allocations will be accounted for in step 2a of future import deliverability allocations using this process. Once an LSE's contract or ownership for an external resource terminates, continued use of its import deliverability allocation for that resource received in Step 2a would become subject to a right of first refusal by the other LSEs that originally received the allocation in Step 1 and then lost it in Step 2b.

Relationship to CRRs

The CAISO is now in the process of determining how Congestion Revenue Rights (CRRs) will be allocated. In addition, there also is an existing process for auctioning Firm Transmission Rights (FTRs). CRRs (which will replace FTRs) provide their holders financial protection from congestion charges. But, they are not necessary to assure the physical ability to import a resource. As long as these deliverability and counting processes allow the sum of all LSE external resources to count only up to the import capability of the transmission, and no more, then adequacy should be assured. Costs of congestion (or excess demand on import capability) does not effect the LSEs resource adequacy, and when congestion is occurring, the ISO would still be getting physical imports into the area equivalent to the counted capability regardless of excess demand to use the import ties. Therefore, possession of CRRs or FTRs should not be a requirement for counting an external resource as deliverable.

Recommendation

The Hybrid Method described above has all of the advantages and avoids all of the problems of the Historical Rights Allocation Method and the Pro Rata Allocation Method. It also is much less complex than the Auction Method, and its outcome is much more likely to avoid unintended consequences. For these reasons, the Hybrid Method for allocating import deliverability is recommended.

APPENDIX G: Percent Variation From Peak

Percent Variation from Peak

2003			2002			2001			2000 (see note)			1999			1998 (see note)		
	MW	% Max		MW	% Max		MW	% Max		MW	% Max		MW	% Max		MW	% Max
1	42,689	0.00%	1	42,441	0.00%	1	41,419	0.00%	1	43,360	0.00%	1	45,884	0.00%	1	44659.12	0.00%
2	42,584	0.25%	2	42,366	0.17%	2	41,392	0.07%	2	43,234	0.29%	2	45,705	0.39%	2	44657.22	0.00%
3	42,539	0.35%	3	41,626	1.92%	3	41,186	0.56%	3	42,964	0.91%	3	45,494	0.85%	3	44321.86	0.76%
4	41,975	1.67%	4	41,385	2.49%	4	40,699	1.74%	4	42,762	1.38%	4	45,449	0.95%	4	44231.65	0.96%
5	41,734	2.24%	5	40,820	3.82%	5	39,805	3.90%	5	42,237	2.59%	5	45,145	1.61%	5	43779.40	1.97%
6	40,664	4.74%	6	40,246	5.17%	6	39,669	4.23%	6	41,322	4.70%	6	44,196	3.68%	6	42955.41	3.81%
7	40,653	4.77%	7	40,232	5.20%	7	38,375	7.35%	7	41,049	5.33%	7	44,153	3.77%	7	42396.94	5.07%
8	39,236	8.09%	8	39,067	7.95%	8	38,148	7.90%	8	39,527	8.84%	8	42,831	6.65%	8	41313.95	7.49%
9	39,064	8.49%	9	38,824	8.52%	9	37,720	8.93%	9	39,019	10.01%	9	42,496	7.38%	9	40749.32	8.75%
10	38,149	10.64%	10	38,597	9.06%	10	37,001	10.67%	10	38,696	10.76%	10	41,423	9.72%	10	40404.74	9.53%
11	38,144	10.65%	11	38,382	9.56%	11	36,743	11.29%	11	38,176	11.96%	11	41,040	10.56%	11	39500.91	11.55%
12	37,793	11.47%	12	37,829	10.86%	12	35,428	14.46%	12	37,489	13.54%	12	40,831	11.01%	12	39147.90	12.34%
13	36,004	15.66%	13	36,111	14.91%	13	33,899	18.16%	13	36,108	16.72%	13	39,058	14.88%	13	37022.03	17.10%
14	34,735	18.63%	14	35,716	15.84%	14	33,482	19.16%	14	34,190	21.15%	14	37,797	17.62%	14	36122.10	19.12%
15	33,287	22.03%	15	33,935	20.04%	15	31,442	24.09%	15	34,024	21.53%	15	36,102	21.32%	15	34197.61	23.43%
16	30,863	27.70%	16	32,443	23.56%	16	30,093	27.35%	16	31,285	27.85%	16	33,739	26.47%	16	31800.21	28.79%
17	30,530	28.48%	17	31,228	26.42%	17	29,196	29.51%	17	30,289	30.14%	17	32,926	28.24%	17	31362.66	29.77%
18	28,207	33.93%	18	28,312	33.29%	18	27,006	34.80%	18	28,324	34.68%	18	29,258	36.23%	18	28576.33	36.01%
19	26,481	37.97%	19	28,076	33.85%	19	26,422	36.21%	19	28,106	35.18%	19	27,052	41.04%	19	27936.62	37.44%
20	25,660	39.89%	20	26,546	37.45%	20	25,545	38.32%	20	26,312	39.32%	20	25,808	43.75%	20	25942.81	41.91%
21	25,154	41.08%	21	25,841	39.11%	21	25,017	39.60%	21	26,177	39.63%	21	25,385	44.68%	21	25637.77	42.59%
22	23,942	43.92%	22	25,363	40.24%	22	24,071	41.88%	22	24,868	42.65%	22	24,261	47.13%	22	24306.13	45.57%
23	23,921	43.97%	23	25,009	41.07%	23	23,898	42.30%	23	24,257	44.06%	23	24,214	47.23%	23	23955.44	46.36%
24	23,432	45.11%	24	24,736	41.72%	24	23,371	43.57%	24	23,897	44.89%	24	23,660	48.43%	24	23683.85	46.97%

*peak load day 8/16 was disrupted by interruptions analysis on second highest peak day 8/17/2000

*peak load day 8/31 was disrupted by interruptions, analysis on second highest peak day 8/12/1998

		Estimated MWs on 45,000 day
2 Hour average:	0.89%	401.26
4 Hour average:	2.69%	1209.15
6 Hour average:	5.25%	2361.66