California ISO
Your Link to Power

California Independent
System Operator Corporation

December 1, 2010

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation
Docket No. ER10-____- 000

Update to Capacity Procurement Mechanism and Exceptional Dispatch

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d, and Part 35 of the rules and regulations of the Federal Energy Regulatory Commission (FERC or Commission), 18 C.F.R. Part 35, and in compliance with Order No. 714 regarding electronic filing of tariff submittals,[1] the California Independent System Operator Corporation (ISO) hereby submits for filing the attached amendments to its Fifth Replacement FERC Electric Tariff.

The instant tariff amendments implement the Capacity Procurement Mechanism (CPM) to replace the ISO's expiring Interim Capacity Procurement Mechanism (ICPM) as the backstop mechanism that authorizes the ISO to procure capacity to address a deficiency or supplement resource adequacy (RA) procurement by Load Serving Entities (LSEs), as needed in order to comply with applicable reliability criteria and maintain reliability of the grid.[2] Although the proposed CPM largely retains the design and key features of the ICPM, the ISO is proposing certain important changes, including the following key revisions: (i) add a new CPM designation category to allow the ISO to procure capacity at risk of retirement that will be needed for reliability the following year; (ii) update the capacity price used to calculate the compensation paid to resources that are designated under the CPM or receive a CPM Exceptional Dispatch; (iii) retain mitigation measures applicable to Exceptional Dispatches made for purposes of addressing reliability requirements related to non-competitive transmission constraints and unit-specific environmental constraints not incorporated into the ISO's full network

[1] *Electronic Tariff Filings*, Order No. 714, FERC Stats. & Regs. ¶ 31,276 (2008).

[2] Capitalized terms not otherwise defined herein have the same meaning as set forth in the ISO Tariff, Appendix A, Definitions.

model or market software that affect the dispatch of generating units in the Sacramento Delta (commonly referred to as "delta dispatch"); and (iv) expand the criteria for selecting among eligible resources for purposes of designating CPM capacity and revise the Exceptional Dispatch provisions to incorporate all of the selection criteria used for CPM designations.

This filing complies with the Commission's orders that accepted the ISO's ICPM and Exceptional Dispatch mitigation provisions on an interim basis, subject to an automatic sunset date, and directed the ISO to submit a filing no later than 120 days prior to the sunset date of such provisions if it seeks to continue to use those provisions beyond that date. By order dated October 16, 2008,[3] the Commission accepted the ICPM as a temporary measure with a sunset date of December 31, 2010. The October 16 Order directed the ISO to make a timely filing to continue its backstop authority beyond that sunset date if needed in order to reliably operate the system.[4] In a subsequent order dated February 20, 2009,[5] the Commission extended the sunset date for the ICPM beyond December 31, 2010 in order to align it with the expiration of the Exceptional Dispatch mitigation provisions that terminate 24 months after the ISO's implementation of the new markets. The February 20 Order resulted in the currently effective ISO Tariff Sections 39.10 and 43 that provide for the Exceptional Dispatch mitigation provisions and the ICPM, respectively, to automatically terminate at midnight on the last day of the twenty-fourth month following their effective date, *i.e.*, March 31, 2011. In accordance with these orders, the ISO submits this filing to extend the backstop capacity procurement mechanism and certain of the Exceptional Dispatch mitigation provisions beyond the March 31, 2011 date.[6]

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[3] *Cal. Indep. Sys. Operator Corp.,* 125 FERC ¶ 61,053 (2008)(October 16 Order).

[4] The October 16 Order states in P117 that: "While we will not direct the CAISO to initiate a stakeholder process by December 1, 2009, given prior Commission action, it should be clear to both the CAISO and its stakeholders that resources utilized for backstop capacity services must be appropriately compensated for their services and that the Commission will not accept a temporary lapse in such compensation. Therefore, if the CAISO needs to rely on backstop capacity services beyond the ICPM's proposed sunset date, in order to reliably operate its system, we expect the CAISO to make a timely filing with the Commission that will ensure the continuation of just and reasonable compensation for the services rendered." The instant filing ensures that there will not be any lapse in compensation for backstop capacity.

[5] *Cal. Indep. Sys. Operator Corp.,* 126 FERC ¶ 61,050 (2009)(February 20 Order).

[6] The February 20 Order states in P 247 that: "Thus, if the CAISO still intends to exceptionally dispatch these non-resource adequacy resources, we require the CAISO to file no later than 120 days prior to the sunset of Exceptional Dispatch mitigation and ICPM, a compensation proposal applicable to such resources that is consistent with the precedent established in the RCST, TCPM, and ICPM proceedings. Alternatively, the CAISO may revise the MRTU Tariff to clarify that non-resource adequacy resources will not be subject to Exceptional Dispatch." 126 FERC ¶ 61,150 (P247).

The ISO proposes an effective date for the amendments proposed in this filing of April 1, 2011. This effective date coincides with the expiration of the Exceptional Dispatch mitigation provisions and the ICPM at midnight on March 31, 2011 pursuant to ISO Tariff Sections 39.10 and 43.

I. EXECUTIVE SUMMARY

The purpose of the RA program is to ensure that adequate resources are available when and where needed to serve load, meet appropriate reserve requirements, and support reliable operation of the ISO controlled grid. There nevertheless may be circumstances in which the RA capacity procured by LSEs may be inadequate to fulfill the ISO's operational needs and enable it to meet applicable reliability criteria. This circumstance could occur for a number of reasons, such as an LSE failing to procure its RA capacity obligations, unforeseen changes arising that affect system conditions or grid operations, or the procured RA resources lacking effectiveness in meeting the ISO's specific reliability needs. In such circumstances, the ISO will be short the needed capacity. It is, therefore, imperative that the ISO have the appropriate tools at its disposal under such circumstances to maintain reliable operations.

Based on these concerns, the ISO, with the active input from its stakeholders, designed the ICPM to provide a backstop capacity procurement mechanism that allows the ISO procure capacity to address a deficiency or supplement RA procurement in order to maintain reliable operations. In designing the ICPM, the ISO's primary goal was to provide it the necessary authority to operate the grid reliably while complementing, rather than supplanting or interfering with, the CPUC's RA program and the bilateral contracting that takes place as part of the RA program. Under the ICPM, the ISO can designate ICPM capacity to cover a shortfall where LSEs have failed to procure sufficient RA capacity;[7] a significant event has occurred that creates the need to supplement already-established RA requirements, or a reliability or operational need requires an Exceptional Dispatch CPM. Resources receiving an ICPM designation are compensated at $41/Kw-year based on the going-forward costs of a 50 MW simple-cycle gas-fired unit built by a merchant generator, plus a 10% adder. Alternatively, a generator can make a cost-based showing with the Commission justifying a higher level of compensation. The actual compensation a unit will receive varies based on the unit's availability during the period of the ICPM designation. The unit will receive compensation above or below $41/kW-year (or its cost-based compensation) depending on whether its ICPM Availability Factor is above or below 95%, respectively. The ICPM was designed as an interim measure, automatically set to expire on March 31, 2010.

[7] This first category contains three sub-categories of different types of circumstances in which an LSE or group of LSEs has failed to procure sufficient RA capacity.

Over the past six months, the ISO has collaborated with its stakeholders to consider a replacement to the expiring ICPM authority. In reviewing the performance of the ICPM and the ISO's new markets, the ISO came to two important conclusions. The first conclusion is that the ICPM has served its intended purposes effectively. The second conclusion is that the ISO's need for backstop capacity procurement authority will continue into the foreseeable future. These two conclusions have driven the design of the CPM, the ISO's proposed permanent replacement to the ICPM. The ISO's proposed CPM continues nearly all of the salient design elements of the ICPM and its interrelationship with Exceptional Dispatch. While most aspects of the ICPM will be retained, the ISO proposes to make several needed updates to the ICPM design. The key elements of the CPM are as follows:

- The existing categories of ICPM designations will be retained in the CPM. A new category of designation will also be added to cover units at risk of retirement that are not needed for reliability in the current RA Compliance Year but will be needed by the end of the following year. This category of CPM designation will be a last resort, backstop measure, The ISO will issue this CPM designation only in very limited circumstances and subject to stringent requirements related to the resource owner's decision to retire the unit and the reliability need for the in the following year,

- The methodology for determining ICPM compensation will be carried over to the CPM. Compensation will continue to be based on going-forward costs plus a 10% adder. The ISO again considered and rejected the notion of basing compensation on the cost of new entry. Units can continue to elect the default compensation amount or make a cost-based showing with the Commission. Based on more recent studies on the going-forward costs of a 50 MW simple-cycle gas unit, the default compensation level will be increased to $55/kW-year.

- The actual compensation a unit receives from its CPM designation will continue to be based on the unit's Availability Factor. That calculation, however, will now account for Maintenance Outages. A resource that takes a Maintenance Outage during its CPM designation will have its payment prorated to account for the period of the outage.

- Under ICPM, once the need to make a designation is identified, the ISO chooses which unit to designate based on the effectiveness of the unit at meeting the reliability need, the capacity costs associated with the unit (*i.e.*, whether the unit will accept the default compensation or requires a higher cost-based compensation level), and the amount of capacity available from a unit relative to the ISO's capacity need. These selection criteria will be retained in the CPM and two new criteria will be added. The two new criteria will allow the ISO to consider the resource's operating characteristics (*e.g.*, dispatchability, ramp rate) and whether the resource is a Use-Limited

Resource or a non-Use-Limited Resource. Because of the close connection between ICPM/CPM and Exceptional Dispatch, these same criteria are being added to the process for selecting the eligible capacity to receive an Exceptional Dispatch.

- The term of the designation for each category of ICPM will be retained in the CPM. In the ICPM development process, the ISO inadvertently failed to identify a term for designations triggered by an Exceptional Dispatch. To correct this oversight, the CPM includes a 30-day designation period for Exceptional Dispatch CPM designations. For the new category of risk of retirement CPM designations, the period of designation is limited to the remainder of the current RA Compliance Year.

- A CPM designation, like an ICPM designation, will be voluntary. A unit need not accept a CPM designation if it does not wish to receive such a designation.

- Similar to the ICPM, based on cost causation principles, individual LSEs that are responsible for RA Capacity shortfalls will be assessed through their respective Scheduling Coordinators the costs of CPM procurement necessary to remedy those shortfalls. The costs of CPM designations related to collective procurement shortfalls, Significant Events, Exceptional Dispatches, and units at risk of retirement will be assessed to the Scheduling Coordinators for the LSEs in the TAC area in which the reliability need arose.

- With the exception of Significant Event CPM designations, those LSEs that pay for the costs of a CPM designation will receive "credit" towards their RA requirements proportionate to the quantity of CPM capacity for which that LSE paid.

The ISO submits that the CPM is a necessary and appropriate backstop mechanism to procure capacity from existing resources as needed for reliable grid operations using a transparent and efficient tariff-based process, and that the Commission should find it just and reasonable.

II. DESCRIPTION OF ICPM

A. <u>Background of ICPM</u>

The RA program was implemented to ensure that adequate resources would be available when and where needed to serve load, meet applicable reserve requirements, and support reliable operation of the ISO Controlled Grid.

Each year the ISO's role in the RA process begins with the publication of the Locational Capacity Technical Study and the Deliverability Study. The Locational

Capacity Technical Study determines the minimum capacity needed in each identified transmission constrained "load pocket" or Local Capacity Area to ensure reliable grid operations. The Deliverability Study establishes the deliverability of generation in the ISO Balancing Authority Area and the total import capability for each import path allocated to each LSE. The information contained in these reports, along with generator data, is used to compile the annual Net Qualifying Capacity (NQC) Report, which lists the NQC of all Participating Generators and other Generating Units that request inclusion in the RA program for the next RA Compliance Year.

LSEs use the NQC report to identify resources eligible to contract for RA Capacity to satisfy their RA requirements. These requirements consist of the Reserve Margin established by the Local Regulatory Authority and the Local Capacity Area Resource requirement. Scheduling Coordinators for LSEs must make these RA Resources available to the ISO in accordance with the requirements of either Section 40.5 for Modified Reserve Sharing LSEs or Section 40.6 for non-Modified Reserve Sharing LSEs.

In the year-ahead and month-ahead timeframes, LSEs are required to provide RA Plans to the ISO demonstrating that their RA requirements will be met for that reporting period. Scheduling Coordinators for these RA Resources also submit year-ahead and monthly Supply Plans to the ISO verifying the commitment to make available the RA Capacity. The ISO then cross-validates the RA Plans and Supply Plans to ensure that the RA requirements are being met.

There may be circumstances, however, where the RA capacity procured by LSEs is insufficient to meet the ISO's operational needs. The existing ICPM was designed to grant the ISO the authority to backstop or supplement LSEs' RA procurement in five situations (discussed below) to ensure that ISO operators have sufficient generation capacity to maintain reliable grid operations. Once the ISO procures ICPM capacity, the unit must follow RA obligations for the amount of capacity procured. ICPM was designed as a complement to, not as a substitute for, procurement under the RA program, and the ISO did not intend for it to interfere with the bilateral contracting processes that take place under the RA program. The effective date of the ICPM authority, which replaced the Reliability Capacity Services Tariff, coincided with the start of the ISO's new market system on April 1, 2009. The ICPM tariff provisions are set to sunset automatically two years after the start of the new markets.

B. <u>The Categories of ICPM Procurement</u>

The existing ICPM tariff provisions permit the ISO to procure five categories of ICPM capacity. First, under ISO Tariff Section 43.1.1, the ISO may procure ICPM capacity to cover instances where a Scheduling Coordinator fails to show that it has procured sufficient Local Capacity Area Resources in an annual or monthly RA Plan. Second, the ISO may designate ICPM capacity under Section 43.1.2 to correct a collective deficiency in Local Capacity Area Resources in the annual RA Plans of applicable Scheduling Coordinators after the opportunity for LSEs to cure the deficiency has been exhausted. Third, the ISO may designate capacity under Section 43.1.3 in response to a Scheduling Coordinator's failure to show sufficient RA Resources in an annual or monthly RA Plan to comply with each LSE's annual and monthly demand and reserve margin requirements. Fourth, ICPM procurement may occur under ISO Tariff Section 43.1.4 if the ISO determines that a significant event[8] occurs during an RA Compliance Year that creates a need to supplement the already-established RA requirements.

Fifth, the ISO is required to offer ICPM procurement under ISO Tariff Section 43.1.5 for resources that are issued an Exceptional Dispatch and are not under an RA or Reliability Must-Run Contract and do not already have an ICPM designation. The ISO proposes to retain all of these designation categories under the CPM, as well as adding a sixth category, discussed below.

C. <u>Compensation Paid for ICPM Capacity</u>

Under the existing Tariff, the compensation for ICPM capacity is based on going-forward fixed costs.[9] Specifically, the ISO used the going-forward fixed costs of a 50 MW simple-cycle gas-fired unit built by a merchant generator, plus a 10% adder. The going-forward costs of such a unit are determined based on a comprehensive study conducted by the California Energy Commission (CEC). The capacity price determined and proposed by the ISO was $41/kW-year,[10] which was approved by the Commission

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8 The ISO Tariff, Appendix A, defines an ICPM Significant Event as:

> A substantial event, or combination of events, that is determined by the CAISO to either result in a material difference from what was assumed in the resource adequacy program for purposes of determining the Resource Adequacy Capacity requirements, or produce a material change in system conditions or in CAISO-Controlled Grid Operations, that causes, or threatens to cause, a failure to meet Applicable Reliability Criteria absent the recurring use of a non-Resource Adequacy Resource(s) on a prospective basis.

9 Going-forward costs are the core fixed costs that a generating unit needs to make itself available for operation for the term of designation, but do not include such elements as return on investment. Going-forward costs are defined here as the sum of fixed operations and maintenance costs, ad valorem costs, and administrative and general costs.

10 Not all units receiving an Exceptional Dispatch ICPM designation will necessarily receive their going-forward fixed costs. Prior to each month, suppliers can decide whether they want to receive ICPM compensation or supplemental revenues compensation in the event they receive an ICPM designation. If a supplier elects supplemental revenues option, the resource will be eligible to be paid as bid of Exceptional Dispatches within the 30-day period subject to a revenue cap that is calculated based on the revenues above what the resource would be paid if the resource were subject to bid mitigation. The supplier can retain such revenues up to the cap, which is the ICPM payment the resource would otherwise be eligible to be paid. Unlike suppliers electing the ICPM compensation, suppliers electing the supplemental revenues option do not have an offer obligation during the 30-day period.

in the October 16 Order.[11]

For owners of resources that believe the $41/kW-year default compensation price is insufficient for particular units, the tariff permits them to cost justify a higher level of compensation in a Section 205 filing with the Commission. To date, no party has made a cost justification filing at FERC for ICPM compensation above the default compensation level of $41/kW-year.[12]

The ISO's backstop capacity mechanism can only procure existing generation for a term of one-year or less (depending on the specific deficiency that is being addressed) and is not intended to incent the development of new generation, Because of the temporary and short-term nature of the ICPM, the ISO argued, and the Commission agreed in its order, that it was not appropriate to adopt a price designed to incent the development of new capacity, otherwise known as the cost of new entry or CONE. The ISO determined that based on the short-term nature of an ICPM designation, providing the going-forward fixed costs plus a 10% adder provided just and reasonable compensation because it provides all units, at a minimum, with compensation for that which the ISO requires – maintaining the ability to stay in the market and submit bids to provide energy. The Commission agreed with the ISO, over stakeholder objections, to base the ICPM capacity price on going-forward fixed costs rather than CONE. Specifically, the Commission found that "the ICPM is a mechanism for procuring capacity for short periods to meet system reliability needs and, therefore, is not designed to encourage new investment"[13]

D. Criteria for Choosing from among Potential Generating Units

Existing ISO Tariff Section 43.3 specifies four factors that the ISO can consider in selecting the capacity for the ICPM designation from among potential units. Those factors are: (1) the effectiveness of the eligible capacity at meeting the reliability need; (2) the capacity costs of the eligible capacity; (3) the quantity of the resource's available capacity relative to the amount of capacity the ISO needs; and (4) if the capacity shortfall is for a local constraint, the effectiveness of the unit at meeting a local constraint. If more than one unit meets these criteria equally, then the ISO will use a random selection method to determine the designation.

The first criteria, which is somewhat self-evident, simply considers whether the unit will actually meet the ISO's reliability need. The second criteria considers whether the unit has indicated it: (a) will accept the default price; (b) has petitioned the

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[11] October 16 Order at PP 41-44.

[12] However, for compensation tied to Exceptional Dispatches, the tariff requires notification seven days in advance of the month to choose compensation based on supplemental revenues capped by the default ICPM price, but without designation as an ICPM resource, or designation as ICPM units at the ICPM price.

[13] October 16 Order at P 41.

Commission for a cost-justified payment in excess of the default price; or (c) will petition the Commission for a cost-justified payment after it has accepted a designation as ICPM capacity. The order of preference among these cost options is to designate the least-cost unit first, which is the default price (*i.e.*, category a), followed by units that will need to be paid a known cost (*i.e.*, category b), followed finally by units whose compensation is not yet known (*i.e.*, category c). The third criteria looks to whether a unit's available capacity is sufficient to meet the ISO's needs. For example, if the ISO needs to procure 50 MW of capacity, the ISO would prefer to procure a unit with a minimum operating output at or below 50 MW, as opposed to a unit with a minimum operating output of 100 MW. In the latter case, the ISO would be forced to over-procure 50 MW of capacity. The fourth criteria, which in some sense is linked to the first requirement, looks to how effectively a unit will address the local constraint it is procured to remedy. As discussed, *infra*, the ISO is proposing two additional criteria for consideration in the selection process and to apply all of these selection criteria to Exceptional Dispatches in ISO Tariff Section 34.9.

E. <u>Voluntary Nature of an ICPM Designation</u>

In the policy development process for ICPM, the ISO considered making acceptance of an ICPM designation mandatory. The ISO determined, however, that this was unnecessary and would be inconsistent with the lack of a general must-offer obligation under the ISO's new markets. Accordingly, if a unit owner does not wish to accept the responsibilities that go along with being procured as ICPM capacity, that unit owner may decline the designation. The ISO does not propose to change the voluntary nature of the designations.

F. <u>Term of ICPM Designations</u>

The length of the minimum and maximum commitment terms for an ICPM designation depend on the type of the ICPM being issued, as specified in ISO Tariff Section 43.2. An ICPM designation for failure of an LSE to show that it has procured sufficient Local Capacity Area Resources in an annual RA Plan has a minimum commitment term of one month and a maximum commitment term of one year. If the ICPM designation results from an LSE's failure to show sufficient Local Capacity Area Resources in the monthly RA Plan, the minimum commitment term is one month and the term may not extend into a subsequent RA Compliance Year. For a collective deficiency of Local Capacity Area Resources in an annual RA Plan, the range of the commitment term for an ICPM designation is from one month to one year, although the designation may not extend into a subsequent RA Compliance Year. In the event of a failure to demonstrate procurement of sufficient RA capacity to comply with an LSE's annual and monthly demand and reserve margin requirements, the minimum commitment is one month if the deficiency is in the monthly RA plan or is a minimum term of one month up to the maximum annual procurement period established by the Local Reliability Authority based on the period of deficiency. This ICPM designation also prohibits extension of the term into the next RA compliance year. An ICPM designation for a significant event has an initial term of 30 days, which may be extended for another 60 days if the significant event persists, in accordance with Section 43.3.5. The ISO does not propose to change the term of designation for the exisitng backstop procurement categories.

G. Notifying the Market of ICPM Designations

Once the ISO designates ICPM capacity, the ISO must provide several types of public notice to the market of the designation. Where capacity has been procured to address an ICPM Significant Event, the ISO must issue a market notice within two days providing preliminary notification of the procurement. Additionally, within 30 days of any ICPM designation, the ISO must post a "designation report" on the ISO's website providing details of the exercise of ICPM tariff authority. The ISO proposes to retain the existing reporting requirements, with additional notification requirements for the new category of ICPM designation,

H. Allocation of ICPM Costs

Like the length of the commitment term, the method for allocating the costs of the ICPM capacity payments varies under Section 43.7 depending on the type of ICPM designation being issued. The ICPM costs of a designation for failure of an LSE to show that it has procured sufficient Local Capacity Area Resources in an annual RA Plan are allocated pro rata to each Scheduling Coordinator for a deficient LSE based on the ratio of that LSE's deficiency to the deficiency within the Transmission Access Charge (TAC) area. Similarly, if the ICPM designation is for a failure of an LSE to show that it has procured sufficient Local Capacity Area Resources in the monthly RA Plan, the ISO will allocate the ICPM costs pro rata to each Scheduling Coordinator for a deficient LSE based on the ratio of that LSE's deficiency to the deficiency within the TAC area. For ICPM designations resulting from a collective deficiency of Local Capacity Area Resources in an annual RA Plan, the ICPM costs are allocated to all Scheduling Coordinators of LSEs serving load in the TAC area in which the deficient local capacity area was located. In the event of an ICPM designation for a failure to demonstrate procurement of sufficient RA resources to comply with an LSE's annual and monthly demand and reserve margin requirements, the ICPM cost allocation is made pro rata to each LSE based on the proportion of its deficiency to the aggregate deficiency. The capacity costs of an ICPM designation for a significant event are allocated to all Scheduling Coordinators for LSEs that serve load in the TAC area where the significant event caused or threatened to cause a failure to meet reliability criteria. The allocation is made based on each Scheduling Coordinator's percentage of actual load in the TAC area to total load in that area. The costs of an Exceptional Dispatch ICPM are allocated in the same manner as an ICPM designation for a significant event. The ISO does not propose to change the cost allocation methodologies applicable to the existing categories of backstop procurement and will add a new allocation methodology for the new category of backstop procurement.

I. The Two-Year Sunset of the ICPM

As discussed above, the Commission's October 16 Order approved the ISO's proposed sunset date for the ICPM of December 31, 2010 and directed the ISO to make a timely filing to continue its backstop authority beyond that sunset date if needed in order to reliably operate the system.[14] In the February 20 Order, the Commission extended the sunset date for the ICPM in order to align it with the Exceptional Dispatch mitigation provisions that terminate 24 months after the ISO's implementation of the new markets. Based on the February 20 Order, the existing ISO Tariff Sections 39.10 and 43, respectively, provide for the Exceptional Dispatch mitigation provisions and the ICPM to automatically terminate at midnight on the last day of the twenty-fourth month following their effective date, which sunset date is March 31, 2011.

The ISO proposed implementing the ICPM for a limited term for several reasons. One factor is that at the time ICPM was being developed, the California Public Utilities Commission (CPUC) was engaged in a proceeding to consider the long-term design of the RA program. The ISO believed that waiting until the CPUC made a final decision in its long-term RA proceeding, and the long-term RA design was known, would allow the ISO to adopt a more durable backstop mechanism that would be consistent and aligned with the CPUC's long-term RA design. Additionally, there was no experience with the ISO's Locational Marginal Pricing-based market at the time ICPM was being developed, and depending on the long-term RA design ultimately adopted by the CPUC, the ISO might have limited, if any experience with that program. For these reasons, the ISO concluded that it was prudent to adopt a sunset date for the ICPM and review it further in two years.

III. STAKEHOLDER ENGAGEMENT AND POLICY DEVELOPMENT PROCESS

The ISO conducted an extensive and robust stakeholder process in developing the CPM proposal, with significant input from stakeholders. In order to meet the December 1, 2010 filing date imposed by the Commission's February 20 Order, the ISO initiated the stakeholder process in the summer of 2010 to update tariff provisions associated with the ICPM and Exceptional Dispatch pricing and bid mitigation and replace the provisions that sunset on March 31, 2011. The stakeholder process involved multiple meetings and conference calls with stakeholders, issuance of several whitepapers discussing the issues, and numerous opportunities for stakeholders to

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[14] The October 16 Order states in P117 that: "While we will not direct the CAISO to initiate a stakeholder process by December 1, 2009, given prior Commission action, it should be clear to both the CAISO and its stakeholders that resources utilized for backstop capacity services must be appropriately compensated for their services and that the Commission will not accept a temporary lapse in such compensation. Therefore, if the CAISO needs to rely on backstop capacity services beyond the ICPM's proposed sunset date, in order to reliably operate its system, we expect the CAISO to make a timely filing with the Commission that will ensure the continuation of just and reasonable compensation for the services rendered."

provide input on the development of the CPM. The resulting proposal reflects this collaborative process.[15]

The ISO began the stakeholder process by publishing an Issue Paper on June 9, 2010 that indicated that the ISO was not proposing a wholesale redesign of the core elements of the ICPM or Exceptional Dispatch tariff provisions because it believed that these provisions were working well and were justified within the existing parameters of the RA program and the ISO's reliability and operational needs. The Issue Paper accordingly identified specific aspects of the ICPM and Exceptional Dispatch measures under review in the initiative and noted that additional issues could be considered to augment the current rules. The ISO conducted a stakeholder conference call on June 16, 2010 to discuss the Issue Paper and asked stakeholders to submit written comments on it by June 23, 2010. Stakeholders responded with extensive comments and feedback on the topics identified in the Issue Paper.

On July 15, 2010, the ISO published a Straw Proposal that described several changes to the ICPM that were under consideration in developing the ISO's CPM proposal. These changes included eliminating the sunset date for the backstop mechanism permanent and expanding the circumstances in which the ISO may issue a CPM designation. The Straw Proposal also asked stakeholders for their views on the calculation of the compensation to be provided for ICPM designations. The Straw Proposal was discussed in a conference call on July 22, 2010 and stakeholders were given the opportunity to file written comments on the Straw Proposal by July 30, 2010. Again, stakeholders submitted extensive comments, which were polarized over three significant issues -- whether the successor backstop mechanism to the ICPM should be interim or permanent, whether and in what circumstances the ISO's authority to issue designations should be extended, and whether going-forward costs (plus the 10 percent adder) or CONE should be used to calculate the backstop capacity cost. Early in the development of the CPM, most stakeholders supported a permanent extension of the CPM authority, including Dynegy, JP Morgan, Calpine and NRG.[16]

Based on stakeholder input on the Straw Proposal, the ISO issued a Draft Final Proposal in this initiative on August 16, 2010. One significant change in the proposal was the decision not to expand the circumstances for procuring CPM capacity to allow transmission and/or generation maintenance outages to occur or to address situations where the output of variable energy resources is lower than their RA capacity values that had previously been under consideration. The ISO reviewed its authority under the

[15] The complete CPM stakeholder record can be found at www.caiso.com/27ae/27ae96bd2e00.html . This record includes the ISO's Issue Paper and proposals, comments submitted by stakeholders, presentations at stakeholder meetings, and draft CPM tariff language.

[16] Dynegy at question 1, http://www.caiso.com/27e7/27e7843f59b80.pdf; NRG at question 1, http://www.caiso.com/27fc/27fc923116b50.pdf, JP Morgan at question 1, http://www.caiso.com/27e7/27e783224fc10.pdf, and Calpine at question 1 http://www.caiso.com/27e7/27e7835d52c80.pdf..

ICPM and Exceptional Dispatch provisions of its tariff and believes that both of these circumstances are already covered under the existing authority to procure for a significant event. The Draft Final Proposal did recommend expanding the ISO's authority to designate CPM capacity to keep a resource in operation that is at risk of retirement during the current RA Compliance Year but that will be needed for reliability by the end of the calendar year following the current RA Compliance Year. In this situation, the CPM designation in the current year is intended as a bridge to ensure that the non-RA resource will remain operable and be available when it is needed for reliability purposes during the following year.

Another change from the Straw Proposal was the determination not to complicate the substitution rule by allowing a resource owner to substitute capacity for a resource under a CPM designation that begins a maintenance outage after the start of, but before completing, the 30-day CPM designation. The ISO proposed instead to pay the resource for only the portion of the 30 days that it is available.

In the Draft Final Proposal, the ISO also proposed to add two new criteria to the existing ICPM criteria for selecting among eligible capacity for a CPM designation. These two new criteria involve consideration of (i) whether the resource is subject to restrictions as a Use-Limited Resource and (ii) the operating characteristics of the resource, such as dispatchability, Ramp Rate, and load-following capability. These two new criteria will enable the ISO to select the resource for a CPM designation that will best respond to the identified reliability need and will be most likely to be available to meet that need.

The Draft Final Proposal further recommended to continue backstop capacity pricing based on going-forward fixed costs (plus a 10 percent adder) rather than switching to pricing based on CONE. The ISO believes that pricing CPM capacity based on the going-forward fixed costs is consistent with the facts that all procurement will be short-term and will come from existing generation resources, and that such pricing will have little, if any, effect on prices in the current bilateral RA market.

In the Draft Final Proposal, the ISO also recommended continuing the existing mitigation provisions for Exceptional Dispatches, which mitigate bids in only two circumstances -- when dispatched for purposes of addressing reliability requirements related to non-competitive transmission constraints and unit-specific environmental constraints not incorporated into the ISO's full network model or for delta dispatch.

The ISO hosted a stakeholder meeting August 23, 2010 to review the Draft Final Proposal and received written comments from stakeholders on September 7, 2010. Stakeholders continued to be polarized over whether the CPM should be interim or permanent and whether the going-forward costs or CONE should be used to calculate the backstop capacity cost. The Western Power Trading Forum ("WPTF"), NRG, Calpine and JP Morgan all opposed the proposal based on compensation tied to the going forward rate.[17] In response to the generators' preference for CONE, the ISO has committed to tackle the problem of diminished generator revenue in the Renewable Energy Initiative currently underway. Many commenters opposed expanding the ISO's authority to issue CPM designations for capacity that is at risk of retirement even though such capacity might be needed to meet future identified reliability needs. The CPUC, SDG&E, Southern California Edison and PG&E opposed the CPM category, primarily on grounds that this authority is duplicative of CPUC authority and that RMR contracts would provide for this contingency.[18] JP Morgan, NRG and RRI Energy generally supported the new CPM category but with conditions that generators be fairly compensated with a transparent selection process.[19]

On September 15, 2010, the ISO posted its Revised Draft Final Proposal. Based on stakeholder comments and discussion at the August 23, 2010 stakeholder meeting, the Revised Draft Final Proposal provided the following: (i) response to comments suggesting that ISO authority to procure capacity at risk of retirement needed for reliability duplicates CPUC authority under General Order 167; (ii) greater detail regarding the compensation of CPM capacity and the role of the CEC; and (iii) discussion of how an existing ICPM designation will become subject to the CPM provisions on a going-forward basis. The ISO held a stakeholder conference call on September 22, 2010 to review the Revised Draft Final Proposal. Stakeholders submitted written comments on September 30 and October 6, 2010.

The ISO also received important feedback from both its Market Surveillance Committee (MSC) and its Department of Market Monitoring (DMM). On October 8, 2010, the MSC held an open meeting to discuss the ISO's proposed ICPM replacement. The MSC had the benefit of engaging on this topic with multiple stakeholders and received formal presentations from representatives of SCE and WPTF.

On October 18, 2010, the MSC adopted an opinion, attached herein as Attachment D, offering its view of the ISO's proposal. The MSC supports the ISO's proposal, concluding that it represents "a reasonable method that balances the need to maintain reliable system operation against the need to limit the amount of intervention by the ISO in market mechanisms." The MSC's primary concern is that it believes the

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17 NRG at question 1, http://www.caiso.com/280a/280abaf31ff20.pdf; Calpine at question 1, http://www.caiso.com/280a/280ab94ae2a0.pdf; WPTF at question 1, http://www.caiso.com/280a/280acbd62d9c0.pdf; and JP Morgan at question 1, http://www.caiso.com/280a/280ab9f315eb0.pdf.

18 CPUC at question 7, http://www.caiso.com/280a/280ab99d13820.pdf; SDG&E at page 3 http://www.caiso.com/280a/280abbca2a330.pdf; SCE at question 7, http://www.caiso.com/280a/280abb82228c0.pdf; and PG&E at question 5, http://www.caiso.com/280a/280acd3f3c880.pdf.

19 NRG at question 7, http://www.caiso.com/280a/280abaf31ff20.pdf; JP Morgan at question 4, http://www.caiso.com/27e7/27e783224fc10.pdf; and RRI Energy at question 4, http://www.caiso.com/27e7/27e78ac51a0e0.pdf.

CPM payment should exceed the going-forward fixed costs where the local capacity requirements exceed the amount of available capacity. Such higher payments, in the MSC's view, could stimulate new generation entry, or at least serve as a signal to demand. The MSC acknowledged, however, that given the small amount of capacity that has been procured through ICPM, the additional complexity this would create may not be justified.

The CPM proposal was presented to the ISO Governing Board on November 2, 2010 and the Board authorized this filing. A copy of the Memorandum to the Board, entitled *Decision on Updating Interim Capacity Procurement and Exceptional Dispatch* is attached to this filing as Attachment E.

The ISO posted draft tariff language for CPM on October 20 and 22, 2010. Stakeholders submitted comments on the draft tariff language through November 1, 2010, and these comments were discussed during a stakeholder conference call on November 3, 2010. Revised draft tariff language was then posted on November 9, 2010, with comments provided through November 18, 2010 and the conference call held on November 23, 2010.

IV. DESCRIPTION OF THE PROPOSED CAPACITY PROCUREMENT MECHANISM

A. Key Design Decisions for the CPM

It is imperative that the ISO have an orderly, pre-approved means to procure backstop capacity where and when needed to meet applicable reliability criteria or otherwise maintain reliable grid operations. Although RA programs are in place under California law, and RA requirements have been established by Local Regulatory Authorities, there may be instances when RA Resources are not sufficient to meet all of the operational needs of the ISO and enable it to meet reliability criteria. This may occur as a result of LSEs failing to comply with RA requirements, LSEs procuring sufficient resources to meet their RA requirements established by Local Regulatory Authorities, but such resources are not fully effective in meeting all of the ISO's specific reliability needs, and unforeseen or changed circumstances affecting system conditions or grid operations. The ISO must have the appropriate tools at its disposal under such circumstances to maintain reliable operations. In particular, the ISO needs the ability to procure resources when such instances occur in order to maintain the reliability of the CAISO Balancing Authority Area. The ICPM has provided the ISO with that ability and, as such, the ISO is retaining the key features of the ICPM in conjunction with a few key modifications that will enhance the program.

In reviewing the performance of both the ICPM and the ISO's new market system over the first 18 months of their operation, the ISO has come to two key conclusions – (i) the ICPM has operated effectively and successfully in fulfilling its intended purpose, and (ii) the need for backstop capacity procurement mechanism continues to exist.

With regard to the first conclusion, the ICPM has worked effectively in concert with the RA program at fulfilling its intended purpose. The ICPM has filled in "the gaps" between a number of existing requirements and programs:

- It has served as a complement to, and not as a substitute for, the RA program, which is the primary means for ensuring that resources are available when and where needed.

- It is not a substitute for RMR Contracts, which are annual contracts for specific units that are needed to meet specific long-term local reliability needs not addressed through RA contracts. As the Commission is aware, the ISO is attempting to transition from reliance on RMR Contracts and to rely more exclusively on procurement for locational requirements by Scheduling Coordinators for LSEs.

- It also is not a substitute for Exceptional Dispatch which permits the ISO, *on a given day*, to dispatch units, whether they are RA, non-RA, RMR or ICPM, out-of-merit order or out-of-market in order, *inter alia,* to prevent a situation that threatens system reliability and which cannot be addressed by the ISO's market optimization and system modeling.

- It is not an emergency measure but rather is a means to avoid such situations.

In addition, the use of, and costs associated with, ICPM procurement have been extremely limited since the mechanism became effective. In the time that the ISO has had ICPM authority, there have been only 23 ICPM designations for 703 MWs with a total cost of $2.7 million. All of these designations were triggered by Exceptional Dispatches rather than being initiated under one of the other ICPM procurement categories.

Further, on June 3, 2010, the CPUC adopted a final decision in its long-term RA proceeding that declined to adopt either a multi-year forward procurement requirement for RA capacity or a centralized capacity market, which essentially leaves the RA program unchanged for the foreseeable future.[20] Because the underlying RA program will remain unchanged, the ISO believes it is reasonable to retain the basic ICPM design, which is aligned with and has worked effectively in conjunction with the RA program, without only a few modifications. The ISO also believes that it is reasonable to expect that, if the ICPM were not to expire, it likely would continue to work effectively, and therefore that the successor backstop mechanism to the ICPM does not require a significantly different design.

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[20] http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/118990.htm.

The second conclusion is that, while the use of ICPM has been rather limited, the potential circumstances and needs that motivated the implementation of ICPM are still relevant today. Moreover, given the significant operational requirements facing the ISO in the near future as a result of the integration of large amounts of variable energy resources, it would be irresponsible for the ISO not to seek the continuation of some equally effective type of backstop capacity procurement mechanism. In order to assure its ability to operate the system reliably under diverse system conditions, the ISO must have both a backstop capacity procurement mechanism comparable to ICPM and an Exceptional Dispatch mechanism as permanent features of its market and operating structure. These diverse system conditions can relate to issues surrounding the integration of variable energy generation sources. As the number of variable energy resources that are on line increase, they will comprise a greater proportion of LSEs' RA capacity and capacity serving load. Because the qualifying capacity for these resources is based on their historical output, the qualifying capacity is merely a statistical estimate that may or may not be available on a given day due to weather. In this case, on any given day (or days) the unit may fail to reach its qualifying capacity even if there are no operational problems with the unit. If adverse weather persists, the variable energy resource may be unable to provide its full RA capacity for an extended period of time. The absence of this capacity could adversely impact system reliability. Through the procurement of backstop capacity, the ISO can address this potential adverse outcome. Additionally, transmission and generation outages can change the topography of the electric system. As a result, resources that previously were not needed for RA purposes may become necessary to maintain capacity requirements. A backstop capacity procurement mechanism enables the ISO to procure specific capacity needed in response to outages in order to maintain the ISO's compliance with applicable reliability criteria.

For these reasons, and based on careful consideration of how the needs for these mechanisms are likely to evolve over the next few years, the ISO seeks Commission approval to retain the salient design aspects of the expiring ICPM to the proposed CPM and to make several needed enhancements to the ICPM design, to update the price paid for capacity under both the CPM and Exceptional Dispatch, and to retain the current bid mitigation provisions for Exceptional Dispatch.

The key enhancements to the ICPM design that the ISO is proposing for the CPM are listed here and discussed more fully in subsequent sections:

- A new CPM procurement category for resources at risk of retirement that the ISO has determined will be needed for reliability in the following year;

- The addition of two criteria the ISO can consider in selecting capacity for a CPM designation or Exceptional Dispatch from among eligible resources that will allow ISO operators to exercise a preference for non-use-limited over use-limited resources and to consider each resource's operating characteristics;

- Adjustment of CPM compensation when a CPM resource becomes unavailable during the CPM procurement period due to a maintenance outage; and

- Updating the price for backstop capacity.

B. New Category of Procurement – Capacity at Risk of Retirement

The ISO proposes to enhance the existing ICPM design by adding to the categories of CPM designations listed in proposed Tariff Section 43.2 a new category of procurement that will permit the ISO to procure the capacity of non-RA units that have demonstrated that they will shut down in the current year because it will be uneconomic for the resource to remain in service but whose operation is projected by the ISO to be needed to meet operational or reliability needs in the year following the year in which the resource would shut down.

While the existing CPM designations are used infrequently, the ISO intends that the proposed CPM designation for a resource at risk of retirement will be a last resort, backstop measure, akin to breaking the glass in case of emergency. The ISO will issue this CPM designation only in very limited circumstances and subject to the ability of the resource requesting the designation to meet the stringent requirements, as set forth in proposed ISO Tariff Section 43.2.6.

The first requirement is that the resource must not be needed for reliability purposes in the current year. This is based on the failure of the unit either to receive a bilateral RA contract or be listed as RA capacity in any LSE's annual RA Plan for the current RA Compliance Year. The second requirement is that the unit did not receive a CPM designation from the ISO in the current year due to any individual or collective deficiency in the LSEs annual RA Plans. Third, ISO technical assessments must project that the resource will be needed for reliability purposes, either for its locational or operational characteristics, in the following year due to some type of changing system conditions. Fourth, ISO technical assessments must project that no new generation will be operational in time to meet the identified reliability need for that resource in the following year. The fifth requirement is that the resource owner must request a CPM designation for the resource at risk of retirement at least 180 days prior to terminating the resource's Participating Generator Agreement or removing the resource from the list of participating resources on Schedule 1 of such agreement. The request must include an affidavit of an executive officer of the company that owns the resource, with supporting financial information and documentation, that attests that it will be uneconomic for the resource to remain in service in the current year and that the decision to retire the unit is definite unless CPM procurement occurs. As the sixth requirement, the ISO must reach a determination, based on a review of the affidavit and supporting financial information and documentation, that the expectation of financial losses and decision to retire the resource are reasonable and supported by the facts.

In the event that all of the six requirements are met, before the ISO issues the CPM designation, it is required under the proposed tariff provisions to prepare a report that explains the basis and need for the CPM designation for risk of retirement, and post that report on the ISO's website. The posting must allow no less than seven days for stakeholders to review and submit comments on the report and no less than 30 days for an LSE to procure capacity from the resource in the alternative to proceeding with the CPM designation.

Once this process is completed, unless the resource has otherwise entered into an arrangement through the bilateral market that relieves its projected revenue insufficiency in the upcoming RA Compliance Year, the ISO may issue the CPM designation to the resource at risk of retirement. Under proposed Section 43.2.6.1, the designation may occur prior to or during the pendency of any review by the ISO's Department of Market Monitoring ("DMM") of the affidavit and supporting financial information and documentation. DMM has publicly committed to undertake such review to assess the accuracy of the information submitted, the reasonableness of the representation and conclusions contained in the submission, and the appropriateness of the resource's conduct and efforts to sell capacity in the bilateral market. DMM's review, or a referral of investigation by DMM to the Commission, however, may not be completed before the ISO needs to issue the CPM designation. The proposed tariff provision therefore clarifies that the ISO may nonetheless proceed with the designation, which will be subject to refund and remain in effect until its term ends or until otherwise ordered by the Commission.

Under proposed Section 43.3.7, a CPM designation for risk of retirement will have a minimum commitment term of one month and a maximum commitment term of one year, based on the number of months for which the capacity is procured within the current year. The term may not extend into the following year, and the CPM designation will be rescinded for any month in the current year during which the resource is procured by an LSE to provide RA capacity.

The ISO submits that this new category of backstop capacity procurement is a necessary and reasonable addition to the ISO Tariff. The authority to issue a CPM designation to procure capacity at risk of retirement is important to the ISO's ability to maintain grid reliability. For example, as generation by variable energy resources increases to accommodate California's 20% renewables portfolio standard (which increases to 33% by 2020), it is important that the ISO have the generation fleet capability needed to meet the changing operational requirements and to integrate the renewable energy into the ISO grid. The proposed backstop will give the ISO the ability to maintain capacity on-line that is otherwise uneconomic and at risk of retirement in the current year one but will be necessary to meet these needs in the following year.

There are other examples where the Commission has granted an ISO or RTO the authority to procure capacity from a particular unit that is needed for reliability in circumstances where there is a risk that such unit will retire. The ISO's proposed risk-of-retirement CPM designation is similar to the system support resource procedures found in the tariff of the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO")(provided with this filing as Attachment F). Section 38.2.7 of the Midwest ISO tariff provides a mechanism for the transmission provider to enter into a pro forma agreement with generating units that are required to maintain system reliability, if such units are uneconomic to remain in service and the owner's decision to decommission or mothball the unit is definite. Another example is the Commission's approval of a deactivation and retirement proposal by PJM Interconnection, LLC ("PJM") that allows it to compensate units (including a default compensation rate based on a unit's going forward costs) that wished to retire but which agreed to remain in operation because PJM needed them for reliability reasons.[21] The Commission noted that its policy was not intended to disrupt any stakeholder processes addressing resource adequacy; the Commission stated it was intended to address the compensation of generators that are required to run for reliability, rather than long-term investment.[22] 110 FERC at P 76. (PJM's relevant tariff provisions are provided with this filing as Attachment G).

Stakeholders do not support the ISO's proposed procurement authority. One concern expressed by stakeholders during the stakeholder initiative was that allowing backstop procurement to prevent the retirement of a resource based on alleged financial circumstances could present a gaming opportunity.

In response to this concern, the ISO revised its proposal to close the loophole where a commercially viable resource could economically withhold its capacity and then shop for the highest form of compensation available through the bilateral market or a CPM designation. The ISO's proposal, therefore, requires that a resource owner submit a formal request for a risk-of-retirement CPM designation for its resource and include with that request (i) a formal statement of its intent to terminate its participating generator agreement or to remove the at-risk resource from a participating generator agreement that covers multiple units, (ii) an affidavit by an executive officer that attests that it will be uneconomic for the resource to remain in service and that the decision to retire the unit is definite unless CPM procurement occurs, and (iii) supporting financial information and documentation for its assertions, The ISO believes that the requirement to provide this information will discourage exploratory or non-legitimate requests for compensation under this CPM category, particularly when viewed in conjunction with the obligations imposed on corporate executives by the Sarbanes-Oxley Act of 2002 and existing ISO Tariff provisions that require market participants to

[21] *PJM Interconnection, LLC,* 110 FERC ¶ 61,053, *order on reh'g,* 112 FERC ¶61,031 (2005).

[22] *PJM Interconnection*, 110 FERC ¶ 61,053, at P 76.

submit truthful information. Further, the request and information will be reviewed by the ISO and analyzed by the ISO's Department of Market Monitoring, with the potential to refer a situation to FERC if the resource's request involves suspected submission of false information or market manipulation in violation of Sections 37.5.1 or 37.7, respectively.

Stakeholders and the CPUC questioned the need for a risk-of-retirement CPM designation given the CPUC's process for reporting and reviewing potential unit retirements in collaboration with the ISO. These parties are concerned that the ISO's proposal duplicates or conflicts with the CPUC's authority under General Order 167 (provided with this filing as Attachment I). The General Order implemented operating and maintenance standards that *inter alia* require generating asset owners to provide at least 90-days advance notice to the CPUC and the ISO of a change in the long-term status of a generating unit and to maintain the unit in readiness for service unless the CPUC, in consultation with the ISO, determines that the unit is unneeded during a specified period of time. This readiness standard, by its own terms, is applicable only to the extent that a regulatory body with relevant ratemaking authority has established a mechanism to compensate the unit for readiness services provided.

The ISO does not agree that there is either duplication or a conflict between the CPUC's process for approving changes in the long-term status of a unit and the ISO's proposed risk-of-retirement backstop mechanism. The ISO will pursue a CPM designation in such cases only after providing stakeholders its assessment of the reliability need for the resource and its determination that the resource is at risk of retirement, and an opportunity for the CPUC to act or a load-serving entity to enter a bilateral arrangement with the resource and thereby obviate the need for CPM procurement. The need identified by the ISO can thus be fully satisfied if the CPUC uses its existing provisions and authority to render a CPM designation unnecessary. It is only if the CPUC does not act, however, that the ISO will break the glass and undertake the needed backstop procurement.

In addition, the proposed risk of retirement CPM designation is consistent with the distinction between state and federal jurisdiction discussed in the recent decision of the U.S. Court of Appeals for the District of Columbia Circuit in *Connecticut Department of Public Utiity. Control v. FERC*.[23] The court recognized that: "State and municipal authorities retain the right to forbid new entrants from providing new capacity, to require retirement of existing generators, to limit new construction to more expensive, environmentally-friendly units, or to take any other action in their role as regulators of generation facilities without direct interference from the Commission."[24] However, the court also explained that: "Petitioners are thus compelled to concede that the Commission may directly establish prices for capacity – or much the same, prices for

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[23] Conn. Dept. of Public Util. Control v. FERC, 569 F.3d 477 (D.C. Cir. 2009).

[24] *Id.* at 481.

failing to acquire enough capacity – even for the express purpose of incentivizing construction of new generation facilities. That the Commission may do so directly would seem to include the power to do so indirectly by setting a target for capacity demand and using a market mechanism to locate the price appropriate to that quantity."[25] Under the court's reasoning, the CPUC through General Order 167 may have authority to apply and enforce operating and maintenance standards on generating units, including a readiness-to-serve standard, however, the ISO may through a backstop mechanism set the level of compensation appropriate to maintain capacity in service that will be needed for reliability. In fact, the readiness standard expressly provides that it does not apply unless a ratemaking authority has a mechanism in place to compensate a generating unit for any readiness services it provides. There is no conflict or duplication between the CPUC process and the ISO's proposed CPM designation and compensation to a unit at risk of retirement that the ISO has determined will be needed for reliability in the following year.

Some stakeholders commented that an RMR contract might be a more appropriate option in such circumstances. The ISO considered this comment but determined that a CPM designation would provide more flexibility because a CPM designation would carry a must-offer obligation in the ISO markets, while an RMR contract would limit the ISO to issuing RMR dispatches only for local reliability in order to help alleviate non-competitive constraints. Also, RMR is limited to local reliability needs; whereas, the ISO may need a unit with specific operational characteristics to address a specific reliability problem to which RMR does not apply.

C. Methodology for CPM Compensation

The ISO proposes to maintain the same methodology for CPM compensation as was approved by FERC for compensation under ICPM. As noted above, ICPM resources are offered a target capacity price equal to the higher of $41/kW-year or a resource's actual going forward costs (which must be supported in a cost justification filing with the Commission) plus a 10 percent adder. Moreover, this capacity payment does not include deduction of Peak Energy Revenues (PER) , *i.e.,* resources keep all of the revenues they earn in Energy and Ancillary Service markets. Going forward costs are defined as the sum of fixed operations and maintenance ("O&M"), *ad valorem* costs, and administrative and general ("A&G") costs, which include insurance. Going forward costs are generally understood to be the minimum fixed costs that a resource needs to recover to remain available for operation. The minimum price of $41/kW-year was derived from the going forward costs, plus 10 %, of a new 50 MW Simple Cycle CT (constructed by a merchant developer), as calculated in the CEC's 2007 study of cost of new generation in California. The ISO included a 10% adder to account for any measurement error in the CEC's study used to set the components of the going-forward fixed costs (described below) or other difficult to quantify costs. In addition, the

[25] *Id.* at 482.

minimum price of $41/kW-year may provide additional fixed cost recovery to units with going forward costs lower than that amount, and serve as a further incentive for LSEs to meet their RA requirements and not rely on the ISO backstop.

In the instant initiative, the ISO reconsidered two possible compensation options. The first was based on the existing methodology based on going-forward costs of a reference unit, and the second was the cost of new entry, or CONE. Stakeholders tended to support one approach or the other. WPTF, JP Morgan, Dynegy and NRG argued that CPM compensation based on CONE would provide needed signals that investment was needed in generation capacity. The CPUC, Southern California Edison, Pacific Gas & Electric, San Diego Gas & Electric and Six Cities, contended that the existing methodology was preferable, considering the infrequent use of ICPM designation and the unlikelihood that the prospect of a 30-day designation could ever incent the development of new generating capacity.[26]

The ISO proposes to maintain the going-forward fixed costs compensation methodology; although, as discussed below, it is updating the minimum price based on the most recent CEC study (provided with this filing as Attachment H). The ISO believes that, for the limited circumstances of CPM designations, the proposed minimum capacity payment amount will meet or exceed the going-forward costs for the vast majority of eligible resources, and where it is not sufficiently compensatory the resource owner can file a resource-specific cost justification with FERC.

The ISO also believes that, due to the short-term nature of a CPM designation, as well as the uncertainty over whether CPM designations will take place for any particular unit, it can not be relied on to incent new generation. The ISO can only procure capacity from existing units, and unbuilt capacity cannot compete against existing capacity as is the case in multi-year forward procurement under a centralized capacity market. Additionally, significant increases in CPM compensation could impact RA procurement in some locations by creating incentives for unit owners not to sign bilateral RA contracts in the hopes of receiving a CPM designation. Thus, although the ISO recognizes the importance of economic signals for the development of new capacity, the CPM is not the appropriate vehicle to send such signals. Moreover, the CPM is not a capacity market. It is simply a tool for the ISO to procure capacity from existing resources on a timely and efficient basis in order to meet reliability needs. For these reasons, the ISO disagrees with the MSC's suggestion that it may be appropriate

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[26] WPTF at question 9, http://www.caiso.com/2821/2821950560d40.pdf; JP Morgan at question 9, http://www.caiso.com/2821/282192353f6f0.pdf,; NRG at question 1, http://www.caiso.com/280a/280abaf31ff20.pdf; Dynegy at question 9, http://www.caiso.com/2821/2821932a4aa40.pdf; CPUC at question 9, http://www.caiso.com/2821/282191c33bd90.pdf; SCE at question 8, http://www.caiso.com/280a/280abb82228c0.pdf; PG&E at question 7, http://www.caiso.com/2821/2821927940df0.pdf; SDGE at question 9, http://www.caiso.com/2821/282193c4501e0.pdf; and Six Cities at question 9, http://www.caiso.com/2821/2821947b59900.pdf.

for CPM payments to exceed going-forward costs in areas where the local capacity requirements exceed the amount of available capacity. The ISO does not believe that such an approach would be an appropriate or effective way of stimulating new generation entry.

Further, continued use of the going-forward cost methodology is consistent with the Commission's October 16 Order that approved the ICPM. Specifically, the Commission found that:

> . . . the ICPM is a mechanism for procuring capacity for short periods to meet system reliability needs and, therefore, is not designed to encourage new investment. Rather, the pricing structure is designed to ensure just and reasonable treatment of non-resource adequacy resources that are needed for reliability services and to provide an incentive to these resources to voluntarily accept ICPM designations. We find this position to be consistent with our previous findings that when similar reliability services are provided by non-resource adequacy resources and resource adequacy resources, similar compensation is warranted.[27]

There are other reasons why uniform CONE pricing is inappropriate for the CPM. Cost of new entry pricing should be considered as a possible backstop price only when there is a capacity deficiency in a local area or system zone and the intent of the mechanism is to incent new generation and the opportunity exists to do just that. That is not the case with the CPM. The ISO can only procure existing capacity through the CPM and the term of designation ranges from one month to a year depending on the underlying deficiency and the category of the designation. Because there is no multi-year forward procurement, new investment cannot compete against existing resources for purposes of designations. Thus, the mechanism is not intended to and does not incent new generation. RA requirements are currently set on both a local area and system basis. Many of the local areas are small relative to total ISO capacity MW and have a concentration of ownership. Even assuming *arguendo* that the CPM backstop mechanism were intended and designed to send investment price signals, the cost of new entry should be considered as a possible backstop price only when there is a capacity deficiency in a local area or system zone. The ISO has determined that over the past few years during which the ISO has conducted its locational capacity requirement studies, only a few locations on the ISO Controlled Grid would warrant high backstop prices if a cost of new entry approach were to be applied. However, most of the capacity in those tight areas is either owned by investor owned utilities or is under multi-year RA contract, thereby indicating that even if a cost of new entry approach were to be applied, it would provide no near-term benefits to suppliers. In the remaining load pockets, where there is a surplus of capacity, additional investment does not seem to be needed in the near term; so using cost of new entry pricing to spur additional

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[27] October 16 Order at P41.

investment is neither needed nor justifiable for the period under consideration . Using cost of new entry as the backstop price in these circumstances could only serve to increase the forward RA prices in these areas to the extent any generation owners have market power.

Also, the ISO does not believe that cost of new entry is the appropriate price benchmark for CPM Significant Event procurement which will result from unexpected, unforeseen and transitory events which create a need for short-term procurement. It is not appropriate to base payments for such procurement on the cost of new entry because the sole purpose of this type of procurement is to employ existing resources that are available to address short-term contingencies or reliability needs, not to provide incentives for new generation. Indeed, new generation cannot compete to provide this service. There is no legitimate basis to pay a price based on cost of new entry to existing resources under these types of transitory circumstances. Even ignoring the fact that new entry could not enter the market in the necessary timeframe to provide the service, there is no indication that new resources should even enter the market at that particular location of the CPM Significant Event in the long-term due to the transient nature of such events. Also, units providing CPM Significant Event service, have already made the decision to remain available in the ISO markets without an RA contract and with only an expectation that they will earn revenues by participating in the markets. At a minimum, the CPM proposal will pay the going-forward costs of those units.

D. <u>Price for CPM Compensation</u>

For CPM, the ISO proposes to continue to base the capacity price on the going-forward costs of a small simple cycle gas unit (as previously used under ICPM), as determined by the California Energy Commission in its most recent generation cost study which evaluated units constructed in 2007-2009. Specifically, the proposed CPM price of $55/kW-year was established using the CEC's updated "Comparative Costs of California Central Station Electricity Generation Technologies" study, issued in 2009. This report was used in the 2009 Integrated Energy Policy Report that was adopted by the CEC on December 16, 2009. The 2009 report includes Tables B4 – B6 that provide the updated information that the ISO used in the CPM determination of going-forward fixed costs. That table is provided below.

CEC 2009

Table B-4 through B-6[28]		**$/kW-Yr (Nominal 2009$)**					
Builder	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**
Merchant	49.9	198.11	9.63	13.09	27.45	55.13	**303.42**
IOU	49.9	152.53	5.54	10.14	27.88	28.09	**224.18**
POU	49.9	111.14	9.72	9.39	28.4	0	**158.64**

As shown in the table, the components of the going-forward fixed costs for the 50 MW simple cycle gas unit, based on a merchant facility, are:

Component	$/kW-Year
Insurance	9.63
Ad valorem	13.09
O&M	27.45
Subtotal	50.17
10% Adder	5.02
Total	$55.19

This total is rounded to $55/kW-year. Hence, to reach the proposed minimum capacity payment of approximately $55/kW-year, the ISO incorporated a 10 percent adder to the going-forward costs of the small simple cycle unit, approximately $50/kW-year. To the extent that a resource owner believes that its going-forward costs, plus 10%, exceed $55/kW-year it may make a cost justification filing with FERC to obtain a higher capacity payment. The ISO proposes to continue using the highest cost unit as the basis for the minimum payment for the same reasons, just discussed, that it adopted that approach for the ICPM.

Several stakeholders, including the CPUC and The Utility Reform Network, expressed concern about the increase in the going-forward costs value for ICPM established using the values in the 2007 CEC report ($41/kW-year) compared to the values that result from using the values in the 2009 CEC report ($55/kW-year), which represents an increase of 34% from the 2007 CEC report. The $55/kW-year minimum price reflects more current cost numbers. The CEC noted these increases were not adequately captured in the 2007 going-forward price and thus some carryover occurred. The CEC also explained that certain costs in the CEC 2009 report, such as operation and maintenance costs, were derived based on actual costs for such elements as

[28] http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF Page B5-B7

reported to the CEC and the costs were not simply derived as a percentage of capital costs (this applies to operation and maintenance costs, ad valorem costs and insurance costs – i.e., the values in the CEC study were based on actual costs and not percentages). The CEC also included a description of the cost of generation model used to derive the going-forward cost.

The ISO believes that its CPM pricing proposal is just and reasonable. It is transparent, does not raise market power concerns, does not unduly "interfere" with bilateral RA procurement and RA capacity prices, should encourage LSEs and suppliers to negotiate contracts for capacity rather that rely on the backstop, and is simple to implement and administer. The CPM proposal will ensure that CPM resources recover their going-forward costs, which is the minimum amount necessary to keep a resource available. Further, because of the 10% adder and the fact that the $55/kW-year price is based on the going-forward costs of the highest priced gas-fired unit, the CPM price should also provide most resources with a revenue contribution toward their capital costs and return. The proposed floor of $55/kW-year will also ensure that RA prices are not dampened by CPM; nor does it set too a high price that would allow suppliers with locational market power to command significantly higher prices (even in local areas where there is surplus capacity but such capacity is held by a small number of suppliers). The CPM price is high enough to ensure that LSEs will not lean on the backstop and avoid RA procurement.

Based on the foregoing discussion, the ISO submits that the use of the CEC 2009 report and the resultant CPM price of the higher of $55/kW-year or a unit's actual going forward costs as filed with FERC are just and reasonable and should be adopted by the Commission.

E. <u>Proration of CPM Compensation for Outages</u>

Currently effective ISO Tariff Section 43.6.1 provides that the monthly ICPM capacity payments to resources designated under the ICPM are calculated as the product of the amount of their ICPM Capacity, the relevant ICPM availability factor for Forced Outages (determined in accordance with Appendix F, Schedule 6), a monthly shaping factor (set forth in Appendix F, Schedule 6), and a fixed ICPM capacity price of $41/kW-year. If the designated resource instead applies for and receives a resource-specific capacity price from FERC under Section 43.6.2.1, the calculation of the monthly ICPM payments follow the same formula in Section 43.6.2.3, except that the resource-specific price is substituted for the $41/kW-year. In Appendix F, Schedule 6, the target availability for a resource designated under an ICPM is 95%. The Availability Factor Table then provides shaping factors that adjust the ICPM Availability Factors above and below the target based on the resource's actual availability net of Forced Outages,

As just discussed, this proposal changes the ICPM capacity price of $41/kW-year to a CPM capacity price of $55/kW-year. In addition, the ISO proposes to add a component to the calculations in Section 43.6.1 (renumbered to Section 43.7.1) and

Section 43.6.2.3 (renumbered to Section 43.7.2.2) to account for Maintenance Outages. This component is the CPM Availability Percentage for Maintenance Outages, which represents the ratio of: 1) the sum of actual availability capacity, taking into account each hour the resource is unavailable due to a Maintenance Outage or non-temperature-related ambient de-rate, across all the hours the unit is designated, to 2) the CPM capacity MW multiplied by the number of hours the unit is designated. In the event that a CPM resource is out for only part of an hour, that hour's MW value will reflect the part of the hour in which the capacity was available. As a result of this change, a resource procured under the CPM that takes a Maintenance Outage during its procurement period (which could be 30 days up to one year) will have its compensation reduced pro rata.

This proposal received support by the CPUC, NCPA, PG&E, SCE, SDG&E, and Six Cities. Some stakeholders supported a replacement rule that would allow the resource owner to provide substitute capacity during the time of the Maintenance Outage. The ISO considered this approach but determined that the additional complexity such a rule would create was unwarranted.

For the same reason that it is just and reasonable to compensate a resource under a CPM designation for its availability, net of the hours it was unavailable due a Forced Outage, it is just and reasonable to refine that calculation further so the resource is compensated for its actual availability net of Forced Outages, Maintenance Outages or non-temperature related ambient derates. Resources should not be paid a capacity payment during periods which they are not available and are unable to provide the service for which they have been designated. A Maintenance Outage is fundamentally in the control of the resource owner, so it is up to the resource owner to make the simple trade-off between forgoing a Maintenance Outage until a later date and receiving pro-rated CPM compensation. In addition, in approving a predecessor calculation target availability payment in the ISO's Reliability Capacity Services Tariff, the Commission found that it was designed to enhance reliability, a key component of which is availability, and that the 95% target availability was a reasonable component of the payment calculation.[29] The Commission also found that the "availability provisions provide economic incentives for generators to be available."[30] Enhancing the calculation of the monthly CPM compensation to exclude payment for hours in which the resource was unavailable due to a Maintenance Outage or non-temperature related ambient derate is consistent with the Commission's previous findings.

F. <u>Allocation of CPM Costs and Crediting of CPM Capacity for CPM Designations</u>

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[29] *Indep. Energy Producers Ass'n v.* Cal. Indep. Sys. Operator Corp.,118 FERC ¶ 61,096, PP 97-98 (2007) (RCST Order); *Indep. Energy Producers Ass'n v.* Cal. Indep. Sys. Operator Corp.,119 FERC ¶ 61,266 (2007) (RCST Rehearing Order).

[30] RCST Order, at P 98.

For those CPM categories that are a straightforward carry-over of the ICPM categories, the ISO proposes to retain the existing ICPM cost allocation provisions. For the new CPM category of resources at risk of retirement, the ISO proposes to apply the cost allocation approach for a significant event CPM designation.

Existing ISO Tariff Sections 43.7.1 through 43.7.6 establish the method for allocating the costs of ICPM capacity payments for each category of ICPM designation. The allocation method for each ICPM category is summarized as follows:

- For insufficient Local Capacity Area Resources in an annual or a monthly RA Plan, the ICPM costs are allocated pro rata to each Scheduling Coordinator for a deficient LSE based on the ratio of that LSE's deficiency to the deficiency within the TAC area.

- For a collective deficiency of Local Capacity Area Resources in an annual RA Plan, the ICPM costs are allocated to all Scheduling Coordinators of LSEs serving load in the TAC area in which the deficient local capacity area was located.

- For insufficient RA resources to comply with an LSE's annual and monthly demand and reserve margin requirements, the ICPM cost allocation is made pro rata to each LSE based on the proportion of its deficiency to the aggregate deficiency.

- For a significant event or Exceptional Dispatch ICPM, the costs are allocated to all Scheduling Coordinators for LSEs that serve load in the TAC area where the need for the designation arose, based on each Scheduling Coordinator's percentage of actual load in the TAC area to total load in that area.

The ISO proposes to add new Section 43.8.7 to this series of tariff provisions in order to establish the appropriate allocation of CPM capacity payments for the new CPM category of resources at risk of retirement needed for reliability. The ISO proposes that the costs of the CPM designations for resources at risk of retirement needed for reliability be allocated in the same manner as a CPM for a significant event or Exceptional Dispatch. The costs will be allocated to all Scheduling Coordinators for LSEs that serve load in the TAC area where the need for the designation arose, based on each Scheduling Coordinator's percentage of actual load in the TAC area to total load in that area.

Not only is the proposed method for allocating the CPM costs for resources at risk of retirement needed for reliability consistent with significant event and Exceptional Dispatch designations, previously approved by the Commission, it is the appropriate allocation method for this CPM category. It will spread the CPM costs to the Scheduling Coordinators for the proximate load -- the LSEs that serve load in the TAC area where the reliability need will exist. As a result, the cost responsibility for the CPM designation of a resource at risk of retirement needed for reliability will be spread to those entities that will benefit most by the ISO's backstop procurement.

In order to recognize the additional capacity subject to a CPM designation for a resource at risk of retirement needed for reliability, the ISO proposes that each Scheduling Coordinator on behalf of an LSE that is allocated the CPM costs be given credit towards the LSE's demand and reserve margin requirements in an amount equal to the LSE's pro rata share of the designated CPM capacity. This crediting provision in proposed Section 43.9(d) is consistent with the crediting provisions for the other CPM categories contained in Section 43.9(a) – (c). Those provisions also provide pro rata credit of the CPM capacity toward the demand and reserve margin requirements of the cost responsible LSEs and have already been approved by the Commission.

The ISO believes that the proposed cost allocation and crediting provisions are consistent with cost causation principles.[31] Section 43.8.7 properly aligns the payment obligations with the entities that will benefit the most from, the ICPM procurement. Section 43.9(d) then properly provides to the entities allocated that cost responsibility credit toward their demand and reserve margin requirements for their pro rata share of the CPM capacity. Further, these allocation and crediting provisions are consistent with the ICPM allocation and crediting provisions that the Commission has previously approved. The ISO requests that the Commission again act and accept the proposed provisions.

G. Selection Criteria to be Used in Issuing ICPM Designations

Existing ISO Tariff Section 43.3 provides that in making ICPM designations, the ISO must consider the effectiveness of the eligible capacity at meeting the designation criteria specified in existing Section 43.1, the capacity costs associated with the eligible capacity, and the quantity of a resource's available eligible capacity, based on a resource's PMin, relative to the remaining amount of capacity needed. In addition, for designations due to an individual or collective insufficiency of RA resources in annual or a monthly RA Plans, the current tariff provides that the ISO will also take into consideration the effectiveness of the eligible capacity in meeting local and/or zonal constraints or other ISO system needs.

The ISO proposes to amend Section 43.3 (which will be renumbered as 43.4) to add two new criteria to use in selecting from among eligible resources once the ISO has determined that a CPM designation is necessary. The proposed new selection criteria are the operating characteristics of the resource, such as dispatchability, ramp rate, and

[31] The Commission has stated its goal is to "allocate to each class of [customer] and to each time period and each company its fair share of costs." *Pennsylvania Power and Light Co.,* Opinion No. 176, 23 FERC ¶ 61,395 at 61,850 (1983).

load-following capability, and whether the resource is subject to restrictions as a use-limited resource. The determination of the need for a CPM designation will be made under the existing ICPM categories,[32] and only once such determination is made will the ISO then apply the criteria listed in proposed Section 43.4 to decide which of the eligible resources to select for the CPM designation.

The first new criterion allows the ISO to select capacity for designation that has specific operational characteristics. This criterion will better enable the ISO to identify and select the optimal capacity for designation in instances where the operating characteristics of the resource are an important factor in responding to the reliability need underlying the designation. The ISO must have the ability to select the capacity that maximizes the reliability features available to the ISO and which will best enable the ISO to meet the identified reliability need and any future reliability need that may arise during the term of the designation. Without this ability, the ISO could be forced to select capacity that has less ability to meet the ISO's potential reliability needs. As the Commission has recognized, the purpose of backstop capacity is to enhance reliability. Common sense and logic dictates that the ISO select those resources that have the best potential and ability for maximize reliability during the term of the designation process.

The second criterion allows the ISO to take into consideration in the selection process whether eligible capacity is provided by a Use-Limited Resource or a non-Use-Limited Resource. As defined in Appendix A of the ISO Tariff, a Use-Limited Resource is a "resource that, due to design considerations, environmental restrictions on operations, cyclical requirements, such as the need to recharge or refill, or other non-economic reasons, is unable to, operate continuously on a daily basis, but is able to operate for a minimum set of consecutive Trading Hours each Trading Day." The ISO will prefer non-Use-Limited Resources, as they offer ISO operations and Market Participants the most value for the cost of a CPM designation. A key objective of the CPM is to obtain needed backstop capacity that is comparable to RA capacity and that will be available to the ISO in the day-ahead and real-time markets throughout the procurement period. For this reason, the CPM designation carries with it a requirement that the resource be available to the ISO in a manner consistent with the must-offer obligations that apply to non-use-limited RA capacity. Use-Limited Resources, however, are subject to operating restrictions as noted above, and as such are exempt from these must-offer obligations. Thus, the ISO would not be able to rely on the availability of Use-Limited Resources to the same extent as it would on non-Use-Limited Resources, and therefore a CPM designation of a Use-Limited Resource would not be as valuable as a designation of a non-Use-Limited Resource, yet the cost of both would be the same. The Commission has recognized that availability is an important factor for purposes of maintaining reliability. It logically follows that, all else being equal, the ISO

[32] Of course, the ISO may determine the need for a CPM designation based on the proposed new category for resources at risk of retirement, but the question of choosing among eligible resources would be moot in this situation.

should select a resource that maximizes availability. The ISO also notes that inclusion of this criterion will protect ratepayers from the potential of double capacity payments in circumstances where a Use-Limited Resource is not available on a given day to address a reliability problem. For example, if the ISO were to designate a Use-Limited Resource and the ISO needed to use the resource during the period of designation but the resource was not available on that particular day due to its use-limitation, the ISO could be required to Exceptionally Dispatch or designate under the CPM a different resource to address the reliability need. That would result in two units being paid a capacity payment, when only one was needed to address the problem. This type of situation should be avoided and can be avoided by the ISO selecting capacity that provides the most value and has a must offer obligation. Further, this criterion will not prohibit Use-Limited Resources from receiving a CPM designation; it will simply add an additional factor, specifically consideration of whether the resource is subject to restrictions as a Use-Limited Resource, to the ISO's selection process.

For these reasons, the two proposed criteria are necessary to allow the ISO to select the resource that is best suited to meet the identified reliability needs and should be accepted by the Commission.

H. <u>Selection Criteria to be Used in Issuing Exceptional Dispatches</u>

Existing Tariff Section 34.9 states that the goal of the ISO is to issue Exceptional Dispatches on a least-cost basis. The provision requires the ISO to consider the effectiveness of the resource, and Start-Up Costs and Minimum Load Costs, when issuing an Exceptional Dispatch to commit a resource to operate at Minimum Load. It also requires the ISO to consider Energy Bids, if available and as appropriate, in issuing Exceptional Dispatches for Energy.

The ISO proposes to amend Section 34.9 to incorporate into the selection of capacity to receive an Exceptional Dispatch, the same selection criteria proposed for CPM designations. The ISO believes that use of these selection criteria for Exceptional Dispatches will assist the ISO in meeting the goal of least-cost dispatch and in identifying the resource that is best suited to meet the need underlying the Exceptional Dispatch decision. Also, it more closely aligns the CPM and Exceptional Dispatch provisions.

In addition, it is important to recognize that a CPM designation can be triggered by an Exceptional Dispatch of non-RA capacity. Indeed, as noted earlier, all ICPM designations to date since the start of the ISO's new market structure in April 2009 have been triggered by Exceptional Dispatches. It is therefore necessary to ensure that the capacity designated for CPM or Exceptional Dispatch is selected in a consistent manner.

Accordingly, the ISO proposes to amend ISO Tariff Section 34.9 to incorporate the existing and two proposed selection criteria into that provision so they apply to Exceptional Dispatches as well as to ICPM designations.

I. Term of Exceptional Dispatch CPMs

In reviewing the ICPM provisions as part of the stakeholder initiative, the ISO realized that existing Tariff Sections 43.2.1 through 43.2.5 establish the term of the ICPM designation for each category of ICPM except Exceptional Dispatch ICPM. In order to correct this oversight, the ISO proposes to add Tariff Section 43.3.6 to provide that Exceptional Dispatch CPMs shall have a term of 30 thirty days. Section 43.3.6 further provides that, if the ISO determines that the circumstances leading to the CPM designation are likely to extend beyond the initial 30-day period, the ISO will issue another Exceptional Dispatch CPM, or other CPM designation, for an additional 30 days.

The proposed 30-day term for Exceptional Dispatch CPMs is consistent with the ISO's current practice of issuing Exceptional Dispatches for 30 days. As mentioned above, since the ICPM authority become effective, the ISO has issued 23 ICPM designations for 703 MWs at a cost of $2.7 million, all of which were triggered by Exceptional Dispatches and were for a term of 30 days.

The ISO accordingly requests that the Commission approve proposed Section 43.3.6 to incorporate into the tariff the 30-day term for Exceptional Dispatch CPMs, consistent with the ISO's existing practices.

J. The Proposed CPM Provisions Do Not Contain a Sunset Provision

As discussed above, at the time the CPM was being developed, the CPUC had a rulemaking proceeding underway to consider the long-term design of the RA program and the ISO lacked experience with the RA program and the Locational Marginal Pricing-based market. The ISO therefore proposed, and the Commission approved, the ICPM as an interim measure, subject to review in two years.

One issue the ISO considered during this stakeholder initiative was whether to retain a sunset date for CPM. The ISO determined that the CPM should be proposed as a feature of the ISO's market design, without a sunset date. This addresses the Commission's stated concern about potential lapses in backstop procurement and compensation for generators by ensuring that there cannot be any such lapse. The ISO based this determination in part on the factor that the interim status is no longer necessary to facilitate changes to the backstop mechanism resulting from the CPUC proceeding. On June 3, 2010, the CPUC issued Decision 10-02018 in Rulemaking 05-12-013 that declined to adopt either a multi-year forward RA procurement obligation or a policy favoring a centralized capacity market. This decision essentially maintained the status quo of the RA program, which obviates the need to significantly modify the backstop mechanism to reflect any long-term design changes to the RA program. Another factor in the determination was that, during the intervening 18 months since the ICPM was implemented, the ISO has acquired experience with the new markets and the ICPM, both of which have operated very successfully and offer no on-going reason why the backstop mechanism should have a sunset date. The ISO therefore proposes to delete the tariff language from Section 43 that sunsets the ICPM and make other conforming changes to numerous provisions to change ICPM to CPM throughout the tariff.

Some stakeholders expressed concern that periodic review of the CPM should be conducted, especially to update the compensation level. In particular, Dynegy, JP Morgan and WPTF expressed concern that the default CPM price could become unreasonable over time if it were not updated on a regular basis.[33] Other stakeholders expressed the view that the ultimate goal should be a market-based mechanism of procurement capacity rather than an administrative process. In Mirant's and the CPUC's view, setting a sunset date for the ICPM replacement will provide more regular opportunities to reform capacity procurement along the lines of a market-based approach.[34]

In response to this concern, the ISO has committed to stakeholders it will include in the Reliability Requirements Business Practice Manual a process to review the level of the CPM payment through a stakeholder initiative to be conducted every two years to ensure that it remains an accurate reflection of the going-forward costs of the reference generating unit. If, with experience, the ISO determines that other aspects of the CPM require revision, it will address those concerns in the same way it would address concerns about any other market design element – through a stakeholder process or a Section 205 filing. If the change is needed, then the ISO will consider that change and make appropriate amendments to its tariff and processes. The ISO does not, however, believe that it is necessary, appropriate, or efficient for the Commission to require that the entire CPM backstop mechanism expire every two years or that the ISO undertake a wholesale review of the CPM on a set schedule. Experience gained while the ICPM has been in effect has identified no issues or problems with the design or effectiveness of the backstop mechanism that warrant continuation of its interim status. Indeed, as the current proposal demonstrates, the essential design elements of the ICPM have functioned effectively and should be retained, with some limited but important enhancements and an update to the compensation rate. The ISO fully expects that the proposed backstop mechanism will work equally effectively and commits to review the compensation level every two years to ensure that it remains appropriate.

[33] JP Morgan at question 1, http://www.caiso.com/2821/282192353f6f0.pdf; Dynegy at question 1, http://www.caiso.com/27e7/27e7843f59b80.pdf; and WPTF at question 1, http://www.caiso.com/2821/2821950560d40.pdf.

[34] Mirant at question 1, http://www.caiso.com/27c0/27c0c4dd688a0.pdf; and CPUC at question 1, http://www.caiso.com/2821/282191c33bd90.pdf.

K. Continuation of Mitigation of Exceptional Dispatches

Section 39.10 in the currently effective ISO Tariff applies Mitigation Measures to all Exceptional Dispatches eligible for Exceptional Dispatch CPM and to Exceptional Dispatch of resources when dispatched for purposes of addressing reliability requirements related to non-competitive transmission constraints and unit-specific environmental constraints not incorporated into the ISO's full network model or for delta dispatch. Consistent with the February 20 Order, Section 39.10 provides that the entire section, along with Sections 11.5.6.7, 43.1.5, and 43.2.6 will expire after the last day of the twenty-fourth calendar month following the effective date, which sunset date is March 31, 2011.

During the stakeholder initiative, the ISO considered whether Exceptional Dispatches should continue to be subject to the ISO's market power mitigation measures. In the Revised Draft Final Proposal, the ISO noted that the number of Exceptional Dispatches that have been subject to bid mitigation has been relatively low in proportion to all Exceptional Dispatches and in proportion to all bid mitigation. The vast amount of energy dispatched through Exceptional Dispatch has been for reasons other than to mitigate congestion on non-competitive paths.

Based on these considerations, the ISO determined that mitigation should continue to apply in the limited set of circumstances where there is a potential for the exercise of locational market power. The ISO's proposal therefore retains the tariff language in Section 39.10 that requires the mitigation of Exceptional Dispatches to mitigate congestion on non-competitive paths and those made under delta dispatch, and deletes tariff language in Sections 39.10, and related Sections 11.5.6.7, 43.1.5, and 43.2.6, that would otherwise cause those provisions to expire.

L. Resources with Carryover ICPM Designation

As previously mentioned, existing ISO Tariff Section 43 contemplates that the ICPM will automatically expire on March 31, 2011, which is 24 months after its effective date. The ISO recognizes that there could be ICPM designations in effect as of that expiration date that need to be carried over under the CPM regime in order to maintain reliability. The ISO is proposing tariff provisions to allow such "carry over" until the term of the original designation expires. Under no circumstances, however, would any capacity designated under ICPM be permitted to "carry over" into the subsequent RA compliance year.

To address this situation, the ISO proposes to amend Section 43 (renumbered to Section 43.1) to provide that a resource procured under the current ICPM provisions whose procurement period extends beyond March 31, 2011 (including Exceptional Dispatch ICPMs) will become subject to the CPM provisions on a going-forward basis as of the effective date of the CPM provisions, including the provisions concerning compensation cost allocation, and settlement. The ICPM resources will be subject to the CPM until such time as each ICPM resource has been finally compensated for its services rendered under the ICPM prior to termination of the ICPM, and the ISO has finally allocated and recovered the ICPM compensation costs. As a result of this amendment, the carry-over ICPM resources will on a going-forward basis receive compensation at the updated $55/kW-year proposed in this filing. Any such designation cannot extend into the subsequent RA compliance year.

The ISO believes that application of the CPM provisions to any carry-over ICPM designations is appropriate and will eliminate the unnecessary complexity of having both ICPM and CPM provisions in operation at the same time.

M. Miscellaneous Tariff Changes

In addition to the tariff modifications discussed above, the ISO proposes the following minor revisions:

- Section 43.2.5.1 numbers the second subsection in that section to correct an oversight in a previous amendment that left that subsection unnumbered.

- Section 43.2.5.2.4 adds “RMR” to the list of status changes referenced in the first sentence of that section in order to make the list consistent with the remainder of the provision that discusses RMR.

- Delete the phrase “within 30 days of the effective date of this section” from Sections 43.6, 43.6.2, and 43.6.2.1 because that time period has lapsed.

The ISO requests that the Commission find that these tariff changes are ministerial and accept them as proposed in this filing.

V. EFFECTIVE DATES

The ISO respectfully requests that the tariff amendments, contained in the instant filing, be approved and given an effective date of April 1, 2011. The current version of ISO Tariff Section 43 specifies that the ICPM tariff provisions “expire at midnight on the last day of the twenty-fourth month following” their effective date. As these provisions became effective April 1, 2009, they expire at midnight on March 31, 2011. An effective date of April 1, 2011 will ensure that the ISO’s authority to procure backstop capacity does not lapse.

VI. COMMUNICATIONS

Communications regarding this filing should be addressed to the following individuals, whose names should be placed on the official service list established by the Secretary with respect to this submittal:

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VII. SERVICE

The ISO has served copies of this transmittal letter, and all attachments, on the California Public Utilities Commission and the California Energy Commission, and all parties with effective Scheduling Coordinator Service Agreements under the ISO Tariff. In addition, the ISO is posting this transmittal letter and all attachments on the ISO website.

VIII. ATTACHMENTS

The following documents, in addition to this transmittal letter, support the instant filing:

Attachment A	Revised ISO Tariff Sheets – Clean
Attachment B	Revised ISO Tariff Sheets – Blackline
Attachment C	Chart of Proposed Tariff Amendments
Attachment D	California ISO Market Surveillance Committee “Opinion on the Capacity Procurement Mechanism and Compensation and Bid Mitigation for Exceptional Dispatch”
Attachment E	Memorandum to California ISO Board of Governors – “Decision on Capacity Procurement Mechanism and Exceptional Dispatch Provisions”

Attachment F	Midwest ISO Tariff, Section 38.2.7
Attachment G	PJM Tariff, Part V
Attachment H	California Energy Commission, *Comparative Costs of California Central Station Electricity Generation* (CEC-200-2009-07SF)
Attachment I	California Public Utilities Commission, General Order No. 167

IX. CONCLUSION

For the foregoing reasons, the ISO respectfully requests that the Commission approve this tariff revision as filed. Please contact the undersigned if you have any questions concerning this matter.

Respectfully submitted,

/s/Beth Ann Burns

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Dated: December 1, 2010

Attachment A – Clean Tariff

Capacity Procurement Mechanism Tariff Amendment

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

11.5.6.7 [NOT USED]

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30.5.2.7 RUC Availability Bids

Scheduling Coordinators may submit RUC Availability Bids for specific Generating Units in the DAM; however, Scheduling Coordinators for Resource Adequacy Capacity or CPM Capacity must submit RUC Availability Bids for that capacity to the extent that the capacity has not been submitted in a Self-Schedule or already been committed to provide Energy or capacity in the IFM. Capacity that does not have Bids for Supply of Energy in the IFM will not be eligible to participate in the RUC process. The RUC Availability Bid component is MW-quantity of non-Resource Adequacy Capacity in $/MW per hour, and $0/MW for Resource Adequacy Capacity or CPM Capacity.

* * *

34.9 Exceptional Dispatch

The CAISO may issue Exceptional Dispatches for the circumstances described in this Section 34.9, which may require the issuance of forced Shut-Downs or forced Start-Ups and shall be consistent with Good Utility Practice. Dispatch Instructions issued pursuant to Exceptional Dispatches shall be entered manually by the CAISO Operator into the Day-Ahead or RTM optimization software so that they will be accounted for and included in the communication of Day-Ahead Schedules and Dispatch Instructions to Scheduling Coordinators. Exceptional Dispatches are not derived through the use of the IFM or RTM optimization software and are not used to establish the LMP at the applicable PNode. The CAISO will record the circumstances that have led to the Exceptional Dispatch.

Except as provided in this Section 34.9, the CAISO shall consider the effectiveness of the resource along with Start-Up Costs and Minimum Load Costs when issuing Exceptional Dispatches to commit a resource to operate at Minimum Load. When the CAISO issues Exceptional Dispatches for Energy, the CAISO shall also consider Energy Bids, if available and as appropriate. In accordance with Good Utility Practice, the CAISO shall make designations of Eligible Capacity for an Exceptional Dispatch CPM based on the following additional criteria:

(1) the effectiveness of the Eligible Capacity at meeting the designation criteria specified in Section 43.2;

(2) the capacity costs associated with the Eligible Capacity;

(3) the quantity of a resource's available Eligible Capacity, based on a resource's PMin, relative to the remaining amount of capacity needed;

(4) the operating characteristics of the resource, such as dispatchability, Ramp Rate, and load-following capability; and

(5) whether the resource is subject to restrictions as a Use-Limited Resource.

The goal of the CAISO will be to issue Exceptional Dispatches on a least cost basis. Imbalance Energy delivered or consumed pursuant to the various types of Exceptional Dispatch is settled according to the provisions in Section 11.5.6.

*** * ***

39.8.1 Bid Adder Eligibility Criteria

To receive a Bid Adder, a Generating Unit must: (i) have a Mitigation Frequency that is greater than eighty percent (80%) in the previous twelve (12) months; and (ii) must not have a contract to be a Resource Adequacy Resource for its entire Net Qualifying Capacity, or be designated under the CPM for its entire Eligible Capacity, or be subject to an obligation to make capacity available under this CAISO Tariff. If a Generating Unit is designated under the CPM for a portion of its Eligible Capacity, the provisions of this section apply only to the portion of the capacity not designated. Scheduling Coordinators for Generating Units seeking to receive Bid Adders must further agree to be subject to the Frequently Mitigated Unit option for a Default Energy Bid. Run hours are those hours during which a Generating Unit has positive metered output. During the first twelve (12) months after the effective date of this Section, the Mitigation Frequency will be based on a rolling twelve (12)-month combination of RMR Dispatches and incremental Bids dispatched out of economic merit order to manage local Congestion from the period prior to the effective date of this Section, which will serve as a proxy for being subject to Local Market Power Mitigation, and a Generating Unit's Local Market Power Mitigation frequency after the effective date of this Section. Generating Units that received RMR Dispatches and/or incremental Bids dispatched out of economic merit order to manage local Congestion in an hour prior to the effective date of this Section will have that hour counted as a mitigated hour in their Mitigation Frequency. After the first twelve (12) months from the effective date of this Section, the Mitigation Frequency will be based entirely on a Generating Unit being mitigated under the MPM-RRD procedures in Sections 31 and 33.

* * *

39.10 Mitigation Of Exceptional Dispatches Of Resources

The CAISO shall apply Mitigation Measures to Exceptional Dispatches of resources when such resources are committed or dispatched under Exceptional Dispatch for purposes of: (1) addressing reliability requirements related to non-competitive transmission Constraints; and (2) addressing unit-specific environmental Constraints not incorporated into the Full Network Model or the CAISO's market software that affect the dispatch of Generating Units in the Sacramento Delta and are commonly known as "Delta Dispatch".

* * *

39.10.3 Eligibility For Supplemental Revenues

Except as provided in Section 39.10.4, a resource that is committed or dispatched under Exceptional Dispatch shall be eligible for supplemental revenues only during such times that the resource meets all of the following criteria:

(i) the resource has notified the CAISO, at least seven days prior to the calendar month in which the Exceptional Dispatch occurs, that the resource has chosen to receive supplemental revenues in lieu of an Exceptional Dispatch CPM designation under Section 43.1.5;

(ii) the resource has been mitigated under Section 39.10;

(iii) the resource is not under an RMR Contract, is not designated as CPM Capacity, and is not a Resource Adequacy Resource, unless the resource is a Partial Resource Adequacy Resource or a partial CPM resource, and the Exceptional Dispatch requires non-RA Capacity or non-CPM Capacity, in which case only the capacity not committed as Resource Adequacy Capacity or CPM Capacity is eligible for supplemental revenues; and

(iv) the resource has a Bid in the IFM, HASP, and RTM for the applicable Operating Day or Operating Hour in which the resource is committed or dispatched under Exceptional Dispatch.

* * *

39.10.4 Limitation On Supplemental Revenues

Supplemental revenues authorized under this Section 39.10 shall not exceed within a 30-day period (this 30-day period begins on the day of the first Exceptional Dispatch of the resource and re-starts on the day of the first Exceptional Dispatch of the resource following the end of any prior 30-day period) the difference between any monthly CPM Capacity Payments due the resource for the 30-day period (calculated according to the ratio of the actual number of days that the resource had capacity designated as CPM Capacity during the 30-day period to the total number of days in the month) and the monthly CPM Capacity Payment, without any CPM Availability Factor adjustment, for which the resource would be eligible pursuant to Section 43.6 had its entire capacity less any Resource Adequacy Capacity been designated as an CPM resource.

* * *

40.9.6.2 Determination of the Non-Availability Charge

The per-MW Non-Availability Charge rate will be the Monthly CPM Capacity Payment price as specified in Schedule 6 of Appendix F of this CAISO Tariff. The Non-Availability Charge for a Resource Adequacy Resource shall be determined by multiplying the resource's capacity subject to the Non-Availability Charge calculated in accordance with Section 40.9.6.1 by the Non-Availability Charge rate.

* * *

40.9.7.3 Determination of Non-Availability Charges and Availability Incentive Payments for Non-Resource-Specific System Resources Providing Resource Adequacy Capacity

A Non-Resource-Specific System Resource that provides Resource Adequacy Capacity and whose actual availability calculated in accordance with Section 40.9.7.2 is less than the Availability Standard defined in Section 40.9.7.1 minus the tolerance band of two and one-half percent (2.5%) for a given month shall be assessed a Non-Availability Charge. This charge for such a resource shall apply to that portion of the resource's designated non-exempt Resource Adequacy Capacity equal to one hundred percent (100%) minus the ratio of its actual availability calculated in accordance with Section 40.9.7.2 to the Availability Standard minus two and one-half percent (2.5%). The Non-Availability Charge will then equal the resource's applicable capacity that is subject to Non-Availability Charges multiplied by the a Non-Availability Charge rate equal to the Monthly CPM Capacity Payment price as specified in Schedule 6 of Appendix F of this CAISO Tariff.

Funds collected for Non-Availability Charges pursuant to this Section 40.9.7.3 in a Trade Month will be used to provide Availability Incentive Payments to non-Resource-Specific System Resources providing Resource Adequacy Capacity that exceed the Availability Standard established in Section 40.9.7.1 plus the tolerance band of two and one-half percent (2.5%) for that same Trade Month. The funds will be distributed to each such resource in proportion to the resource's share of the total non-exempt Resource Adequacy Capacity provided by non-Resource-Specific System Resources that are eligible for Availability Incentive Payments or the month.

Any Availability Incentive Payment to a non-resource specific System Resource providing Resource Adequacy Capacity under this Section 40.9.7 3 will be capped at three times the Non-Availability Charge rate multiplied by the amount of the resource's non-exempt Resource Adequacy Capacity. Any remaining monthly surplus of Non-Availability Charges from non-Resource-Specific System Resources providing Resource Adequacy Capacity in a Trade Month will be credited against the Real-Time neutrality charge for that Trade Month in accordance with Section 11.5.2.3. Only revenues received from the assessment of Non-Availability Charges to non-Resource-Specific System Resources providing Resource Adequacy Capacity will be used to fund Availability Incentive Payments for non-Resource-Specific System Resources providing Resource Adequacy Capacity.

43. Capacity Procurement Mechanism

43.1 Interim Capacity Procurement Mechanism

The ICPM as well as changes made to other Sections to implement the ICPM shall expire at midnight on the last day of the twenty-fourth month following the effective date of this Section and shall be replaced with the CPM. ICPM designations in existence on the date the CPM becomes effective shall, as of that date, be subject to the CPM, including the provisions concerning compensation, cost allocation and Settlement, until such time as the ICPM resources have been finally compensated for their services rendered under the ICPM prior to the termination of the ICPM, and the CAISO has finally allocated and recovered the costs associated with such ICPM compensation.

43.2 Capacity Procurement Mechanism Designation

The CAISO shall have the authority to designate Eligible Capacity to provide CPM Capacity services under the CPM to address the following circumstances, as discussed in greater detail in Section 43:

(i) Insufficient Local Capacity Area Resources in an annual or monthly Resource Adequacy Plan;

(ii) Collective deficiency in Local Capacity Area Resources;

(iii) Insufficient Resource Adequacy Resources in an LSE's annual or monthly Resource Adequacy Plan;

(iv) A CPM Significant Event;

(v) A reliability or operational need for an Exceptional Dispatch CPM; and

(vi) Capacity at risk of retirement within the current RA Compliance Year that will be needed for reliability by the end of the calendar year following the current RA Compliance Year.

43.2.1 SC Failure To Show Sufficient Local Capacity Area Resources

43.2.1.1 Annual Resource Adequacy Plan

Where a Scheduling Coordinator fails to demonstrate in an annual Resource Adequacy Plan, submitted separately for each represented LSE, procurement of each LSE's share of Local Capacity Area Resources, as determined in Section 40.3.2 for each month of the following Resource Adequacy Compliance Year, the CAISO shall have the authority to designate CPM Capacity; provided, however, that the CAISO shall not designate CPM Capacity under this Section 43.2.1.1 until after the Scheduling Coordinator has had the opportunity to cure the deficiency as set forth in Section 40.7. The CAISO's authority to designate CPM Capacity under this Section 43.2.1.1 is to ensure that each Local Capacity Area in a TAC Area in which the LSE serves Load has Local Capacity Area Resources in the amounts and locations necessary to comply with the Local Capacity Technical Study criteria provided in Section

40.3.1.1, after assessing the effectiveness of Generating Units under RMR Contracts, if any, and all Resource Adequacy Resources reflected in all submitted annual Resource Adequacy Plans and any supplements thereto, as may be permitted by the CPUC, Local Regulatory Authority, or federal agency and provided to the CAISO in accordance with Section 40.7, whether or not such Generating Units under RMR Contracts and Resource Adequacy Resources are located in the applicable Local Capacity Area.

43.2.1.2 Monthly Resource Adequacy Plan

Where a Scheduling Coordinator fails to demonstrate in a monthly Resource Adequacy Plan, submitted separately for each represented LSE, procurement of each LSE's share of Local Capacity Area Resources, as determined in Section 40.3.2 for the reported month, the CAISO shall have the authority to designate CPM Capacity; provided, however, that the CAISO shall not designate CPM Capacity under this Section 43.2.1.2 until after the Scheduling Coordinator has had the opportunity to cure the deficiency as set forth in Section 40.7. The CAISO's authority to designate CPM Capacity under this Section 43.2.1.2 is to ensure that each Local Capacity Area in a TAC Area in which the LSE serves Load has Local Capacity Area Resources in the amounts and locations necessary to comply with the Local Capacity Technical Study criteria provided in Section 40.3.1.1, after assessing the effectiveness of Generating Units under RMR Contracts, if any, and all Resource Adequacy Resources reflected in all submitted annual and monthly Resource Adequacy Plans and any supplements thereto, as may be permitted by the CPUC, Local Regulatory Authority, or federal agency and provided to the CAISO in accordance with Section 40.7, whether or not such Generating Units under RMR Contracts and Resource Adequacy Resources are located in the applicable Local Capacity Area.

43.2.2 Collective Deficiency In Local Capacity Area Resources

The CAISO shall have the authority to designate CPM Capacity where the Local Capacity Area Resources specified in the annual Resource Adequacy Plans of all applicable Scheduling Coordinators, after the opportunity to cure under Section 43.2.2.1 has been exhausted, fail to ensure compliance in one or more Local Capacity Areas with the Local Capacity Technical Study criteria provided in Section 40.3.1.1, regardless of whether such resources satisfy, for the deficient Local Capacity Area, the minimum amount of Local Capacity Area Resources identified in the Local Capacity Technical Study, and after assessing the effectiveness of Generating Units under RMR Contracts, if any, and all Resource

Adequacy Resources reflected in all submitted annual Resource Adequacy Plans, whether or not such Generating Units under RMR Contracts and Resource Adequacy Resources are located in the applicable Local Capacity Area. The CAISO may, pursuant to this Section 43.2.2, designate CPM Capacity in an amount and location sufficient to ensure compliance with the Reliability Criteria applied in the Local Capacity Technical Study.

43.2.2.1 LSE Opportunity to Resolve Collective Deficiency in Local Capacity Area Resources

Where the CAISO determines that a need for CPM Capacity exists under Section 43.2.2, but prior to any designation of CPM Capacity, the CAISO shall issue a Market Notice, no later than sixty (60) days before the beginning of the Resource Adequacy Compliance Year, identifying the deficient Local Capacity Area and the quantity of capacity that would permit the deficient Local Capacity Area to comply with the Local Capacity Technical Study criteria provided in Section 40.3.1.1 and, where only specific resources are effective to resolve the Reliability Criteria deficiency, the CAISO shall provide the identity of such resources. Any Scheduling Coordinator may submit a revised annual Resource Adequacy Plan within thirty (30) days of the beginning of the Resource Adequacy Compliance Year demonstrating procurement of additional Local Capacity Area Resources consistent with the Market Notice issued under this Section.

Any Scheduling Coordinator that provides such additional Local Capacity Area Resources consistent with the Market Notice under this Section shall have its share of any CPM procurement costs under Section 43.8.3 reduced on a proportionate basis. If the full quantity of capacity is not reported to the CAISO under revised annual Resource Adequacy Plans in accordance with this Section, the CAISO may designate CPM Capacity sufficient to alleviate the deficiency.

43.2.3 SC Failure To Show Sufficient Resource Adequacy Resources

The CAISO shall have the authority to designate CPM Capacity where a Scheduling Coordinator fails to demonstrate in an annual or monthly Resource Adequacy Plan, submitted separately for each represented LSE, procurement of sufficient Resource Adequacy Resources to comply with each LSE's annual and monthly Demand and Reserve Margin requirements under Section 40; provided that the CAISO shall not designate CPM Capacity under this Section 43.2.3 until after the Scheduling Coordinator has had the opportunity to cure the deficiency as set forth in Section 40.7; provide further that the CAISO shall not designate CPM Capacity under this Section 42.2.3 unless there is an overall net deficiency in meeting the total annual or monthly Demand and Reserve Margin requirements, whichever is applicable, after taking into account all LSE demonstrations in their applicable or monthly Resource Adequacy Plans.

43.2.4 CPM Significant Events

The CAISO may designate CPM Capacity to provide service on a prospective basis following CPM Significant Event, to the extent necessary to maintain compliance with Reliability Criteria and taking into account the expected duration of the CPM Significant Event.

43.2.5 Exceptional Dispatch CPM

Except as provided in Section 43.2.5.1, the CAISO shall designate as CPM Capacity, to provide service on a prospective basis, the capacity of a resource that responds to an Exceptional Dispatch if the Exceptional Dispatch is issued pursuant to Section 34.9.1, subsections (6), (9) or (10) of Section 34.9.2, or Section 34.9.3, unless the Exceptional Dispatch directs the curtailment or shut down of the resource.

43.2.5.1 Limitation on Eligibility for Exceptional Dispatch CPM Designation

The following capacity is not eligible to receive an Exceptional Dispatch CPM designation under this Section 43.2.5.1:

(1) RA Capacity, RMR Capacity, and CPM Capacity; and

(2) Capacity of a resource that is eligible to receive supplemental revenues under Section 39.10.3 during any month for which the resource has notified the CAISO under Section 39.10.3 that it chooses to receive supplemental revenues in lieu of an Exceptional Dispatch CPM designation.

43.2.5.2 Quantity of Capacity included in an Exceptional Dispatch CPM Designation

43.2.5.2.1 Exceptional Dispatch Commitments of Non RA, Non RMR and Non CPM Resources

If a resource does not have any self-schedule, market-based commitment, or RA, RMR or CPM Capacity and receives an Exceptional Dispatch CPM designation under Section 43.2.5 following an Exceptional Dispatch eligible for an CPM designation, the CAISO shall designate as CPM Capacity the greater of the resource's PMin or the amount of capacity specified by the Exceptional Dispatch.

43.2.5.2.2 Exceptional Dispatch of Partial RA, Partial CPM Unit, or Market Committed Resource

If a resource is a Partial Resource Adequacy Resource, has an CPM designation of less than its entire capacity, has a Self Schedule or has a market based commitment, or has already received an Exceptional Dispatch CPM designation under Section 43.2.5, the CAISO shall designate as CPM Capacity the amount by which the Exceptional Dispatch exceeded the greater of –

(1) the capacity that the resources must make available to the CAISO as the result of an RA Capacity or CPM Capacity obligation; if any; and

(2) the sum of any Self-Schedule and any market-based commitment or dispatch of the resource.

43.2.5.2.3 Subsequent Exceptional Dispatch

If the CAISO, during the term of a resource's Exceptional Dispatch CPM designation, issues an Exceptional Dispatch to the resource that requires Energy in excess of the sum of the resource's CPM Capacity and RA Capacity, the CAISO will increase the capacity designated as Exceptional Dispatch CPM Capacity by the amount equal to the difference between the Exceptional Dispatch and the sum of the resource's CPM Capacity or RA Capacity. The increase will be effective for the remainder of the term of the Exceptional Dispatch CPM Designation and retroactively to the beginning of the 30-day term or the first day of the month in which the increase occurs, whichever is later. Any incremental Exceptional Dispatch issued within any 30-day CPM term does not result in a new 30-day term.

43.2.5.2.4 Change in RA, RMR or CPM Status

If a resource has an RA, RMR or CPM Capacity obligation that pre-existed the resource's Exceptional Dispatch CPM designation and, during the term of the resource's Exceptional Dispatch CPM designation, the amount of the resource's RA, RMR or CPM Capacity is reduced, the CAISO will increase the CPM designation by the amount, if any, necessary to ensure that the sum of Exceptional Dispatch CPM designation quantity and any remaining RA Capacity is not less than PMin. If capacity that receives an Exceptional Dispatch CPM designation becomes RA Capacity or receives a monthly CPM designation or Significant Event designation or receives an RMR Contract as of a certain date, then the Exceptional Dispatch CPM designation shall be reduced by the amount of the new RA Capacity, CPM Significant Event designation, or RMR Contract from that date through the rest of the 30-day term.

43.2.6 Capacity At Risk Of Retirement Needed For Reliability

The CAISO shall have the authority to designate CPM Capacity to keep a resource in operation that is at risk of retirement during the current RA Compliance Year and that will be needed for reliability by the end of the calendar year following the current RA Compliance Year. The CAISO may issue this risk of retirement CPM designation in the event that all of the following requirements apply:

(1) the resource was not contracted as RA Capacity nor listed as RA Capacity in any LSE's annual Resource Adequacy Plan during the current RA Compliance Year;

(2) the CAISO did not identify any deficiency, individual or collective, in an LSE's annual Resource Adequacy Plan for the current RA Compliance Year that resulted in a CPM designation for the resource in the current RA Compliance Year;

(3) CAISO technical assessments project that the resource will be needed for reliability purposes, either for its locational or operational characteristics, by the end of the calendar year following the current RA Compliance Year;

(4) no new generation is projected by the ISO to be in operation by the start of the subsequent RA Compliance Year that will meet the identified reliability need;

(5) the resource owner submits to the CAISO and DMM, at least 180 days prior to terminating the resource's PGA or removing the resource from PGA Schedule 1, a request for a CPM designation under this Section 43.2.6 and the affidavit of an executive officer of the company who has the legal authority to bind such entity, with the supporting financial information and documentation discussed in the BPM for Reliability Requirements, that attests that it will be uneconomic for the resource to remain in service in the current RA Compliance Year and that the decision to retire is definite unless CPM procurement occurs;

(6) the CAISO reviews the affidavit and supporting financial information and documentation submitted by the resource owner pursuant to Section 43.2.6(5) and determines that the expectation of losses and decision to retire the resource are reasonable and supported by fact.

Prior to issuing the CPM designation, the CAISO shall prepare a report that explains the basis and need for the CPM designation. The CAISO shall post the report on the CAISO's Website and allow an opportunity of no less than seven (7) days for stakeholders to review and submit comments on the report and no less than thirty (30) days for an LSE to procure Capacity from the resource.

43.2.6.1 Risk Of Retirement CPM Designation Pending Review

The CAISO may issue a risk of retirement CPM designation pursuant to Section 43.2.6 prior to or during the pendency of any review by DMM of the affidavit and supporting financial information and documentation submitted by the resource owner or a referral of investigation to the Commission by DMM pursuant to Appendix P of the CAISO Tariff. Such CPM designation shall be subject to refund and shall remain in effect until it terminates under Section 43.3.7 or until otherwise ordered by the Commission.

43.3 Terms Of CPM Designation

43.3.1 SC Annual Plan Failure To Show Local Capacity Area Resources

CPM Capacity designated under Section 43.2.2..1 shall have a minimum commitment term of one (1) month and a maximum commitment term of one (1) year, based on the period(s) of overall shortage as reflected in the annual Resource Adequacy Plans that have been submitted. The term of the designation may not extend into a subsequent Resource Adequacy Compliance Year.

43.3.2 SC Month Plan Failure To Show Local Capacity Area Resources

CPM Capacity designated under Section 43.2.1.2 shall have a minimum commitment term of one (1) month. The term of the designation may not extend into a subsequent Resource Adequacy Compliance Year.

43.3.3 Annual Plan Collective LCA Resources Insufficient

CPM Capacity designated under Section 43.2.2 shall have a minimum commitment term of one (1) month and a maximum commitment term of one year, based on the period(s) of overall shortage as reflected in the annual Resource Adequacy Plans that have been submitted. The term of the designation may not extend into a subsequent Resource Adequacy Compliance Year.

43.3.4 SC Failure To Show Sufficient Resource Adequacy Resources

CPM Capacity designated under Section 43.2.3 shall: (a) have a minimum commitment term of one (1) month and a maximum commitment term equal to the maximum annual procurement period established by the Local Reliability Authority based on the period of the deficiency reflected in the annual Resource Adequacy Plan or (b) have a commitment term of one (1) month if the deficiency is in the monthly Resource Adequacy Plan. The term of the designation may not extend into a subsequent Resource Adequacy Compliance Year.

43.3.5 Term –CPM Significant Event

CPM Capacity designated under Section 43.2.4 shall have an initial term of thirty (30) days. If the CAISO determines that the CPM Significant Event is likely to extend beyond the thirty (30) day period, the CAISO shall extend the designation for another sixty (60) days. During this additional sixty (60) day period, the CAISO will provide Market Participants with an opportunity to provide alternative solutions to meet the CAISO's operational and reliability needs in response to the CPM Significant Event, rather than rely on the CAISO's designation of capacity under the CPM. The CAISO shall consider and implement, if acceptable to the CAISO in accordance with Good Utility Practice, such alternative solutions provided by Market Participants in a timely manner. If Market Participants do not submit any alternatives to the designation of CPM capacity that are fully effective in addressing the deficiencies in Reliability Criteria resulting from CPM Significant Event, the CAISO shall extend the term of the designation under Section 43.2.4 for the expected duration of the CPM Significant Event.

If the solutions offered by Market Participants are only partially effective in addressing the CAISO's operational and reliability needs resulting from the CPM Significant Event, the CAISO shall extend the designation under Section 43.2.4 for the expected duration of the CPM Significant Event, but only as to the amount of CPM Capacity necessary to satisfy the CAISO's operational and reliability needs after taking into account the effective capacity provided by the alternative solution. If there is a reasonable alternative solution that fully resolves the CAISO's operational and reliability needs, the CAISO will not extend the designation under Section 43.2.4.

43.3.6 Term – Exceptional Dispatch CPM

Exceptional Dispatch CPM Capacity designated under Section 43.2.5 shall have a term of thirty (30) days. If the CAISO determines that the circumstances that led to the Exceptional Dispatch are likely to extend beyond the initial thirty (30) day period, the CAISO shall issue an Exceptional Dispatch CPM or other CPM designation for an additional thirty (30) days.

43.3.7 Term - Capacity At Risk Of Retirement Needed For Reliability

A CPM designation for Capacity at risk of retirement under Section 43.2.6 shall have a minimum commitment term of one (1) month and a maximum commitment term of one (1) year, based on the number of months for which the capacity is to be procured within the current RA Compliance Year, The term of the designation may not extend into a subsequent Resource Adequacy Compliance Year. The CAISO shall rescind the CPM designation for any month during which the resource is under contract with an LSE to provide RA Capacity.

43.4 Selection Of Eligible Capacity Under The CPM

In accordance with Good Utility Practice, the CAISO shall make designations of Eligible Capacity as CPM Capacity under Section 43.2 based on the following criteria:

(1) the effectiveness of the Eligible Capacity at meeting the designation criteria specified in Section 43.2;

(2) the capacity costs associated with the Eligible Capacity;

(3) the quantity of a resource's available Eligible Capacity, based on a resource's PMin, relative to the remaining amount of capacity needed;

(4) the operating characteristics of the resource, such as dispatchability, Ramp Rate, and load-following capability;

(5) whether the resource is subject to restrictions as a Use-Limited Resource; and

(6) for designations under Section 43.2.3, the effectiveness of the Eligible Capacity in meeting local and/or zonal constraints or other CAISO system needs.

In making this determination, the CAISO will attempt to designate lower cost resources that have specified a capacity price before designating resources that have not specified a capacity price, taking into account factors (1), (3), (4), (5) and (6) of this Section concerning the relative effectiveness of the resource and the resource's PMin. If after applying these criteria, two or more resources that are eligible for designation equally satisfy these criteria, the CAISO shall utilize a random selection method to determine the designation between those resources.

While the CAISO does not have to designate the full capability of a resource, the CAISO may designate under the CPM an amount of CPM Capacity from a resource that exceeds the amount of capacity identified to ensure compliance with the Reliability Criteria set forth in Section 40.3 due to the PMin or other operational requirements/limits of a resource that has available capacity to provide CPM service. The CAISO shall not designate the capacity of a resource for an amount of capacity that is less than the resource's PMin.

43.5 Obligations Of A Resource Designated Under The CPM

43.5.1 Availability Obligations

Capacity from resources designated under the CPM shall be subject to all of the availability, dispatch, testing, reporting, verification and any other applicable requirements imposed under Section 40.6 on Resource Adequacy Resources identified in Resource Adequacy Plans. In accordance with those requirements, CPM Capacity designated under the CPM shall meet the Day-Ahead availability requirements specified in Section 40.6.1 and the Real-Time availability requirements of Section 40.6.2. Also in accordance with those requirements, Generating Units designated under the CPM that meet the definition of Short Start Units shall have the obligation to meet the additional availability requirements of Section 40.6.3, and Generating Units designated under the CPM that meet the definition of Long Start Units will have the rights and obligations specified in Section 40.6.7.1.

If the CAISO has not received an Economic Bid or a Self-Schedule for CPM Capacity, the CAISO shall utilize a Generated Bid in accordance with the procedures specified in Section 40.6.8.

In addition to Energy Bids, resources designated under the CPM shall submit Ancillary Service Bids for their CPM Capacity to the extent that the resource is certified to provide the Ancillary Service.

43.5.2 Obligation To Provide Capacity And Termination

The decision to accept an CPM designation shall be voluntary for the Scheduling Coordinator for any resource. If the Scheduling Coordinator for a resource accepts an CPM designation, it shall be obligated to perform for the full quantity and full period of the designation with respect to the amount of CPM Capacity for which it has accepted an CPM designation. If a Participating Generator's or Participating

Load's Eligible Capacity is designated under the CPM after the Participating Generator or Participating Load has filed notice to terminate its Participating Generator Agreement or Participating Load Agreement or withdraw the Eligible Capacity from its Participating Generator Agreement or Participating Load Agreement, and the Scheduling Coordinator for the resource agrees to provide service under the CPM, then the Scheduling Coordinator shall enter into a new Participating Generator Agreement or Participating Load Agreement, as applicable, with the CAISO.

43.6 Reports

The CAISO shall publish the following reports and notices.

43.6.1 CPM Designation Market Notice

The CAISO shall issue a Market Notice within two (2) Business Days of an CPM designation under Sections 43.2.1 through 43.2.6. CPM designations as a result of Exceptional Dispatches shall be subject to the reporting requirement set forth in Section 34.9.4. The Market Notice shall include a preliminary description of what caused the CPM designation, the name of the resource(s) procured, the preliminary expected duration of the CPM designation, the initial designation period, and an indication that a designation report is being prepared in accordance with Section 43.6.2.

43.6.2 Designation Of A Resource Under The CPM

The CAISO shall post a designation report to the CAISO Website and provide a Market Notice of the availability of the report within the earlier of thirty (30) days of procuring a resource under Sections 43.2.1 through 43.2.6 or ten (10) days after the end of the month. The designation report shall include the following information:

(1) A description of the reason for the designation (LSE procurement shortfall, Local Capacity Area Resource effectiveness deficiency, or CPM Significant Event), and an explanation of why it was necessary for the CAISO to utilize the CPM authority);

(2) The following information would be reported for all backstop designations:

(a) the resource name;

(b) the amount of CPM Capacity designated (MW),

(c) an explanation of why that amount of CPM Capacity was designated,

(d) the date CPM Capacity was designated,

(e) the duration of the designation; and

(f) the price for the CPM procurement; and

(3) If the reason for the designation is an CPM Significant Event, the CAISO will also include:

(a) a discussion of the event or events that have occurred, why the CAISO has procured CPM Capacity, and how much has been procured;

(b) an assessment of the expected duration of the CPM Significant Event;

(c) the duration of the initial designation (thirty (30) days); and

(d) a statement as to whether the initial designation has been extended (such that the backstop procurement is now for more than thirty (30) days), and, if it has been extended, the length of the extension.

43.6.3 Non-Market And Repeated Market Commitment Of Non-RA Capacity

Within ten (10) calendar days after the end of each month, the CAISO shall post a report to the CAISO Website that identifies for the prior month:

(1) Any non-market commitments of non-Resource Adequacy Capacity; and

(2) All market commitments of non-Resource Adequacy Capacity.

The CAISO will provide a Market Notice of the availability of this report. The report will not include commitments of RMR Generation capacity, Resource Adequacy Capacity or designated CPM Capacity. The report shall include the following information:

(a) the name of the resource;

(b) the IOU Service Area and Local Capacity Area (if applicable);

(c) the maximum capacity committed in response to the event (MW);

(d) how capacity was procured (for example, by RUC or Exceptional Dispatch);

(e) the reason capacity was committed; and

(f) information as to whether or not all Resource Adequacy Resources and previously-designated CPM Capacity were used first and, if not, why they were not.

43.6.4 Board Of Governors Report

The CAISO will include in the operations report provided to the CAISO Governing Board at each board meeting a summary of CPM costs.

43.7 Payments To Resources Designated Under The CPM

Scheduling Coordinators for Eligible Capacity may submit to the CAISO an intention to be paid a monthly CPM Capacity Payment under Section 43.7.1 or Section 43.7.2. Scheduling Coordinators for Eligible Capacity will be able to change their selections annually within thirty (30) days of a CAISO Market Notice seeking such payment preferences. To the extent a Scheduling Coordinator for Eligible Capacity does not submit a selection to be compensated in accordance with Section 43.7.2, the Scheduling Coordinator shall be deemed to have selected to be paid on a resource-specific basis pursuant to Section 43.7.2, for purposes of the CAISO's CPM designation determinations.

43.7.1 Monthly CPM Capacity Payment

Scheduling Coordinators representing resources receiving payment under this Section 43.7.1 shall receive a monthly CPM Capacity Payment for each month of CPM designation equal to the product of the amount of their CPM Capacity, the relevant CPM Availability Factor for Forced Outages, as determined in accordance with Appendix F, Schedule 6, a monthly shaping factor as set forth in Appendix F, Schedule 6, a fixed CPM Capacity price of $55/kW-year and the CPM Availability Percentage for Maintenance Outages, so that the formula for determining the monthly CPM Capacity Payment would be as follows:

(CPM Capacity MW) x (CPM Availability Factor for Forced Outages) x (1/12 monthly shaping factor) x ($55/kW-year) x CPM Availability Percentage for Maintenance Outages.

The CPM Availability Percentage for Maintenance Outages is equal to the ratio of: (1) the sum of the CPM Capacity MW for each hour of the month across all hours of the month, where the actual capacity MW available to the CAISO, if less than the CPM Capacity MW, shall be substituted for CPM Capacity

MW for each hour the resource is not available due to a Maintenance Outage or non-temperature-related ambient de-rates to (2) the product of CPM Capacity MW and the total hours in the month.

The foregoing formula shall apply to all CPM Capacity receiving monthly CPM Capacity Payments under this Section 43.7.1 except for CPM Capacity designated to respond to an CPM Significant Event or an Exceptional Dispatch CPM, in which case the monthly CPM Capacity Payment shall be based proportionately on the actual number of days the resource was designated as CPM Capacity during the month to the total number of days in the month.

For purposes of CPM designations, except for designations for CPM Significant Events and Exceptional Dispatch CPM, the CPM Availability Factor for Forced Outages shall be calculated as the ratio of: (1) the sum of the CPM Capacity MW for each hour of the month across all hours of the month, where the actual capacity MW available to the CAISO, if less than the CPM Capacity MW, shall be substituted for CPM Capacity MW for each hour the resource is not available due to a Forced Outage or temperature-related ambient de-rate, to (2) the product of CPM Capacity MW and the total hours in the month.

For purposes of CPM designations for CPM Significant Events and Exceptional Dispatch CPM, the CPM Availability Factor for Forced Outages shall be calculated as the ratio of: (1) the sum of the CPM Capacity MW for each hour across all hours of the month or part of the month for which a unit is designated, whichever is applicable, where the actual capacity MW available to the CAISO, if less than the CPM Capacity MW, shall be substituted for CPM Capacity MW for each hour the resource is not available due to a Forced Outage or temperature-related ambient de-rate, to (2) the product of CPM Capacity MW and the total hours in the month or part of the month for which a unit is designated, whichever is applicable.

43.7.2 Resource-Specific CPM Capacity Payment

If a Scheduling Coordinator for Eligible Capacity believes that the $55/kW-year CPM Capacity price under Section 43.7.1 will not compensate a resource for its going forward costs, as calculated in accordance with the formula provided in Section 43.7.2.2, the Scheduling Coordinator may annually in accordance with Section 43.7, inform the CAISO of what proposed higher CPM Capacity price would compensate the resource for its going forward costs and which the Scheduling Coordinator is willing to have the CAISO use for purposes of the CPM designation process ("going forward cost offer price").

43.7.2.1 Failure to Submit Going Forward Cost Offer Price

A Scheduling Coordinator for a resource is not required to submit a specific going forward cost offer price for such resource under the process provided for in Section 43.7; however, except for an Exceptional Dispatch CPM designation, a Scheduling Coordinator that has not previously identified the going forward cost offer price for a resource must notify the CAISO of what that price is before any CAISO designation of that resource's capacity as CPM Capacity can become effective. In the case of an Exceptional Dispatch CPM designation on behalf of a resource that has not selected the supplemental revenues option, the CPM designation shall become effective notwithstanding the resource's failure to select compensation pursuant to Section 43.7.1 or to identify a going forward cost offer price pursuant to Section 43.7.2. In such a case, the CAISO shall use the compensation under Section 43.7.1 for both dispatch and compensation for the 30-day term. In the case of a Scheduling Coordinator that has not previously identified the going forward cost offer price for a resource, the cap on supplemental revenues under Section 39.10.4 will be calculated using the monthly capacity payment under Section 43.7.1.

43.7.2.1.1 Determination of Capacity Price

If the CAISO designates a resource that has proposed an CPM Capacity price above $55/kW-year, and the sales from the resource are under the jurisdiction of the FERC, the Scheduling Coordinator for the resource shall make a limited resource-specific filing before the FERC to determine the just and reasonable capacity price for the going forward costs for the resource to be used in applying the CAISO's FERC jurisdictional monthly CPM Capacity Payment formula. If the sales from the resource are not under the jurisdiction of the FERC, the Scheduling Coordinator for the resource shall make a non-jurisdictional filing with the FERC to determine the just and reasonable capacity price for the going forward costs for the resource to be used in applying the CAISO's FERC-jurisdictional monthly CPM Capacity Payment formula.

43.7.2.1.2 Going Forward Cost

In making the cost justification filing with FERC for an CPM Capacity price above $55/kW-year, the Scheduling Coordinator for the resource may not propose -- and shall not get paid --an amount higher than the going forward cost offer price that it had previously proposed to the CAISO as its going forward cost offer price under Section 43.7 or this Section 43.7.2, either prior to or at the time of CPM designation.

Going forward costs for any resource-specific filing under this Section shall be calculated based on the following formula:

> (fixed operation & maintenance costs, plus ad valorem taxes, plus administrative & general costs, plus ten percent (10%) of the foregoing amounts),

provided such costs shall be converted to a fixed $/kW-year amount.

43.7.2.2 Resource-Specific Monthly CPM Capacity Payment

Scheduling Coordinators representing resources receiving payment under Section 43.7.2 shall receive a monthly CPM Capacity Payment for each month of CPM designation equal to the product of the amount of their CPM Capacity, the relevant CPM Availability Factor for Forced Outages as determined in accordance with Appendix F, Schedule 6, a monthly shaping factor as set forth in Appendix F, Schedule 6, the resource-specific CPM Capacity price, as determined by FERC and the CPM Availability Percentage for Maintenance Outages, in accordance with the following formula:

> (CPM Capacity MW) x (CPM Availability Factor for Forced Outages) x (1/12 monthly shaping factor) x (the resource-specific CPM Capacity price as determined by FERC) x CPM Availability Percentage for Maintenance Outages.

The CPM Availability Percentage for Maintenance Outages is equal to the ratio of: (1) the sum of the CPM Capacity MW for each hour of the month across all hours of the month, where the actual capacity MW available to the CAISO, if less than the CPM Capacity MW, shall be substituted for CPM Capacity MW for each hour the resource is not available due to a Maintenance Outage or non-temperature-related ambient de-rate to (2) the product of CPM Capacity MW and the total hours in the month.

The foregoing formula shall apply to all CPM Capacity receiving monthly CPM Capacity Payments under Section 43.7.2 except for CPM Capacity designated to respond to an CPM Significant Event or Exceptional Dispatch CPM, in which case the monthly CPM Capacity Payment shall be based proportionately on the actual number of days the resource was designated as CPM Capacity during the month and available to the CAISO to the total number of days in the month.

Prior to the determination by FERC of the resource-specific going forward costs for CPM Capacity designated and paid pursuant to Section 43.7.2, the CAISO shall proceed as follows. For the period between the CAISO's designation and the FERC's determination, the CAISO shall utilize the $55/kW-year rate for purposes of the resource-specific monthly CPM Capacity Payment for financial Settlement. This amount shall be subject to surcharge based on the outcome of the FERC proceeding so that the resource will receive any higher actual resource-specific payment as determined by FERC for the full period of the CPM designation. Once approved by FERC, the CAISO shall apply the higher of $55/kW-year or the resource-specific CPM Capacity price as determined by the FERC.

For purposes of CPM designations, except for designations for CPM Significant Events, the CPM Availability Factor for Forced Outages shall be calculated as the ratio of: (1) the sum of the CPM Capacity MW for each hour of the month across all hours of the month, where the actual capacity MW available to the CAISO, if less than the CPM Capacity MW, shall be substituted for CPM Capacity MW for each hour the resource is not available due to a Forced Outage or temperature-related ambient de-rates, to (2) the product of CPM Capacity MW and the total hours in the month.

For purposes of CPM designations for CPM Significant Events, the CPM Availability Factor for Forced Outages shall be calculated as the ratio of: (1) the sum of the CPM Capacity MW for each hour across all hours of the month or part of the month for which a unit is designated, whichever is applicable, where the actual capacity MW available to the CAISO, if less than the CPM Capacity MW, shall be substituted for CPM Capacity MW for each hour the resource is not available and is not on an authorized Outage, to (2) the product of CPM Capacity MW and the total hours in the month or part of the month for which a unit is designated, whichever is applicable.

For purposes of this Section 43.7.2, an authorized Outage shall be limited to a CAISO Approved Maintenance Outage.

43.7.3 Market Payments

In addition to the CPM Capacity Payment identified in Section 43.7, CPM resources shall be entitled to retain any revenues received as a result of their selection in the CAISO Markets, provided, however, that

CPM resources are required to participate in the RUC process through submission of a zero ($0) dollar RUC Availability Bid and are not eligible to receive compensation through the RUC process.

43.8 Allocation Of CPM Capacity Payment Costs

For each month, the CAISO shall allocate the costs of CPM Capacity Payments made pursuant to Section 43.7 as follows:

43.8.1 LSE Shortage Of Local Capacity Area Resources In Annual Plan

If the CAISO makes CPM designations under Section 43.2.1.1 to address a shortage resulting from the failure of a Scheduling Coordinator for an LSE to identify sufficient Local Capacity Area Resources to meet its applicable Local Capacity Area capacity requirements in its annual Resource Adequacy Plan, then the CAISO shall allocate the total costs of the CPM Capacity Payments for such CPM designations (for the full term of those CPM designations) pro rata to each Scheduling Coordinator for an LSE based on the ratio of its Local Capacity Area Resource Deficiency to the sum of the deficiency of Local Capacity Area Resources in the deficient Local Capacity Area(s) within a TAC Area. The Local Capacity Resource Deficiency under this Section shall be computed on a monthly basis and the CPM Capacity Payments allocated based on deficiencies during the month(s) covered by the CPM designation(s).

43.8.2 LSE Shortage Of Local Capacity Area Resources In Month Plan

If the CAISO makes CPM designations under Section 43.2.1.2 to address a shortage resulting from the failure of a Scheduling Coordinator for an LSE to identify sufficient Local Capacity Area Resources to meet its applicable Local Capacity Area capacity requirements in its monthly Resource Adequacy Plan, then the CAISO shall allocate the total costs of the CPM Capacity Payments for such CPM designations (for the full term of those CPM designations) pro rata to each Scheduling Coordinator for an LSE based on the ratio of its Local Capacity Area Resource Deficiency to the sum of the deficiency of Local Capacity Area Resources in the deficient Local Capacity Area(s) within a TAC Area.

43.8.3 Collective Deficiency In Local Capacity Area Resources

If the CAISO makes designations under Section 43.2.2, the CAISO shall allocate the costs of such designations to all Scheduling Coordinators for LSEs serving Load in the TAC Area(s) in which the deficient Local Capacity Area was located. The allocation will be based on the Scheduling Coordinators' proportionate share of Load in such TAC Area(s) as determined in accordance with Section 40.3.2, excluding Scheduling Coordinators for LSEs that procured additional capacity in accordance with Section 43.2.1.2 on a proportionate basis, to the extent of their additional procurement.

43.8.4 LSE Shortage Of Demand Or Reserve Margin Requirement In Plan

If the CAISO makes CPM designations under Section 43.2.3, then the CAISO will allocate the total costs of the CPM Capacity Payments for such CPM designations (for the full term of those CPM designations) pro rata to each LSE based on the proportion of its deficiency to the aggregate deficiency.

43.8.5 Allocation Of CPM Significant Event Costs

If the CAISO makes any CPM Significant Event designations under Section 43.2.4, the CAISO shall allocate the costs of such designations to all Scheduling Coordinators for LSEs that serve Load in the TAC Area(s) in which the CPM Significant Event caused or threatened to cause a failure to meet Reliability Criteria based on the percentage of actual Load of each LSE represented by the Scheduling Coordinator in the TAC Area(s) to total Load in the TAC Area(s) as recorded in the CAISO Settlement system for the actual days during any Settlement month period over which the designation has occurred.

43.8.6 Allocation Of Exceptional Dispatch CPMs

If the CAISO makes any Exceptional Dispatch ICPM designations under Section 43.2.5, the CAISO shall allocate the costs of such designations to all Scheduling Coordinators for LSEs that serve Load in the TAC Area(s) in which the need for the Exceptional Dispatch CPM arose based on the percentage of actual Load of each LSE represented by the Scheduling Coordinator in the TAC Area(s) to total Load in the TAC Area(s) as recorded in the CAISO Settlement system for the actual days during any Settlement month period over which the designation has occurred.

43.8.7 Allocation of CPM Costs For Resources At Risk of Retirement

If the CAISO makes any CPM designations under Section 43.2.6 for resources at risk of retirement needed for reliability, the CAISO shall allocate the costs of such designations to all Scheduling Coordinators for LSEs that serve Load in the TAC Area(s) in which the need for the CPM designation arose based on the percentage of actual Load of each LSE represented by the Scheduling Coordinator in the TAC Area(s) to total Load in the TAC Area(s) as recorded in the CAISO Settlement system for the actual days during any Settlement month period over which the designation has occurred.

43.9 Crediting Of CPM Capacity

The CAISO shall credit CPM designations to the resource adequacy obligations of Scheduling Coordinators for Load Serving Entities as follows:

(a) To the extent the cost of CPM designation under Section 43.2.1.1 is allocated to a Scheduling Coordinator on behalf of a LSE under Section 43.8.1, the CAISO shall provide the Scheduling Coordinator on behalf of the LSE, for the term of the designation, credit towards (1) the LSE's Local Capacity Area Resource obligation under Section 40.3.2 in an amount equal to the LSE's pro rata share of the CPM Capacity designated under Section 43.2.1.1 and (2) the LSE's Demand and Reserve Margin requirements determined under Section 40 in an amount equal to the LSE's pro rata share of the CPM Capacity designated under Section 43.2.1.1.

(b) To the extent the cost of CAISO designation under Section 43.2.2 is allocated to a Scheduling Coordinator on behalf of a LSE under Section 43.8.3, the CAISO shall provide the Scheduling Coordinator on behalf of the LSE, for the term of the designation, credit towards the LSE's Demand and Reserve Margin requirements determined under Section 40 in an amount equal to the LSE's pro rata share of the CPM Capacity designated under Section 43.2.2.

(c) To the extent the cost of CPM designation under Section 43.2.3 is allocated to a Scheduling Coordinator on behalf of a LSE under Section 43.8.4, and the designation is for greater than one month under Section 43.3.4, the CAISO shall provide the Scheduling Coordinator on behalf of the LSE, for the term of the designation, credit towards the LSE's Demand and Reserve Margin requirements determined under Section 40 in an amount equal to the LSE's pro rata share of the CPM Capacity designated under Section 43.2.3.

(d) To the extent the cost of CPM designation under Section 43.2.6 is allocated to a Scheduling Coordinator on behalf of a LSE under Section 43.8.7, and the designation is for greater than one month under Section 43.3.7, the CAISO shall provide the Scheduling Coordinator on behalf of the LSE, for the term of the designation, credit towards the LSE's Demand and Reserve Margin requirements determined under Section 40 in an amount equal to the LSE's pro rata share of the CPM Capacity designated under Section 43.2.6.

(e) The credit provided in this Section shall be used for determining the need for the additional designation of CPM Capacity under Section 43.2 and for allocation of CPM costs under Section 43.8.

(f) For each Scheduling Coordinator that is provided credit pursuant to this Section, the CAISO shall provide information, including the quantity of capacity procured in MW, necessary to allow the CPUC, other Local Regulatory Authority, or federal agency with jurisdiction over the LSE on whose behalf the credit was provided to determine whether the LSE should receive credit toward its resource adequacy requirements adopted by such agencies or authorities.

* * *

Appendix A Master Definitions

*** * ***

Capacity Procurement Mechanism

The Capacity Procurement Mechanism, as set forth in Section 43.

*** * ***

CPM

Capacity Procurement Mechanism

CPM Availability Factor

A factor as set forth in Appendix F, Schedule 6 that is used in calculating a resource's monthly CPM Capacity Payment.

CPM Capacity

Capacity of Generating Units, System Units, System Resources, or Participating Load that is designated under the CPM in accordance with Section 43 during the term of the designation.

CPM Capacity Payment

The payment provided pursuant to Section 43.6.

CPM Significant Event

A substantial event, or a combination of events, that is determined by the CAISO to either result in a material difference from what was assumed in the resource adequacy program for purposes of determining the Resource Adequacy Capacity requirements, or produce a material change in system conditions or in CAISO Controlled Grid operations, that causes, or threatens to cause, a failure to meet Reliability Criteria absent the recurring use of a non-Resource Adequacy Resource(s) on a prospective basis.

* * *

Eligible Capacity

Capacity of Generating Units, System Units, System Resources, or Participating Load that is not already under a contract to be a Resource Adequacy Resource, is not under an RMR Contract or is not currently designated as CPM Capacity that effectively resolves a procurement shortfall or reliability concern and thus is eligible to be designated under the CPM in accordance with Section 43.1.

* * *

Exceptional Dispatch CPM

An Exceptional Dispatch CPM under Section 43.1.5 with a term of 30 days.

* * *

Appendix F Rate Schedules

Schedule 6
CPM SCHEDULES

Monthly CPM Capacity Payment

The monthly CPM Capacity Payment shall be calculated by multiplying the monthly shaping factor of 1/12 by the annual CPM Capacity price of $55/kW-year in accordance with Section 43.7.1, unless the Scheduling Coordinator for the CPM Capacity resource has agreed to another price that has been determined in accordance with Section 43.7.2.

Availability

The target availability for a resource designated under CPM is 95%. Incentives and penalties for availability above and below the target are as set forth in the table below, entitled "Availability Factor Table." The CAISO shall calculate availability on a monthly basis using actual availability data. The CPM Availability Factor for Forced Outages for each month shall be calculated using the following curve:

AVAILABILITY FACTOR TABLE

Availability	Capacity Payment Factor	ICPM Availability Factor
100%	3.3%	1.139
99%	3.3%	1.106
98%	3.3%	1.073

97%	2.5%	1.040
96%	1.5%	1.015
95%	-	1.000
94%	-1.5%	.985
93%	-1.5%	.970
92%	-1.5%	.955
91%	-1.5%	.940
90%	-1.5%	.925
89-80%	-1.7%*	.908-.755
79-41%	-1.9%*	.736-.014
-40%	-	0.0

*The "Capacity Payment Factor" decreases by 1.7% and 1.9% respectively for every 1% decrease in availability.

The CPM Capacity Payment shall be adjusted upward from the 95% availability starting point by the positive percentages listed as the "Capacity Payment Factor" above, by multiplication by the amounts listed for each CPM Availability Factor above 95%, so that, for example, if a 97% availability is achieved for the month, then the CPM Capacity Payment for that month would be the monthly value for 95% plus an additional 4% (1.5% for the first percent availability above 95%, and 2.5% for the second percent availability above 95%), i.e., multiplication of the otherwise applicable CPM Capacity Payment by the CPM Availability Factor of 1.040. Reductions in the CPM Capacity Payment shall be made correspondingly according to the "Capacity Payment Factor" above for monthly availability levels falling short of the 95% availability starting point, by multiplication by the amounts listed for each CPM Availability Factor below 95%.

* * *

Attachment B – Marked Tariff

Capacity Procurement Mechanism Tariff Amendment

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

11.5.6.7 ~~Settlement of Exceptional Dispatch Energy from Exceptional Dispatches of Resources Mitigated Pursuant to Section 39.10~~[NOT USED]

~~This entire Section 11.5.6.7 shall be effective until the end of the 24th month following the effective date of this Section 11.5.6.7, after which date this entire Section 11.5.6.7 shall no longer apply.~~

* * *

30.5.2.7 RUC Availability Bids

Scheduling Coordinators may submit RUC Availability Bids for specific Generating Units in the DAM; however, Scheduling Coordinators for Resource Adequacy Capacity or CPM~~ICPM~~ Capacity must submit RUC Availability Bids for that capacity to the extent that the capacity has not been submitted in a Self-Schedule or already been committed to provide Energy or capacity in the IFM. Capacity that does not have Bids for Supply of Energy in the IFM will not be eligible to participate in the RUC process. The RUC Availability Bid component is MW-quantity of non-Resource Adequacy Capacity in $/MW per hour, and $0/MW for Resource Adequacy Capacity or CPM~~ICPM~~ Capacity.

* * *

34.9 Exceptional Dispatch

The CAISO may issue Exceptional Dispatches for the circumstances described in this Section 34.9, which may require the issuance of forced Shut-Downs or forced Start-Ups and shall be consistent with Good Utility Practice. Dispatch Instructions issued pursuant to Exceptional Dispatches shall be entered manually by the CAISO Operator into the Day-Ahead or RTM optimization software so that they will be accounted for and included in the communication of Day-Ahead Schedules and Dispatch Instructions to Scheduling Coordinators. Exceptional Dispatches are not derived through the use of the IFM or RTM optimization software and are not used to establish the LMP at the applicable PNode. The CAISO will record the circumstances that have led to the Exceptional Dispatch.

Except as provided in this Section 34.9, the CAISO shall consider the effectiveness of the resource along with Start-Up Costs and Minimum Load Costs when issuing Exceptional Dispatches to commit a resource to operate at Minimum Load. When the CAISO issues Exceptional Dispatches for Energy, the CAISO shall also consider Energy Bids, if available and as appropriate. In accordance with Good Utility Practice, the CAISO shall make designations of Eligible Capacity for an Exceptional Dispatch CPM based on the following additional criteria:

(1) the effectiveness of the Eligible Capacity at meeting the designation criteria specified in Section 43.2;

(2) the capacity costs associated with the Eligible Capacity;

(3) the quantity of a resource's available Eligible Capacity, based on a resource's PMin, relative to the remaining amount of capacity needed;

(4) the operating characteristics of the resource, such as dispatchability, Ramp Rate, and load-following capability; and

(5) whether the resource is subject to restrictions as a Use-Limited Resource.

The goal of the CAISO will be to issue Exceptional Dispatches on a least cost basis. Imbalance Energy delivered or consumed pursuant to the various types of Exceptional Dispatch is settled according to the provisions in Section 11.5.6.

* * *

39.8.1 Bid Adder Eligibility Criteria

To receive a Bid Adder, a Generating Unit must: (i) have a Mitigation Frequency that is greater than eighty percent (80%) in the previous twelve (12) months; and (ii) must not have a contract to be a Resource Adequacy Resource for its entire Net Qualifying Capacity, or be designated under the CPM~~ICPM~~ for its entire Eligible Capacity, or be subject to an obligation to make capacity available under this CAISO Tariff. If a Generating Unit is designated under the CPM~~ICPM~~ for a portion of its Eligible Capacity, the provisions of this section apply only to the portion of the capacity not designated. Scheduling Coordinators for Generating Units seeking to receive Bid Adders must further agree to be subject to the Frequently Mitigated Unit option for a Default Energy Bid. Run hours are those hours during which a Generating Unit has positive metered output. During the first twelve (12) months after the effective date of this Section, the Mitigation Frequency will be based on a rolling twelve (12)-month combination of RMR Dispatches and incremental Bids dispatched out of economic merit order to manage local Congestion from the period prior to the effective date of this Section, which will serve as a proxy for being subject to Local Market Power Mitigation, and a Generating Unit's Local Market Power Mitigation frequency after the effective date of this Section. Generating Units that received RMR Dispatches and/or incremental Bids dispatched out of economic merit order to manage local Congestion in an hour prior to the effective date of this Section will have that hour counted as a mitigated hour in their Mitigation Frequency. After the first twelve (12) months from the effective date of this Section, the Mitigation Frequency will be based entirely on a Generating Unit being mitigated under the MPM-RRD procedures in Sections 31 and 33.

* * *

39.10 Mitigation Of Exceptional Dispatches Of Resources

The~~During the period commencing on the effective date of this section and ending at midnight on the last day of the fourth calendar month following such effective date, the CAISO shall apply Mitigation Measures to all Exceptional Dispatches eligible for an Exceptional Dispatch ICPM designation under Section 43.1.5. During the period commencing on the first day of the fifth calendar month following the effective date of this section and ending at midnight on the last day of the twenty-fourth calendar month following such effective date, the~~ CAISO shall apply Mitigation Measures to Exceptional Dispatches of resources when such resources are committed or dispatched under Exceptional Dispatch for purposes of: (1) addressing reliability requirements related to non-competitive transmission Constraints; and (2) addressing unit-specific environmental Constraints not incorporated into the Full Network Model or the CAISO's market software that affect the dispatch of Generating Units in the Sacramento Delta and are commonly known as "Delta Dispatch". ~~After the last day of the twenty-fourth calendar month following the effective date of this section, this entire Section 39.10 and the entirety of related Section 11.5.6.7, Section 43.1.5, and Section 43.2.6 shall no longer apply.~~

* * *

39.10.3 Eligibility For Supplemental Revenues

Except as provided in Section 39.10.4, a resource that is committed or dispatched under Exceptional Dispatch shall be eligible for supplemental revenues only during such times that the resource meets all of the following criteria:

(i) the resource has notified the CAISO, at least seven days prior to the calendar month in which the Exceptional Dispatch occurs, that the resource has chosen to receive supplemental revenues in lieu of an Exceptional Dispatch CPM~~ICPM~~ designation under Section 43.1.5;

(ii) the resource has been mitigated under Section 39.10;

(iii) the resource is not under an RMR Contract, is not designated as CPM~~ICPM~~ Capacity, and is not a Resource Adequacy Resource, unless the resource is a Partial Resource Adequacy Resource or a partial CPM~~ICPM~~ resource, and the Exceptional Dispatch requires non-RA Capacity or non-CPM~~ICPM~~ Capacity, in which case only the capacity not committed as Resource Adequacy Capacity or CPM~~ICPM~~ Capacity is eligible for supplemental revenues; and

(iv) the resource has a Bid in the IFM, HASP, and RTM for the applicable Operating Day or Operating Hour in which the resource is committed or dispatched under Exceptional Dispatch.

* * *

39.10.4 Limitation On Supplemental Revenues

Supplemental revenues authorized under this Section 39.10 shall not exceed within a 30-day period (this 30-day period begins on the day of the first Exceptional Dispatch of the resource and re-starts on the day of the first Exceptional Dispatch of the resource following the end of any prior 30-day period) the difference between any monthly CPM~~ICPM~~ Capacity Payments due the resource for the 30-day period (calculated according to the ratio of the actual number of days that the resource had capacity designated as CPM~~ICPM~~ Capacity during the 30-day period to the total number of days in the month) and the monthly CPM~~ICPM~~ Capacity Payment, without any CPM~~ICPM~~ Availability Factor adjustment, for which the resource would be eligible pursuant to Section 43.6 had its entire capacity less any Resource Adequacy Capacity been designated as an CPM~~ICPM~~ resource.

* * *

40.9.6.2 Determination of the Non-Availability Charge

The per-MW Non-Availability Charge rate will be the Monthly CPM~~ICPM~~ Capacity Payment price as specified in Schedule 6 of Appendix F of this CAISO Tariff. The Non-Availability Charge for a Resource Adequacy Resource shall be determined by multiplying the resource's capacity subject to the Non-Availability Charge calculated in accordance with Section 40.9.6.1 by the Non-Availability Charge rate.

* * *

40.9.7.3 Determination of Non-Availability Charges and Availability Incentive Payments for Non-Resource-Specific System Resources Providing Resource Adequacy Capacity

A Non-Resource-Specific System Resource that provides Resource Adequacy Capacity and whose actual availability calculated in accordance with Section 40.9.7.2 is less than the Availability Standard defined in Section 40.9.7.1 minus the tolerance band of two and one-half percent (2.5%) for a given month shall be assessed a Non-Availability Charge. This charge for such a resource shall apply to that portion of the resource's designated non-exempt Resource Adequacy Capacity equal to one hundred percent (100%) minus the ratio of its actual availability calculated in accordance with Section 40.9.7.2 to the Availability Standard minus two and one-half percent (2.5%). The Non-Availability Charge will then equal the resource's applicable capacity that is subject to Non-Availability Charges multiplied by the a Non-Availability Charge rate equal to the Monthly CPM~~ICPM~~ Capacity Payment price as specified in Schedule 6 of Appendix F of this CAISO Tariff.

Funds collected for Non-Availability Charges pursuant to this Section 40.9.7.3 in a Trade Month will be used to provide Availability Incentive Payments to non-Resource-Specific System Resources providing Resource Adequacy Capacity that exceed the Availability Standard established in Section 40.9.7.1 plus the tolerance band of two and one-half percent (2.5%) for that same Trade Month. The funds will be distributed to each such resource in proportion to the resource's share of the total non-exempt Resource Adequacy Capacity provided by non-Resource-Specific System Resources that are eligible for Availability Incentive Payments or the month.

Any Availability Incentive Payment to a non-resource specific System Resource providing Resource Adequacy Capacity under this Section 40.9.7 3 will be capped at three times the Non-Availability Charge rate multiplied by the amount of the resource's non-exempt Resource Adequacy Capacity. Any remaining monthly surplus of Non-Availability Charges from non-Resource-Specific System Resources providing

Resource Adequacy Capacity in a Trade Month will be credited against the Real-Time neutrality charge for that Trade Month in accordance with Section 11.5.2.3. Only revenues received from the assessment of Non-Availability Charges to non-Resource-Specific System Resources providing Resource Adequacy Capacity will be used to fund Availability Incentive Payments for non-Resource-Specific System Resources providing Resource Adequacy Capacity.

43. ~~Interim~~ Capacity Procurement Mechanism

43.1 Interim Capacity Procurement Mechanism

~~This Section 43 shall be referred to as the Interim Capacity Procurement Mechanism (ICPM).~~The ICPM as well as changes made to other Sections to implement the ICPM shall expire at midnight on the last day of the twenty-fourth month following the effective date of this Section and shall be replaced with the CPM. ICPM designations in existence on the date the CPM becomes effective shall, as of that date, be subject to the CPM, including~~section , except that~~ the provisions concerning compensation, cost allocation and Settlement,~~ shall remain in effect~~ until such time as the ICPM resources have been finally compensated for their services rendered under the ICPM prior to the termination of the ICPM, and the CAISO has finally allocated and recovered the costs associated with such ICPM compensation.

43.~~1~~2 Capacity Procurement Mechanism Designation

The CAISO shall have the authority to designate Eligible Capacity to provide CPM~~ICPM~~ Capacity services under the CPM to address the following circumstances,~~ICPM~~ as discussed in greater detail in Section 43~~follows~~:

(i) Insufficient Local Capacity Area Resources in an annual or monthly Resource Adequacy Plan;

(ii) Collective deficiency in Local Capacity Area Resources;

(iii) Insufficient Resource Adequacy Resources in an LSE's annual or monthly Resource Adequacy Plan;

(iv) A CPM Significant Event;

(v) A reliability or operational need for an Exceptional Dispatch CPM; and

(vi) Capacity at risk of retirement within the current RA Compliance Year that will be needed for reliability by the end of the calendar year following the current RA Compliance Year.

43.~~1~~2.1 SC Failure To Show Sufficient Local Capacity Area Resources

43.2~~1~~.1.1 Annual Resource Adequacy Plan

Where a Scheduling Coordinator fails to demonstrate in an annual Resource Adequacy Plan, submitted separately for each represented LSE, procurement of each LSE's share of Local Capacity Area Resources, as determined in Section 40.3.2 for each month of the following Resource Adequacy Compliance Year, the CAISO shall have the authority to designate CPM~~ICPM~~ Capacity; provided, however, that the CAISO shall not designate CPM~~ICPM~~ Capacity under this Section 43.2~~1~~.1.1 until after the Scheduling Coordinator has had the opportunity to cure the deficiency as set forth in Section 40.7. The CAISO's authority to designate CPM~~ICPM~~ Capacity under this Section 43.2~~1~~.1.1 is to ensure that each Local Capacity Area in a TAC Area in which the LSE serves Load has Local Capacity Area Resources in the amounts and locations necessary to comply with the Local Capacity Technical Study criteria provided in Section 40.3.1.1, after assessing the effectiveness of Generating Units under RMR Contracts, if any, and all Resource Adequacy Resources reflected in all submitted annual Resource Adequacy Plans and any supplements thereto, as may be permitted by the CPUC, Local Regulatory Authority, or federal agency and provided to the CAISO in accordance with Section 40.7, whether or not such Generating Units under RMR Contracts and Resource Adequacy Resources are located in the applicable Local Capacity Area.

43.2~~1~~.1.2 Monthly Resource Adequacy Plan

Where a Scheduling Coordinator fails to demonstrate in a monthly Resource Adequacy Plan, submitted separately for each represented LSE, procurement of each LSE's share of Local Capacity Area Resources, as determined in Section 40.3.2 for the reported month, the CAISO shall have the authority to designate CPM~~ICPM~~ Capacity; provided, however, that the CAISO shall not designate CPM~~ICPM~~ Capacity under this Section 43.2~~1~~.1.2 until after the Scheduling Coordinator has had the opportunity to cure the deficiency as set forth in Section 40.7. The CAISO's authority to designate CPM~~ICPM~~ Capacity under this Section 43.2.1.2~~1.1~~ is to ensure that each Local Capacity Area in a TAC Area in which the LSE serves Load has Local Capacity Area Resources in the amounts and locations necessary to comply with the Local Capacity Technical Study criteria provided in Section 40.3.1.1, after assessing the effectiveness of Generating Units under RMR Contracts, if any, and all Resource Adequacy Resources reflected in all submitted annual and monthly Resource Adequacy Plans and any supplements thereto, as may be permitted by the CPUC, Local Regulatory Authority, or federal agency and provided to the CAISO in accordance with Section 40.7, whether or not such Generating Units under RMR Contracts and Resource Adequacy Resources are located in the applicable Local Capacity Area.

43.~~1~~2.2 Collective Deficiency In Local Capacity Area Resources

The CAISO shall have the authority to designate CPM~~ICPM~~ Capacity where the Local Capacity Area Resources specified in the annual Resource Adequacy Plans of all applicable Scheduling Coordinators, after the opportunity to cure under Section 43.2~~1~~.2.1 has been exhausted, fail to ensure compliance in one or more Local Capacity Areas with the Local Capacity Technical Study criteria provided in Section 40.3.1.1, regardless of whether such resources satisfy, for the deficient Local Capacity Area, the minimum amount of Local Capacity Area Resources identified in the Local Capacity Technical Study, and after assessing the effectiveness of Generating Units under RMR Contracts, if any, and all Resource Adequacy Resources reflected in all submitted annual Resource Adequacy Plans, whether or not such Generating Units under RMR Contracts and Resource Adequacy Resources are located in the applicable Local Capacity Area. The CAISO may, pursuant to this Section 43.2~~1~~.2, designate CPM~~ICPM~~ Capacity in an amount and location sufficient to ensure compliance with the Reliability Criteria applied in the Local Capacity Technical Study.

43.2~~1~~.2.1 LSE Opportunity to Resolve Collective Deficiency in Local Capacity Area Resources

Where the CAISO determines that a need for CPM~~ICPM~~ Capacity exists under Section 43.2~~1~~.2, but prior to any designation of CPM~~ICPM~~ Capacity, the CAISO shall issue a Market Notice, no later than sixty (60) days before the beginning of the Resource Adequacy Compliance Year, identifying the deficient Local Capacity Area and the quantity of capacity that would permit the deficient Local Capacity Area to comply with the Local Capacity Technical Study criteria provided in Section 40.3.1.1 and, where only specific resources are effective to resolve the Reliability Criteria deficiency, the CAISO shall provide the identity of such resources. Any Scheduling Coordinator may submit a revised annual Resource Adequacy Plan within thirty (30) days of the beginning of the Resource Adequacy Compliance Year demonstrating procurement of additional Local Capacity Area Resources consistent with the Market Notice issued under this Section.

Any Scheduling Coordinator that provides such additional Local Capacity Area Resources consistent with the Market Notice under this Section shall have its share of any CPM~~ICPM~~ procurement costs under Section 43.8~~7~~.3 reduced on a proportionate basis. If the full quantity of capacity is not reported to the CAISO under revised annual Resource Adequacy Plans in accordance with this Section, the CAISO may designate CPM~~ICPM~~ Capacity sufficient to alleviate the deficiency.

43.~~1~~2.3 SC Failure To Show Sufficient Resource Adequacy Resources

The CAISO shall have the authority to designate CPM~~ICPM~~ Capacity where a Scheduling Coordinator fails to demonstrate in an annual or monthly Resource Adequacy Plan, submitted separately for each represented LSE, procurement of sufficient Resource Adequacy Resources to comply with each LSE's annual and monthly Demand and Reserve Margin requirements under Section 40; provided that the CAISO shall not designate CPM~~ICPM~~ Capacity under this Section 43.2~~1~~.3 until after the Scheduling Coordinator has had the opportunity to cure the deficiency as set forth in Section 40.7; provide further that the CAISO shall not designate CPM~~ICPM~~ Capacity under this Section 42.2~~1~~.3 unless there is an overall net deficiency in meeting the total annual or monthly Demand and Reserve Margin requirements, whichever is applicable, after taking into account all LSE demonstrations in their applicable or monthly Resource Adequacy Plans.

43.~~1~~2.4 ~~I~~CPM Significant Events

The CAISO may designate ~~I~~CPM Capacity to provide service on a prospective basis following CPM~~an ICPM~~ Significant Event, to the extent necessary to maintain compliance with Reliability Criteria and taking into account the expected duration of the CPM~~ICPM~~ Significant Event.

43.~~1~~2.5 Exceptional Dispatch ~~I~~CPM

Except as provided in Section 43.2~~1~~.5.1, the CAISO shall designate as CPM~~ICPM~~ Capacity, to provide service on a prospective basis, the capacity of a resource that responds to an Exceptional Dispatch if the Exceptional Dispatch is issued pursuant to Section 34.9.1, subsections (6), (9) or (10) of Section 34.9.2, or Section 34.9.3, unless the Exceptional Dispatch directs the curtailment or shut down of the resource.

43.2~~1~~.5.1 Limitation on Eligibility for Exceptional Dispatch ~~I~~CPM Designation

The following capacity is not eligible to receive an Exceptional Dispatch CPM~~ICPM~~ designation under this Section 43.2~~1~~.5.1:

(1)- RA Capacity, RMR Capacity, and CPM~~ICPM~~ Capacity; and

(2) Capacity of a resource that is eligible to receive supplemental revenues under Section 39.10.3 during any month for which the resource has notified the CAISO under Section 39.10.3 that it chooses to receive supplemental revenues in lieu of an Exceptional Dispatch CPM~~ICPM~~ designation.

43.2~~1~~.5.2 Quantity of Capacity included in an Exceptional Dispatch CPM~~ICPM~~ Designation

43.2~~1~~.5.2.1 Exceptional Dispatch Commitments of Non RA, Non RMR and Non CPM~~ICPM~~ Resources

If a resource does not have any self-schedule, market-based commitment, or RA, RMR or CPM~~ICPM~~ Capacity and receives an Exceptional Dispatch ~~I~~CPM designation under Section 43.2~~1~~.5 following an Exceptional Dispatch eligible for an ~~I~~CPM designation, the CAISO shall designate as ~~I~~CPM Capacity the greater of the resource's PMin or the amount of capacity specified by the Exceptional Dispatch.

43.2~~1~~.5.2.2 Exceptional Dispatch of Partial RA, Partial CPM~~ICPM~~ Unit, or Market Committed Resource

If a resource is a Partial Resource Adequacy Resource, has an CPM~~ICPM~~ designation of less than its entire capacity, has a Self Schedule or has a market based commitment, or has already received an Exceptional Dispatch ~~I~~CPM designation under Section 43.2~~1~~.5, the CAISO shall designate as ~~I~~CPM Capacity the amount by which the Exceptional Dispatch exceeded the greater of –

(1) the capacity that the resources must make available to the CAISO as the result of an RA Capacity or CPM~~ICPM~~ Capacity obligation; if any; and

(2) the sum of any Self-Schedule and any market-based commitment or dispatch of the resource.

43.2~~1~~.5.2.3 Subsequent Exceptional Dispatch

If the CAISO, during the term of a resource's Exceptional Dispatch CPM~~ICPM~~ designation, issues an Exceptional Dispatch to the resource that requires Energy in excess of the sum of the resource's

CPM~~ICPM~~ Capacity and RA Capacity, the CAISO will increase the capacity designated as Exceptional Dispatch CPM~~ICPM~~ Capacity by the amount equal to the difference between the Exceptional Dispatch and the sum of the resource's CPM~~ICPM~~ Capacity or RA Capacity. The increase will be effective for the remainder of the term of the Exceptional Dispatch CPM~~ICPM~~ Designation and retroactively to the beginning of the 30-~~-~~day term or the first day of the month in which the increase occurs, whichever is later. Any incremental Exceptional Dispatch issued within any 30-day CPM~~ICPM~~ term does not result in a new 30-day term.

43.2~~1.~~5.2.4 Change in RA, RMR or ~~I~~CPM Status

If a resource has an RA, RMR ~~Capacity~~ or CPM~~ICPM~~ Capacity obligation that pre-existed the resource's Exceptional Dispatch CPM~~ICPM~~ designation and, during the term of the resource's Exceptional Dispatch CPM~~ICPM~~ designation, the amount of the resource's RA, RMR ~~Capacity~~ or CPM~~ICPM~~ Capacity is reduced, the CAISO will increase the CPM~~ICPM~~ designation by the amount, if any, necessary to ensure that the sum of Exceptional Dispatch CPM~~ICPM~~ designation quantity and any remaining RA Capacity is not less than PMin. If capacity that receives an Exceptional Dispatch CPM~~ICPM~~ designation becomes RA Capacity or receives a monthly CPM~~ICPM~~ designation or Significant Event designation or receives an RMR Contract as of a certain date, then the Exceptional Dispatch CPM~~ICPM~~ designation shall be reduced by the amount of the new RA Capacity, CPM~~ICPM~~ Significant Event designation, or RMR Contract from that date through the rest of the 30-day term.

43.2.6 Capacity At Risk Of Retirement Needed For Reliability

The CAISO shall have the authority to designate CPM Capacity to keep a resource in operation that is at risk of retirement during the current RA Compliance Year and that will be needed for reliability by the end of the calendar year following the current RA Compliance Year. The CAISO may issue this risk of retirement CPM designation in the event that all of the following requirements apply:

(1) the resource was not contracted as RA Capacity nor listed as RA Capacity in any LSE's annual Resource Adequacy Plan during the current RA Compliance Year;

(2) the CAISO did not identify any deficiency, individual or collective, in an LSE's annual Resource Adequacy Plan for the current RA Compliance Year that resulted in a CPM designation for the resource in the current RA Compliance Year;

(3) CAISO technical assessments project that the resource will be needed for reliability purposes, either for its locational or operational characteristics, by the end of the calendar year following the current RA Compliance Year;

(4) no new generation is projected by the ISO to be in operation by the start of the subsequent RA Compliance Year that will meet the identified reliability need;

(5) the resource owner submits to the CAISO and DMM, at least 180 days prior to terminating the resource's PGA or removing the resource from PGA Schedule 1, a request for a CPM designation under this Section 43.2.6 and the affidavit of an executive officer of the company who has the legal authority to bind such entity, with the supporting financial information and documentation discussed in the BPM for Reliability Requirements, that attests that it will be uneconomic for the resource to remain in service in the current RA Compliance Year and that the decision to retire is definite unless CPM procurement occurs;

(6) the CAISO reviews the affidavit and supporting financial information and documentation submitted by the resource owner pursuant to Section 43.2.6(5) and determines that the expectation of losses and decision to retire the resource are reasonable and supported by fact.

Prior to issuing the CPM designation, the CAISO shall prepare a report that explains the basis and need for the CPM designation. The CAISO shall post the report on the CAISO's Website and allow an opportunity of no less than seven (7) days for stakeholders to review and submit comments on the report and no less than thirty (30) days for an LSE to procure Capacity from the resource.

43.2.6.1 Risk Of Retirement CPM Designation Pending Review

The CAISO may issue a risk of retirement CPM designation pursuant to Section 43.2.6 prior to or during the pendency of any review by DMM of the affidavit and supporting financial information and documentation submitted by the resource owner or a referral of investigation to the Commission by DMM pursuant to Appendix P of the CAISO Tariff. Such CPM designation shall be subject to refund and shall remain in effect until it terminates under Section 43.3.7 or until otherwise ordered by the Commission.

43.~~2~~3 Terms Of ~~I~~CPM Designation

43.~~2~~3.1 SC Annual Plan Failure To Show Local Capacity Area Resources

CPM~~ICPM~~ Capacity designated under Section 43.2.2~~1.1~~.1 shall have a minimum commitment term of one (1) month and a maximum commitment term of one (1) year, based on the period(s) of overall shortage as reflected in the annual Resource Adequacy Plans that have been submitted. The term of the designation may not extend into a subsequent Resource Adequacy Compliance Year.

43.~~2~~3.2 SC Month Plan Failure To Show Local Capacity Area Resources

CPM~~ICPM~~ Capacity designated under Section 43.2~~1~~.1.2 shall have a minimum commitment term of one (1) month. The term of the designation may not extend into a subsequent Resource Adequacy Compliance Year.

43.~~2~~3.3 Annual Plan Collective LCA Resources Insufficient

CPM~~ICPM~~ Capacity designated under Section 43.2~~1~~.2 shall have a minimum commitment term of one (1) month and a maximum commitment term of one year, based on the period(s) of overall shortage as reflected in the annual Resource Adequacy Plans that have been submitted. The term of the designation may not extend into a subsequent Resource Adequacy Compliance Year.

43.~~2~~3.4 SC Failure To Show Sufficient Resource Adequacy Resources

CPM~~ICPM~~ Capacity designated under Section 43.2~~1~~.3 shall: (a) have a minimum commitment term of one (1) month and a maximum commitment term equal to the maximum annual procurement period established by the Local Reliability Authority based on the period of the deficiency reflected in the annual Resource Adequacy Plan or (b) have a commitment term of one (1) month if the deficiency is in the monthly Resource Adequacy Plan. The term of the designation may not extend into a subsequent Resource Adequacy Compliance Year.

43.~~2~~3.5 Term ~~– I~~CPM Significant Event

CPM~~ICPM~~ Capacity designated under Section 43.2~~1~~.4 shall have an initial term of thirty (30) days. If the CAISO determines that the CPM~~ICPM~~ Significant Event is likely to extend beyond the thirty (30) day period, the CAISO shall extend the designation for another sixty (60) days. During this additional sixty (60) day period, the CAISO will provide Market Participants with an opportunity to provide alternative solutions to meet the CAISO's operational and reliability needs in response to the CPM~~ICPM~~ Significant Event, rather than rely on the CAISO's designation of capacity under the CPM~~ICPM~~. The CAISO shall consider and implement, if acceptable to the CAISO in accordance with Good Utility Practice, such alternative solutions provided by Market Participants in a timely manner. If Market Participants do not submit any alternatives to the designation of CPM~~ICPM~~ capacity that are fully effective in addressing the deficiencies in Reliability Criteria resulting from CPM~~ICPM~~ Significant Event, the CAISO shall extend the term of the designation under Section 43.~~1~~2.4 for the expected duration of the CPM~~ICPM~~ Significant Event.

If the solutions offered by Market Participants are only partially effective in addressing the CAISO's operational and reliability needs resulting from the CPM~~ICPM~~ Significant Event, the CAISO shall extend the designation under Section 43.2~~1~~.4 for the expected duration of the CPM~~ICPM~~ Significant Event, but only as to the amount of CPM~~ICPM~~ Capacity necessary to satisfy the CAISO's operational and reliability needs after taking into account the effective capacity provided by the alternative solution. If there is a reasonable alternative solution that fully resolves the CAISO's operational and reliability needs, the CAISO will not extend the designation under Section 43.2.4. ~~1.4. In no event shall the term of the designation under Section 43.1.4 extend beyond midnight on December 31, 2010.~~

43.3.6 Term – Exceptional Dispatch CPM

Exceptional Dispatch CPM Capacity designated under Section 43.2.5 shall have a term of thirty (30) days. If the CAISO determines that the circumstances that led to the Exceptional Dispatch are likely to extend beyond the initial thirty (30) day period, the CAISO shall issue an Exceptional Dispatch CPM or other CPM designation for an additional thirty (30) days.

43.3.7 Term - Capacity At Risk Of Retirement Needed For Reliability

A CPM designation for Capacity at risk of retirement under Section 43.2.6 shall have a minimum commitment term of one (1) month and a maximum commitment term of one (1) year, based on the number of months for which the capacity is to be procured within the current RA Compliance Year, The term of the designation may not extend into a subsequent Resource Adequacy Compliance Year. The CAISO shall rescind the CPM designation for any month during which the resource is under contract with an LSE to provide RA Capacity.

43.4 Selection Of Eligible Capacity Under The CPM

In accordance with Good Utility Practice, the CAISO shall make designations of Eligible Capacity as CPM~~ICPM~~ Capacity under Section 43.2~~1~~ based on the following criteria:

(1) the effectiveness of the Eligible Capacity at meeting the designation criteria specified in Section 43.2~~1~~;

(2) the capacity costs associated with the Eligible Capacity;

(3) the quantity of a resource's available Eligible Capacity, based on a resource's PMin, relative to the remaining amount of capacity needed; ~~and~~

(4) the operating characteristics of the resource, such as dispatchability, Ramp Rate, and load-following capability;

(5) whether the resource is subject to restrictions as a Use-Limited Resource; and

(6~~(4~~) for designations under Section 43.2~~41.1~~.3, the effectiveness of the Eligible Capacity in meeting local and/or zonal constraints or other CAISO system needs.

In making this determination, the CAISO will attempt to designate lower cost resources that have specified a capacity price before designating resources that have not specified a capacity price, taking into account factors (1), (3), (4), (5) and (6~~4~~) of this Section concerning the relative effectiveness of the resource and the resource's PMin. If after applying these criteria, two or more resources that are eligible for designation equally satisfy these criteria, the CAISO shall utilize a random selection method to determine the designation between those resources.

While the CAISO does not have to designate the full capability of a resource, the CAISO may designate under the CPM~~ICPM~~ an amount of CPM~~ICPM~~ Capacity from a resource that exceeds the amount of capacity identified to ensure compliance with the Reliability Criteria set forth in Section 40.3 due to the PMin or other operational requirements/limits of a resource that has available capacity to provide

CPM~~ICPM~~ service. The CAISO shall not designate the capacity of a resource for an amount of capacity that is less than the resource's PMin.

43.4<u>5</u> Obligations Of A Resource Designated Under The ~~I~~CPM

43.4<u>5</u>.1 Availability Obligations

Capacity from resources designated under the CPM~~ICPM~~ shall be subject to all of the availability, dispatch, testing, reporting, verification and any other applicable requirements imposed under Section 40.6 on Resource Adequacy Resources identified in Resource Adequacy Plans. In accordance with those requirements, CPM~~ICPM~~ Capacity designated under the CPM~~ICPM~~ shall meet the Day-Ahead availability requirements specified in Section 40.6.1 and the Real-Time availability requirements of Section 40.6.2. Also in accordance with those requirements, Generating Units designated under the CPM~~ICPM~~ that meet the definition of Short Start Units shall have the obligation to meet the additional availability requirements of Section 40.6.3, and Generating Units designated under the CPM~~ICPM~~ that meet the definition of Long Start Units will have the rights and obligations specified in Section 40.6.7.1.

If the CAISO has not received an Economic Bid or a Self-Schedule for CPM~~ICPM~~ Capacity, the CAISO shall utilize a Generated Bid in accordance with the procedures specified in Section 40.6.8.

In addition to Energy Bids, resources designated under the CPM~~ICPM~~ shall submit Ancillary Service Bids for their CPM~~ICPM~~ Capacity to the extent that the resource is certified to provide the Ancillary Service.

43.4<u>5</u>.2 Obligation To Provide Capacity And Termination

The decision to accept an CPM~~ICPM~~ designation shall be voluntary for the Scheduling Coordinator for any resource. If the Scheduling Coordinator for a resource accepts an CPM~~ICPM~~ designation, it shall be obligated to perform for the full quantity and full period of the designation with respect to the amount of CPM~~ICPM~~ Capacity for which it has accepted an CPM~~ICPM~~ designation. If a Participating Generator's or Participating Load's Eligible Capacity is designated under the CPM~~ICPM~~ after the Participating Generator or Participating Load has filed notice to terminate its Participating Generator Agreement or Participating Load Agreement or withdraw the Eligible Capacity from its Participating Generator Agreement or Participating Load Agreement, and the Scheduling Coordinator for the resource agrees to provide service under the CPM~~ICPM~~, then the Scheduling Coordinator shall enter into a new Participating Generator Agreement or Participating Load Agreement, as applicable, with the CAISO.

43.~~5~~6 Reports

The CAISO shall publish the following reports and notices.

43.~~5~~6.1 ~~I~~CPM Designation Market Notice

The CAISO shall issue a Market Notice within two (2) Business Days of an CPM~~ICPM~~ designation under Sections 43.2~~1~~.1 through 43.2.6. CPM~~1.4. ICPM~~ designations as a result of Exceptional Dispatches shall be subject to the reporting requirement set forth in Section 34.9.4. The Market Notice shall include a preliminary description of what caused the CPM~~ICPM~~ designation, the name of the resource(s) procured, the preliminary expected duration of the CPM~~ICPM~~ designation, the initial designation period, and an indication that a designation report is being prepared in accordance with Section 43.6~~5~~.2.

43.~~5~~6.2 Designation Of A Resource Under The ~~I~~CPM

The CAISO shall post a designation report to the CAISO Website and provide a Market Notice of the availability of the report within the earlier of thirty (30) days of procuring a resource under Sections 43.2~~1~~.1 through 43.2.6~~1.4~~ or ten (10) days after the end of the month. The designation report shall include the following information:

(1) A description of the reason for the designation (LSE procurement shortfall, Local Capacity Area Resource effectiveness deficiency, or CPM~~ICPM~~ Significant Event), and an explanation of why it was necessary for the CAISO to utilize the CPM~~ICPM~~ authority);

(2) The following information would be reported for all backstop designations:

(a) the resource name;

(b) the amount of CPM~~ICPM~~ Capacity designated (MW),

(c) an explanation of why that amount of CPM~~ICPM~~ Capacity was designated,

(d) the date CPM~~ICPM~~ Capacity was designated,

(e) the duration of the designation; and

(f) the price for the CPM~~ICPM~~ procurement; and

(3) If the reason for the designation is an CPM~~ICPM~~ Significant Event, the CAISO will also include:

(a) a discussion of the event or events that have occurred, why the CAISO has procured CPM~~ICPM~~ Capacity, and how much has been procured;

(b) an assessment of the expected duration of the CPM~~ICPM~~ Significant Event;

(c) the duration of the initial designation (thirty (30) days); and

(d) a statement as to whether the initial designation has been extended (such that the backstop procurement is now for more than thirty (30) days), and, if it has been extended, the length of the extension.

43.~~5~~6.3 Non-Market And Repeated Market Commitment Of Non-RA Capacity

Within ten (10) calendar days after the end of each month, the CAISO shall post a report to the CAISO Website that identifies for the prior month:

(1) Any non-market commitments of non-Resource Adequacy Capacity; and

(2) All market commitments of non-Resource Adequacy Capacity.

The CAISO will provide a Market Notice of the availability of this report. The report will not include commitments of RMR Generation capacity, Resource Adequacy Capacity or designated CPM~~ICPM~~ Capacity. The report shall include the following information:

(a) thet~~he~~ name of the resource;

(b) the IOU Service Area and Local Capacity Area (if applicable);

(c) the maximum capacity committed in response to the event (MW);

(d) how capacity was procured (for example, by RUC or Exceptional Dispatch);

(e) the reason capacity was committed; and

(f) information as to whether or not all Resource Adequacy Resources and previously-designated CPM~~ICPM~~ Capacity were used first and, if not, why they were not.

43.~~5~~6.4 Board Of Governors Report

The CAISO will include in the operations report provided to the CAISO Governing Board at each board meeting a summary of CPM~~ICPM~~ costs.

43.~~6~~7 Payments To Resources Designated Under The ~~I~~CPM

~~Within thirty (30) days of the effective date of this Section 43,~~ Scheduling Coordinators for Eligible Capacity may submit to the CAISO an intention to be paid a monthly CPM~~ICPM~~ Capacity Payment under Section 43.7~~6~~.1 or Section 43.7~~6~~.2. Scheduling Coordinators for Eligible Capacity will be able to change their selections annually within thirty (30) days of a CAISO Market Notice seeking such payment preferences. To the extent a Scheduling Coordinator for Eligible Capacity does not submit a selection to be compensated in accordance with Section 43.7.2~~6.1~~, the Scheduling Coordinator shall be deemed to have selected to be paid on a resource-specific basis pursuant to Section 43.7~~6~~.2, for purposes of the CAISO's CPM~~ICPM~~ designation determinations.

43.~~6~~7.1 Monthly ~~I~~CPM Capacity Payment

Scheduling Coordinators representing resources receiving payment under this Section 43.7~~6~~.1 shall receive a monthly CPM~~ICPM~~ Capacity Payment for each month of CPM~~ICPM~~ designation equal to the product of the amount of their CPM~~ICPM~~ Capacity, the relevant CPM~~ICPM~~ Availability Factor for Forced Outages, as determined in accordance with Appendix F, Schedule 6, a monthly shaping factor as set forth in Appendix F, Schedule 6, ~~and~~ a fixed CPM~~ICPM~~ Capacity price of $55~~41~~/kW-year and the CPM Availability Percentage for Maintenance Outages, so that the formula for determining the monthly CPM~~ICPM~~ Capacity Payment would be as follows:

> (CPM~~ICPM~~ Capacity MW) x (CPM~~ICPM~~ Availability Factor for Forced Outages) x (1/12 monthly shaping factor) x ($55~~41~~/kW-year) x CPM Availability Percentage for Maintenance Outages.~~).~~

The CPM Availability Percentage for Maintenance Outages is equal to the ratio of: (1) the sum of the CPM Capacity MW for each hour of the month across all hours of the month, where the actual capacity MW available to the CAISO, if less than the CPM Capacity MW, shall be substituted for CPM Capacity MW for each hour the resource is not available due to a Maintenance Outage or non-temperature-related ambient de-rates to (2) the product of CPM Capacity MW and the total hours in the month.

The foregoing formula shall apply to all CPM~~ICPM~~ Capacity receiving monthly CPM~~ICPM~~ Capacity Payments under this Section 43.7~~6~~.1 except for CPM~~ICPM~~ Capacity designated to respond to an CPM~~ICPM~~ Significant Event or an Exceptional Dispatch CPM~~ICPM~~, in which case the monthly CPM~~ICPM~~ Capacity Payment shall be based proportionately on the actual number of days the resource was designated as CPM~~ICPM~~ Capacity during the month to the total number of days in the month.

For purposes of CPM~~ICPM~~ designations, except for designations for CPM~~ICPM~~ Significant Events and Exceptional Dispatch CPM~~ICPM~~, the CPM~~ICPM~~ Availability Factor for Forced Outages shall be calculated as the ratio of: (1) the sum of the CPM~~ICPM~~ Capacity MW for each hour of the month across all hours of the month, where the actual capacity MW available to the CAISO, if less than the CPM~~ICPM~~ Capacity MW, shall be substituted for CPM~~ICPM~~ Capacity MW for each hour the resource~~ is not available and~~ is not available due to a Forced~~on an authorized~~ Outage or temperature-related ambient de-rate, to (2) the product of CPM~~ICPM~~ Capacity MW and the total hours in the month.

For purposes of CPM~~ICPM~~ designations for CPM~~ICPM~~ Significant Events and Exceptional Dispatch CPM~~ICPM~~, the CPM~~ICPM~~ Availability Factor for Forced Outages shall be calculated as the ratio of: (1) the sum of the CPM~~ICPM~~ Capacity MW for each hour across all hours of the month or part of the month for which a unit is designated, whichever is applicable, where the actual capacity MW available to the CAISO, if less than the CPM~~ICPM~~ Capacity MW, shall be substituted for CPM~~ICPM~~ Capacity MW for each hour the resource is not available due to a Forced~~and is not on an authorized~~ Outage or temperature-related ambient de-rate, to (2) the product of CPM~~ICPM~~ Capacity MW and the total hours in the month or part of the month for which a unit is designated, whichever is applicable.

~~For purposes of this Section 43.6.1, an authorized Outage shall be limited to a CAISO Approved Maintenance Outage.~~

43.~~6~~7.2 Resource-Specific ~~I~~CPM Capacity Payment

If a Scheduling Coordinator for Eligible Capacity believes that the \$55~~41~~/kW-year CPM~~ICPM~~ Capacity price under Section 43.7~~6~~.1 will not compensate a resource for its going forward costs, as calculated in accordance with the formula provided in Section 43.7~~6~~.2.2, the Scheduling Coordinator may~~, within thirty (30) days of the effective date of this Section 43 and~~ annually ~~thereafter~~ in accordance with Section 43.7~~6~~, inform the CAISO of what proposed higher CPM~~ICPM~~ Capacity price would compensate the resource for its going forward costs and which the Scheduling Coordinator is willing to have the CAISO use for purposes of the CPM~~ICPM~~ designation process ("going forward cost offer price").

43.7~~6~~.2.1 Failure to Submit Going Forward Cost Offer Price

A Scheduling Coordinator for a resource is not required to submit a specific going forward cost offer price for such resource ~~within thirty (30) days after the effective date of Section 43 or~~ under the process provided for in Section 43.7~~6~~; however, except for an Exceptional Dispatch CPM~~ICPM~~ designation, a Scheduling Coordinator that has not previously identified the going forward cost offer price for a resource must notify the CAISO of what that price is before any CAISO designation of that resource's capacity as CPM~~ICPM~~ Capacity can become effective. In the case of an Exceptional Dispatch CPM~~ICPM~~ designation on behalf of a resource that has not selected the supplemental revenues option, the CPM~~ICPM~~ designation shall become effective notwithstanding the resource's failure to select compensation pursuant to Section 43.7~~6~~.1 or to identify a going forward cost offer price pursuant to Section 43.7~~6~~.2. In such a case, the CAISO shall use the compensation under Section 43.7~~6~~.1 for both dispatch and compensation for the 30-day term. In the case of a Scheduling Coordinator that has not previously identified the going forward cost offer price for a resource, the cap on supplemental revenues under Section 39.10.4 will be calculated using the monthly capacity payment under Section 43.7~~6~~.1.

43.7~~6~~.2.1.1 Determination of Capacity Price

If the CAISO designates a resource that has proposed an CPM~~ICPM~~ Capacity price above \$55~~41~~/kW-year, and the sales from the resource are under the jurisdiction of the FERC, the Scheduling Coordinator for the resource shall make a limited resource-specific filing before the FERC to determine the just and reasonable capacity price for the going forward costs for the resource to be used in applying the CAISO's FERC jurisdictional monthly CPM~~ICPM~~ Capacity Payment formula. If the sales from the resource are not under the jurisdiction of the FERC, the Scheduling Coordinator for the resource shall make a non-jurisdictional filing with the FERC to determine the just and reasonable capacity price for the going forward costs for the resource to be used in applying the CAISO's FERC-jurisdictional monthly CPM~~ICPM~~ Capacity Payment formula.

43.~~6~~7.2.1.2 Going Forward Cost

In making the cost justification filing with FERC for an CPM~~ICPM~~ Capacity price above $55~~41~~/kW-year, the Scheduling Coordinator for the resource may not propose -- and shall not get paid --an amount higher than the going forward cost offer price that it had previously proposed to the CAISO as its going forward cost offer price under Section 43.7~~6~~ or this Section 43.7~~6~~.2, either prior to or at the time of CPM~~ICPM~~ designation.

Going forward costs for any resource-specific filing under this Section shall be calculated based on the following formula:

> (fixed operation & maintenance costs, plus ad valorem taxes, plus administrative & general costs, plus ten percent (10%) of the foregoing amounts),

provided such costs shall be converted to a fixed $/kW-year amount.

43.7~~6~~.2.2~~3~~ Resource-Specific Monthly CPM~~ICPM~~ Capacity Payment

Scheduling Coordinators representing resources receiving payment under ~~this~~ Section 43.7~~6~~.2 shall receive a monthly CPM~~ICPM~~ Capacity Payment for each month of CPM~~ICPM~~ designation equal to the product of the amount of their CPM~~ICPM~~ Capacity, the relevant CPM~~ICPM~~ Availability Factor for Forced Outages as determined in accordance with Appendix F, Schedule 6, a monthly shaping factor as set forth in Appendix F, Schedule 6, ~~and~~ the resource-specific CPM~~ICPM~~ Capacity price, as determined by FERC and the CPM Availability Percentage for Maintenance Outages, in accordance with the following formula:

> (CPM~~ICPM~~ Capacity MW) x (CPM~~ICPM~~ Availability Factor for Forced Outages) x (1/12 monthly shaping factor) x (the resource-specific CPM~~ICPM~~ Capacity price as determined by FERC) x CPM Availability Percentage for Maintenance Outages.~~).~~

The CPM Availability Percentage for Maintenance Outages is equal to the ratio of: (1) the sum of the CPM Capacity MW for each hour of the month across all hours of the month, where the actual capacity

MW available to the CAISO, if less than the CPM Capacity MW, shall be substituted for CPM Capacity MW for each hour the resource is not available due to a Maintenance Outage or non-temperature-related ambient de-rate to (2) the product of CPM Capacity MW and the total hours in the month.

The foregoing formula shall apply to all CPM~~ICPM~~ Capacity receiving monthly CPM~~ICPM~~ Capacity Payments under ~~this~~ Section 43.7~~6~~.2 except for CPM~~ICPM~~ Capacity designated to respond to an CPM~~ICPM~~ Significant Event or Exceptional Dispatch CPM~~ICPM~~, in which case the monthly CPM~~ICPM~~ Capacity Payment shall be based proportionately on the actual number of days the resource was designated as CPM~~ICPM~~ Capacity during the month and available to the CAISO to the total number of days in the month.

Prior to the determination by FERC of the resource-specific going forward costs for CPM~~ICPM~~ Capacity designated and paid pursuant to ~~this~~ Section 43.7~~6~~.2, the CAISO shall proceed as follows. For the period between the CAISO's designation and the FERC's determination, the CAISO shall utilize the $55~~41~~/kW-year rate for purposes of the resource-specific monthly CPM~~ICPM~~ Capacity Payment for financial Settlement. This amount shall be subject to surcharge based on the outcome of the FERC proceeding so that the resource will receive any higher actual resource-specific payment as determined by FERC for the full period of the CPM~~ICPM~~ designation. Once approved by FERC, the CAISO shall apply the higher of $55~~41~~/kW-year or the resource-specific CPM~~ICPM~~ Capacity price as determined by the FERC.

For purposes of CPM~~ICPM~~ designations, except for designations for CPM~~ICPM~~ Significant Events, the CPM~~ICPM~~ Availability Factor for Forced Outages shall be calculated as the ratio of: (1) the sum of the CPM~~ICPM~~ Capacity MW for each hour of the month across all hours of the month, where the actual capacity MW available to the CAISO, if less than the CPM~~ICPM~~ Capacity MW, shall be substituted for CPM~~ICPM~~ Capacity MW for each hour the resource is not available due to a Forced~~and is not on an authorized~~ Outage or temperature-related ambient de-rates, to (2) the product of CPM~~ICPM~~ Capacity MW and the total hours in the month.

For purposes of CPM~~ICPM~~ designations for CPM~~ICPM~~ Significant Events, the CPM~~ICPM~~ Availability Factor for Forced Outages shall be calculated as the ratio of: (1) the sum of the CPM~~ICPM~~ Capacity MW for each hour across all hours of the month or part of the month for which a unit is designated, whichever is applicable, where the actual capacity MW available to the CAISO, if less than the CPM~~ICPM~~ Capacity

MW, shall be substituted for CPM~~ICPM~~ Capacity MW for each hour the resource is not available and is not on an authorized Outage, to (2) the product of CPM~~ICPM~~ Capacity MW and the total hours in the month or part of the month for which a unit is designated, whichever is applicable.

For purposes of this Section 43.7~~6~~.2, an authorized Outage shall be limited to a CAISO Approved Maintenance Outage.

43.~~6~~7.3 Market Payments

In addition to the ~~I~~CPM Capacity Payment identified in Section 43.7, CPM~~6, ICPM~~ resources shall be entitled to retain any revenues received as a result of their selection in the CAISO Markets, provided, however, that CPM~~ICPM~~ resources are required to participate in the RUC process through submission of a zero ($0) dollar RUC Availability Bid and are not eligible to receive compensation through the RUC process.

43.~~7~~8 Allocation Of ~~I~~CPM Capacity Payment Costs

For each month, the CAISO shall allocate the costs of CPM~~ICPM~~ Capacity Payments made pursuant to Section 43.7~~6~~ as follows:

43.~~7~~8.1 LSE Shortage Of Local Capacity Area Resources In Annual Plan

If the CAISO makes CPM~~ICPM~~ designations under Section 43.2~~1~~.1.1 to address a shortage resulting from the failure of a Scheduling Coordinator for an LSE to identify sufficient Local Capacity Area Resources to meet its applicable Local Capacity Area capacity requirements in its annual Resource Adequacy Plan, then the CAISO shall allocate the total costs of the CPM~~ICPM~~ Capacity Payments for such CPM~~ICPM~~ designations (for the full term of those CPM~~ICPM~~ designations) pro rata to each Scheduling Coordinator for an LSE based on the ratio of its Local Capacity Area Resource Deficiency to the sum of the deficiency of Local Capacity Area Resources in the deficient Local Capacity Area(s) within a TAC Area. The Local Capacity Resource Deficiency under this Section shall be computed on a monthly basis and the CPM~~ICPM~~ Capacity Payments allocated based on deficiencies during the month(s) covered by the CPM~~ICPM~~ designation(s).

43.~~7~~8.2 LSE Shortage Of Local Capacity Area Resources In Month Plan

If the CAISO makes CPM~~ICPM~~ designations under Section 43.2~~1~~.1.2 to address a shortage resulting from the failure of a Scheduling Coordinator for an LSE to identify sufficient Local Capacity Area

Resources to meet its applicable Local Capacity Area capacity requirements in its monthly Resource Adequacy Plan, then the CAISO shall allocate the total costs of the CPM~~ICPM~~ Capacity Payments for such CPM~~ICPM~~ designations (for the full term of those CPM~~ICPM~~ designations) pro rata to each Scheduling Coordinator for an LSE based on the ratio of its Local Capacity Area Resource Deficiency to the sum of the deficiency of Local Capacity Area Resources in the deficient Local Capacity Area(s) within a TAC Area.

43.~~7~~8.3 Collective Deficiency In Local Capacity Area Resources

If the CAISO makes designations under Section 43.2.2, the CAISO shall allocate the costs of such designations to all Scheduling Coordinators for LSEs serving Load in the TAC Area(s) in which the deficient Local Capacity Area was located. The allocation will be based on the Scheduling Coordinators' proportionate share of Load in such TAC Area(s) as determined in accordance with Section 40.3.2, excluding Scheduling Coordinators for LSEs that procured additional capacity in accordance with Section 43.~~1.~~2.1.2 on a proportionate basis, to the extent of their additional procurement.

43.~~7~~8.4 LSE Shortage Of Demand Or Reserve Margin Requirement In Plan

If the CAISO makes CPM~~ICPM~~ designations under Section 43.2~~1~~.3, then the CAISO will allocate the total costs of the CPM~~ICPM~~ Capacity Payments for such CPM~~ICPM~~ designations (for the full term of those CPM~~ICPM~~ designations) pro rata to each LSE based on the proportion of its deficiency to the aggregate deficiency.

43.~~7~~8.5 Allocation Of ~~I~~CPM Significant Event Costs

If the CAISO makes any CPM~~ICPM~~ Significant Event designations under Section 43.2~~1~~.4, the CAISO shall allocate the costs of such designations to all Scheduling Coordinators for LSEs that serve Load in the TAC Area(s) in which the CPM~~ICPM~~ Significant Event caused or threatened to cause a failure to meet Reliability Criteria based on the percentage of actual Load of each LSE represented by the Scheduling Coordinator in the TAC Area(s) to total Load in the TAC Area(s) as recorded in the CAISO Settlement system for the actual days during any Settlement month period over which the designation has occurred.

43.~~7~~8.6 Allocation Of Exceptional Dispatch ~~I~~CPMs

If the CAISO makes any Exceptional Dispatch ICPM designations under Section 43.~~1.~~2.5, the CAISO shall allocate the costs of such designations to all Scheduling Coordinators for LSEs that serve Load in the TAC Area(s) in which the need for the Exceptional Dispatch CPM~~ICPM~~ arose based on the percentage of actual Load of each LSE represented by the Scheduling Coordinator in the TAC Area(s) to total Load in the TAC Area(s) as recorded in the CAISO Settlement system for the actual days during any Settlement month period over which the designation has occurred.

43.8.7 Allocation of CPM Costs For Resources At Risk of Retirement

If the CAISO makes any CPM designations under Section 43.2.6 for resources at risk of retirement needed for reliability, the CAISO shall allocate the costs of such designations to all Scheduling Coordinators for LSEs that serve Load in the TAC Area(s) in which the need for the CPM designation arose based on the percentage of actual Load of each LSE represented by the Scheduling Coordinator in the TAC Area(s) to total Load in the TAC Area(s) as recorded in the CAISO Settlement system for the actual days during any Settlement month period over which the designation has occurred.

43.~~8~~9 Crediting Of ~~I~~CPM Capacity

The CAISO shall credit CPM~~ICPM~~ designations to the resource adequacy obligations of Scheduling Coordinators for Load Serving Entities as follows:

(a) To the extent the cost of CPM~~ICPM~~ designation under Section 43.2~~1~~.1.1 is allocated to a Scheduling Coordinator on behalf of a LSE under Section 43.8~~7~~.1, the CAISO shall provide the Scheduling Coordinator on behalf of the LSE, for the term of the designation, credit towards (1) the LSE's Local Capacity Area Resource obligation under Section 40.3.2 in an amount equal to the LSE's pro rata share of the CPM~~ICPM~~ Capacity designated under Section 43.2~~1~~.1.1 and (2) the LSE's Demand and Reserve Margin requirements determined under Section 40 in an amount equal to the LSE's pro rata share of the CPM~~ICPM~~ Capacity designated under Section 43.2~~1~~.1.1.

(b) To the extent the cost of CAISO designation under Section 43.2~~1~~.2 is allocated to a Scheduling Coordinator on behalf of a LSE under Section 43.8~~7~~.3, the CAISO shall provide the Scheduling Coordinator on behalf of the LSE, for the term of the designation, credit towards the LSE's Demand and Reserve Margin requirements determined under Section 40 in an amount equal to the LSE's pro rata share of the CPM~~ICPM~~ Capacity designated under Section 43.2~~1~~.2.

(c) To the extent the cost of CPM~~ICPM~~ designation under Section 43.2~~1~~.3 is allocated to a Scheduling Coordinator on behalf of a LSE under Section 43.8~~7~~.4, and the designation is for greater than one month under Section 43.3~~2~~.4, the CAISO shall provide the Scheduling Coordinator on behalf of the LSE, for the term of the designation, credit towards the LSE's Demand and Reserve Margin requirements determined under Section 40 in an amount equal to the LSE's pro rata share of the CPM~~ICPM~~ Capacity designated under Section 43.2~~1~~.3.

(d) To the extent the cost of CPM designation under Section 43.2.6 is allocated to a Scheduling Coordinator on behalf of a LSE under Section 43.8.7, and the designation is for greater than one month under Section 43.3.7, the CAISO shall provide the Scheduling Coordinator on behalf of the LSE, for the term of the designation, credit towards the LSE's Demand and Reserve Margin requirements determined under Section 40 in an amount equal to the LSE's pro rata share of the CPM Capacity designated under Section 43.2.6.

(e~~(d~~) The credit provided in this Section shall be used for determining the need for the additional designation of CPM~~ICPM~~ Capacity under Section 43.2~~1~~ and for allocation of CPM~~ICPM~~ costs under Section 43.8~~7~~.

(f~~e~~) For each Scheduling Coordinator that is provided credit pursuant to this Section, the CAISO shall provide information, including the quantity of capacity procured in MW, necessary to allow the CPUC, other Local Regulatory Authority, or federal agency with jurisdiction over the LSE on whose behalf the credit was provided to determine whether the LSE should receive credit toward its resource adequacy requirements adopted by such agencies or authorities.

* * *

Appendix A Master Definitions

****

~~Interim~~ Capacity Procurement Mechanism

The ~~Interim~~ Capacity Procurement Mechanism, as set forth in Section 43.

****

~~I~~CPM

~~Interim~~ Capacity Procurement Mechanism

~~I~~CPM Availability Factor

A factor as set forth in Appendix F, Schedule 6 that is used in calculating a resource's monthly ~~I~~CPM Capacity Payment.

~~I~~CPM Capacity

Capacity of Generating Units, System Units, System Resources, or Participating Load that is designated under the ~~I~~CPM in accordance with Section 43 during the term of the designation.

~~I~~CPM Capacity Payment

The payment provided pursuant to Section 43.6.

~~I~~CPM Significant Event

A substantial event, or a combination of events, that is determined by the CAISO to either result in a material difference from what was assumed in the resource adequacy program for purposes of determining the Resource Adequacy Capacity requirements, or produce a material change in system conditions or in CAISO Controlled Grid operations, that causes, or threatens to cause, a failure to meet Reliability Criteria absent the recurring use of a non-Resource Adequacy Resource(s) on a prospective basis.

* * *

Eligible Capacity

Capacity of Generating Units, System Units, System Resources, or Participating Load that is not already under a contract to be a Resource Adequacy Resource, is not under an RMR Contract or is not currently designated as ~~I~~CPM Capacity that effectively resolves a procurement shortfall or reliability concern and thus is eligible to be designated under the ~~I~~CPM in accordance with Section 43.1.

* * *

Exceptional Dispatch ~~I~~CPM

An Exceptional Dispatch ~~I~~CPM under Section 43.1.5 with a term of 30 days.

* * *

Appendix F Rate Schedules

* * *

Schedule 6
CPM~~ICPM~~ SCHEDULES

Monthly CPM~~ICPM~~ Capacity Payment

The monthly CPM~~ICPM~~ Capacity Payment shall be calculated by multiplying the monthly shaping factor of 1/12 by the annual CPM~~ICPM~~ Capacity price of $55~~41~~/kW-year in accordance with Section 43.7~~6~~.1, unless the Scheduling Coordinator for the CPM~~ICPM~~ Capacity resource has agreed to another price that has been determined in accordance with Section 43.7~~6~~.2.

Availability

The target availability for a resource designated under CPM~~ICPM~~ is 95%. Incentives and penalties for availability above and below the target are as set forth in the table below, entitled "Availability Factor Table." The CAISO shall calculate availability on a monthly basis using actual availability data. The CPM~~ICPM~~ Availability Factor for Forced Outages for each month shall be calculated using the following curve:

AVAILABILITY FACTOR TABLE

Availability ~~(excluding only Scheduled Maintenance)~~	**Capacity Payment Factor**	**ICPM Availability Factor**
100%	3.3%	1.139
99%	3.3%	1.106
98%	3.3%	1.073
97%	2.5%	1.040
96%	1.5%	1.015
95%	-	1.000
94%	-1.5%	.985
93%	-1.5%	.970
92%	-1.5%	.955
91%	-1.5%	.940
90%	-1.5%	.925
89-80%	-1.7%*****	.908-.755
79-41%	-1.9%*****	.736-.014
-40%	-	0.0

*The "Capacity Payment Factor" decreases by 1.7% and 1.9% respectively for every 1% decrease in availability.

The CPM~~ICPM~~ Capacity Payment shall be adjusted upward from the 95% availability starting point by the positive percentages listed as the "Capacity Payment Factor" above, by multiplication by the amounts listed for each CPM~~ICPM~~ Availability Factor above 95%, so that, for example, if a 97% availability is achieved for the month, then the CPM~~ICPM~~ Capacity Payment for that month would be the monthly value for 95% plus an additional 4% (1.5% for the first percent availability above 95%, and 2.5% for the second percent availability above 95%), i.e., multiplication of the otherwise applicable CPM~~ICPM~~ Capacity Payment by the CPM~~ICPM~~ Availability Factor of 1.040. Reductions in the CPM~~ICPM~~ Capacity Payment shall be made correspondingly according to the "Capacity Payment Factor" above for monthly availability levels falling short of the 95% availability starting point, by multiplication by the amounts listed for each CPM~~ICPM~~ Availability Factor below 95%.

* * *

Attachment C – Table of Sections Changed

Capacity Procurement Mechanism Amendment

California Independent System Operator Corporation

New Tariff Section	Old Tariff Section (if applicable)	Purpose of Amendment
11.5.6.7	N/A	ministerial
30.5.2.7	N/A	ministerial
34.9	N/A	more closely aligns selection criteria for issuing an exceptional dispatch to match the new criteria for selecting among resources eligible for a CPM designation
39.8.1	N/A	ministerial
39.10	N/A	makes bid mitigation for exceptional dispatch permanent
39.10.3	N/A	ministerial
39.10.4	N/A	ministerial
40.9.6.2	N/A	ministerial
40.9.7.3	N/A	ministerial
43.1	N/A	provides carryover provisions for ICPM designations in place at time of ICPM expiration
43.2	43.1	lists the categories of CPM designations
43.2.1	43.1.1	ministerial
43.2.1.1	43.1.1.1	ministerial
43.2.1.2	43.1.1.2	ministerial
43.2.2	43.1.2	ministerial
43.2.2.1	43.1.2.1	ministerial
43.2.3	43.1.3	ministerial

New Tariff Section	Old Tariff Section (if applicable)	Purpose of Amendment
43.2.4	43.1.4	ministerial
43.2.5	43.1.5	ministerial
43.2.5.1	43.1.5.1	ministerial
43.2.5.2	43.1.5.2	ministerial
43.2.5.2.1	43.1.5.2.1	ministerial
43.2.5.2.2	43.1.5.2.2	ministerial
43.2.5.2.3	43.1.5.2.3	ministerial
43.2.5.2.4	43.1.5.2.4	updates provision providing for automatic increase in CPM capacity procurement where existing RA, RMR, or CPM capacity obligation is decreased
43.2.6	N/A	creates CPM designation for capacity at risk of retirement needed for reliability in the year following the planned retirement
43.2.6.1	N/A	specifies what happens to a CPM designation for capacity at risk of retirement while potential factual review of submitted materials is pending within DMM or at the Commission
43.3	43.2	ministerial
43.3.1	43.2.1	ministerial
43.3.2	43.2.2	ministerial
43.3.3	43.2.3	ministerial
43.3.4	43.2.4	ministerial
43.3.5	43.2.5	ministerial
43.3.6	N/A	specifies term of 30 days for exceptional dispatch CPM designation

New Tariff Section	Old Tariff Section (if applicable)	Purpose of Amendment
43.3.7	N/A	specifies term of 30 days to one year for capacity at risk of retirement CPM designation
43.4	43.3	adds two additional characteristics for ISO to consider in selecting among resources eligible for a CPM designation
43.5	43.4	ministerial
43.5.1	43.4.1	ministerial
43.5.2	43.4.2	ministerial
43.6	43.5	ministerial
43.6.1	43.5.1	ministerial
43.6.2	43.5.2	ministerial
43.6.3	43.5.3	ministerial
43.6.4	43.5.4	ministerial
43.7	43.6	ministerial
43.7.1	43.6.1	provides for proration of CPM payment based on planned outages
43.7.2	43.6.2	ministerial
43.7.2.1	43.6.2.1	ministerial
43.7.2.1.1	43.6.2.1.1	ministerial
43.7.2.1.2	43.6.2.2	ministerial
43.7.2.2	43.6.2.3	provides for proration of CPM payment based on planned outages

New Tariff Section	Old Tariff Section (if applicable)	Purpose of Amendment
43.7.3	43.6.3	ministerial
43.8	43.7	ministerial
43.8.1	43.7.1	ministerial
43.8.2	43.7.2	ministerial
43.8.3	43.7.3	ministerial
43.8.4	43.7.4	ministerial
43.8.5	43.7.5	ministerial
43.8.6	43.7.6	ministerial
43.8.7	N/A	specifies how costs of CPM designation for capacity at risk of retirement are allocated
43.9	43.8	updates provision providing LSE credit towards its RA requirements for CPM capacity costs allocated to the LSE
Appendix F, Schedule 6	N/A	updates availability factor tables and clarifies their use in conjunction with the compensation proration for planned outages

Attachment D – MSC Final CPM Opinion

Capacity Procurement Mechanism Amendment

California Independent System Operator Corporation

FINAL

Opinion on the Capacity Procurement Mechanism and Compensation and Bid Mitigation for Exceptional Dispatch

by

Frank A. Wolak, Chairman
James Bushnell, Member
Benjamin F. Hobbs, Member
Market Surveillance Committee of the California ISO

October 18, 2010

Summary

This opinion comments on the ISO's Capacity Procurement Mechanism (CPM) proposal, which is the successor to the backstop Interim Capacity Procurement Mechanism (ICPM). The CPM has many features of the ICPM. Most notably, both mechanisms procure generation capacity that is not currently designated as Resource Adequacy (RA) capacity to meet certain specified operating needs for which there is insufficient RA capacity. Capacity designated through the CPM mechanism would have obligations similar to RA capacity in terms of being available to the ISO for scheduling and dispatch during the period covered by the CPM designation. The ISO is proposing that the CPM be a permanent backstop capacity mechanism to procure capacity from existing generation units.

This opinion considers the three major aspects of the CPM proposal: (1) whether the ISO should have a permanent backstop capacity procurement mechanism, (2) the terms and conditions under which it should make backstop capacity purchases, and (3) the price it should pay for this capacity. We strongly support the need for the ISO to have the authority to make backstop capacity purchases. The circumstances under which the ISO can procure backstop capacity under the CPM proposal represents, in our opinion, a reasonable method that balances the need to maintain reliable system operation against the need to limit the amount of intervention by the ISO in market mechanisms. Although we generally support the ISO's proposal, we believe that the CPM payment should be set above going-forward fixed costs in areas where the local capacity requirement is greater or equal to the amount of available capacity. However, we recognize that the need for the ISO file a replacement for the current ICPM in a timely manner is inconsistent with the need for a potentially lengthy stakeholder process to design a scarcity pricing mechanism for the CPM product. We also note that if the quantity of CPM procurement does rise dramatically above current levels, this could be a signal that the RA process is procuring the wrong type of capacity for reliable system operation.

1. Introduction

The Resource Adequacy (RA) process is designed to ensure that sufficient generation capacity is made available to the ISO markets during all hours of the year, so that the system can be reliably operated. All load-serving entities are required to a make a showing to the California ISO that they have procured sufficient generation capacity in each of the Local Capacity Areas (LCAs) where they serve load obligations during peak hours of the year (as well as all hours of the year), and that they have procured sufficient capacity on a system-wide basis to meet their total RA requirements. This showing is first done on an annual basis, with a monthly true-up.[1] Because the local and system-wide RA capacity demands are determined from forecasts of demand and transmission and generation capacity availability, it is possible that because of unexpected demand levels or outages of generation units or transmission lines, there may be inadequate RA capacity in a LCA or on a system-wide basis for the ISO to operate the system reliably. The CPM proposal is designed to play two roles: first it provides a framework for the ISO to purchase additional RA-like capacity in the event that load-serving entities did not purchase sufficient RA capacity to meet forecast needs; second it allows for procurement of non-RA capacity in circumstances where actual needs diverge from forecasted needs.

In preparing this opinion, the MSC has discussed this topic at several Market Surveillance Committee meetings, most recently on October 8, 2010. In addition, individual MSC members have participated in conference calls and meetings with ISO staff, market participants, and state regulatory staff to discuss the CPM proposal. We would like to acknowledge their very helpful input. Finally, we would like to thank, in particular, Ellen Wolfe of Resero Consulting and Jeff Nelson of Southern California Edison for their comprehensive presentations on this topic at the October 8 MSC meeting.

2. A Permanent Capacity Procurement Backstop Authority for the CAISO

Because the RA procurement process will increasingly involve resources such as intermittent renewable generation and demand response whose performance is less predictable than conventional fossil fuel generation resources, we expect that there will be periods when an insufficient amount of RA capacity has been made available to the ISO. Under these circumstances, it is reasonable for the ISO to have the authority to procure the necessary backstop capacity to ensure that it can maintain system reliability. We also expect high short-term energy prices to provide a strong signal for non-RA generation unit owners to make their capacity available to the ISO operators, even if these units are not given a CPM designation.

Because even a well-designed RA process will yield small shortfalls under certain system conditions, there will always be a need for the ISO to have a backstop capacity procurement authority. Therefore, the MSC supports the adoption of the CPM without a sunset date. However, this does not imply that the ISO should not revisit the design of the CPM process at a future date if aspects of the RA process change. The form of the backstop capacity procurement mechanism must change to adapt to the new system operation challenges created by revisions to the RA procurement process.

[1] Retailers must procure 100% of their local capacity needs, but only 90% of their system-wide capacity needs on an annual basis. The remainder of their system-wide capacity needs can be delayed until the month-ahead procurement process.

Stakeholders and ISO staff have identified two important sets of issues relating to the CPM. The first involves its role as a true "backstop" to the RA process. The second relates to the fact that CPM may play an increasing role in filling a mismatch between RA requirements and true resource needs.

The RA process in California is decentralized and suffers from a lack of price transparency. As a result, the process could yield less RA capacity than the ISO deems necessary for its reliability requirements. This backstop role provides both discipline to the RA market and an added layer of reliability assurance to the ISO. The discipline that it provides helps to ensure that load-serving entities (LSEs) meet their obligations, and mitigates the impact of local market power in markets for local capacity requirements. At the same time, by providing a backstop price that would apply in the absence of adequate procurement, the CPM payment can influence RA prices. Because the RA process involves several steps, each with some level of regulatory uncertainty, the CPM price does not appear to be acting as either a firm cap or floor on the price of RA capacity, but it is reasonable to expect that it has some influence on price in the bilateral capacity market.

The second set of issues relate to the expanding realm of unanticipated RA needs. In addition to filling a gap in the face of an unexpected shock to the supply or demand for conventional "capacity," CPM may play an increasingly important role of procuring capabilities from resources that are not captured in the definition of capacity. This has long been a problem with capacity-based markets and processes, which define their products in terms of capabilities rather than the provision of specific services. It is a problem that will likely become more acute as the role of intermittent supply and demand resources increases. These factors increase the need for a CPM-like mechanism. Our individual discussions with stakeholders and comments made by them at the October 8 MSC meeting on the CPM proposal has also highlighted important questions such as whether flexible resources are being sufficiently compensated for providing ramping and load-following capabilities that could be considered "scarce".

An important signal of the severity of this problem will be the quantity of CPM capacity procured. If it remains very small, in the neighborhood of what existed during the first 17 months of operation of the new market design (averaging about 30 MW in each month), then the RA process will appear to be continuing to fill the bulk of the needs. Otherwise, a large increase in the amount of CPM capacity designations will make it difficult to argue that the CPM process is only a backstop for the ISO to purchase capacity to meet incremental or unanticipated reliability needs that are missing in the existing RA procurement process. This logic suggests a significant market monitoring function associated with the CPM to compile data on how much CPM capacity is procured, the reasons for its procurement, and at what cost and from which market participants, in order to ensure that CPM remains a small backstop procurement mechanism for all load-serving entities.[2]

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[2] The ISO issues a market notice for each ICPM designation that provides the reason, MW amount, duration, resource ID and cost of each designation. The ISO briefs the CPUC on each backstop procurement following the designation. This will continue under the CPM proposal.

3. Circumstances Governing Backstop Procurement

The CPM proposal provides four ways for a non-RA generation unit to receive a CPM designation. First, a LSE may simply have purchased insufficient generation capacity to meet its RA requirements through the annual or monthly procurement process. Second, unexpected system conditions—what the proposal calls a significant event—may arise that cause the ISO operators to revise the RA capacity requirements for a local area or on a system-wide basis. Under either of these circumstances, the ISO operators would like to guarantee that additional existing generation capacity is available and offering to supply energy and ancillary services to the ISO's markets. The CPM proposal is designed to provide a level of assurance to the ISO operators that this backstop generation capacity will be made available to the day-ahead market in a manner that is equivalent to the assurance provided by RA generation units.

Besides the above two circumstances, the CPM proposal will also provide any existing non-RA generation capacity that receives an exceptional dispatch instruction with a 30-day CPM contract, if that capacity is not currently under an RA contract or an RMR contract and is not already fulfilling a prior CPM designation.[3] Exceptional dispatch instructions occur because ISO operators issue a dispatch instruction to a generation unit outside of the ISO market mechanism to meet an operating constraint that is not included in day-ahead, hour-ahead or real-time nodal pricing process. Because these dispatch instructions are issued outside of ISO market mechanisms, the generation unit owner is paid the maximum of its default energy bid or the LMP at its location for the energy it provides if the unit is relieving a constraint that is deemed to be non-competitive. For exceptional dispatch instructions issued to relieve competitive constraints, the unit earns the higher of its bid price and the LMP at its location. As additional compensation to non-RA generation capacity for being available to respond to this exceptional dispatch instruction, the CPM proposal issues a 30-day CPM designation for the capacity. Under the ISO's current ICPM system, exceptional dispatch has been the only reason the ISO has issued CPM designations during the first 17 months of market operation.

The CPM proposal provides a fourth and new way (not in the ICPM system) for a non-RA generation unit to receive a CPM payment in the current year. If the ISO determines through operational studies that a generation resource will be needed in the following year to maintain reliable grid operations, but it will shut down in the current year because of insufficient revenues, this unit can receive a CPM designation. This rationale for a CPM payment to a non-RA unit in the current year is problematic to implement because it can create an incentive for non-RA units in the current year that are likely to be needed to provide RA capacity in a future year to threaten to retire. However, the ISO believes that it must have the ability (that the CPM proposal provides) to prevent non-RA generation units from shutting down that the ISO operators believe are needed to meet demand in future year. Moreover the ISO proposal includes a number of

[3] A generating resource can be "partial RA" if it commits a portion but not all of its capacity under an RA contract. In such cases the CPM designation would apply–as the ICPM does today–to the non-RA capacity of the resource.

provisions to ensure that the resource is in a financial situation that would warrant retirement before providing the CPM payment.

A common theme in all of these rationales for a CPM designation is that the ISO operators have determined that an existing non-RA (or partial RA) generation unit needs to make its non-RA capacity available in order to operate the system reliably. Failure to meet the annual RA capacity requirements, a change in capacity requirements because of a "significant event", a temporary change in a capacity requirement because of the need to meet an unmodeled operating constraint, and paying an existing generation unit to remain in operation are therefore all reasonable uses of backstop capacity procured under the CPM mechanism.

While we understand that the CPM designation provides the ISO operators with additional financially binding assurances that existing non-RA capacity will continue to offer into the ISO markets, we question why short-term energy and ancillary services markets do not become sufficiently remunerative for these resources as a result of the shortfall in RA capacity that made the CPM designation of an existing non-RA generation unit necessary. If the ISO markets appropriately price scarcity and include all constraints in the price calculation, then extra capacity payments would not be necessary to entice those plants to remain in the market.[4] Evidently, these non-RA generation unit owners have decided to continue to participate in ISO markets despite not receiving an RA capacity contract for their unit during the current month. This decision was likely due to the expectation that the unit would earn sufficient revenues during the month to cover its production costs and going forward costs through the energy and ancillary services market. Alternatively, the prospect of a CPM designation and the associated payment stream combined with expected energy and ancillary services market revenue could be the reason these non-RA units participate in ISO markets. However, given the inadequacies in the energy markets that have led to the need for exceptional dispatch and RA mechanisms, we acknowledge that there are likely to be circumstances in which energy and ancillary service market revenues would be insufficient to keep a non-RA unit that is actually needed in the market. We hope that as scarcity pricing is implemented and the constraints that cause exceptional dispatches are included in the market software, these circumstances will become rarer. However, it is possible that the increased penetration of intermittent renewable resources together with inadequate incentives for flexible capacity may instead make those circumstances more frequent. Through its "Renewable Integration Market and New Product Review Initiative," the ISO is current studying what additional products it will need to offer to meet these reliability challenges.

4. Pricing of CPM Capacity

A major point of contention among stakeholders is whether the CPM payment should be set equal to the cost of new entry (CONE) or going-forward fixed costs. There are a number of factors that argue in favor of paying the latter to CPM capacity, as the ISO is proposing. First, CPM payments are only made to *existing* non-RA generation capacity on a short-term basis. Second, particularly in Local Capacity Areas (LCAs),

[4] Of course, if this was true, then a major rationale for the RA capacity procurement process would disappear as well.

there is likely to be insufficient competition among suppliers to provide RA capacity,[5] so that the level of the CPM payment is likely to impact the price that retailers are willing to pay for RA units. However, the uncertainty associated with the process used by the California Public Utilities Commission (CPUC) to determine whether an LSE is excused from paying the penalty for failing to procure RA capacity from a generation unit owner that sets too high of an asking price for its capacity implies the CPM price does not function as a hard cap on RA capacity prices. In fact, a number of stakeholders commented that some load-serving entities had paid above the current ICPM price for RA capacity.

A third reason for paying only going-forward fixed-costs is that the ISO may not wish to provide a signal for new entry within certain LCAs because there is already adequate existing generation *capacity* in those LCAs to meet this demand. Some stakeholders have expressed concern that there is too little investment in California in the type of flexible capacity needed to accommodate high amounts of renewable generation capacity. However, overpaying for all capacity within LCAs with a capacity surplus would do little or nothing to correct that problem.

On the other hand, the case for setting a higher level of payment (such as CONE) for CPM is much stronger in LCAs where there is a clear need for new generation capacity. In other words, it is reasonable to expect RA prices to reflect the scarcity of existing capacity and it would be a concern if the CPM payment were preventing this. However, an important consideration in making this pricing decision is the degree to which higher RA prices could stimulate new entry in a LCA. As an example of this phenomenon, it is extremely difficult, if not impossible, to site and build new generation capacity near the city of San Francisco. If entry is unlikely due to local siting difficulties, higher RA payments imply a transfer of revenues from consumers to generation unit owners, with no accompanying supply-side market efficiency benefits because this higher price for capacity will not cause new investment in these LCAs to occur. On the other hand, it is possible that these higher payments might provide a small but nonetheless appropriate incentive for more demand response, or increase the economic attractiveness of transmission upgrades that could alleviate those high local prices.

Further, if LCAs do not feature excess capacity, energy and ancillary services market revenues should not be as limited as they could be in areas where an RA process ensures sufficient capacity to prevent short-term prices from reflecting scarcity. Even though local market-power mitigation may require default energy bids from units in these areas, the current ISO market allows prices to rise up to $5000/MWh during extreme local scarcity conditions. Therefore, generators are not being denied the opportunity to earn scarcity rents in the energy market. However, we recognize that as long as there remains a general need for an RA mechanism to incent investment, such a mechanism

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[5] In the short-term, a local RA market may resemble a bilateral monopoly market, if there is only one supplier and one purchaser of the capacity. The outcome then depends on the negotiating strength of the parties, which in turn depends on what alternatives they have should negotiations fail. The attractiveness of the alternatives to the parties, and thus their relative negotiating strength, would be affected by the CPUC waiver and CPM; however, this influence is difficult to quantify because of the uncertainties in the waiver process.

should reflect scarcity, and for the sake of consistency, prices for capacity (including CPM) should reflect that scarcity.

In summary, we believe the proposed CPM payment level is appropriate for the majority of circumstances where capacity is not scarce. In areas where capacity is scarce we would support a mechanism that allows RA prices to rise above going-forward cost levels. Even if this does not stimulate new generation entry it does send a signal to demand. However, we realize that including a variable price mechanism in the CPM would make it more complex and require definition of triggers and price levels; this complexity is hard to justify when the amounts of capacity presently procured are so tiny. The ISO could announce plans to institute such a mechanism if the amounts of CPM capacity procured grow significantly. A mechanism that allows RA prices to rise when capacity is short need not necessarily be the CPM, however. If the CPUC review process made clear that either a higher cap on RA values in capacity-constrained LCAs would be applied, or that waivers of RA obligations in such areas would be viewed more stringently, RA prices could rise above the CPM rate regardless of its level.

5. Price Discrimination between Existing and New Capacity

A final more general issue that has been raised in the context of the discussion of the CPM payment mechanism is the potential price discrimination between new and existing generation units in the price paid for RA capacity. Some stakeholders have asserted that new generation units are typically paid a price close to CONE for providing RA capacity through the CPUC's long-term procurement process. The assertion is also that most existing generation capacity is instead paid close to going-forward fixed costs through the annual RA procurement process. As a consequence many suppliers have argued that a differential pricing structure for RA capacity, which favors new generation at the expense of incumbents, has emerged. We do not dispute or endorse these claims as we have not been able to verify them or refute them due to the lamentable lack of transparency in the RA market.

In thinking about the consequences of price discrimination between new and existing generation units, it important to distinguish between wealth transfers from generation unit owners to consumers and the market efficiency consequences of this bilateral procurement strategy. If paying lower capacity prices to an existing generation unit does not impact its availability, or its incentive to make incremental operating efficiency-improving investments, then this lower price simply represents a wealth transfer from existing generation units to electricity consumers. However, maintenance, upgrading, and life-extension decisions are important in all stages of a generating unit's life-cycle, and so we would expect significant efficiency impacts of price discrimination, especially for older units.

Another way that market efficiency can be adversely impacted by this price discrimination is if new suppliers know that they will become existing suppliers shortly after they build a new generation unit. Consequently, new entrants will ask for a much higher price to construct the new generation unit in order to compensate for the fact they will receive a much lower capacity price once they enter and their generation unit becomes existing capacity. This logic implies that new suppliers will require higher average bilateral contract prices in order to enter relative to the case that new and existing generation units are paid similar prices. Consequently, in the long run, utilities (and their customers) may pay as much for RA as in a nondiscriminatory system, or even more if the efficiency consequences are large.

While this issue merits serious consideration, we feel that the CPM is too blunt an instrument to correct whatever market dynamics are at play. The fundamental potential for such pricing outcomes lies with the concentration of purchases within a few large LSEs. Extremely large LSEs can have the ability to procure capacity with an eye towards reducing RA prices regardless of the specific market rules for the RA process. This is true even in centralized capacity markets. Whether these LSEs have an *incentive* to do so, depends on their regulatory status and oversight.

6. Conclusion

In summary, we support the ISO proposal, but recognize the need for the CPM price to be allowed to rise above going-forward fixed costs in areas where capacity is scarce. In addition, a dramatic increase in the amount of capacity procured through the CPM process in the future could indicate an insufficient definition of capacity for the RA process.

As long as the California ISO continues with a capacity-based bilateral RA procurement process, it will require a backstop procurement process to ensure that it has sufficient generation capacity that adheres to the terms and conditions of the RA capacity product. The circumstances under which the CPM proposal will procure this backstop capacity are consistent with the goals of reliable system operation and limited interference with existing ISO market mechanisms. A major challenge for the ISO and California Public Utilities Commission will be to restructure the current RA procurement process so that the CPM designation remains a very limited backstop procurement process--as opposed to a mechanism for the ISO to purchase capacity that provides a ongoing and valuable service but that is not purchased in the RA process because the offer price for this capacity is deemed to be too high.

California's ambitious renewable energy goals emphasize the importance of adapting the resource adequacy process and set of products purchased in the ISO markets to ensure that all of the attributes of generation units that enhance system reliability are appropriately valued so that demand at all locations in the California ISO control area can be met in the most efficient manner possible. We look forward to working with the ISO, California Public Utilities Commission and market participants to define these products and the resource adequacy process that ensures they will be efficiently provided to the California ISO operators.

Attachment E – Board Memo

Capacity Procurement Mechanism Amendment

California Independent System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Keith Casey, Vice President, Market & Infrastructure Development

Date: October 26, 2010

Re: Decision on Capacity Procurement Mechanism and Exceptional Dispatch Provisions

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This memorandum requires Board action.

EXECUTIVE SUMMARY

The California Public Utilities Commission (CPUC) and other local regulatory authorities have established resource adequacy programs to ensure that the ISO has sufficient resources offered into its market to maintain reliable grid operation. However, under special circumstances, the resource adequacy capacity may not be sufficient to meet the ISO's operational needs. In this case, the ISO uses provisions within its tariff authority to procure backstop capacity. The current provisions for backstop capacity purchases have been in effect since the April 1, 2009 start-up of the new market structure, under the "interim" capacity procurement mechanism and exceptional dispatch provisions. However, the interim mechanism and certain elements of the exceptional dispatch design expire on March 31, 2011, and FERC has required the ISO to file successor provisions no later than 120 days prior to that date, or by December 1, 2010.

Management is seeking the ISO Board of Governors' approval of its proposed capacity procurement mechanism and exceptional dispatch provisions to replace the current interim mechanism. The capacity procurement mechanism allows the ISO to procure supply capacity for a minimum of 30 days and up to a full year to backstop any shortfall in the yearly or monthly resource adequacy procurement by load-serving entities or to meet operational needs due to significant unexpected changes in system conditions. Exceptional dispatch provisions allow the ISO to commit or dispatch resources on a day-ahead or real-time basis beyond their market schedules, and, if such dispatches use non-resource adequacy capacity, to compensate the capacity with either going-forward fixed costs or supplemental revenues. In addition, when the ISO issues an exceptional dispatch for capacity that is not under a resource adequacy contract, it triggers a 30-day procurement of the capacity under the capacity procurement mechanism provisions.

Management's current proposal retains most of the provisions of the existing mechanisms and also offers some needed enhancements, as indicated in the following summary of key elements:

1. Non-resource adequacy capacity will be compensated at a compensation rate that reflects the going-forward fixed cost of a hypothetical 50 megawatt generating unit, as established by the California Energy Commission (CEC). The capacity procurement mechanism and the exceptional dispatch will use the same compensation rate, which is the same as in the current mechanism and will be updated every two years. Suppliers that believe that their actual costs exceed the default rate can file at FERC for a higher rate. Using this mechanism, the actual compensation rate will increase from the amount non-resource adequacy capacity receives under the current backstop mechanism, $41 per kilowatt-year, to $55 per kilowatt-year.
2. These mechanisms will be permanent features of the ISO market structure, rather than an interim mechanism.
3. The criteria the ISO currently uses to select specific capacity when more than one resource option is available will be expanded to prefer resources that do not have a limitation on the amount of energy they can produce in a given period, and that have desired performance characteristics.
4. The current criteria for using the interim capacity procurement mechanism will be expanded to include capacity at risk of retirement within six months when the ISO's reliability studies indicate the capacity is needed within the next two years.
5. A resource procured under the capacity procurement mechanism that takes a planned maintenance outage during the 30-day procurement period will have its compensation reduced pro rata, which corrects a gap in the current rules.
6. A resource procured under the current interim capacity procurement mechanism whose procurement period extends beyond March 31, 2011 will automatically be converted to the new rules for the remainder of the procurement period after that date.
7. In response to a FERC directive, the ISO re-evaluated the existing bid mitigation provisions for exceptional dispatch and found them to be adequate and appropriate. Management proposes no changes to those existing provisions.

In light of FERC's December 1, 2010 filing deadline and the importance of these provisions for the continued reliable operation of the ISO grid, Management requests the Board to approve the following motion:

> ***Moved, that the ISO Board of Governors approves the proposed capacity procurement mechanism and exceptional dispatch provisions, as detailed in the memorandum dated October 26, 2010; and***
>
> ***Moved, that the ISO Board of Governors authorizes Management to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the proposed tariff change.***

BACKGROUND

The existing interim capacity procurement mechanism (ICPM) was designed as a backstop mechanism to allow the ISO to procure additional supply capacity in instances where resource adequacy procurement by load serving entities does not fully meet the requirements, or when necessary under unforeseen conditions to maintain reliable grid operation. The ICPM allows the ISO to make capacity designations from 30 days up to a full year, to establish the compensation rate for procuring backstop capacity services and allocate the costs incurred. An ICPM designation carries with it a requirement for the designated capacity to comply with the must-offer obligations that are applicable to resource adequacy capacity under the tariff, and as such is intended only for procuring capacity that is not already designated as resource adequacy capacity. Acceptance of an ICPM designation by the resource owner is voluntary. In addition, a resource owner accepting an ICPM designation has the choice of accepting the pre-specified compensation rate or filing with FERC for a higher rate.

In contrast, an exceptional dispatch by the ISO is short-term. An exceptional dispatch may be a commitment instruction issued the day before, or up to a few hours before a resource is needed, or it may be a dispatch instruction that is issued within the operating hour. Such instructions are considered "exceptional" in the sense that they are issued manually by ISO operators rather than through the ISO market software. Exceptional dispatch may apply to both resource adequacy and non-resource adequacy capacity, and compliance with the instruction is not voluntary. Because of the potential for a resource located in a critically constrained area of the grid to exercise market power when needed for reliability, the exceptional dispatch rules include a market power mitigation provision.

When the ISO issues an exceptional dispatch to non-resource adequacy capacity, the resource owner is entitled to additional compensation. This compensation is a capacity payment that FERC has ordered be roughly comparable to the compensation paid to resource adequacy resources. For consistency, the rate at which ISO-procured non-resource adequacy capacity is paid is the same for both the ICPM and exceptional dispatch. In the event the ISO issues an exceptional dispatch to resource adequacy capacity, no capacity payment is provided because the requirement of the resource to comply is deemed to be part of the resource's obligations under the resource adequacy must-offer provisions.

When these mechanisms were developed prior to the start-up of the new market structure, the primary concerns raised by some parties were that: (1) the ISO would use them excessively, which would depress market prices, and (2) the compensation rate should be set at a high enough level to signal scarcity and stimulate new investment, whereas the ISO's proposed compensation rate was designed only to compensate for a resource's going-forward fixed costs.

Regarding the first concern, experience with the new market structure that went into operation on April 1, 2009, has shown that the actual use and costs of ICPM and exceptional dispatch have been far less than stakeholders anticipated in their comments when these provisions were filed at FERC. Since April 1, 2009, there have been only 23 ICPM designations (all triggered by exceptional dispatches), for a total of 703 MW, at a total cost of $2.7 million with no procurement lasting longer than 30 days.

Regarding the compensation rate, FERC accepted the ISO's proposed ICPM as an "interim" mechanism with a March 31, 2011 sunset with the understanding that the CPUC was then conducting a proceeding to consider adopting a multi-year forward resource adequacy requirement with a centralized capacity market. At that time, the ISO and the stakeholders anticipated that the successor mechanism would be designed to be consistent with and complementary to the CPUC's revised long-term resource adequacy framework. On June 3, 2010, the CPUC adopted a final decision in the long-term resource adequacy proceeding that leaves the current resource adequacy program essentially unchanged. The implication of this decision for the current initiative is that the provisions adopted here must be aligned with, and complementary to, the existing resource adequacy framework, and must be expected to remain in place indefinitely.

PROPOSAL DISCUSSION

During the course of the stakeholder process, the most contentious issues were the compensation rate, the basis for issuing capacity procurement mechanism designations including the use of the CPM to procure capacity at risk of retirement, and expansion of the selection criteria to consider use limitations and resource performance characteristics. Each of these issues is discussed below.

<u>Compensation Rate</u>

Stakeholders were divided between setting the compensation rate based on the cost of new entry (i.e., to signal supply scarcity and elicit new investment) versus setting the rate at the going-forward fixed-costs of a typical 50 MW generation unit (going-forward fixed costs are the minimum costs that a unit needs to cover to remain available for service and operable). Although some suppliers argued that resources should be paid for a return on capital investment, they have also noted that the capacity procurement mechanism, by itself, is not an investment vehicle. Management proposes the going-forward fixed-cost compensation rate for the following reasons:

- Under the ICPM, all resources have elected compensation at the pre-specified capacity procurement rate (currently $41 kW/year) in lieu of notifying the ISO they intend to file at FERC for higher rates. This indicates that the current rate structure provides sufficient compensation to cover costs; and

- The backstop procurement mechanism is designed for short-term capacity purchases and therefore not designed to incent investment in generation. A cost of new entry compensation design which includes capital investments costs is not appropriate for short-term capacity procurement.

The ISO is mindful of the impact of renewable energy on energy and ancillary services market prices and the expected resulting reduction in spot market revenues for conventional resources, but has concluded that the mechanisms discussed here for backstop procurement are not the appropriate vehicles for trying to address this concern. The ISO has started a separate major stakeholder initiative – the renewable integration market and product review – to address this and other market design issues related to the increasing participation of renewable resources in the ISO market.

This proposal includes updating the procurement compensation rate every two years based on a report produced by the CEC that provides an assessment of the levelized going-forward costs of a new hypothetical 50 MW generating unit. The CEC model used to support the going-forward cost calculations was first developed in 2003 and then updated in 2007 and 2009.

Basis for Issuing CPM Designations

During the stakeholder process the ISO considered whether it was necessary to expand its ability to procure capacity through the CPM: (1) in advance of the day-ahead or real-time markets to allow a transmission or generator maintenance outage to proceed under existing grid conditions; or (2) in the event a sustained loss of intermittent energy causes material reductions in the available resource adequacy capacity. The latter concern will become more acute as the amount of intermittent capacity fulfills a great portion of the resource adequacy procurement requirements on load-serving entities. Management determined that it is appropriate for the ISO to engage in backstop procurement to address these two situations, and that the tariff authorizes designation of ICPM capacity for a significant event. Management therefore proposes to address these needs through simple continuation of the ICPM provisions rather than by modifying those provisions.

During the stakeholder process the ISO also considered whether to expand its ability to procure capacity to ensure that resources that are needed for reliability but are at risk of retirement can be paid a capacity payment to keep them in service. Many stakeholders do not support this ISO procurement authority. One concern is that allowing backstop procurement to prevent the retirement of a resource based on alleged financial circumstances will present a gaming opportunity. Management recognizes that it cannot and should not be expected to assess the financial situation of a resource to ensure definitively that the resource is at risk of retirement due to insufficient revenues. Rather, Management proposes to rely, as it has for certain other situations where it must rely on the assertions of a market participant, on (1) a formal declaration by the resource owner of its intent to terminate its participating generator agreement, (2) the submission of financial information plus an affidavit from a company executive regarding its financial situation, (3) existing tariff requirements to submit truthful information, with the potential to refer a situation to FERC if the resource's request appears questionable, and (4) information concerning the resource's financial situation and business case for retirement, including its going-forward costs, projected revenues and opportunity costs. This information will be analyzed by the Department of Market Monitoring to ensure against possible economic withholding of capacity and the ISO will consider the analysis done by the Department of Market Monitoring in its consideration of whether to procure such a resource.

Some parties have questioned the need for this retirement provision and pointed out that the CPUC has an established process for reporting and reviewing potential retirements in collaboration with the ISO. They are concerned that this proposal conflicts with that authority. Management does not believe that there is a conflict. The ISO would pursue a CPM designation in such cases only after providing stakeholders its assessment of the reliability need for the resource and its determination that the resource is at risk of retirement, and an opportunity for the CPUC or a load-serving entity to enter a bilateral arrangement with the resource and thereby obviate the need for CPM procurement. The need identified by the ISO can thus be fully satisfied if the CPUC uses its existing provisions and authority to render a CPM designation unnecessary. If the CPUC does not, however, the ISO will have the needed backstop capability.

Selection Criteria for CPM and Exceptional Dispatch

Management's proposal includes other important new provisions that will refine the ISO's selection process of resources eligible to receive a CPM designation or an exceptional dispatch. When issuing a CPM designation, the ISO proposes to take into account the availability of the resource. Certain resource adequacy resources are deemed "use-limited resources" due to constraints on the amount of energy they can produce. Examples of such resources include hydro resources that are dependent on water availability and thermal generation units that are under emission limitations. Under the new provisions, the ISO proposes to select non-use-limited resources over use-limited resources. The non use-limited criterion is especially important for a CPM designation (or when an exceptional dispatch would trigger a CPM for non-resource adequacy capacity) because only non-use-limited resources are required to comply with the must-offer obligations of the tariff. Thus, if the ISO were to select a use-limited resource for a CPM, the ISO would have limited ability to commit and dispatch that resource over the CPM designation period. In addition, the ISO proposes to take into account the operational characteristics of the resource and select resources that best meet operational needs. Management believes that these proposed enhancements are warranted in light of the growing amount of intermittent capacity in the supply fleet to meet the state's renewable energy goals, changes to the grid resulting from transmission expansion, and the expected retirement of dispatchable resources under the once-through cooling regulations.

Other Key Features

A key feature of the proposal is the elimination of the ICPM sunset date. Management considers this a prudent course of action because the current tariff provisions have been working reasonably well, capacity procurements have been relatively infrequent, and such backstop procurement capability should always be available to the ISO. Additionally, the CPUC resource adequacy program is essentially unchanged and thus durable backstop provisions will continue to provide the same protections as before. Most stakeholders agree that maintaining this procurement mechanism on only an interim basis is no longer necessary.

Last, and receiving broad stakeholder support, capacity payments made to generators procured under the CPM will be prorated to take into account planned outages taken during the term of the CPM procurement.

POSITIONS OF THE PARTIES

Stakeholder Process

Between June and September 2010, the ISO conducted three stakeholder calls, one meeting and provided four opportunities to provide written comments. Client services also conducted outreach to stakeholders to gain additional insight into positions and areas of concern. Several stakeholders recommended that the ISO seek a formal opinion from the Market Surveillance Committee. In response, the Market Surveillance Committee led a discussion at its October 8 meeting and later adopted a formal opinion supporting Management's proposal. In addition, the CEC presented its cost of generation model and an overview of that model and the going-forward cost methodology at the

August 23 stakeholder meeting. A matrix of the elements of this proposal and stakeholders' positions on each of those elements is provided as Attachment A.

The Market Surveillance Committee's Opinion is provided as Attachment B.

The Department of Market Monitoring has also provided comments and is supportive of the ISO's proposal as explained in the Department of Market Monitoring market monitoring report that is included in this month's Board book.

Key issues of stakeholder concern

Capacity procurement mechanism compensation: Going-forward or cost of new entry

Issue: The generator community supports the cost of a new entry model, while the load serving entity sector supports the going-forward cost methodology.

Response: The ISO has been a proponent of cost of new entry in the context of a multi-year forward resource adequacy framework and a forward capacity market, but does not believe that cost of new entry is appropriate for backstop capacity procurement. Although the ISO is concerned with the ability of conventional generators needed to support the state's renewable energy goals to earn sufficient revenues, Management believes this is a matter that should be addressed in the separate, ongoing renewable integration market and product review initiative.

Compensating resources needed for reliability that are at risk of retirement

Issue: Stakeholders were generally dismissive of the ISO needing the authority to procure resources that are needed for reliability but are at risk of retirement. In particular, some stakeholders noted that the CPUC already has provisions to procure and compensate these resources, and that reliability must-run contracts can serve this purpose. In addition, some stakeholders argued that this type of CPM procurement would result in having capacity under a resource adequacy must-offer obligation in excess of the CPUC's preferred planning reserve margin.

Response: Expansion of the ISO's backstop procurement mechanism to address potential retirement of a unit needed for reliability within the next two years does not duplicate the CPUC's program, nor does it preclude the CPUC acting on its existing provisions and thereby obviating the need for the ISO to make a CPM designation. The ISO has committed to providing full information to market participants regarding the need for, and its intent to issue, a CPM for such a resource, and to allow an opportunity for the CPUC, one of its jurisdictional load-serving entities, or even a non-CPUC jurisdictional entity to enter an alternative arrangement with the resource prior to any CPM designation. The reliability must run contract is not a well suited alternative to CPM because the current reliability must run pro forma terms are designed narrowly for addressing local reliability and non-competitive constraints, and any expansion of applicability would require a lengthy stakeholder process to expand the applicability and develop a different cost allocation as well as individual negotiation of terms with each resource. The benefit of using the CPM for this situation is that it provides standard terms that can be simply and promptly applied when needed. Finally, with regard to concern about having excess capacity under the must-offer obligation, one potential mitigation is the opportunity noted above for the CPUC or the load-serving entities to procure the resource ahead of any CPM designation. In addition, the ISO can mitigate this concern under existing tariff provisions by allocating shares of the CPM capacity in the form of credits to load-serving entities to offset their monthly resource adequacy requirements.

Procurement authority for a sustained loss of intermittent energy

Issue: Some stakeholders argued that this use of CPM is not needed because the variability of wind and solar resource adequacy resources is already taken into account by the CPUC's counting rules for these resources, and if it happens that actual energy output falls significantly below the qualifying capacity determined by these rules, then the ISO should seek revision of the rules rather than perform backstop procurement.

Response: The sustained loss of intermittent capacity during peak periods has been documented and is a growing concern due to the increasing reliance on this type of resource. Although such occurrences could lead ultimately to revision of the resource adequacy capacity counting rules, the ISO must still manage any reliability impacts promptly when the problem arises. Similar to current backstop provisions, the ISO envisions using this authority rarely, but must be prepared to use it if needed.

MANAGEMENT RECOMMENDATION

Management requests Board approval of the capacity procurement mechanism and exceptional dispatch provisions as detailed in this memorandum. The benefits of implementing these provisions will ensure that the ISO has the necessary tools to address the challenges to maintaining grid reliability in the future. These provisions will complement the state's resource adequacy program without adding unnecessary costs, as the existing provisions have done to date.

Attachment F – Midwest ISO Tariff Section 38.2.7

Capacity Procurement Mechanism Amendment

California Independent System Operator Corporation

System Support Resource (SSR) procedures maintain system reliability by providing a mechanism for the Transmission Provider to enter into agreements with Market Participants that own or operate Generation Resources or Synchronous Condenser Units (SCUs) that are required by the Transmission Provider to maintain system reliability, if such Generation Resources or SCUs are uneconomic to remain in service and otherwise would be decommissioned, placed into extended reserve shutdown or disconnected from the Transmission Provider Region.

The SSR procedures include: (a) a requirement that any Market Participant planning to decommission, place into extended reserve shutdown or disconnect any Generation Resource or SCU located within the Transmission Provider Region must notify the Transmission Provider of such events by submitting a completed Attachment Y to the Transmission Provider documenting the proposed plans for such Generation Resource or SCU, at least twenty-six (26) weeks prior to taking such steps; (b) Market Participants must submit all necessary information to enable the Transmission Provider to evaluate whether SSR Unit status is appropriate for such Generation Resource or SCU; (c) if the Transmission Provider determines that SSR Unit status is justified for a Generation Resource or SCU, the Transmission Provider and such Market Participant shall enter into an SSR Agreement, in accordance with the Attachment Y-1 form of agreement; (d) the SSR Unit will be operated in accordance with the terms of the SSR Agreement, which contains detailed terms and conditions regarding operation and compensation of such Generation Resource or SCU; (e) costs to compensate an SSR Unit will be allocated to the Market Participants serving Load that benefits from the operation of the SSR Unit; and (f) the Transmission Provider shall annually review the reliability requirements of the Transmission Provider Region and shall determine which, if any, SSR Agreements should be extended. These SSR rules do not apply to Generation Resources and SCUs located outside the Transmission Provider Region.

a. SSR Unit Notification Procedures. A Market Participant shall complete and deliver to the Transmission Provider Attachment Y, Notification of Potential Generation Resource or SCU Change of Status, if a Market Participant plans to either: (i) decommission and retire a Generation Resource or a SCU that it either owns or operates; (ii) suspend operation of and place into extended reserve shutdown such Generation Resource or SCU for a period of more than two (2) months; or (iii) disconnect such Generation Resource or SCU from the Transmission System for a period of more than two (2) months. Attachment Y must be submitted to the Transmission Provider at least twenty-six (26) weeks prior to the Market Participant engaging in any of the aforementioned activities.

The Transmission Provider shall treat Attachment Y as Confidential Information, but the Transmission Provider will disclose the existence of an Attachment Y-1 form of SSR Agreement upon execution of any such agreement. Attachment Y must (i) state that the Generation Resource or SCU owner's decision is definite; (ii) describe the type of shutdown which will affect the Generation Resource or SCU (*i.e.,* permanent retirement, placing into extended reserve shutdown, seasonal shutdown, etc.); (iii) identify the expected duration of the shutdown; and (iv) describe the time period that would be required to return the Generation Resource or SCU to service if the Market Participant proceeds with the shutdown of the Generation Resource or SCU.

A Market Participant that asserts that a Generation Resource or SCU will be decommissioned, placed into extended reserve shutdown, or disconnected from the

Transmission Provider Region will have Attachment Y executed by an executive officer of the owner or operator of the Generation Resource or SCU attesting to the facts supporting that claim, who has the legal authority to bind such entity.

b. Evaluation of SSR Unit Application. Before entering into an SSR Agreement with any Generation Resource or SCU, the Transmission Provider shall assess feasible alternatives to the proposed SSR Agreement. The Transmission Provider will determine whether the Generation Resource or SCU is necessary for system reliability based on the criteria set forth in the Business Practices Manuals. The Transmission Provider shall post the criteria upon which it evaluates whether an SSR Unit meets the test of operational necessity to ensure that the Transmission System is operated reliably. The list of alternatives that the Transmission Provider shall consider include (as reasonable for each type of reliability concern identified): (i) redispatch/reconfiguration through operator instruction; (ii) remedial action plans; (iii) special protection schemes initiated on Generation Resource trips or unplanned Transmission Outages; and (iv) demand response alternatives. The Market Participant that owns or operates the Generation Resource or SCU subject to review under this section shall provide the Transmission Provider with all necessary data, including but not limited to, financial, engineering, economic and operating data, required to enable the Transmission Provider to evaluate whether such Generation Resource or SCU meets the aforementioned criteria. The Transmission Provider will provide to all Market Participants that are LSEs or purchase Energy and/or Operating Reserve to serve LSEs potentially impacted by the SSR Unit designation with the non-economic information relative to the use of an SSR Unit including Energy and/or Operating Reserve deployed if an SSR Agreement is executed.

c. Execution of SSR Agreement. The Transmission Provider shall enter into an SSR Agreement with the Market Participant owning or operating an SSR Unit in accordance with Attachment Y-1. During the period that a Generation Resource or SCU is subject to an executed Attachment Y-1 agreement, it shall qualify as an SSR Unit. SSR service is a contracted service between the Market Participant that owns or operates an SSR Unit and the Transmission Provider and shall be for an initial term of twelve (12) months, unless exigent circumstances require a longer term agreement. The Attachment Y-1 agreement will be filed with the Commission. The Transmission Provider must have available the entire Capacity of each SSR Unit.

d. Operation of SSR Unit. Once the Transmission Provider has entered into an SSR Agreement with a Generation Resource or SCU, the Transmission Provider shall have the right to dispatch the SSR Unit at any time for reliability of the facilities within the Transmission Provider Region. The Transmission Provider shall make every attempt to minimize the use of an SSR Unit. The Transmission Provider will dispatch the SSR Unit as early as possible once conditions are identified that require the use of the SSR Unit and will make best efforts to minimize the uneconomic dispatch of the SSR Unit(s). The SSR Agreement found in Attachment Y to this Tariff shall provide for equitable compensation to an SSR Unit when it is dispatched for reliability purposes by the Transmission Provider.

e. Scheduling Rules for SSR Units. No later than 1000 hours EST the day prior to the Operating Day, the Transmission Provider shall notify Market Participants with SSR Units as to the quantity (in MW and/or MVAR) and time period of Energy, Operating Reserve and/or Other Ancillary Services required from each SSR Unit.

f. SSR Unit Participation in Markets. A Market Participant may offer Capacity from SSR Units in the Day-Ahead Energy and Operating Reserve Market, RAC or Real-Time Energy and Operating Reserve Market during times when the Transmission Provider has requested the Market Participant to run the SSR Unit at less than full Capacity unless this would impair the ability of the SSR Unit to provide the Energy, Operating Reserve or Other Ancillary Services requested by the Transmission Provider.

Market Participants that own or operate an SSR Unit shall not use the SSR Unit to: (i) participate in Interchange Schedules; (ii) except as otherwise provided in Section 38.2.6.d.i, and except for plant auxiliary Load obligations under the SSR Agreement, use the SSR Unit as a Self-Scheduled Resource to submit Self-Schedules for Energy and/or Operating Reserve; (iii) submit Self-Schedules for Other Ancillary Services, if applicable, to the extent that Other Ancillary Services are required by the Transmission Provider under this Section; and (iv) participate in the Energy and Operating Reserve Markets, except for incremental Offers of additional Capacity beyond the amount designated by the Transmission Provider as necessary for reliability purposes to the extent allowed in the SSR Agreement.

g. SSR Unit Compensation.

i. The Transmission Provider will determine appropriate compensation for the Market Participant owning the Generation Resources or SCUs deemed to be SSR Units based on the determination made in accordance with Section 38.2.7.b above. Prior to the execution of the SSR Agreement the Transmission Provider will negotiate with the Market Participant to determine an appropriate level of compensation due the Market Participant for a period of one (1) year to defer the Market Participant's decision to decommission, place into extended reserve shutdown, or retire the Generation Resource or SCU. The Market Participant will receive appropriate compensation for the entire period of time the Generation Resource or SCU is required as an SSR Unit.

ii. In assessing the compensation provisions to be included in the Attachment Y-1, the Transmission Provider will require the following data from the Market Participant regarding the SSR Unit: gross book cost, acquisition cost adjustments, intangible plant values, tax payments, administration and general expenses, salvage value, depreciation, amortization of interconnection rights, and lease costs.

iii. The Transmission Provider will evaluate the following factors in negotiating the SSR Unit compensation: (i) fixed operating and maintenance costs; (ii) applicable state, federal or property taxes; and (iii) costs of repairs or upgrades needed to meet applicable environmental regulations or local operating permit requirements. Any compensation to the SSR Unit will be reduced by expected debits under Schedule 2 of this Tariff, expected payments under Resource adequacy programs, and expected revenue from Energy and Operating Reserve Market transactions. The negotiated compensation between the Transmission Provider and the SSR Unit will be filed with the Commission as specified in the executed Attachment Y-1.

h. Allocation of SSR Unit Costs. The costs of operating an SSR Unit plus any other payments made pursuant to the SSR contract shall be allocated on a *prorata* basis to the Market Participants serving Load as an LSE or on behalf of an LSE in the Local Balancing Authority Area(s) which requires the operation of the SSR Unit for reliability purposes. For the purposes of this Section, any SSR Unit located within the footprint of the American

Transmission Company shall be allocated to all Market Participants within the footprint of the American Transmission Company on a *pro rata* basis.

i. Annual Review of SSR Unit Status. On an annual basis, the Transmission Provider will review Generation Resource or SCU characteristics to determine whether the Generation Resource or SCU is qualified to remain as an SSR Unit in coordination with a review of the Transmission Provider's annual regional transmission expansion plan in Section 38.2.6.b. If so, the Transmission Provider will enter into a subsequent SSR Agreement at least ninety (90) days prior to the termination date of the existing SSR Agreement. If not, the SSR Agreement will expire by its own terms and the Generation Resource or SCU will lose its SSR Unit status and will be decommissioned, placed into extended reserve shutdown or disconnected from the Transmission Provider Region by the Market Participant.

Attachment G – PJM Tariff Part V

Capacity Procurement Mechanism Amendment

California Independent System Operator Corporation

V. GENERATION DEACTIVATION

References to section numbers in this Part V refer to sections of this Part V, unless otherwise specified.

Preamble:

Deactivation of generating units in the PJM Region shall be governed by this Part V of this Tariff.

Effective Date: 9/17/2010

113 Notices

113.1 Generation Owner Notice:

When a Generation Owner desires to deactivate a generating unit located in the PJM Region, such Generation Owner, or its Designated Agent, must provide notice of such proposed Deactivation in writing to the Transmission Provider no later than 90 days prior to the proposed Deactivation Date for the generating unit. This notice shall include an indication of whether the generating unit is being retired or mothballed, the desired Deactivation Date, and a good faith estimate of the amount of any project investment and the time period the generating unit would be out of service for repairs, if any, that would be required to keep the unit in, or return the unit to, operation. PJM shall promptly provide a copy of such notice to the Market Monitoring Unit.

113.2 Notice of Reliability Impact:

Within 30 days of the receipt of the Generation Owner's notice pursuant to section 113.1 of this Tariff, the Transmission Provider shall inform Generation Owner, or its Designated Agent, whether the Deactivation of the generating unit would adversely affect the reliability of the Transmission System. In the event there are no reliability issues associated with the proposed Deactivation of the generating unit, Transmission Provider shall so notify Generation Owner, or its Designated Agent, and the Generation Owner or its Designated Agent may deactivate its generating unit at any time thereafter. The Generation Owner shall coordinate with the appropriate Transmission Owner and the Transmission Provider regarding the removal of any transmission equipment located at the generating unit proposed for Deactivation. In the event the Transmission Provider determines that, in accordance with established reliability criteria, the Deactivation of Generation Owner's generating unit would adversely affect the reliability of the Transmission System absent upgrades to the Transmission System, it shall notify the Generation Owner, or its Designated Agent, of the reliability concerns. Such notice shall (1) identify the specific reliability impact resulting from the proposed Deactivation of the generating unit; and (2) provide an initial estimate of the period of time it will take to complete the Transmission System reliability upgrades necessary to alleviate the reliability impact. Regardless of whether the Deactivation of the generating unit would adversely affect the reliability of the Transmission System, the Generation Owner or its Designated Agent may deactivate its generating unit, subject to the notice requirements in section 113.1 of this Tariff. Within 60 days of Generation Owner's or its Designated Agent's notice pursuant to section 113.1 of this Tariff, the Generation Owner or its Designated Agent shall inform Transmission Provider whether the generating unit proposed for Deactivation will continue operating beyond its desired Deactivation Date during the period of construction of the Transmission System reliability upgrades necessary to alleviate the reliability impact resulting from the Deactivation of the generating unit, and if the generating unit will continue operating, provide the Transmission Provider with an updated estimate of the amount of any project investment and the time period the generating unit would be out of service for repairs, if any, that would be required to keep the unit in, or return the unit to, operation. For generating units that will continue operating beyond their desired Deactivation Dates, Transmission Provider shall (a) within 75 days of Generation Owner's or its Designated Agent's notice pursuant to section 113.1 of this Tariff, provide an updated estimate of the period of time it will take to complete the Transmission System upgrades necessary to alleviate the reliability impact; and (b) within 90 days of Generation Owner's or its Designated Agent's notice pursuant to section 113.1 of this Tariff, post on its internet site full details of the transmission upgrades necessary to alleviate the reliability impact that would result from the Deactivation of the generating unit. Upon receipt of notification from the Transmission Provider that Deactivation of the generating unit would cause reliability concerns, the Generation Owner shall immediately be entitled to file with the Commission a cost of service rate to recover the entire cost of operating the generating unit until such time as the generating unit is deactivated pursuant to this Part V ("Cost of Service Recovery Rate"). In the alternative, the Generation Owner may elect to receive the Deactivation Avoidable Cost Credit provided under this Part V.

113.3 Subsequent Deactivation Notice for Generating Units Continuing to Operate:

In the event that a Generation Owner or its Designated Agent, which has informed Transmission Provider pursuant to section 113.2 that a generating unit will continue operating, desires to deactivate such generating unit prior to the completion date of the Transmission System reliability upgrades necessary to alleviate the reliability impact resulting from the Deactivation of the generating unit, or the date that the Transmission Provider otherwise determines, in accordance with established reliability criteria, that the continued operation of the generating unit is no longer necessary for the reliability of the Transmission System, the Generation Owner or its Designated Agent shall provide notice of such proposed Deactivation in writing to the Transmission Provider no later than 90 days prior to the desired Deactivation Date for the generating unit.

Effective Date: 9/17/2010

114 Deactivation Avoidable Cost Credit:

In the event that the Generation Owner or its Designated Agent informs Transmission Provider pursuant to section 113.2 that it will continue operating a generating unit beyond its desired Deactivation Date, the Generation Owner or its Designated Agent shall receive a monthly Deactivation Avoidable Cost Credit for such continued operation pursuant to the terms and conditions of this section 114.

Subject to section 119 of this Tariff, a Generation Owner or its Designated Agent shall be eligible for Deactivation Avoidable Cost Credits commencing on the later of the proposed Deactivation Date of its generating unit or the day after the Generation Owner or its Designated Agent submits the informational filing pursuant to section 116 of this Tariff and continuing until the earlier of such time as the generating unit is deactivated or the completion date of the necessary

Transmission System reliability upgrades that would alleviate the reliability impact resulting from the Deactivation of the generating unit, or the Transmission Provider otherwise determines, in accordance with established reliability criteria, that the continued operation of the generating unit is no longer necessary for the reliability of the Transmission System. The Transmission Provider shall give at least thirty days notice to a Generation Owner or its Designated Agent of the date when continued operation of a generating unit is no longer required under Part V of the Tariff.

Deactivation Avoidable Cost Credits shall be determined according to the following formula:

Deactivation Avoidable Cost Credit = ((Deactivation Avoidable Cost Rate + Applicable Adder) * MW capability of the unit * Number of days in the month) – Actual Net Revenues

Where:

Deactivation Avoidable Cost Rate is the Generation Owner's Deactivation Avoidable Cost Rate determined pursuant to section 115 of this Tariff.

Applicable Adder is the appropriate adder specified below:

First Year Adder: 10 percent of the Generation Owner's Deactivation Avoidable Cost Rate. This adder shall apply commencing on the desired Deactivation Date of the generating unit proposed for Deactivation and for the 12 months thereafter.

Second Year Adder: 20 percent of the Generation Owner's Deactivation Avoidable Cost Rate. This adder shall apply commencing on the first day of the 13th month after the desired Deactivation Date of the generating unit proposed for Deactivation and for the 12 months thereafter.

Third Year Adder: 35 percent of the Generation Owner's Deactivation Avoidable Cost Rate. This adder shall apply commencing on the first day of the 25th month after the desired Deactivation Date of the generating unit proposed for Deactivation and for the 12 months thereafter.

Fourth Year Adder: 50 percent of the Generation Owner's Deactivation Avoidable Cost Rate. This adder shall apply commencing on the first day of the 37th month after the desired Deactivation Date of the generating unit proposed for Deactivation and until the earlier of such time as the generating unit is deactivated or the completion date of the necessary Transmission System reliability upgrades that would alleviate the reliability impact resulting from the Deactivation of the generating unit, or the Transmission Provider otherwise determines, in accordance with established reliability criteria, that the continued operation of the generating unit is no longer necessary for the reliability of the Transmission System.

If the Generation Owner, or its Designated Agent, provides the Transmission Provider with notice pursuant to section 113.1 of this Tariff 180 days prior to the proposed Deactivation Date of the generating unit, the First Year Adder will be increased to 14 percent of the Generation Owner's Deactivation Avoidable Cost Rate. For each additional 30 days notice greater than 180 days, the First Year Adder will increase by 1 percent of the Generation Owner's Deactivation Avoidable Cost Rate, up to a maximum of 20 percent for 12 months notice or greater.

(Deactivation Avoidable Cost Rate + Applicable Adder) is expressed in $/MW day.

Actual Net Revenues are all revenues from PJM markets and unit-specific bilateral contracts net of marginal cost of service recoverable under cost-based offers to sell energy from operating capacity on the PJM Interchange Energy Market under the Operating Agreement, not less than zero.

Deactivation Avoidable Cost Credit shall not be less than zero. If at any time, the Deactivation Avoidable Cost Rate + Applicable Adder, expressed in $/MW day, exceeds the Daily Capacity Deficiency Rate, the Generation Owner shall be credited the Daily Capacity Deficiency Rate multiplied by the generating unit's MW capability, less any Actual Net Revenues.

The Market Monitoring Unit and the generating unit owner shall attempt to come to agreement on the appropriate level of each component included in the Deactivation Avoidable Cost Credit. If a generating unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost components, the Market Monitoring Unit may petition the Commission for an order that would require the generating unit owner to include an appropriate cost component. This provision is duplicated in section IV.2 of Attachment M – Appendix.

Effective Date: 9/17/2010

115 Deactivation Avoidable Cost Rate:

The Deactivation Avoidable Cost Rate for a generating unit proposed for Deactivation shall be determined using the following formula:

Deactivation Avoidable Cost Rate = ((AOML + AAE + AME + AVE + ATFI + ACC + ACLE) / 12) +APIR

Where:

- **AOML (Avoidable Operations and Maintenance Labor)** consists of the avoidable labor expenses related directly to operations and maintenance of the generating unit proposed for Deactivation for the twelve months preceding the Generation Owner's notice pursuant to section 113.1 of this Tariff. The categories of expenses included in AOML are those incurred for: (a) on-site based labor engaged in operations and maintenance activities; (b) off-site based labor engaged in on-site operations and maintenance activities directly related to the generating unit; and (c) off-site based labor engaged in off-site operations and maintenance activities directly related to generating unit equipment removed from the generating unit site.

- **AAE (Avoidable Administrative Expenses)** consists of the avoidable administrative expenses related directly to employees at the generating unit proposed for Deactivation for twelve months preceding the Generation Owner's notice pursuant to section 113.1 of this Tariff. The categories of expenses included in AAE are those incurred for: (a) employee expenses (except employee expenses included in AOML); (b) environmental fees; (c) safety and operator training; (d) office supplies; (e) communications; and (f) annual plant test, inspection and analysis.

- **AME (Avoidable Maintenance Expenses)** consists of avoidable maintenance expenses (other than expenses included in AOML) related directly to the generating unit proposed for Deactivation for the twelve months preceding the Generation Owner's notice pursuant to section 113.1 of this Tariff. The categories of expenses included in AME are those incurred for: (a) chemical and materials consumed during maintenance of the generating unit; and (b) rented maintenance equipment used to maintain the generating unit.

- **AVE (Avoidable Variable Expenses)** consists of avoidable variable expenses related directly to the generating unit proposed for Deactivation incurred in the twelve months preceding the Generation Owner's notice pursuant to section 113.1 of this Tariff. The categories of expenses included in AVE are those incurred for: (a) water treatment chemicals and lubricants; (b) water, gas, and electric service (not for power generation); and (c) waste water treatment.

- **ATFI (Avoidable Taxes, Fees and Insurance)** consists of avoidable expenses related directly to the generating unit proposed for Deactivation incurred in the twelve months preceding the Generation Owner's notice pursuant to section 113.1 of this Tariff. The categories of expenses included in AFTI are those incurred for: (a) insurance; (b) permits and licensing fees; (c) site security and utilities for maintaining security at the site; and (d) property taxes.

- **ACC (Avoidable Carrying Charges)** consists of avoidable short term carrying charges related directly to the generating unit proposed for Deactivation in the twelve months preceding the Generation Owner's notice pursuant to section 113.1 of this Tariff. Avoidable short term carrying charges shall include short term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC, short term is the time period in which a reasonable replacement of inventory for normal, expected operations can occur.

- **ACLE (Avoidable Corporate Level Expenses)** consists of avoidable corporate level expenses directly related to the generating unit proposed for Deactivation incurred in the twelve months preceding the Generation Owner's notice pursuant to section 113.1 of this Tariff. Avoidable corporate level expenses shall include only such expenses that are directly linked to providing tangible services required for the operation of the generating unit proposed for Deactivation. The categories of avoidable expenses included in ACLE are those incurred for: (a) legal services; (b) environmental reporting; and (c) procurement expenses.

- **APIR (Avoidable Project Investment Recovery Rate)** = PI/NMR

Where:

PI is the amount of project investment required to enable a generating unit proposed for Deactivation to continue operating beyond its proposed Deactivation Date.

NMR is the number of months beyond the proposed Deactivation Date of a generating unit proposed for Deactivation that the Transmission Provider has specified in its updated estimate pursuant to section 113.2 of this Tariff that such generating unit shall be required to operate.

PI recovered through the APIR, shall not commence before the in-service date of the PI. The amount recovered through the APIR shall not exceed the actual amount of the PI, and in no event shall recovery through the APIR exceed $2 million.

For the purpose of determining Deactivation Avoidable Cost Rate, avoidable expenses are incremental expenses directly required for the operation of a generating unit proposed for Deactivation that a Generation Owner would not incur if such generating unit deactivated on its proposed Deactivation Date rather than continuing to operate beyond its proposed Deactivation Date. A generating unit owner shall direct all inquiries regarding avoidable expenses to the Market Monitoring Unit.

For the purpose of determining a Deactivation Avoidable Cost Rate, avoidable expenses shall exclude variable costs recoverable under cost-based offers to sell energy from operating capacity on the PJM Interchange Energy Market under the Operating Agreement.

Effective Date: 9/17/2010

116 Filing and Updating of Deactivation Avoidable Cost Rate:

As of the proposed Deactivation Date of a generating unit or as of the day prior to the effective date of an updated Deactivation Avoidable Cost Rate, the Generation Owner or its Designated Agent shall file with the Commission, for informational purposes, the Deactivation Avoidable Cost Rate, along with applicable cost support and a certification by an officer of the Generation Owner or its Designated Agent attesting to the accuracy of the Deactivation Avoidable Cost Rate. Generation Owner or its Designated Agent may update the Deactivation Avoidable Cost Rate annually, as well as, following materially adverse unforeseen circumstances affecting the unit that increase the costs incurred by the Generation Owner. Generation Owner, or its Designated Agent, shall provide Transmission Provider with a copy of informational filings submitted pursuant to this section 116. Crediting of the Deactivation Avoidable Cost Credit to the Generation Owner or its Designated Agent by the Transmission Provider shall commence on the later of the day following the date of this informational filing or the proposed Deactivation Date of the Generation Owner’s generating unit.

Effective Date: 9/17/2010

117 Excess Project Investment Required:

In the event that a Generation Owner has informed Transmission Provider pursuant to section 113.2 that a generating unit will continue operating beyond its desired Deactivation Date, but such generating unit cannot continue to operate without PI, as defined in the APIR set forth in section 115 of this Tariff, that exceeds the limit for recovery of PI specified in the APIR, the Generation Owner, or its Designated Agent, may file a rate with the Commission to recover the PI in excess of the permissible limit for recovery of PI through the APIR. Prior to PI in excess of the recovery limit set forth in the APIR being made, the need for such PI shall be verified by an independent third party retained by the Generation Owner, or its Designated Agent, and provided to the Transmission Provider. Transmission Provider shall credit Generation Owner the amount of such rate commencing on the effective date established by the Commission for the rate.

Effective Date: 9/17/2010

118 Refund of Project Investment Reimbursement:

In the event that the Generation Owner's PI in the generating unit proposed for Deactivation and credited either under section 117 of this Tariff or through the APIR set forth in section 115 of this Tariff enables the generating unit to remain operational beyond the completion date of the necessary Transmission System reliability upgrades that would alleviate the reliability impact resulting from the Deactivation of the generating unit, or the date that the Transmission Provider otherwise determines, in accordance with established reliability criteria, that the continued operation of the generating unit is no longer necessary for the reliability of the Transmission System, and the generating unit remains in service beyond such date, the Generation Owner or its Designated Agent shall refund Transmission Provider a pro-rata share of the amount of any PI for which it received reimbursement pursuant to section 117 and/or the APIR set forth in section 115 of this Tariff. The Refund of Project Investment Reimbursement shall be determined using the following formula:

Refund of Project Investment Reimbursement = ((Number of months the PI permits the generating unit proposed for Deactivation to operate – The number of months Transmission Provider determines is required to construct the Transmission System reliability upgrades necessary to alleviate the reliability impact resulting from the Deactivation of the generating unit) / (Number of months the PI permits the generating unit proposed for Deactivation to operate)) * (The amount of the PI/ (Number of months the PI allows the generating unit proposed for Deactivation to continue to operate past the completion date of the necessary Transmission System reliability upgrades that would alleviate the reliability impact resulting from the Deactivation of the generating unit, or the date that the Transmission Provider otherwise determines, in accordance with established reliability criteria, that the continued operation of the generating unit is no longer necessary for the reliability of the Transmission System)).

Where:

The number of months the PI permits the generating unit proposed for Deactivation to operate is determined by the Generation Owner or its Designated Agent and verified by an independent entity.

Generation Owner or its Designated Agent shall make the Refund of Project Investment Reimbursement each month for the number of months the PI allows the generating unit proposed for Deactivation to continue to operate past the completion date of the necessary Transmission System reliability upgrades that would alleviate the reliability impact resulting from the Deactivation of the generating unit, or the date that the Transmission Provider otherwise determines, in accordance with established reliability criteria, that the continued operation of the generating unit is no longer necessary for the reliability of the Transmission System and shall be credited to transmission customers in such month on the same basis as costs are allocated under section 120. The months the generating unit proposed for Deactivation continues to operate past the completion date of the necessary Transmission System reliability upgrades that would alleviate the reliability impact resulting from the Deactivation of the generating unit, or the date that the Transmission Provider otherwise determines, in accordance with established reliability criteria, that the continued operation of the generating unit is no longer necessary for the reliability of the Transmission System need not be continuous, and the Refund of Project Investment Reimbursement will continue regardless of ownership of the generating unit.

Effective Date: 9/17/2010

118A Recovery of Project Investment:

A Generation Owner or its Designated Agent shall be entitled to continue to recover its PI costs under section 115 and/or section 117 of this Tariff in situations where the Transmission Provider subsequently determines the generation unit is no longer needed for reliability of the Transmission System and the generating unit is deactivated prior to recovering its PI costs; provided however, that any PI cost recovery pursuant to this section shall be net of any PI reimbursements already credited to the Generation Owner to its Designated Agent pursuant to section 117 and/or the APIR set forth in section 115 of this Tariff.

Effective Date: 9/17/2010

119 Cost of Service Recovery Rate:

Notwithstanding anything to the contrary in Part V of this Tariff, a Generation Owner with a generating unit proposed for Deactivation that continues operating beyond its proposed Deactivation Date may file with the Commission a cost of service rate to recover the entire cost of operating the generating unit until such time as the generating unit is deactivated pursuant to this Part V ("Cost of Service Recovery Rate"). In the event that the Generation Owner or its Designated Agent files a rate pursuant to this section 119, the Generation Owner shall not be eligible to receive Deactivation Avoidable Cost Credits or any compensation pursuant to section 117 of this Tariff, except as provided pursuant to this section 119, and Transmission Provider shall pay the Generation Owner the Cost of Service Recovery Rate accepted by the Commission commencing on the effective date established by the Commission for the rate. In the event the Generation Owner or its Designated Agent already is receiving Deactivation Avoidable Cost Credits, prior to filing an Cost of Service Recovery Rate, such Deactivation Avoidable Cost Credits will cease as of the date that the Generation Owner or its Designated Agent files its Cost of Service Recovery Rate, and the Transmission Provider shall begin paying the Generation Owner or its Designated Agent the Cost of Service Recovery Rate accepted by the Commission commencing on the effective date established by the Commission for the rate. In the event the Generation Owner or its Designated Agent already is receiving compensation pursuant to section 117 of this Tariff, prior to filing an Cost of Service Recovery Rate, such compensation shall continue until the effective date established by the Commission for the Cost of Service Recovery Rate.

A generating resource owner shall direct all inquiries regarding avoidable expenses to the Market Monitoring Unit. If a generating resource owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost components, the Market Monitoring Unit may petition the Commission for an order that would require the generating resource owner to include an appropriate cost component. This provision is duplicated in section IV.2 of Attachment M – Appendix.

Effective Date: 9/17/2010

120 Cost Allocation:

The costs incurred to compensate Generation Owners pursuant to this Part V of this Tariff shall be an additional transmission charge allocated to the load in the Zone(s) of the Transmission Owner(s) that will be assigned financial responsibility for the reliability upgrades necessary to alleviate the reliability impact that would result from the Deactivation of the generating unit and this new charge shall be collected monthly from such loads in addition to all other charges for transmission service to such loads.

Effective Date: 9/17/2010

121 Performance Standards:

A generating unit proposed for Deactivation that continues to operate for reliability beyond its desired Deactivation Date pursuant to Part V of the Tariff shall continue to be operated according to existing standards applicable to generating units located in the PJM Region.

Effective Date: 9/17/2010

122 Black Start Units:

Nothing in this Part V of the Tariff relieves owners of Black Start Units of any obligations or requirements set forth in Schedule 6A of the Tariff, including (a) the two year rolling commitment to provide Black Start Service; (b) the notice requirements for terminating such commitment; or (c) the forfeiture of Black Start Service revenues for failure to fulfill such commitment.

Effective Date: 9/17/2010

Attachment H – CEC Report

Capacity Procurement Mechanism Amendment

California Independent System Operator Corporation

CALIFORNIA
ENERGY
COMMISSION

COMPARATIVE COSTS OF CALIFORNIA CENTRAL STATION ELECTRICITY GENERATION

FINAL STAFF REPORT

January 2010
CEC-200-2009-07SF

Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

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Abstract

The 2009 *Comparative Cost of California Central Station Electricity Generation Technologies Report* updates the levelized cost of generation estimates that were prepared for the *2007 Integrated Energy Policy Report* (*IEPR*). The California Energy Commission staff provides revised levelized cost estimates, including the cost assumptions for 21 central station generation technologies: 6 gas-fired, 13 renewable, nuclear, and coal-integrated gasification combined cycle. All levelized costs are developed using the Energy Commission's Cost of Generation Model. The levelized costs are useful for evaluating the financial feasibility of a generation technology and comparing the cost of one particular energy technology with another.

The analysis presented in the report is an improvement over the 2007 report in five ways. First, the staff presents a range of cost estimates (low, medium, and high) that can be expected for each of these technologies. The calculated range will allow users to consider the associated risks and uncertainties that may affect project development. Second, the staff examined the variables that may change in the future to develop a range of forward levelized cost estimates—a shortcoming identified in the *2007 IEPR*. Third, the model now calculates levelized costs using a cash-flow accounting method for merchant projects, instead of the revenue requirement approach that was used for the *2007 IEPR*. The revenue requirement accounting method can overstate the cost of merchant alternative technologies by as much as 30 percent. Fourth, the staff estimates transmission transaction costs and the cost of transmission to the first point of interconnection. Fifth, the model has the option to carry forward taxes to the following years in addition to the traditional option to take taxes in the current year. This option is used herein for the high-cost case.

Keywords: Cost of Generation, cost of electrical generation, cost of wholesale electricity, levelized costs, instant cost, overnight cost, installed cost, fuel cost, forecasting natural gas prices, fixed operation and maintenance, variable O&M, heat rate, technology, annual, alternative technologies, renewable technologies, combined cycle, simple cycle, combustion turbine, integrated gasification, coal, fuel, natural gas, nuclear fuel, heat rate degradation, capacity degradation, financial variables, capital structure, cost of capital, cost of debt, debt period, cost of equity, corporate taxes, tax benefits, depreciation period, tax credits, merchant, IOU, POU, and CPUC

Executive Summary

The goal of the staff levelized cost of generation project is to have a single set of the most current levelized cost estimates and supporting data that would contribute to energy program studies at the California Energy Commission (Energy Commission) and other state agencies. The levelized cost of a resource represents a constant cost per unit of generation that is commonly used to compare one unit's generation cost with other resources over similar periods. These levelized costs are useful for comparing the financial feasibility of different electricity generation technologies. Since most studies involving new generation or transmission require an assessment of the comparative cost of generation for various generation technologies, the data provided in this report is essential for any resource planning study.

There are numerous studies that provide levelized cost estimates for individual generation technologies, but it is difficult to compare the merits of these different estimates without understanding the underlying assumptions. Since plant characteristics, capital costs, plant operations, financing arrangements, and tax assumptions can vary, different assumptions will produce significantly different levelized cost estimates. It is, therefore, important to have a consistent set of assumptions to be able to compare the merits of each generation technology.

The *2009 Comparative Cost of California Central Station Electricity Generation Technologies Report* updates the levelized cost of generation estimates that were prepared for the *2007 Integrated Energy Policy Report* (*IEPR*). The Energy Commission staff retained the services of KEMA, Inc., to derive a set of cost drivers for renewable, coal-integrated gasification combined cycle, and nuclear generation technologies.[1] Consultants from Aspen provided the cost assumptions for natural gas generation and assisted in the development of the modeling. The Energy Commission staff used the generation technology characterizations to update the levelized cost estimates for plants that may be developed by merchants, investor-owned utilities (IOUs), and publicly owned utilities (POUs). The average levelized cost of generation results for projects starting in 2009 are summarized in **Table 1** and **Figure 1.**[2]

Merchant facilities are plants financed by private investors and sell electricity to the competitive wholesale power market. IOU plants are built by the utility and are typically less expensive than merchant facilities due to lower financing costs. However, there appear to be instances where IOU construction costs are higher. Furthermore, some merchant renewable technology plants, such as solar units, can be less expensive due to the effect of cash-flow financing with tax benefits. The POU plants are, in general, the least expensive

[1] The characterization of the different generation technologies and supporting documentation are presented in a Public Interest Energy Research (PIER) interim project report prepared by KEMA, Inc., *Renewable Energy Cost of Generation Update* (CEC-500-2009-084), July 2009.

[2] Nuclear Westinghouse AP1000, ocean-wave, and offshore wind technologies are assumed to not be viable in California until about 2018. Tables and figures for 2009 exclude these technologies.

because of lower financing costs and tax exemptions. As shown in the table and figure, POUs can build and operate a simple cycle power plant at less than one-half the cost of either of the other two developers. However, where tax benefits are large, as in the early years of this study, a merchant or IOU can build and operate a renewable technology power plant at a lower cost than the POU.

In this report, the Energy Commission staff incorporates two directives from the *2007 IEPR* and the *2008 Update Report*. First, staff now provides a range of levelized cost estimates, illustrated in **Figure 2**. These ranges reflect not only the wide array of various component costs and operational factors, such as capacity factor, but also the cost of financing and the unpredictability of future tax benefits. This figure shows that the range of costs of a technology can be more significant than the differences in average costs between generation technologies. Looking at this figure it is difficult to know for sure which of the first 13 technologies is the least costly. These large ranges demonstrate that choosing one set of assumptions leading to a point estimate of levelized cost value may not reflect actual market dynamics and possible range of costs when evaluating resource development options. The uncertainty of these costs also implies that other factors, such as environmental impact and system diversity, should be prominent considerations in system planning.

The high values and wide ranges of the simple cycle units deserve special explanation. The high cost of these units reflect their extensive use as peaking units and, as such, are not comparable to the other load-following and base load units. The wide cost ranges for the conventional simple cycle units primarily reflect the variation in potential capacity factors, which emphasizes the importance of applying reasonable operating levels for estimating levelized costs. The wide range of the hydroelectric units reflects the unusually large variation in capital costs of the various potential hydro projects.

The other IEPR directive was to determine the long-term changes in cost variables that determine levelized cost, the most significant of which is instant cost. Instant cost, sometimes referred to as *overnight cost*, is the initial capital expenditure. **Figure 3** summarizes staff's long-term projection of instant costs in real 2009 dollars. Most of the units have little or no expected improvement in terms of real cost over the 20-year period except for two of the renewable technologies that are important to California's resource development, wind and solar, which show a significant cost decline. Solar photovoltaic, which has seen cost reductions since the *2007 IEPR*, is projected to show the most improvement of all the technologies, bringing its capital cost within range of the gas-fired combined cycle units near the end of the study period.

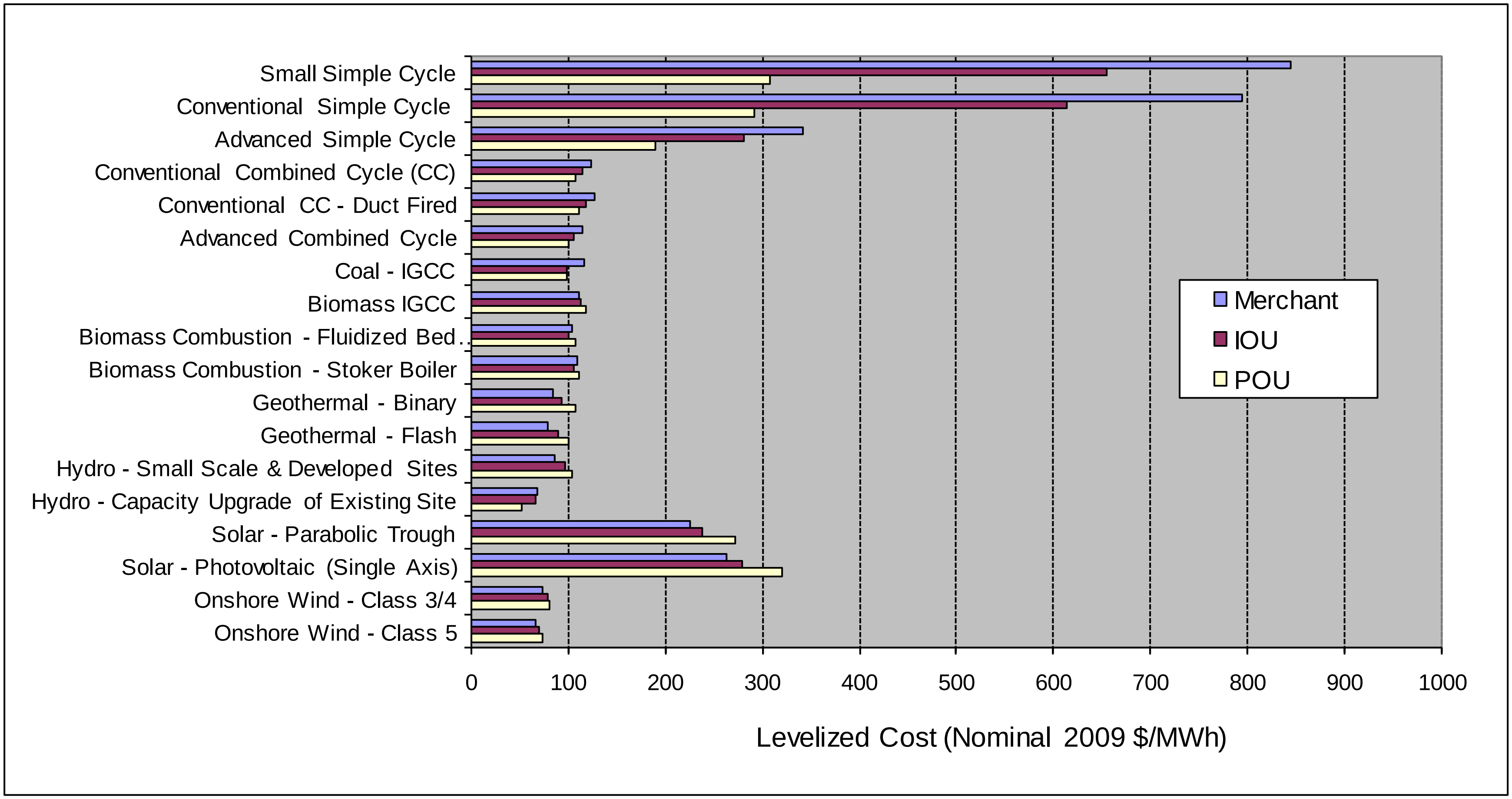
The effect of instant cost on levelized cost depends on the complicated and unpredictable assumptions of financing, operational costs and, most importantly, tax credits. Tax credits are both complicated and uncertain and are discussed within the main body of the report. The uncertainty of these assumptions can change the levelized costs dramatically.

Table 1: Summary of Average Levelized Costs—In-Service in 2009

In-Service Year = 2009 (Nominal 2009 $)	Size	Merchant			IOU			POU		
	MW	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh
Small Simple Cycle	49.9	346.91	844.31	84.43	269.31	655.69	65.57	252.90	308.01	30.80
Conventional Simple Cycle	100	326.51	794.67	79.47	252.53	614.84	61.48	239.02	291.10	29.11
Advanced Simple Cycle	200	280.91	341.84	34.18	230.86	281.03	28.10	234.37	190.29	19.03
Conventional Combined Cycle (CC)	500	758.01	123.84	12.38	701.17	114.76	11.48	657.95	107.91	10.79
Conventional CC - Duct Fired	550	727.66	127.38	12.74	670.88	117.64	11.76	627.39	110.25	11.03
Advanced Combined Cycle	800	699.97	114.36	11.44	649.05	106.23	10.62	610.57	100.14	10.01
Coal - IGCC	300	747.38	116.83	11.68	628.75	98.32	9.83	629.53	98.49	9.85
Biomass IGCC	30	656.89	109.99	11.00	666.72	111.65	11.16	701.86	117.58	11.76
Biomass Combustion - Fluidized Bed Boiler	28	683.49	104.02	10.40	661.87	100.75	10.08	698.48	106.42	10.64
Biomass Combustion - Stoker Boiler	38	726.41	108.25	10.83	710.28	105.87	10.59	740.14	110.42	11.04
Geothermal - Binary	15	427.95	83.11	8.31	475.41	93.52	9.35	505.80	106.91	10.69
Geothermal - Flash	30	422.60	78.91	7.89	467.95	88.51	8.85	494.92	100.59	10.06
Hydro - Small Scale & Developed Sites	15	165.65	86.47	8.65	181.77	95.54	9.55	189.61	103.50	10.35
Hydro - Capacity Upgrade of Existing Site	80	135.40	66.96	6.70	131.31	65.39	6.54	99.17	51.29	5.13
Solar - Parabolic Trough	250	376.70	224.70	22.47	399.04	238.27	23.83	452.71	271.52	27.15
Solar - Photovoltaic (Single Axis)	25	439.58	262.21	26.22	466.76	278.71	27.87	533.55	320.00	32.00
Onshore Wind - Class 3/4	50	203.33	72.41	7.24	217.56	77.75	7.78	220.99	80.52	8.05
Onshore Wind - Class 5	100	208.69	65.47	6.55	222.94	70.19	7.02	225.69	72.44	7.24

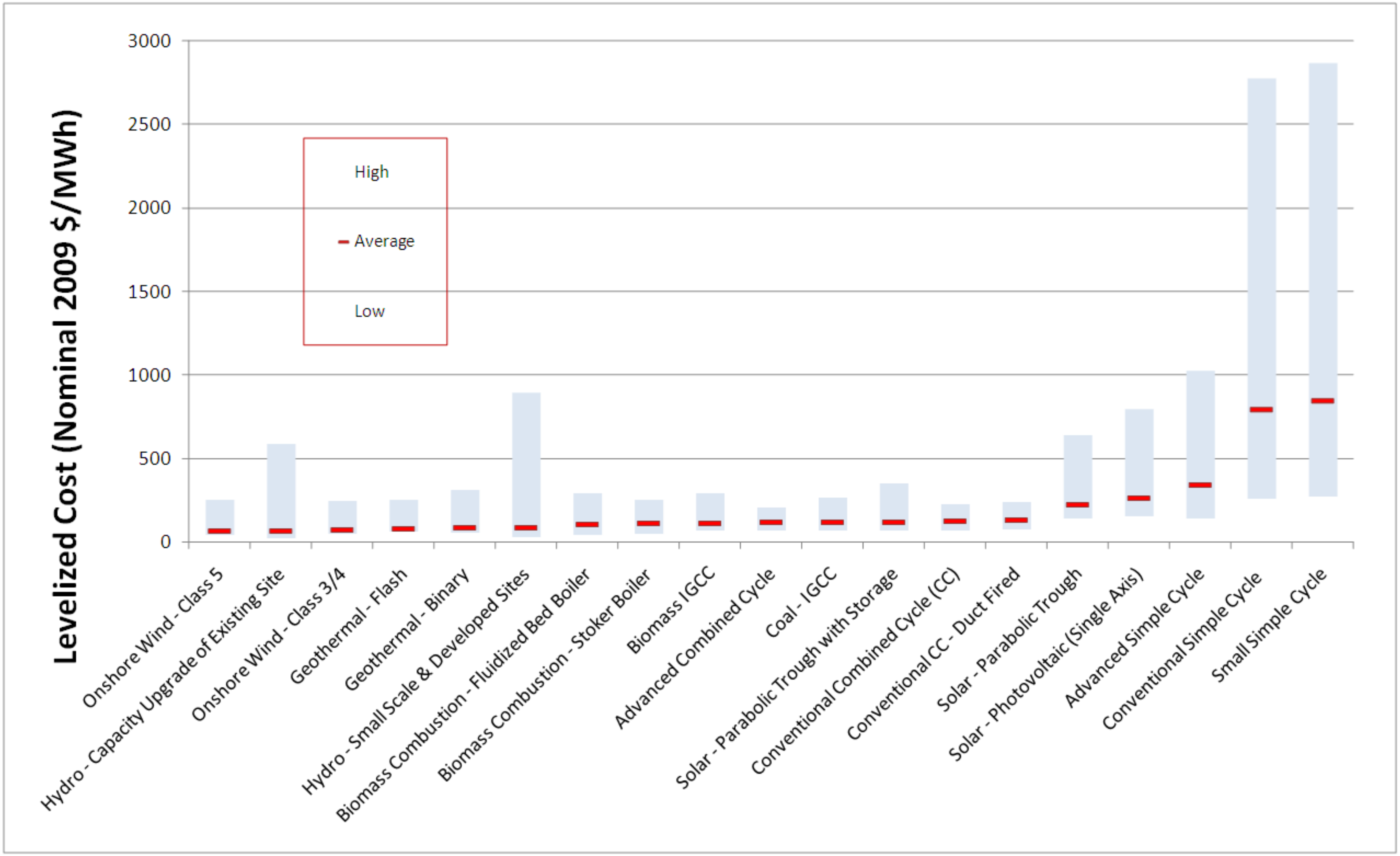
Source: Energy Commission

Figure 1: Summary of Average Levelized Costs—In-Service in 2009



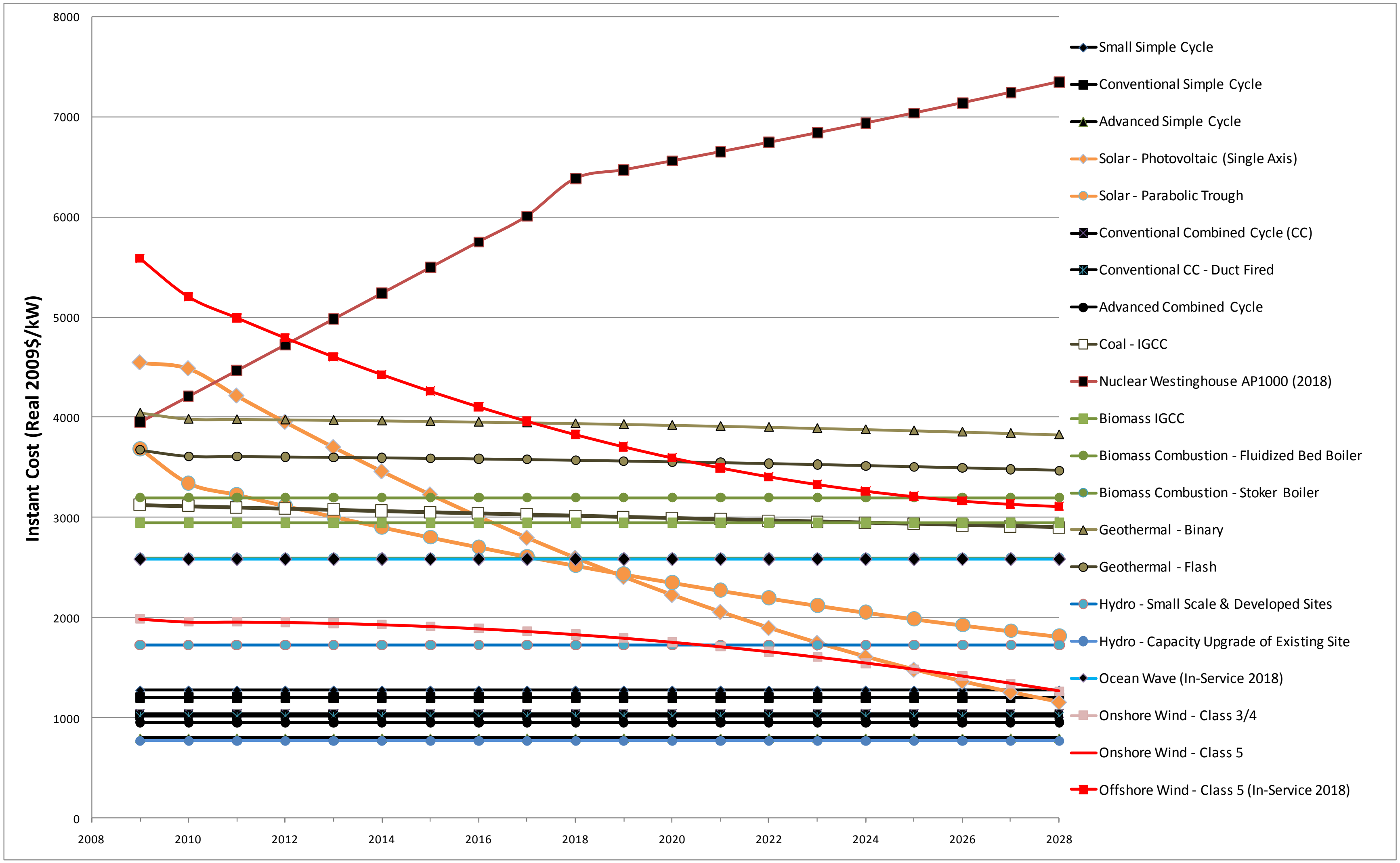
Source: Energy Commission

Figure 2: Range of Levelized Cost for a Merchant Plant In-Service in 2009



Source: Energy Commission

Figure 3: Average Instant Cost Trend (Real 2009 $/kW)

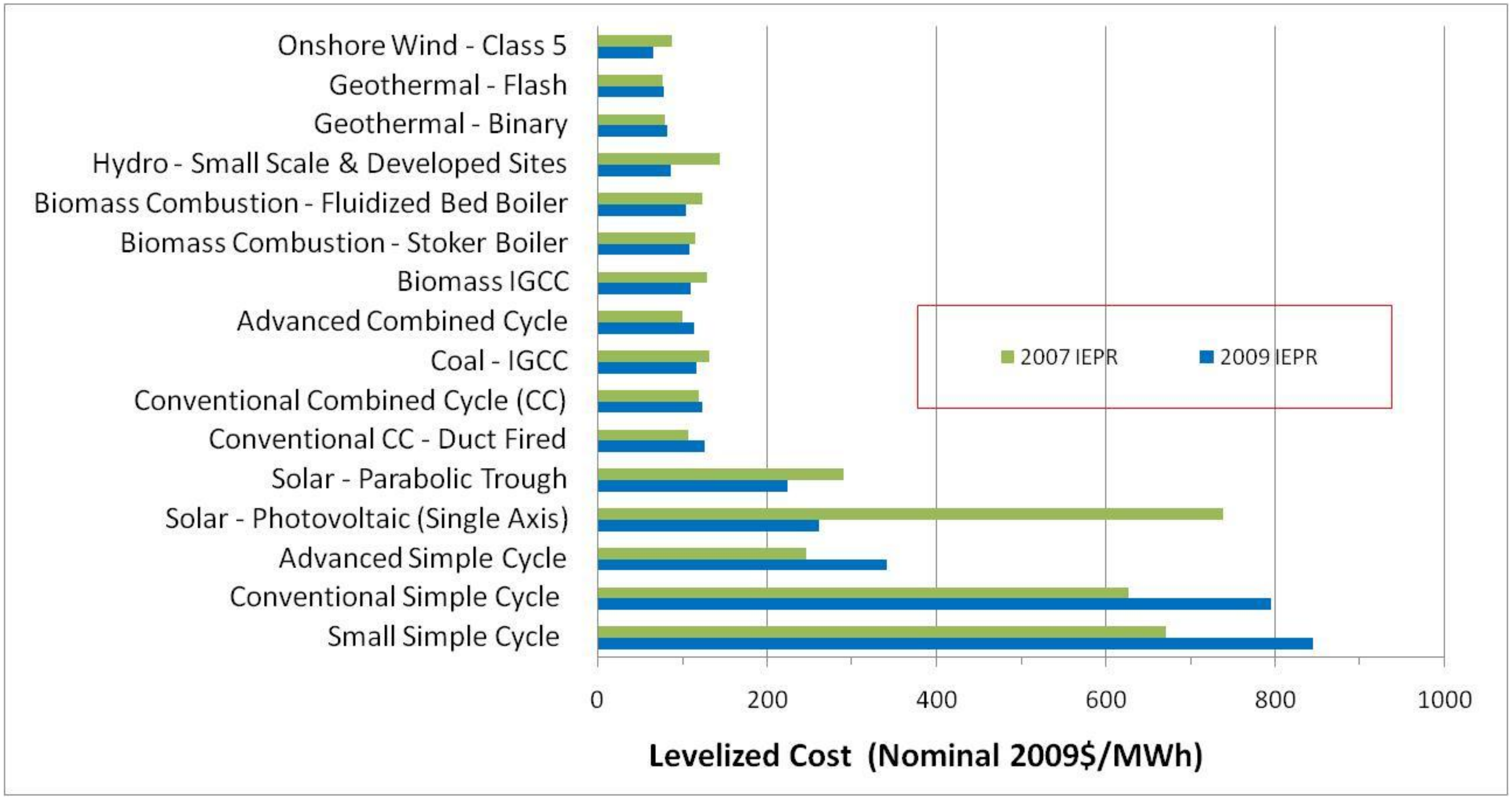


Source: Energy Commission

Figure 4 compares the average *2009 IEPR* levelized costs for merchant plants to those of the *2007 IEPR.* Although the cost differences are somewhat obscured by the complex differences in tax benefits, a number of worthwhile observations can be noted:

- Wind Class 5 has lower levelized costs compared to the *2007 IEPR b*ecause of a higher assumed capacity factor and more favorable tax benefits.
- All the biomass units have lower levelized costs, primarily because of better tax benefits.
- The coal-integrated gasification combined cycle technology shows a comparable cost to the 2007 value but would be expected to be much higher with the addition of carbon capture and sequestration that is now required by law in California to meet the environmental performance standard. However, this increased cost is offset by higher tax credits, a decrease in the base instant cost without carbon capture and sequestration, and the higher capacity factor assumed by KEMA (80 percent as compared to previous 60 percent).
- The geothermal technologies have slightly higher levelized costs primarily because of the assumed higher instant cost, which is partially offset by higher tax credits.
- The solar trough unit shows a significant decrease in levelized cost because of lower instant costs and higher tax credits.
- The solar photovoltaic unit shows a significant decrease in cost because of a decline in instant cost and increased tax benefits—which may reflect both the size difference and improvement in cost.
- Gas-fired technology levelized costs are generally higher primarily because large capital cost increases, as shown in **Table 2**. Higher average fuel cost projections also contribute to this increase in cost. Even though the increases in capital costs are greater for the combined cycle unit, the impact on levelized cost is seen more in the simple cycle units, where fixed cost is the major cost component.

Figure 4: Comparing 2009 Average Levelized Costs to *2007 IEPR* Results (In-Service in 2009)



Source: Energy Commission

Table 2: Increases in Instant Cost From *2007 IEPR* to *2009 IEPR*

Gas-Fired Technology	MW	*2007 IEPR*	*2009 IEPR*	Increase
Small Simple Cycle	49.9	$1,017	$1,292	26.95%
Conventional Simple Cycle	100	$966	$1,231	27.33%
Advanced Simple Cycle	200	$794	$827	4.12%
Conventional Combined Cycle (CC)	500	$810	$1,095	35.08%
Conventional CC - Duct Fired	550	$834	$1,080	29.56%
Advanced Combined Cycle	800	$800	$990	23.72%

Source: Energy Commission

Changes in the Cost of Generation Model

The levelized costs provided in this report were developed using the Energy Commission's Cost of Generation Model (Model). The Model was first used to produce cost of generation estimates for the *2003 IEPR*, then again for the *2007 IEPR*. The *2007 IEPR* effort greatly improved the model structure, data, and documentation, making it more accurate and easier to use. The 2009 Model has a number of improvements relative to the 2007 version:

- The Model has an option setting to produce average, high, and low levelized costs.
- The Model can estimate the cost of transmission from the interconnection point to the delivery point.
- The Model can calculate tax losses as either taken in a single year or carried forward to future years. Staff continues to use the assumption of taking losses in a single year for the average- and low-cost cases, but uses the latter for its high-cost case.
- The treatment of merchant modeling has been changed from revenue requirement to cash flow after learning that using revenue requirement overstates the levelized cost for the renewable technologies with tax benefits (tax deductions, tax credits, and accelerated depreciation) by as much as 30 percent.
- The Model has the ability to include the cost of carbon in its calculation, but staff has not used this function to calculate how carbon adders may affect levelized cost estimates, because these values have not yet been established.

The Model continues to offer two important analytical functions of the *2007 IEPR* Cost of Generation Model: screening curves and sensitivity curves to allow users to evaluate the effect of individual cost factors.

The Model can still produce a wholesale electricity price forecast, but now also provides an estimate of high and low forecast values. This feature estimates the fixed cost component and applies the variable cost factors from a production cost or market model to produce a wholesale electricity price forecast. Wholesale electricity price forecasts are useful for many resource planning studies.

The Cost of Generation Model and the levelized cost of generation results presented in an August staff draft report were the subject of a August 25, 2009, IEPR Committee workshop. This final report and the Model were modified to reflect the comments from the workshop. The staff final report and the Model will be available on the Energy Commission's website.

Using This Report

This report is intended to provide a basic assessment of some of the fundamental attributes that are generally considered when evaluating the cost of building and operating different electricity generation technology resources. However, careful consideration must be taken on how the levelized costs are used for evaluating electricity generation options. Levelized costs are typically nominal values, not precise estimates. The cost estimates are typically based on a specific set of assumptions, but in reality will vary depending on the scope of analysis and the specific generation project. Comparing the levelized cost of one generation technology against another may be useful when levelized costs are of significantly different magnitudes, but problematic where levelized costs are close.

The levelized cost analysis does not capture all of the system, environmental or other relevant attributes that would typically be examined by a portfolio manager when conducting a comprehensive "comparative value analysis" of a variety of competing resource options. The levelized costs estimates do not account for the generation service attributes, the value that different technologies have to the electricity system or represent the negotiated market prices for short-term or long-term power purchase contracts. These estimates do not predict how the units will actually operate in an electric system, how the units will affect the operation of other facilities, or their effect on total system costs. Finally, the levelized cost estimates presented in this report do not address environmental, system diversity or risk factors that are a vital planning aspect for all resource development studies. A portfolio analysis will vary depending on the particular criteria and measurement goals of each study.

The data used in this report is the most current set of generation technology characterizations available, based on surveys of recently constructed projects and information from industry experts. The COG Model has been modified to capture the attributes of different developers and examine a range of possible cost drivers that may affect levelized cost calculations. Therefore it is important to use the Model and the information in this report carefully. The following guidelines and subsequent issues are intended to provide clarity on the proper use of this report:

- Levelized cost, or for that matter any generation or transmission study, should not rely on single point estimates. There is wide variation in operational and cost data. Single point values are based on one set of conditional assumptions are simplistic and will not represent the range of costs that a developer may encounter. All studies should be based on a range of data to capture the uncertainties that developers and ratepayers will likely encounter.

- Where the use of single point estimates become unavoidable (for example, setting contractual terms), the assumptions should be carefully documented to allow replication and understanding of the results.

Additional studies are required to explore the implications of these large cost bandwidths. Staff has identified the following two study areas:

- The data and levelized costs reported in the COG Report should be integrated into a decision analysis platform, such as the RAND robust decision-making (RDM) studies to assess the meaning and impact of the large bandwidth of costs.
- The fixed cost data reported in the COG Report should be combined with production cost simulations to produce scenario studies in order to assess the implications of this large bandwidth.
- The characterization of technologies included in this report and supporting documentation provides a baseline range of assumptions that have undergone public scrutiny and comments. Use of values outside these ranges should be well-supported and documented.
- The data collected for this COG Report is applicable to statewide transmission studies and should be used to help characterize the cost inputs to such studies.
- In the absence of project-specific or scenario-specific models of levelized cost, the COG Model should be used as a default standard for generating levelized costs as either an input to further analysis or as a standalone result.

Organization of Report

The report is organized as follows:

- Chapter 1 reports the levelized cost estimates—the output of the Model. The chapter provides the levelized cost estimates for 21 technologies. The levelized cost estimates and the component costs are provided for three classes of developers: merchant, IOUs, and POUs, often referred to as municipal utilities. These costs will be provided at three levels: high, average, and low.
- Chapter 2 summarizes the inputs to the data assumptions for the three cost levels.
- Appendix A provides a general description of the Energy Commission's Cost of Generation Model, instructions on how to use the Model, and a description of the various unique features of the Model, such as screening and sensitivity curves.
- Appendix B provides component, detailed levelized costs for merchant plants, IOUs, and POUs in both dollars per megawatt-hour ($/MWh) and dollars per kilowatt-year ($/kW-Year).

- Appendix C provides the documentation for the gas-fired technology data assumptions provided in Chapter 2.
- Appendix D documents the natural gas fuel prices, including the method for developing the high and low gas prices.
- Appendix E provides the documentation for the transmission loss and cost data.
- Appendix F provides a description of the Revenue Requirement and Cash-Flow financial accounting techniques used in the COG Model.
- Appendix G provides a list of contacts if further information about the Model or model data is needed.
- Appendix H summarizes the staff's response to comments received at or as result of the August 25, 2009, workshop on the COG Model and Report.

CHAPTER 1: Summary of Technology Costs

This chapter summarizes the estimated levelized costs of the 21 technologies using the Cost of Generation Model (Model), which include nuclear, fossil fuel, and various renewable technologies. The levelized costs include a range of average, high, and low estimates. This chapter also compares the average levelized cost estimates to the *2007 Integrated Energy Policy Report (IEPR)* results.

Definition of Levelized Cost

The levelized cost of a resource represents a constant cost per unit of generation computed to compare one unit's generation costs with other resources over similar periods. This is necessary because both the costs and generation capabilities differ dramatically from year to year between generation technologies, making spot comparisons using any year problematic.

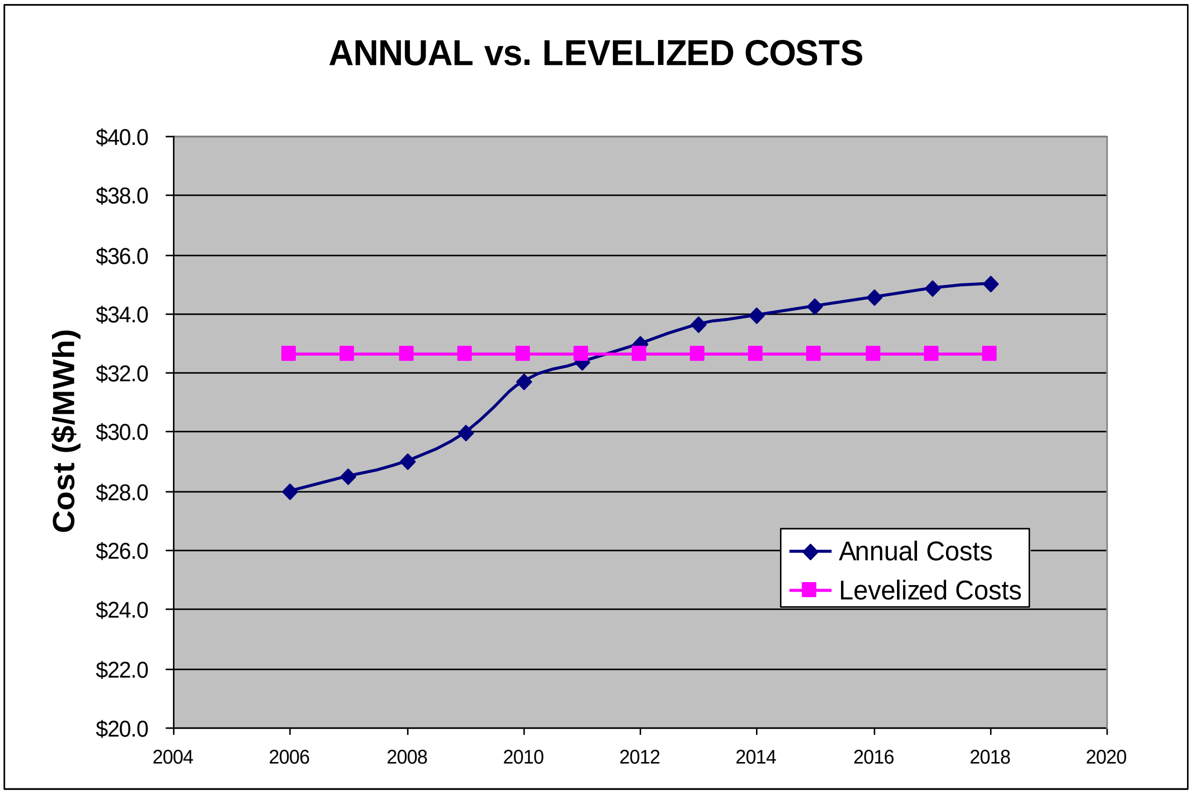
The levelized cost formula used in this model first sums the net present value of the individual cost components and then computes the annual payment with interest (or discount rate, *r*) required to pay off that present value over the specified period *T*. The formula is as follows:

$$\text{Levelized cost} = \sum_{t=1}^{T} \frac{Cost_t}{(1+r)^t} * \frac{r*(1+r)^T}{((1+r)^T - 1)}$$

These results are presented as a cost per unit of generation over the period under investigation. This is done by dividing the costs by the sum of all the expected generation over the time horizon being analyzed. The most common presentation of levelized costs is in dollars per megawatt-hour ($/MWh) or cents per kilowatt-hour (¢/kWh).

Levelized cost is generated by the Cost of Generation Model, using multiple algorithms. Using dozens of cost, financial, and tax assumptions, the Model calculates the annual costs for a technology on an annual basis, finds a present value of those annual costs, and then calculates a levelized cost. **Figure 5** is a fictitious illustration of the relationship between annual costs and levelized costs. This relationship is defined by the fact that levelized cost values are equal to the net present value of the current and future annual costs. This annualized (or levelized) cost value allows for the comparison of one technology against the other, whereas the differing annual costs are not easily compared.

Figure 5: Illustration of Levelized Cost



Source: Energy Commission

Levelized Cost Components

Levelized costs consist of fixed and variable cost components as shown in **Table 3**.

All of these costs vary depending on whether the project is a merchant facility, an investor-owned utility (IOU), or a publicly owned utility (POU). In addition, the costs can vary with location because of differing land costs, fuel costs, construction costs, operational costs, and environmental licensing costs. These costs are discussed in detail in Chapter 2 but are defined briefly as follows.

Table 3: Summary of Levelized Cost Components

Fixed Cost
Capital and Financing – The total cost of construction, including financing the plant
Insurance – The cost of insuring the power plant
Ad Valorem – Property taxes
Fixed O&M – Staffing and other costs that are independent of operating hours
Corporate Taxes – State and federal taxes
Variable Costs
Fuel Cost – The cost of the fuel used
Variable O&M – Operation and maintenance costs that are a function of operating hours

Source: Energy Commission

Capital and Financing Costs

The capital cost includes the total costs of construction: land purchase and development; permitting including emission reduction credits; the power plant equipment; interconnection including transmission costs; and environmental control equipment. The financing costs are those incurred through debt and equity financing and are incurred by the developer annually in a manner similar to financing a home. The irregular annual costs, therefore, are levelized by this cost structure.

Insurance Cost

Insurance is the cost of insuring the power plant, similar to insuring a home. The annual costs are based on an estimated first-year cost and are then escalated by nominal inflation throughout the life of the power plant. The first-year cost is estimated as a percentage of the installed cost per kilowatt for a merchant facility and POU plant. For an IOU plant, the first-year cost is a percentage of the book value.[3]

Ad Valorem

Ad valorem costs are annual property tax payments paid as a percentage of the assessed value and are usually transferred to local governments. POU power plants are generally exempt from these taxes but may pay in-lieu fees. The assessed values for power plants are set by the State Board of Equalization as a percentage of book value for an IOU and as depreciation-factored value for a merchant facility.

[3] Book value is the net of all assets less all liabilities.

Fixed Operating and Maintenance

Fixed operating and maintenance (O&M) costs are the costs that occur regardless of how much the plant operates. These costs are not uniformly defined by all interested parties but generally include staffing, overhead and equipment (including leasing), regulatory filings, and miscellaneous direct costs.

Corporate Taxes

Corporate taxes are state and federal taxes, which are not applicable to a POU. The calculation of these taxes is different for a merchant facility than for an IOU. Neither calculation method lends itself to a simple explanation, but in general the taxes depend on depreciated values and are adjusted for interest on debt payments. The federal taxes are adjusted for the state taxes similar to an adjustment for a homeowner.

Fuel Cost

Fuel cost is the cost of fuel, most commonly expressed in dollars per megawatt-hour. For a thermal power plant, it is the heat rate (British thermal unit per kilowatt-hour [Btu/kWh]) multiplied by the cost of the fuel (dollars per million Btu [$/MMBtu]). This includes start-up fuel costs, as well as the on-line operating fuel usage. Allowance is made in the calculation for the degradation of a power plant's heat rate over time.

Variable Operations and Maintenance

Variable O&M costs are a function of the number of hours a power plant operates. Most importantly, this includes yearly maintenance and overhauls. Variable O&M also includes repairs for forced outages, consumables (non-fuel products), water supply, and annual environmental costs.

Summary of Levelized Costs

Table 4 summarizes average levelized costs for the various generation technologies, depending on whether they are developed by merchant owners, IOUs, or POUs[4]. The levelized costs are provided in the most common formats, dollars per kilowatt-year ($/kW-Year), $/MWh and ¢/kWh. All costs are in nominal dollars and are for generation units that begin operation in 2009. **Table 5** shows the corresponding data for the technologies that begin operation in 2018, when the ocean wave, offshore wind, and nuclear technologies are

[4] Nuclear Westinghouse AP1000, ocean-wave, and offshore wind technologies are assumed to not be viable in California until about 2018. Tables and figures for 2009 exclude these technologies.

assumed to have become viable in California. **Figure 6** and **Figure 7** show this same information as graphs.

This comparison of costs should always be used with discretion since these technologies are not interchangeable in their value to the system, However, a number of cost differences can be noted for general screening purposes. In general, the IOU plants are less expensive than the merchant facilities because of lower financing costs. However, the merchant plants for some of the renewable technologies, such as the solar units, become less expensive because of the effect of cash-flow financing and tax benefits. The POU plants are the least expensive because of lower financing costs and tax exemptions. This difference is most significant for the simple cycle units, where levelized costs for merchant or IOU projects are twice that of a POU.

A shortcoming noted in the *2007 IEPR* was that the levelized cost estimates did not capture long-term changes in cost variables, the most significant of which determining levelized cost is instant cost. Instant cost, sometimes referred to as *overnight cost*, is the initial capital expenditure. **Figure 8** summarizes the long-term trend in instant cost in real 2009 dollars. Most of the units have little or no expected improvement over the 20-year period, but two of the renewable technologies that are important to California's resource development, wind and solar, show a significant cost decline. Solar photovoltaic, which has shown dramatic cost change since 2007, is expected to show the most improvement of all the technologies, bringing its capital cost within range of the gas-fired combined cycle units.

The variations in levelized costs depend on a complicated set of assumptions on financing, operational costs, and, most importantly, tax credits. The patterns of the levelized costs become indecipherable when captured in a single figure. Accordingly, the levelized cost estimates are broken up into four figures for average merchant costs: **Figure 9** shows the trend for Conventional Technologies, **Figure 10** for Renewable Technologies, **Figure 11** for Base Load Technologies, and **Figure 12** for Load Following and Intermittent Technologies.

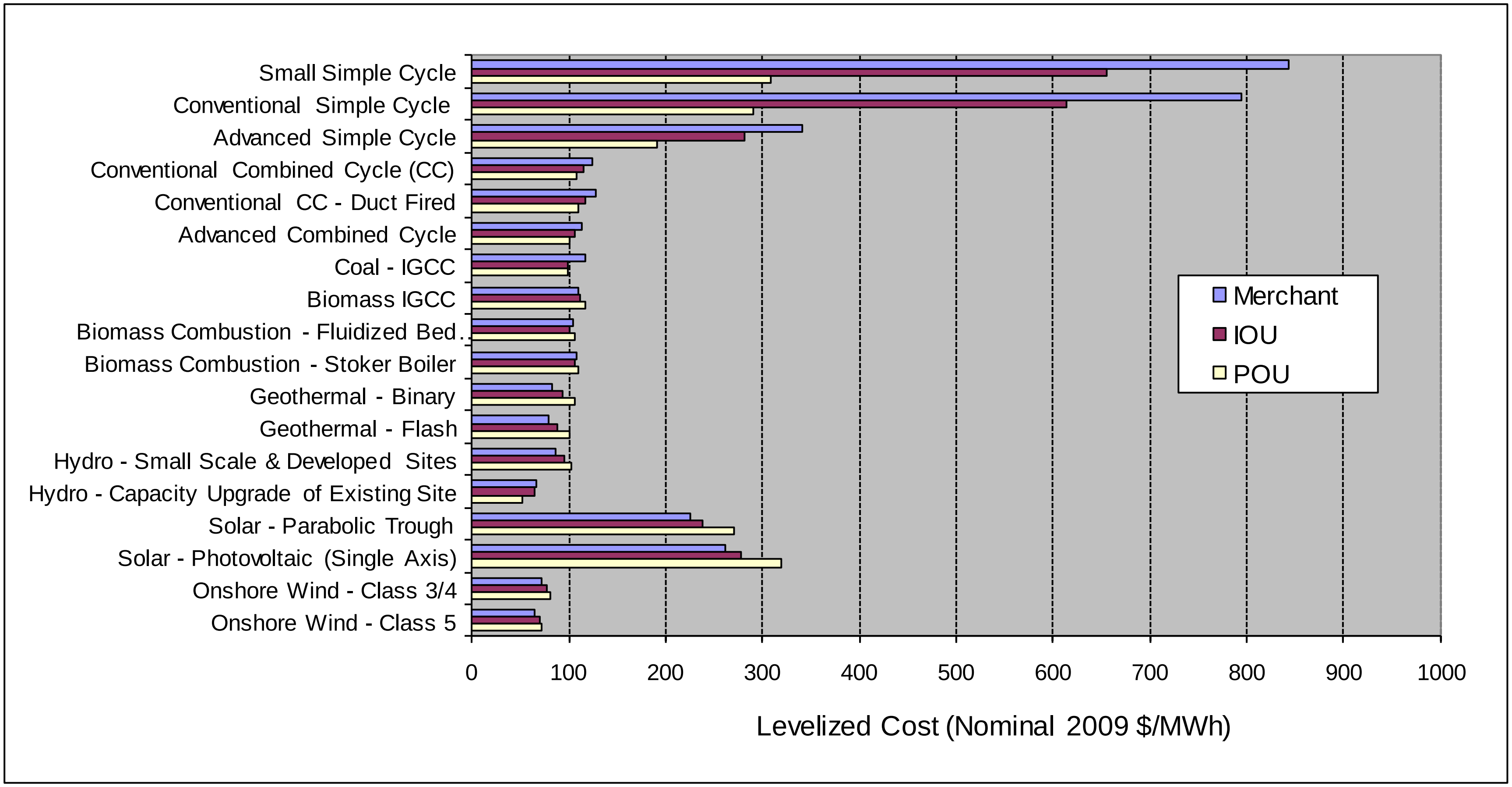
Tax credits, which are both complicated and uncertain, obscure the interpretation of this data, b**u**t it is clear that real levelized cost of gas-fired and biomass technologies trend upward, primarily from fuel cost increases. Nuclear continues to rise beyond competitive range. Wind, coal-integrated gasification combined cycle (coal-IGCC), and solar technologies trend downward. The other technologies show no or very little cost improvement. The jumps in the years between 2012 and 2018 reflect the end of federal tax credits included in both the 2008 Energy Policy Act and the 2009 American Recovery and Reinvestment Act.

Table 4: Summary of Average Levelized Costs—In-Service in 2009

In-Service Year = 2009 (Nominal 2009 $)	Size	Merchant			IOU			POU		
	MW	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh
Small Simple Cycle	49.9	346.91	844.31	84.43	269.31	655.69	65.57	252.90	308.01	30.80
Conventional Simple Cycle	100	326.51	794.67	79.47	252.53	614.84	61.48	239.02	291.10	29.11
Advanced Simple Cycle	200	280.91	341.84	34.18	230.86	281.03	28.10	234.37	190.29	19.03
Conventional Combined Cycle (CC)	500	758.01	123.84	12.38	701.17	114.76	11.48	657.95	107.91	10.79
Conventional CC - Duct Fired	550	727.66	127.38	12.74	670.88	117.64	11.76	627.39	110.25	11.03
Advanced Combined Cycle	800	699.97	114.36	11.44	649.05	106.23	10.62	610.57	100.14	10.01
Coal - IGCC	300	747.38	116.83	11.68	628.75	98.32	9.83	629.53	98.49	9.85
Biomass IGCC	30	656.89	109.99	11.00	666.72	111.65	11.16	701.86	117.58	11.76
Biomass Combustion - Fluidized Bed Boiler	28	683.49	104.02	10.40	661.87	100.75	10.08	698.48	106.42	10.64
Biomass Combustion - Stoker Boiler	38	726.41	108.25	10.83	710.28	105.87	10.59	740.14	110.42	11.04
Geothermal - Binary	15	427.95	83.11	8.31	475.41	93.52	9.35	505.80	106.91	10.69
Geothermal - Flash	30	422.60	78.91	7.89	467.95	88.51	8.85	494.92	100.59	10.06
Hydro - Small Scale & Developed Sites	15	165.65	86.47	8.65	181.77	95.54	9.55	189.61	103.50	10.35
Hydro - Capacity Upgrade of Existing Site	80	135.40	66.96	6.70	131.31	65.39	6.54	99.17	51.29	5.13
Solar - Parabolic Trough	250	376.70	224.70	22.47	399.04	238.27	23.83	452.71	271.52	27.15
Solar - Photovoltaic (Single Axis)	25	439.58	262.21	26.22	466.76	278.71	27.87	533.55	320.00	32.00
Onshore Wind - Class 3/4	50	203.33	72.41	7.24	217.56	77.75	7.78	220.99	80.52	8.05
Onshore Wind - Class 5	100	208.69	65.47	6.55	222.94	70.19	7.02	225.69	72.44	7.24

Source: Energy Commission

Figure 6: Summary of Average Levelized Costs—In-Service 2009



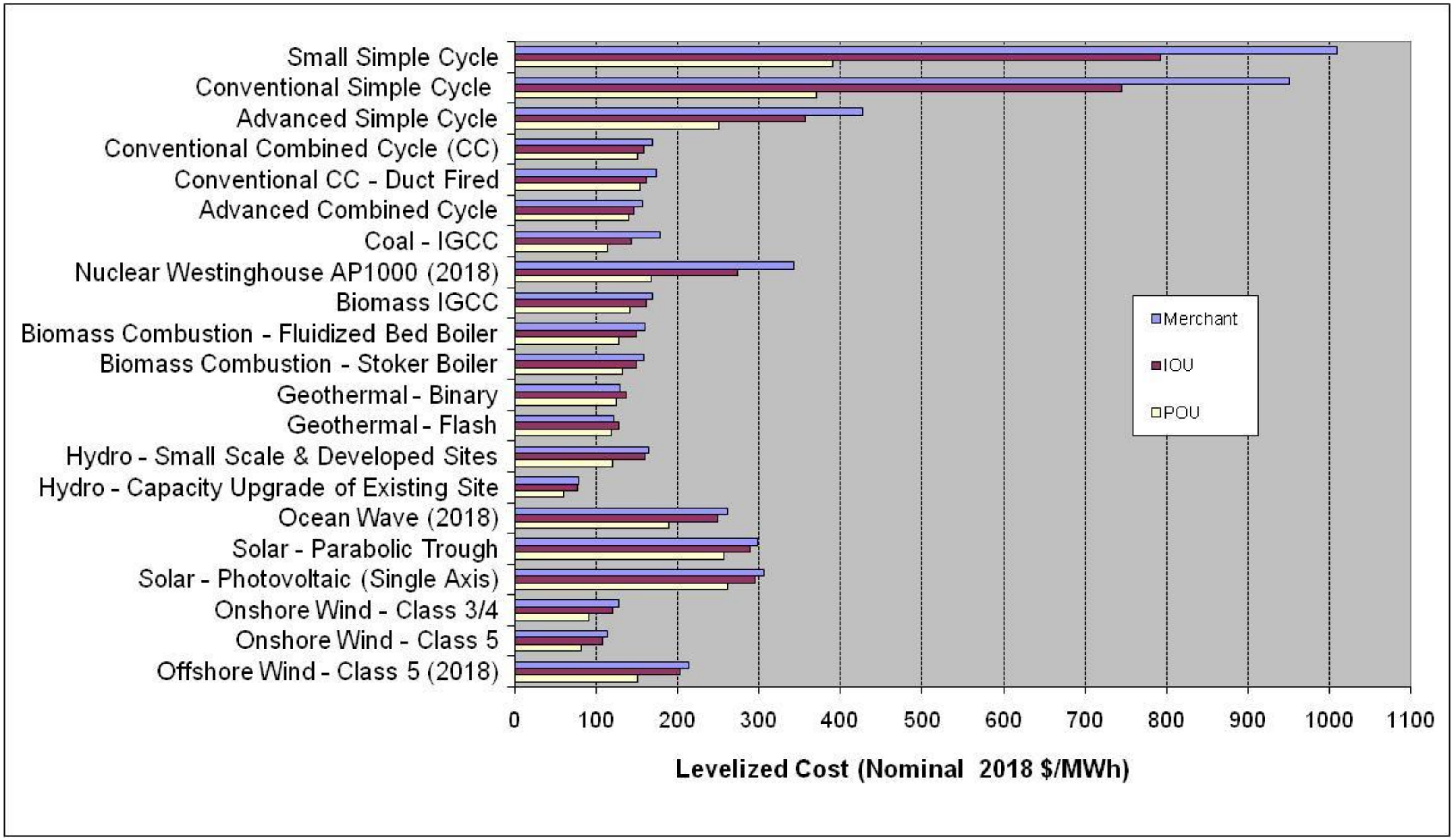
Source: Energy Commission

Table 5: Summary of Average Levelized Costs—In-Service in 2018

In-Service Year = 2018 (Nominal 2018 $)	Size	Merchant			IOU			POU		
	MW	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh
Small Simple Cycle	49.9	414.60	1009.05	100.91	325.28	791.95	79.20	319.89	389.59	38.96
Conventional Simple Cycle	100	390.84	951.22	95.12	305.67	744.21	74.42	303.61	369.76	36.98
Advanced Simple Cycle	200	346.62	421.80	42.18	288.69	351.44	35.14	304.98	247.62	24.76
Conventional Combined Cycle (CC)	500	1036.06	169.27	16.93	968.66	158.54	15.85	916.25	150.28	15.03
Conventional CC - Duct Fired	550	992.58	173.75	17.38	925.36	162.27	16.23	872.76	153.37	15.34
Advanced Combined Cycle	800	958.86	156.66	15.67	898.41	147.04	14.70	851.64	139.68	13.97
Coal - IGCC	300	2422.09	178.14	17.81	911.10	142.48	14.25	723.39	113.17	11.32
Nuclear Westinghouse AP1000 (2018)	960	1139.56	342.41	34.24	1929.55	273.07	27.31	1171.66	166.85	16.68
Biomass IGCC	30	1006.20	168.48	16.85	966.60	161.86	16.19	841.43	140.97	14.10
Biomass Combustion - Fluidized Bed Boiler	28	1054.11	160.43	16.04	974.35	148.32	14.83	837.48	127.60	12.76
Biomass Combustion - Stoker Boiler	38	1061.71	158.22	15.82	998.40	148.82	14.88	890.68	132.88	13.29
Geothermal - Binary	15	666.46	129.42	12.94	695.05	136.73	13.67	591.29	124.98	12.50
Geothermal - Flash	30	646.49	120.72	12.07	674.90	127.66	12.77	580.53	117.99	11.80
Hydro - Small Scale & Developed Sites	15	315.28	164.59	16.46	304.10	159.84	15.98	220.33	120.27	12.03
Hydro - Capacity Upgrade of Existing Site	80	157.31	77.80	7.78	152.81	76.09	7.61	115.80	59.88	5.99
Ocean Wave (2018)	40	511.74	261.71	26.17	485.22	249.02	24.90	361.85	189.33	18.93
Solar - Parabolic Trough	250	500.65	298.64	29.86	483.85	288.92	28.89	427.05	256.13	25.61
Solar - Photovoltaic (Single Axis)	25	512.14	305.50	30.55	494.76	295.43	29.54	436.12	261.57	26.16
Onshore Wind - Class 3/4	50	357.14	127.19	12.72	337.44	120.59	12.06	248.91	90.69	9.07
Onshore Wind - Class 5	100	363.57	114.06	11.41	343.90	108.27	10.83	255.53	82.02	8.20
Offshore Wind - Class 5 (2018)	350	731.39	214.16	21.42	690.08	202.78	20.28	504.75	151.21	15.12

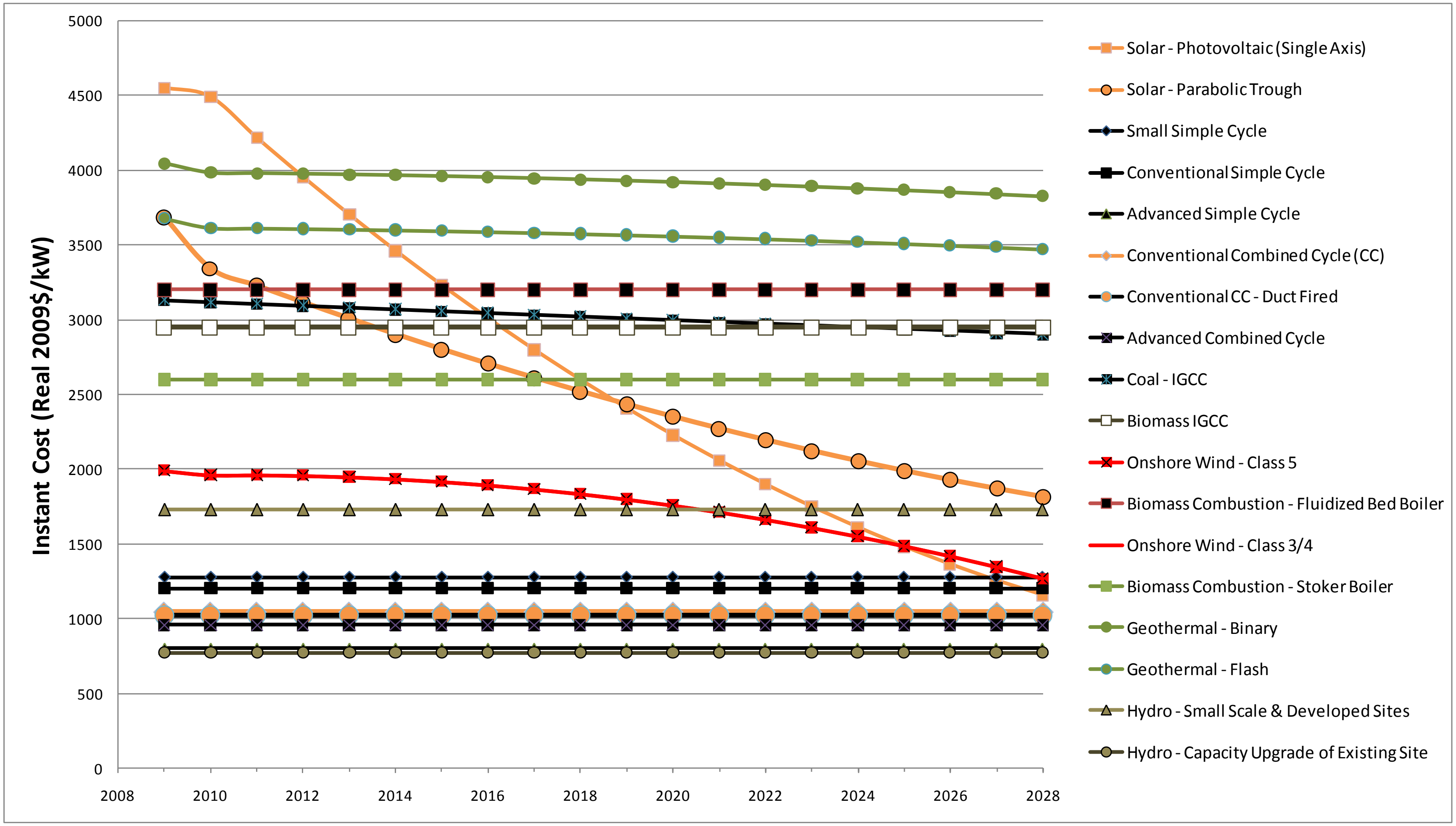
Source: Energy Commission

Figure 7: Summary of Average Levelized Costs—In-Service in 2018



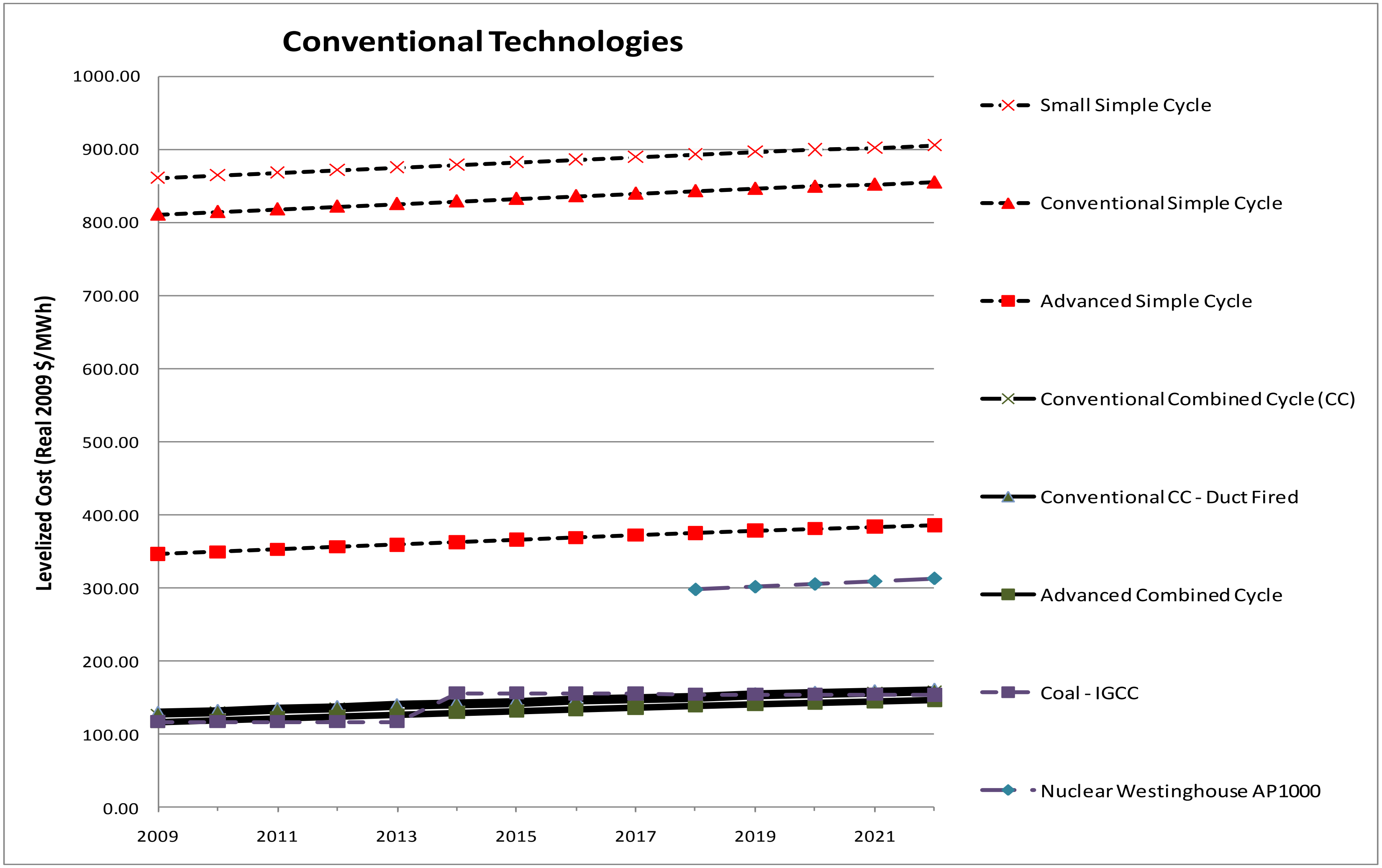
Source: Energy Commission

Figure 8: Average Instant Cost Trend (Real 2009 $/kW)



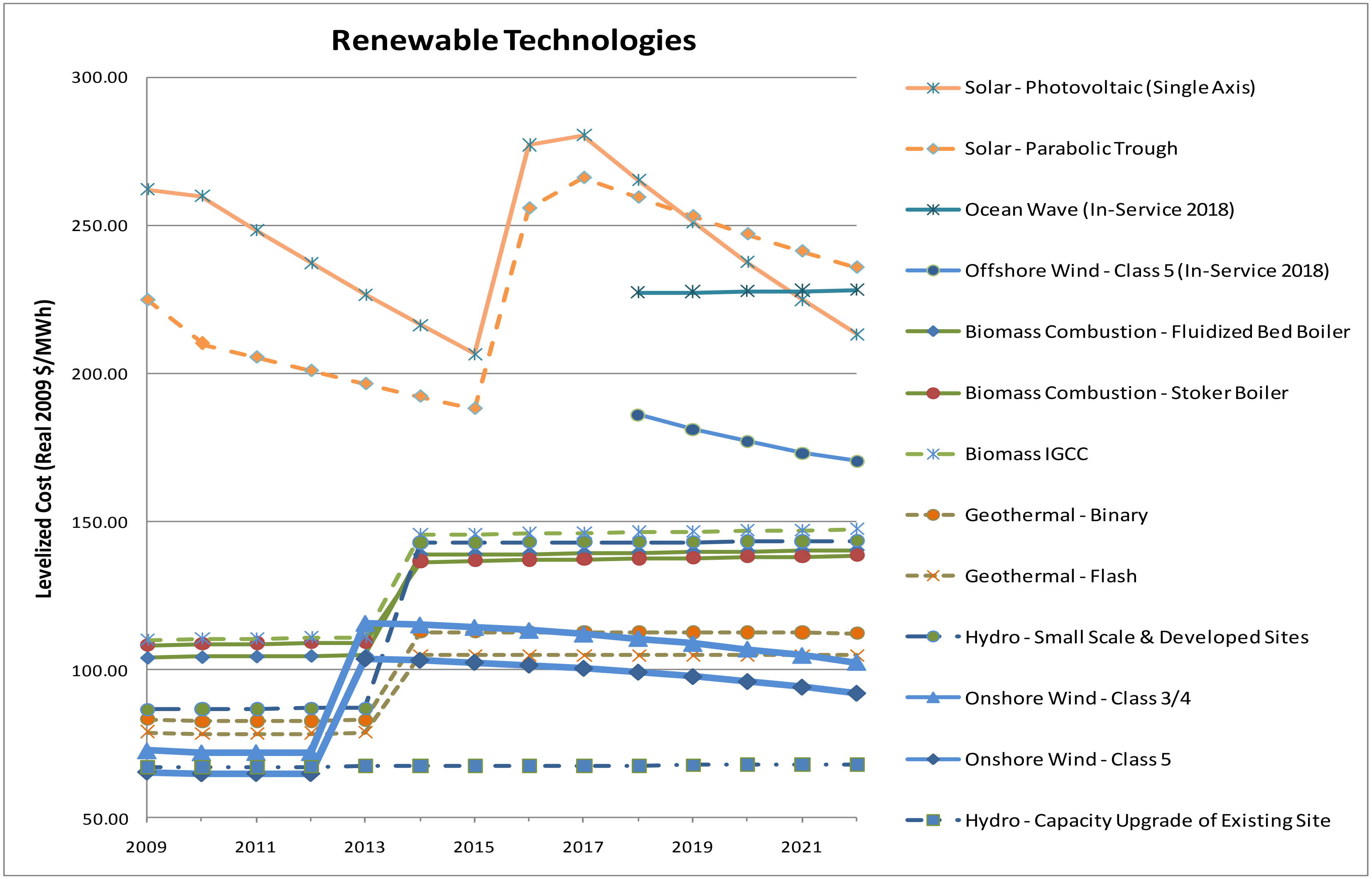
Source: Energy Commission

Figure 9: Average Merchant Levelized Cost Trend for Conventional Technologies



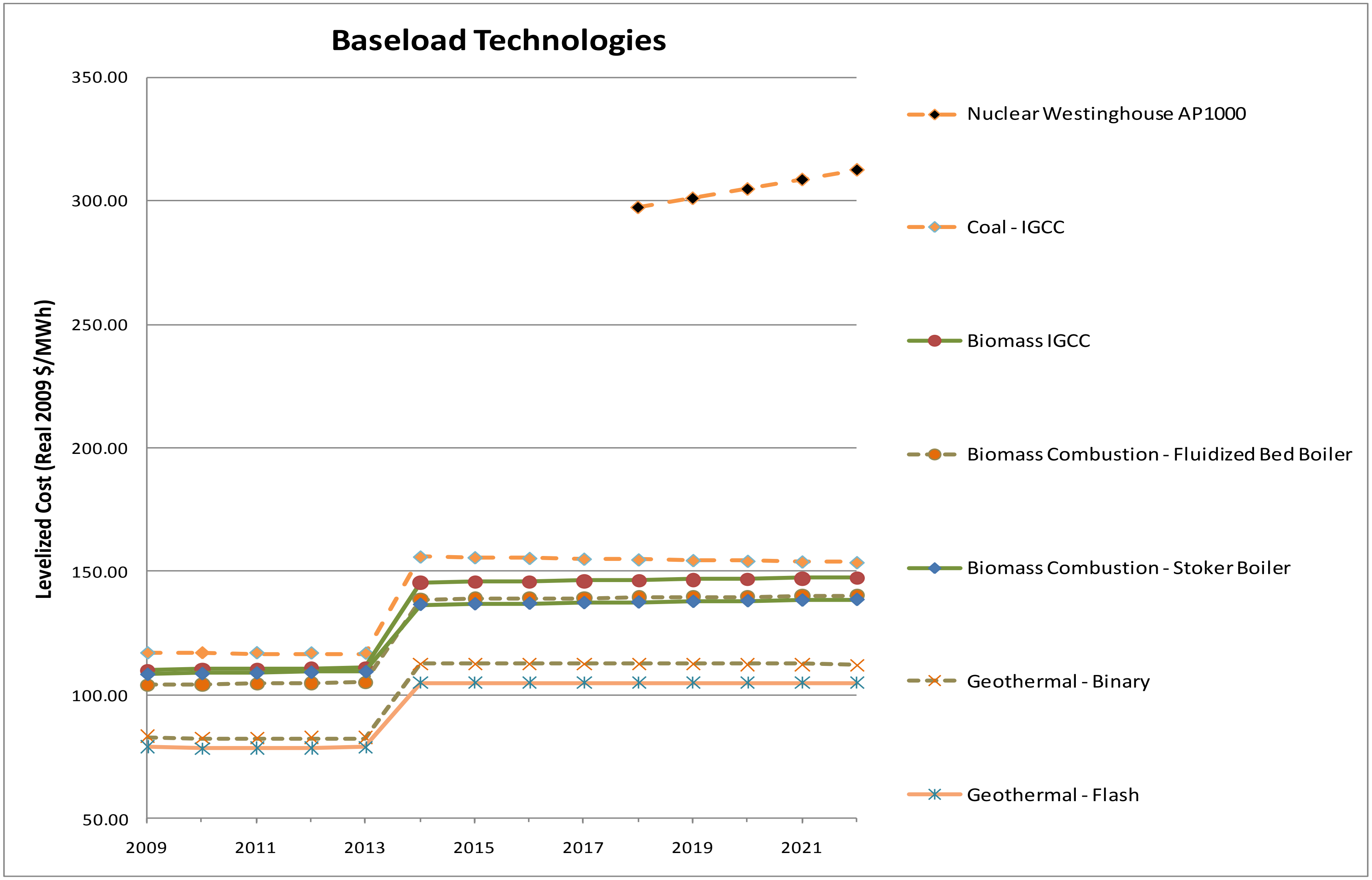
Source: Aspen Consulting

Figure 10: Average Merchant Levelized Cost Trend for Renewable Technologies



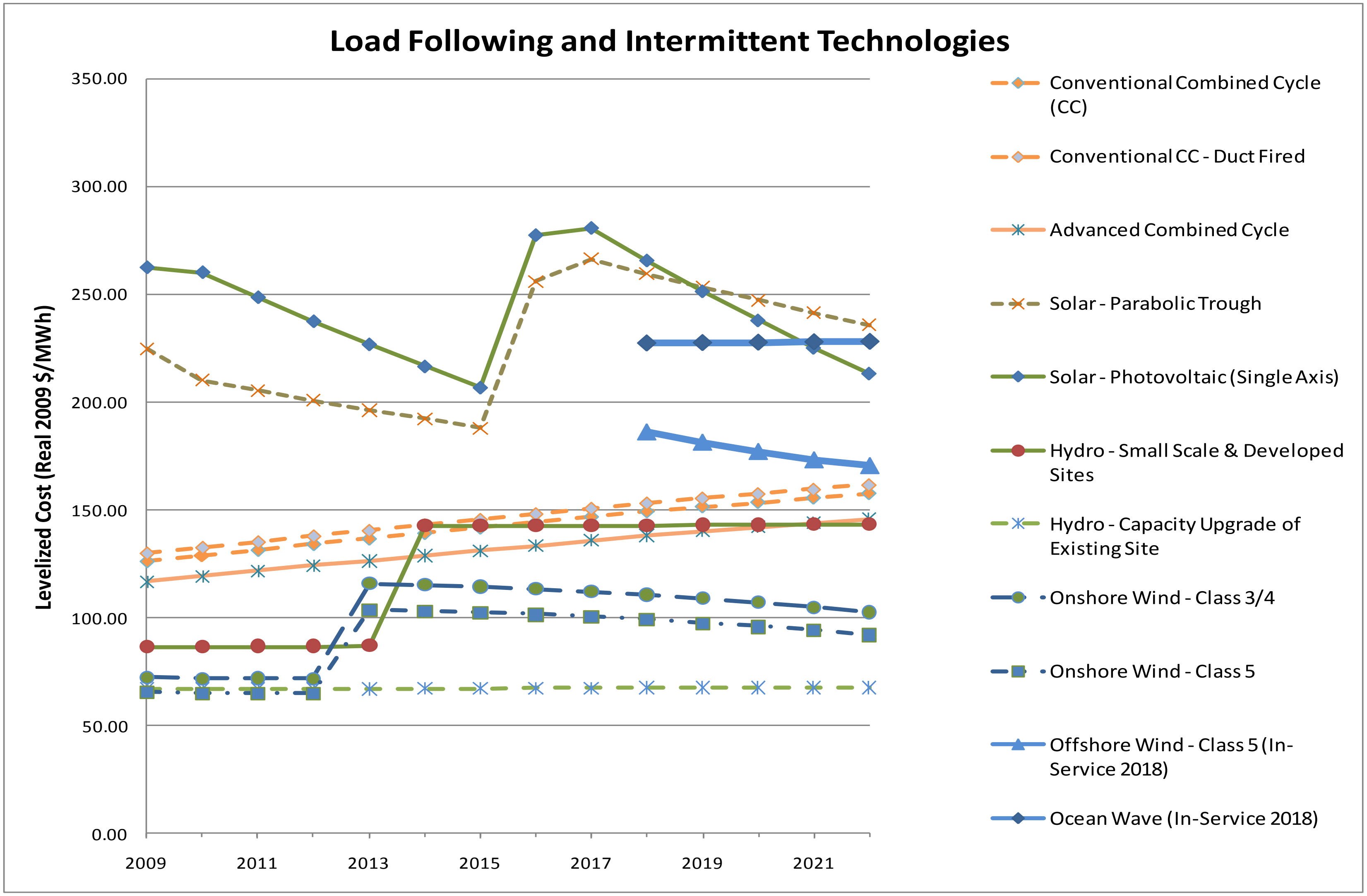
Source: Aspen Consulting

Figure 11: Average Merchant Levelized Cost Trend for Baseload Technologies



Source: Aspen Consulting

Figure 12: Average Merchant Levelized Cost Trend for Load Following and Intermittent Technologies



Source: Aspen Consulting

Component Costs

Table 6 shows the levelized cost components in $/MWh for a merchant plant coming on-line in 2009. **Figure 13** shows the same data differentiating only between the fixed and variable costs. **Table 7** and **Figure 14** show the comparable information for a merchant plant coming on-line in 2018.

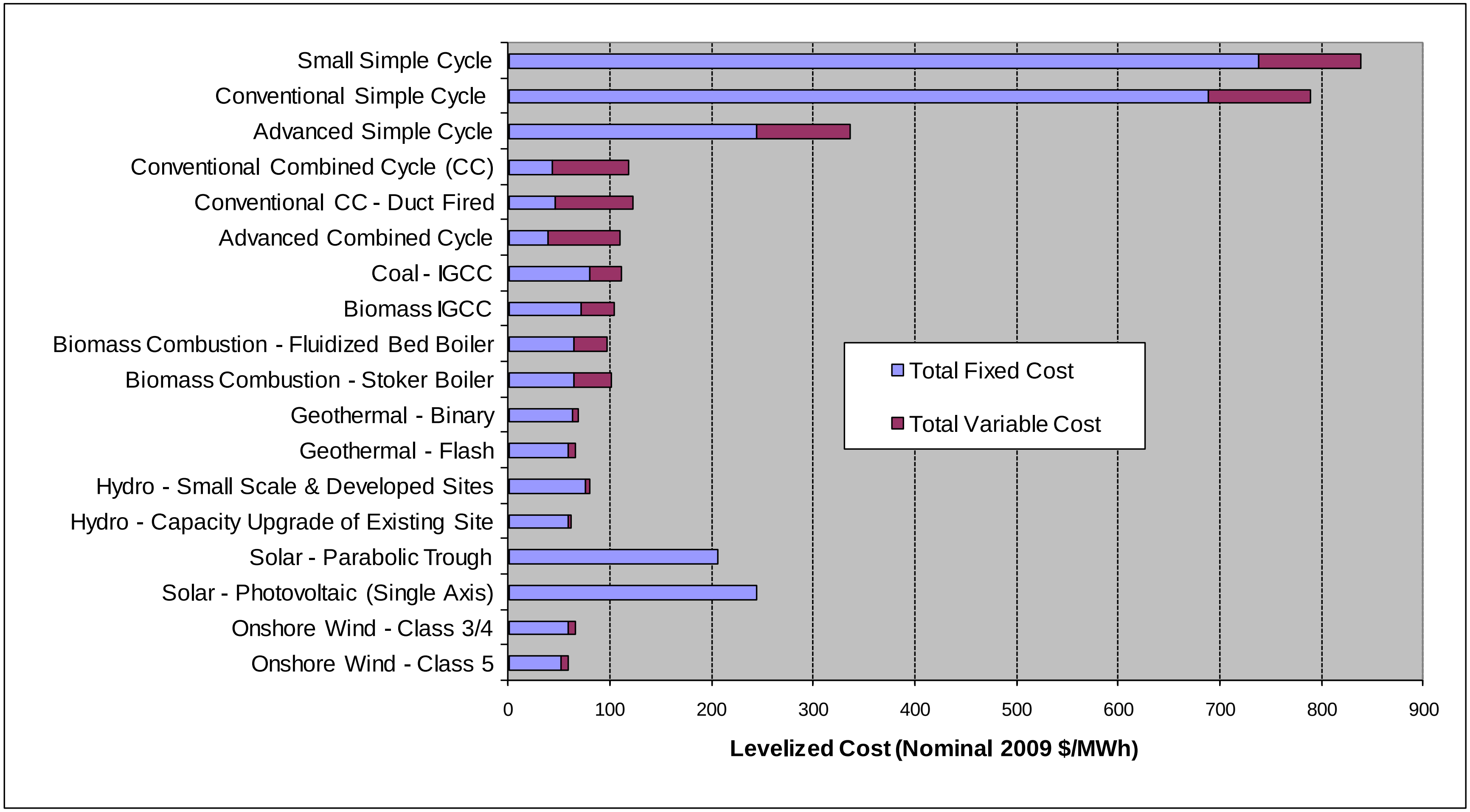
Even though the operating portion of the levelized cost for simple cycle units is only about 15–18 percent of the cost, depending on the year, it is more than 65–70 percent of the total cost for a combined cycle unit. For coal-IGCC and the biomass units, the operating cost is not as large, but still significant. For the other units, operating costs are a small portion of their total cost.

Table 6: Average Levelized Cost Components for In-Service in 2009—Merchant Plants

		$/MWh (Nominal $)											¢/kWh
In-Service Year = 2009 (Nominal 2009 $)	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**	Fuel	Variable O&M	**Total Variable Cost**	Transmission Cost	**Total Levelized Cost**	**Total Levelized Cost**
Small Simple Cycle	49.9	482.17	23.44	31.87	66.81	134.18	**738.46**	95.54	5.08	**100.62**	5.24	**844.31**	**84.43**
Conventional Simple Cycle	100	459.43	22.33	30.36	48.56	128.14	**688.82**	95.54	5.08	**100.62**	5.24	**794.67**	**79.47**
Advanced Simple Cycle	200	158.70	7.71	10.49	22.79	44.28	**243.98**	88.15	4.47	**92.62**	5.24	**341.84**	**34.18**
Conventional Combined Cycle (CC)	500	28.64	1.38	1.88	1.61	9.42	**42.93**	72.05	3.66	**75.71**	5.21	**123.84**	**12.38**
Conventional CC - Duct Fired	550	30.26	1.46	1.99	1.67	9.95	**45.32**	73.19	3.66	**76.85**	5.21	**127.38**	**12.74**
Advanced Combined Cycle	800	25.91	1.25	1.70	1.34	8.52	**38.73**	67.17	3.26	**70.43**	5.21	**114.36**	**11.44**
Coal - IGCC	300	72.98	3.83	5.21	9.38	-11.33	**80.08**	19.38	11.98	**31.36**	5.38	**116.83**	**11.68**
Biomass IGCC	30	59.97	3.84	5.08	29.12	-26.40	**71.62**	26.75	5.08	**31.84**	6.54	**109.99**	**11.00**
Biomass Combustion - Fluidized Bed Boiler	28	60.92	3.78	5.00	17.56	-23.00	**64.26**	27.35	5.83	**33.18**	6.58	**104.02**	**10.40**
Biomass Combustion - Stoker Boiler	38	48.64	3.02	4.00	27.66	-18.49	**64.83**	28.06	8.91	**36.97**	6.45	**108.25**	**10.83**
Geothermal - Binary	15	84.76	6.52	9.85	11.15	-48.94	**63.33**	0.00	5.94	**5.94**	13.83	**83.11**	**8.31**
Geothermal - Flash	30	74.41	5.74	8.67	13.19	-43.22	**58.79**	0.00	6.61	**6.61**	13.51	**78.91**	**7.89**
Hydro - Small Scale & Developed Sites	15	93.65	7.03	10.62	11.10	-46.78	**75.62**	0.00	4.85	**4.85**	6.00	**86.47**	**8.65**
Hydro - Capacity Upgrade of Existing Site	80	43.98	2.97	4.48	7.53	-0.84	**58.12**	0.00	3.16	**3.16**	5.68	**66.96**	**6.70**
Solar - Parabolic Trough	250	257.53	16.58	0.00	47.03	-114.69	**206.45**	0.00	0.00	**0.00**	18.26	**224.70**	**22.47**
Solar - Photovoltaic (Single Axis)	25	317.91	20.47	0.00	47.03	-141.44	**243.96**	0.00	0.00	**0.00**	18.26	**262.21**	**26.22**
Onshore Wind - Class 3/4	50	74.66	5.53	8.36	5.90	-36.18	**58.28**	0.00	6.97	**6.97**	7.16	**72.41**	**7.24**
Onshore Wind - Class 5	100	65.77	4.87	7.37	5.20	-31.88	**51.34**	0.00	6.97	**6.97**	7.16	**65.47**	**6.55**

Source: Energy Commission

Figure 13: Fixed and Variable Costs for In-Service in 2009—Merchant Plants



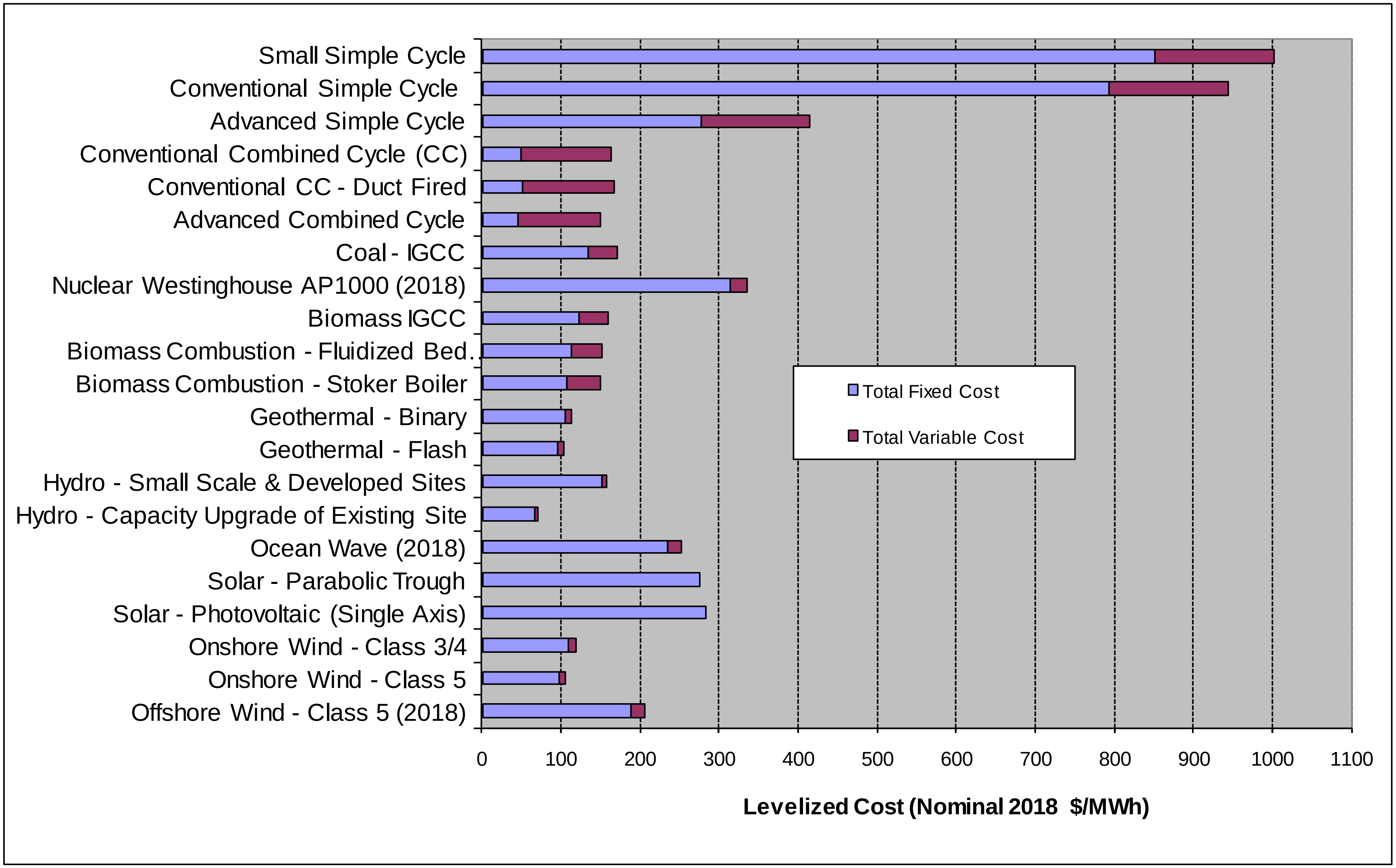
Source: Energy Commission

Table 7: Average Levelized Cost Components for In-Service in 2018—Merchant Plants

		$/MWh (Nominal $)									
In-Service Year = 2018 (Nominal 2018 $)	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**	Fuel	Variable O&M	**Total Variable Cost**	**Transmission Cost**
Small Simple Cycle	49.9	554.87	26.89	36.69	79.88	154.26	**852.59**	144.29	5.88	**150.17**	**6.29**
Conventional Simple Cycle	100	528.71	25.62	34.96	58.14	147.34	**794.76**	144.29	5.88	**150.17**	**6.29**
Advanced Simple Cycle	200	182.65	8.85	12.08	22.53	50.93	**277.04**	133.14	5.33	**138.47**	**6.29**
Conventional Combined Cycle (CC)	500	32.95	1.59	2.17	1.93	10.83	**49.46**	108.82	4.74	**113.56**	**6.25**
Conventional CC - Duct Fired	550	34.82	1.68	2.29	1.99	11.44	**52.22**	110.54	4.74	**115.29**	**6.25**
Advanced Combined Cycle	800	29.82	1.44	1.96	1.59	9.80	**44.61**	101.45	4.36	**105.81**	**6.25**
Coal - IGCC	300	86.44	4.25	5.79	11.26	26.64	**134.38**	22.92	14.38	**37.30**	**6.46**
Nuclear Westinghouse AP1000 (2018)	960	202.84	12.52	20.66	31.26	46.83	**314.11**	13.32	8.25	**21.57**	**6.73**
Biomass IGCC	30	76.15	4.41	5.85	34.94	1.77	**123.11**	31.42	6.10	**37.52**	**7.84**
Biomass Combustion - Fluidized Bed Boiler	28	77.10	4.33	5.76	21.07	5.15	**113.41**	32.13	6.99	**39.12**	**7.90**
Biomass Combustion - Stoker Boiler	38	61.57	3.47	4.60	33.19	3.99	**106.82**	32.97	10.69	**43.66**	**7.73**
Geothermal - Binary	15	101.39	7.28	11.04	13.38	-27.43	**105.67**	0.00	7.14	**7.14**	**16.61**
Geothermal - Flash	30	88.87	6.40	9.71	15.84	-24.28	**96.54**	0.00	7.94	**7.94**	**16.23**
Hydro - Small Scale & Developed Sites	15	120.08	8.07	12.23	13.32	-2.15	**151.55**	0.00	5.83	**5.83**	**7.20**
Hydro - Capacity Upgrade of Existing Site	80	50.57	3.41	5.16	9.05	-1.01	**67.18**	0.00	3.79	**3.79**	**6.82**
Ocean Wave (2018)	40	178.95	11.82	17.91	26.74	-1.09	**234.34**	0.00	18.43	**18.43**	**8.94**
Solar - Parabolic Trough	250	216.90	13.01	17.28	56.43	-26.88	**276.73**	0.00	0.00	**0.00**	**21.91**
Solar - Photovoltaic (Single Axis)	25	223.64	13.41	17.81	56.43	-27.70	**283.59**	0.00	0.00	**0.00**	**21.91**
Onshore Wind - Class 3/4	50	88.81	5.85	8.88	7.09	-0.42	**110.21**	0.00	8.37	**8.37**	**8.60**
Onshore Wind - Class 5	100	78.24	5.16	7.82	6.24	-0.37	**97.09**	0.00	8.37	**8.37**	**8.60**
Offshore Wind - Class 5 (2018)	350	152.55	10.06	15.24	11.66	-0.72	**188.79**	0.00	16.74	**16.74**	**8.63**

Source: Energy Commission

Figure 14: Average Levelized Cost Components for In-Service in 2018—Merchant Plants



Source: Energy Commission

Levelized Costs—High and Low

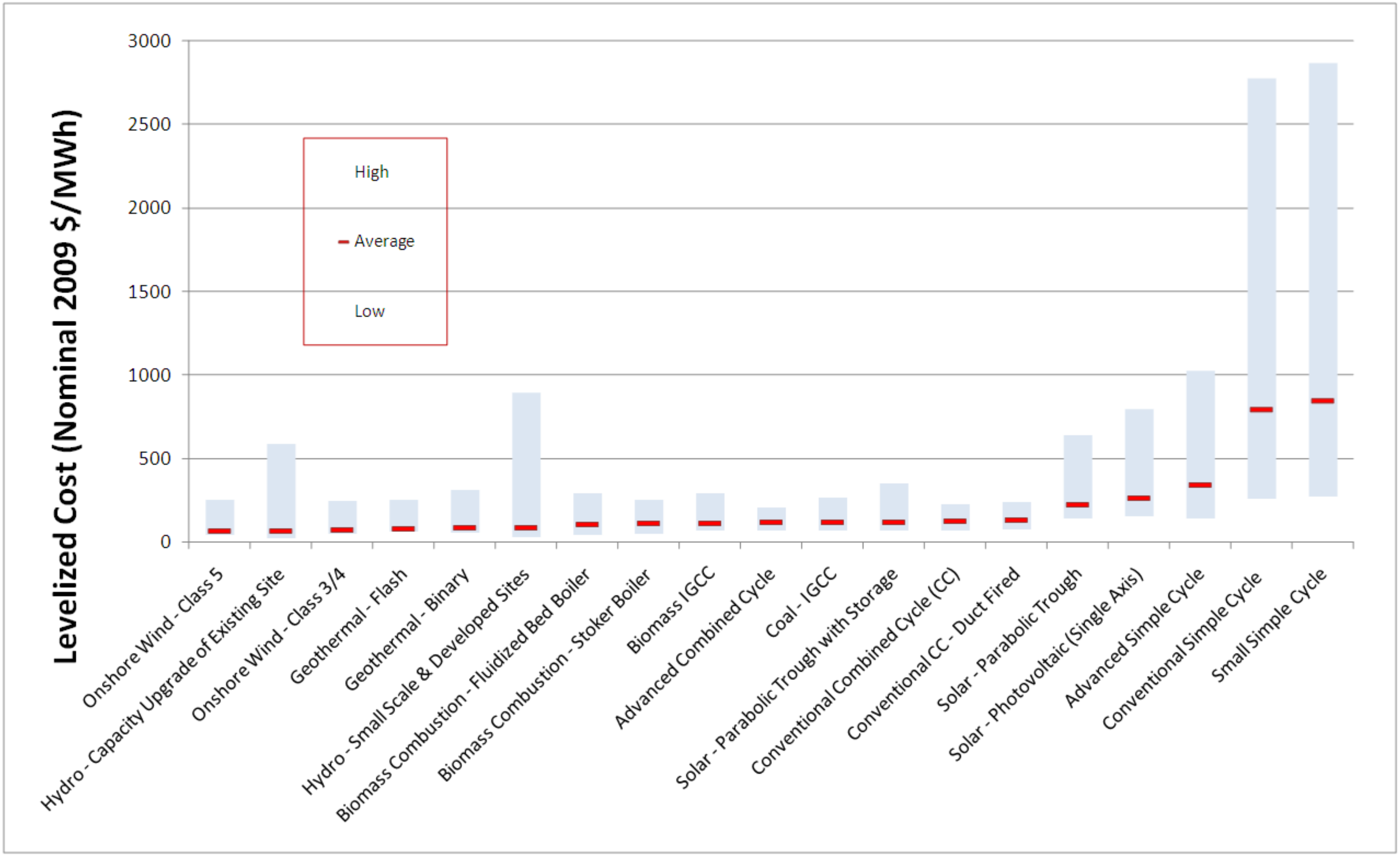
Staff provided the average levelized cost tables and graphs since this is the data that is most commonly understood and requested by various entities—and all too commonly misused. It is also important to understanding levelized costs and its various components. Relying on the average values, however, is misleading and can lead to poor decisions. These average levelized costs are based on a set of conditional assumptions that may not necessarily occur. Actual costs can vary dramatically as shown in **Figure 15**. **Figure 16** shows this same data with the vertical axis expanded to make it more readable. **Figure 17** and **Figure 18** show the same data for technologies coming on-line in 2018.

Definitions of these costs are important to understanding the figures. The average cost is based on a set of typical assumptions that are considered to be the most common values for the respective technologies. The 15 plant type and plant cost assumptions are described in Chapter 2, using the most likely set of financing and tax benefit assumptions. This can be thought of as a baseline nominal case. Each component of this average represents a most-likely-to-occur value.

The averages are a useful starting point for a more complete analysis that incorporates the full range of reasonably expected values. The high value is the maximum level that can reasonably be expected to occur. The highest plant cost and finance assumptions are relatively easy to define based on data observations. The tax benefit assumptions, which are a function of the political posture of the government, are unpredictable. The staff assumed the minimum tax benefits combined with the option of not being able to take all the tax credits in the year they occur. Similarly, the low value is the minimum level that can reasonably be expected, assuming lowest plant cost and finance assumptions that might occur, plus the most favorable tax benefits. The high and the low trends are not the extreme points that can be defined, but rather a reasonable bandwidth of costs given the current knowledge and understanding of these factors.

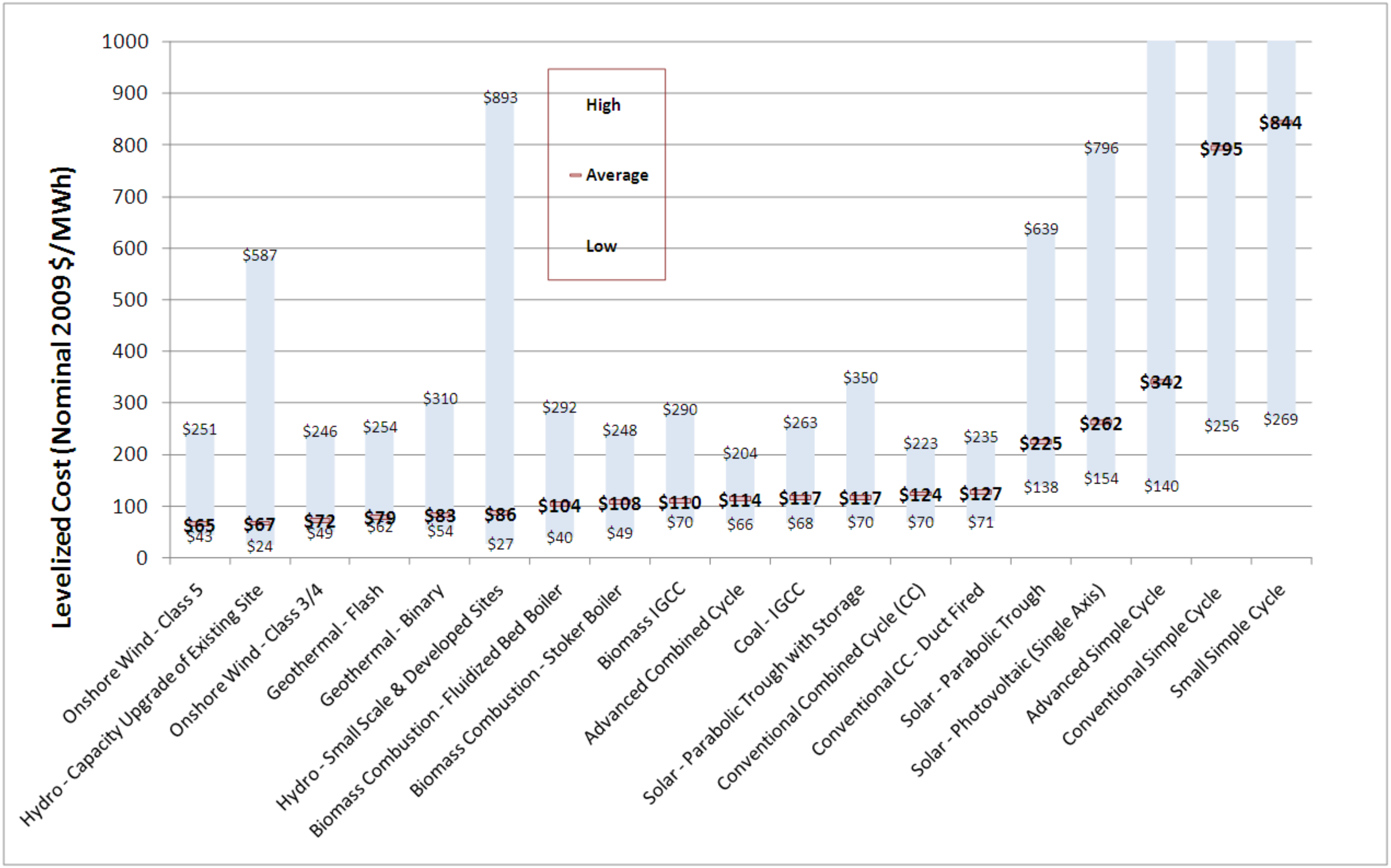
A casual examination of these figures shows that the apparent differences in average cost can be misleading in considering the range of possible costs. The high/low ranges of the conventional simple cycle units are striking and primarily reflect the range in capacity factors. In contrast, the wide range for the hydro units reflects the rather large variation in capital costs.

Figure 15: Range of Levelized Cost for a Merchant Plant In-Service in 2009



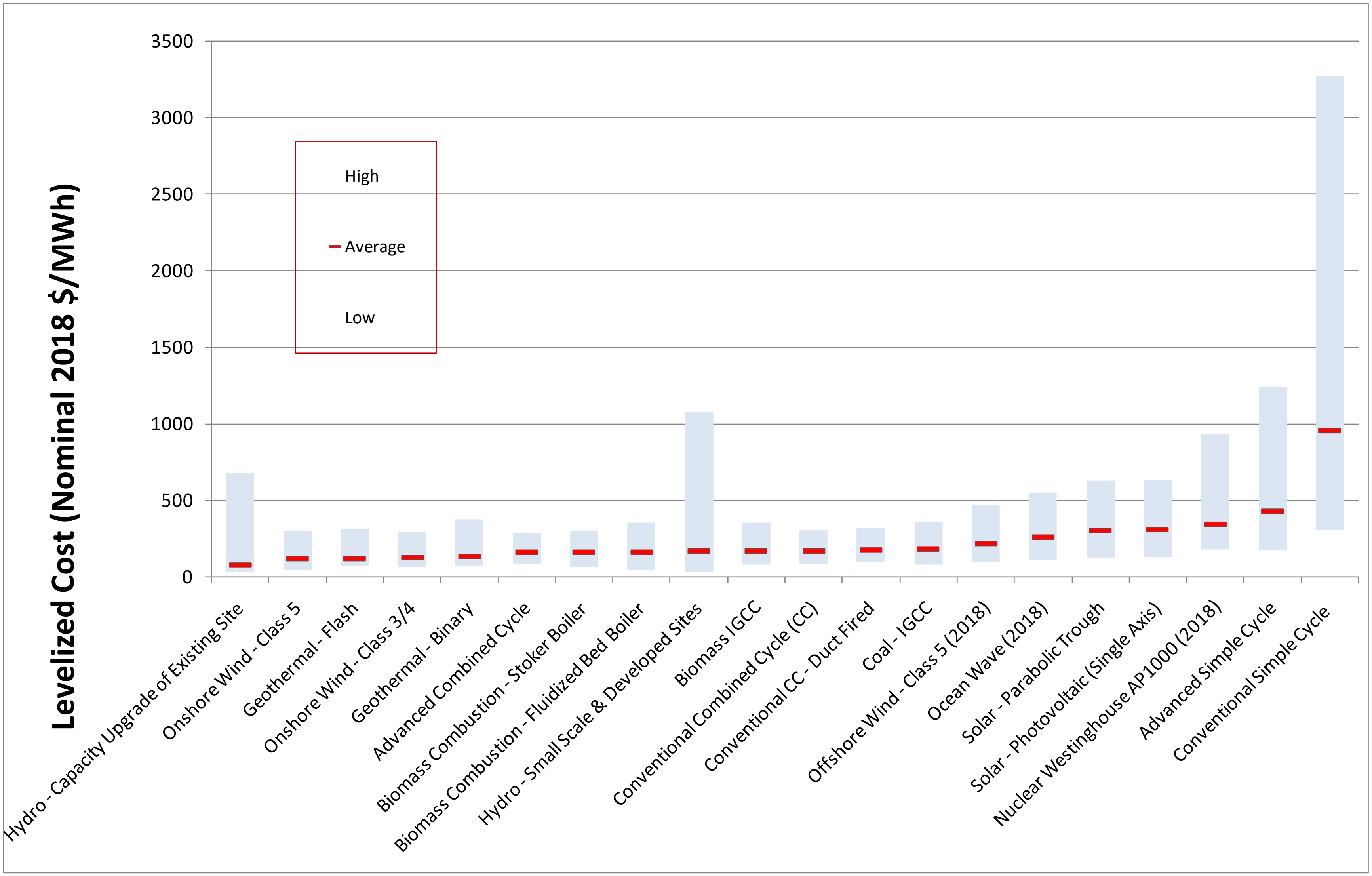
Source: Energy Commission

Figure 16: Range of Levelized Cost for a Merchant Plant In-Service in 2009—Enlarged



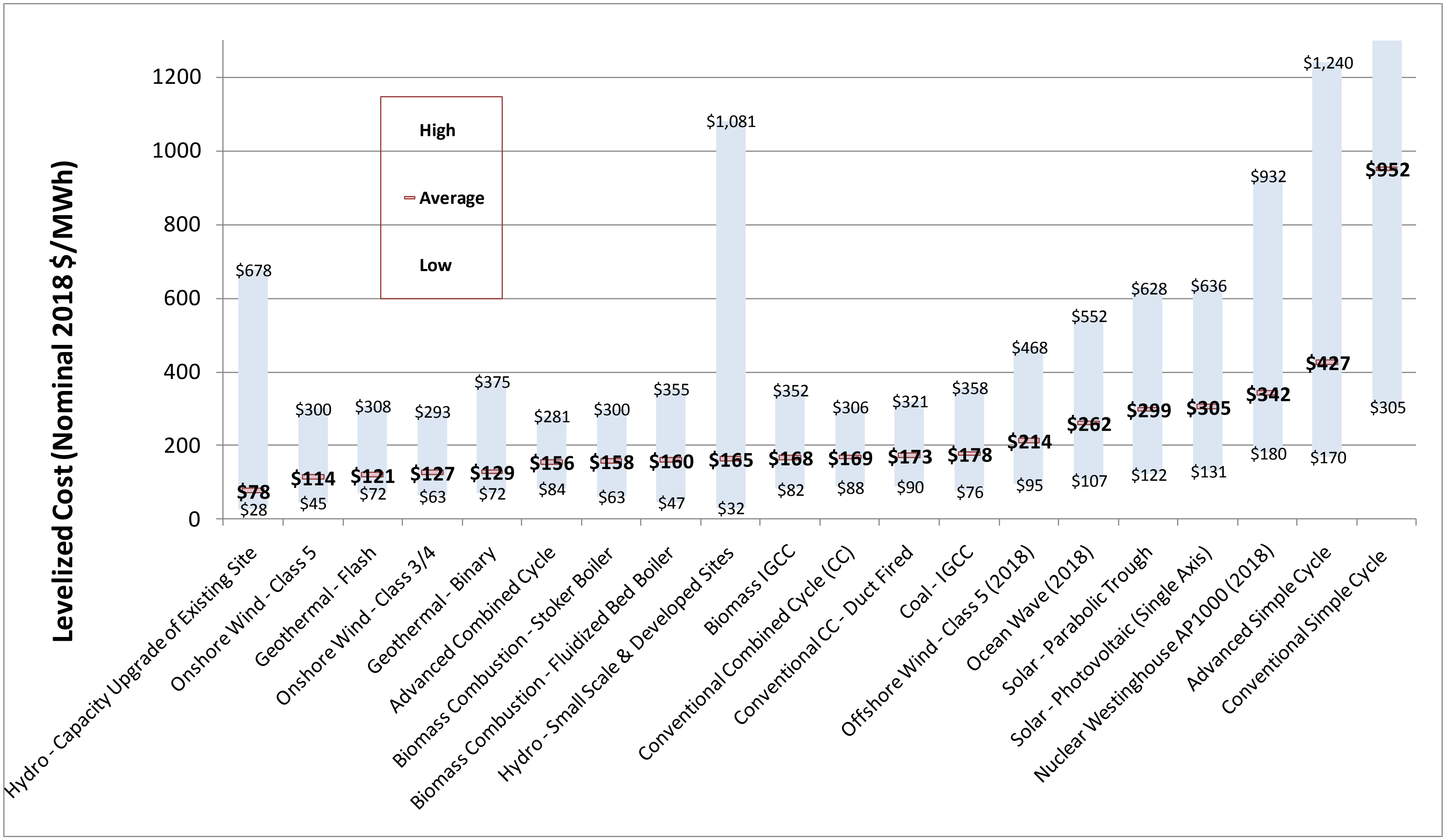
Source: Energy Commission

Figure 17: Range of Levelized Cost for Merchant Plant In-Service in 2018



Source: Energy Commission

Figure 18: Range of Levelized Cost for Merchant Plant In-Service in 2018—Enlarged



Source: Energy Commission

Effect of Tax Benefits

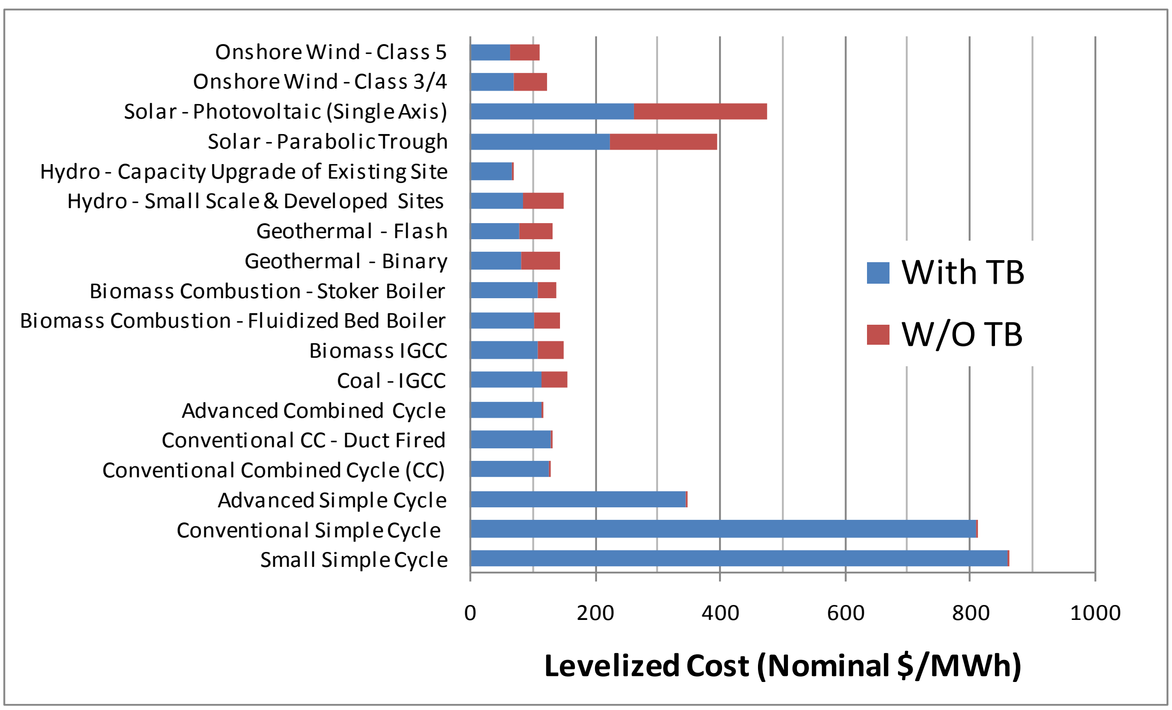
Tax benefits can have a large impact on levelized cost calculations, particularly for renewable technologies. It is important, therefore, to have a good interpretation of tax codes and uncertainty on how they may change when existing regulations expire.

Tax benefits fall into three categories:

- Accelerated depreciation
- Tax credits and tax deductions
- Property tax exemptions – for solar units only

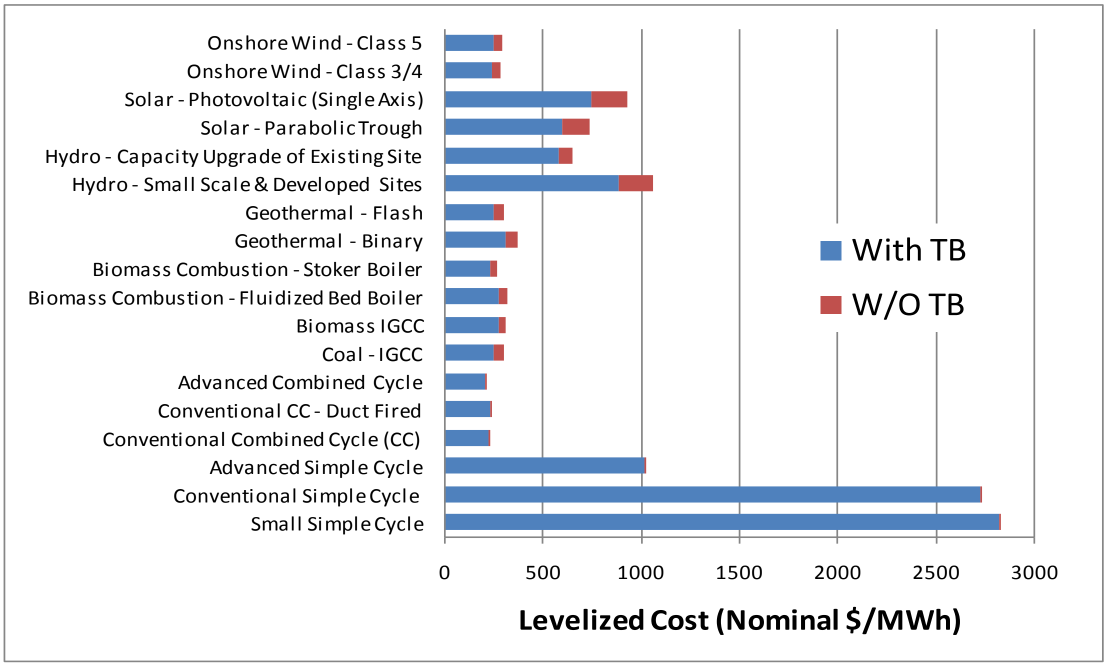
The assumptions for these tax benefits are summarized in Chapter 2. The effect of the tax benefits are shown in **Figure 19** for the Average Case, and in **Figure 20** and **Figure 21** for the High and Low Cases, respectively. All the technologies can take advantage of tax benefits, but only the renewable and alternative technologies have significant tax benefits. Solar has the largest benefits of any of the technologies.

Figure 19: Effect of Tax Benefits (TB)—Average Case



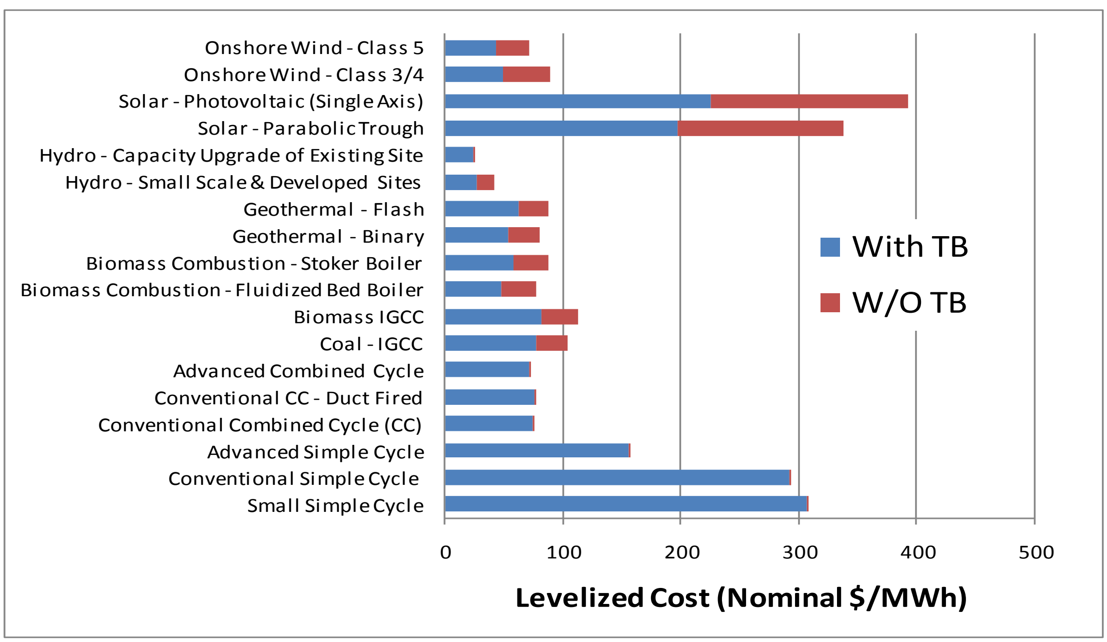
Source: Energy Commission

Figure 20: Effect of Tax Benefits (TB)—High Case



Source: Energy Commission

Figure 21: Effect of Tax Benefits (TB)—Low Case



Source: Energy Commission

Comparison to *2007 IEPR* Levelized Costs

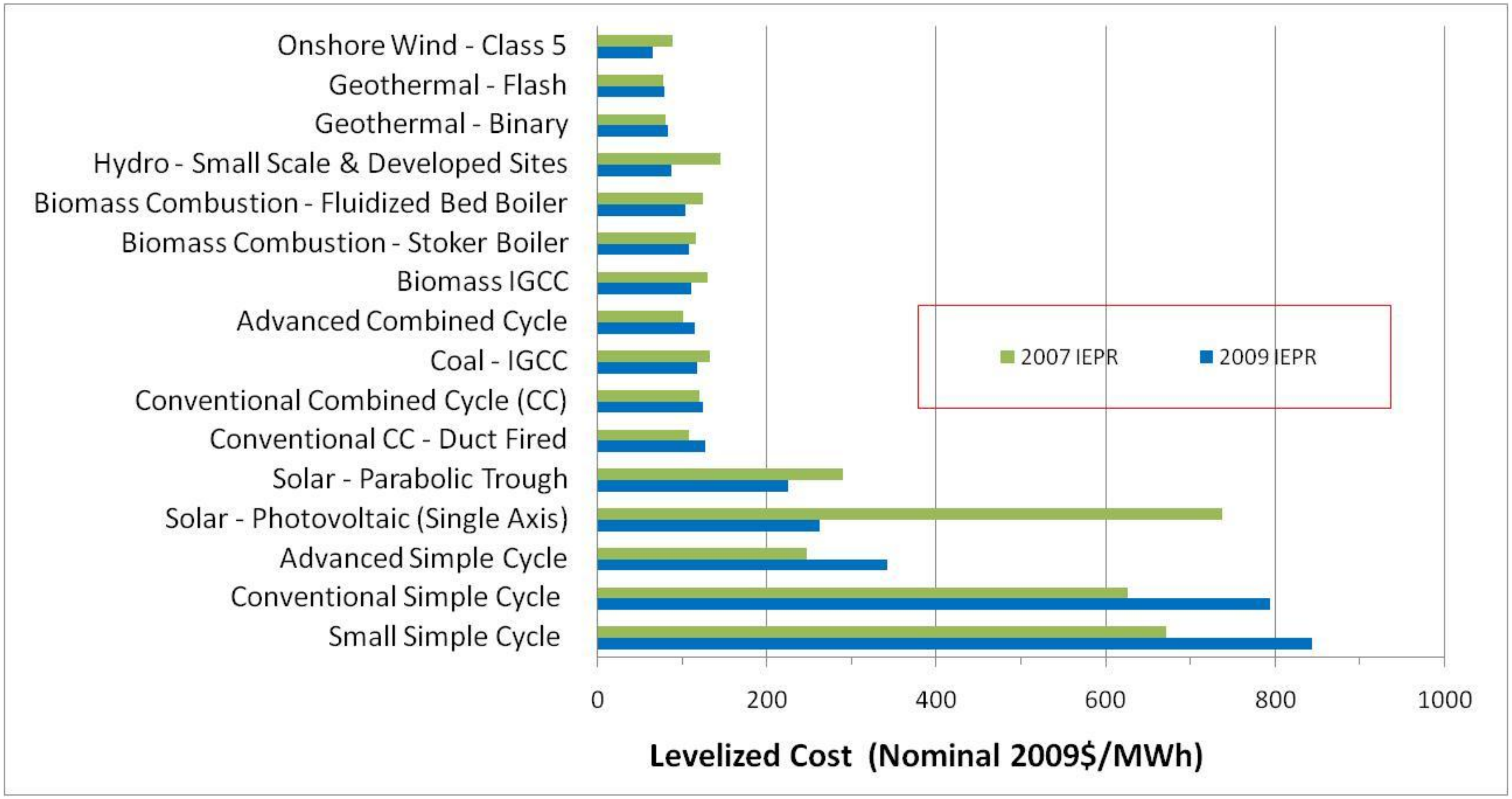
Figure 22 compares the preliminary *2009 IEPR* estimates to the *2007 IEPR* values for the in-service year 2009.

Figure 23 provides the same comparison for the in-service year 2018. These costs are highly affected by tax benefits. **Table 8** compares the change in tax benefits used for the *2009 IEPR* estimates to those in the *2007 IEPR*. **Table 9** shows the same comparison of plants with an in-service date of 2018. These tables show that the effect of tax benefits is much larger in 2009 than in 2018. Although the relationship of the various cost factors that include the tax benefits is complex, a number of worthwhile observations are noted:

- Wind Class 5 is slightly lower in cost for 2009, but by 2018 it is higher than that of the *2007 IEPR* estimates. These differences are largely from changes in the tax treatment.
- All the biomass units have lower levelized costs in 2009 but higher costs in 2018. Although the instant costs are lower, the difference is driven largely by the tax assumptions: higher in the early years, lower in the later years.
- The coal-IGCC technology shows a comparable cost to the 2007 value but would be much higher with the addition of carbon capture and sequestration (CCS) that is now required by law in California to meet the environmental performance standard. However, this increased cost is offset by higher tax credits, a decrease in the base instant cost without CCS, and the higher capacity factor assumed by KEMA (80 percent as compared to previous 60 percent).
- The geothermal technologies have slightly higher levelized costs in the early years and a much higher levelized cost in 2018. Although the instant costs are significantly higher, the difference is primarily from changes in the tax credits.
- Ocean wave has a much lower levelized cost because of a dramatic reduction in the instant cost.
- The solar trough unit shows a significant decrease in levelized cost because of lower instant costs and higher tax credits.
- The solar photovoltaic unit shows a dramatic decrease in cost in 2009, which may reflect the size difference more than cost improvement, and an even larger decrease in 2018 that is primarily from the dramatic decrease in instant cost.

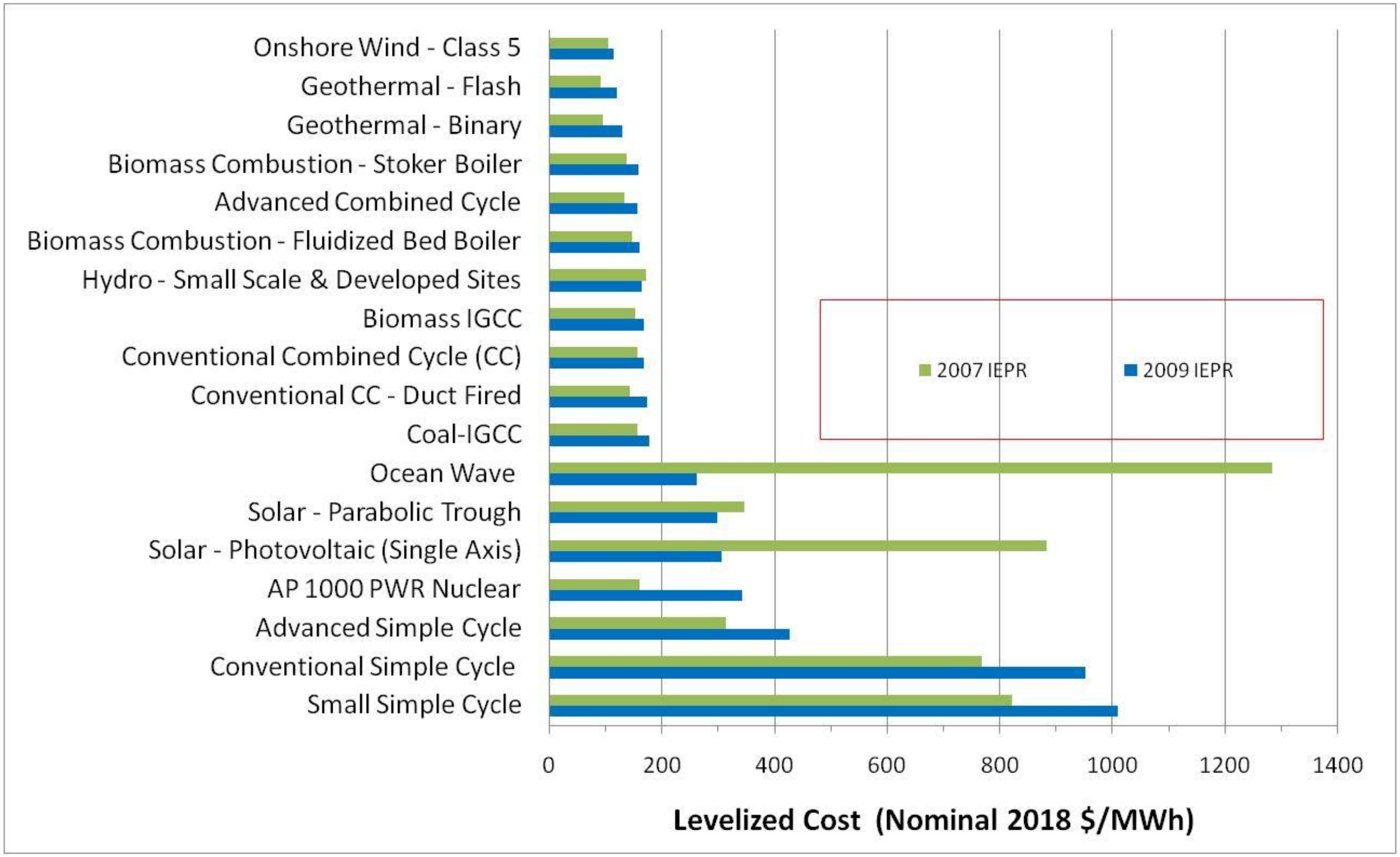
Gas-fired technologies are generally higher primarily because of the dramatic increases capital cost, as shown in **Table 10**. The effect of the increased capital cost is seen mostly in the simple cycle units, where fixed cost is the major cost component. The change in combined cycle costs is lessened due to a higher assumed capacity factor. The change in nuclear costs is partially masked by the *2007 IEPR* estimate being based on average costs, whereas the 2009 estimate reflects a more specific technology.

Figure 22: Comparing *2009 IEPR* Levelized Costs to *2007 IEPR*—In-Service in 2009



Source: Energy Commission

Figure 23: Comparing *2009 IEPR* Levelized Costs to *2007 IEPR*—In-Service in 2018



Source: Energy Commission

Table 8: *2009 IEPR* Merchant Tax Benefits vs. *2007 IEPR*—In-Service in 2009

Technology In-Service Year = 2009	2009 IEPR (Nominal 2009 $/MWh) Cost With Tax Benefits	2009 IEPR Cost Without Tax Benefits	2009 IEPR Tax Benefit	2009 IEPR As a % of Cost w/o Tax Benefits	2007 IEPR (Nominal 2009 $/MWh) Cost With Tax Benefits	2007 IEPR Cost Without Tax Benefits	2007 IEPR Tax Benefit	2007 IEPR As a % of Cost w/o Tax Benefits
Coal - IGCC	116.83	160.49	43.66	27%	132.72	137.07	4.36	3%
Biomass - IGCC	109.99	167.75	57.76	34%	129.19	150.31	21.12	14%
Biomass - Direct Combustion W/ Fluidized Bed	104.02	160.76	56.74	35%	123.96	155.23	31.27	20%
Biomass - Direct Combustion W/Stoker Boiler	108.25	153.67	45.42	30%	116.03	146.63	30.60	21%
Geothermal - Binary	83.11	169.99	86.88	51%	79.39	117.35	37.96	32%
Geothermal - Dual Flash	78.91	155.42	76.51	49%	77.13	114.45	37.32	33%
Hydro - Small Scale	86.47	180.53	94.06	52%	144.97	168.00	23.03	14%
Solar - Parabolic Trough	224.70	495.59	270.88	55%	289.96	376.47	86.52	23%
Solar - Photovoltaic (Single Axis)	262.21	596.47	334.26	56%	737.64	1010.02	272.38	27%
Wind - Class 5	65.47	132.31	66.84	51%	88.10	123.90	35.80	29%

Source: Energy Commission

Table 9: *2009 IEPR* Merchant Tax Benefits vs. *2007 IEPR*—In-Service in 2018

Technology In-Service Year = 2018	2009 IEPR (Nominal 2018 $/MWh) Cost With Tax Benefits	2009 IEPR Cost Without Tax Benefits	2009 IEPR Tax Benefit	2009 IEPR As a % of Cost w/o Tax Benefits	2007 IEPR (Nominal 2018 $/MWh) Cost With Tax Benefits	2007 IEPR Cost Without Tax Benefits	2007 IEPR Tax Benefit	2007 IEPR As a % of Cost w/o Tax Benefits
Coal - IGCC	178.14	182.08	3.94	2%	161.62	166.80	5.18	3%
AP 1000 PWR Nuclear	342.41	342.53	0.11	0%	156.70	172.45	15.76	9%
Biomass - IGCC	168.48	192.24	23.76	12%	153.92	179.01	25.09	14%
Biomass - Direct Combustion W/ Fluidized Bed	160.43	183.74	23.31	13%	147.05	184.20	37.15	20%
Biomass - Direct Combustion W/Stoker Boiler	158.22	176.93	18.71	11%	137.48	173.83	36.35	21%
Geothermal - Binary	129.42	189.62	60.20	32%	95.45	140.53	45.08	32%
Geothermal - Dual Flash	120.72	173.66	52.94	30%	92.87	137.20	44.33	32%
Hydro - Small Scale	164.59	203.17	38.58	19%	172.76	200.11	27.35	14%
Ocean - Wave (2018)	261.71	319.65	57.95	18%	1282.96	1441.32	158.35	11%
Solar - Parabolic Trough	298.64	409.85	111.21	27%	347.07	449.83	102.77	23%
Solar - Photovoltaic (Single Axis)	305.50	420.15	114.65	27%	883.24	1201.58	318.33	26%
Wind - Class 5	114.06	139.34	25.28	18%	530.30	697.96	167.66	24%

Source: Energy Commission

Table 10: Increases in instant Cost From *2007 IEPR* to *2009 IEPR*

Gas-Fired Technology In-Service Year = 2009	MW	2007 IEPR	2009 IEPR	Increase
Small Simple Cycle	49.9	$1,017	$1,292	26.95%
Conventional Simple Cycle	100	$966	$1,231	27.33%
Advanced Simple Cycle	200	$794	$827	4.12%
Conventional Combined Cycle (CC)	500	$810	$1,095	35.08%
Conventional CC - Duct Fired	550	$834	$1,080	29.56%
Advanced Combined Cycle	800	$800	$990	23.72%

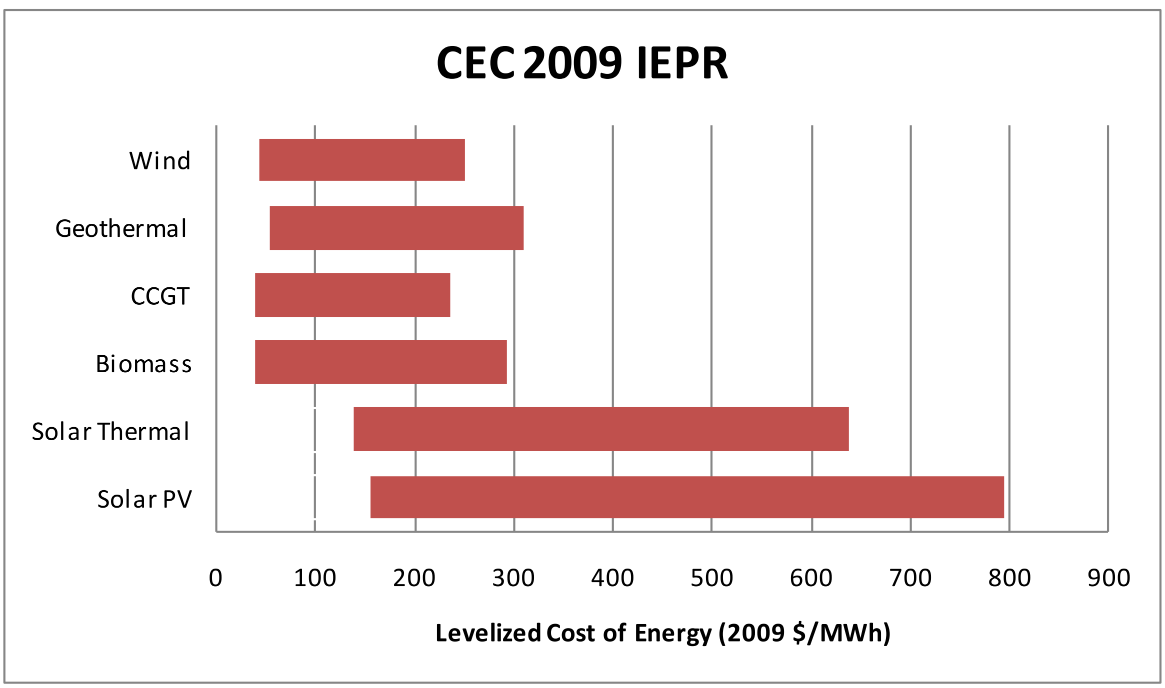
Source: Energy Commission

Comparison to CPUC 33 Percent Renewable Portfolio Standard Report

Figure 24 summarizes the range of levelized cost estimates for the *2009 IEPR* and **Figure** 25 summarizes the range of levelized costs from the draft June 2009 California Public Utilities Commission report on *33% Renewable Portfolio Standard Implementation Analysis*. In both cases, the total range of each technology cost is shown across the various configurations of that technology category.

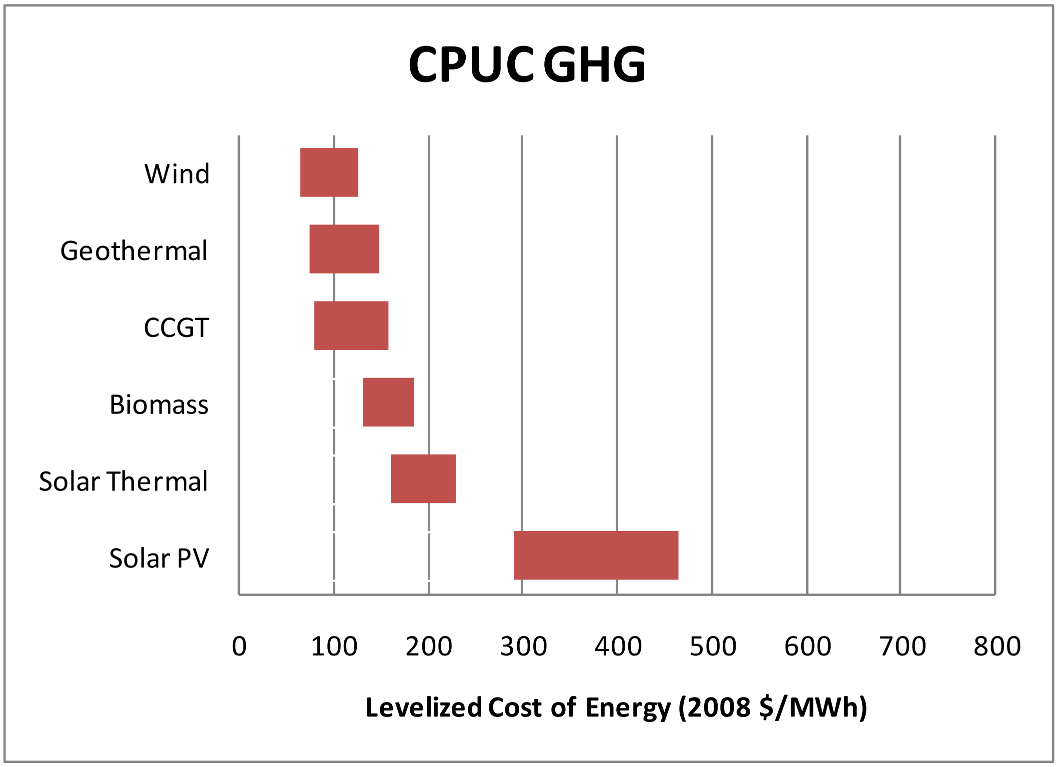
The *2009 IEPR* estimates represent a complete range of all costs, including an element of uncertainty associated with tax benefits. The CPUC range is more limited in that it represents only a range of average costs throughout the West and regions within the state. It does not reflect potential differences in costs developing over time, using a single base cost forecast and adjusting for regional and transmission investment differences. The *IEPR* ranges reflect differences in how the technologies might develop through 2018 and empirical observed ranges in similar locations. Regional differences can then be applied to these estimates for specific projects.

Figure 24: Range of Technology Costs for *2009 IEPR*



Source: Energy Commission

Figure 25: Range of Technology Costs for CPUC 33% RPS Report

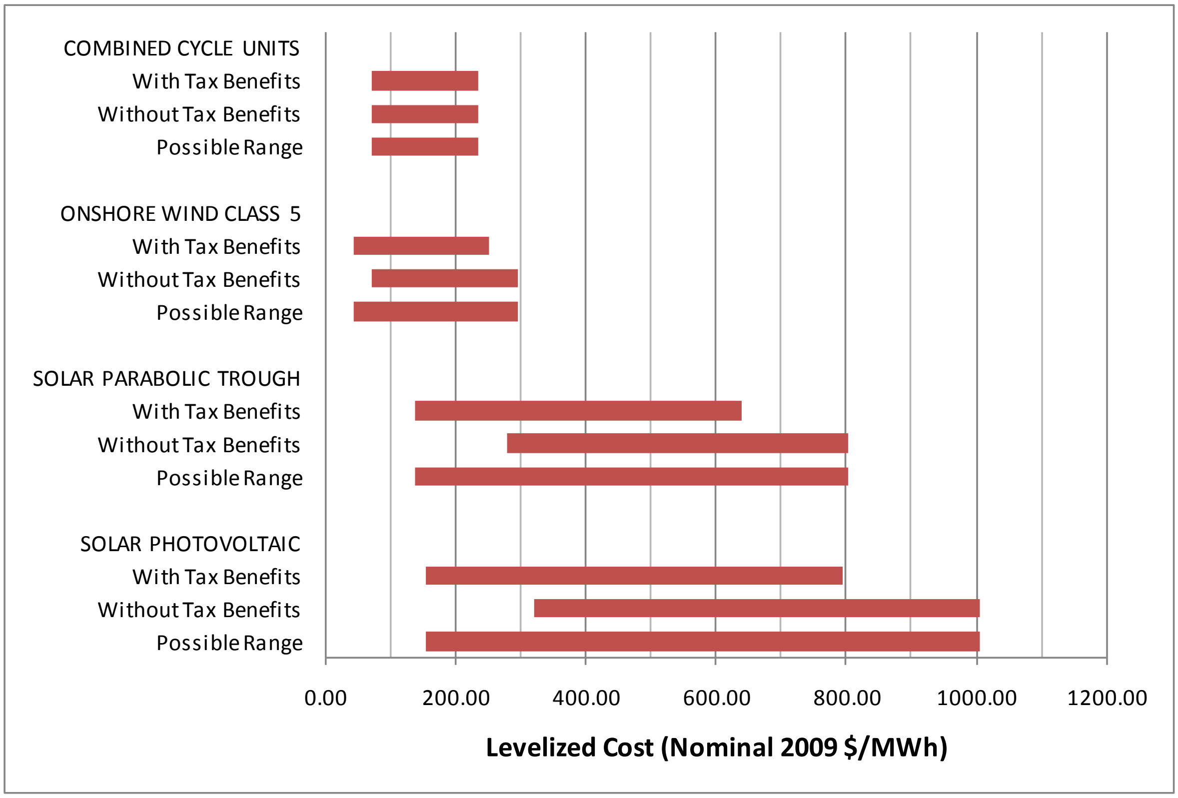


Source: June 2009 Draft CPUC 33% RPS Report

Possible Range of Levelized Costs

Figure 26 illustrates the maximum possible range of levelized costs for selected technologies. The figure shows the range of costs with and without tax benefits. The low value is the cost including tax benefits. The high value is the high cost without the tax benefits. These two points define the possible range of costs.

Figure 26: Maximum Possible Range of Levelized Costs

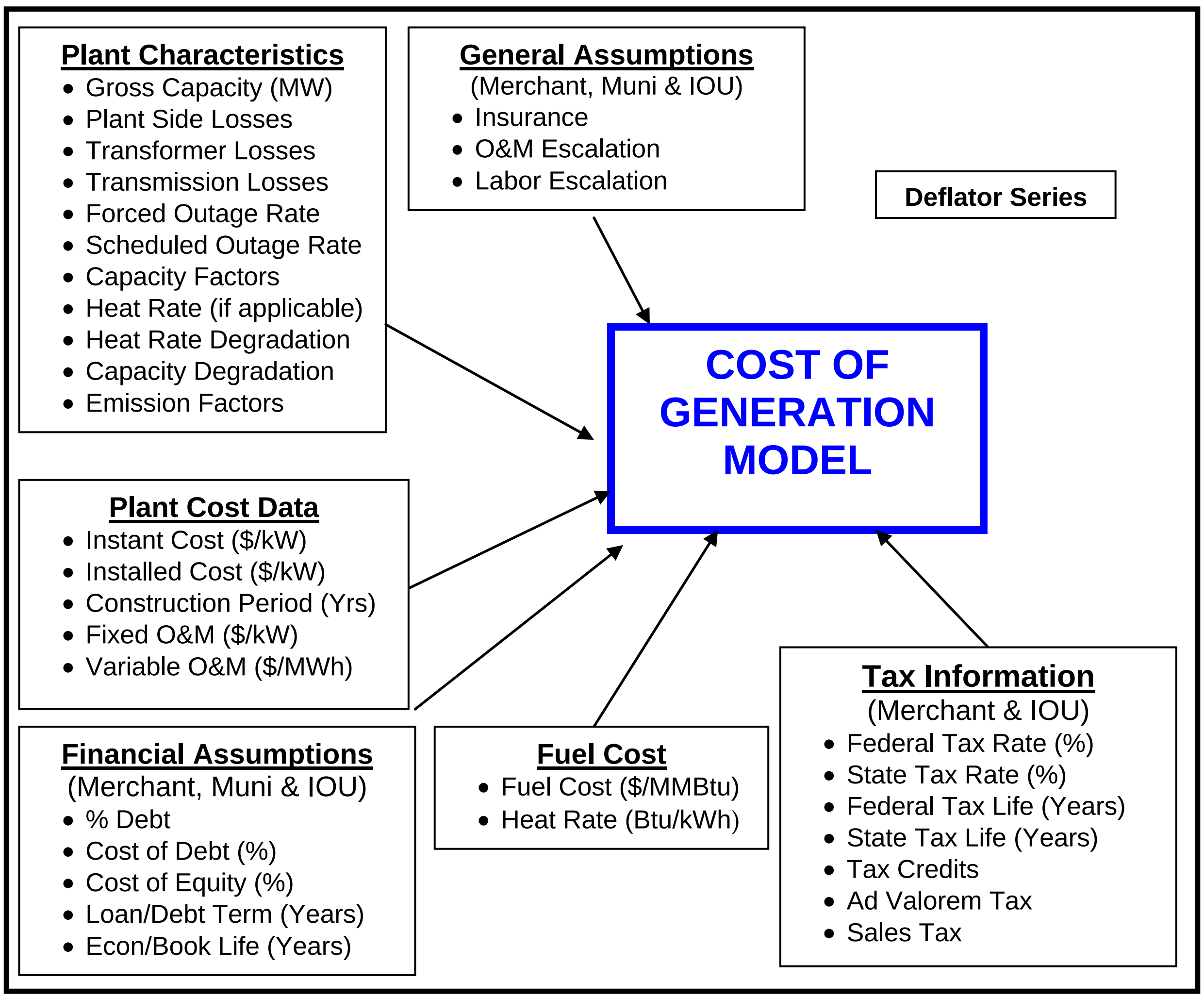


Source: Energy Commission

CHAPTER 2: Assumptions

This chapter summarizes the assumptions that were used to develop the levelized costs presented in the previous chapter. The details of these assumptions can be found in Appendix C for gas-fired generation and in the July 2009 Public Interest Energy Research (PIER) interim report *Renewable Energy Cost of Generation Update* (CEC-500-2009-084) for renewable, nuclear, and IGCC generation. **Figure 27** is a block diagram of the input assumptions.

Figure 27: Block Diagram of Input Assumptions



Source: Energy Commission

The assumptions are organized into five categories:

- Plant Data
- Plant Cost Data
- Fuel Cost and Inflation Data
- Financial Assumptions
- General Assumptions

Plant Data

Table 11 summarizes the plant data assumptions (power plant characteristics) for the average case. **Table 12** and **Table 13** summarize the same data for the high and low cases.

Gross Capacity (MW)

This is the capacity of the power plant absent plant-side losses, that is, the capacity of the power plant before accounting for the power used by the plant for operational purposes. Net Capacity is the capacity of the plant net of plant-side losses.

Plant Side Losses (Percentage)

These are sometimes defined as "parasitic losses" or "station service losses." This is the power consumed by the power plant as a part of its normal operation. It can also be defined as the difference between the gross capacity and net capacity.

Transformer Losses (Percentage)

Transformer losses are the losses in uplifting the power from the low voltage side of the transformer (generator voltage) to the high voltage side of the transformer (transmission voltage).

Transmission Losses (Percentage)

Transmission losses represent the power lost in getting the power from the high side of the transformer to the load center (sometimes designated as "GMM to Load Center").

Table 11: Plant Data—Average Case

Technology - Plant Data	Gross Capacity (MW)	Plant Side Losses	Transformer Losses	Transmission Losses	Scheduled Outage Factor	Forced Outage Rate	Capacity Factor	HHV Heat Rate (Btu/kWh)	Degradation (%/Year)		Emission Factors (Lbs/MWh)					
									Capacity	Heat Rate	NOx	VOC	CO	CO2	SOx	PM10
Small Simple Cycle	49.9	3.40%	0.50%	2.09%	2.72%	5.56%	5.00%	9,266	0.05%	0.05%	0.279	0.054	0.368	1080.2	0.013	0.134
Conventional Simple Cycle	100	3.40%	0.50%	2.09%	3.18%	4.13%	5.00%	9,266	0.05%	0.05%	0.279	0.054	0.368	1080.2	0.013	0.134
Advanced Simple Cycle	200	3.40%	0.50%	2.09%	3.18%	4.13%	10.00%	8,550	0.05%	0.05%	0.099	0.031	0.190	996.7	0.008	0.062
Conventional Combined Cycle (CC)	500	2.90%	0.50%	2.09%	6.02%	2.24%	75.00%	6,940	0.20%	0.20%	0.070	0.208	0.024	814.9	0.005	0.037
Conventional CC - Duct Fired	550	2.90%	0.50%	2.09%	6.02%	2.24%	70.00%	7,050	0.20%	0.20%	0.076	0.315	0.018	825.4	0.009	0.042
Advanced Combined Cycle	800	2.90%	0.50%	2.09%	6.02%	2.24%	75.00%	6,470	0.20%	0.20%	0.064	0.018	0.056	758.9	0.005	0.031
Coal - IGCC	300	6.00%	0.50%	2.09%	15.00%	5.00%	80.00%	7,580	0.05%	0.10%	0.220	0.009	0.079	153.2	0.063	0.031
Biomass IGCC	30	3.50%	0.50%	5.00%	3.00%	8.00%	75.00%	10,500	0.05%	0.20%	0.074	0.009	0.029	N/A	0.020	0.100
Biomass Combustion - Fluidized Bed Boiler	28	6.00%	0.50%	5.00%	3.00%	8.00%	85.00%	10,500	0.10%	0.15%	0.074	0.009	0.079	N/A	0.020	0.100
Biomass Combustion - Stoker Boiler	38	4.00%	0.50%	5.00%	3.00%	8.00%	85.00%	11,000	0.10%	0.15%	0.075	0.012	0.105	N/A	0.034	0.100
Geothermal - Binary	15	5.00%	0.50%	5.00%	4.00%	2.50%	90.00%	N/A	4.00%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Geothermal - Flash	30	5.00%	0.50%	5.00%	4.00%	2.50%	94.00%	N/A	4.00%	N/A	0.191	0.011	0.058	N/A	0.026	0.000
Hydro - Small Scale & Developed Sites	15	10.00%	0.50%	5.00%	9.40%	5.10%	30.40%	N/A	2.00%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Hydro - Capacity Upgrade of Existing Site	80	5.00%	0.50%	5.00%	9.40%	5.10%	30.40%	N/A	2.00%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Solar - Parabolic Trough	250	22.40%	0.50%	5.00%	2.20%	1.60%	27.00%	N/A	0.50%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Solar - Photovoltaic (Single Axis)	25	22.40%	0.50%	5.00%	0.00%	2.00%	27.00%	N/A	0.50%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Onshore Wind - Class 3/4	50	0.10%	0.50%	5.00%	1.39%	2.00%	37.00%	N/A	1.00%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Onshore Wind - Class 5	100	0.10%	0.50%	5.00%	1.39%	2.00%	42.00%	N/A	1.00%	N/A	0.000	0.000	0.000	N/A	N/A	N/A

Source: Energy Commission

Table 12: Plant Data—High Case

Technology - Plant Data	Gross Capacity (MW)	Plant Side Losses	Transformer Losses	Transmission Losses	Scheduled Outage Factor	Forced Outage Rate	Capacity Factor	HHV Heat Rate Btu/kWh	Degradation (%/Year)		Emission Factors (Lbs/MWh)					
									Capacity	Heat Rate	NOx	VOC	CO	CO2	SOx	PM10
Small Simple Cycle	49.9	4.20%	0.50%	2.09%	2.72%	5.56%	2.50%	10,000	0.05%	0.20%	0.279	0.054	0.368	1165.8	0.013	0.134
Conventional Simple Cycle	100	4.20%	0.50%	2.09%	3.18%	4.13%	2.50%	10,000	0.05%	0.20%	0.279	0.054	0.368	1165.8	0.013	0.134
Advanced Simple Cycle	200	4.20%	0.50%	2.09%	3.18%	4.13%	5.00%	8,700	0.05%	0.20%	0.099	0.031	0.190	1014.2	0.008	0.062
Conventional Combined Cycle (CC)	500	4.00%	0.50%	2.09%	6.02%	2.24%	55.00%	7,200	0.20%	0.20%	0.070	0.208	0.024	839.4	0.005	0.037
Conventional CC - Duct Fired	550	4.00%	0.50%	2.09%	6.02%	2.24%	50.00%	7,400	0.20%	0.20%	0.076	0.315	0.018	862.7	0.009	0.042
Advanced Combined Cycle	800	4.00%	0.50%	2.09%	6.02%	2.24%	55.00%	6,710	0.20%	0.20%	0.064	0.018	0.056	782.2	0.005	0.031
Coal - IGCC	300	7.00%	0.50%	2.09%	22.50%	7.50%	70.00%	8,025	0.10%	0.20%	0.314	0.009	0.079	163.1	0.094	0.031
Biomass IGCC	30	4.50%	0.50%	5.00%	6.00%	10.00%	60.00%	11,000	0.10%	0.25%	0.074	0.009	0.029	N/A	0.020	0.200
Biomass Combustion - Fluidized Bed Boiler	28	7.00%	0.50%	5.00%	6.00%	10.00%	75.00%	11,000	0.20%	0.20%	0.074	0.009	0.079	N/A	0.020	0.200
Biomass Combustion - Stoker Boiler	38	7.00%	0.50%	5.00%	6.00%	10.00%	75.00%	13,500	0.20%	0.20%	0.075	0.012	0.105	N/A	0.034	0.200
Geothermal - Binary	15	10.00%	0.50%	5.00%	12.00%	2.80%	80.00%	N/A	4.00%	N/A	0.000	0.000	0.000	N/A	0.000	0.000
Geothermal - Flash	30	5.00%	0.50%	5.00%	12.00%	2.80%	90.00%	N/A	4.00%	N/A	0.191	0.011	0.058	N/A	0.026	0.000
Hydro - Small Scale & Developed Sites	15	13.00%	0.50%	5.00%	9.56%	6.70%	12.50%	N/A	2.25%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Hydro - Capacity Upgrade of Existing Site	80	15.00%	0.50%	5.00%	9.56%	6.70%	12.50%	N/A	2.25%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Solar - Parabolic Trough	250	24.00%	0.50%	5.00%	4.20%	1.60%	26.00%	N/A	1.00%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Solar - Photovoltaic (Single Axis)	25	24.00%	0.50%	5.00%	0.00%	8.00%	26.00%	N/A	1.00%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Onshore Wind - Class 3/4	50	0.10%	0.50%	5.00%	1.83%	2.70%	41.00%	N/A	1.00%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Onshore Wind - Class 5	100	0.10%	0.50%	5.00%	1.83%	2.70%	40.00%	N/A	1.00%	N/A	0.000	0.000	0.000	N/A	N/A	N/A

Source: Energy Commission

Table 13: Plant Data—Low Case

Technology - Plant Data	Gross Capacity (MW)	Plant Side Losses	Transformer Losses	Transmission Losses	Scheduled Outage Factor	Forced Outage Rate	Capacity Factor	HHV Heat Rate (Btu/kWh)	Degradation (%/Year)		Emission Factors (Lbs/MWh)					
									Capacity	Heat Rate	NOx	VOC	CO	CO2	SOx	PM10
Small Simple Cycle	49.9	2.30%	0.50%	2.09%	2.72%	5.56%	10.00%	9,020	0.05%	0.05%	0.279	0.054	0.368	1051.5	0.013	0.134
Conventional Simple Cycle	100	2.30%	0.50%	2.09%	3.18%	4.13%	10.00%	9,020	0.05%	0.05%	0.279	0.054	0.368	1051.5	0.013	0.134
Advanced Simple Cycle	200	2.30%	0.50%	2.09%	3.18%	4.13%	20.00%	8,230	0.05%	0.05%	0.099	0.031	0.190	959.4	0.008	0.062
Conventional Combined Cycle (CC)	500	2.00%	0.50%	2.09%	6.02%	2.24%	90.00%	6,600	0.20%	0.20%	0.070	0.208	0.024	769.4	0.005	0.037
Conventional CC - Duct Fired	550	2.00%	0.50%	2.09%	6.02%	2.24%	85.00%	6,700	0.20%	0.20%	0.076	0.315	0.018	781.1	0.009	0.042
Advanced Combined Cycle	800	2.00%	0.50%	2.09%	6.02%	2.24%	90.00%	6,310	0.20%	0.20%	0.064	0.018	0.056	735.6	0.005	0.031
Coal - IGCC	300	5.00%	0.50%	2.09%	7.50%	2.50%	90.00%	7,100	0.00%	0.10%	0.126	0.009	0.079	143.3	0.031	0.031
Biomass IGCC	30	2.50%	0.50%	2.09%	2.00%	6.00%	85.00%	10,000	0.00%	0.15%	0.074	0.009	0.029	N/A	0.020	0.025
Biomass Combustion - Fluidized Bed Boiler	28	5.00%	0.50%	2.09%	2.00%	6.00%	90.00%	9,800	0.00%	0.10%	0.074	0.009	0.079	N/A	0.020	0.025
Biomass Combustion - Stoker Boiler	38	2.40%	0.50%	2.09%	2.00%	6.00%	90.00%	10,250	0.00%	0.10%	0.075	0.012	0.105	N/A	0.034	0.025
Geothermal - Binary	15	5.00%	0.50%	2.09%	2.00%	2.20%	95.00%	N/A	4.00%	N/A	0.000	0.000	0.000	N/A	0.000	0.000
Geothermal - Flash	30	5.00%	0.50%	2.09%	2.00%	2.20%	98.00%	N/A	4.00%	N/A	0.191	0.011	0.058	N/A	0.026	0.000
Hydro - Small Scale & Developed Sites	15	9.20%	0.50%	2.09%	9.20%	3.80%	61.50%	N/A	1.75%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Hydro - Capacity Upgrade of Existing Site	80	5.00%	0.50%	2.09%	9.20%	3.80%	61.50%	N/A	1.75%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Solar - Parabolic Trough	250	20.40%	0.50%	2.09%	2.20%	1.60%	28.00%	N/A	0.25%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Solar - Photovoltaic (Single Axis)	25	20.00%	0.50%	2.09%	0.00%	1.00%	28.00%	N/A	0.25%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Onshore Wind - Class 3/4	50	0.10%	0.50%	2.09%	0.96%	1.30%	34.00%	N/A	1.00%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Onshore Wind - Class 5	100	0.10%	0.50%	2.09%	0.96%	1.30%	44.00%	N/A	1.00%	N/A	0.000	0.000	0.000	N/A	N/A	N/A

Source: Energy Commission

Schedule Outage Factor (SOF)

This is a term developed by the North American Reliability Council's (NERC)[5] Generating Availability Data System (GADS).[6] The NERC/GADS term is used to define the maintenance period. SOF is the ratio of scheduled outage hours (SOH) to the period hours (PH), typically the hours in a year (8,760), that is, the percentage of the year that a plant is on scheduled maintenance. If a plant has 876 hours of scheduled maintenance, then its SOF is 10 percent. This is generally synonymous with the commonly misused modeling term maintenance outage rate (MOR). The formula for this measure is:

SOF = SOH/PH

Forced Outage Rate (FOR)

This is a NERC/GADS term to measure a power plant's rate of failure. This calculation ignores the period during reserve shutdown (economic shutdown). The FOR is based solely on when it is called upon to be dispatched. The simplified GADS formula for this measure is:

FOR = FOH / (FOH + SH)

Where: FOH = Forced Outage Hours (Hours of Failed Operation)

SH = Service Hours (Hours of Successful Operation)

This is a commonly used characterization but is very simplified since a power plant can have a partial failure and operate at reduced power. The more precise term is equivalent FOR (EFOR), which includes other plant variables. EFOR is relevant for analyzing the performance of operating power plants. However, it should be understood that where EFOR data is available, it is applied to the Model. For simplicity, the term FOR is used in the Model, with the understanding that the appropriate value is really EFOR.

Capacity Factor (Percentage)

The capacity factor (CF) is specified as a percentage and is a measure of how much the power plant operates. More precisely, it is equal to the energy generated by the power plant during the year divided by the energy it could have generated if it had run at its full capacity throughout the entire year (Gross MW x 8,760 hours). For a solar plant, the gross MW are measured at the DC level, as opposed to AC level.

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[5] NERC was developed as a result of the Northeast blackout on November 9, 1965. It is a non-profit organization that was created in 1968 to improve the reliability of the electric system.

[6] NERC recognized the need to gather data to be effective in proposing reliability measures and created GADS in 1979.

Heat Rate (Btu/kWh)

Heat rates are a measure of the efficiency of power plants. It is the amount of heat supplied in British thermal units (Btu) to generate 1 kWh of electricity. The smaller the heat rate, the greater the efficiency. The efficiency of a power plant can be calculated as 3,413 divided by the heat rate (3,413 being the conversion factor to convert 1 kWh into Btu).

Capacity Degradation Factor (Percentage)

This is the percentage that the gross capacity will decrease each year from wear and tear, which affects not only the capacity, but also the energy generation. This is reflected in the energy calculation in the Model. This degradation can be partially offset by maintenance, such that a true characterization would have an up and down characterization that trends generally downward. The fluctuation reflects the wear and tear, followed by an improved period. The factor used herein is an equivalent constant annual amount that reflects both the net effect of the deterioration and maintenance periods.

Heat Rate Degradation Factor (Percentage)

Heat rate degradation is a measure of the decrease in efficiency due to aging. It is the percentage that the heat rate will increase per year. Similar to capacity degradation, it fluctuates up and down, generally trending downward. The percentage used herein is an equivalent annual amount that reflects both the net effect of the deterioration and maintenance periods.

Plant Cost Data

Table 14 summarizes the data for the average case. Since the ocean wave and offshore wind technologies do not become feasible until 2018, the data shown here are the 2018 costs deflated to 2009 dollars. **Table 15** and **Table 16** summarize the corresponding high and low cases.

Table 14: Plant Cost Data—Average Case

Plant Cost Data Start Year = 2009 (2009 Dollars)	Gross Capacity (MW)	Instant Costs ($/kW)			Construction Period (%/Year)						Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)
		Base	Environmental Compliance	Total	Year-0	Year-1	Year-2	Year-3	Year-4	Year-5		
Small Simple Cycle	49.9	1,277	15	1,292	100%	0%	0%	0%	0%	0%	23.94	4.17
Conventional Simple Cycle	100	1,204	27	1,231	100%	0%	0%	0%	0%	0%	17.40	4.17
Advanced Simple Cycle	200	801	26	827	75%	25%	0%	0%	0%	0%	16.33	3.67
Conventional Combined Cycle (CC)	500	1,044	51	1,095	75%	25%	0%	0%	0%	0%	8.62	3.02
Conventional CC - Duct Fired	550	1,021	59	1,080	75%	25%	0%	0%	0%	0%	8.30	3.02
Advanced Combined Cycle	800	957	33	990	75%	25%	0%	0%	0%	0%	7.17	2.69
Coal - IGCC	300	3,128	56	3,184	80%	20%	0%	0%	0%	0%	52.35	9.57
Biomass IGCC	30	2,950	47	2,997	75%	25%	0%	0%	0%	0%	150.00	4.00
Biomass Combustion - Fluidized Bed Boiler	28	3,200	54	3,254	80%	20%	0%	0%	0%	0%	99.50	4.47
Biomass Combustion - Stoker Boiler	38	2,600	58	2,658	80%	20%	0%	0%	0%	0%	160.10	6.98
Geothermal - Binary	15	4,046	0	4,046	40%	40%	20%	0%	0%	0%	47.44	4.55
Geothermal - Flash	30	3,676	42	3,718	40%	40%	20%	0%	0%	0%	58.38	5.06
Hydro - Small Scale & Developed Sites	15	1,730	0	1,730	100%	0%	0%	0%	0%	0%	17.57	3.48
Hydro - Capacity Upgrade of Existing Site	80	771	0	771	100%	0%	0%	0%	0%	0%	12.59	2.39
Solar - Parabolic Trough	250	3,687	0	3,687	100%	0%	0%	0%	0%	0%	68.00	0.00
Solar - Photovoltaic (Single Axis)	25	4,550	0	4,550	100%	0%	0%	0%	0%	0%	68.00	0.00
Onshore Wind - Class 3/4	50	1,990	0	1,990	95%	5%	0%	0%	0%	0%	13.70	5.50
Onshore Wind - Class 5	100	1,990	0	1,990	95%	5%	0%	0%	0%	0%	13.70	5.50

Source: Energy Commission

Table 15: Plant Cost Data—High Case

Plant Cost Data Start Year = 2009 (2009 Dollars)	Gross Capacity (MW)	Instant Costs ($/kW)			Construction Period (%/Year)						Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)
		Base	Environmental Compliance	Total	Year-0	Year-1	Year-2	Year-3	Year-4	Year-5		
Small Simple Cycle	49.9	1,567	11	1,578	75%	25%	0%	0%	0%	0%	42.44	9.05
Conventional Simple Cycle	100	1,495	23	1,518	75%	25%	0%	0%	0%	0%	42.44	9.05
Advanced Simple Cycle	200	919	23	942	50%	40%	10%	0%	0%	0%	39.82	8.05
Conventional Combined Cycle (CC)	500	1,349	40	1,389	50%	40%	10%	0%	0%	0%	12.62	3.84
Conventional CC - Duct Fired	550	1,325	45	1,370	50%	40%	10%	0%	0%	0%	12.62	3.84
Advanced Combined Cycle	800	1,218	27	1,245	50%	40%	10%	0%	0%	0%	10.97	3.42
Coal - IGCC	300	3,892	66	3,957	60%	40%	0%	0%	0%	0%	65.33	11.95
Biomass IGCC	30	3,688	63	3,751	50%	40%	10%	0%	0%	0%	175.00	4.50
Biomass Combustion - Fluidized Bed Boiler	28	4,800	80	4,880	60%	40%	0%	0%	0%	0%	150.00	10.00
Biomass Combustion - Stoker Boiler	38	3,250	83	3,333	50%	40%	10%	0%	0%	0%	200.00	8.73
Geothermal - Binary	15	5,881	0	5,881	45%	45%	10%	0%	0%	0%	54.65	5.12
Geothermal - Flash	30	5,279	41	5,320	45%	45%	10%	0%	0%	0%	67.14	5.28
Hydro - Small Scale & Developed Sites	15	2,770	0	2,770	35%	40%	25%	0%	0%	0%	28.83	5.54
Hydro - Capacity Upgrade of Existing Site	80	1,638	0	1,638	35%	40%	25%	0%	0%	0%	27.05	5.00
Solar - Parabolic Trough	250	3,900	0	3,900	100%	0%	0%	0%	0%	0%	92.00	0.00
Solar - Photovoltaic (Single Axis)	25	5,005	0	5,005	100%	0%	0%	0%	0%	0%	92.00	0.00
Onshore Wind - Class 3/4	50	3,025	0	3,025	45%	45%	10%	0%	0%	0%	17.13	7.66
Onshore Wind - Class 5	100	3,025	0	3,025	45%	45%	10%	0%	0%	0%	17.13	7.66

Source: Energy Commission

Table 16: Plant Cost Data—Low Case

Plant Cost Data Start Year = 2009 (2009 Dollars)	Gross Capacity (MW)	Instant Costs ($/kW)			Construction Period (%/Year)						Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)
		Base	Environmental Compliance	Total	Year-0	Year-1	Year-2	Year-3	Year-4	Year-5		
Small Simple Cycle	49.9	914	21	935	100%	0%	0%	0%	0%	0%	6.68	0.88
Conventional Simple Cycle	100	842	33	875	100%	0%	0%	0%	0%	0%	6.68	0.88
Advanced Simple Cycle	200	693	31	724	100%	0%	0%	0%	0%	0%	6.27	0.79
Conventional Combined Cycle (CC)	500	777	59	836	100%	0%	0%	0%	0%	0%	5.76	2.19
Conventional CC - Duct Fired	550	753	69	822	100%	0%	0%	0%	0%	0%	5.76	2.19
Advanced Combined Cycle	800	759	37	796	100%	0%	0%	0%	0%	0%	5.01	1.95
Coal - IGCC	300	2,356	42	2,398	80%	20%	0%	0%	0%	0%	39.79	7.17
Biomass IGCC	30	2,655	26	2,681	100%	0%	0%	0%	0%	0%	125.00	3.00
Biomass Combustion - Fluidized Bed Boiler	28	1,600	29	1,629	100%	0%	0%	0%	0%	0%	70.00	3.00
Biomass Combustion - Stoker Boiler	38	1,750	32	1,782	90%	10%	0%	0%	0%	0%	107.80	4.70
Geothermal - Binary	15	2,318	0	2,318	40%	40%	20%	0%	0%	0%	40.32	4.31
Geothermal - Flash	30	2,534	44	2,578	35%	35%	30%	0%	0%	0%	49.62	4.85
Hydro - Small Scale & Developed Sites	15	945	0	945	100%	0%	0%	0%	0%	0%	9.88	1.90
Hydro - Capacity Upgrade of Existing Site	80	514	0	514	100%	0%	0%	0%	0%	0%	8.77	1.60
Solar - Parabolic Trough	250	3,408	0	3,408	100%	0%	0%	0%	0%	0%	60.00	0.00
Solar - Photovoltaic (Single Axis)	25	4,095	0	4,095	100%	0%	0%	0%	0%	0%	60.00	0.00
Onshore Wind - Class 3/4	50	1,440	0	1,440	90%	10%	0%	0%	0%	0%	10.28	4.82
Onshore Wind - Class 5	100	1,440	0	1,440	90%	10%	0%	0%	0%	0%	10.28	4.82

Source: Energy Commission

Instant Cost

Instant cost, sometimes referred to as overnight cost, is the initial capital expenditure. The instant costs do not include the costs incurred during construction (see installed cost). Instant costs include all costs: the component cost, land cost, development cost, permitting cost, connection equipment such as transmission, and environmental control costs.

Installed Cost

Installed cost is the total cost of building a power plant. It includes not only the instant costs, but also the costs associated with the fact that it takes time to build a power plant. Thus, it includes a building loan, sales taxes, and the costs associated with escalation of costs during construction.

Construction Period

The construction costs depend on the number of years to build the power plant since the loan period is increased. Year 0 is the last year of construction, and for a 5-year construction period. Year 5 would be the first year.

Fixed Operations and Maintenance Cost

Conceptually, fixed O&M comprises those costs that occur regardless of how much the plant operates. The costs included in this category are not always consistent from one assessment to the other but always include labor and the associated overhead costs. Other costs that are not consistently included are equipment (and leasing of equipment), regulatory filings, and miscellaneous direct costs. The Energy Commission staff uses the latter convention that includes these other costs.

Variable Operations and Maintenance Cost

Variable O&M is a function of the power plant operation and includes costs for:

- Scheduled outage maintenance including annual maintenance and overhauls
- Forced outage maintenance
- Water supply
- Environmental equipment maintenance

Scheduled outage maintenance is by far the largest expenditure.

Fuel Cost and Inflation Data

The fuel prices used in this report are summarized in **Table 17**. The natural gas average California prices are the final *2007 IEPR* price series. The high and low prices were derived as explained in Appendix D. KEMA developed the nuclear, coal, and biomass fuel prices. The deflator series is taken from Moody's Economy.com, dated November 11, 2008.

Table 17: Fuel Prices ($/MMBtu)

Year	Deflator Seiies 2009=1	Average CA	High CA	Low CA	Average Uranium	High Uranium	Low Uranium	Average Gassified Coal	High Gassified Coal	Low Gassified Coal	Average Biomass	High Biomass	Low Biomass
2009	1.000	6.56	9.13	4.74	0.63	0.74	0.53	1.80	3.13	1.31	2.00	3.00	1.75
2010	1.015	6.97	9.86	4.74	0.65	0.74	0.57	2.10	3.65	1.53	2.04	2.55	1.53
2011	1.031	7.29	10.45	4.75	0.68	0.78	0.59	2.15	3.74	1.57	2.08	2.60	1.56
2012	1.047	7.87	11.39	4.95	0.72	0.83	0.62	2.20	3.82	1.60	2.12	2.65	1.59
2013	1.064	8.28	12.10	5.06	0.75	0.87	0.64	2.24	3.90	1.64	2.16	2.70	1.62
2014	1.080	8.74	12.88	5.21	0.79	0.92	0.67	2.29	3.99	1.67	2.20	2.75	1.65
2015	1.097	9.01	13.36	5.26	0.82	0.94	0.69	2.34	4.07	1.71	2.24	2.80	1.68
2016	1.115	9.68	14.44	5.55	0.85	0.96	0.73	2.39	4.15	1.74	2.28	2.85	1.71
2017	1.133	10.20	15.32	5.76	0.88	0.99	0.76	2.43	4.23	1.78	2.33	2.91	1.74
2018	1.151	10.91	16.47	6.07	0.91	1.01	0.80	2.48	4.31	1.81	2.37	2.96	1.78
2019	1.170	11.78	17.86	6.46	0.94	1.04	0.84	2.52	4.39	1.84	2.41	3.02	1.81
2020	1.188	12.23	18.63	6.63	0.97	1.06	0.88	2.57	4.47	1.88	2.46	3.08	1.85
2021	1.207	12.66	19.37	6.79	1.00	1.10	0.89	2.61	4.55	1.91	2.51	3.13	1.88
2022	1.226	13.64	20.95	7.24	1.02	1.14	0.90	2.66	4.62	1.94	2.55	3.19	1.92
2023	1.245	14.16	21.82	7.44	1.05	1.17	0.91	2.70	4.70	1.97	2.60	3.25	1.95
2024	1.265	14.77	22.86	7.70	1.07	1.21	0.93	2.75	4.78	2.00	2.65	3.32	1.99
2025	1.284	14.73	22.86	7.61	1.10	1.25	0.94	2.79	4.85	2.04	2.70	3.38	2.03
2026	1.304	15.35	23.90	7.87	1.12	1.29	0.95	2.84	4.95	2.08	2.75	3.44	2.07
2027	1.324	15.75	24.60	8.01	1.15	1.33	0.96	2.90	5.04	2.11	2.81	3.51	2.11
2028	1.343	16.15	25.31	8.16	1.17	1.36	0.98	2.95	5.14	2.16	2.86	3.58	2.15
2029	1.363	16.80	26.39	8.43	1.20	1.40	0.99	3.01	5.23	2.20	2.91	3.64	2.19
2030	1.383	17.46	27.50	8.71	1.22	1.44	1.00	3.06	5.33	2.24	2.97	3.71	2.23
2031	1.404	18.08	28.58	8.94	1.25	1.49	1.02	3.12	5.42	2.27	3.03	3.78	2.27
2032	1.424	18.73	29.69	9.19	1.28	1.54	1.03	3.17	5.52	2.31	3.08	3.86	2.31
2033	1.445	19.33	30.75	9.41	1.31	1.58	1.05	3.23	5.62	2.36	3.14	3.93	2.36
2034	1.467	19.95	31.84	9.64	1.34	1.63	1.06	3.29	5.72	2.40	3.20	4.00	2.40
2035	1.488	20.57	32.93	9.86	1.37	1.68	1.07	3.35	5.82	2.44	3.26	4.08	2.45
2036	1.510	21.27	34.15	10.12	1.40	1.73	1.09	3.41	5.93	2.49	3.33	4.16	2.49
2037	1.532	21.98	35.39	10.38	1.43	1.78	1.10	3.47	6.04	2.53	3.39	4.24	2.54
2038	1.555	22.72	36.70	10.65	1.47	1.84	1.12	3.53	6.14	2.58	3.45	4.32	2.59
2039	1.578	23.50	38.08	10.94	1.50	1.89	1.13	3.60	6.26	2.62	3.52	4.40	2.64
2040	1.601	24.30	39.50	11.23	1.53	1.95	1.15	3.66	6.37	2.67	3.59	4.48	2.69
2041	1.624	25.12	40.95	11.52	1.57	2.01	1.17	3.73	6.48	2.72	3.65	4.57	2.74
2042	1.648	25.96	42.46	11.81	1.61	2.07	1.18	3.79	6.60	2.77	3.72	4.65	2.79
2043	1.673	26.82	44.00	12.11	1.64	2.13	1.20	3.86	6.72	2.82	3.79	4.74	2.85
2044	1.697	27.72	45.61	12.42	1.68	2.20	1.21	3.93	6.84	2.87	3.87	4.83	2.90
2045	1.722	28.65	47.28	12.74	1.72	2.26	1.23	4.00	6.96	2.92	3.94	4.92	2.95
2046	1.747	29.61	49.03	13.07	1.76	2.33	1.25	4.08	7.09	2.97	4.01	5.02	3.01

Source: Energy Commission

Financial Assumptions

Financial assumptions include capital structure, debt term, and economic/book life.

Table 18 summarizes the capital structure assumptions being used in the Model. Note that the debt to equity split is different for merchant gas-fired plants than other technology plants (renewables and alternative technologies). The rationale is that financial institutions are likely to see power purchase agreements signed under legislative and regulatory mandates, such as the Renewables Portfolio Standard (RPS), as less risky than those signed under open market conditions. The average case assumptions for IOU and merchant plants are taken from the Board of Equalization's *2008 Capitalization Rate Study*[7] and adjusted to match May 2009 financial market conditions. This source was chosen because it was developed by another state agency using a public review process. Debt costs for all three owner types were derived from public sources as of May 2009. Note that the equity rates of return are after-tax rates that are *grossed up* in the model to before-tax rates. The corresponding assumptions for the high- and low-cost cases for renewable plants are based on KEMA estimates. The appropriate discount rates and allowance for funds used during construction (AFUDC) rates are based on the weighted average cost of capital (WACC).

Table 18: Capital Cost Structure

	Average Case			
	% Equity	Equity Rate	Debt Rate	WACC
Merchant Fossil	60.0%	14.47%	7.49%	10.46%
Merchant Alternatives	40.0%	14.47%	7.49%	8.45%
Default IOU	52.0%	11.85%	5.40%	7.70%
Default POU	0.0%	0.0%	4.67%	4.67%
	High Case			
	% Equity	Equity Rate	Debt Rate	WACC
Merchant Fossil	80.0%	18.00%	10.00%	15.59%
Merchant Alternatives	60.0%	18.00%	10.00%	13.17%
Default IOU	55.0%	15.00%	9.00%	10.65%
Default POU	0.0%	0.0%	7.00%	7.00%
	Low Case			
	% Equity	Equity Rate	Debt Rate	WACC
Merchant Fossil	40.0%	14.47%	7.49%	8.45%
Merchant Alternatives	35.0%	14.00%	6.00%	7.21%
Default IOU	50.0%	10.00%	6.00%	6.78%
Default POU	0.0%	0.0%	4.00%	4.00%

Source: Energy Commission

[7] Board of Equalization, *Capitalization Rate Study*, March 2008, http://www.boe.ca.gov/proptaxes/pdf/2008capratestudy.pdf

General Assumptions

Insurance

Insurance is calculated differently depending on the type of developer. For an IOU, the cost is a fraction of the book value. For a merchant or POU plant, the cost is calculated as a fraction of the installed cost, and then escalated with nominal inflation. The fraction assumed for all three entities is 0.6 percent and is based on a California Public Utility Commission (CPUC) survey of brokers used in preparing the Market Price Referent[8].

Operation and Maintenance Escalation

Escalation of costs above general inflation for both fixed and variable O&M are estimated at 0.5 percent based on reviews of industry forecasts and the judgment of the analysts.

Book and Tax Life Assumptions

Book life represents the period over which shareholders expect to recover their initial investment. The debt term applies only to merchant developers as they are more likely to have project-specific financing.

Table 19 summarizes the debt term, book life, equipment life, and depreciation assumptions. They are shown for the average, high, and low cases used in the COG Modeling. The debt term assumptions are applicable to the merchant modeling only. They are not considered to be applicable to the IOU and POU modeling, which sets the debt life equal to the book life. This is done as debt is not project-specific for these developers; it is done on a companywide basis. The depreciation periods are used for the federal and state tax assumptions. The base federal tax life is taken from IRS Pub. 946 (2008), App. B, Asset class 49.[9] Accelerated depreciation allowances for certain technologies arise from the Energy Policy Acts dating back to 1992. These accelerated depreciation periods are a tax benefit that is captured in the COG Model and range of calculated levelized costs.

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[8] California Public Utilities Commission, Energy Division, "Resolution E-4214," December 18, 2008.

[9] http://www.irs.gov/pub/irs-pdf/p946.pdf

Table 19: Life Term Assumptions

Technology	Debt Term (Years)			Book Life (Years)	Equipment (Years)	Depreciation (Years)	
	Average	High	Low			Federal	State
Small Simple Cycle	12	10	20	20	20	15	15
Conventional Simple Cycle	12	10	20	20	20	15	15
Advanced Simple Cycle	12	10	20	20	20	15	15
Conventional Combined Cycle (CC)	12	10	20	20	20	20	20
Conventional CC - Duct Fired	12	10	20	20	20	20	20
Advanced Combined Cycle	12	10	20	20	20	20	20
Coal - IGCC	15	10	20	20	40	15	20
Nuclear Westinghouse AP1000 (2018)	20	20	20	40	40	20	30
Biomass IGCC	15	10	20	20	20	5	20
Biomass Combustion - Fluidized Bed Boiler	12	10	20	20	20	5	20
Biomass Combustion - Stoker Boiler	12	10	20	20	20	5	20
Geothermal - Binary	20	20	20	30	30	5	20
Geothermal - Flash	20	20	20	30	30	5	20
Hydro - Small Scale & Developed Sites	20	20	20	30	30	5	30
Hydro - Capacity Upgrade of Existing Site	20	20	20	30	30	5	30
Ocean Wave (In-Service 2018)	20	20	20	30	30	5	30
Solar - Parabolic Trough	15	10	20	20	20	5	20
Solar - Photovoltaic (Single Axis)	15	10	20	20	20	5	20
Onshore Wind - Class 3/4	20	20	20	30	30	5	30
Onshore Wind - Class 5	20	20	20	30	30	5	30
Offshore Wind - Class 5 (In-Service 2018)	20	20	20	30	30	5	30

Source: Energy Commission

Federal and State Tax Rates

Corporate taxes are state and federal taxes as listed by the Franchise Tax Board and Internal Revenue Service. Again, these taxes depend on the developer type. A POU is exempt from state and federal taxes. The calculation of taxes for a merchant facility or IOU power plant is based on the taxable income. The rates are shown in **Table 20**.

Table 20: Federal and State Tax Rates

Tax	Rate
Federal Tax	35.0%
CA State Tax	8.84%
Total Tax Rate	40.7%

Source: Energy Commission

Ad Valorem

In California, ad valorem (property tax) differs depending on the developer:

- The merchant-owned facility tax is based on the market value assessed by the Board of Equalization, which is assumed to be equal initially to the installed cost of the facility. The value reflects the market value of the asset but may not increase in value at a rate faster than 2 percent per annum per Proposition 13. The Model includes the assumption that an initial rate of 1.07 multiplied by the installed cost of the power plant and a property tax depreciation factor.
- The utility-owned plant tax is based on the value assessed by the Board of Equalization and is set to the net depreciated book value. The Model includes the assumption an initial cost of 1.07 multiplied by the book value. Counties are allocated property tax revenues based on the share of rate base within each county.
- Publicly owned plants are exempt from paying property taxes but may pay a negotiated in-lieu fee, which the Model assumes is equal to the calculated property tax.

Solar units are exempt from ad valorem. This is a tax benefit that is captured in the COG Model and is reflected in with and without tax benefit calculations in the report.

Sales Tax

California sales tax is estimated as 7.94 percent based on the 2007 Legislative Analyst's Office estimate. This does not include the temporary 1 percent surcharge because it is set to expire by the 2011-2012 fiscal year. Nevertheless, the sales tax does not show up directly in the analysis because the reported installed cost estimates are presumed to already include the sales tax, which is treated as a depreciable cost under federal tax law.

Tax Credits

Table 21 summarizes the technologies that are eligible for renewable energy production tax credits (REPTC) and renewable energy production incentives (REPI) for municipal utilities. The table summarizes those plants eligible for federal business energy or investment tax credits BETC/ITC under the 2005 and 2008 federal Energy Policy Acts (EPAct) and the 2009 American Recovery and Reinvestment Act (ARRA). The ARRA made most of the technologies that had been eligible for the REPTC also eligible for the ITC if the latter provided a larger benefit. The ARRA also allows those technologies claiming the ITC to be able to recover the entire benefit in a single year as a "grant" rather than capping the ITC that can be claimed at the amount of net taxable income in any single year. The REPI amount is adjusted for the proportion that is actually paid out from available federal funds, which is currently 19 percent of amounts eligible and requested for both Tier I and II. In addition, the table lists the amount of the state property tax exemption for solar technologies in the average case. For the high-cost cases, these tax credits and exemptions are allowed to expire after the legal deadline specified for each technology and program.

Table 21: Summary of Tax Credits

Federal Renewable Energy Tax Incentives - 2008 EPAct and 2009 ARRA			Biomass					
Technology	**Coal IGCC[1]**	**Wind**	**Open Loop (Ag waste)**	**Closed Loop**	**Geothermal[2]**	**Small Hydro**	**Ocean Wave**	**Solar[3]**
Production Tax Credit								
Credit (2008$)/MWH	$1.26	$21	$10	$21	$21	$10	$10	
Credit (1993$)/MWH		$15	$7.50	$15	$15	$7.50	$7.50	
Duration (Years)	10	10	10	10	10	10	10	
Expiration	2009	2012	2013	2013	2013	2013	2013	
Eligibility	Merchant	Merchant	Merchant	Merchant	Merchant	Merchant	Merchant	
Investment Tax Credit								
Credit	20%				10%			*30%/10%*
Depreciable value reduced	10%				5%			*15%/5%*
Expiration	2009				NA			2016
Loss Carryforward Period (Yrs)	20				20			20
Eligibility	Merchant / IOU				Merchant / IOU			Merchant / IOU
ARRA Grant								
ITC in-lieu of PTC	30%	30%	30%	30%	*30%*	30%	30%	30%
Expiration	2014	2013	2014	2014	2014	2014	2014	2014
Eligibility	Merchant / IOU	Merchant / IOU	Merchant / IOU	Merchant / IOU	*Merchant*	Merchant / IOU	Merchant / IOU	Merchant / IOU
Production Incentive[4]								
Tier I Payment		$4.1		$4.1	$4.1		$4.1	$4.1
Tier II Payment			$3.9					
Duration (Years)		10	10	10	10		10	10
Expiration		2017	2017	2017	2017		2017	2017
Eligibility		POU/Coops	POU/Coops	POU/Coops	POU/Coops		POU/Coops	POU/Coops

Notes:

1 - IGCC Production Credit is separate from REPTC, but similarly structured. Based on "refined coal" = $4.375/(13900 Btu/ton for anthracite / HR*(1+ParasiticLoad) for IGCC). Expiration date for ARRA ITC ambiguous.

2 - Geothermal ITC does not expire. Unclear as to whether the ARRA increased the ITC for geothermal to 30% until 2014, and whether self-sales are eligible

3 - Solar ITC reverts to 10 percent in 2016

4 - REPI payments scaled based on 2007 shares of paid to applications

Source: Aspen

Comparison to *2007 IEPR* Assumptions

Table 22 compares key assumptions used for the *2009 IEPR* to those included in the *2007 IEPR*. The data for the first six technologies comes from Aspen Consulting, both for the *2007 IEPR* and for the *2009 IEPR*. The differences are due to having two more years of data and the change from just relying on survey data to also examining additional sources as described in Appendix C. The change in capacity factor comes from a reassessment of the performance of the California generating units since 2006. The increase in instant cost is documented back in **Table 10**. The changes in fixed and variable O&M are somewhat misleading as some of the variable costs were shifted to the fixed cost category to be more consistent with current practices of various other data collectors.

The rest of the technology data was provided in 2007 by NCI Consulting, as documented in the *2007 IEPR*. The 2009 data is provided by KEMA, Inc., and can be found in its supporting document *Renewable Energy Cost of Generation Update*. However, the two of the technologies that show the most change, ocean wave and solar photovoltaic, are not comparable in size.

Table 22: Comparison to *2007 IEPR*

Technology	Gross Capacity (MW)		Capacity Factor (%)		Instant Cost ($/kW)		Fixed O&M ($/kW-Year)		Variable O&M ($/MWh)	
In-Service Year = 2009 (2009$)	**2009 IEPR**	**2007 IEPR**	**2009 IEPR**	**2007 IEPR**	**2009 IEPR**	**2007 IEPR**	**2009 IEPR**	**2007 IEPR**	**2009 IEPR**	**2007 IEPR**
Small Simple Cycle	49.9	49.9	5%	5%	1292	1017	23.94	18.42	4.17	28.01
Conventional Simple Cycle	100	100	5%	5%	1231	966	17.40	11.43	4.17	27.59
Advanced Simple Cycle	200	200	10%	15%	827	794	16.33	7.41	3.67	27.26
Conventional Combined Cycle (CC)	500	500	75%	60%	1095	810	8.62	10.21	3.02	5.96
Conventional CC - Duct Fired	550	550	70%	60%	1080	834	8.30	9.88	3.02	4.53
Advanced Combined Cycle	800	800	75%	60%	990	800	7.17	8.73	2.69	4.04
Coal - IGCC	300	575	80%	60%	3184	2292	52.35	38.20	9.57	3.27
AP 1000 PWR Nuclear	960	1000	86%	85%	3950	3081	147.70	147.68	5.27	5.27
Biomass - IGCC	30	21.25	75%	85%	2997	3255	150.00	163.73	4.00	3.27
Biomass - Direct Combustion W/ Fluidized Bed	28	25	85%	85%	3254	3292	99.50	158.28	4.47	3.27
Biomass - Direct Combustion W/Stoker Boiler	38	25	85%	85%	2658	3023	160.10	141.90	6.98	3.27
Geothermal - Binary	15	50	90%	95%	4046	3226	47.44	76.41	4.55	3.79
Geothermal - Dual Flash	30	50	94%	93%	3718	2990	58.38	87.32	5.06	3.72
Hydro - Small Scale	15	181	30%	52%	1730	4301	17.57	14.19	3.48	3.00
Ocean - Wave (2018)	40	1	26%	15%	2587	7511	36.00	32.75	12.00	25.49
Solar - Parabolic Trough	250	63.5	27%	27%	3687	4194	68.00	65.49	0.00	0.00
Solar - Photovoltaic (Single Axis)	25	1	27%	22%	4550	10023	68.00	26.20	5.50	0.00
Wind - Class 5	100	50	42%	34%	1990	2043	13.70	32.75	0.00	0.00

Source: Energy Commission

Glossary

Acronym	Definition
$/kW	$ Per kilowatt-hour
$/MMBtu	$/Million Btu
$/MWh	$ per megawatt-hour
¢/kWh	Cents per kilowatt-hour
ACC	Air-cooled condenser
ACOE	Army Corps of Engineers
AFC	Application for Certification
AFUDC	Allowance for funds used during construction
BETC/ITC	Business energy or investment tax credits
Btu	British thermal unit
Btu/kWh	British thermal unit per kilowatt-hour
CC	Combined cycle
CCS	Carbon capture and sequestration
CERA	Cambridge Energy Research Associates
CF	Capacity factor
coal-IGCC	Coal-integrated gasification combined cycle
CPUC	California Public Utilities Commission
CRS	Congressional Research Service
CT	Combustion turbine
DG	Distributed generation
DSM	Demand-side management
EAO	Energy Annual Outlook
EFOR	Equivalent FOR
EIA	Energy Information Administration
Energy Commission	California Energy Commission
EPAct	Energy Policy Act

Acronym	Definition
FOR	Forced outage rate
GADS	Generating Availability Data System
GW/GWh	Gigawatt/Gigawatt-hour
HHV	Higher heating value
HRSG	Heat recovery steam generator
IEPR	*Integrated Energy Policy Report*
IOU	Investor-owned utility
kW	Kilowatt
LCR	Local capacity requirements
MID	Modesto Irrigation District
Model	Cost of Generation Model
MOR	Maintenance outage rate
MW/MWh	Megawatt/megawatt-hour
NERC	North American Reliability Council
NWPCC	Northwest Power and Conservation Council
O&M	Operating and maintenance
ODCs	Other direct costs
PIER	Public Interest Energy Research
PMT	Payment (used as annual levelized cost)
POU	Publicly owned utility
PPAs	Power purchase agreements
PPI	Producers Price Index
PV	Present value
QFER	Quarterly Fuels and Energy Report
REPI	Renewable energy production incentives
REPTC	Renewable energy production tax credits
REZ	Resource energy zone
RPS	Renewables Portfolio Standard

Acronym	Definition
SC	Simple cycle
SCR	Selective catalytic reduction
SOF	Schedule outage factor
SOH	Scheduled outage hours
WACC	Weighted average cost of capital
WEP	Wholesale electricity prices
WSAC	Wet surface air condenser

APPENDIX A: Cost of Generation Model

This appendix describes the Cost of Generation Model (Model), including its inputs and outputs. This appendix also describes ancillary features that the model provides:

- The screening curve function
- The sensitivity curve function
- The wholesale electricity price forecast function

Model Overview

A simplified flow chart of the Model's inputs and outputs is shown in **Figure A-1**.

Using the inputs on the left side of the flow chart, which are described in detail later in this chapter, the Model can produce the outputs shown on the right side of the flow chart. The top set of output boxes show the levelized costs:

- Levelized fixed costs
- Levelized variable costs
- Total levelized costs (Fixed + Variable)

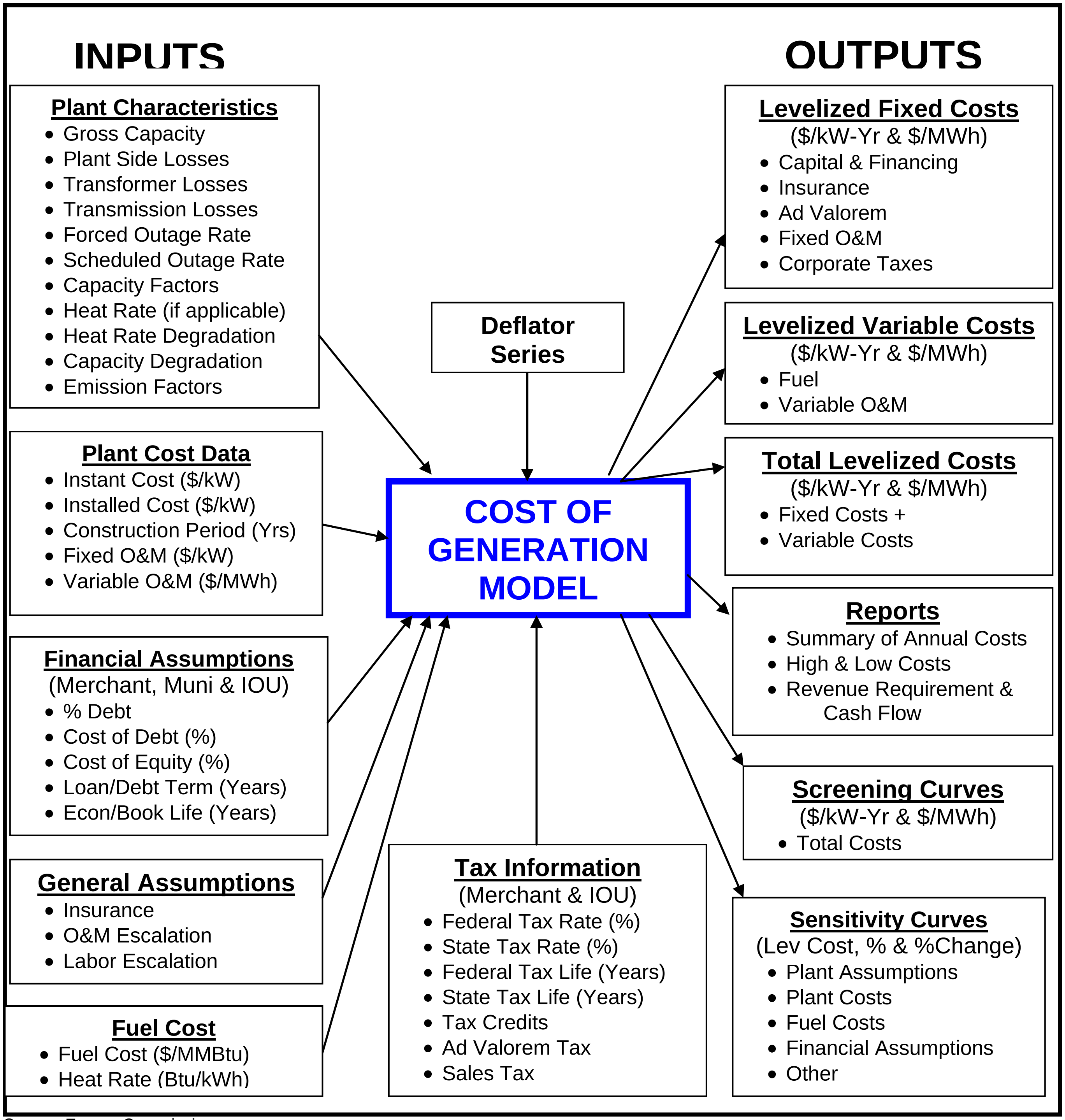
These are typical results from most cost of generation models. These results are used in almost any study that involves the cost of generation technologies. They can be used to evaluate the cost of a generation technology as a part of a feasibility study or to compare the differences between generation technologies. They also can be used for system generation or transmission studies.

This Model is more useful than the typical model since it also provides high and low levelized costs. It is also more unique than the traditional model since it can create three other outputs that are useful, but not commonly provided in the models:

- Annual costs, which are not traditionally displayed in both a table and a graph.
- Screening curves, which show the relationship between levelized cost and capacity factor—an addition that makes the Model much more useful in evaluating cost of generation costs and comparing different technologies.
- Sensitivity curves, which show the percentage change in outputs (levelized cost) as various input variables are changed.

In addition, the Model can also be used to forecast the cost of wholesale electricity, which is explained later in the chapter.

Figure A-1: Cost of Generation Model Inputs and Outputs



Source: Energy Commission

Model Structure

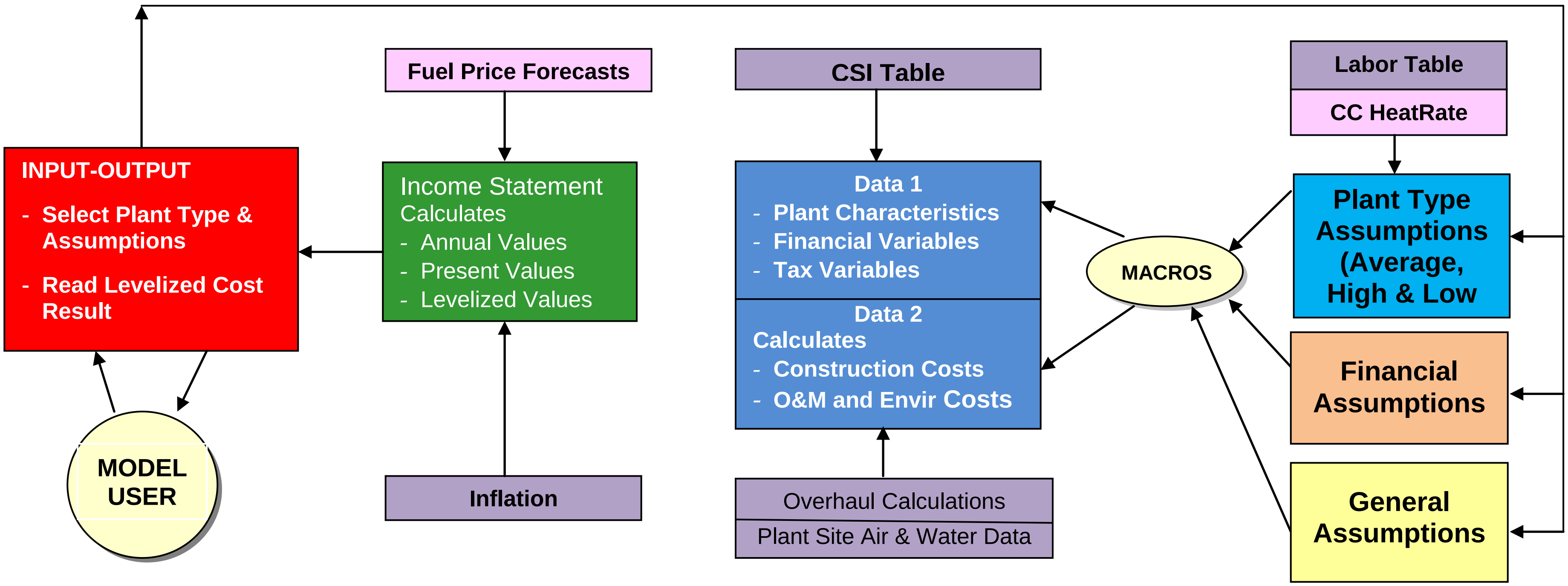
The Model is a spreadsheet model that calculates levelized costs for 21 technologies. These include nuclear, combined cycle, integrated gasification combined cycle, simple cycle, and various renewable technologies. The Model is designed to accommodate additional technologies and includes a function for storing the results of scenario runs for these technologies. The Model is contained within a single Excel file or workbook using Microsoft terminology. This workbook consists of 20 spreadsheets or worksheets, but 2 of these are informational and do not contribute to the calculations.

The relationship of these worksheets is illustrated in **Figure A-2**.

Changes	Tracks Model modifications using version numbers.
Instructions	General Instructions & Model Description.
WEP Forecast	Estimates Wholesale Electric Price Forecast
Adders	Provides Adder Costs that can be entered exogenously for the combined cycle & simple cycle units.
Input-Output	User selects Assumptions - Levelized Costs are reported along with some key data values.
Data 1	Plant, Financial, & Tax Data are summarized - User can override data for unique scenarios.
Data 2	Construction, O&M Costs are calculated in base year dollars.
Income Statement	Calculates Annual Costs and Levelizes those Costs – Using Revenue Requirement accounting
Income Cash -Flow	Calculates Annual Costs and Levelizes those Costs – Using Cash-Flow accounting
Plant Type Assumptions	Summary of Data Assumptions summary for each Plant Type.
PTA - Average	Average Plant Type Assumptions
PTA - High	High Plant Type Assumptions
PTA - Low	Low Plant Type Assumptions
Financial Assumptions	Data Assumptions summary of all Financial Data.
Tax Incentives	Summary of Tax Incentives
General Assumptions	General Assumptions summary such as Inflation Rates & Tax Rates.
Plant Site Air & Water Data	Regional Air Emissions & Water Costs - Used by Data 2 Worksheet.
Overhaul Calcs	Calculates Overhaul & Equipment Replacement Costs - Used by Data 2 Worksheet.
Inflation	Calculates Historical & Forward Inflation Rates based on GDP Price Deflator Series - Used by Income Statement Worksheet.
Fuel Price Forecasts	Fuel Price Forecast - Used by the Income Statement Worksheet.
Heat Rate Table	Shows the regression and provides the Heat Rate factors.
Labor Table	Calculates the Labor Cost components.

Source: Energy Commission

Figure A-2: Block Diagram for Cost of Generation Model



Source: Energy Commission

One way to better understand the Model is to visualize the "Income Revenue" and "Income Cash-Flow" worksheets as a model, the "Input-Output" worksheet as the control module, which also summarizes the results, and the remaining worksheets as data inputs. Data 1 and 2 could be considered the data set (broken into two parts) that is derived from the Plant Type Assumptions worksheets and the remaining worksheets (auxiliary data).

Input-Output Worksheet

This is where the user selects the generation technology and characteristics and reads the final result. **Figure A-3** shows the Input Selection box, Through the use of drop-down windows, the user selects the power plant type, the financial assumptions, the general assumptions, fuel type, and regional location of the power plant. The user enters the start year.

Figure A-3: Technology Assumptions Selection Box

INPUT SELECTION	
Plant Type Assumptions (Select)	Combined Cycle Standard - 2 Turbines, Duct Firing
Financial (Ownership) Assumptions (Select)	Merchant Fossil
Ownership Type For Scenarios	Merchant
General Assumptions (Select)	Default
Base Year (All Costs In 2009 Dollars)	2009
Fuel Type (Accept Default)	Solar
Data Source	*KEMA 5-23-09*
Start (Inservice) Year (Enter)	2009
Natural Gas Price Forecast (Select)	CA Average
Plant Site Region (Air & Water) (Select)	CA - Avg.
Study Perspective (Select)	To Delivery Point
Reported Construction Cost Basis (Select)	Instant
Turbine Configuration (Select)	2
Carbon Price Forecast(Select)	No Carbon Price
Cost Scenario(Select)	Mid-range
Tax Loss Treatment (Select)	Loss Recovered in Single Year

Source: Energy Commission

The remaining options are more complex and require further description. The study perspective sets the location of the calculation: plant side of the transformer, transmission side of the transformer, or the delivery point. All data reported in this Model are based on the point of power delivery, that is, the electricity user. The reported construction cost basis allows the user to enter the data as instant or installed. The turbine configuration allows for non-standard configurations for the combined cycle units. The standard configuration is two combustion turbine units and one steam generator—thus the number "2." The next entry is carbon price—but these prices have not yet been established by the Energy Commission and are therefore not used in *IEPR*. The Cost Scenario allows the user to select an average, high, or low set of assumptions. The Tax Loss Treatment allows the user to have the model carry tax losses forward or to take them all in the current year.

The Model collects the relevant data as directed by the selection box and delivers it to the data worksheets. The income statement then uses the data worksheets to calculate the levelized costs and reports those costs back to the input-output worksheet to the table shown in **Figure A-4**. This version for the first time reports transmission service costs.

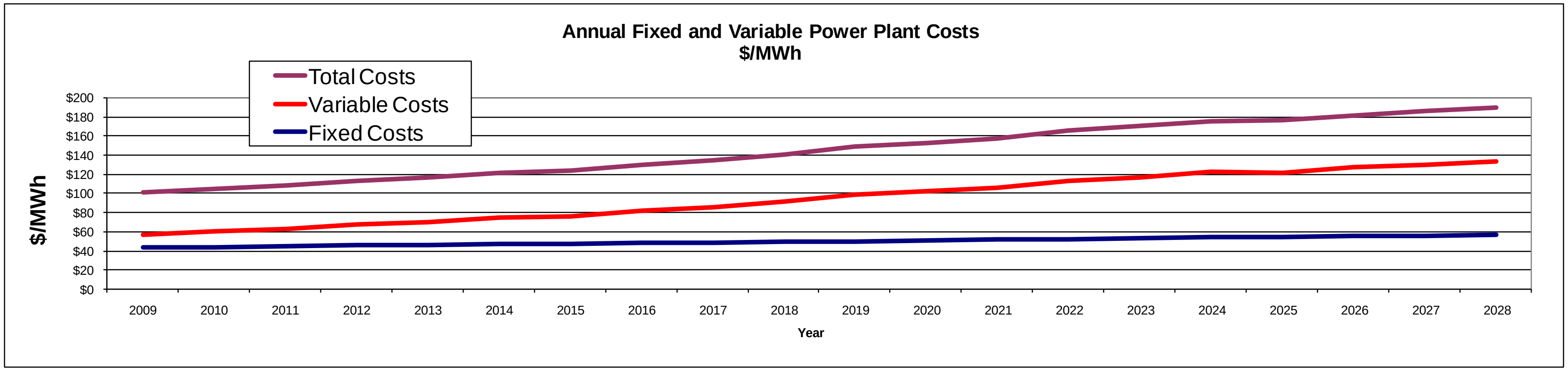
Figure A-4: Levelized Cost Output

OUTPUT RESULTS		
SUMMARY OF LEVELIZED COSTS Combined Cycle Standard - 2 Turbines, Duct Firing		
Start Year = 2009 (2009 Dollars)	$/kW-Yr	$/MWh
Capital & Financing - Construction	$182.87	$31.93
Insurance	$8.83	$1.54
Ad Valorem Costs	$12.01	$2.10
Fixed O&M	$9.52	$1.66
Corporate Taxes (w/Credits)	$60.17	$10.51
Fixed Costs	**$273.41**	**$47.74**
Fuel & GHG Emissions Costs	$418.13	$73.01
Variable O&M	$22.12	$3.86
Variable Costs	**$440.25**	**$76.87**
Transmission Service Costs	$29.82	$5.21
Total Levelized Costs	**$743.48**	**$129.82**

Source: Energy Commission

Figure A-5 shows the annual costs as a table and a graph. This is useful as information and in identifying model problems.

Figure A-5: Annual Costs—Merchant Combined Cycle Plant



	Levelized	NPV	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Fixed Costs	$48	$394	$44	$44	$45	$45	$46	$47	$47	$48	$49	$49	$50	$51	$51	$52	$53	$54	$54	$55	$56	$56
Variable Costs	$82	$678	$58	$61	$63	$68	$71	$75	$77	$82	$86	$92	$99	$102	$106	$113	$117	$122	$122	$127	$130	$133
Total Costs	$130	$1,072	$101	$105	$108	$113	$117	$121	$124	$130	$135	$141	$149	$153	$157	$165	$170	$176	$176	$182	$186	$190

Source: Energy Commission

Assumptions Worksheets

Most of the data used in the Model are compiled into these three worksheets. These worksheets store the data for the multitude of technologies and data assumptions that give the Model its flexibility

Plant Type Assumptions—This worksheet stores the power plant characteristics and cost data, such as plant size, capacity factor, outage rates, heat rates, degradation factors, construction periods, instant costs, operation and maintenance costs, environmental costs, and water usage costs.

Financial Assumptions—This worksheet stores the capital structure and cost of capital data for the three main categories of ownership: merchant, IOU, and publicly owned. The worksheet provides the relative percentages of equity as opposed to long-term debt, as well as the cost of capital for these two basic financing mechanisms. It also provides data on eligibility for tax credits.

General Assumptions—These are a multitude of assumptions that are common to all power plant types, such as inflation rates, tax rates, tax credits, as well as transmission losses and ancillary service rates.

Based on the user selections in the input-output worksheet, the relevant data in these assumptions worksheets are gathered by a macro and sent to the data worksheets. These values are color-coded within the worksheets as follows:

Indicates area for data modification
Plant Type Assumptions
Financial Assumptions
General Assumptions

Source: Energy Commission

Data Worksheets

This is where the macro stores the data selected from the above-described assumptions worksheets. It also performs some basic calculations to prepare data for the income statement worksheet. Data 1 and Data 2 worksheets can be envisioned as two parts of the main dataset to be used in the income statement. These are separated solely to keep the worksheets to a reasonable size. Data 1 and 2 also provide the opportunity for the user to modify or replace the data that came from the assumptions worksheets. Care should be taken to modify only those areas that are shaded in color.

Data 1—This worksheet summarizes key data: plant capacity size and energy data, fuel use (such as heat rate and generation), operational performance data (such as forced outage rate and scheduled outage factor), key financial data (such as inflation rates and capital structure), and tax information (such as tax rates and tax benefits). It also does some calculations to compute certain necessary variables.

Heat Rate Table—This worksheet shows the regression that created the heat rate formula as a function of capacity factor in the Data 1 worksheet.

Data 2—This worksheet calculates Instant Cost, Installed Cost, Fixed O&M, and Variable O&M. These calculations depend on data from the following worksheets:

Plant Site Air and Water Data—These are emission and water costs on regional basis that are located outside the Data 2 worksheet.

Overhaul Calculations—These costs are calculated outside the Data 2 worksheet since they are non-periodic overhaul costs that require special treatment to derive the necessary base-year costs needed by the Data 2 worksheet.

All the data in these worksheets are for base-year dollars. These costs are used by the income statement worksheet to calculate the yearly values and account for inflation.

Labor Table—This worksheet calculates the labor costs that are used in the fixed O&M cost calculations in the Data 2 worksheet.

Fuel Price Forecasts—This worksheet provides the fuel prices ($/MMBtu) to the income statement worksheet. For the natural gas price forecast, it provides prices by utility service area, as well as a California average value. It allows storage of different forecasts if needed to study various scenarios. These forecasts should be updated regularly to represent the most recent Energy Commission forecasts. The inflation factors used in this worksheet come from and must absolutely be consistent with the inflation worksheet.

Inflation—This worksheet provides inflation factors used by the income statement worksheet, needed to inflate the various capital and O&M costs. This worksheet calculates two inflation values to simplify the income statement calculations: a historical inflation rate, used for the period from the base year to the start year, and a forward inflation rate, used for the period from the start year to the end of the study.

Income Statement Worksheet

The Model has two Income Statement worksheets: revenue requirement for IOU and POU power plants and cash-flow for merchant plants. In each case, the Income Statement takes the data from the above data sources and calculates the fixed and variable cost components of total levelized cost. It develops the yearly costs, the present values of those costs, and finally the levelized costs.

Model Limitations

Models are inherently limited because a number of assumptions must be made for each generation technology. This section discusses these limitations and what this model has done to overcome these limitations. However, a cost of generation model is essentially a screening model. These models assume an average set of assumptions, which may not be applicable to the plant being assessed. Also, these cost estimates tell nothing about how the power plant will affect the system. Better answers to both of these questions can be found by using a production cost or market model. Finally, all of this ignores environmental, risk, and diversity factors, which may in the final analysis be the determining factors.

The key assumptions in modeling that can lead to errors are:

- Capital costs
- Fuel costs
- Capacity factors
- Heat rates for thermal plants

Capital Costs

Deriving capital costs is challenging, particularly for alternative technologies since costs tend to drop with increased development over time. Even for well-developed technologies, such as combined cycle and simple cycle plants, it is difficult because of varying location and situational costs. Developers generally keep this information confidential to maintain a competitive edge over other developers. The Energy Commission surveyed actual costs for simple cycle and combined cycle units during the *2007 IEPR,* agreeing to keep specific data confidential. Although this was done very systematically and proved to be highly accurate, an updated assessment for this *2009 IEPR* finds that these costs have changed so dramatically that staff's present estimates for simple cycle units are 35 percent higher and for combined cycle units 50 percent higher.

Fuel Costs

Fuel cost is highly unpredictable and difficult to forecast with a high degree of accuracy. Appendix D illustrates just how difficult it is to accurately forecast fuel cost data, showing estimating errors up to several hundred percent.

Capacity Factors

Models are inherently limited because the user must assume a specific capacity factor, which may or may not be applicable to the power plant under consideration. This is a common problem for combined cycle and simple cycle power plants. Combined cycle units are all too commonly modeled as having capacity factors in the vicinity of 90 percent, but the historical information on California power plants, as summarized in **Table A-1**, shows that the average is closer to 60 percent or less. The Model attempts to deal with this problem using the screening curve function, as described below.

Table A-1: Actual Historical Capacity Factors

Power Plant	QFER 2004	QFER 2005
Moss Landing Power Plant	55.5%	52.6%
Los Medanos	74.3%	74.7%
Sunrise Power	62.1%	65.7%
Elk Hills Power, LLC	79.9%	72.4%
High Desert Power Project	51.9%	50.3%
Sutter	72.0%	51.3%
Delta Energy Center	72.6%	69.5%
Blythe Energy LLC	26.8%	19.6%
La Paloma Generating	57.2%	46.4%
Von Raesfeld	nd	31.6%
Woodland	nd	51.5%
Average	61.3%	53.2%

Source: Energy Commission

Heat Rates

An actual thermal power plant being considered, such as a combined cycle unit, may operate at an entirely different capacity factor than that selected for the Model. In fact, these plants typically operate at different capacity factors from month to month and even day to day. These varying capacity factors result in differing heat rates. A combined cycle unit has the most efficient (lowest) heat rate at full power. Operation at lower power levels produces less efficient operation (higher heat rates). Two identical power plants with the same capacity factor can have widely different average annual heat rates. For example, both could have 50 percent capacity factors if one operated at full power for half of the year and the other operated at half power for the entire year. Obviously, the latter unit would have a much higher heat rate.

Energy Commission Features to Overcome Modeling Limitations

Recognizing the many factors that compromise a cost of generation estimate, the Energy Commission has implemented a number of features in its data collection and modeling.

Data Collection

Beginning with *2007 IEPR*, the Energy Commission implemented a data collection process that gathered actual as-built data from the California power plant developers. This year the process concentrated on comparing staff's data against other reliable sources as a benchmark. The Commission will continue to gather this data using the most knowledgeable engineers and reevaluating estimates in light of changing prices and nominal escalation.

High and Low Forecasts

The Energy Commission has modified its data gathering and model to provide high and low estimates trying to capture the most reasonably high- and low-cost parameters available.

Completeness of Assumptions

There is a tendency to oversimplify the modeling by ignoring cost factors such as plant-side losses, which can have a large impact. The Energy Commission's Cost of Generation Model captures all assumptions, including plant-side losses, transformer losses, construction periods, transmission losses, capacity degradation, heat-rate degradation, environmental compliance costs, and transmission costs

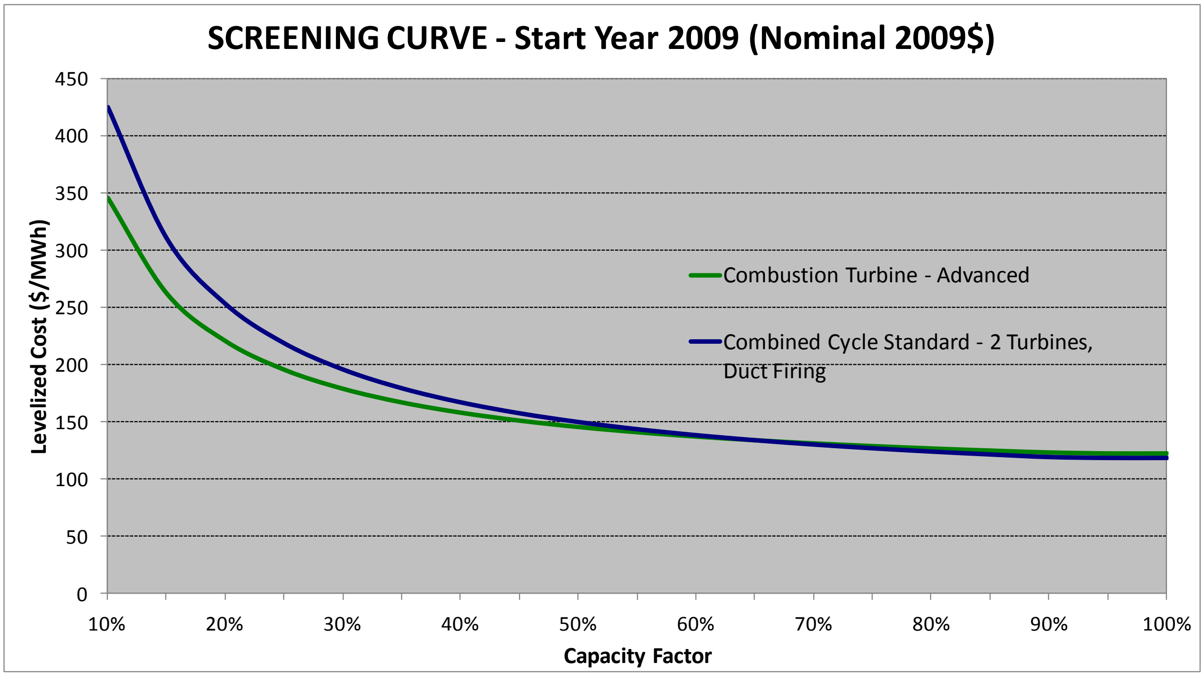
Model's Screening Curve Function

Screening curves allow one to estimate the levelized cost for various capacity factors, rather than the singular capacity factor that is typical of models. This is useful in many ways. The most obvious is that it allows the user to estimate levelized costs for its specific assumption of capacity factor. It also allows the user to assess the cost risk of incorrectly estimating the capacity factor. It allows for the comparison of various technologies as a function of capacity factor – that is, at what capacity factor one technology becomes less costly than another.

The Energy Commission's Cost of Generation Model is somewhat unique in that it recognizes the reality that heat rate is a function of capacity factor and corrects for this in the screening curve. By analyzing historical data from operating power plants in California (Energy Commission's QFER database), it was possible to find a relationship between capacity factor and heat rate that has a high statistical level of confidence—and that formula (through regression) has been embedded in the Model.

The levelized cost can be shown as $/MWh or $/kW-Year**. Figure A-6** illustrates a $/MWh screening curve. **Figure A-7** shows the corresponding interface window.

Figure A-6: Screening Curve in Terms of Dollars per Megawatt Hour



Source: Energy Commission

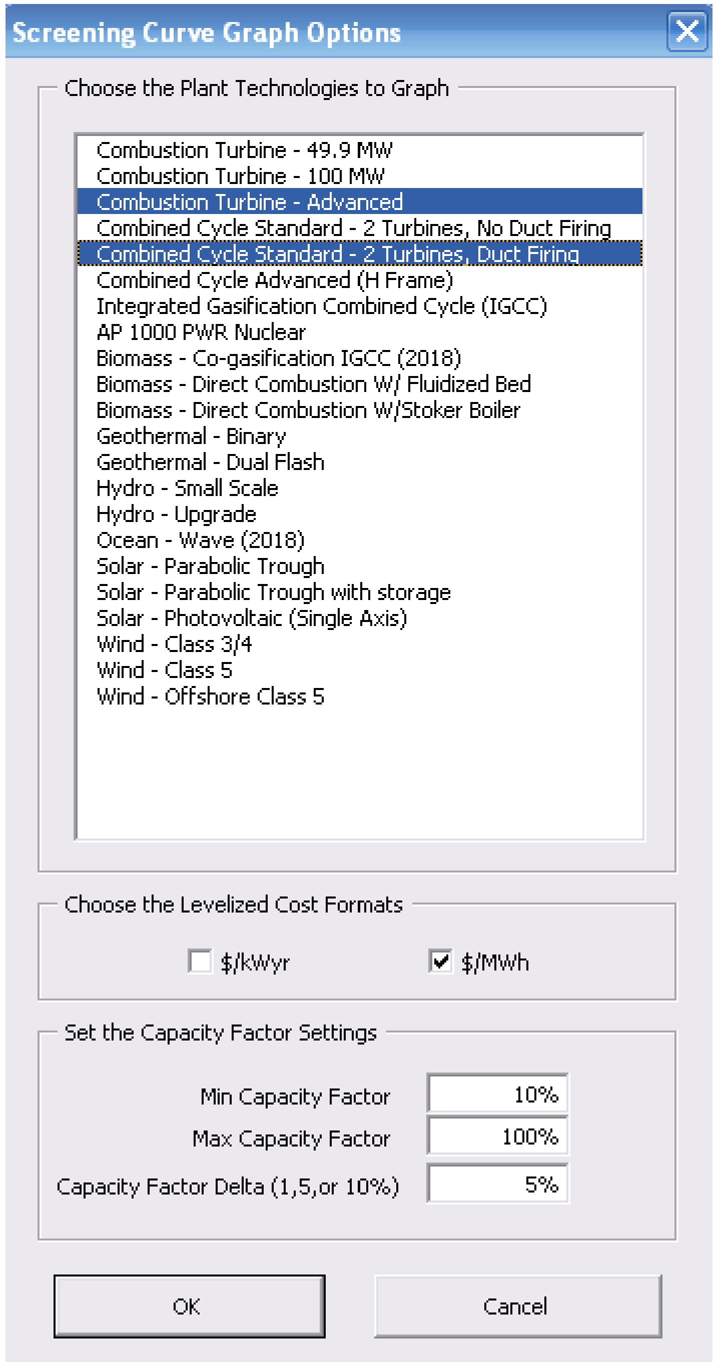
Model's Sensitivity Curve Function

Although the screening curves can prove useful, they address only one variable to the base case assumptions when estimating levelized costs—the capacity factor. Staff's new sensitivity curves address a multitude of assumptions: capacity factor, fuel prices, installed cost, discount rate (WACC), percentage equity, cost of equity, cost of debt, and any other variable that should be considered. Sensitivity curves show the effect on total levelized cost by varying any of these parameters in three formats:

- Levelized cost ($/MWh or $/kW-Yr)
- Change in levelized cost as a percentage
- Change in levelized cost as incremental levelized cost from the base value ($/MWh or $/kW-Yr).

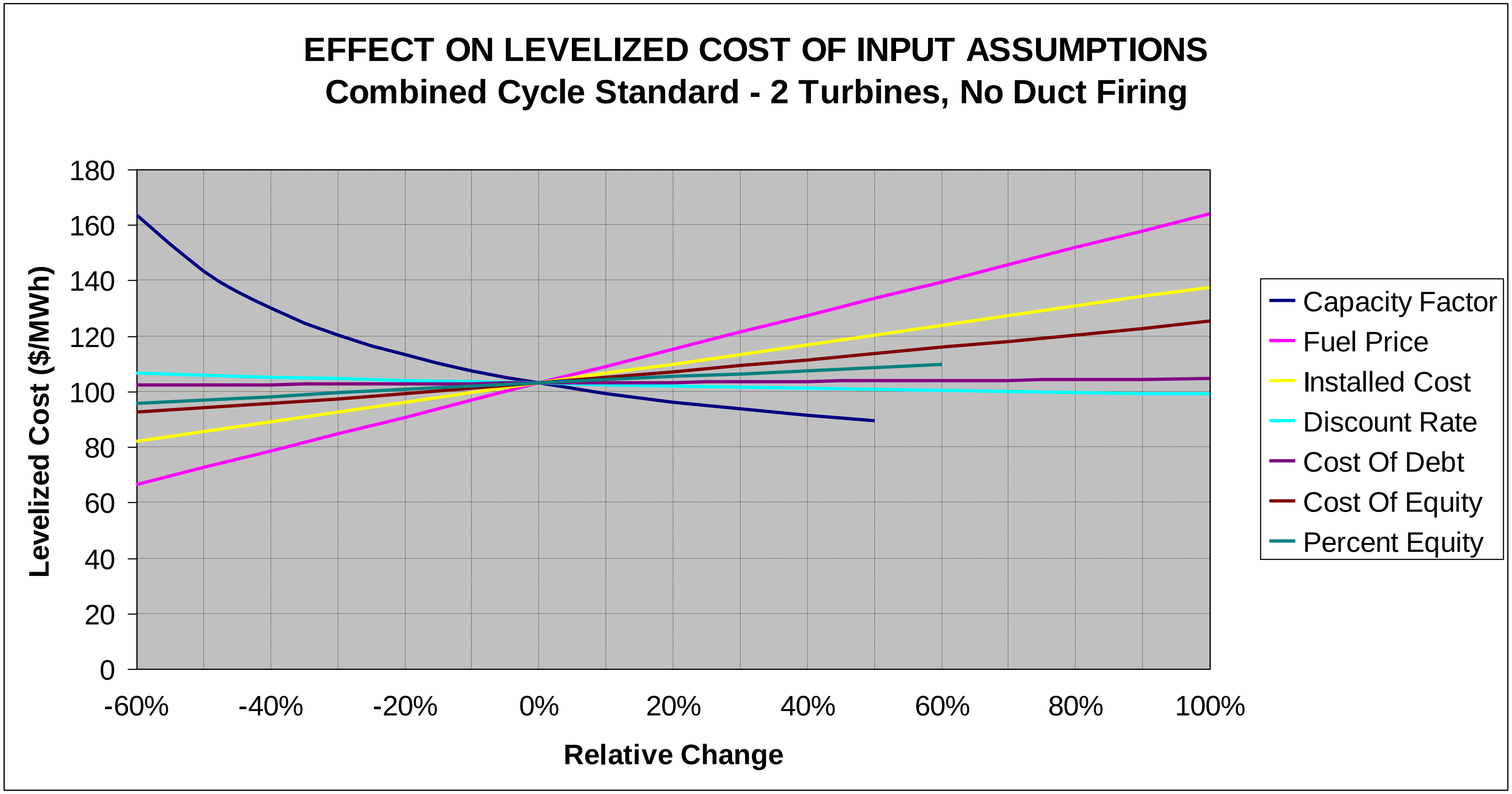
Figure A-8 shows a sensitivity curve. **Figure A-9** shows the interface window for the above sensitivity curve.

Figure A-7: Interface Window for Screening Curve



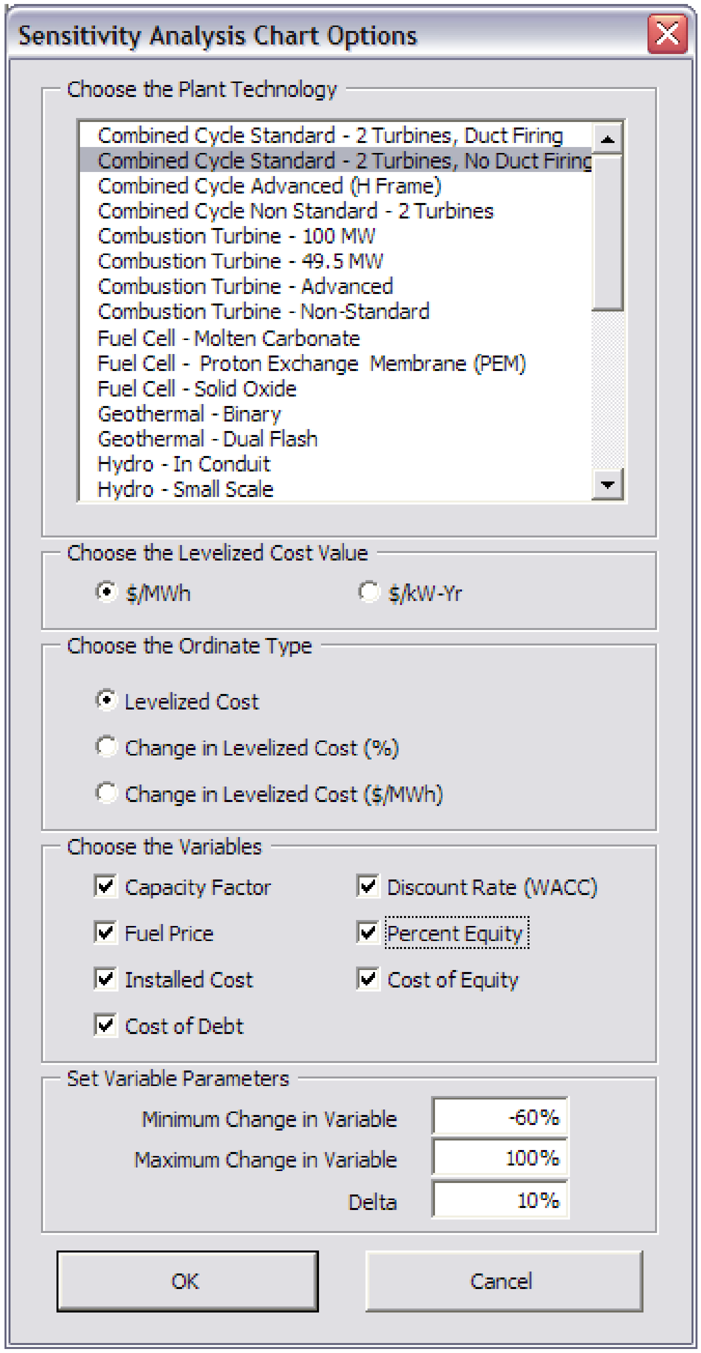
Source: Energy Commission

Figure A-8: Sample Sensitivity Curve



Source: Energy Commission

Figure A-9: Interface Window for Screening Curves



Source: Energy Commission

Model's Wholesale Electricity Price Forecast Function

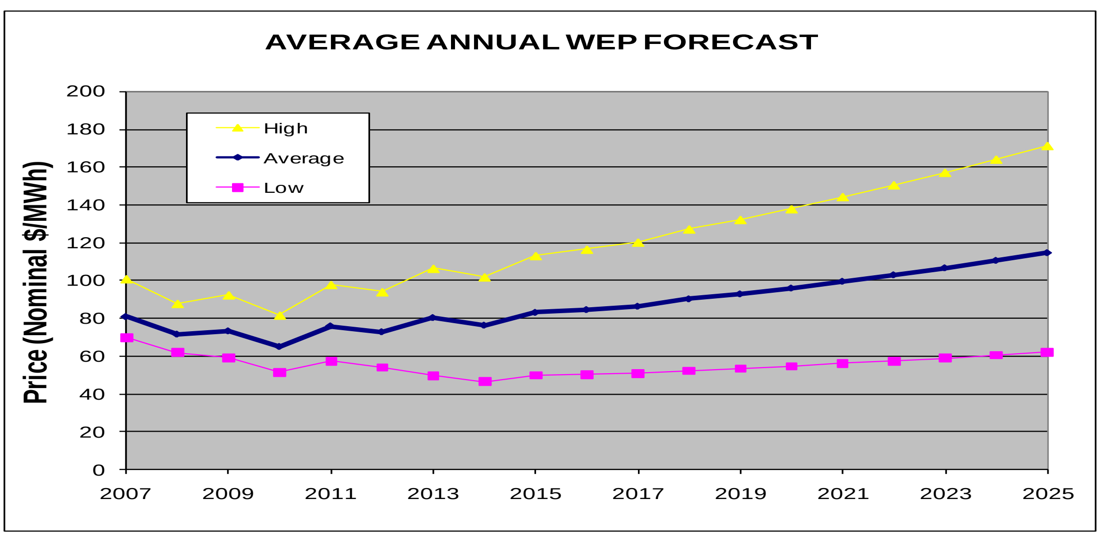
The Model can be used along with the Marketsym model—or some other production cost model—to forecast wholesale electricity prices. The Model can calculate the fixed-cost portion of the wholesale electricity prices (WEP), but not the variable portion. The Marketsym model, on the other hand, can calculate the variable portion of the WEP, but not the fixed portion.

The details of this process are complicated and outside the scope of this report but can be briefly explained as follows. To estimate the fixed portion, the Model must be run to emulate the fixed cost for each of the combined cycles on-line during the period from 2001 to the end of the forecast period. These annual costs are then analyzed to find the following for each year of the forecast period: the most expensive unit in each year, the least expensive unit in each year, and the average cost of all the generating units.

The Marketsym model is run in the cost-based mode to produce market clearing prices for all the years of the forecast using all the above-identified resource additions. The Marketsym model is then run for a high and low gas price.

The fixed costs from the Model are then added to the variable costs from the Marketsym model to get the WEP forecast. **Figure A-10** illustrates the resulting wholesale electricity price forecast. The maximum wholesale electricity price is the most expensive generating unit in each year. The minimum wholesale electricity price is the least expensive generating unit in each year. The average wholesale electricity price is the average of all the generating units operating in that year.

Figure A-10: Illustrative Example for Wholesale Electricity Price Forecast



Source: Energy Commission

APPENDIX B: Component Levelized Costs

Chapter 1 summarized levelized component costs only in $/MWh for merchant plants only. This appendix provides within **Table B-1** through **Table B-6** a comprehensive summary in $/MWh and $/kW-Year, for merchant, IOU and POU plants for the average case.

Table B-1: Component Costs for Merchant Plants (Nominal $/MWh)

In-Service Year = 2009 (Nominal 2009 $)	Size MW	$/MWh (Nominal $) Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**	Fuel	Variable O&M	**Total Variable Cost**	Transmission Cost	**Total Levelized Cost**
Small Simple Cycle	49.9	482.17	23.44	31.87	66.81	134.18	**738.46**	95.54	5.08	**100.62**	5.24	**844.31**
Conventional Simple Cycle	100	459.43	22.33	30.36	48.56	128.14	**688.82**	95.54	5.08	**100.62**	5.24	**794.67**
Advanced Simple Cycle	200	158.70	7.71	10.49	22.79	44.28	**243.98**	88.15	4.47	**92.62**	5.24	**341.84**
Conventional Combined Cycle (CC)	500	28.64	1.38	1.88	1.61	9.42	**42.93**	72.05	3.66	**75.71**	5.21	**123.84**
Conventional CC - Duct Fired	550	30.26	1.46	1.99	1.67	9.95	**45.32**	73.19	3.66	**76.85**	5.21	**127.38**
Advanced Combined Cycle	800	25.91	1.25	1.70	1.34	8.52	**38.73**	67.17	3.26	**70.43**	5.21	**114.36**
Coal - IGCC	300	72.98	3.83	5.21	9.38	-11.33	**80.08**	19.38	11.98	**31.36**	5.38	**116.83**
Biomass IGCC	30	59.97	3.84	5.08	29.12	-26.40	**71.62**	26.75	5.08	**31.84**	6.54	**109.99**
Biomass Combustion - Fluidized Bed Boiler	28	60.92	3.78	5.00	17.56	-23.00	**64.26**	27.35	5.83	**33.18**	6.58	**104.02**
Biomass Combustion - Stoker Boiler	38	48.64	3.02	4.00	27.66	-18.49	**64.83**	28.06	8.91	**36.97**	6.45	**108.25**
Geothermal - Binary	15	84.76	6.52	9.85	11.15	-48.94	**63.33**	0.00	5.94	**5.94**	13.83	**83.11**
Geothermal - Flash	30	74.41	5.74	8.67	13.19	-43.22	**58.79**	0.00	6.61	**6.61**	13.51	**78.91**
Hydro - Small Scale & Developed Sites	15	93.65	7.03	10.62	11.10	-46.78	**75.62**	0.00	4.85	**4.85**	6.00	**86.47**
Hydro - Capacity Upgrade of Existing Site	80	43.98	2.97	4.48	7.53	-0.84	**58.12**	0.00	3.16	**3.16**	5.68	**66.96**
Solar - Parabolic Trough	250	257.53	16.58	0.00	47.03	-114.69	**206.45**	0.00	0.00	**0.00**	18.26	**224.70**
Solar - Photovoltaic (Single Axis)	25	317.91	20.47	0.00	47.03	-141.44	**243.96**	0.00	0.00	**0.00**	18.26	**262.21**
Onshore Wind - Class 3/4	50	74.66	5.53	8.36	5.90	-36.18	**58.28**	0.00	6.97	**6.97**	7.16	**72.41**
Onshore Wind - Class 5	100	65.77	4.87	7.37	5.20	-31.88	**51.34**	0.00	6.97	**6.97**	7.16	**65.47**

Source: Energy Commission

Table B-2: Component Costs for IOU Plants (Nominal $/MWh)

In-Service Year = 2009 (Nominal 2009 $)	Size MW	$/MWh (Nominal $) Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**	Fuel	Variable O&M	**Total Variable Cost**	Transmission Cost	**Total Levelized Cost**
Small Simple Cycle	49.9	371.37	13.49	24.69	67.87	68.39	**545.81**	99.40	5.16	**104.56**	5.32	**655.69**
Conventional Simple Cycle	100	353.82	12.85	23.52	49.33	65.43	**504.96**	99.40	5.16	**104.56**	5.32	**614.84**
Advanced Simple Cycle	200	121.36	4.41	8.07	23.15	22.47	**179.45**	91.72	4.54	**96.26**	5.32	**281.03**
Conventional Combined Cycle (CC)	500	21.74	0.79	1.44	1.64	5.08	**30.69**	75.07	3.71	**78.78**	5.29	**114.76**
Conventional CC - Duct Fired	550	22.97	0.83	1.53	1.69	5.36	**32.38**	76.26	3.71	**79.97**	5.29	**117.64**
Advanced Combined Cycle	800	19.67	0.71	1.31	1.37	4.59	**27.65**	69.99	3.31	**73.29**	5.29	**106.23**
Coal - IGCC	300	60.21	2.19	4.00	9.53	-14.96	**60.98**	19.72	12.17	**31.88**	5.47	**98.32**
Biomass IGCC	30	60.65	2.20	4.03	29.25	-23.03	**73.10**	26.87	5.10	**31.98**	6.57	**111.65**
Biomass Combustion - Fluidized Bed Boiler	28	59.67	2.17	3.97	17.64	-22.63	**60.82**	27.47	5.85	**33.33**	6.61	**100.75**
Biomass Combustion - Stoker Boiler	38	47.72	1.73	3.17	27.79	-18.15	**62.26**	28.18	8.95	**37.13**	6.47	**105.87**
Geothermal - Binary	15	91.92	3.94	7.21	11.38	-40.94	**73.51**	0.00	5.98	**5.98**	14.03	**93.52**
Geothermal - Flash	30	80.93	3.47	6.35	13.47	-36.06	**68.16**	0.00	6.65	**6.65**	13.70	**88.51**
Hydro - Small Scale & Developed Sites	15	99.04	4.24	7.76	11.26	-37.69	**84.61**	0.00	4.89	**4.89**	6.04	**95.54**
Hydro - Capacity Upgrade of Existing Site	80	41.81	1.79	3.28	7.65	1.95	**56.48**	0.00	3.18	**3.18**	5.72	**65.39**
Solar - Parabolic Trough	250	262.48	9.54	0.00	47.28	-99.37	**219.93**	0.00	0.00	**0.00**	18.35	**238.27**
Solar - Photovoltaic (Single Axis)	25	323.91	11.77	0.00	47.28	-122.59	**260.37**	0.00	0.00	**0.00**	18.35	**278.71**
Onshore Wind - Class 3/4	50	77.68	3.33	6.09	5.97	-29.56	**63.51**	0.00	7.02	**7.02**	7.22	**77.75**
Onshore Wind - Class 5	100	68.44	2.93	5.37	5.26	-26.05	**55.94**	0.00	7.02	**7.02**	7.22	**70.19**

Source: Energy Commission

Table B-3: Component Costs for POU Plants (Nominal $/MWh)

In-Service Year = 2009 (Nominal 2009 $)	Size MW	$/MWh (Nominal $) Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**	Fuel	Variable O&M	**Total Variable Cost**	Transmission Cost	**Total Levelized Cost**
Small Simple Cycle	49.9	135.36	11.84	11.43	34.58	0.00	**193.21**	104.12	5.25	**109.38**	5.42	**308.01**
Conventional Simple Cycle	100	128.99	11.28	10.89	25.14	0.00	**176.30**	104.12	5.25	**109.38**	5.42	**291.10**
Advanced Simple Cycle	200	58.41	5.11	4.93	15.73	0.00	**84.17**	96.08	4.62	**100.70**	5.42	**190.29**
Conventional Combined Cycle (CC)	500	15.62	1.37	1.32	1.68	0.00	**19.98**	78.77	3.78	**82.55**	5.38	**107.91**
Conventional CC - Duct Fired	550	16.50	1.44	1.39	1.73	0.00	**21.07**	80.02	3.78	**83.80**	5.38	**110.25**
Advanced Combined Cycle	800	14.13	1.24	1.19	1.39	0.00	**17.96**	73.43	3.37	**76.80**	5.38	**100.14**
Coal - IGCC	300	43.26	3.78	3.65	9.71	0.00	**60.41**	20.11	12.39	**32.51**	5.57	**98.49**
Biomass IGCC	30	43.59	3.81	3.68	29.81	-2.58	**78.31**	27.38	5.20	**32.58**	6.69	**117.58**
Biomass Combustion - Fluidized Bed Boiler	28	42.96	3.76	3.63	17.98	-2.58	**65.74**	27.98	5.96	**33.94**	6.74	**106.42**
Biomass Combustion - Stoker Boiler	38	34.35	3.00	2.90	28.33	-2.58	**66.00**	28.70	9.12	**37.82**	6.60	**110.42**
Geothermal - Binary	15	61.21	7.01	6.73	12.75	-2.18	**85.52**	0.00	6.20	**6.20**	15.19	**106.91**
Geothermal - Flash	30	53.86	6.17	5.93	15.08	-2.18	**78.86**	0.00	6.90	**6.90**	14.83	**100.59**
Hydro - Small Scale & Developed Sites	15	65.29	7.48	7.18	12.19	0.00	**92.14**	0.00	5.08	**5.08**	6.28	**103.50**
Hydro - Capacity Upgrade of Existing Site	80	27.56	3.16	3.03	8.28	0.00	**42.03**	0.00	3.31	**3.31**	5.95	**51.29**
Solar - Parabolic Trough	250	190.47	16.66	0.00	48.38	-2.72	**252.78**	0.00	0.00	**0.00**	18.74	**271.52**
Solar - Photovoltaic (Single Axis)	25	235.05	20.55	0.00	48.38	-2.72	**301.26**	0.00	0.00	**0.00**	18.74	**320.00**
Onshore Wind - Class 3/4	50	50.21	5.75	5.52	6.35	-2.18	**65.66**	0.00	7.31	**7.31**	7.55	**80.52**
Onshore Wind - Class 5	100	44.24	5.07	4.87	5.59	-2.18	**57.58**	0.00	7.31	**7.31**	7.55	**72.44**

Source: Energy Commission

Table B-4: Component Costs for Merchant Plants (Nominal $/kW-Year)

In-Service Year = 2009 (Nominal 2009 $)	Size MW	$/kW-Yr (Nominal $) Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**	Fuel	Variable O&M	**Total Variable Cost**	Transmission Cost	**Total Levelized Cost**
Small Simple Cycle	49.9	198.11	9.63	13.09	27.45	55.13	**303.42**	39.25	2.09	**41.34**	2.15	**346.91**
Conventional Simple Cycle	100	188.77	9.17	12.48	19.95	52.65	**283.02**	39.25	2.09	**41.34**	2.15	**326.51**
Advanced Simple Cycle	200	130.42	6.34	8.62	18.73	36.39	**200.49**	72.44	3.67	**76.12**	4.30	**280.91**
Conventional Combined Cycle (CC)	500	175.27	8.47	11.51	9.88	57.64	**262.77**	441.00	22.38	**463.38**	31.86	**758.01**
Conventional CC - Duct Fired	550	172.85	8.35	11.36	9.52	56.84	**258.91**	418.13	20.88	**439.01**	29.74	**727.66**
Advanced Combined Cycle	800	158.58	7.66	10.42	8.22	52.16	**237.04**	411.14	19.93	**431.07**	31.86	**699.97**
Coal - IGCC	300	466.89	24.52	33.34	60.03	-72.46	**512.31**	123.99	76.64	**200.63**	34.43	**747.38**
Biomass IGCC	30	358.17	22.94	30.36	173.91	-157.67	**427.71**	159.78	30.35	**190.13**	39.05	**656.89**
Biomass Combustion - Fluidized Bed Boiler	28	400.27	24.82	32.85	115.36	-151.09	**422.21**	179.73	38.30	**218.03**	43.26	**683.49**
Biomass Combustion - Stoker Boiler	38	326.41	20.27	26.83	185.62	-124.07	**435.06**	188.29	59.81	**248.09**	43.26	**726.41**
Geothermal - Binary	15	436.46	33.55	50.71	57.40	-252.00	**326.13**	0.00	30.61	**30.61**	71.21	**427.95**
Geothermal - Flash	30	398.51	30.72	46.44	70.64	-231.48	**314.83**	0.00	35.40	**35.40**	72.37	**422.60**
Hydro - Small Scale & Developed Sites	15	179.40	13.46	20.35	21.26	-89.61	**144.86**	0.00	9.30	**9.30**	11.49	**165.65**
Hydro - Capacity Upgrade of Existing Site	80	88.92	6.00	9.07	15.23	-1.70	**117.52**	0.00	6.39	**6.39**	11.49	**135.40**
Solar - Parabolic Trough	250	431.73	27.80	0.00	78.84	-192.27	**346.10**	0.00	0.00	**0.00**	30.60	**376.70**
Solar - Photovoltaic (Single Axis)	25	532.94	34.31	0.00	78.84	-237.12	**408.98**	0.00	0.00	**0.00**	30.60	**439.58**
Onshore Wind - Class 3/4	50	209.65	15.53	23.48	16.58	-101.60	**163.64**	0.00	19.58	**19.58**	20.12	**203.33**
Onshore Wind - Class 5	100	209.65	15.53	23.48	16.58	-101.61	**163.63**	0.00	22.22	**22.22**	22.84	**208.69**

Source: Energy Commission

Table B-5: Component Costs for IOU Plants (Nominal $/kW-Year)

		$/kW-Yr (Nominal $)										
In-Service Year = 2009 (Nominal 2009 $)	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**	Fuel	Variable O&M	**Total Variable Cost**	**Transmission Cost**	**Total Levelized Cost**
Small Simple Cycle	49.9	152.53	5.54	10.14	27.88	28.09	**224.18**	40.83	2.12	**42.95**	2.18	**269.31**
Conventional Simple Cycle	100	145.33	5.28	9.66	20.26	26.87	**207.40**	40.83	2.12	**42.95**	2.18	**252.53**
Advanced Simple Cycle	200	99.69	3.62	6.63	19.02	18.46	**147.41**	75.35	3.73	**79.08**	4.37	**230.86**
Conventional Combined Cycle (CC)	500	132.80	4.82	8.83	10.04	31.01	**187.50**	458.69	22.68	**481.37**	32.29	**701.17**
Conventional CC - Duct Fired	550	130.97	4.76	8.71	9.66	30.59	**184.68**	434.89	21.17	**456.06**	30.14	**670.88**
Advanced Combined Cycle	800	120.16	4.36	7.99	8.35	28.07	**168.93**	427.62	20.20	**447.83**	32.29	**649.05**
Coal - IGCC	300	385.06	13.99	25.60	60.96	-95.68	**389.93**	126.08	77.79	**203.87**	34.95	**628.75**
Biomass IGCC	30	362.16	13.16	24.08	174.67	-137.51	**436.55**	160.47	30.48	**190.95**	39.21	**666.72**
Biomass Combustion - Fluidized Bed Boiler	28	391.99	14.24	26.06	115.86	-148.64	**399.51**	180.47	38.46	**218.93**	43.44	**661.87**
Biomass Combustion - Stoker Boiler	38	320.12	11.63	21.28	186.43	-121.74	**417.72**	189.06	60.05	**249.11**	43.44	**710.28**
Geothermal - Binary	15	467.29	20.02	36.64	57.85	-208.10	**373.70**	0.00	30.41	**30.41**	71.30	**475.41**
Geothermal - Flash	30	427.88	18.33	33.55	71.19	-190.62	**360.33**	0.00	35.17	**35.17**	72.45	**467.95**
Hydro - Small Scale & Developed Sites	15	188.41	8.07	14.77	21.43	-71.70	**160.98**	0.00	9.30	**9.30**	11.49	**181.77**
Hydro - Capacity Upgrade of Existing Site	80	83.97	3.60	6.58	15.35	3.92	**113.43**	0.00	6.39	**6.39**	11.49	**131.31**
Solar - Parabolic Trough	250	439.57	15.97	0.00	79.18	-166.41	**368.31**	0.00	0.00	**0.00**	30.72	**399.04**
Solar - Photovoltaic (Single Axis)	25	542.46	19.71	0.00	79.18	-205.31	**436.04**	0.00	0.00	**0.00**	30.72	**466.76**
Onshore Wind - Class 3/4	50	217.37	9.31	17.04	16.71	-82.73	**177.70**	0.00	19.65	**19.65**	20.21	**217.56**
Onshore Wind - Class 5	100	217.37	9.31	17.04	16.71	-82.73	**177.69**	0.00	22.31	**22.31**	22.94	**222.94**

Source: Energy Commission

Table B-6: Component Costs for POU Plants (Nominal $/kW-Year)

In-Service Year = 2009 (Nominal 2009 $)	Size MW	$/kW-Yr (Nominal $) Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**	Fuel	Variable O&M	**Total Variable Cost**	Transmission Cost	**Total Levelized Cost**
Small Simple Cycle	49.9	111.14	9.72	9.39	28.40	0.00	**158.64**	85.50	4.31	**89.81**	4.45	**252.90**
Conventional Simple Cycle	100	105.92	9.26	8.94	20.64	0.00	**144.76**	85.50	4.31	**89.81**	4.45	**239.02**
Advanced Simple Cycle	200	71.94	6.29	6.08	19.37	0.00	**103.67**	118.33	5.70	**124.03**	6.67	**234.37**
Conventional Combined Cycle (CC)	500	95.23	8.33	8.04	10.22	0.00	**121.82**	480.26	23.05	**503.31**	32.82	**657.95**
Conventional CC - Duct Fired	550	93.91	8.21	7.93	9.85	0.00	**119.89**	455.34	21.52	**476.86**	30.64	**627.39**
Advanced Combined Cycle	800	86.16	7.53	7.28	8.50	0.00	**109.48**	447.73	20.53	**468.27**	32.82	**610.57**
Coal - IGCC	300	276.53	24.18	23.35	62.10	0.00	**386.16**	128.57	79.21	**207.78**	35.59	**629.53**
Biomass IGCC	30	260.21	22.75	21.98	177.93	-15.42	**467.45**	163.44	31.04	**194.48**	39.93	**701.86**
Biomass Combustion - Fluidized Bed Boiler	28	281.95	24.65	23.81	118.03	-16.95	**431.48**	183.64	39.14	**222.78**	44.21	**698.48**
Biomass Combustion - Stoker Boiler	38	230.26	20.13	19.45	189.91	-17.32	**442.43**	192.38	61.12	**253.50**	44.21	**740.14**
Geothermal - Binary	15	289.58	33.17	31.86	60.31	-10.32	**404.60**	0.00	29.34	**29.34**	71.85	**505.80**
Geothermal - Flash	30	265.01	30.36	29.16	74.22	-10.73	**388.01**	0.00	33.94	**33.94**	72.96	**494.92**
Hydro - Small Scale & Developed Sites	15	119.60	13.70	13.16	22.34	0.00	**168.80**	0.00	9.31	**9.31**	11.50	**189.61**
Hydro - Capacity Upgrade of Existing Site	80	53.30	6.11	5.86	16.01	0.00	**81.28**	0.00	6.39	**6.39**	11.50	**99.17**
Solar - Parabolic Trough	250	317.58	27.77	0.00	80.66	-4.54	**421.47**	0.00	0.00	**0.00**	31.24	**452.71**
Solar - Photovoltaic (Single Axis)	25	391.91	34.27	0.00	80.66	-4.54	**502.30**	0.00	0.00	**0.00**	31.24	**533.55**
Onshore Wind - Class 3/4	50	137.82	15.79	15.16	17.42	-5.99	**180.19**	0.00	20.06	**20.06**	20.73	**220.99**
Onshore Wind - Class 5	100	137.82	15.79	15.16	17.42	-6.80	**179.39**	0.00	22.77	**22.77**	23.53	**225.69**

Source: Energy Commission

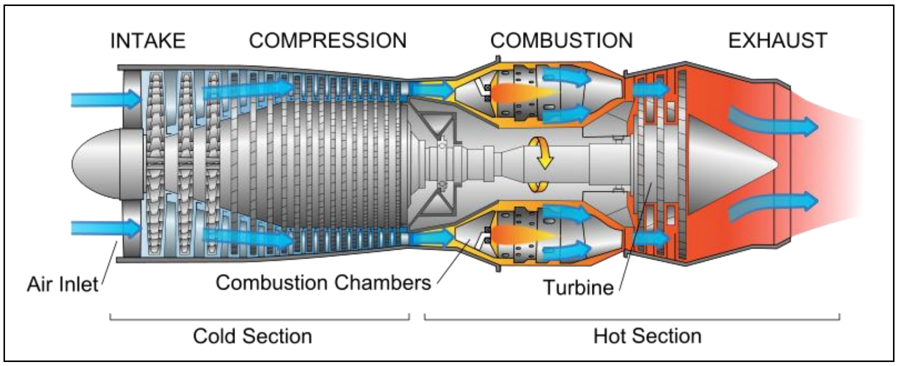
APPENDIX C: Gas-Fired Plants Technology Data

This appendix provides supporting information for the conventional and advanced gas-fired generation technology data assumptions provided in Chapter 2.

Conventional Simple Cycle

This technology is most commonly referred to as a combustion turbine or gas turbine. The combustion turbines included herein are aeroderivatives that were developed from the jet engines. They produce thrust from the exhaust gases, as illustrated **Figure C-1**.

Figure C-1: Aeroderivative Gas Turbine



Source: Wikipedia

F-Class gas turbines in simple cycle configuration are often used in other areas of the country, but there is not a single F-Class turbine currently operating in simple cycle mode in California, and due to the lower efficiency of the F-Class in simple cycle mode, such use in within California in the future is unlikely. Therefore, for the Model the most prevalent peaking turbine, the GE LM6000 gas turbine, is considered the basis for the two conventional simple cycle gas turbine cases.

Advanced Simple Cycle

The advanced simple cycle gas turbine selected for evaluation is the GE LMS100 gas turbine. The LMS100, an aeroderivative gas turbine, provides increased power output due to the addition of an intercooling system. The intercooling system takes compressed air from the low-pressure compressor, cools it to optimal temperatures, and then redelivers it to the high-pressure compressor, reducing the work of compression and increasing the pressure ratio and mass flow through the turbine. In simple cycle applications, the LMS100 can achieve 44 percent thermal efficiency, which is an approximately 10 point improvement over other turbines in its size range[10].

Due to the intercooling systems the LMS100 requires significantly more cooling infrastructure than other aeroderivative gas turbines. This cooling can be accommodated by a wet cooling tower, a wet surface air condenser (WSAC), or an air-cooled condenser (ACC). The use of a wet cooling tower is assumed. **Figure C-2** provides a cross-section view of the LMS100 gas turbine.

Conventional Combined Cycle

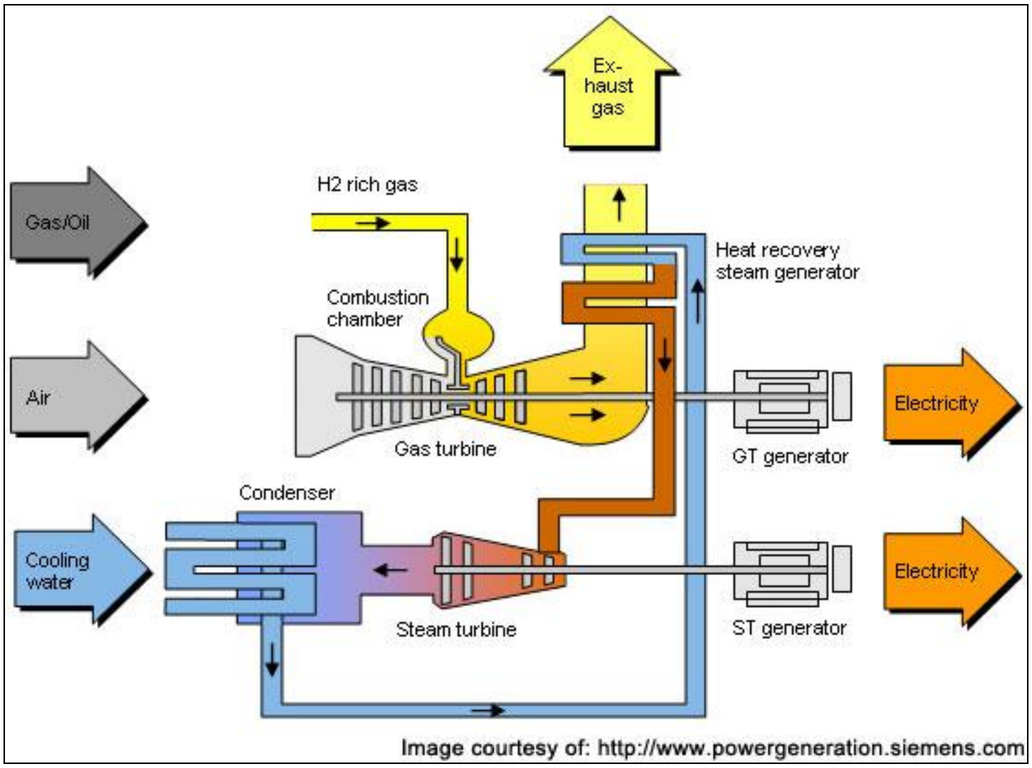
This technology combines a conventional steam turbine with one or more simple cycle units to derive an outstanding level of efficiency. The exhaust heat of the simple cycle unit is used to heat steam in the heat recovery section that leads to the steam turbine, as shown in **Figure C-3**.

Figure C-2: LMS100 Gas Turbine

Source: http://ge.ecomagination.com/site/media/lms1/zoom-03.jpg

[10] Information extracted from http://ge.ecomagination.com/site/products/lms1.html.

Figure C-3: Combined Cycle Process Flow



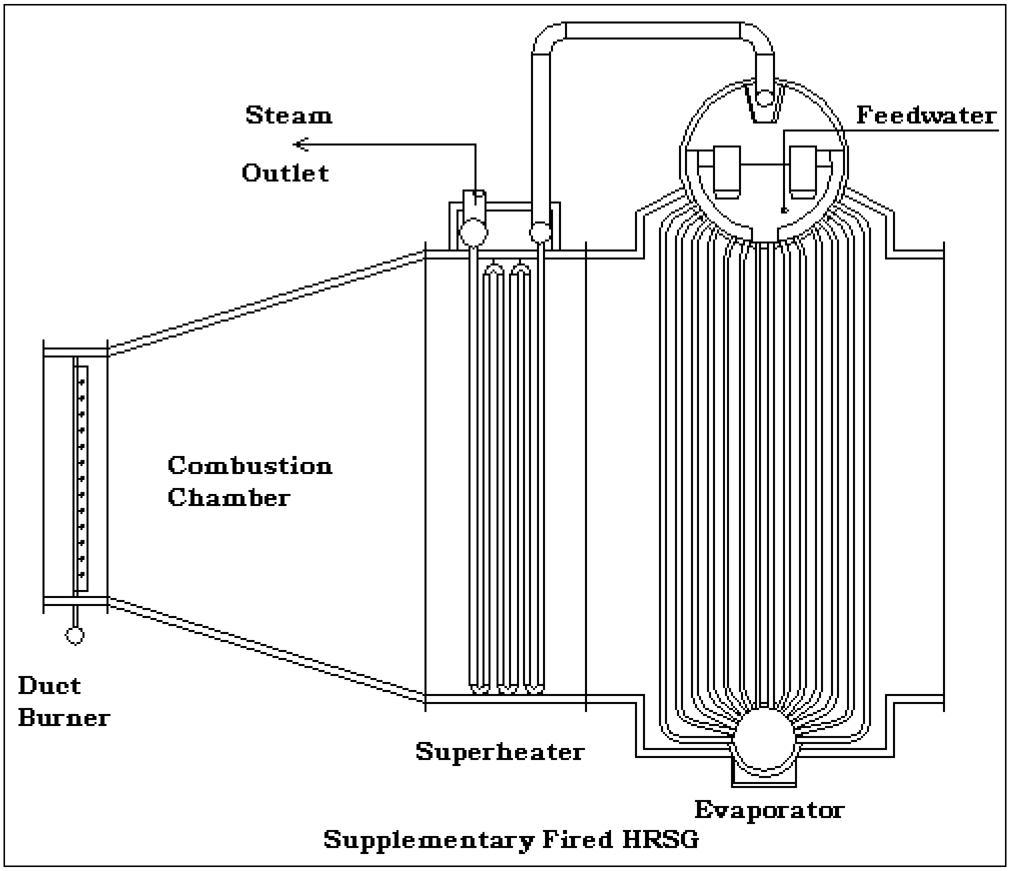
The typical combined cycle power plant built in California is based on the F-Frame gas turbine and typically includes two gas turbines and one steam turbine. However, the number of gas turbines and steam turbines vary significantly at the existing gas turbine combined cycle power plants in California. The general layout of a combined cycle power plant is provided in **Figure C-4**.

Figure C-4: Combined Cycle Power Plant General Arrangement

Conventional Combined Cycle With Duct Firing

Combined cycle systems can integrate duct burners after the gas turbine and before the heat recovery steam generator (HRSG) to increase power production. Duct firing affects power production only in the steam cycle portion of the combined cycle power generation and so is an inherently less efficient use of natural gas than the natural gas used to fire the gas turbine and make steam. Duct firing primarily provides peaking power and, if a plant's capacity factor is determined based on the total duct fired rating, will cause a corresponding decrease in the plant's annual capacity factor due to the limited use of the duct burners. The efficiency for duct firing, essentially the steam cycle efficiency, is similar to the efficiency of conventional simple cycle gas turbines but less efficient than advanced simple cycle gas turbines. The general layout of a combined cycle power plant HRSG, showing the added duct burners and combustion chamber on the far left, is provided in **Figure C-5**.

Figure C-5: Combined Cycle Power Plant HRSG Diagram

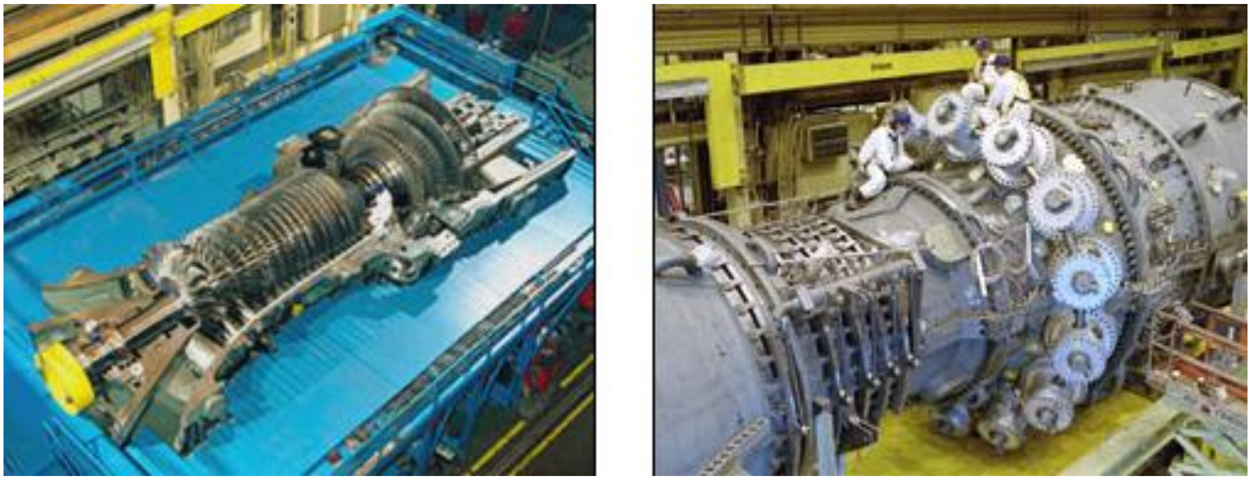


Source: http://www.nawabi.de/chemical/hrsg/HRSGimg5_9d.gif

Advanced Combined Cycle

The H System™ uses a closed-loop steam cooling system that allows the turbine to fire at a higher temperature to increase fuel efficiency to approximately 60 percent with reduced emissions and less fuel consumption per megawatt generated. This design also reduces the amount of cooling required per megawatt produced by the gas turbine, reducing the relative amount of necessary cooling infrastructure. **Figure C-6** shows an H-frame turbine during assembly and the outside of a completed H-frame gas turbine.

Figure C-6: GE H-Frame Gas Turbine



Source: http://www.gepower.com/prod_serv/products/gas_turbines_cc/en/h_system/9h_photos.htm

Plant Data

Plant data are the plant characteristics of the selected conventional gas-fired technologies selected for implementation in the Model. This data generally has been collected by Commission staff and consultants for the *IEPR*. Other sources are noted where relevant.

Selection and Description of Technologies

Two categories of gas-fired technologies are included: simple cycle and combined cycle. The six gas turbine technology cases selected for inclusion in the Model have the following basic designs:

- Conventional Simple cycle – One LM6000 Gas Turbine
- Conventional Simple cycle – Two LM6000 Gas Turbines
- Advanced Simple cycle – Two LMS100 Gas Turbines
- Conventional Combined cycle – Two F-Class Turbines
- Conventional Combined cycle with Duct Burners – Two F-Class Turbines
- Advanced Combined cycle – Two H Class Turbines

In each conventional case, staff has provided the most common gas turbine technologies currently used or proposed for use California, and these conventional technologies are likely to be proposed and built in California into the near future. The configuration/size for the conventional technology power plants were selected based on their general prevalence in the existing power plant fleet.

Gross Capacity (MW)

The gross capacity assumed for six gas turbine technologies selected for implementation into the Model are provided in **Table C-1**.

Table C-1: Gross Capacity Ratings for Typical Configurations

Technology Case	Gross Capacity
Conventional SC – One LM6000 Turbine	49.9 MW
Conventional SC – One LM6000 Turbine	100 MW
Advanced SC – Two LMS100 Turbines	200 MW
Conventional CC (no duct burners) – Two F-Class Turbines	500 MW
Conventional CC (duct burners) – Two F-Class Turbines	550 MW
Advanced CC – Two H-Class Turbines	800 MW

Source: Energy Commission

The selected gross capacities assume that some form of air preconditioning is used to increase/stabilize the generating capacity while operating at high temperature and that the turbines are not significantly derated by operating at high elevation.

Combined and Simple Cycle Data Collection

The *2007 IEPR* analysis was the starting point for the analysis presented here. That analysis was updated to reflect either changed underlying costs (for example, inflation), or reanalysis of the original survey data to reflect further understanding gained since 2007. These costs were then supplemented with recent data and estimates from other sources such as government agencies, financial analysis institutions, and control area operators. Fuel use and operational data for California facilities were updated as well from the Commission's QFER database. Much of this analysis confirmed the underlying results from the *2007 IEPR*.

In preparing the *2007 IEPR*, staff submitted to power plant developers a data request for all the combined-2cycle (but not cogeneration) and simple cycle power plants that were certified by the Energy Commission starting in 1999 and on-line since 2001 through the first quarter of 2006. These plants are summarized in **Table C-2**, together with the in-service year and county location.

Table C-2: Surveyed Power Plants

Combined Cycle Plants (19)			Simple Cycle Plants (15)		
Plant Name	**County**	**Operating**	**Plant Name**	**County**	**Operating**
Los Medanos	Contra Costa	2001	Wildflower Larkspur [2]	San Diego	2001
Sutter	Sutter	2001	Wildflower Indigo [2]	Riverside	2001
Delta	Contra Costa	2002	Drews Alliance [2]	San Bernardino	2001
Moss Landing	Monterey	2002	Century Alliance [2]	San Bernardino	2001
La Paloma	Kern	2003	Hanford [2]	Kings	2001
High Desert	San Bernardino	2003	Calpeak Escondido [2]	San Diego	2001
MID Woodland [1,2]	Stanislaus	2003	Calpeak Border [2]	San Diego	2001
Sunrise	Kern	2003	Gilroy [2]	Santa Clara	2002
Blythe I	Riverside	2003	King City [2]	Monterey	2002
Elk Hills	Kern	2003	Henrietta	Kings	2002
Von Raesfeld [1]	Santa Clara	2005	Los Esteros	Santa Clara	2003
Metcalf	Santa Clara	2005	Tracy Peaker	San Joaquin	2003
Magnolia [1]	Los Angeles	2005	Kings River Peaker [1,2]	Fresno	2005
Malburg [1]	Los Angeles	2005	Ripon	San Joaquin	2006
Pastoria	Kern	2005	Riverside	Riverside	2006
Mountainview [3]	San Bernardino	2006			
Palomar	San Diego	2006			
Cosumnes	Sacramento	2006			
Walnut	Stanislaus	2006			

Notes:
1 – Muni-owned facility
2 – Emergency Siting or SPPE Cases
3 – IOU-owned facility

Source: Energy Commission

Capital cost information was requested from all 34 plants, while operating costs were requested from plants that began regular operations in 2005 or earlier. The data requests for the combined cycle and simple cycle units were divided into capital costs and operating and maintenance costs, as summarized in **Table C-3**.

Table C-3: Summary of Requested Data by Category

Capital Cost Parameters	Operating & Maintenance Cost Parameters
Gas Turbine and Combustor Make/Models	Total Annual Operating Costs
Steam Turbine Make/Model	Operating Hours
Total Capital Cost of Facility	Startup/Shutdown Hours
Gas Turbine Cost	Natural Gas Sources
Steam Turbine Cost	Duct Burner Natural Gas Use
Air Inlet Treatment Cost	Water Supply Source/Cost/Consumption
Cooling Tower/Air Cooled Condenser Cost	Labor (Staffing and Cost)
Water Treatment Facilities	Non-Fuel Annual Operating Costs (Consumables, etc.)
Site Footprint and Land Cost	Annual Regulatory Costs (Filings, Consumables, etc.)
Total Construction Costs (Labor/Equipment/etc.)	Major Scheduled Overhaul Frequency/Cost
Cost of Site Grading	Normal Annual Maintenance Costs
Cost of Pipeline Linear Construction	Reconciliation of QFER data (MW generation and total fuel use)
Cost of Transmission Linear Construction	
Cost of Licensing/Permitting Project	
Air Pollution Control Costs	
Cost of Air Quality Offsets	

Source: Energy Commission

The information request for each power plant was tailored according to the design of that plant. For example, simple cycle facilities did not include questions about steam turbines and duct burners. After receipt of the information requests responses, they were reviewed, and additional data or clarification of data was requested, as appropriate for each power plant, to complete and validate the information to the extent possible. As much of this data was gathered under confidentiality agreements, the details can be presented and discussed only in general, collective terms. Through spreadsheet analysis and comparison of relative costs as a function of various variables, it was possible to determine a suitable base cost plus adders to atypical configurations for the six categories described below.

No new or revised information requests were completed for the new power plants built or starting operation since the *2007 IEPR* information request. However, a large amount of additional capital and operating cost data was gathered through third-party sources, with the vast majority of this third party collected cost data coming from Jeff King of the Northwest Power and Conservation Council (NWPCC) and Stan Kaplan of the Congressional Research Service (CRS).

Outage Rates

Outages are divided into two categories, those that are foreseen or scheduled, and those that are unforeseen or forced. Outages differ from curtailments in that curtailments are considered to be caused by either discretionary choices (for example, responses to economic signals) or by resource shortages (for example, lack of fuel or renewable energy sources). Curtailments are represented in different ways elsewhere in the model.

The scheduled outage factor (SOF) was derived from National Electricity Reliability Council (NERC) GADS data for California generation resources:

- NERC GADS Vintage 2002-2007 CA CCs 500-900 MW: 6.02 percent
- NERC GADS 2002-2007 CA CTs 45-99 MW: 2.72 percent
- NERC GADS 2002-2007 CA CTs 100 and greater: 3.18 percent

Likewise, effective forced outage rates (EFOR and EFORd) were collected for California Generation Resources. The EFOR is measured against the period when the unit is operating, that is, it excludes non-operational hours due to curtailments when developing the rate. This is particularly important for low capacity factor resources such as simple cycle units. The EFORd values are used in the model.

- NERC GADS Vintage 2002-2007 CA CCs 500-900 MW EFORd: 3.5 percent (2.24 percent)
- NERC GADS 2002-2007 CA CTs 45-99 MW EFORd: 19.19 percent (5.65 percent)
- NERC GADS 2002-2007 CA CTs 100 and greater: EFORd: 11.60 percent (4.13 percent)

Capacity Factor (Percentage)

The actual capacity factors (CF) were determined for the existing California conventional LM6000 simple cycle power plants and F-Class combined cycle power plants, based on the monthly QFER data from 2001 to 2008 for 25 simple cycle facilities and 15 combined cycle facilities, and are provided in **Table C-4** and **Table C-5**. The capacity factors were derived using the following simple equation:

QFER net generation (MWh) /(facility generation capacity(MW) x hrs/year) = Capacity Factor

The combustion turbine units Anaheim, Glenarm, Grayson, Malaga, MID Ripon, Niland, and Riverside are publicly owned utilities (POUs); and Barre, Center, Etiwanda, and Mira Loma are investor-owned utilities (IOUs). The other power plants are all merchant facilities.

The capacity factors for the combined cycle units are based on the annual average duct-fired capacity for each facility. Magnolia and Cosumnes are POUs, and Palomar and Mountainview are IOUs. The other power plants are all merchant facilities.

The staff recommended capacity factors were determined by examination of historical capacity factor data in the Energy Commission's QFER database, as summarized in **Table** C-4 and **Table C-5** as well as an examination of production cost simulations. **Table** C-6 provides the average-cost, high-cost, and low-cost capacity factors that were recommended for use in the Model.

Table C-4: Simple Cycle Facility Capacity Factors

Year	Anaheim	Barre	Center	Creed	Etiwanda	Feather	Gilroy	Goose Haven	King City
2001	21.88%								
2002	29.90%						4.90%		3.90%
2003	25.41%			3.26%		3.66%	5.41%	3.10%	4.04%
2004	13.07%			2.39%		3.92%	5.65%	2.57%	4.99%
2005	12.29%			2.20%		3.03%	4.13%	2.46%	3.75%
2006	12.85%			2.66%		3.73%	4.21%	2.75%	3.80%
2007	11.45%	2.14%	1.90%	3.06%	1.61%	6.06%	7.21%	3.44%	5.43%
2008	12.04%	1.10%	1.10%	3.78%	0.86%	6.48%	7.77%	3.67%	5.77%

Year	Lambie	Riverview	Wolfskill	Yuba City	Glenarm	Grayson	Hanford	Henrietta	Indigo
2001							3.23%		
2002							4.89%	3.38%	0.33%
2003	3.24%	3.66%	3.85%	4.34%			2.24%	2.29%	5.86%
2004	3.69%	4.14%	5.01%	4.22%	5.43%	8.05%	1.20%	1.28%	6.28%
2005	3.62%	4.89%	3.74%	8.22%	2.78%	4.17%	3.95%	1.52%	4.71%
2006	2.80%	4.29%	3.96%	5.21%	4.97%	2.85%	2.62%	2.24%	4.40%
2007	3.47%	6.37%	4.87%	5.94%	4.50%	1.26%	4.43%	2.45%	6.86%
2008	3.51%	7.15%	6.14%	8.32%	4.07%	6.11%	5.69%	5.60%	9.90%

Year	Malaga	Larkspur	Los Esteros	MID Ripon	Mira Loma	Niland	Riverside
2001							
2002		1.18%	9.42%				
2003		4.01%	16.08%				
2004		4.74%	15.92%				
2005		3.85%	4.58%				
2006	7.58%	2.89%	3.87%	2.00%			7.53%
2007	15.52%	6.00%	4.79%	3.09%	1.72%		4.80%
2008	17.59%	8.02%	7.91%	3.85%	1.04%	9.21%	9.43%

Source: Energy Commission

Table C-5: Combined Cycle Facility Capacity Factors

Year	Magnolia	Moss Landing	High Desert	Sutter	Los Medanos	La Paloma	Delta	Sunrise
2001				32.1%	23.3%			
2002		28.4%		72.8%	76.4%		41.1%	
2003		57.9%	31.9%	62.9%	69.4%	34.6%	71.5%	32.3%
2004		55.5%	51.9%	67.3%	76.4%	57.2%	76.0%	62.1%
2005	10.8%	52.6%	50.3%	47.9%	76.8%	46.4%	72.8%	65.7%
2006	31.2%	57.7%	54.0%	41.5%	62.7%	57.0%	65.7%	70.2%
2007	49.4%	70.3%	61.1%	52.5%	74.4%	62.6%	71.6%	71.5%
2008	54.5%	62.2%	63.4%	57.1%	66.4%	62.6%	65.4%	70.2%
Year	**Blythe**	**Metcalf**	**Mountainview**	**Pastoria**	**Elk Hills**	**Palomar**	**Consumnes**	
2001								
2002								
2003								
2004	26.8%				82.6%			
2005	19.6%	36.3%	1.6%	38.3%	74.4%			
2006	23.2%	44.9%	52.7%	70.6%	71.7%	51.7%	57.8%	
2007	26.1%	55.4%	68.2%	73.5%	77.5%	69.9%	85.0%	
2008	30.1%	61.4%	72.3%	74.6%	73.7%	75.1%	87.6%	

Source: Energy Commission

Table C-6: Recommended Capacity Factors

Technology Case	Owner	Assumed Capacity Factor		
		Average	High	Low
Conventional Simple Cycle (both sizes)	Merchant/IOU	5%	2.5%	10%
	Muni	10%	3%	20%
Advanced Simple Cycle	Merchant/IOU	10%	5%	20%
	Muni	15%	10%	30%
Conventional Combined Cycle	All Owners	75%	55%	90%
Conventional Combined Cycle w/Duct Burners	All Owners	70%	50%	85%
Advanced Combined Cycle	All Owners	75%	55%	90%

Note: High and Low are based on cost implications not on the specific value of the capacity factor.

Source: Energy Commission

The advanced simple cycle capacity factors were increased somewhat from the assumed conventional simple cycle capacity factors due to an assumption of increased use due to higher efficiency. The advanced combined cycle capacity factors were assumed to be the same as the conventional non-duct-firing combined cycle capacity factors as these plants are presumed to replace conventional plants in the dispatch order.

There is a clear overall increase in both simple cycle and combined cycle capacity factor over the past few years in both the QFER and California ISO *Annual Report on Market Issues and Performance*. Therefore, the recommended capacity factors are higher than those used in the previous version of the Model.

Plant-Side Losses (Percentage)

The plant-side losses were estimated by analyzing the QFER data for the same facilities analyzed for capacity factor and heat rate. The plant-side losses, determined through the difference in the reported gross vs. reported net generation, for the existing California conventional LM6000 simple cycle power plants and F-Class combined cycle power plants, based on the monthly QFER data from 2001 to 2008 for 25 simple cycle facilities and 15 combined cycle facilities, are provided in **Table C-7**and **Table C-8**. Based on this data, staff recommends the average-cost, high-cost, and low-cost plant-side losses shown in **Table C-9**.

Staff does not have data to suggest significantly different plant side loss factors for advanced combined cycle facilities. The advanced simple cycle facilities may have increased plant-side losses due to the power required for the turbine inter-cooling auxiliary facilities; however, staff has no specific information to obtain values different from those determined for the LM6000 gas turbine facilities, so the same range is currently recommended.

Table C-7: Simple Cycle Facility Plant-Side Losses (%)

Anaheim	Barre	Center	Creed	Etiwanda	Feather	Gilroy	Goose Haven	King City
3.58%	n/a	n/a	3.62%	n/a	3.99%	3.05%	3.94%	4.15%
Lambie	**Riverview**	**Wolfskill**	**Yuba City**	**Glenarm**	**Grayson**	**Hanford**	**Henrietta**	**Indigo**
4.14%	3.14%	3.64%	4.19%	3.27%	3.39%	3.45%	2.91%	2.69%
Malaga	**Larkspur**	**Los Esteros**	**MID Ripon**	**Mira Loma**	**Niland**	**Riverside**		
2.33%	2.84%	3.40%	6.09%[a]	n/a	7.89%[a]	n/a		

Source: Energy Commission

Note:
[a] This data does not appear reasonable given the known plant design and was not used to determine the plant side losses recommended values.

Table C-8: Combined Cycle Facility Plant-Side Losses (%)

Magnolia	Moss Landing	High Desert	Sutter	Los Medanos	La Paloma	Delta	Sunrise
3.53%	3.34%	2.95%	3.80%	2.02%	3.23%	2.17%	3.10%
Blythe	**Metcalf**	**Mountainview**		**Pastoria**	**Elk Hills**	**Palomar**	**Consumnes**
n/a	2.15%	3.86%		2.84%	2.20%	2.56%	2.54%

Source: Energy Commission

Table C-9: Summary of Recommended Plant-Side Losses (%)

Technology	Average	High	Low
All Combined Cycle (CC)	2.9%	4.0%	2.0%
All Simple Cycle (SC)	3.4%	4.2%	2.3%

Source: Energy Commission

Heat Rate (Btu/kWh)

The actual heat rates, reported as higher heating value (HHV), determined for the existing California conventional LM6000 simple cycle power plants and F-Class combined cycle power plants , based on the monthly QFER data from 2001 to 2008 for 25 simple cycle facilities and 15 combined cycle facilities, are provided in **Table C-10** and **Table C-11.** The heat rates were derived using the following simple equation:

QFER heat input (MMBTU)/QFER net generation (kWh) = heat rate (Btu/kWh)

Table C-10: Simple Cycle Facility Heat Rates (Btu/kWh, HHV)

Year	Anaheim	Barre	Center	Creed	Etiwanda	Feather	Gilroy	Goose Haven	King City
2001	9,178								
2002	9,208						10,187		10,109
2003	9,325			10,124		9,578	10,341	10,095	10,075
2004	9,744			10,075		9,748	10,029	10,156	10,191
2005	10,170			10,170		9,448	9,970	10,175	10,259
2006	10,213			10,749		9,487	10,102	10,101	10,156
2007	9,499	11,744	10,640	10,251	11,051	10,308	10,073	10,358	9,749
2008	9,424	12,057	10,587	10,247	12,062	10,258	10,125	10,304	9,862

Year	Lambie	Riverview	Wolfskill	Yuba City	Glenarm	Grayson	Hanford	Henrietta	Indigo
2001							10,295		
2002							10,263	10,177	10,091
2003	9,953	10,235	9,942	9,710			10,279	10,263	10,236
2004	10,089	10,015	10,150	9,549	11,969	11,510	10,127	10,419	10,061
2005	10,169	10,069	10,297	9,452	12,434	11,548	10,675	10,582	10,137
2006	10,317	11,585	10,154	9,338	10,226	11,885	10,220	10,291	10,154
2007	10,145	10,101	10,319	10,071	10,439	12,322	10,798	10,491	9,934
2008	10,152	10,217	10,208	10,051	10,604	11,522	10,137	10,434	10,000

Year	Malaga	Larkspur	Los Esteros	MID Ripon	Mira Loma	Niland	Riverside
2001							
2002		9,972	10,345				
2003		10,065	10,275				
2004		10,011	10,404				
2005		10,236	10,480				
2006	9,470	10,208	10,309	12,749			9,526
2007	9,999	10,047	10,346	12,494	11,138		9,372
2008	9,957	10,019	10,708	11,629	11,992	10,257	9,528

Source: Energy Commission

Table C-11: Combined Cycle Facility Heat Rates (Btu/kWh, HHV)

Year	Magnolia	Moss Landing	High Desert	Sutter	Los Medanos	La Paloma	Delta	Sunrise
2001				6,982	6,947			
2002		7,136		7,089	7,090		7,295	
2003		7,081	7,321	7,156	7,239	7,198	7,310	7,524
2004		7,069	7,348	7,193	7,191	7,133	7,289	7,213
2005	7,614	7,099	7,356	7,458	7,290	7,234	7,288	7,206
2006	7,340	7,052	7,343	7,451	7,337	7,167	7,324	7,295
2007	7,456	7,084	7,047	7,406	7,210	7,166	7,317	7,274
2008	7,233	7,127	7,055	7,430	7,218	7,172	7,321	7,266
Year	**Blythe**	**Metcalf**	**Mountainview**		**Pastoria**	**Elk Hills**	**Palomar**	**Consumnes**
2001								
2002								
2003								
2004	7,416					6,855		
2005	7,419	7,028			7,230	6,990		
2006	7,436	7,048	7,252		7,050	7,051	7,069	7,198
2007	7,825	7,042	7,063		7,062	7,050	7,038	7,042
2008	7,808	6,884	7,141		7,032	7,063	6,959	7,047

Source: Energy Commission

Table C-12 provides the average-cost, high-cost, and low-cost heat rates that were recommended for use in the Model. These values are higher (in other words, less efficient) than those reported by manufacturers and often used in other studies because these values include real-world operations such as start-ups and load following.

The advanced turbine technology heat rates were determined using data from turbine manufacturers and from the Energy Information Administration (EIA) 2006 forecast.

Table C-12: Summary of Recommended Heat Rates (Btu/kWh, HHV)

Technology	Average [a]	High [a]	Low [b]
Conventional Simple Cycle (SC) [c]	9,266	10,000	9,020
Advanced SC	8,550	8,700	8,230
Conventional Combined Cycle (CC)	6,940	7,200	6,600
Conventional CC W/ Duct Firing	7,050	7,400	6,700
Advanced CC	6,510	6,710	6,310

Notes:
[a] Average and High cost recommended values are based on an analysis of average and high QFER heat rates and current turbine technology (for example the average heat rate for the conventional simple cycle is based on new projects installing the next generation of LM6000 gas turbine). [b] Low cost recommended values are based on new and clean heat rates from turbine manufacturers. Average heat rates in COG Model are presented as a regression formula based on QFER data.[c] The conventional simple cycle values are recommended for both the single turbine (49.9 MW) and two turbine (100 MW) cases and are based on NXGen LM6000 gas turbine efficiencies that are higher than most of the existing LM6000-powered plants.
Source: Energy Commission

Heat Rate Degradation

Heat rate degradation is the percentage that the heat rate will increase per year. For this report, the heat rate degradation estimates are:

- For simple cycle units: 0.05 percent per year.
- For combined cycle units: 0.2 percent per year.

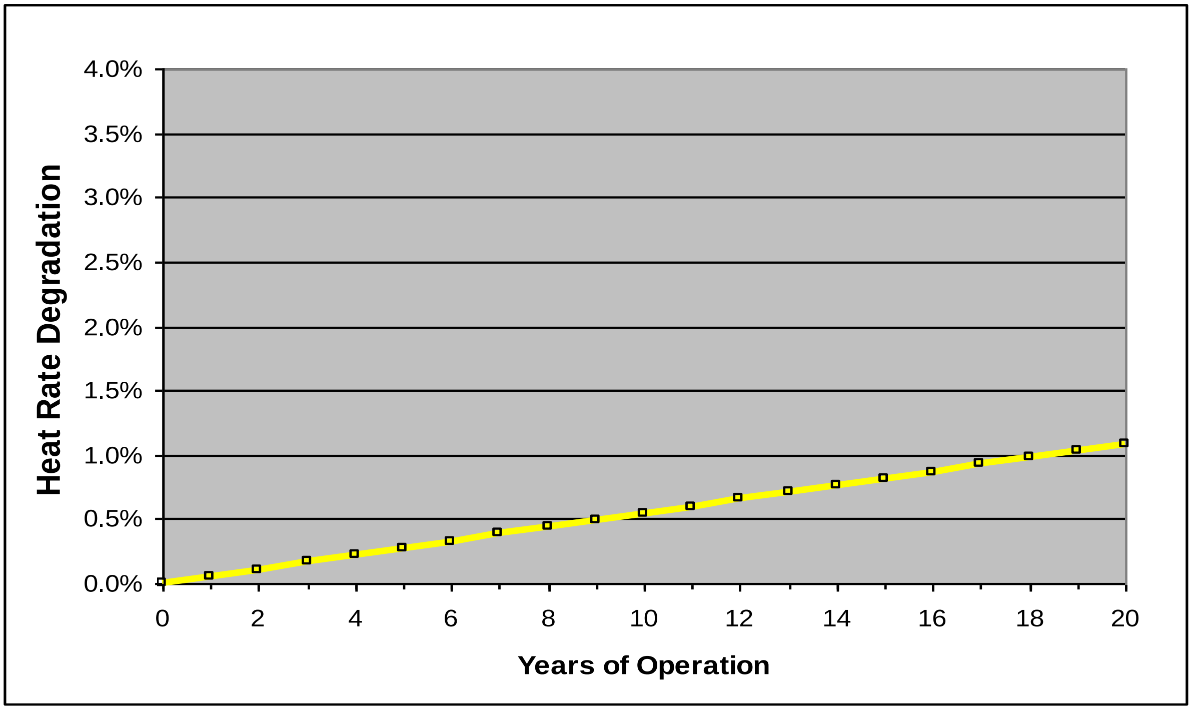
These values were estimated using General Electric data provided under the Aspen data survey. The rule for simple cycle units (combustion turbines) is that they degrade 3 percent between overhauls, which is every 24,000 hours. The actual time between overhauls, therefore, is a function of capacity factor as shown in **Table C-13**. The staff elected to use a 5 percent capacity factor based on the capacity factors observed in the survey data, and calculated degradation of 0.05 percent per year. **Figure C-7** shows the results, designated as "Equivalent SC Degradation."

Table C-13: Annual Heat Rate Degradation vs. Capacity Factor

Technology	Assumed Capacity Factor	Years Between Overhauls
Simple Cycle Units	5%	N/A
Simple Cycle Units	10%	27
Combined Cycle Units	50%	5.5
Combined Cycle Units	60%	4.6
Combined Cycle Units	70%	3.9
Combined Cycle Units	80%	3.4

Source: Energy Commission

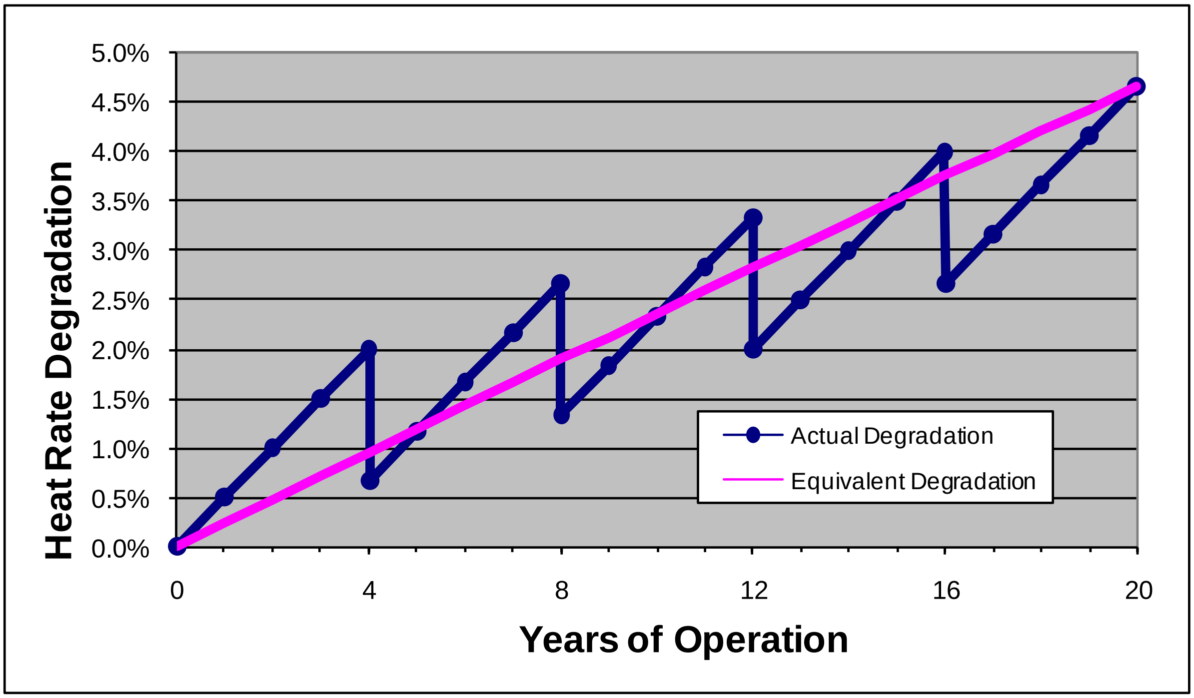
Figure C-7: Simple Cycle Heat Rate Degradation



Source: Energy Commission

The computation for the combined cycle units is more complex due to its higher capacity factor, estimated herein to be roughly 75 percent and 70 percent for a duct-fired unit, based on the QFER data and other historical information. The staff simplified this assumption by using four years for both technologies. This results in 4 major overhauls during its 20-year book life, as shown in **Figure C-8**. This means that the simple cycle units will degrade 3 percent during that period. Since the steam generator portion is essentially 1/3 of the system and remains essentially stable, and the overall system deteriorates 2/3 of the 3 percent of the simple cycle during the 4-year period, which is 2 percent; and recovers 2/3 of its 2 percent deterioration during the overhaul, which is 1 and 1/3 percent (2/3*2 = 4/3% = 1 1/3%). The degradation factor is equal to the slope of the curve, 0.24 percent per year. Since this factor has a small effect on levelized cost, this approximation is quite adequate. The details of this can be found in the Model User's Guide.

Figure C-8: Combined Cycle Heat Rate Degradation



Source: Energy Commission

Capacity Degradation

This value captures the degradation of capacity averaged over the life of the power plant It accounts for both the degradation of capacity due to wear and tear and the improvement in capacity due to periodic overhauls. It is an average as the plant capacity degrades and then is improved due to the many overhauls the plant experiences during its lifetime. Capacity Degradation is provided as an annual percentage. For the combined cycle and simple cycle units, the capacity degradation value is assumed to be equal to the heat rate degradation percentages.

The implementation of the capacity degradation factor is done by making two simplifying assumptions. The first assumption is that the capacity degradation can be ignored in the calculation of $/kW-Yr of the Income Statement Worksheet, based on the assumption that the $/kW-Yr should be considered to be based on the original installed gross capacity, similar to installed cost. That is, it should not be based on the average value of the degraded capacity (for example, the geometric mean of time-weighted capacities over the study period). It is captured only on the energy side.

The second assumption is that the impact on the energy generated can be represented by a constant annual average value, rather than as actual annual values that decrease over the years.

In each case, an average energy value (PMT) is calculated by first calculating a present value (PV) of the actual energy values and then using that PV to find the levelized energy value (PMT), similar to what is done in the Income Statement Worksheet for dollar values. This calculation of the PV is subtle and can best be illustrated using simplified nomenclature. If E_t are the annual decreasing energy values for years (t) 0 through N, then $E_t = E_C(1-CD)^t$, where E_C is the annual energy in the absence of capacity degradation and CD is the Capacity Degradation Factor. Each of the annual degraded values of this energy series can be converted to a present value by dividing by the factor $(1+DR,)^t$ where DR is the discount rate and t is number of the year. The present value (PV) of the entire series, therefore, can be represented as:

$$PV = \sum_{t=1}^{N} \frac{E_t}{(1+DR)^t} = \sum_{t=}^{N} \frac{E_C(1-CD)^t}{(1+DR)^t}$$

This can be easily rearranged to:

$$PV = \sum_{t=}^{N} \frac{E_C}{(1+DR)^t/(1-CD)^t} = \sum_{t=1}^{N} \frac{E_C}{[(1+DR)/(1-CD)]^t}$$

Adding 1 and subtracting 1 in the denominator, as shown, does not change the value but allows this to be put in a more usable form:

$$PV = \sum_{t=1}^{N} \frac{E_C}{[1+(1+DR)/(1-CD)-1]^t} = \sum_{t=1}^{N} \frac{E_C}{(1+i)^t}; where: \quad i = [(1+DR)/(1-CD)]-1$$

The formula is now a present value of constant value E_C, where the interest rate is equal to $[(1+DR)/(1-CD)]-1$.

Emission Factors

The criteria pollutant emission factors for the six gas turbine cases were estimated using permitted emission data from the following recent Energy Commission siting cases:

- Conventional CT (both cases) – Riverside Energy Resource Center Units 3 and 4
- Advanced CT – Panoche Energy Center
- Conventional CC (no duct firing) – Carlsbad Energy Center
- Conventional CC (duct firing) – Avenal Energy
- Advanced CC – Inland Empire Energy Center

The criteria pollutant emission factors recommended by staff for use in the Model based on these recent projects are provided in **Table C-14**.

The criteria pollutant emissions are based on permitted rather than actual emissions; therefore, average, high, and low values do not apply as the permitted emissions are assumed to be related to a consistent interpretation of Best Available Control Technology requirements within California.

The carbon dioxide emission factors were determined based on the efficiency for each technology based on an emission factor of 52.87 lb/MMBtu.[11] **Table C-15** provides the staff recommended carbon dioxide emission factors for each technology case based on the recommended heat rates shown in **Table C-12** .

Table C-14: Recommended Criteria Pollutant Emission Factors (lbs/MWh)

Technology	NO_x	VOC	CO	SO_x	PM10
Conventional Simple Cycle (SC) [a]	0.279	0.054	0.368	0.013	0.134
Advanced SC	0.099	0.031	0.190	0.008	0.062
Conventional Combined Cycle (CC)	0.070	0.208	0.024	0.005	0.037
Conventional CC w/Duct Firing	0.076	0.315	0.018	0.009	0.042
Advanced CC	0.064	0.018	0.056	0.005	0.031

Notes:
[a] The conventional simple cycle values are recommended for both the single turbine (49.9 MW) and two turbine (100 MW) cases.

Source: Energy Commission

Table C-15: Recommended Carbon Dioxide Emission Factors (lbs/MWh)

Technology	Average	High	Low
Conventional Simple Cycle (SC) [a]	1,080	1,166	1,052
Advanced SC	997	1,014	959
Conventional Combined Cycle (CC)	815	839	769
Conventional CC w/Duct Firing	825	863	781
Advanced CC	759	782	736

Notes:
[a] The conventional simple cycle values are recommended for both the single turbine (49.9 MW) and two turbine (100 MW) cases.

Source: Energy Commission

[11] Emission factor is from the California Air Resources Board for natural gas with an assumed heating content (HHV) between 1,000 and 1,025 Btu/scf.

Plant Cost Data

The plant costs data were obtained from surveys conducted for the *2007 IEPR* and from project cost data obtained through research conducted by third parties.[12]

Instant and Installed Capital Costs

The plant cost data is now identified for average, high, and low cost cases; therefore the specificity of the design has been simplified. All projects are assumed to have selective catalytic reduction (SCR) for control of nitrogen oxides emissions and an oxidation catalyst for control of carbon monoxide emissions. **Table C-16** indicates how the following design considerations generally drive the plant capital costs:

Table C-16: Plant Design Factors vs. Capital Cost Implications

Plant Design Factor	High	Low
Larger Project (MW)		S
Bay Area Project	S	
Los Angeles Area Project	S	
Non-Urban Site		W
Co-Located W/ Other Power Facilities		S
Linear Interconnection Distances	W	
Wet Cooling		W
Dry Cooling	W	
Greenfield Site		W
Brownfield Site (uncontaminated)	W	
Reclaimed Water Source		
Evaporative Coolers/Foggers	W	
Inlet Air Chiller	W	
Zero Liquid Discharge	W	

Note: S – Strong correlation, W - Weak correlation

Source: Energy Commission

[12] Additional power plant project cost data obtained from Jeff King of NWPCC and Stan Kaplan of CRS.

Capital Cost Analysis Method

All costs were corrected for a California power plant in 2009 dollars. The power plant cost estimates from the various reference sources were corrected to 2009 dollars using the following calculation method:

(Raw Cost) x (Relative State Costs[13]) x (Capital Cost Yearly Index[14]) x (Project size correction factors) x (adjustment for Installed/Instant Costs) = Adjusted Instant Capital Cost in 2009$

Where:

Raw Cost = Announced instant cost or as-built installed cost depending on the project from ***Table C-21***

Relative State Cost = California Index/Index for project location, see below for state factors

Capital Cost Yearly Index = see below for Power Plant Cost Index

Project size corrections = 2007 IEPR number of turbines/MW corrections indexed to 2009

Installed/Instant Cost Adjustment – 9.8 percent based on known announced vs. as-built costs

Table C-17 provides the Army Corps of Engineers' (ACOE) state construction cost adjustment factors.

Table C-17: State Adjustment Factors

State	Index	State	Index	State	Index	State	Index	State	Index
AL	0.90	HI	1.18	MA	1.18	NM	0.94	SD	0.87
AK	1.21	ID	0.97	MI	1.04	MY	1.15	TN	0.87
AZ	0.95	IL	1.11	MN	1.15	NC	0.84	TX	0.86
AR	0.88	IN	1.00	MS	0.89	ND	0.92	UT	0.94
CA	**1.18**	IA	0.96	MO	1.02	OH	1.04	VT	0.96
CO	0.98	KS	0.94	MT	0.96	OK	0.85	VA	0.96
CT	1.20	KY	0.98	NE	0.97	OR	1.09	WA	1.07
DE	1.12	LA	0.88	NV	1.09	PA	1.09	WV	1.03
FL	0.91	ME	0.98	NH	1.05	RI	1.15	WI	1.07
GA	0.89	MD	0.98	NJ	1.20	SC	0.85	WY	0.91

Source: ACOE, March 2008 (note 2009 values have been published but, due to at least one apparent major error in the 2009 index, the 2008 index has been used in this evaluation).

Table C-18 presents the power plant construction cost index that is primarily based on information from Cambridge Energy Research Associates (CERA).

[13] The ACOE state cost index.

[14] The CERA power plant construction cost index.

As can be seen there was a power plant cost factor increase higher than inflation starting as early as 1998 with a more significant power plant cost factor increase from 2004 to 2008 that has begun to reverse recently based on recent Producers Price Index (PPI) data.

The power plant size, economy of scale, was adjusted for combined cycle plants using a factor for the number of turbines as determined in the *IEPR* and adjusted by the power plant cost index to 2009 dollars; and an additional adjustment for duct firing size was also made to adjust to the no-duct firing case and the 50 MW duct firing case. Finally for simple cycle projects an adjustment for project size was made, again using the *2007 IEPR* values adjusted using the power plant cost index to 2009 dollars. A summary of these project size adjustments is provided in **Table C-19.**

Table C-18: Power Plant Cost Index

Year	Index	Year	Index
1998	0.91	2004	1.24
1999	0.95	2005	1.37
2000	1	2006	1.56
2001	1.05	2007	1.71
2002	1.11	2008	1.82
2003	1.17	2009	1.75

Source: CERA 2008, with 2009 also based on evaluation of PPI Index.

Table C-19: Project Capital Cost—Size/Design Adjustments

Project Design Factor	Cost Adjustment
CC – Number of Turbines [a]	$103.5 +/- for each gas turbine -/+ 2 turbines
CC – Duct Firing	Add $255 x duct firing MW fraction of total MW
SC – Project Size	$1.55 +/- per MW -/+ 96 MW
Advanced SC – Project Size	$103.5 +/- for each gas turbine -/+ 2 turbines

Note:
[a] Applies to Advanced CC case as well and is valid from 1 to 4 turbines.
[b] Uses CC value with MW ratio of LMS100 to F-Frame turbine.

Source: Energy Commission

Combined Cycle Capital Costs

Table C-20 provides the assumed design configuration of the three combined cycle cases**.**

The projects with announced instant or as-built installed cost data that were evaluated to determine the recommended average, high, and low capital cost values for the three combined cycle cases are shown in **Table C-21**.

All of the advanced turbine projects are G-frame turbines; however, no G-frame turbine projects have been proposed in California as of May 2009. The Application for Certification (AFC) level data available for the Inland Empire H-frame turbine project is not considered reasonable or representative, given the known problems during the construction of that project; so it was not used.

Table C-20: Base Case Configurations—Combined Cycle

500 MW Combined Cycle Base Configuration
1) 500 MW Plant W/O Duct Firing 2) Two F-Frame Turbines W/One Steam Generator
550 MW Combined Cycle Base Configuration
1) 500 MW Plant W/Duct Firing 2) Two F-Frame Turbines W/One Steam Generator 3) 50 MW of Duct Firing
800 MW Advanced Combined Cycle Base Configuration
1) 800 MW Plant W/O Duct Firing 2) Two H-Frame Turbines W/Single Shaft Generators

Source: Energy Commission

Table C-21: Raw Installation Cost Data for Combined Cycle Projects

Project Name	State	Size (MW)	Raw Cost ($/kW)	Year	As-Built? (Y/N)
Conventional F-Frame Projects					
Arlington Valley	AZ	570	$439	2001	N
Arrow Canyon	NV	500	$540	2000	N
Arsenal Hill	LA	454	$610	2006	N
Avenal Power Center	CA	600	$883	2008	N
Bighorn	NV	591	$863	2008	N
Blythe Energy Project I	CA	520	$673	2004	Y
Blythe Energy Project II	CA	520	$481	2002	N

Project Name	State	Size (MW)	Raw Cost ($/kW)	Year	As-Built? (Y/N)
Cane Island Combined Cycle	FL	300	$1,167	2008	N
Chuck Lenzie (ex Moapa) Phase I	NV	580	$481	2004	N
Chuck Lenzie (ex Moapa) Phase II	NV	580	$481	2004	N
Colusa	CA	657	$1,024	2008	N
Community Power Plant	CA	565	$775	2008	N
Coyote Springs	OR	261	$691	2001	N
Current Creek	UT	525	$659	2006	N
Front Range Power	CO	480	$535	2002	N
Gateway (ex Contra Costa 8)	CA	530	$698	2007	N
Goldendale Energy Center	WA	277	$531	2001	N
Grays Harbor Energy Center	WA	650	$462	2001	N
Greenland Energy Center	FL	553	$1,085	2008	N
Harquahala	AZ	1000	$400	2000	N
Harry Allen CC	NV	500	$1,364	2008	N
Hines Unit 4	FL	461	$491	2006	N
Lake Side	UT	534	$650	2006	N
Langley Gulch	ID	330	$1,295	2009	N
Luna Energy Facility (formerly Deming)	NM	570	$439	2002	N
Mesquite	AZ	1250	$400	2000	N
Mirant Willow Pass	CA	550	$1,064	2008	N
Otay Mesa	CA	510	$539	2002	N
Port Washington Generating Station Unit 1	WI	510	$611	2002	N
Port Washington Generating Station Unit 2	WI	545	$580	2002	N
Richmond County	NC	600	$1,208	2008	N
Rocky Mountain Energy Center	CO	621	$580	2001	N
San Gabriel	CA	656	$793	2007	N
Silverbow	MT	500	$680	2002	N
Silverhawk	NV	570	$702	2002	N
Tesla (Original FPL)	CA	1120	$625	2001	N
Tesla (PG&E proposal)	CA	560	$1,518	2008	N
Thetford	MI	639	$815	2007	N
Tracy CC (SPP)	NV	541	$778	2008	Y

Project Name	State	Size (MW)	Raw Cost ($/kW)	Year	As-Built? (Y/N)
Treasure Coast Energy Center	FL	291	$884	2008	N
West Phoenix 5	AZ	530	$415	2000	N
Mountainview	CA	1054	Confidential	2006	Y
Palomar	CA	546	Confidential	2006	Y
Blythe	CA	520	Confidential	2003	Y
Delta	CA	882	Confidential	2002	Y
Elk Hills	CA	550	Confidential	2003	Y
High Desert	CA	830	Confidential	2003	Y
La Paloma	CA	1080	Confidential	2003	Y
Los Medanos	CA	566	Confidential	2001	Y
Metcalf	CA	600	Confidential	2005	Y
Moss Landing	CA	1060	Confidential	2002	Y
Pastoria	CA	750	Confidential	2005	Y
Sunrise	CA	585	Confidential	2003	Y
Sutter	CA	543	Confidential	2001	Y
Cosumnes	CA	500	Confidential	2006	Y
Magnolia	CA	310	Confidential	2005	Y
Advanced Turbine Projects					
Cape Canaveral Energy Center	FL	1219	$817	2008	N
Port Westward	OR	399	$719	2006	Y
West County Energy Center Unit 1	FL	1219	$510	2006	N
West County Energy Center Unit 2	FL	1219	$462	2006	N
West County Energy Center Unit 3	FL	1219	$638	2008	N
Riviera Beach Energy Center	FL	1207	$935	2008	N

Source: Energy Commission, NWPCC, CRS

Table C-22 shows the recommended instant costs for the three combined cycle cases in the Model.

There are two factors of concern regarding these recommended cost values. First, the reduction in the cost index from 2008 to 2009 has a lower level of confidence than the other annual index values; and second, the Advanced CC case cost is based on very limited data for a different advanced gas turbine type. However, it is reasonable to have an economy of scale reduction in cost that is, somewhat muted for the Advanced CC case, based on increased project generation capacity.

Table C-22: Total Instant/Installed Costs for Combined Cycle Cases

Combined Cycle Case (Nominal 2009$)	Average ($kW)	High ($kW)	Low ($kW)
Conventional 500 MW CC without Duct Firing	$1,044	$1,349	$777
Conventional 550 MW CC with Duct Firing	$1,021	$1,325	$753
Advanced 800 MW CC without Duct Firing	$957	$1,218	$759

Note: The high and low values are based on the 10 percentile and 90 percentile values for the evaluated projects.

Source: Energy Commission

Simple Cycle Capital Costs

Table C-23 provides the assumed design configuration of the three simple cycle cases**.**

The projects with announced instant or as-built installed cost data that were evaluated to determine the recommended average, high, and low capital cost values for the three simple cycle cases are shown in **Table C-24**.

Table C-23: Base Case Configurations—Simple Cycle

49.9 MW Simple Cycle Base Configuration
1) 49.9 MW Plant 2) One LM6000 Gas Turbine w/Chiller Air Pretreatment
100 MW Simple Cycle Base Configuration
1) 100 MW Plant 2) Two LM6000 Gas Turbines w/Chiller Air Pretreatment
200 MW Advanced Simple Cycle Base Configuration
1) 200 MW Plant 2) Two LMS100 Gas Turbines w/Evaporative Cooler Air Pretreatment

Source: Energy Commission

Table C-24: Raw Cost Data for Simple Cycle Projects

Project Name	State	Size (MW)`	Raw Cost ($/kW)	Year	As-Built? (Y/N)
Conventional LM6000 Gas Turbine Projects					
Agua Mansa	CA	43	$1,000	2002	N
Almond Expansion	CA	150	$1,333	2008	N
Apache Station	NV	40	$750	2001	N
Barre	CA	47	$1,409	2007	Y
Black Mountain	AZ	90	$694	2007	N
Burbank GT	CA	50	$706	2000	N
Canyon Power Plant	CA	194	$1,082	2008	N
Center	CA	47	$1,409	2007	Y
Feather River Energy Center	CA	45	$889	2001	N
Gadsby 4-6	UT	120	$628	2001	N
Grapeland	CA	47	$1,409	2007	Y
Mira Loma	CA	47	$1,409	2007	Y
Miramar	CA	46	$705	2004	Y
MMC Chula Vista	CA	94	$851	2007	N
MMC Escondido	CA	47	$1,064	2008	N
Orange Grove	CA	96	$885	2007	N
Pyramid 1-4	NM	168	$706	2002	N
San Francisco Peaking Plant	CA	193	$1,399	2008	N
San Francisco Potrero Plant	CA	145	$966	2004	N
Yucca GT 5 & GT 6	AZ	96	$802	2008	N
Henrietta	CA	96	Confidential	2002	Y
Hanford	CA	95	Confidential	2001	Y
Gilroy	CA	135	Confidential	2002	Y
King City	CA	45	Confidential	2002	Y
Kings River	CA	96	Confidential	2005	Y
Ripon	CA	95	Confidential	2006	Y
Riverside	CA	96	Confidential	2006	Y
LMS100 Advanced Gas Turbine Projects					
Groton 1	SD	95	$726	2006	Y
Panoche Energy Center	CA	400	$750	2008	N
Sentinel CPV Ph I	CA	728	$604	2007	N
Walnut Energy Park	CA	515	$544	2007	N

Source: Energy Commission, NWPCC, CRS

Table C-25 shows the recommended instant costs for the three combined cycle cases in the Model.

Table C-25: Total Instant/Installed Costs for Simple Cycle Cases

Simple Cycle Case (Nominal 2009$)	Average ($/kW)	High ($/kW)	Low ($/kW)
Conventional 49.9 MW SC	$1,277	$1,567	$914
Conventional 100 MW SC	$1,204	$1,495	$842
Advanced 200 MW SC	$801	$919	$693

Note: The high and low values are based on the 10 percentile and 90 percentile values for the evaluated projects.

Source: Energy Commission

There are two factors of concern regarding these recommended cost values. First, the reduction in the cost index from 2008 to 2009 has a lower level of confidence than the other annual index values. Second, the Advanced SC case cost is based on very limited data for a different advanced gas turbine type. The significantly lower cost for the Advanced SC case seems to overstate the potential for economy of scale reduction in cost, particularly since the LMS100 technology requires an increase in auxiliary equipment costs. Therefore, there is a low level of confidence with the Advanced SC costs.

Construction Periods

The staff-recommended construction periods for use in the Model are based on an analysis of the facilities surveyed for the *2007 IEPR* and other known project construction periods. **Table C-26** provides the average-cost, high-cost, and low-cost heat rates that were recommended for use in the Model.

Table C-26: Summary of Recommended Construction Periods (months)

Technology	Average	High	Low
Conventional Combined Cycle (CC)	26	36	20
Conventional CC W/ Duct Firing	26	36	20
Advanced CC	26	36	20
Conventional Simple Cycle (SC) [a]	9	16	4
Advanced SC [b]	15	20	12

Note:

[a] The conventional simple cycle values are recommended for both the single turbine (49.9 MW) and two turbine (100 MW) cases.

[b] Engineering estimate using the anticipated 18-month Panoche case construction duration as slightly higher than average value due to it being a four-turbine project rather than a two- turbine project.

Source: Energy Commission

Construction periods can be influenced by many factors, including greenfield or brownfield sites, the overall complexity of the design of the facility, the constraints due to site size or location, and a myriad of other factors. The recommended values assume a "normal" range of factors and do not include extraordinary circumstances.

Fixed and Variable O&M Costs

Combined Cycle Operating Costs

The operating costs consist of three components: fixed O&M, variable O&M, and fuel.

Fixed O&M is composed of two components: staffing costs and non-staffing costs. Non-staffing costs are composed of equipment, regulatory filings and other direct costs (ODCs).

Variable O&M is composed of the following components:

- Outage Maintenance – Annual maintenance and overhauls and forced outages.
- Consumables Maintenance
- Water Supply Costs

Simple Cycle Operating Costs

The operating costs consist of two components: fixed O&M and variable O&M.

Fixed O&M is composed of two components: staffing costs and non-staffing costs. Non-staffing costs are composed of equipment, regulatory filings, and ODCs. As with the combined cycle fixed costs, staffing costs for simple cycle units, and thus total fixed O&M, were found to vary with plant size. In this case, outage costs were found to vary little with the historic generation. This may be because these costs are driven more by starts than by hours of operation. For this reason, these costs were placed in fixed costs instead. This practice appears to be more consistent with the cost estimates developed by other agencies and analysts.

Variable O&M is composed of the following components:

- Consumables Maintenance
- Water Supply Costs

Table C-27and **Table C-28** summarize the Fixed and Variable O&M Components, respectively.

Table C-27: Fixed O&M

Technology	Average	High	Low
Small Simple Cycle	23.94	42.44	6.68
Conventional Simple Cycle (SC)	17.40	42.44	6.68
Advanced Simple Cycle	16.33	39.82	6.27
Conventional Combined Cycle (CC	8.62	12.62	5.76
Conventional CC W/ Duct Firing	8.30	12.62	5.76
Advanced CC	7.17	10.97	5.01

Source: Energy Commission

Table C-28: Variable O&M

Technology	Average	High	Low
Small Simple Cycle	4.17	9.05	0.88
Conventional Simple Cycle (SC)	4.17	9.05	0.88
Advanced Simple Cycle	3.67	8.05	0.79
Conventional Combined Cycle (CC	3.02	3.84	2.19
Conventional CC W/ Duct Firing	3.02	3.84	2.19
Advanced CC	2.69	3.42	1.95

Source: Energy Commission

Comparing Operating and Maintenance Costs

Table C-29 compares the cost ranges developed for this analysis to similar costs reported by other agencies and analysts around the United States. The average case used here is within the range reported elsewhere when looking at the total O&M costs.

Table C-29: Comparison of O&M Cost Estimates

	Fixed O&M	Variable O&M	Total O&M
	$/KW-yr	$/MWh	$/kW-Yr
Conventional CC			
2008 Midwest ISO Joint Coord. System Plan (1200 MW)	$34.61	$2.15	$46.84
2008 CRS Report for Congress 12-13-2008 (400 MW-conventional)	$20.66	$3.05	$38.04
2008 NPPC 6th Power Plan (305 MW)	$17.18	$3.56	$37.43
2007 UCS RPS analysis (2005) UCS case _ave CEC	$10.58	$4.73	$37.49
2009 CEC Cost of Generation (550 MW)-High Cost	***$12.62***	***$3.84***	***$34.49***
2009 CEC Cost of Generation (550 MW)-Average	***$8.30***	***$3.02***	***$25.50***
2007 EIA Assumptions Annual Energy Outlook	$13.22	$2.18	$25.65
2007 UCS RPS analysis (2005) EIA case	$13.16	$2.14	$25.34
Lazard Study (550 MW)	$5.85	$2.75	$21.51
2008 PJM CONE Studies (600 MW)	$21.20	NA	$21.20
2009 CEC Cost of Generation (500 MW)-Low Cost	***$5.76***	***$2.19***	***$18.26***
Standard CC Confidential submitted 2009 (550 MW)	*$6.12*	*$0.89*	*$11.19*
Advanced CC			
2007 UCS RPS analysis (2005) UCS case	$16.20	$3.26	$34.78
2009 CEC Cost of Generation (800 MW)-High Cost	***$10.97***	***$3.42***	***$30.36***
2007 UCS RPS analysis (2005) EIA case	$12.38	$2.14	$24.55
2008 CRS Report for Congress 12-13-2008 (400 MW Advanced)	$12.11	$2.09	$23.99
2009 CEC Cost of Generation (800 MW) - Average	***$7.17***	***$2.69***	***$22.47***
2009 CEC Cost of Generation (800 MW)-Low Cost	***$5.01***	***$1.95***	***$16.10***
Conventional CT			
2009 CEC Cost of Generation (100 MW)-High Cost	***$42.44***	***$9.05***	***$46.41***
2008 Midwest ISO Joint Coord. System Plan (1200 MW)	$18.03	$3.72	$19.66
2009 CEC Cost of Generation (100 MW)	***$17.40***	***$4.17***	***$19.23***
Standard and Poors April 15, 2009 (cap not listed)	$15.00	$2.50	$16.10
2008 NPPC 6th Power Plan	$15.32	$4.38	$17.24
NYISO NERA LM6000 w/SCR (Central case)	$14.51	$3.50	$16.04
PJM CONE CT GE FA 170 MW (2008)	$14.10	NA	$14.10
RETI (Capacity Value 2007) CEC data	$14.63	NA	$14.63
2007 EIA Assumptions Annual Energy Outlook	$12.83	$3.78	$14.48
2009 CEC Cost of Generation (100 MW)-Low Cost	***$6.68***	***$0.88***	***$7.07***
Advanced CT			
2009 CEC Cost of Generation (200 MW)-High Cost	***$39.82***	***$8.05***	***$46.81***
2009 CEC Cost of Generation (200 MW)-Average	***$16.33***	***$3.56***	***$19.55***
PJM CONE CT 2008 (Siemens Flexplant 10)	$19.03	NA	$19.03
PJM CONE CT 2008 (LMS 100)	$17.40	NA	$17.40
2007 EIA Assumptions Annual Energy Outlook	$11.15	$3.35	$14.09
2007 UCS RPS analysis (2005) EIA case	$11.14	$3.38	$14.10
2007 UCS RPS analysis (2005) UCS case-Ave. CEC	$7.20	$3.04	$9.86
LMS 100 Confidential (Submitted 2009)	$7.00	$2.50	$9.19
2009 CEC Cost of Generation (200 MW)-Low Cost	***$6.27***	***$0.79***	***$6.95***

Note: The high and low values for the 2009 analysis are based on the 5 percentile and 95 percentile values for the evaluated projects.
Source: Energy Commission review of noted documents.

APPENDIX D: Natural Gas Prices

The Model requires natural gas price forecasts for the time frame being modeled. Because natural gas prices were not forecast by the Energy Commission for the *2009 IEPR*, this report uses the natural gas prices based on those developed in the *2007 IEPR* and then adjusted to provide high and low inputs. These are shown in **Table D-1**. In order to convert these into Utility specific gas prices, the gas area prices are generation weighted as shown in **Table D-2.**

Table D-1: Natural Gas Prices by Area (Nominal $/MMBtu)

	California (Nominal$/MMBtu)												
YEAR	**NG PG&E BB FG**	**NG PG&E LT FG**	**NG SMUD FG <85mmcf/d**	**NG SMUD FG >85mmcf/d**	**NG Kern River FG**	**NG Mojave PL FG**	**NG SCE Coolwater FG**	**NG SoCalGas FG**	**NG Blythe FG**	**NG SoCal Production FG**	**NG TEOR Cogen FG**	**NG SDG&E FG**	**NG Otay Mesa FG**
2009	$6.55	$6.72	$6.49	$6.55	$5.78	$5.78	$6.71	$6.80	$6.35	$6.21	$6.38	$6.35	$6.35
2010	$7.16	$7.33	$7.10	$7.16	$6.24	$6.24	$7.33	$7.06	$6.62	$6.64	$6.83	$6.62	$6.62
2011	$7.38	$7.55	$7.32	$7.38	$6.60	$6.60	$7.55	$7.44	$6.98	$7.02	$7.22	$7.00	$6.99
2012	$8.12	$8.29	$8.06	$8.12	$7.04	$7.04	$8.29	$7.97	$7.48	$7.49	$7.69	$7.50	$7.50
2013	$8.51	$8.68	$8.45	$8.51	$7.44	$7.44	$8.68	$8.38	$7.87	$7.91	$8.13	$7.90	$7.90
2014	$8.96	$9.14	$8.90	$8.96	$7.89	$7.89	$9.14	$8.86	$8.32	$8.38	$8.61	$8.35	$8.35
2015	$9.36	$9.54	$9.29	$9.36	$8.19	$8.19	$9.53	$9.03	$8.46	$8.70	$8.94	$8.46	$8.46
2016	$9.85	$10.03	$9.79	$9.85	$8.97	$8.97	$10.03	$9.78	$9.14	$9.51	$9.77	$9.03	$9.03
2017	$10.48	$10.66	$10.41	$10.48	$9.47	$9.47	$10.66	$10.30	$9.63	$10.04	$10.32	$9.62	$9.61
2018	$11.25	$11.44	$11.18	$11.25	$10.14	$10.14	$11.43	$10.99	$10.27	$10.74	$11.04	$10.26	$10.26
2019	$12.21	$12.41	$12.14	$12.21	$10.94	$10.94	$12.40	$11.82	$11.03	$11.59	$11.91	$11.02	$11.02
2020	$12.64	$12.84	$12.57	$12.64	$11.39	$11.39	$12.83	$12.29	$11.47	$12.03	$12.37	$11.46	$11.46
2021	$13.00	$13.20	$12.93	$13.00	$11.84	$11.84	$13.19	$12.76	$11.92	$12.50	$12.85	$11.90	$11.90
2022	$13.95	$14.15	$13.87	$13.95	$12.81	$12.81	$14.14	$13.76	$12.88	$13.51	$13.89	$12.86	$12.86
2023	$14.50	$14.71	$14.43	$14.50	$13.29	$13.29	$14.70	$14.25	$13.35	$14.01	$14.41	$13.34	$13.34
2024	$15.10	$15.31	$15.02	$15.10	$13.89	$13.89	$15.30	$14.89	$13.96	$14.64	$15.05	$13.95	$13.95
2025	$15.05	$15.26	$14.97	$15.05	$13.84	$13.84	$15.25	$14.84	$13.91	$14.59	$15.00	$13.90	$13.90
2026	$15.65	$15.86	$15.57	$15.65	$14.44	$14.44	$15.85	$15.48	$14.52	$15.21	$15.64	$14.51	$14.51
2027	$16.07	$16.28	$15.99	$16.07	$14.82	$14.82	$16.27	$15.88	$14.88	$15.61	$16.05	$14.88	$14.87
2028	$16.49	$16.70	$16.40	$16.49	$15.21	$15.21	$16.69	$16.29	$15.25	$16.02	$16.47	$15.24	$15.24
2029	$17.13	$17.35	$17.05	$17.13	$15.82	$15.82	$17.34	$16.94	$15.87	$16.65	$17.12	$15.86	$15.86
2030	$17.79	$18.01	$17.71	$17.79	$16.45	$16.45	$18.01	$17.61	$16.50	$17.31	$17.79	$16.50	$16.49

Source: Energy Commission

Table D-2: Natural Gas Prices by Utility (Nominal $/MMBtu)

Trans Area	Fuel Group	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Annual Average Fuel Price ($/MMBtu)																						
PG&E	NG PG&E BB FG	6.55	7.16	7.38	8.12	8.51	8.96	9.36	9.85	10.48	11.25	12.21	12.64	13.00	13.95	14.50	15.10	15.05	15.65	16.07	16.49	17.13
PG&E	NG PG&E LT FG	6.72	7.33	7.55	8.29	8.68	9.14	9.54	10.03	10.66	11.44	12.41	12.84	13.20	14.15	14.71	15.31	15.26	15.86	16.28	16.70	17.35
PG&E	NG SoCal Production FG	6.21	6.64	7.02	7.49	7.91	8.38	8.70	9.51	10.04	10.74	11.59	12.03	12.50	13.51	14.01	14.64	14.59	15.21	15.61	16.02	16.65
PG&E	NG TEOR Cogen FG	6.38	6.83	7.22	7.69	8.13	8.61	8.94	9.77	10.32	11.04	11.91	12.37	12.85	13.89	14.41	15.05	15.00	15.64	16.05	16.47	17.12
PG&E	NG Kern River FG	5.78	6.24	6.60	7.04	7.44	7.89	8.19	8.97	9.47	10.14	10.94	11.39	11.84	12.81	13.29	13.89	13.84	14.44	14.82	15.21	15.82
PG&E	**Weighted Fuel Price**	**6.44**	**7.01**	**7.28**	**7.92**	**8.33**	**8.79**	**9.15**	**9.75**	**10.35**	**11.09**	**12.02**	**12.46**	**12.85**	**13.81**	**14.35**	**14.95**	**14.90**	**15.51**	**15.92**	**16.34**	**16.98**
SCE	NG Coolwater	6.71	7.33	7.55	8.29	8.68	9.14	9.53	10.03	10.66	11.43	12.40	12.83	13.19	14.14	14.70	15.30	15.25	15.85	16.27	16.69	17.34
SCE	NG Mojave PL	5.78	6.24	6.60	7.04	7.44	7.89	8.19	8.97	9.47	10.14	10.94	11.39	11.84	12.81	13.29	13.89	13.84	14.44	14.82	15.21	15.82
SCE	NG SCG	6.80	7.06	7.44	7.97	8.38	8.86	9.03	9.78	10.30	10.99	11.82	12.29	12.76	13.76	14.25	14.89	14.84	15.48	15.88	16.29	16.94
SCE	NG TEOR Cogen	6.38	6.83	7.22	7.69	8.13	8.61	8.94	9.77	10.32	11.04	11.91	12.37	12.85	13.89	14.41	15.05	15.00	15.64	16.05	16.47	17.12
SCE	NG Kern River	5.78	6.24	6.60	7.04	7.44	7.89	8.19	8.97	9.47	10.14	10.94	11.39	11.84	12.81	13.29	13.89	13.84	14.44	14.82	15.21	15.82
SCE	**Weighted Fuel Price**	**6.57**	**6.88**	**7.26**	**7.77**	**8.20**	**8.66**	**8.88**	**9.64**	**10.08**	**10.77**	**11.60**	**12.06**	**12.52**	**13.52**	**14.02**	**14.64**	**14.59**	**15.22**	**15.62**	**16.02**	**16.66**
SDG&E	NG Otay Mesa	6.35	6.62	6.99	7.50	7.90	8.35	8.46	9.03	9.61	10.26	11.02	11.46	11.90	12.86	13.34	13.95	13.90	14.51	14.87	15.24	15.86
SDG&E	NG SDG&E	6.35	6.62	7.00	7.50	7.90	8.35	8.46	9.03	9.62	10.26	11.02	11.46	11.90	12.86	13.34	13.95	13.90	14.51	14.88	15.24	15.86
SDG&E	**Weighted Fuel Price**	**6.35**	**6.62**	**7.00**	**7.50**	**7.90**	**8.35**	**8.46**	**9.03**	**9.62**	**10.26**	**11.02**	**11.46**	**11.90**	**12.86**	**13.34**	**13.95**	**13.90**	**14.51**	**14.88**	**15.24**	**15.86**
SMUD	NG SMUD FG (<85mmcf/d)	6.49	7.10	7.32	8.06	8.45	8.90	9.29	9.79	10.41	11.18	12.14	12.57	12.93	13.87	14.43	15.02	14.97	15.57	15.99	16.40	17.05
SMUD	NG SMUD FG (>85mmcf/d)	6.55	7.16	7.38	8.12	8.51	8.96	9.36	9.85	10.48	11.25	12.21	12.64	13.00	13.95	14.50	15.10	15.05	15.65	16.07	16.49	17.13
SMUD	**Weighted Fuel Price**	**6.52**	**7.13**	**7.35**	**8.09**	**8.48**	**8.93**	**9.32**	**9.82**	**10.44**	**11.21**	**12.18**	**12.61**	**12.96**	**13.91**	**14.46**	**15.06**	**15.01**	**15.61**	**16.03**	**16.45**	**17.09**
IID/LADWP	NG SCG	6.80	7.06	7.44	7.97	8.38	8.86	9.03	9.78	10.30	10.99	11.82	12.29	12.76	13.76	14.25	14.89	14.84	15.48	15.88	16.29	16.94
IID/LADWP	**Weighted Fuel Price**	**6.80**	**7.06**	**7.44**	**7.97**	**8.38**	**8.86**	**9.03**	**9.78**	**10.30**	**10.99**	**11.82**	**12.29**	**12.76**	**13.76**	**14.25**	**14.89**	**14.84**	**15.48**	**15.88**	**16.29**	**16.94**
STATEWIDE AVERAGE PRICE		**6.56**	**6.97**	**7.29**	**7.87**	**8.28**	**8.74**	**9.01**	**9.68**	**10.20**	**10.91**	**11.78**	**12.23**	**12.66**	**13.64**	**14.16**	**14.77**	**14.73**	**15.35**	**15.75**	**16.15**	**16.80**
Trans Area	Fuel Group	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Generation (MWh)																						
PG&E	NG PG&E BB FG	139,221	151,782	156,345	162,703	173,161	178,880	168,916	173,817	173,817	173,817	173,817	173,817	173,817	173,817	173,817	173,817	173,817	173,817	173,817	173,817	173,817
PG&E	NG PG&E LT FG	145,222	156,910	147,178	143,131	139,911	140,003	139,363	145,221	145,221	145,221	145,221	145,221	145,221	145,221	145,221	145,221	145,221	145,221	145,221	145,221	145,221
PG&E	NG SoCal Production FG	23,771	22,071	22,058	21,793	21,475	22,019	22,122	22,142	22,142	22,142	22,142	22,142	22,142	22,142	22,142	22,142	22,142	22,142	22,142	22,142	22,142
PG&E	NG TEOR Cogen FG	46,848	46,839	46,841	46,931	46,767	46,770	46,779	46,908	46,908	46,908	46,908	46,908	46,908	46,908	46,908	46,908	46,908	46,908	46,908	46,908	46,908
PG&E	NG Kern River FG	73,577	73,282	72,412	72,303	69,389	69,913	70,634	69,389	69,389	69,389	69,389	69,389	69,389	69,389	69,389	69,389	69,389	69,389	69,389	69,389	69,389
PG&E	**Total Generation**	**428,638**	**450,883**	**444,834**	**446,861**	**450,704**	**457,585**	**447,813**	**457,477**	**457,477**	**457,477**	**457,477**	**457,477**	**457,477**	**457,477**	**457,477**	**457,477**	**457,477**	**457,477**	**457,477**	**457,477**	**457,477**
SCE	NG Coolwater	11,911	10,486	10,777	8,889	6,491	5,802	6,464	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713
SCE	NG Mojave PL	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763
SCE	NG SCG	268,641	247,060	245,783	244,098	260,724	259,501	263,812	268,149	268,149	268,149	268,149	268,149	268,149	268,149	268,149	268,149	268,149	268,149	268,149	268,149	268,149
SCE	NG TEOR Cogen	29,752	29,767	29,742	29,818	29,711	29,714	29,726	29,792	76,506	76,506	76,506	76,506	76,506	76,506	76,506	76,506	76,506	76,506	76,506	76,506	76,506
SCE	NG Kern River	69,807	69,706	68,238	67,903	64,143	65,319	65,469	64,606	134,217	134,217	134,217	134,217	134,217	134,217	134,217	134,217	134,217	134,217	134,217	134,217	134,217
SCE	**Total Generation**	**381,874**	**358,782**	**356,304**	**352,472**	**362,831**	**362,100**	**367,235**	**371,023**	**487,349**	**487,349**	**487,349**	**487,349**	**487,349**	**487,349**	**487,349**	**487,349**	**487,349**	**487,349**	**487,349**	**487,349**	**487,349**
SDG&E	NG Otay Mesa	22,013	21,100	21,277	21,136	21,026	21,017	21,762	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703
SDG&E	NG SDG&E	37,195	35,539	46,993	53,164	53,513	54,003	58,088	57,912	57,912	57,912	57,912	57,912	57,912	57,912	57,912	57,912	57,912	57,912	57,912	57,912	57,912
SDG&E	**Total Generation**	**59,209**	**56,639**	**68,271**	**74,300**	**74,539**	**75,020**	**79,850**	**79,615**	**79,615**	**79,615**	**79,615**	**79,615**	**79,615**	**79,615**	**79,615**	**79,615**	**79,615**	**79,615**	**79,615**	**79,615**	**79,615**
SMUD	NG SMUD FG (<85mmcf/d)	20,903	22,265	21,819	21,552	21,154	21,462	29,631	31,182	31,183	31,183	31,184	31,184	31,185	31,185	31,186	31,186	31,187	31,187	31,187	31,187	31,187
SMUD	NG SMUD FG (>85mmcf/d)	20,903	22,265	21,819	21,552	21,154	21,462	29,631	31,182	31,183	31,183	31,184	31,184	31,185	31,185	31,186	31,186	31,187	31,187	31,187	31,187	31,187
SMUD	**Total Generation**	**41,806**	**44,530**	**43,638**	**43,104**	**42,308**	**42,924**	**59,262**	**62,364**	**62,365**	**62,366**	**62,367**	**62,368**	**62,369**	**62,370**	**62,371**	**62,372**	**62,373**	**62,373**	**62,373**	**62,373**	**62,373**
IID/LADWP	NG SCG	268,641	247,060	245,783	244,098	260,724	259,501	263,812	268,149	268,150	268,151	268,152	268,153	268,154	268,155	268,156	268,157	268,158	268,159	268,160	268,161	268,162
IID/LADWP	**Total Generation**	**268,641**	**247,060**	**245,783**	**244,098**	**260,724**	**259,501**	**263,812**	**268,149**	**268,150**	**268,151**	**268,152**	**268,153**	**268,154**	**268,155**	**268,156**	**268,157**	**268,158**	**268,159**	**268,160**	**268,161**	**268,162**
STATEWIDE GENERATION		**1,180,167**	**1,157,893**	**1,158,830**	**1,160,835**	**1,191,106**	**1,197,129**	**1,217,972**	**1,238,629**	**1,354,956**	**1,354,958**	**1,354,960**	**1,354,962**	**1,354,964**	**1,354,966**	**1,354,968**	**1,354,970**	**1,354,972**	**1,354,973**	**1,354,974**	**1,354,975**	**1,354,976**

Source: Energy Commission

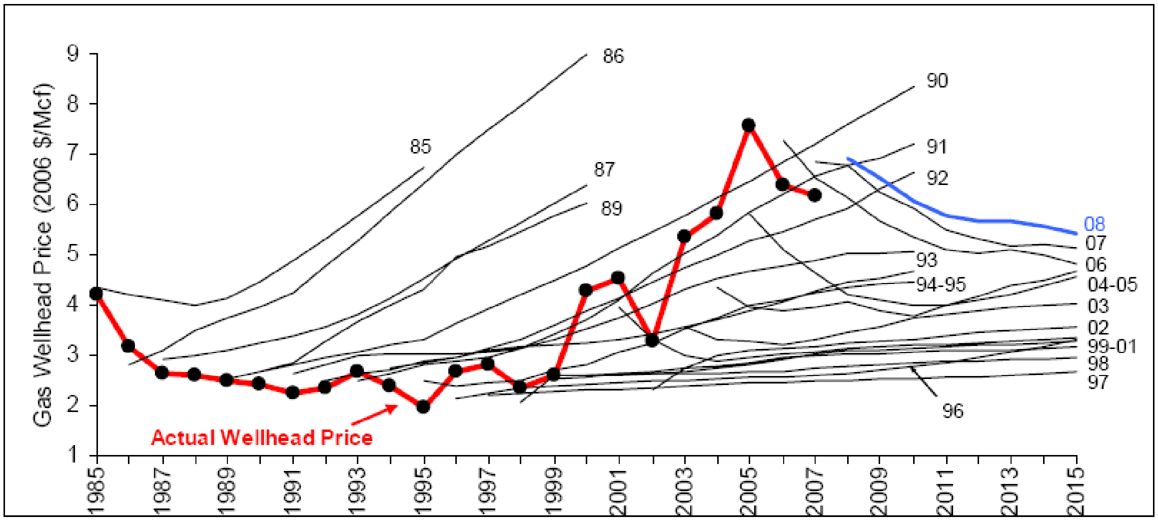
Method for High/Low Values

The outset that the typical high and low natural gas price forecasts are upper limits for each year in the forecast period. Such forecasts are not intended to be interpreted as sustainable over the forecast period. It is expected that in individual years, fuel costs may achieve these limits but that in subsequent years market forces will drive the prices back toward the forecasted average value. The high and low gas prices needed for the Model are different in that they are intended to be average sustainable high and low values to have meaningful levelized cost estimates.

The forecasting of high and low natural gas prices is daunting as it requires an assessment of all the factors that might cause the gas price to deviate from the expected value. There are of course all the unknown future conditions such as changes in demand, temperature deviations, hydro conditions, and economic development. But there are also other factors that might cause the forecaster to miss the mark such as unknown future equipment costs, market power, and poor forecasting. Staff decided to assess these many factors collectively and somewhat indirectly by simply looking backward at the historical limits of forecasting. That is, staff assumes that present forecasts will most likely miss the mark to the degree that previous forecasts failed to predict natural gas prices.

To do this, staff elected to use Energy Information Administration (EIA) natural gas price data that quantifies their forecasting errors. The EIA, like the Energy Commission, has the ability to make forecasts and is therefore a reasonable proxy for an Energy Commission effort. It also provides possibly the most complete historical summary of forecasting errors available. **Figure D-1** shows EIA's historical record of errors in forecasting. It compares EIA's Energy Annual Outlook (EAO) forecasts to actual natural gas prices. The numerical identification is the last two digits of the EAO forecast; for example, "85" signifies the 1985 EAO forecast. It is apparent that in their earlier forecasts, the EIA tended to overestimate natural gas prices. In more recent years, there was a tendency to underestimate natural gas prices. The salient point, however, is that this very competent group of professionals was consistently unable to predict natural gas prices even in the near term. This demonstrates that natural gas price forecasting is a daunting task and that average gas price forecasts are inevitably wrong, making a range of forecasts necessary to recognize the risk involved in relying on these point forecasts.

Figure D-1: Historical EIA Wellhead Natural Gas Price Forecast vs. Actual Price



Source: Berkeley National Lab

Table D-3 shows the corresponding percentage errors for each of these EAO forecasts, as calculated by the EIA. Note that the percentage error in any year can vary from being 721.7 percent too high to being 65.3 percent too low. **Table D-4** shows the same data but rearranged as a function of the number of the forecast year. That is, the first year of each forecast is aligned under the designation "1st"—the second year of each forecast is aligned under the designation "2nd"—and so forth. Forecasts AEO1982–AEO1984 have been deleted since the early years of these forecasts are not provided by EIA, making this data unusable. **Figure D-2** shows this same data graphically. The data initially appears to be meaningless; however, it can be made to be quite useful.

Table D-3: Percentage Errors in EIA Forecasting

Forecast	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
AEO 1982	72.0	182.1	299.6	344.6	375.6	401.0																	
AEO 1983	16.7	60.1	107.4	132.5	169.8	207.4					721.7												
AEO 1984	10.4	49.3	92.3	114.6	144.6	180.1					501.7												
AEO 1985	3.6	34.4	59.0	60.2	74.2	95.9	135.0	156.3	150.1	215.4	330.3												
AEO 1986		-10.8	17.1	35.4	50.5	64.4	91.9	114.2	112.9	173.4	280.3	213.0	231.9	339.9	341.8	193.4							
AEO 1987			9.6	15.2	24.6	33.5	51.5	56.6	51.0	89.7	162.9					105.0							
AEO 1989*				-4.1	0.6	11.4	29.9	48.1	49.1	88.1	153.5	119.5	125.3	195.8	193.7	89.7							
AEO 1990					5.3	10.2					89.1					45.8					24.9		
AEO 1991						3.5	15.8	21.3	12.8	30.6	61.7	19.9	17.9	48.5	50.2	1.8	7.8	71.9	18.2	18.1	-0.6	26.5	39.9
AEO 1992							2.8	6.2	-0.4	16.1	51.6	15.7	18.2	53.7	55.1	3.5	5.9	60.5	7.7	5.8	-13.1	7.6	17.4
AEO 1993								6.1	-5.1	13.0	48.5	12.4	12.0	45.2	42.7	-5.8	-3.9	45.9	-1.4	-3.4	-22.5	-5.4	1.1
AEO 1994									-2.8	14.9	46.2	11.0	11.5	39.2	30.4	-19.0	-21.5	13.4	-26.4	-29.5	-42.9	-29.5	-23.1
AEO 1995										2.3	28.9	-10.0	-11.0	9.8	9.6	-30.2	-27.6	7.1	-27.1	-29.1	-41.8	-28.7	-24.1
AEO 1996											5.2	-19.8	-19.7	1.6	-3.9	-40.4	-42.8	-19.4	-49.3	-52.6	-62.9	-55.7	-53.6
AEO 1997												-6.3	-21.4	-2.8	-9.2	-43.9	-46.6	-25.0	-52.5	-55.5	-65.3	-58.5	-56.7
AEO 1998													-1.0	12.1	3.0	-37.2	-40.5	-17.1	-48.4	-52.5	-63.3	-56.3	-54.2
AEO 1999														0.9	-1.9	-40.1	-42.1	-17.8	-48.1	-51.8	-62.4	-54.6	-52.8
AEO 2000															-2.0	-39.3	-43.3	-21.4	-50.9	-54.0	-63.7	-56.0	-53.5
AEO 2001																-7.8	-12.9	0.8	-43.9	-50.5	-61.4	-53.9	-52.1
AEO 2002																	0.6	-30.1	-48.1	-47.9	-59.0	-51.1	-49.4
AEO 2003																		-5.6	-33.2	-42.8	-57.1	-50.8	-48.3
AEO 2004																			1.9	-26.8	-49.3	-41.8	-39.6
AEO 2005																				-1.4	-24.7	-22.7	-28.5
AEO 2006																					6.5	11.9	2.2
AEO 2007																						7.3	9.6
AEO 2008																							-0.3
Average	25.7	63.0	97.5	99.7	105.7	111.9	54.5	58.4	46.0	71.5	190.9	39.5	36.4	67.6	59.1	11.7	-22.2	4.9	-28.7	-31.6	-38.7	-30.1	-25.9
High	72.0	182.1	299.6	344.6	375.6	401.0	135.0	156.3	150.1	215.4	721.7	213.0	231.9	339.9	341.8	193.4	7.8	71.9	18.2	18.1	24.9	26.5	39.9
Low	3.6	-10.8	9.6	-4.1	0.6	3.5	2.8	6.1	-5.1	2.3	5.2	-19.8	-21.4	-2.8	-9.2	-43.9	-46.6	-30.1	-52.5	-55.5	-65.3	-58.5	-56.7

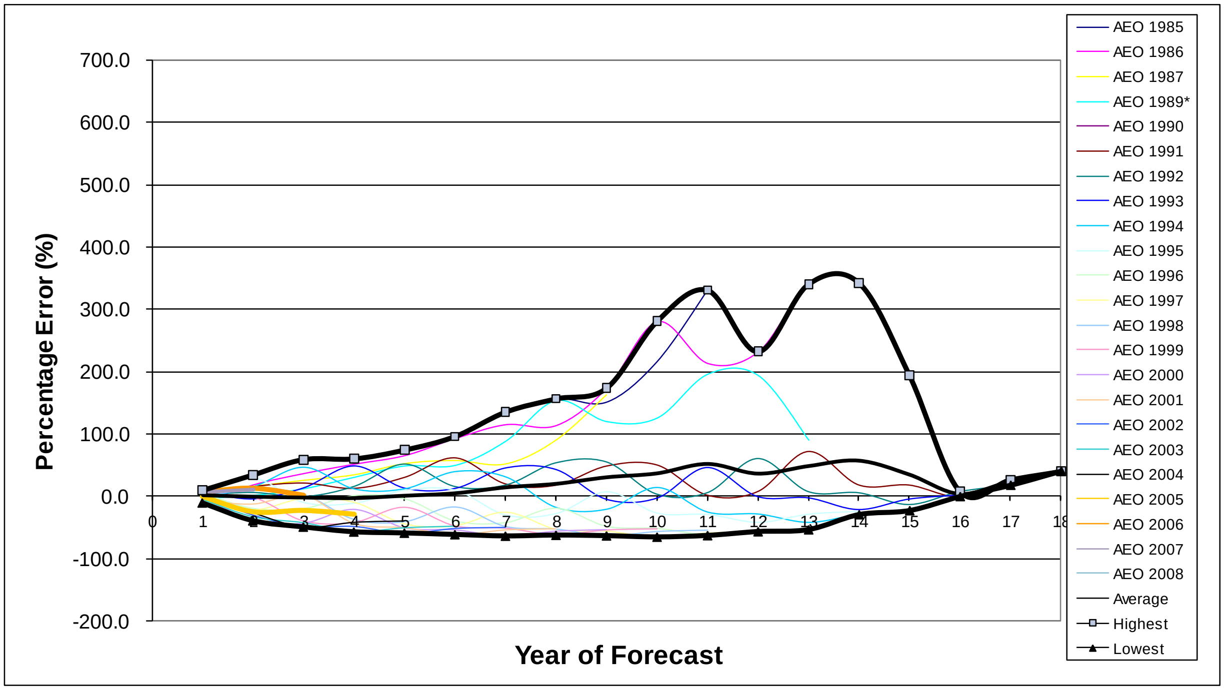
Source: EIA

Table D-4: Percentage Errors in the Year of Forecast

Forecast	1st	2nd	3rd	4th	5th	6th	7th	8th	9th	10th	11th	12th	13th	14th	15th	16th	17th	18th
AEO 1985	3.6	34.4	59.0	60.2	74.2	95.9	135.0	156.3	150.1	215.4	330.3							
AEO 1986	-10.8	17.1	35.4	50.5	64.4	91.9	114.2	112.9	173.4	280.3	213.0	231.9	339.9	341.8	193.4			
AEO 1987	9.6	15.2	24.6	33.5	51.5	56.6	51.0	89.7	162.9					105.0				
AEO 1989*	-4.1	0.6	11.4	29.9	48.1	49.1	88.1	153.5	119.5	125.3	195.8	193.7	89.7					
AEO 1990	5.3	10.2					89.1					45.8					24.9	
AEO 1991	3.5	15.8	21.3	12.8	30.6	61.7	19.9	17.9	48.5	50.2	1.8	7.8	71.9	18.2	18.1	-0.6	26.5	39.9
AEO 1992	2.8	6.2	-0.4	16.1	51.6	15.7	18.2	53.7	55.1	3.5	5.9	60.5	7.7	5.8	-13.1	7.6	17.4	
AEO 1993	6.1	-5.1	13.0	48.5	12.4	12.0	45.2	42.7	-5.8	-3.9	45.9	-1.4	-3.4	-22.5	-5.4	1.1		
AEO 1994	-2.8	14.9	46.2	11.0	11.5	39.2	30.4	-19.0	-21.5	13.4	-26.4	-29.5	-42.9	-29.5	-23.1			
AEO 1995	2.3	28.9	-10.0	-11.0	9.8	9.6	-30.2	-27.6	7.1	-27.1	-29.1	-41.8	-28.7	-24.1				
AEO 1996	5.2	-19.8	-19.7	1.6	-3.9	-40.4	-42.8	-19.4	-49.3	-52.6	-62.9	-55.7	-53.6					
AEO 1997	-6.3	-21.4	-2.8	-9.2	-43.9	-46.6	-25.0	-52.5	-55.5	-65.3	-58.5	-56.7						
AEO 1998	-1.0	12.1	3.0	-37.2	-40.5	-17.1	-48.4	-52.5	-63.3	-56.3	-54.2							
AEO 1999	0.9	-1.9	-40.1	-42.1	-17.8	-48.1	-51.8	-62.4	-54.6	-52.8								
AEO 2000	-2.0	-39.3	-43.3	-21.4	-50.9	-54.0	-63.7	-56.0	-53.5									
AEO 2001	-7.8	-12.9	0.8	-43.9	-50.5	-61.4	-53.9	-52.1										
AEO 2002	0.6	-30.1	-48.1	-47.9	-59.0	-51.1	-49.4											
AEO 2003	-5.6	-33.2	-42.8	-57.1	-50.8	-48.3												
AEO 2004	1.9	-26.8	-49.3	-41.8	-39.6													
AEO 2005	-1.4	-24.7	-22.7	-28.5														
AEO 2006	6.5	11.9	2.2															
AEO 2007	7.3	9.6																
AEO 2008	-0.3																	
Average	0.6	-1.8	-3.1	-4.0	-0.2	3.8	13.3	19.0	29.5	35.8	51.0	35.5	47.6	56.4	34.0	2.7	22.9	39.9
Highest	9.6	34.4	59.0	60.2	74.2	95.9	135.0	156.3	173.4	280.3	330.3	231.9	339.9	341.8	193.4	7.6	26.5	39.9
Lowest	-10.8	-39.3	-49.3	-57.1	-59.0	-61.4	-63.7	-62.4	-63.3	-65.3	-62.9	-56.7	-53.6	-29.5	-23.1	-0.6	17.4	39.9

Source: Energy Commission

Figure D-2: Percentage Errors in the Year of Forecast



Source: Energy Commission

Table D-5 and **Table D-6** show this same data but with the overestimates and the underestimates tabulated separately. **Figure D-3** and **Figure D-4** show the summary portion graphically at the bottom of the respective tables.

Table D-5: Percentage Errors in Overestimates

Forecast	1st	2nd	3rd	4th	5th	6th	7th	8th	9th	10th	11th	12th	13th	14th	15th	16th	17th	18th
AEO 1985	3.6	34.4	59.0	60.2	74.2	95.9	135.0	156.3	150.1	215.4	330.3							
AEO 1986		17.1	35.4	50.5	64.4	91.9	114.2	112.9	173.4	280.3	213.0	231.9	339.9	341.8	193.4			
AEO 1987	9.6	15.2	24.6	33.5	51.5	56.6	51.0	89.7	162.9					105.0				
AEO 1989*		0.6	11.4	29.9	48.1	49.1	88.1	153.5	119.5	125.3	195.8	193.7	89.7					
AEO 1990	5.3	10.2					89.1					45.8					24.9	
AEO 1991	3.5	15.8	21.3	12.8	30.6	61.7	19.9	17.9	48.5	50.2	1.8	7.8	71.9	18.2	18.1		26.5	39.9
AEO 1992	2.8	6.2		16.1	51.6	15.7	18.2	53.7	55.1	3.5	5.9	60.5	7.7	5.8		7.6	17.4	
AEO 1993	6.1		13.0	48.5	12.4	12.0	45.2	42.7			45.9					1.1		
AEO 1994		14.9	46.2	11.0	11.5	39.2	30.4			13.4								
AEO 1995	2.3	28.9			9.8	9.6			7.1									
AEO 1996	5.2			1.6														
AEO 1997																		
AEO 1998		12.1	3.0															
AEO 1999	0.9																	
AEO 2000																		
AEO 2001			0.8															
AEO 2002	0.6																	
AEO 2003																		
AEO 2004	1.9																	
AEO 2005																		
AEO 2006	6.5	11.9	2.2															
AEO 2007	7.3	9.6																
AEO 2008																		
Average	4.3	14.7	21.7	29.3	39.3	47.9	65.7	89.5	102.4	114.7	132.1	108.0	127.3	117.7	105.7	4.4	22.9	39.9
Highest	9.6	34.4	59.0	60.2	74.2	95.9	135.0	156.3	173.4	280.3	330.3	231.9	339.9	341.8	193.4	7.6	26.5	39.9
Low	0.6	0.6	0.8	1.6	9.8	9.6	18.2	17.9	7.1	3.5	1.8	7.8	7.7	5.8	18.1	1.1	17.4	39.9

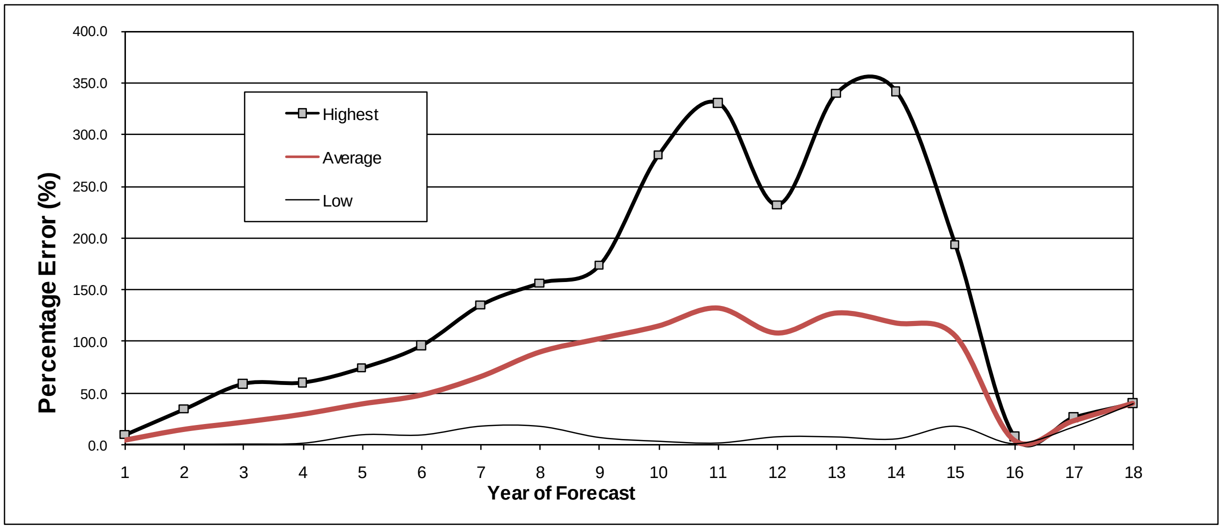
Source: Energy Commission

Table D-6: Percentage Errors in Underestimates

Forecast	1st	2nd	3rd	4th	5th	6th	7th	8th	9th	10th	11th	12th	13th	14th	15th	16th	17th	18th
AEO 1985																		
AEO 1986	-10.8																	
AEO 1987																		
AEO 1989*	-4.1																	
AEO 1990																		
AEO 1991																-0.6		
AEO 1992			-0.4												-13.1			
AEO 1993		-5.1							-5.8	-3.9		-1.4	-3.4	-22.5	-5.4			
AEO 1994	-2.8							-19.0	-21.5		-26.4	-29.5	-42.9	-29.5	-23.1			
AEO 1995			-10.0	-11.0			-30.2	-27.6		-27.1	-29.1	-41.8	-28.7	-24.1				
AEO 1996		-19.8	-19.7		-3.9	-40.4	-42.8	-19.4	-49.3	-52.6	-62.9	-55.7	-53.6					
AEO 1997	-6.3	-21.4	-2.8	-9.2	-43.9	-46.6	-25.0	-52.5	-55.5	-65.3	-58.5	-56.7						
AEO 1998	-1.0			-37.2	-40.5	-17.1	-48.4	-52.5	-63.3	-56.3	-54.2							
AEO 1999		-1.9	-40.1	-42.1	-17.8	-48.1	-51.8	-62.4	-54.6	-52.8								
AEO 2000	-2.0	-39.3	-43.3	-21.4	-50.9	-54.0	-63.7	-56.0	-53.5									
AEO 2001	-7.8	-12.9		-43.9	-50.5	-61.4	-53.9	-52.1										
AEO 2002		-30.1	-48.1	-47.9	-59.0	-51.1	-49.4											
AEO 2003	-5.6	-33.2	-42.8	-57.1	-50.8	-48.3												
AEO 2004		-26.8	-49.3	-41.8	-39.6													
AEO 2005	-1.4	-24.7	-22.7	-28.5														
AEO 2006																		
AEO 2007																		
AEO 2008	-0.3																	
Average	-4.2	-21.5	-27.9	-34.0	-39.7	-45.9	-45.7	-42.7	-43.4	-43.0	-46.2	-37.0	-32.1	-25.4	-13.9	-0.6		
High	-0.3	-1.9	-0.4	-9.2	-3.9	-17.1	-25.0	-19.0	-5.8	-3.9	-26.4	-1.4	-3.4	-22.5	-5.4	-0.6		
Lowest	-10.8	-39.3	-49.3	-57.1	-59.0	-61.4	-63.7	-62.4	-63.3	-65.3	-62.9	-56.7	-53.6	-29.5	-23.1	-0.6		

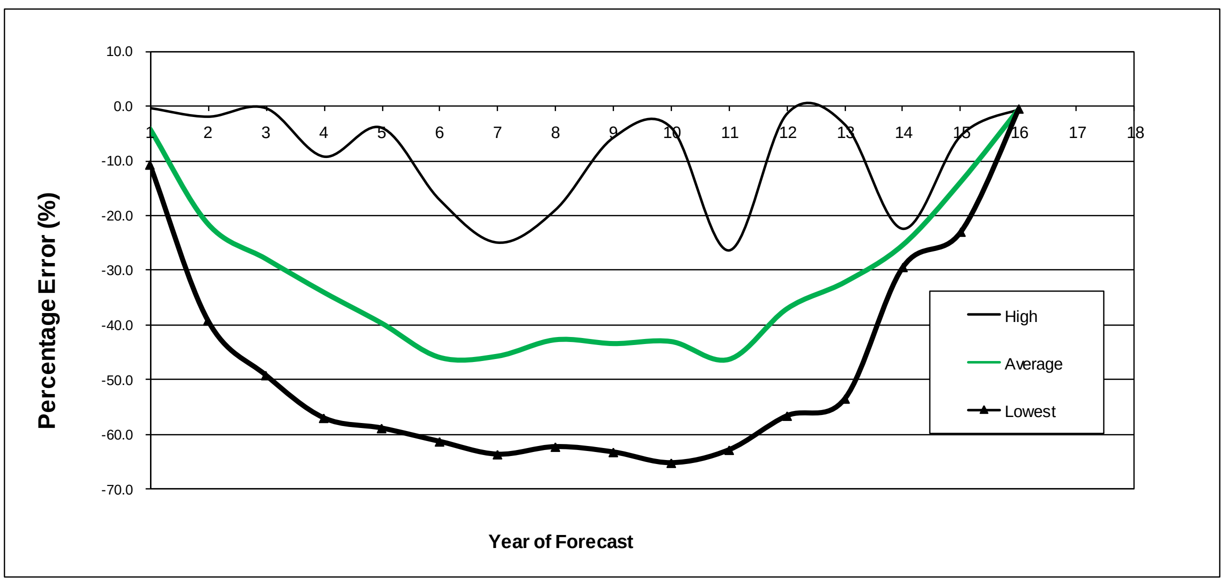
Source: Energy Commission

Figure D-3: Percentage Error in Overestimates



Source: Energy Commission

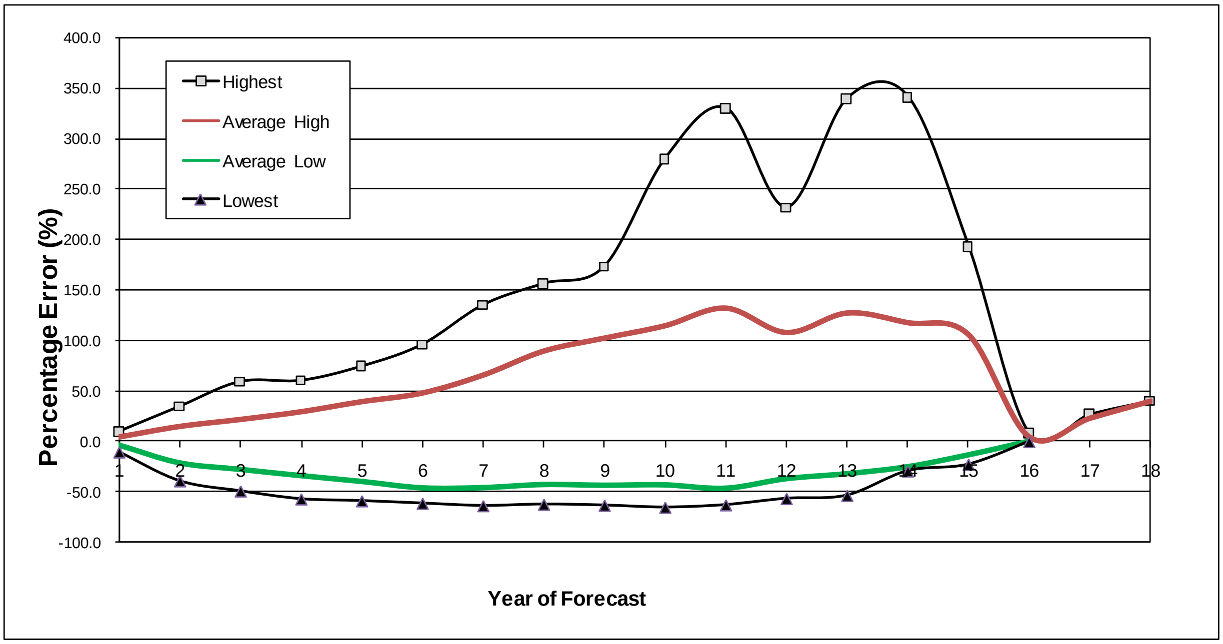
Figure D-4: Percentage Error in Underestimates



Source: Energy Commission

Figure D-5 combines the values above that are of interest: the highest and lowest errors recorded plus the average high and the average low. **Figure D-5** displays the upper and lower limits of the errors plus average high and low errors.

Figure D-5: Average Overestimates and Underestimates

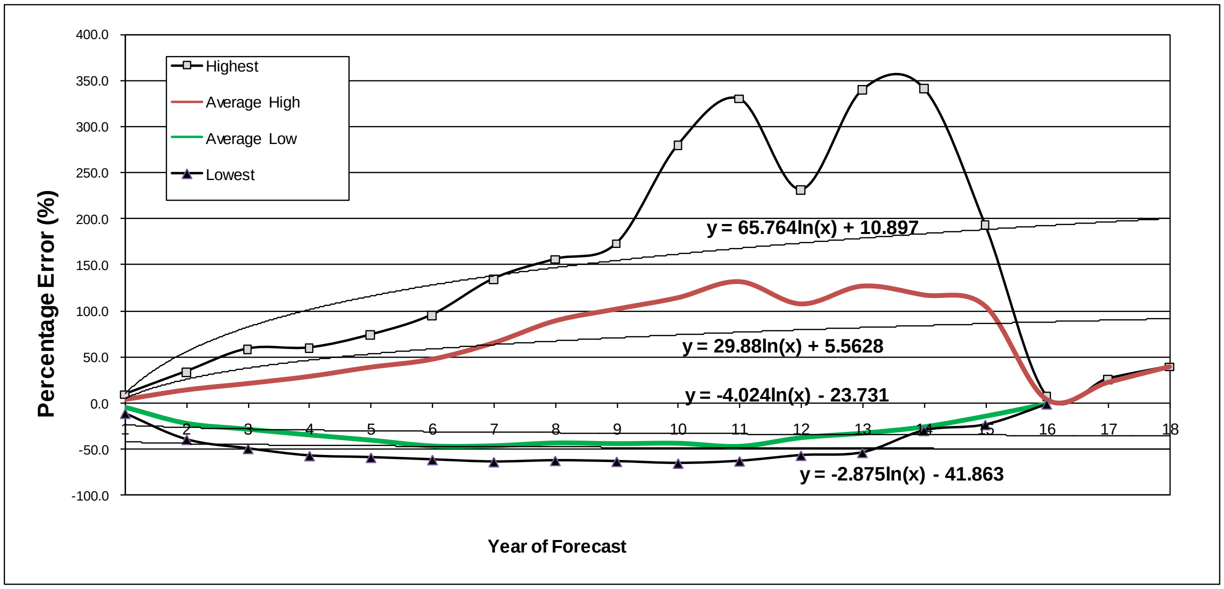


Source: Energy Commission

However, the shapes of these curves are not directly useful for forecasting as they are so irregular and random. The expectation may be that on average the errors would more smoothly increase over the years, and tend to level off in the later years. To convert these unlikely shapes into more average shapes that capture the trend of the errors, logarithmic trendlines were developed for each of these curves, as shown in **Figure D-6.**

Table D-7 summarizes these trendline forecasting errors in the first four columns. The next four columns show the resulting scaling factors calculated from these trendline forecast errors. The last five columns use the final *2007 IEPR* natural gas prices as the Model natural gas prices and the high-low gas prices based on these scaling factors. The scaling factors are shifted two years to account for the fact that the *2007 IEPR* prices are now two years old. **Figure D-7** shows these same prices in a graph. As a reasonableness test, **Figure D-8** compares the Model natural gas prices to some other recent natural gas prices. Two of these forecasts are very close to the calculated high average, probably because their forecast still reflects the early natural gas prices that extended into the early part of the year but have been proven to be inaccurate for 2009.

Figure D-6: Trendlines for Average Overestimates and Underestimates



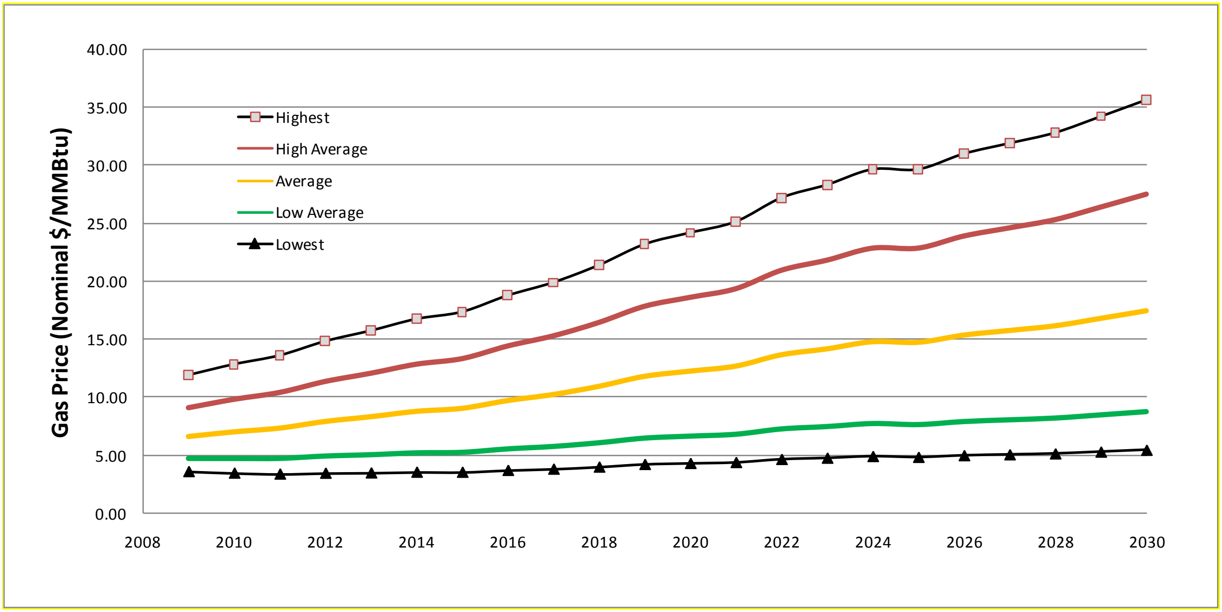
Source: Energy Commission

Table D-7: Trendlines for Average Overestimates and Underestimates

Year of Forecast	Forecast Errors (%)				Forecast Factors				2009 Preliminary Gas Prices (Nominal $/MMBtu)					
	Highest	High Average	Low Average	Lowest	Highest	High Average	Low Average	Lowest	Year	Highest	High Average	Average	Low Average	Lowest
3	83.1	38.4	-28.2	-45.0	1.82	1.39	0.72	0.55	2009	11.94	9.13	6.56	4.74	3.58
4	102.1	47.0	-29.3	-45.8	1.85	1.41	0.68	0.49	2010	12.87	9.86	6.97	4.74	3.45
5	116.7	53.7	-30.2	-46.5	1.87	1.43	0.65	0.46	2011	13.63	10.45	7.29	4.75	3.36
6	128.7	59.1	-30.9	-47.0	1.89	1.45	0.63	0.44	2012	14.85	11.39	7.87	4.95	3.44
7	138.9	63.7	-31.6	-47.5	1.90	1.46	0.61	0.42	2013	15.76	12.10	8.28	5.06	3.47
8	147.6	67.7	-32.1	-47.8	1.92	1.47	0.60	0.40	2014	16.76	12.88	8.74	5.21	3.53
9	155.4	71.2	-32.6	-48.2	1.93	1.48	0.58	0.39	2015	17.38	13.36	9.01	5.26	3.53
10	162.3	74.4	-33.0	-48.5	1.94	1.49	0.57	0.38	2016	18.79	14.44	9.68	5.55	3.69
11	168.6	77.2	-33.4	-48.8	1.95	1.50	0.56	0.37	2017	19.91	15.32	10.20	5.76	3.80
12	174.3	79.8	-33.7	-49.0	1.96	1.51	0.56	0.36	2018	21.40	16.47	10.91	6.07	3.98
13	179.6	82.2	-34.1	-49.2	1.97	1.52	0.55	0.36	2019	23.20	17.86	11.78	6.46	4.21
14	184.5	84.4	-34.4	-49.5	1.98	1.52	0.54	0.35	2020	24.19	18.63	12.23	6.63	4.30
15	189.0	86.5	-34.6	-49.6	1.99	1.53	0.54	0.35	2021	25.15	19.37	12.66	6.79	4.38
16	193.2	88.4	-34.9	-49.8	1.99	1.54	0.53	0.34	2022	27.20	20.95	13.64	7.24	4.65
17	197.2	90.2	-35.1	-50.0	2.00	1.54	0.53	0.34	2023	28.32	21.82	14.16	7.44	4.76
18	201.0	91.9	-35.4	-50.2	2.01	1.55	0.52	0.33	2024	29.65	22.86	14.77	7.70	4.91
19	204.5	93.5	-35.6	-50.3	2.01	1.55	0.52	0.33	2025	29.65	22.86	14.73	7.61	4.84
20	207.9	95.1	-35.8	-50.5	2.02	1.56	0.51	0.32	2026	30.99	23.90	15.35	7.87	4.98
21	211.1	96.5	-36.0	-50.6	2.02	1.56	0.51	0.32	2027	31.89	24.60	15.75	8.01	5.06
22	214.2	97.9	-36.2	-50.7	2.03	1.57	0.51	0.32	2028	32.80	25.31	16.15	8.16	5.14
23	217.1	99.3	-36.3	-50.9	2.04	1.57	0.50	0.32	2029	34.19	26.39	16.80	8.43	5.30
24	219.9	100.5	-36.5	-51.0	2.04	1.58	0.50	0.31	2030	35.63	27.50	17.46	8.71	5.46

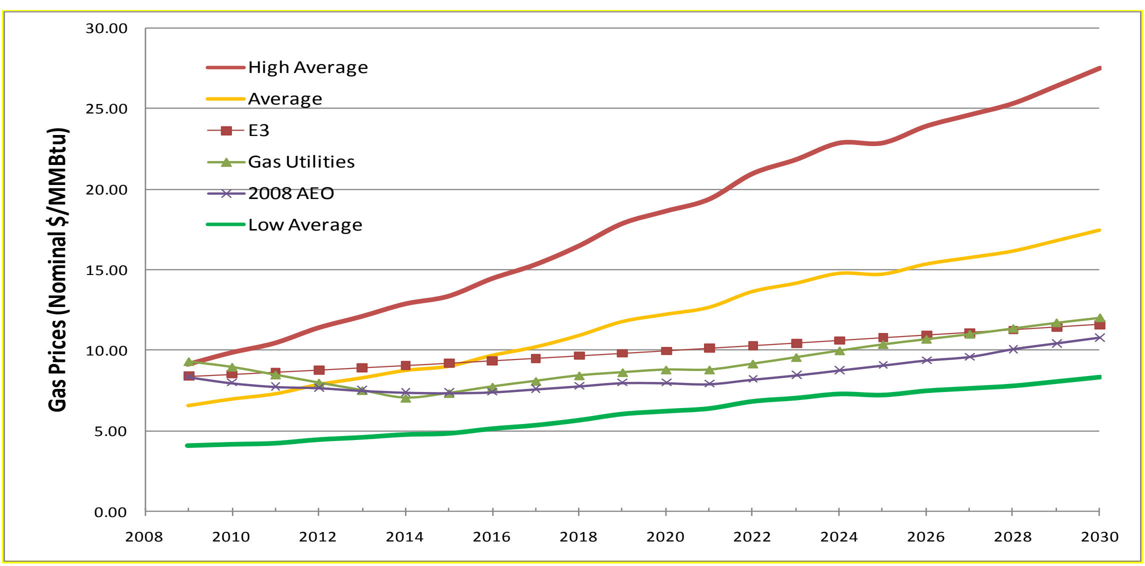
Source: Energy Commission

Figure D-7: Model Input Natural Gas Prices



Source: Energy Commission

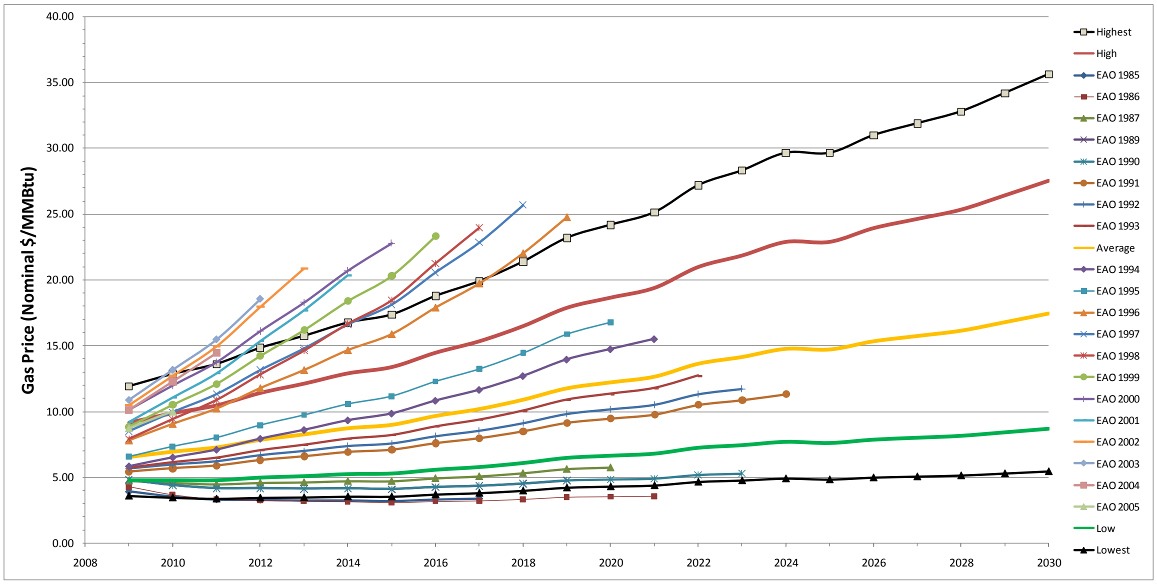
Figure D-8: Model Input Natural Gas Prices Compared With Other Gas Price Forecasts



Source: Energy Commission

Is it realistic to expect that the forecasted errors are sustainable to the extent proposed here? **Figure D-9** addresses this concern. It shows trendline natural gas prices constructed similar to those described above for all of the yearly EIA forecast errors, with Energy Commission trendline forecasts superimposed.

Figure D-9: Natural Gas Prices for All EIA Forecasts vs. Model Input Prices



Source: Energy Commission

It is not easy to compare Energy Commission forecasts to the EIA forecasts since the EIA forecasts are for a limited number of years. It is impossible to say if these forecasts would continue this same trend beyond the forecast period to 2030. However, the data suggests that Energy Commission forecasts fit within the EIA data.

APPENDIX E: Transmission Parameters

Transmission parameters include losses and costs. These are separated into two general categories because of a key difference in a characteristic between conventional and renewable resources. The former are able to be located near load centers and along existing transmission corridors because the fuel can be brought to the power plant. The latter must be located at the energy source, which typically is located far from load centers or transmission corridors. Losses increase with distance, and costs increase with the length of the line. In addition, such lines are most often trunk lines that do not provide other network benefits for interchange among load centers.

It is important to note that there is difference between "costs" and "rates." In this case, the incremental costs of adding transmission to deliver new power can be readily identified by comparing the costs of meeting loads with one set of resources versus another set. However, rates can reflect policy decisions about how to allocate those costs. Those policies can take into account a number of factors that extend beyond the typical economic efficiency criterion. This analysis focuses solely on using the efficiency criterion because incorporating those other factors requires a more extensive system-wide analysis. On the other hand, excluding or ignoring these costs implicitly assumes that these costs are zero.[15]

Transmission Losses

Transmission losses represent the power lost from the point of first interconnection to the point of delivery to the load-serving entity in the California ISO control area. This point of delivery is considered to be the substation at the demarcation between the transmission and distribution system. Losses through the distribution system are not included, so these would have to be added to make these resources comparable to distributed generation (DG) and demand-side management (DSM).

Renewable Generation Losses

For renewables, the losses for California resources are assumed to be 5 percent based on the Renewable Energy Transmission Initiatives *Phase 1B Report*.

[15] As is often the case in many analyses, attempting to ignore the consequences of a particular aspect is identical to making an invalid assumption that the parameter equals zero. In all of these cases, it is necessary to make some type of assumption, even if it cannot be validated with rigorous support.

Conventional Generation Losses

Conventional technologies include gas-fired, coal-fired, and nuclear. These technologies are presumed to be located near load centers, transmission interconnections and fuel transport lines. These losses are estimated based on an average computed for the California ISO control area. California ISO assigns loss factor to locational marginal pricing, assuming local capacity requirements (LCR) losses are appropriate) and then adding in intertie losses. The resulting local area losses from California ISO *2009 Local Capacity Technical Analysis Final Report and Study Results* sub-area transmission losses, based on the equation:

Losses (MW)/Total Load (MW)

- Stockton: 27/1436 = 1.88%
- Sierra Area: 107/2126 = 5%
- Greater Bay Area: 253/10,244 = 2.46 %
- Big Creek Ventura: 143/4734 = 3%
- Humboldt: 9/200 = 4.5 %
- LA Basin: 202/19612 = 1%
- Greater Fresno: 124/3381 = 3.67%
- Kern: 16/1316 = 1.22%
- San Diego: 126/5052 = 2.45%

The weighted average losses for all areas are shown in **Table E-1**.

Table E-1: Average Transmission Losses for Conventional Generation

Load Area	Losses %	Load (MW)
Stockton	1.88%	1436
Sierra Area	5.00%	2126
Greater Bay Area	2.46%	10244
Big Creek Ventura	3.00%	4734
Humbolt	4.50%	200
LA Basin	1.00%	19612
Greater Fresno	3.67%	3381
Kern	1.22%	1316
San Diego	2.45%	5052
Weighted Average =	**2.07%**	

Source: California Independent System Operator, *2009 Local Capacity Technical Analysis Final Report and Study Results.*

Transmission Costs

Transmission costs are composed of two components. The first is the California ISO transmission access charge for all generators. The second is the project-specific cost incurred for trunk lines constructed to interconnect a resource energy zone (REZ) to the control area network.

Transmission Access Charge

The following quote is taken from a March 31, 2009, California ISO filing on transmission access charges:

> "The transmission Access Charges provided in the present filing revise the Access Charges and Wheeling Access Charges provided for informational purposes in the CAISO's submission of March 6, 2009 in Docket No. ER09-824 (deemed by the Commission as filed on March 9, 2009). The changes in the present filing are effective March 1, 2009, in accordance with CAISO Tariff Appendix F, Schedule 3, Section 8. Worksheets illustrating the recalculation of the CAISO's transmission Access Charges are included with the present transmittal letter as Attachment A. The recalculated rates for each of the TAC Areas, effective March 1, 2009, are as follows:
>
> - Northern Area- $4.2727/MWh
> - East/Central Area $4.3512/MWh
> - Southern Area $4.3219/MWh

Based on this filing, an average rate of $4.30 per MWH was included in the costs for all generation technologies.

Transmission Interconnection Costs

In the *2007 IEPR* Scenario Analysis, the Energy Commission estimated the cost of adding sufficient transmission to meet a high renewable generation level relying on in-state resources. This was Scenario 4A. The weighted average costs for REZs identified in that scenario were calculated, as shown in **Table E-2**. These averages include additions in REZs in which no additional transmission capacity is presumed to be required, for example, Tehachapi. These interconnection costs are then added as a separate component in the Model, and then allocated on a per-MWh basis assuming IOU financing under FERC regulation.

Table E-2: Transmission Interconnection Costs per *2007 IEPR* Scenario 4A

Resource Type	Transmission Area[1]	Installed Capacity (MW)	Transmission Costs ($MM)	$/kW
Geothermal	IID	1,526		
	SCE	264		
	PG&E	625		
	Total	**2,415**	**$613**	**$254**
Solar (CSP)	IID	450		
	Imperial Valley	500		
	SDG&E	100		
	SCE	1,350		
	LADWP	0		
	PG&E	300		
	Total	**2,700**	**$374**	**$138**
Wind	IID	0		
	Imperial Valley	600		
	SDG&E	500		
	SCE	6,702		
	LADWP	200		
	PG&E	2,136		
	Total	**10,138**	**$749**	**$74**
Wood/Wood Waste	IID	40		
	SDG&E	219		
	SCE	235		
	PG&E	497		
	Total	**991**	**$39**	**$39**

Source: California Energy Commission, *2007 Integrated Energy Policy Report*.

APPENDIX F: Revenue Requirement and Cash Flow

This appendix describes the Revenue Requirement and Cash-Flow financial accounting used in the COG Model. It describes the modeling algorithms, the development of these algorithms and their respective effects on levelized costs.

Revenue Requirement accounting was used exclusively in the *2007 IEPR*. Although staff was aware that this accounting technique was only truly applicable to IOU and POU developers, and that Cash-Flow accounting was more applicable to merchant developers, initial studies indicated that the differences were small. In the interest of keeping the modeling as simple as reasonably possible, Revenue Requirements was used for all three categories of developers. Studies subsequent to the *2007 IEPR* disclosed that the differences are only small where there are no significant tax benefits: accelerated depreciation, tax credits and Ad Valorem (property tax) exemptions for solar plants. These studies disclosed that Revenue Requirements could overstate the levelized cost for renewable technologies by as much as 30 percent, depending on the applicable tax benefits – keeping in mind that these tax benefits do change over time. Accordingly, for the *2009 IEPR* staff has changed the merchant accounting to reflect cash-flow accounting for Merchant plants.

Algorithms

The complexity of the COG modeling algorithms comes from the need to quantify the revenue, which cannot be known for the generalized case because there is no specified revenue. It is therefore logically set to an amount that is just adequate to meet all expenses. This leads to the dilemma that the revenue cannot be known until the state and federal taxes are calculated, but the state and federal taxes cannot be calculated before the revenue is known—thus the need for simultaneous equations. **Table F-1** illustrates the applicable accounting elements for a binary geothermal unit, which are applicable for both Revenue Requirement and the Cash-Flow accounting – except POUs have neither taxes nor equity payments to account for. Actual values are shown to illustrate the components but are not necessary to the development of the algorithms.

The first row shows the revenue required, which is by our definition equals the levelized cost. It is the sum of all costs: operating expenses; capital cost and financing cost; and state and federal taxes. The before tax income, which is the revenue left after accounting for the operating expenses, must pay the taxes and the capital cost and financing costs (equity and debt). The remaining revenue after paying taxes must pay for debt and return on and of equity which is defined as after tax income. Therefore, Revenue is equal to operating expenses plus before tax income.

Table F-1: Comparison of Revenue Requirement to Cash-Flow

Geothermal - Binary	**Revenue Requirement ($/MWh)**	**Cash-Flow ($/MWh)**
Revenue Requirement *(R)*	$104.29	$83.11
Minus Operating Expenses (O&M, Fuel, Insurance and Ad Valorem) *(OE)*	$47.28	$47.28
Equals Before Tax Income *(BTI)*	$57.01	$35.82
Minus Taxes *(T_f+T_s)*	($44.98)	($48.94)
Equals Debt and Equity Payments *(ATI)*	$102.00	$84.76
Debt Payment	$50.96	$50.96
Equity Payments	$51.04	$32.81
Total Debt and Equity Payments *(ATI)*	$102.00	$84.76

Source: California Energy Commission

- Revenue (*R*) must equal the sum of:
  - Operating Expenses (O*E*):
    - Fixed O&M Costs
    - Insurance & Ad Valorem (Property Taxes)
    - Fuel Cost
    - Variable O&M
  - Before Tax Income[16] (*BTI*):
    - State (T_s) and Federal (T_f) Taxes
    - After Tax Income (*ATI*) is equal to the debt and equity payments

$$R = OE + BTI = OE + ATI + T_f + T_s$$

- Taxable Income is calculated separately for State and Federal as:
  - Taxable State Income: Before Tax Income (*BTI*) – State Deductions (D_s)
  - Taxable Federal Income: Before Tax Income (*BTI*) – Federal Deductions (D_f) – State Taxes (T_s) –Tax Deduction for Manufacturing Activities (TDMA) – Geothermal Depletion Allowance (GDA)[17]
  - State Deductions (D_s): State Depreciation and Interest on Loan

[16] Before Tax Income (BTI) is also called Operating Income or Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA)

[17] GDA is ignored in the model as developers cannot use both GDA & REPTC. Using REPTC is more advantageous as default.

- Federal Deductions (Ds): Federal Depreciation, Interest on Loan, Manufacturing Activities (TDMA), and Geothermal Depletion Allowance (GDA)
- Federal Tax Credits (C_f): BETC, REPTC & REPI

- Taxes are equal to respective Tax Rates (t_f, t_s) times Taxable Income – Tax Credits (C)
  - Federal Taxes: $T_f = t_f(BTI - D_f - T_s) - C_f = t_f(ATI + T_f - D_f) - C_f$

    Solving for T_f: $T_f = \dfrac{t_f(ATI - D_f) - C_f}{(1 - t_f)}$

  - State Taxes: $T_s = t_s(BTI - D_s) - C = t_s(ATI + T_f + T_s - D_s) - C_s$

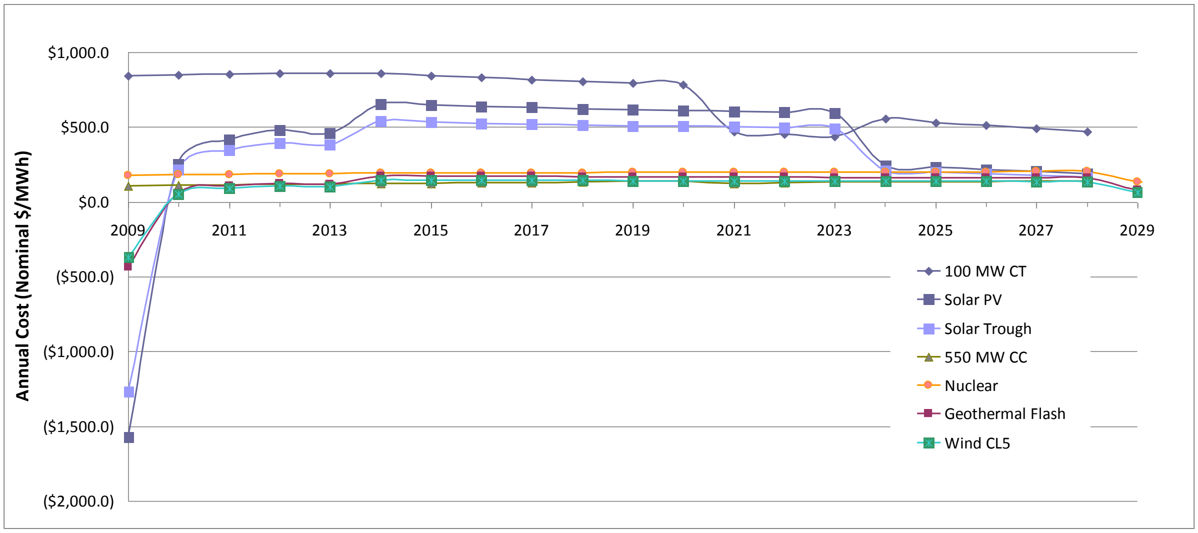
    Solving for T_s: $T_s = \dfrac{t_s(ATI + T_f - D_s) - C_s}{(1 - t_s)}$

These formulas are applicable to both Revenue Requirement and Cash-Flow accounting. The difference is in how the equity payments are calculated. This affects only the fixed costs and in only two categories: Capital and Financing Cost and Corporate Taxes (state and federal taxes)

Revenue Requirement

In the Revenue Requirement Income Sheet, the equity return payments are calculated as a percent of the depreciated value of the technology for each year—there is no linkage among years, unlike the cash-flow analysis. Since investment and depreciated value is known a priori, calculating the before-tax net revenue and equity return is straightforward, and taxes are simply a percentage of that income. This results in revenue payments as shown in **Figure F-2**.

Figure F-2: Annual Revenue Stream for Revenue Requirement Accounting

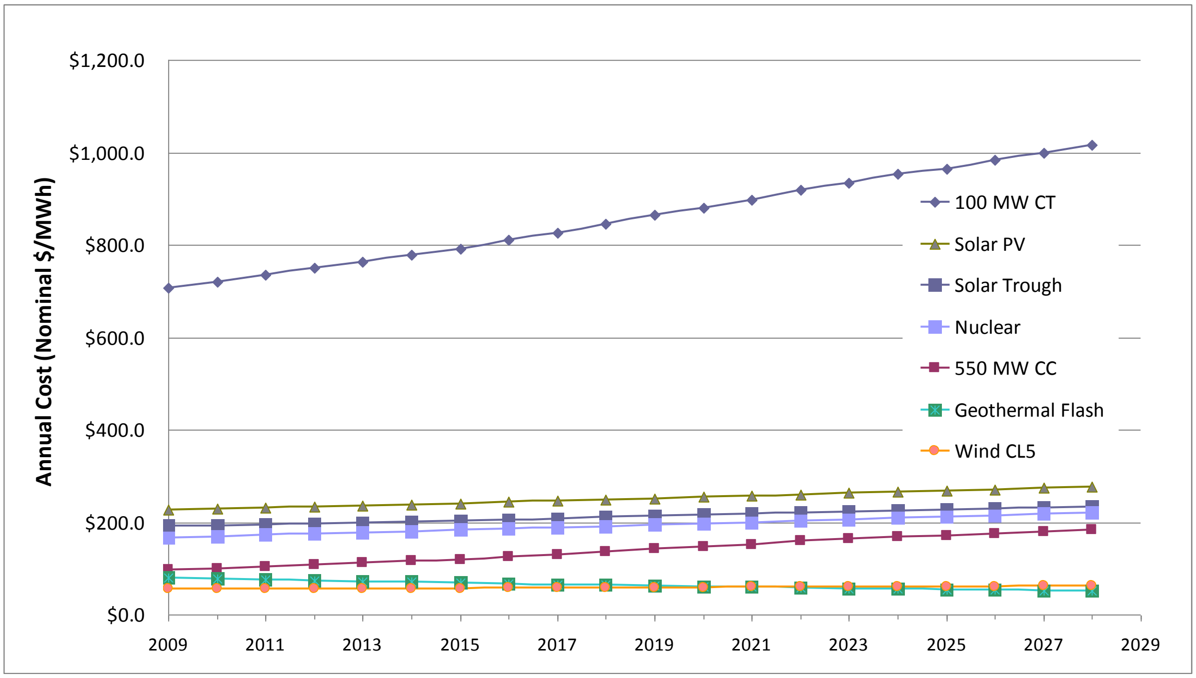


Source: California Energy Commission

Cash-Flow

In the Cash-Flow Income Statement, the equity payments must be calculated using a minimization method, where a uniform stream of revenue payments (increasing or decreasing depending on contractual terms) is created while just meeting the net present value of the equity payments over the economic life of the plant necessary to compensate the investors. Because the revenue level is a function of after-tax income plus taxes, and taxes are a function of the before tax income, and the revenue amount must be a relatively level stream over the years, the model must solve for how equity income will vary among years so as to achieve the net present value target for equity return over the entire period, not one year at a time. In other words, unlike the revenue requirement method, the equity return in any one year is not independent of the return in other years. The corresponding annual payments are shown in **Figure F-3**.

Figure F-3: Annual Revenue Stream for Cash-Flow Accounting



Source: California Energy Commission

The SCE/E3 COG Model used in the CPUC MPR uses the Excel Goal Seek function to change the projected revenue by changing the contract price so that the net present value of the equity return equals the target equity return after paying taxes. The Black & Veatch (B&V) COG Model used for the RETI studies used the Excel Table function the making a linear estimate of how the net revenue function changes with the contract price paid. Both Excel functions produce similar results because the Goal Seek function uses a similar linear estimate method duplicated in the Table function setup. Staff elected to use the Table function similar to the B&V COG model because it allows for automatic adjustment of the target contract price without having to run Goal Seek separately for each change in technology, assumptions, or scenarios. However, the authors found that the change in net revenue was not a linear function over the full range of contract prices due to the more complex representation of expenses and taxes in the COG model compared to the B&V RETI model. Instead a piecewise linear function was created using the Table function to capture the nonlinear relationship.[18]

For two reasons, the revenue requirements and cash flow may not necessarily arrive at the same value. The first reason is since the revenue requirement calculates the annual revenue separately for each year, changes in the relationships among years does not affect the revenue requirement within an individual year. The annual revenue requirement is simply a

[18] The Table function calculation can be found on the Income_Cash Flow worksheet in the model, starting at cell B167.

function of the weighted average cost of capital that equals the discount rate used to calculate the levelized cost of capital. For the cash flow method, cost components are discounted by three different discount rates—the interest rate for debt, the rate of return for equity for the profit, and the weighted average of these two for expenses. The resulting net present value of each of these stream of values is a nonlinear function of each discount rate. The sum of nonlinear functions does not equal the nonlinear function of the sums. The former is the cash flow method, the latter is the revenue requirement function. The second reason is that tax incentives typically are applied to nominal values asset values and income streams. Moving the net present value of income from one period to another can have secondary tax consequences that then change the revenue target in an endogenous fashion. Typically the difference between the cash flow and revenue requirement results is not large, but it typically becomes significant where large tax incentives are applicable to a technology.

APPENDIX G: Contact Personnel

The following is a list of the Energy Commission and contractor personnel who participated in the development of the Model, the data gathering process and the computer simulations, along with their phone numbers and e-mail addresses. This list is intended to facilitate information requests related to this report. If you are in doubt as to whom to contact, you can contact the author, who will direct you to the appropriate source.

SUBJECT	PERSONNEL	PHONE	EMAIL
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APPENDIX H: Comments and Responses

August 25, 2009, Workshop

Morning Session

Comment by	Location in Webex	Comment	Response
Commissioner Byron	1h 5 m	Have you thought about how to incorporate PV with thermal storage into the COG Model?	Yes, KEMA generated two sets of costs for solar parabolic trough with 6-8 hours of energy storage. This increased both the capacity factor and the cost. There are important operational issues that need further clarification before this technology can be added into the model. As an aside, none of the proposed solar thermal plants in California include storage.
Commissioner Byron	1h 32m	The 2007 levelized cost are lower for certain technologies than the 2009 costs.	Much of this is because of the unforeseen escalation of construction costs. This was not fully captured in the *2007 IEPR*, but was better represented in 2009. However, in several cases, new assessments showed higher costs than in the 2007 assessment. This situation often arises when an alternative view is brought to bear on a study.
Tony Braun – counsel to California Municipal Utilities Association	1h 46m	For most renewable energy resources, a triangle model is used. Contracts are negotiated between a private developer and POUs to take advantage of available tax credits. Tax exempt financing is used to pay for the project output to take advantage of tax exempt securities. How much of this financing structure was reflected in the renewable cost numbers?	We did not incorporate that kind of project financing, particularly because the CMUA example is a project-specific case. The staff COG Model is designed to reflect parameters that can be generalized across projects. If we had a very detailed description of how that financing works, we could implement it into the model if its use is widespread. With more detailed descriptions, the model could be used to evaluate individual projects.

Comment by	Location in Webex	Comment	Response
Matt Barmack - Calpine	1h 48m	Some people at Lawrence Berkley Lab have done a lot of work on project finance structures for renewable. Have you taped into any of that work?	Staff looked at their report and used a fair amount of their information. The municipal co-financing model was not generalized to our study because we did not have sufficient information about the prevalence of these financing mechanisms. This model is designed to reflect parameters that can be generalized across projects. The values in this particular study are to be used for planning studies, not for evaluating specific identifiable projects.
Matt Barmack - Calpine	1h 48m	Are the differences in renewables using cash flow modeling and revenue requirements driven by the modeling, or the differences in assumptions about merchant cost of capital vs. IOU cost of capital?	It is in the modeling. Staff used identical assumptions except that of revenue requirement vs. cash flow.
Matt Barmack - Calpine	1h 50m	There is a lot of work out there that shows the equivalence of the cash flow and revenue requirement approach, using comparable assumptions, for investment decisions. I encourage you to look into that some more because I am not sure your result is correct.	Staff reviewed the study referenced by the commenter. That study only provided a simple mathematical model that assumed away many of the empirical issues that arise in project accounting. It did not address the differences in the debt and equity discount rates that arises in cash flow versus revenue requirement modeling, nor the non-linearities in the tax depreciation rates and renewable energy incentives.
Matt Barmack - Calpine	1h 52m	There are a lot of claims in the model that IOU facilities are cheaper than merchant facilities. I encourage you to use a little more neutral language. Maybe talk about the term of commitment instead of IOU vs. merchant.	The report explains how financing and tax benefits will affect the levelized costs for either a merchant, IOU or POU project.
Matt Barmack - Calpine	1h 53m	I think you can be much more guarded about your estimates of the installed costs of some of the newer conventional technologies. It was counter factual and counter intuitive that the installed costs of an H class combined cycle was lower than the costs of a normal combined cycle	The only H class and advanced CT cost estimates staff have are from the EIA, which assumes these technologies will be less expensive than the current technologies. Staff has much more knowledge and experience with the F class turbines. More knowledge on the H class turbines would allow us to make a better comparison.

Comment by	Location in Webex	Comment	Response
Ken Swane – Navigant consulting	1h 58m	The transmission access cost in your assumptions does not match up to what the CA ISO has on their March 2009 Tariff.	Staff used information from the March 2009 Tariff. A statewide average was used because the rates were quite close. Staff sourced this on the “plant data input page.”
Even Hughes – consultant in biomass and geothermal	2h	What is the basis for such a steep cost decline for solar PV?	Experience and learning curve effects. Maximum power point tracking and different inverter technologies. 12-18% of cost reduction over time attributed to learning effects. The model reflects a range of costs.
Matthew Campbell – Sun Power	2h 5m	Many years ago, the price of polysilicon and the global shortage of PV panels forced us off the experience curve. Recently we got back on the curve. Because the industry changes so frequently, we think the COG Model and assumptions should be updated on a real time basis rather than every two years.	The current analysis assumes a return to that experience curve. Staff can apply information if parties are willing to provide detailed assumptions for the technology modeling.
Roffy Manasean. - Southern California Edison	2h 12m	Why did they cost of nuclear increase so much from 2007 to 2009?	Most of the research for 2007 was done using the 2003 MIT landmark study. This 2009 analysis reflects expected costs in Europe and recent utilities’ analyses in the U.S. Also, many of the other data assumptions have changed in various reports since the 2007 IE.
Roffy Manasean. - Southern California Edison	2h 18m	The report says that one of the variable cost components for simple cycle units got shifted to a fixed cost component. It seems like a big difference because of the shift	It seems like a big shift internally, but the final total annual O&M cost number is roughly the same.
Craig Lewis – right cycle (advocacy consultant	2h 24m	$4.50 per watt for solar in model. Germany is making deals for under $4 per watt. How much attention is being given to how much faster the solar experience curve can be driven down once	The model reflects a range of costs, with $4.50 per watt only the middle of that range. Please review the full range that reflects the projects assessment. There are many effects in the market that can drive the experience curve. A feed-in-tariff could drive

Comment by	Location in Webex	Comment	Response
agency AB 1106)		we get a comprehensive feed-in-tariff in California?	costs down, and those effects probably are encompassed in the range of forecasted costs contained in the model.

Docketed Comments

Comment by	Comment	Response
Richard Murray – Landscape Architects, Environmental Planners	Energy close to its point of use can use existing infrastructure with minor modifications; this can save on the cost of new construction. Line energy losses are roughly 7.5% through transmission from place to place.	The comment is valid, and there is a substantial body of analysis dealing with the avoided costs of distributed deployment of renewables. However, this is not applicable to the staff COG Model, which is intended to cover only utility-scale plants that sell their entire output to the bulk power market. Smaller scale PV plants are usually intended to serve customer loads, at least in part, and would produce these types of line loss savings and often have different financing and operational considerations as a result.
Richard Murray – Landscape Architects, Environmental Planners	Bare land or low yield farm land could be utilized for PV when other crops are unavailable. PV energy farming is equally as important to our economy as other crops. PV farming would be listed under schedule B of the Williamson act which lists uses acceptable by different counties.	This is a policy issue beyond the scope of the technical analysis used to develop this model. This issue should be addressed as a policy issue in the IEPR proceeding
Richard Murray – Landscape Architects, Environmental Planners	The market price references (MPR) are tied to the costs associated with new natural gas-fired power plants. The PG&E small renewable generator power purchase agreement uses only the MPR without considering other inflation costs estimated by the CPUC. The small entrepreneur will need assistance through adjusted MPR, low interest loans, or governmental help.	While the COG Model could be used to compute the MPR for the CPUC, that agency chooses to use its own model. The policy on how solar developers should be compensated is beyond the scope of the technical analysis used to develop this model.
Matt Barmack - Calpine	The treatment of financing costs is imbalanced and has a bias towards IOUs. The model assumes limits on the contract term for merchant plants. The model ignores the fact that low financing costs reflect buyer's commitments to pay for the majority or all the capital costs of a project. A merchant plant with similar PPA terms as an IOU would have similar costs. The model ignores the fact that rate payers tend to absorb cost	The model is designed to compute only the cash costs of the generation technology in question and leaves out many other factors that are relevant to selecting among technologies, including relative risk burdens associated with ownership, relative environmental impacts, and differences in operational characteristics and how that fits with system requirements. Such a model is beyond anyone's capability to design in this format. The results from this model should never be used to make simple

Comment by	Comment	Response
	over-runs associated with IOUs while investors tend to absorb cost over-runs associated with merchant plants.	comparisons between technologies and ownership.
Matt Barmack - Calpine	The draft report says that POU plants are the cheapest to finance because of lower financing costs and tax exemptions. Tax exemptions only shift the capital costs from rate payers and developers to tax payers.	Again, the staff COG Model is designed to access relative costs, although we attempted to identify these cost components.
Matt Barmack - Calpine	The costs of H class CCGTs are virtually unknown. Also the same story for the LMS100 turbines for small simple cycle facilities. We believe these estimates should be tagged as "speculative" in the report.	We agree that the costs for the advanced CC and CT designs are less reliable than for the F frame and aeroderivative turbines where there is a considerable amount of actual project information. We will add a comment to that effect in the Report.
Richard Raushenbush - Greenvolts	What is the basis for the 27% capacity factor for Solar PV (single axis) in table 11? Was DC or AC output used in the calculation? We think the estimates may be understated. If converting DC to AC, how were the losses of that conversion calculated?	The capacity factor calculated using AC and DC parameters should be comparable to within 5%, with the AC capacity factor lower. Staff believe that 27% is in the range supported by project experience but would acknowledge that higher and lower results are to be expected depending on project siting and design.
Richard Raushenbush - Greenvolts	What is the basis for the 22.4% plant side losses for solar PV (single axis) in table 11? Does this number reflect the conversion of DC to AC output and other losses? If this is the case, we believe the report may be double counting the losses.	Plant side losses were derived by considering expected module performance plus thermal degradation. Inverter losses were accounted for by using expected performance charts common in the solar industry for inverters. The inverter losses were then compared to other representative projects in the consultant's database for comparative accuracy and to verify agreement
Richard Raushenbush - Greenvolts	We believe that the assumption of 5% transmission losses for renewable and 2.09% for fossil fuel plants is too simplistic and can create an inaccurate cost comparison. This number should be based on the distance from load center. We believe the transmission losses should be lower for PV as many plants can be built close to the load center.	The losses were based on averages from CAISO data matched with the likely location of renewables around the state. While some PV may be located near load centers, the majority of proposed projects are located in desert regions far from load centers. The model is constructed to reflect general assumptions, not project specific or optimistic assumptions. The loss calculations reflect this premise.

Comment by	Comment	Response
Mary Hoffman – Solutions for Utilities, Inc	The KEMA report uses a gross capacity 25 MHW and 100 MW for solar PV plants. It is inaccurate to compare various cost components of solar PV plants with different capacities.	The Energy Commission staff agrees.
Mary Hoffman – Solutions for Utilities, Inc	The feed-in-tariff program can be very successful for smaller size solar PV plants. The report should be expanded to include costs for the 1-3 MW solar PV single axis plants.	The Energy Commission staff agrees and will revise the KEMA report. However, the COG Model is intended to cover only utility-scale plants that sell their entire output to the bulk power market. Smaller scale PV plants are usually intended to serve customer loads, at least in part, and often have different financing and operational considerations as a result.
Mary Hoffman – Solutions for Utilities, Inc	Why is “instant costs” used instead of “installed costs”? Installed costs incorporate construction costs, and I believe this would be a more appropriate cost measure.	The instant cost used in the COG Model includes all construction and pre-construction costs. The Model uses instant cost to produce installed cost. The conversion from instant to installed cost covers only the cost of the construction loan (AFUDC) and sales tax.
Mary Hoffman – Solutions for Utilities, Inc	Are shipping charges for all materials during construction of the plant included in the model? For smaller facilities, they are 1.5% - 2% of the cost of materials delivered to the site.	All construction and preconstruction costs, including shipping, are included in the estimate of instant cost. Note that the COG Model does not address small scale plants; it only calculates costs for utility-scale plants selling 100% of output to the bulk power market.
Mary Hoffman – Solutions for Utilities, Inc	For solar PV, ad valorem taxes are 0%. The yearly taxes to the county assessor on the unsecured equipment are 1.07%. Shouldn’t the 1.07% be calculated into ad valorem? Also, The KEMA report, page 96, shows no real property taxes nor ad valorem taxes; are these calculated elsewhere?	The ad valorem estimate is not a part of the KEMA Report. It is used only in the staff COG Model, and is shown in the staff COG Report as a component of the levelized cost. See Tables 6 and 7 and also Appendix A. The 1.07% comes from the BOE and does not distinguish between secured and unsecured property tax. The state property tax exemption for solar applies to all property.
Mary Hoffman – Solutions for Utilities, Inc	Page 52 of the COG report has “insurance “assumed at 0.6%. This is ok for solar PV facilities of 25 MW–100 MW size, but will not be accurate for facilities in the size of 1 MW–3 MW.	The 0.6% is used in the staff COG Model to calculate the levelized cost for utility scale central station technologies. Levelized costs were not calculated for the size of 1–3 MW. Therefore, insurance costs were not estimated. It would be expected that they would be

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		a different value.
Mary Hoffman – Solutions for Utilities, Inc	What rates have been used to determine worker's compensation calculations for labor during construction and after the project is online? SCIF has raised worker's compensation rates for construction trades over the past few years. Has this been accounted for in the model? Also, premiums for workers compensation will vary widely based on the total dollar of premium paid per year by the employer. Has this been accounted for in the model?	The model uses cost build-up information that accounts for general categories of cost experience. KEMA consultants were not asked to provide detailed cost build-ups for each energy supply option. For the gas-fired plants, labor compensation rates are based on the Pacific Region estimates by job classification published by the Bureau of Labor Statistics. (USBLS, Employer Costs for Employee Compensation, Historical Listing (Quarterly), March 12, 2009.) For the other technologies, construction and operational costs are estimated on an aggregated basis and do not reflect summation of individual components. However, the estimates do reflect the recent escalation in construction costs, which have several factors driving those increases. For the gas-fired plants, labor compensation rates are based on the Pacific Region estimates by job classification published by the Bureau of Labor Statistics. (USBLS, Employer Costs for Employee Compensation, Historical Listing (Quarterly), March 12, 2009.) For the other technologies, construction and operational costs are estimated on an aggregated basis and do not reflect summation of individual components. However, the estimates do reflect the recent escalation in construction costs, which have several factors driving those increases.
Mary Hoffman – Solutions for Utilities, Inc	For solar PV facilities: how is it determined which facilities have permit fees, report costs, and or animal and plant life mitigation fees? Also, permit fees should be analyzed separately for smaller sized projects (1 – 3 MW) as they are proportionately more expensive.	The model uses cost build-up information that accounts for general categories of cost experience. Commission consultants were not asked to provide detailed cost build-ups for each energy supply option
Mary Hoffman – Solutions for	Page 38, table 8 of the staff report for merchant plants has a solar PV tax benefit of $334.28 MWh. Page 26, Table 6 of the staff report has "average levelized cost	The $334.28 per MWh (in Table 8) is calculated by running the COG Model with and without tax benefits (accelerated depreciation, tax credits and property taxes). The $141.44 per

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Utilities, Inc	component for in service 2009- merchant plants" taxes as "-$141.44 per MWh. How were these two numbers calculated?	MWh of Table 6 is calculated by the COG Model as a part of the levelized cost calculations. The actual tax calculation is mathematically complex and not easy to characterize. It will, however, be made available in the soon to be released User's Guide for the COG Model.
Mary Hoffman – Solutions for Utilities, Inc	The staff report says the model has the ability to include the cost of carbon in its calculation, but this function has not been used to calculate how carbon adders may affect levelized cost estimates. This calculation should be performed and available to all interested parties.	The COGModel has the ability to incorporate the cost of carbon, not to calculate it. The actual costs will be developed in future Energy Commission studies and be the subject of workshops and/or hearings.
Mary Hoffman – Solutions for Utilities, Inc	The Staff Report, on page 3, Table 1: "Summary of Average Levelized Costs - In Service in 2009," "Merchant," Solar PV, based on a 25-MW capacity facility is indicated as 26.22 cents per kWh. The cost of a 1 – 3 MW solar pv plant would be higher. Staff and KEMA should include the costs of these smaller facilities in their analysis.	The 1-3 MW size will be added to the KEMA Report. However, the COG Model is intended to cover only utility-scale plants that sell their entire output to the bulk power market. Smaller scale PV plants are usually intended to serve customer loads, at least in part, and often have different financing and operational considerations as a
Matthew Campbell – Sun Power	SunPower proposes that the CEC include both central station and distributed PV power plants as separate line items in its COG Model. The two resource types have different strengths with distributed power plants being faster to interconnect and permit but achieving lower economies of scale than central station plants.	The Energy Commission staff is considering adding distributed generation to its COG Model for future IEPRs.
Matthew Campbell – Sun Power	We propose that the COGs consider a 20 MW distributed PV power plant and a 200 MW central station PV power plant	Staff agree that experience gained over the next years may provide a sound basis for implementing the recommendation. Staff did not compare costs for different plant sizes since insufficient experience exists to validate cost estimates.
Matthew Campbell – Sun Power	Sun Power recommends increasing the assumed capacity factor for the 25MW single-axis PV system from 27% to 30% (AC). The 30% capacity factor is	Staff believe 27% is in the range supported by project experience, but would acknowledge that higher and lower results are to be expected depending on project siting and design.

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	similar to what we anticipate for our California PV power plants such as the 210 MW California Valley Solar Ranch. SunPower has studied 10 years of historical annual variation in solar resource in the Mojave Desert and anticipates an annual variation in capacity factor of +-5% around the 30 year average used to estimate capacity factors.	
Matthew Campbell – Sun Power	SunPower recommends increasing the 20 year equipment and depreciation life to 30 years, the same value used for wind turbines in the draft report. Unlike wind, PV power plants have very little mechanical wear and maintenance requirements and operate under relatively benign conditions. PV panels and trackers are well established technologies with over thirty years of demonstrated performance.	Staff agrees conceptually, but did not have sufficient visibility to financing packages for utility scale PV projects to validate more aggressive assumptions.
Matthew Campbell – Sun Power	SunPower recommends a debt term of 20 years, the same as assumed for wind. Both wind and large-scale PV plants are financed using standard power project finance regimes and share similar characteristics.	Staff recognizes that aggressive financing assumptions have been used for some larger PV projects. Staff does not have sufficient visibility to financing packages for utility scale (>20MW) PV projects to validate more aggressive assumptions at this time.
Matthew Campbell – Sun Power	In the draft report an O&M cost of $68/kW per year is assumed for both a PV and CSP power plant. Sun Power's experience in operating more than 300 MW of solar power plants using a wide variety of system technology around the world is that the O&M cost for PV is dramatically lower than CSP. We recommend using an assumed value for the study of$30/kWp/year.	While there is some field experience with large CSP plants there is little or none with comparably sized PV plants. Staff recognizes the need to monitor experience for both options closely as it accumulates.
Matthew Campbell – Sun Power	Owing to the scaling of very large scale PV module factories, the introduction of new technologies, and the availability of sufficient silicon feedstock, the price of PV power plants is falling dramatically.	Module price as a proxy for cost would suggest module costs continue to trend strongly downward, but fully built-up module cost is not the sort of information we can access in the public domain.

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PG&E	Future studies could be further enhanced by including an assessment of variability in costs of construction, both in terms of labor and materials	The COG Report provides this sensitivity through its range of high and low assumptions that reflect the cost factors identified by the commenter.
PG&E	Should consider that cost information may be skewed by market conditions/value at a particular point in time if there is an over or under supply of particular components	This was recognized as a short coming in the *2007 IEPR*. The COG's instant cost calculations in the *2009 IEPR* adjusted for this.
PG&E	Combined cycles (CC) are more complex than simple cycle units. Intuitively this leads to the conclusion that CCs should cost more.	The cost per MW for CCs is lower than for CTs because the per MW cost for the steam turbine component of the CCs is about half that of the CT component, so the average of the CTs and the steam component will be lower than just the CT alone, even accounting for the higher additional costs.
PG&E	Would like to see levelized costs for combined cycle units with 60% capacity factors, as these units will probably help to integrate renewables.	The Energy Commission staff assessment of currently operating plants indicates the higher capacity factors of 70% for CCs with duct-firing and 75% without duct-firing. It would be helpful if PG&E could provide its assessment that leads to a 60% capacity factor, which reflects our earlier 2007 COG assessment.
PG&E	Would like to see evaluation of reciprocating technologies in future updates of the COG Report.	There are no "utility scale" uses of reciprocating engines. Those are all DG and community scale applications. However, the Energy Commission is considering augmenting future COG Reports to include these community scale technologies, and will keep your suggestion in mind.
PG&E	Would like to see a sensitivity analysis around the aggressive experience curve for both solar PV and solar thermal	The COG Report provides this sensitivity through its range of high and low assumptions.
PG&E	Would like to see a wide range of estimates for small hydro, that are supplemental to an existing project, in future COG Reports.	The COG Report provides this sensitivity through its range of high and low assumptions
SCE	Figure 3 of the draft staff report shows that solar resources are among the most costly resources when ranked by instant costs in 2010. Yet, their levelized cost	Only the simple cycle units have a larger $/MWh levelized cost than the solar units, not the combined cycle or any of the other conventional or renewable units. This has to do with the very low

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	is below both conventional and simple cycle resources. This result is counterintuitive and misleading	capacity factors for CTs versus other technologies. It is always problematic to compare peakers to intermediate and base load units as they serve different purposes. It might be helpful for you to examine the cost comparison on a $/kW-Year basis in Table B-4.
SCE	The choice of plant used for the natural gas resources is inappropriate. The simple cycle gas turbine uses a GE LM6000 as compared to an F-Class turbine, which is less costly.	The LM 6000 simple cycle units were used as our standard, rather than F-Class because there is not a single F-Class simple cycle operating in California. This is explained on page C-1 of Appendix C. You should also be aware that the CTs recently constructed by Edison at four different sites were all LM6000s.
SCE	The combined cycle unit chosen is based on an F-Frame unit but the chosen (100 MW) size does not allow for the economies of scale a 500 MW unit would provide.	The combined cycle units in the COG Report are based on two 175 MW turbines, not 100 MW. The COG Report's combined cycle sizes of 500 MW for a non duct-fired unit and 550 MW for a duct-fired unit are the most commonly proposed and built sizes in California going back to 1999
SCE	The input cost assumptions for the various technologies may be inaccurate. The CEC should cross-validate the analysis assumptions against other recent studies to understand the nature of the differences.	The Energy Commission staff has made the most extensive study of technology costs today using all known data. This is particularly true for the gas-fired units which rely on the actual survey of California developers for the *2007 IEPR* plus a survey of all known available estimates for the 2009. We know of no additional sources of data.
SCE	The methodology for the conversion to levelized cost may be inappropriate.	The Energy Commission staff COG Model is in its third generation and has undergone scrutiny of many reviewers. Staff has benchmarked the Model against other models, including the SCE Model used in the MPR and found it to be within 1%. The only components that did not exactly match were equity and its effect on corporate taxes. This was found to be traceable to the SCE Model using cash-flow and the COG Model using revenue requirement. For the 2009 COG we have changed our merchant modeling to cash-flow so the models should now match even more closely. However, differences may remain in assumptions about

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		contract terms and cost escalations. Staff would appreciate more precise and documented comments about these concerns so that they can be addressed.
SCE	Levelized costs may not appropriately take into account the value of energy	A COG Model by definition reflects the cost of the technology, not the value of the energy to the system. This would require a system model, such as a production cost model.
SCE	Information for the nuclear technologies in the draft staff report does not appear to be correct. Table 19 of the draft staff report identifies the book life for the AP1000 Pressurized Water Reactor (PWR) as 20 years and the equipment life as 40 years.	SCE is correct. The book life for nuclear should be 40 years and the equipment life 60 years. This was an error in Table 19 due to the data for nuclear being inadvertently switched with coal-IGCC during the preparation of the table. This error is in the table only and not reflected in the levelized costs.
SCE	Figure 20 in the draft staff report shows that the levelized cost for AP 1000 PWR increased by approximately 100% since the issuance of the 2007 IEPR. SCE's understanding is that the instant costs increased, but only by about 30%. Upon discussion with the Energy Commission staff, we understand that the version of technology utilized for this report is different from that used in the *2007 IEPR*. Therefore, this is not a valid comparison, and we recommend that the comparison between the two IEPRs be removed	In the 2007 work, a generic reactor was used for the costs estimates. In 2009, the CEC consultant made a thorough analysis of the nuclear technologies most likely to be implemented within the state over the next twenty years and concluded that at this time, the AP-1000 would be the most likely implementation. The 2009 cost estimates are therefore based on more specific estimation of feasible nuclear technology implementation than the 2007 estimates were. The comparison of these technologies across COG Reports is problematic where technologies are changing. That does not mean that the comparisons are meaningless. It is important for reviewers to be made aware of our changes in estimates. The nuclear costs are particularly problematic as they are subject to change and cannot be known with any real certainty – thus the need for our bandwidth costs in the COG Report. However, we can modify the COG Report to state this difference.
SCE	EIA Instant costs vary dramatically from the Energy Commission's estimates.	This is to be expected, particularly for alternative technologies, where costs can be changing dramatically over time, assessments are made based on different data samplings, and the COG Report is based on California specific costs, where EIA costs are national

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		averages. Staff feels that its estimates are superior, particularly for California gas-fired units where they reflect actual survey data. We devoted resources to our California specific assessment that the EIA could not possibly have duplicated. However, all of this misses the primary message of the COG Report that single values cannot be known with certainty, as suggested by the EIA figure you provided.
SCE	The Energy Commission should explicitly recognize that resources are not interchangeable.	The Energy Commission staff does recognize this fact. This is why the report includes Figures 9–12 to illustrate this difference, even if on a general level. This was emphasized again in the workshop. Staff agrees that this is a salient point and will make an additional effort to further emphasize this point in the COG Report.
Elaine Chang, DrPh - SCAQMD	It is unclear whether the report has addressed the cost impacts of environmental externalities.	This was not within the scope of the COG work. However, environmental permitting and compliance costs were included where appropriate and known. These included air quality permitting costs.
Elaine Chang, DrPh - SCAQMD	According to the report (page 9), the cost of carbon capture and sequestration was not included.	This was not included due to the fact that the Energy Commission has not yet established the necessary data. This will involve workshops and/or hearings in the future.
Elaine Chang, DrPh - SCAQMD	It is unclear whether the cost of offsets were accounted for.	The cost of offsets were included in Chapter 2, Assumptions. The estimated emission rates can be found in Tables 11-13 and the corresponding estimated costs are in Tables 14 -16.

Attachment I – CPUC General Order 167

Capacity Procurement Mechanism Amendment

California Independent System Operator Corporation

Public Utilities Commission of the State of California

General Order No. 167

Enforcement of Maintenance and Operation Standards for Electric Generating Facilities

Effective September 02, 2005.

**(D.04-05-017 adopted May 6, 2004;
D.04-05-018 adopted May 6, 2004;
D.04-12-049 adopted December 16, 2004;
D.05-08-038 adopted August 25, 2005
in R.02-11-039; as modified by
D.06-01-047 adopted January 26, 2006; as modified by Resolution No. E-4184 adopted August 21, 2008; and as modified by D.08-11-009 adopted November 6, 2008)**

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1.0 PURPOSE

The purpose of this General Order is to implement and enforce standards for the maintenance and operation of electric generating facilities and power plants so as to maintain and protect the public health and safety of California residents and businesses, to ensure that electric generating facilities are effectively and appropriately maintained and efficiently operated, and to ensure electrical service reliability and adequacy. The General Order provides a continuing method to implement and enforce General Duty Standards for Operations and Maintenance, Generator Maintenance Standards (Maintenance Standards), Generator Operation Standards (Operation Standards), and any other standard adopted pursuant to Public Utilities Code § 761.3 (Chapter 19 of the Second Extraordinary Session of 2001-02 (SBX2 39, Burton *et al.*). The General Order also provides a means to enforce the protocols for the scheduling of power plant outages of the California Independent System Operator. The General Order is based on the authority vested in the California Public Utilities Commission by the California Constitution; California statutes and court decisions; prior Commission decisions and orders; and federal law including, but not limited to, the Federal Power Act, 16 U.S.C. § 791 *et seq.*, and section 714 of the Energy Policy Act of 1992, 16 U.S.C. § 824(g). Nothing in this general order diminishes, alters, or reduces the Commission's existing authority to inspect power plants and to request data from those power plants to assure continued maintenance and operation of the facilities in order to support public safety and the reliability of California's electricity supply.

2.0 DEFINITIONS/ACRONYMS

2.1 "Active Service" means the status of an electric generating unit that is interconnected, is capable of operating in parallel with the electricity grid, and has achieved commercial operation.

2.2 "California Independent System Operator" or "ISO" is that nonprofit public benefit corporation authorized under Public Utilities Code § 345 *et seq.* to operate California's wholesale power grid. For purpose of information-sharing under this General Order, ISO is considered to be a governmental agency.

2.3 "Commission" means the California Public Utilities Commission.

2.4 "Committee" means the California Electricity Generation Facilities Standards Committee, formed pursuant to Public Utilities Code § 761.3(b).

2.5 "Consumer Protection and Safety Division" or "CPSD" means that division of the Commission, or any successor entity, designated by the Commission to enforce this General Order.

2.6 “Exigent circumstance” means any condition related to the operation and maintenance of a Generating Asset that may result in imminent danger to public health or safety, including electrical service reliability or adequacy, or to persons in the proximity of a Generating Asset.

2.7 “General Duty Standards” means the Standards 1 through 3 and 5 & 6 from the General Duty Standards for Operation and Maintenance, adopted by the Committee on May 2, 2003, and revised on June 3, 2003, and set forth as Attachment A to Committee Resolution No. 3, which was filed with the Commission on June 6, 2003. This initial set of General Duty Standards is set forth in Appendix A to this General Order. “General Duty Standards” also includes any subsequent amendments or revisions to those standards

2.8 “Generating Asset” means any device owned by an electrical corporation (as that term is defined in Public Utilities Code § 218) or located in the State of California used for the generation of electric energy. To be a Generating Asset, the device must have a metered output, or an administratively defined group of generating devices that may or may not have individual metered outputs, but are aggregated for performance measurement. *However*, for the purposes of this General Order, a Generating Asset does not include:

2.8.1 A nuclear powered generating facility that is federally regulated and subject to standards developed by the Nuclear Regulatory Commission, and whose owner or operator participates as a member of the Institute of Nuclear Power Operations, *provided* that the owner or operator of such a facility shall comply with the reporting requirements of Public Utilities Code § 761.3(d).

2.8.2 A qualifying small power production facility or a qualifying cogeneration facility within the meaning of sections 201 and 210 of Title 11 of the federal Public Utility Regulatory Policies Act of 1978 (16 U.S.C. §§ 796(17), 796(18) & 824a-3) and the regulations adopted pursuant to those sections by the Federal Energy Regulatory Commission (18 C.F.R. §§ 292.101 to –602, inclusive), *provided* that an electrical corporation that has a contract with a qualifying small power production facility, or a qualifying cogeneration facility, with a name plate rating of 10 megawatts or greater, shall comply with the reporting requirements of Public Utilities Code § 761.3(d)(2)(B).

2.8.3 A generation unit installed, operated, and maintained at a customer site, exclusively to serve that customer’s load.

2.8.4 A facility owned by a local publicly owned electric utility as defined in Public Utility Code § 9604(d).

2.8.5 A facility at a public agency that is used to generate electricity incidental to the provision of water or wastewater treatment.

2.8.6 A facility owned by a city and county operating as a public utility, furnishing electric service as provided in Public Utility Code § 10001.

2.9 "Generating Asset Owner" means any person or entity owning, controlling, operating, or managing a Generating Asset. "Generating Asset Owner" includes, but is not limited to, an electrical corporation (as that term is defined in Public Utilities Code § 218). "Generating Asset Owner" does not include any governmental agency described in Public Utilities Code § 761.3(h). Although for the various purposes of this General Order more than one person or entity may meet the preceding definition, this section is not intended to require duplicate or redundant filings or notifications for any particular Generating Asset.

2.10 "Generating Availability Data System" or "GADS" means that data base system maintained by the North American Electric Reliability Council (NERC) which collects, records, and retrieves operating information for improving the performance of electric generating equipment.

2.11 "Generator Logbook Standards (Hydroelectric Energy)" means the "Logbook Standards for Hydroelectric Generating Facilities," adopted by the Committee on April 7, 2004, and filed with the Commission on April 14, 2004. The Generator Logbook Standards (Hydroelectric Energy) are set forth as Appendix C to this General Order. "Generator Logbook Standards (Hydroelectric Energy)" also includes any subsequent amendments or revisions to those standards.

2.12 "Generator Logbook Standards (Thermal Energy)" means the "Electricity Generating Facility Logbook Standards for Thermal Power Plants," adopted by the Committee on April 1, 2003, and filed with the Commission on April 2, 2003. The Generator Logbook Standards (Thermal Energy) are set forth as Appendix B to this General Order. "Generator Logbook Standards (Thermal Energy)" also includes any subsequent amendments or revisions to those standards.

2.13 "Generator Maintenance Standards" means the Maintenance Standards in the "Maintenance Standards for Generators with Suggested Implementation and Enforcement Model" adopted by the Committee on May 2, 2003, and filed with the Commission on May 16, 2003. The Generator Maintenance Standards are set forth as Appendix D to this

General Order. "Generator Maintenance Standards" also includes any subsequent amendments or revisions to those standards.

2.14 "Generator Operation Standards" means the Operation Standards in the "Operations Standards for Generating Asset Owners" adopted by the Committee on October 27, 2004, and filed with the Commission on November 1, 2004. The Generator Operation Standards are set forth as Appendix E to this General Order. "Generator Operation Standards" also includes any subsequent amendments or revisions to those standards.

2.15 "Initial Certification" means the first document filed by a Generating Asset Owner for a specific Generating Asset certifying that the Generating Asset Owner has adopted and is implementing a Maintenance Plan for that Generating Asset as required by Section 7.0 of this General Order, or an Operation Plan for that Generating Asset as required by Section 8.0.

2.16 "NERC" means the North American Electric Reliability Council or any successor thereto.

2.17 "Notify CPSD," "file with the Commission," "filing," or "file" means (unless otherwise indicated) to send a written communication by the U.S. Mail or a more expeditious express mail service to the Consumer Protection and Safety Division, Electric Generation Performance Program, at the address specified in subsection 15.2 of this General Order. These written communications are not filed with the Commission's Docket Office.

2.18 "Outage Coordination Protocol" means that document set forth as sheets 509-535 (effective October 13, 2000) in the ISO tariff to coordinate schedules for maintenance, repair and construction of generating units, sections of the ISO controlled grid, and interconnections, as well as any subsequent amendments to the document.

2.19 "Scheduling Logging for the ISO of California" or "SLIC" is a web-based system application and procedure, and any successor system, used by the ISO and external clients for scheduling of generator outages.

2.20 "Standards" is a collective term including all the individual standards enforced pursuant to this General Order: General Duty Standards, Generating Logbook Standards (Hydroelectric Energy), Generating Logbook Standards (Thermal Energy), Generator Maintenance Standards, Generator Operation Standards, and the Outage Coordination Protocol of the ISO, as set forth in subsection 9.1 of this General Order.

2.21 "Thermal Energy" is the production of electricity from heat generated from combustion of fuels, recovery of heat from discharges from a turbine or other device powered by the combustion of fuels, and geothermal energy.

3.0 REQUIRED COMPLIANCE

3.1 Basic Requirement. Unless exempted below, all Generating Asset Owners shall comply with all Standards and all sections of this General Order for each Generating Asset. A Generating Asset's eligibility for an exemption shall be determined by summing the nameplate rating generating capacities of all units at that plant or location.

3.2 Small Facilities. Generating Assets smaller than one megawatt are currently exempt from enforcement of the Standards pursuant to this General Order. Notwithstanding this exemption, Generating Asset Owners of such Generating Assets shall cooperate in any Commission or CPSD investigation, inspection, or audit by permitting access to those Generating Assets and by providing information (orally or written) or documents about the maintenance and operation of those Generating Assets if so requested by the Commission or CPSD.

3.3 Medium Facilities. Generating Assets of one megawatt or larger but smaller than 50 megawatts are exempt from Generator Logbook Standards (Hydroelectric Energy), Generator Logbook Standards (Thermal Energy), Generator Maintenance Standards, and Generator Operation Standards. Accordingly, such Generating Assets are subject to all requirements of this General Order except for sections 5, 6, 7, and 8. Notwithstanding these exemptions, such facilities must follow prudent practices as required by sections 5.2, 6.2, 7.4 and 8.4.

3.4 Switching Centers. Switching centers controlling 50 megawatts or more of hydroelectric power must keep logbooks concerning switching center operations for all remotely controlled Generating Assets of one megawatt or larger, as provided in section 6.2.

3.5 Hydroelectric Facilities. Hydroelectric facilities licensed by the Federal Energy Regulatory Commission are exempt from Sections 7.0, 8.0, 9.0, 10.3, 10.4 and 15.1.

4.0 GENERAL DUTY STANDARDS

4.1 The General Duty Standards are set forth in Appendix A to this General Order, as modified by any subsequent amendments or revisions to those standards.

4.2 Unless exempted, all Generating Asset Owners shall operate their Generating Assets in compliance with the General Duty Standards, until such time as the Commission implements and enforces detailed operation standards applicable to said Generating Assets, at which time the General Duty Standards will cease to be applicable.

4.3 Section 4.0 ceases to be applicable on and after December 20, 2004. General Duty Standards have been incorporated as necessary and appropriate for (a) facilities 50 megawatts and larger in the specific Maintenance and Operation Standards (Sections 7.0 and 8.0 along with Appendices D and E), and (b) medium facilities in Items 5.2, 6.2, 7.4 and 8.4.

5.0 GENERATOR LOGBOOK STANDARDS (THERMAL ENERGY)

5.1 Required Logbooks. Unless exempted, all Generating Asset Owners shall maintain facility logbooks in conformance with the Generator Logbook Standards (Thermal Energy) for those Generating Assets generating electricity by the use of thermal energy.

5.2 Exemption. Generating Assets of less than 50 megawatts are exempt from this section 5.0. Notwithstanding this exemption, each Generating Asset one megawatt or larger and smaller than 50 megawatts is required to maintain a reasonable log of operations and maintenance in a manner consistent with prudent industry practice.

5.3 Verified Statement. For each nonexempt Generating Asset, the Generating Asset Owner shall file one original verified statement with the Director of the Commission's CPSD. The verified statement shall include the following:

5.3.1 The identify of the Generating Asset owned by an electrical corporation or located in California (with relevant identification and contact information);

5.3.2 Confirmation that the facility is maintaining logbooks in compliance with the requirements for Generator Logbook Standards (Thermal Energy);

5.3.3 Confirmation that the compliance document required by subsection 5.6 has been prepared and is available at the generation facility site;

5.3.4 Confirmation that logbooks and the compliance document are being and will be updated and maintained as necessary; and

5.3.5 Signature, name, title, address, telephone number, facsimile number, electronic mail address, and other relevant information regarding the authorized representative of the Generating Asset Owner.

5.4 Time of Filing. For each Generating Asset in Active Service on the effective date of this General Order, the Generating Asset Owner shall file the Verified Statement within 27 days of the effective date of this General Order.

5.5 Time of Filing for Other Assets. For each Generating Asset placed in Active Service after the effective date of this General Order, the Generating Asset Owner shall file the Verified Statement within 30 days of the Generating Asset being placed in Active Service. When a Generating Asset Owner acquires a Generating Asset from an existing Generating Asset Owner, the new owner shall file a verified statement within 30 days of the effective date of the transfer of title or within 30 days of the transfer of possession, whichever date is later.

5.6 Compliance Document. Each Generating Asset Owner shall prepare and maintain a compliance document. The compliance document will be available at the generation facility site. The compliance document will show:

5.6.1 Where data required by the Generator Logbook Standards (Thermal Energy) is recorded and maintained.

5.6.2 How data is recorded and maintained (*e.g.,* hard copy or electronic).

5.6.3 Any necessary format or presentation protocols that must be understood to decipher the meaning of the electronically or manually maintained data.

5.6.4 Anything else reasonably necessary to fulfill or demonstrate compliance with the Generator Logbook Standards (Thermal Energy).

5.7 Electronic Database Minimum Requirements. Power plants which are in the planning stage on the effective date of this subsection, and all future power plants, shall employ electronic database systems for maintaining plant logbooks, and such systems shall meet the following minimum requirements. When logbooks are updated at an existing power plant to include electronic database systems, the logbook systems shall meet the following minimum requirements. The minimum requirements are that the logbook electronic database systems are:

5.7.1. Electronically searchable.

5.7.2. Secure (i.e., changes are tracked and documented).

6.0 GENERATOR LOGBOOK STANDARDS (HYDROELECTRIC ENERGY)

6.1 Required Logbooks. Unless exempted, all Generating Asset Owners shall maintain facility logbooks in conformance with the Generator Logbook Standards (Hydroelectric Energy) for those Generating Assets generating electricity by the use of hydroelectric energy.

6.2 Exemption. Locally-controlled generating assets smaller than 50 megawatts are exempt from the entirety of this section 6.0. Notwithstanding this exemption, each locally-controlled Generating Asset of one megawatt or larger is required to maintain a reasonable log of operations and maintenance in a manner consistent with prudent industry practice. Switching centers that control 50 megawatts or more do not fall under this exemption and must keep logbooks concerning switching center operations for all remotely-controlled Generating Assets of one megawatt or larger.

6.3 Verified Statement. For each nonexempt Generating Asset, the Generating Asset Owner shall file one original verified statement with the Director of the Commission's CPSD. The verified statement shall include at least the following:

6.3.1 The identify of the Generating Asset owned by an electrical corporation or located in California (with relevant identification and contact information);

6.3.2 Confirmation that the facility is maintaining logbooks in conformance with the Logbook Standards for Hydroelectric Facilities;

6.3.3 Confirmation that the compliance document required by subsection 6.6 has been prepared and is available at the generation facility site or remote control or switching center;

6.3.4 Confirmation that logbooks and the compliance document are being and will be updated and maintained as necessary; and

6.3.5 Signature, name, title, address, telephone number, facsimile number, electronic mail address, and other relevant information regarding the authorized representative of the Generating Asset Owner.

6.4 Time of Filing. For each Generating Asset in Active Service on the effective date of this General Order, the Generating Asset Owner shall file the Verified Statement within 27 days of the effective date of this General Order.

6.5 Time of Filing for Other Assets. For each Generating Asset placed in Active Service after the effective date of this General Order, the Generating Asset Owner shall file the Verified Statement within 30 days of the Generating Asset being placed in Active Service. When a Generating Asset Owner acquires a Generating Asset from an existing Generating Asset Owner, the new owner shall file a verified statement within 30 days of the effective date of the transfer of title or within 30 days of the transfer of possession, whichever date is later.

6.6 Compliance Document. Each Generating Asset Owner shall prepare and maintain a compliance document. The compliance document will be available at the generation facility site or remote control or switching center. The compliance document will show:

6.6.1 Where data required by the Logbook Standards for Hydroelectric Facilities is recorded and maintained.

6.6.2 How data is recorded and maintained (*e.g.*, hard copy or electronic).

6.6.3 Any necessary format or presentation protocols that must be understood to decipher the meaning of the electronically or manually maintained data.

6.6.4 Anything else reasonably necessary to fulfill or demonstrate compliance with the Logbook Standards for Hydroelectric Facilities.

7.0 GENERATOR MAINTENANCE STANDARDS

7.1 Applicability of Standards. All Generating Asset Owners shall maintain their Generating Assets in compliance with the Generator Maintenance Standards. Guidelines on how a Generating Asset Owner may comply are available from CPSD.

7.2 Maintenance Plan.

7.2.1. Contents. A Maintenance Plan is a paper or electronic document that shows how the Generating Asset Owner's maintenance practices and policies comply with each Maintenance Standard for each Generating Asset. The Maintenance Plan may be in the form of a narrative, index, spreadsheet, database, web site, or other form. The Maintenance Plan shall specifically identify the procedures and criteria that are used to comply with each Maintenance Standard. Existing equipment manuals, checklists, warranty requirements, and other documents may be identified to demonstrate compliance. If any of these documents are contradictory, the Maintenance Plan should resolve the contradiction. Where the Generating Asset Owner's maintenance does not satisfy a Maintenance Standard, the Maintenance Plan shall show how and when maintenance will be brought into compliance.

7.2.2. <u>Availability</u>. The current Maintenance Plan for each Generating Asset will be available in the vicinity of each Generating Asset or, in the case of a plant or facility with multiple Generating Assets, in the central business office located at that plant or facility. Upon CPSD's request, a Generating Asset Owner shall submit the current Maintenance Plan (or requested portion thereof) to CPSD in the manner specified in subsection 15.2 of this General Order.

7.2.3. <u>Initial Certification</u>. The Generating Asset Owner shall file an Initial Certification with CPSD that certifies either:

7.2.3.1. <u>Compliance.</u> The Generating Asset Owner has adopted and is implementing a Maintenance Plan that complies with all Generator Maintenance Standards, or

7.2.3.2. <u>Noncompliance.</u> The Generating Asset Owner has (a) identified and documented deficiencies in its maintenance practices and policies, and (b) adopted a course of corrective actions that is reasonably designed to achieve compliance with the Generator Maintenance Standards within 180 days of the date of Initial Certification.

7.2.4. <u>Filing Date for Initial Certification.</u>

7.2.4.1. <u>Asset in Active Service</u>. For each Generating Asset in Active Service on the effective date of Section 7.0 of this General Order, the Generating Asset Owner shall file the Initial Certification within 45 days of the effective date of this section of the General Order.

7.2.4.2. <u>Other Assets</u>: For each Generating Asset placed in Active Service after the effective date of Section 7.0 of this General Order, the Generating Asset Owner shall file the Initial Certification within 90 days of the Generating Asset being placed in Active Service. When a Generating Asset Owner acquires a Generating Asset from an existing Generating Asset Owner, the new owner shall file its Initial Certification within 90 days of the effective date of the transfer of title or within 90 days of the transfer of possession, whichever date is later.

7.3. Maintenance Plan Summary.

7.3.1. Contents. A Maintenance Plan Summary is a paper or electronic document that summarizes the Maintenance Plan. It shall summarize how the Generation Asset Owner’s maintenance complies with each Maintenance Standard. It shall be in the format and include the content elements specified by the Commission’s Executive Director. Where the Generating Asset Owner’s maintenance does not satisfy a Maintenance Standard, the Maintenance Plan Summary shall summarize how and when maintenance will be brought into compliance.

7.3.2. Filing Date.

7.3.2.1. Initial Filing for Assets in Active Service. For each Generating Asset in Active Service, the Generating Asset Owner shall file a Maintenance Plan Summary with CPSD within 120 days of the date the Executive Director specifies the contents and format.

7.3.2.2. Other Assets: For each Generating Asset placed in Active Service after the effective date of Section 7.0 of this General Order, the Generating Asset Owner shall file the Maintenance Plan Summary at the same time as it files its Initial Certification. When a Generating Asset Owner acquires a Generating Asset from an existing Generating Asset Owner, the new owner shall file its Maintenance Plan Summary at the same time it files its Initial Certification.

7.3.2.3. Updates. The Maintenance Plan Summary shall be updated and refiled with CPSD every other year pursuant to a schedule to be determined by CPSD.

7.4. Exemption. Generating Assets smaller than 50 megawatts are exempt from the entirety of Section 7.0. Notwithstanding this exemption, generating assets one megawatt or larger and smaller than 50 megawatts are required to observe the following requirements:

7.4.1. Each facility shall be operated in a safe, reliable, and efficient manner that reasonably protects the public health and safety of California residents, businesses, and the community.

7.4.2. Each facility shall be operated so as to be reasonably available to meet the demand for electricity, and promote electric supply system reliability, in a manner consistent with prudent industry practice.

7.4.3. Each facility shall be operated in a reasonable and prudent manner consistent with industry standards while satisfying the legislative finding that each facility is an essential facility providing a critical and essential good to the California public.

8.0 GENERATOR OPERATION STANDARDS

8.1 Applicability of Standards. All Generating Asset Owners shall operate their Generating Assets in compliance with the Generator Operation Standards. Guidelines on how a Generating Asset Owner may comply are available from CPSD.

8.2 Operation Plan.

8.2.1. Contents. An Operation Plan is a paper or electronic document that shows how the Generating Asset Owner's operation practices and policies comply with each Operation Standard for each Generating Asset. The Operation Plan may be in the form of a narrative, index, spreadsheet, database, web site, or other form. The Operation Plan shall specifically identify the procedures and criteria that are used to comply with each Operation Standard. Existing equipment manuals, checklists, warranty requirements, and other documents may be identified to demonstrate compliance. If any of these documents are contradictory, the Operation Plan should resolve the contradiction. Where the Generating Asset Owner's operation does not satisfy an Operation Standard, the Operation Plan shall show how and when operation will be brought into compliance.

8.2.2. Availability. The current Operation Plan for each Generating Asset will be available in the vicinity of each Generating Asset or, in the case of a plant or facility with multiple Generating Assets, in the central business office located at that plant or facility. Upon CPSD's request, a Generating Asset Owner shall submit the current Operation Plan (or requested portion thereof) to CPSD in the manner specified in subsection 15.2 of this General Order.

8.2.3. Initial Certification. The Generating Asset Owner shall file an Initial Certification with CPSD that certifies either:

8.2.3.1. Compliance. The Generating Asset Owner has adopted and is implementing an Operation Plan that complies with all Generator Operation Standards, or

8.2.3.2. Noncompliance. The Generating Asset Owner has (a) identified and documented deficiencies in its operation practices and policies, and (b) adopted a course of corrective actions that is reasonably designed to achieve compliance with the Generator Operation Standards within 90 days of the date of Initial Certification.

8.2.4. Filing Date for Initial Certification.

8.2.4.1. Asset in Active Service. For each Generating Asset in Active Service on the effective date of Section 8.0 of this General Order, the Generating Asset Owner shall file the Initial Certification within 90 days of the effective date of this section of the General Order.

8.2.4.2. Other Assets: For each Generating Asset placed in Active Service after the effective date of Section 8.0 of this General Order, the Generating Asset Owner shall file the Initial Certification within 90 days of the Generating Asset being placed in Active Service. When a Generating Asset Owner acquires a Generating Asset from an existing Generating Asset Owner, the new owner shall file its Initial Certification within 90 days of the effective date of the transfer of title or within 90 days of the transfer of possession, whichever date is later.

8.3 Operation Plan Summary.

8.3.1. Contents. An Operation Plan Summary is a paper or electronic document that summarizes the Operation Plan. It shall summarize how the Generation Asset Owner’s operation complies with each Operation Standard. It shall be in the format and include the content elements specified by the Commission’s Executive Director. Where the Generating Asset Owner’s operation does not satisfy an Operation Standard, the Operation Plan Summary shall summarize how and when operation will be brought into compliance.

8.3.2 Filing Date.

8.3.2.1. Initial Filing for Assets in Active Service. For each Generating Asset in Active Service, the Generating Asset Owner shall file an Operation Plan Summary with CPSD within 120 days of the date the Executive Director specifies the contents and format.

8.3.2.2. Other Assets: For each Generating Asset placed in Active Service after the effective date of Section 8.0 of this General Order, the Generating Asset Owner shall file the Operation Plan Summary at the same time as it files its Initial Certification. When a Generating Asset Owner acquires a Generating Asset from an existing Generating Asset Owner, the new owner shall file its Operation Plan Summary at the same time it files its Initial Certification.

8.3.2.3. Updates. The Operation Plan Summary shall be updated and refiled with CPSD every other year pursuant to a schedule to be determined by CPSD.

8.4. Exemption. Generating Assets smaller than 50 megawatts are exempt from the entirety of Section 8.0. Notwithstanding this exemption, generating assets one megawatt or larger and smaller than 50 megawatts are required to observe the following requirements:

8.4.1. Each facility shall be operated in a safe, reliable, and efficient manner that reasonably protects the public health and safety of California residents, businesses, and the community.

8.4.2. Each facility shall be operated so as to be reasonably available to meet the demand for electricity, and promote electric supply system reliability, in a manner consistent with prudent industry practice.

8.4.3. Each facility shall be operated in a reasonable and prudent manner consistent with industry standards while satisfying the legislative finding that each facility is an essential facility providing a critical and essential good to the California public.

9.0 INDEPENDENT SYSTEM OPERATOR (ISO) OUTAGE COORDINATION PROTOCOL

9.1 Compliance. All Generating Asset Owners shall comply with the Outage Coordination Protocol adopted by the California Independent System Operator.

10.0 INFORMATION REQUIREMENTS

10.1 Provision of Information. Upon CPSD's request, a Generating Asset Owner shall provide information in writing concerning (a) a Generating Asset; (b) the operation or maintenance of the Generating Asset; (c) the, Initial Certification, Recertification, Corrective Plan, or Notice of Material Change pertaining to the Generating Asset; (d) any Maintenance, Operation, or Corrective Plans pertaining to the Generating Asset; (e) the design, performance, or history of a Generating Asset; (f) event or outage data concerning a Generating Asset including, but not limited to, unavailability reports or outage cause reports; (g) accounts, books, contracts, memoranda, papers, records, inspection reports of government agencies or other persons; and (h) any other documents or materials. These information requests shall be reasonably related to the requirements of this General Order. If CPSD has indicated when, where, and in what form the information is to be provided, the Generating Asset Owner will provide the information in that manner and will otherwise cooperate with CPSD in the provision of information. Except for an exigent circumstance, a minimum of five business days will be provided for the response. If CPSD determines the existence of an exigent circumstance, CPSD may establish a shorter response period for information reasonably required for CPSD to understand or respond to the exigent circumstance.

10.2 Authorization for Release of Information. Upon CPSD's request, a Generating Asset Owner shall authorize governmental agencies to release and provide directly to CPSD any information in that agency's or entity's possession regarding the operation or maintenance of that Generating Asset Owner's Generating Asset. To the extent such agencies have designated information as confidential, CPSD will not disclose that information to the public unless (a) CPSD has been authorized by that agency or entity to disclose the information; (b) the Commission orders or permits disclosure; or (c) a court of competent jurisdiction orders or permits disclosure. Where appropriate, the Commission may enter into a confidentiality agreement with such agency. Upon CPSD's request, a Generating Asset Owner shall authorize other persons or entities to release and provide directly to CPSD any information in the possession of that person or entity regarding the operation or maintenance of that Generating Asset Owner's Generating Asset, in which case the Generating Asset Owner may make a claim of confidentiality pursuant to subsection 15.4 of this General Order.

10.3 Generating Asset Information. A Generating Asset Owner's obligations to provide or authorize the release of information specified in subsections 10.1 and 10.2 include, but are not limited by, the following specific requirements concerning Generating Assets:

10.3.1 Monthly Report to ISO. As required by Public Utilities Code § 761.3(g), each Generating Asset Owner owning or operating a Generating Asset in California with a rated maximum capacity of 50 megawatts or greater shall provide a monthly report to the ISO (once the ISO has announced it is ready to receive such monthly reports) that identifies any periods during the preceding month when the unit was unavailable to produce electricity or was available only at reduced capacity. The report will include the reasons for any such unscheduled unavailability or reduced capacity.

10.3.2 Submission of Information to NERC. Except for Generating Assets for which NERC does not accept data, each Generating Asset Owner shall submit generator design, performance, and event data to NERC for inclusion in GADS. Within the categories of data that NERC accepts, CPSD may specify the data the Generating Asset Owner must submit to NERC. If requested by CPSD, a Generating Asset Owner shall concurrently provide CPSD with a copy of all data submitted to NERC for inclusion in GADS.

10.3.3 Transitional Compliance Period. If upon the effective date of this General Order, a Generating Asset Owner is not submitting generator design, performance, or event data concerning a Generating Asset to NERC for inclusion in GADS, the Generating Asset Owner shall do so within a transitional period of 180 days of the effective date of this General Order. Upon CPSD's request, the Generating Asset Owner shall provide comparable data directly to CPSD until the Generating Asset Owner begins to submit that information to NERC and the information becomes available to CPSD.

10.3.4 Historical Information. Upon CPSD's request, and for any period after January 1, 1998, a Generating Asset Owner shall provide CPSD and/or NERC with generator design, performance, or event data concerning a Generating Asset.

10.3.5 Nuclear Facility Data.

10.3.5.1. As required by Public Utilities Code § 761.3(d)(1)(B), each Generating Asset Owner who owns or operates a nuclear powered generating facility shall file with the

Oversight Board and CPSD an annual schedule of maintenance, including repairs and upgrades, for each generating facility. The annual schedule of maintenance shall be filed with CPSD by October 15 for the maintenance scheduled for the following calendar year, and shall be updated quarterly thereafter on the fifteenth day of each January, April and July. The first such schedule shall be filed by October 15, 2005. The filing with CPSD shall be the same as the filing with the ISO (pursuant to Section 2.2 of the ISO's Outage Coordination Protocol or other ISO requirement) or, if different, shall clearly indicate that it is different and briefly summarize the differences. The owner or operator of a nuclear powered generation facility shall make good faith efforts to conduct its maintenance in compliance with its filed plan and shall report to the Oversight Board and the ISO any significant variations from its filed plan.

10.3.5.2. As required by Public Utilities Code § 761.3(d)(1)(C), each Generating Asset Owner who owns or operates a nuclear powered generating facility shall report on a monthly basis to the Oversight Board and CPSD all actual planned and unplanned outages of each facility during the preceding month. The report shall be filed with CPSD by the 10th day of each month for the period covering the immediately prior month (e.g., filed by September 10 for outages in August), with the first report filed by September 10, 2005. The filing with CPSD shall be the same as the filing with the ISO (pursuant to the ISO's Outage Coordination Protocol, or other ISO requirement) or, if different, shall clearly indicate that it is different and briefly summarize the differences. The owner or operator of a nuclear powered generating facility shall report on a daily basis to the Oversight Board and the ISO the daily operational status and availability of each facility.

10.3.6 <u>Qualifying Facility Data:</u> Pursuant to Public Utilities Code § 761.3(d)(2)(B):

10.3.6.1. An electrical corporation that has a contract with a qualifying small power production facility, or a qualifying cogeneration facility, with a name plate rating of 10 megawatts or greater, shall report the information specified below (§ 10.3.6.4) to the

Oversight Board and CPSD. The specified information shall be reported by the electrical corporation only if the information is provided to the electrical corporation by the qualifying facility pursuant to a contract.

10.3.6.2. Each qualifying facility with a name plate rating of 10 megawatts or greater shall report the information specified below (§ 10.3.6.4) directly to the Oversight Board and the ISO if the information is not provided to an electrical corporation by the qualifying facility pursuant to a contract with the electrical corporation.

10.3.6.3. Each electrical corporation shall file a report with CPSD, the Oversight Board and ISO by the thirty-first day of March covering the period of the immediately prior calendar year (e.g., January 1 through December 31). The first report shall be filed by March 31, 2006, and be updated annually thereafter on each subsequent thirty-first day of March. The report shall list each qualifying facility with which the electrical corporation had a contract for part or all of the prior calendar year. The list shall identify whether or not the information specified below (§ 10.3.6.4) was provided by the qualifying facility to the electrical corporation pursuant to a contract. If so, the electrical corporation shall include the specified information in its report. If not, the electrical corporation need not provide the specified information in its report, but the qualifying facility shall provide the information directly to the Oversight Board and the ISO. On the same day the report is filed with CPSD, the electrical corporation shall serve a copy of its report on each qualifying facility which it determines did not provide the specified information pursuant to a contract along with a cover letter. The cover letter shall inform the qualifying facility that the qualifying facility must provide the data specified below (§ 10.3.6.4) directly to the Oversight Board and ISO pursuant to Pub. Util. Code § 761.3(d)(2)(B), or pursue the matter with the electrical corporation within 30 days of the date of the letter.

10.3.6.4. Specified Information: The maintenance schedules for each qualifying facility, including all actual planned and unplanned outages of the qualifying facility, and the daily operational status and availability of the qualifying facility.

10.4 Safety-related Incidents. Within 24 hours of its occurrence, a Generating Asset Owner shall report to the Commission's emergency reporting web site any safety-related incident involving a Generating Asset. If internet access is unavailable, the Generating Asset Owner may report using the backup telephone system. Such reporting shall include any incident that has resulted in death to a person; an injury or illness to a person requiring overnight hospitalization; a report to Cal/OSHA, OSHA, or other regulatory agency; or damage to the property of the Generating Asset Owner or another person of more than $50,000. The Generating Asset Owner shall also report any other incident involving a Generating Asset that has resulted in significant negative media coverage (resulting in a news story or editorial from one media outlet with a circulation or audience of 50,000 or more persons) when the Generating Asset Owner has actual knowledge of the media coverage. If not initially provided, a written report also will be submitted within five business days of the incident. The report will include copies of any reports concerning the incident that have been submitted to other governmental agencies.

11.0 AUDITS, INSPECTIONS, AND INVESTIGATIONS

11.1 General Requirement. A Generating Asset Owner shall cooperate with CPSD during any audit, inspection, or investigation (including but not limited to tests, technical evaluations, and physical access to facilities). An audit, inspection, or investigation may extend to any records pertaining to the specifications, warranties, logbooks, operations, or maintenance of the Generating Asset. Generating Asset Owners, as entities subject to ongoing regulation under this General Order, are hereby notified that these audits, inspections, or investigations will occur on a regular, systematic, and recurring basis supplemented as needed by additional audits, inspections, or investigations to ensure compliance with this General Order.

11.2 Interviews and Testimony. Upon CPSD’s request, a Generating Asset Owner, its employees, and its contractors shall provide testimony under oath or submit to interviews concerning a Generating Asset, its specifications, warranties, logbooks, operations, or maintenance.

11.3 Tests and Technical Evaluations. Upon CPSD’s request, a Generating Asset Owner shall conduct a test or technical evaluation of a Generating Asset (or shall contract with an auditor, consultant, or other expert, mutually selected by CPSD and the Generating Asset Owner, to conduct the test or technical evaluation) so as to provide information reasonably necessary for determining compliance with the Standards enforced by this General Order. The Generating Asset Owner will pay all costs and liabilities resulting from such tests or technical evaluations, except for CPSD’s own staff expenses. If a test or technical evaluation may reasonably result in the reduced or suspended generation from a Generating Asset, the Generating Asset Owner shall notify CAISO as soon as the Generating Asset Owner becomes aware of the test or technical evaluation. To the extent feasible, Commission staff shall schedule such tests or evaluations to minimize generation disruptions and shall, as appropriate, coordinate its activities with CAISO.

11.4 Preservation of Records. A Generating Asset Owner shall retain all records including logbooks, whether in paper or electronic format, concerning the operation and maintenance of a Generating Assert for five years. Any subsequent modification to a record must show the original entry, the modified entry, the date of the modification, the person who made or authorized the modification, and the reason for the modification.

11.5 Third-Party Audits, Tests, or Technical Evaluations. During an audit, test, or technical evaluation conducted under this section 11.0, a Generating Asset Owner may submit, or authorize access to, audits, tests, inspections, or technical evaluations previously performed by government agencies, insurance companies, or other persons or entities. While this third-party information may be relevant to the inquiry, the information may not be sufficient, in and of itself, to demonstrate compliance with the standards. CPSD will determine whether a third-party audit, test, inspection, or technical evaluation is sufficient for the purposes of this section 11.0.

12.0 VIOLATIONS

12.1 Violation. A violation is the failure of a Generating Asset Owner to comply with a requirement of this General Order. A Generating Asset's Owner's lawful and reasonable assertion of its rights under this General Order or state or federal law will not be considered a failure to cooperate under any provision of this General Order.

12.2 Retaliation. Any adverse action, as that term has been used and applied under Title VII of the Civil Rights Act, 42 U.S.C. § 2000e *et seq*. or the California Fair Employment and Housing Act, Gov. Code § 12940 *et seq.*, taken by a Generating Asset Owner against an officer, employee, agent, contractor, subcontractor, or customer of a Generating Asset Owner for reporting a Violation of the Standards, reporting a Violation of this General Order, or providing information during the course of an audit, inspection, or investigation is also a Violation of this General Order.

13.0 COMMISSION PROCEEDINGS

13.1 Formal Enforcement Proceedings. In responding to alleged Violations of this General Order, the Commission may initiate any formal proceeding authorized by the California Constitution, the Public Utilities Code, other state and federal statutes, court decisions or decrees, the Commission's RULES OF PRACTICE AND PROCEDURE, or prior Commission decisions or rulings.

13.2 Other Commission Remedies. In enforcing the provisions of this General Order, the Commission may pursue any other remedy authorized by the California Constitution, the Public Utilities Code, other state or federal statutes, court decisions or decrees, or otherwise by law or in equity.

13.3 Imposition of Fines for Specified Violations

13.3.1 Specified Violations. For specified Violations of this General Order, the Director of CPSD and his/her designee may assess a scheduled fine or, in the alternative, proceed with any remedy otherwise available to CPSD or the Commission. Scheduled fines may be assessed by CPSD only for the Violations referenced in subsection 13.3.2 of this General Order. CPSD shall notify the Generating Asset Owner, in writing, of any specified Violations and assessed fines, and shall include notice of the right to contest the fine as set forth in subsections 13.3.4 and 13.3.8 of this General Order. No fine assessed by CPSD pursuant to this subsection shall become payable if contested by the Generating Asset Owner pursuant to subsection 13.3.4.

13.3.2 Schedule of Fines. The Specified Violations and the corresponding fines that may be assessed are set forth in Appendix F to this General Order. The Commission may modify this schedule of fines no earlier than 30 days after providing reasonable notice and affording interested persons with an opportunity to comment.

13.3.3 Acceptance of Assessed Fine. A Generating Asset Owner may either accept or appeal the assessment of a scheduled fine. In the event the Generating Asset Owner accepts the assessment and elects to pay the scheduled fine in lieu of an appeal, the Generating Asset Owner shall so notify CPSD in writing within 30 days of the assessment, shall pay the fine in full, and shall bring itself into compliance with the applicable provision(s) of the General Order within 30 days of the written acceptance. Fines shall be submitted to CPSD for payment into the State Treasury to the credit of the General Fund. Fines are delinquent if not paid within 30 days of the Generating Asset Owner's acceptance; and, thereafter, the balance of the fine bears interest at the legal rate for judgments.

13.3.4 Appeal of Citation. If a Generating Asset Owner appeals the citation and assessment of a scheduled fine, the Generating Asset Owner must file its Notice of Appeal within 30 days of the date of the citation. In the event of such a contest, staff shall, at its discretion, proceed with evidentiary hearings on the appeal, or withdraw the citation where facts and circumstances warrant such action and provide a written notice of withdrawal to the Generating Asset Owner. In the event of an appeal, any remedy available may be imposed, and the remedy shall not be mandated or limited to the scheduled fine.

13.3.5 Default. If a Generating Asset Owner (a) notifies CPSD of acceptance of a scheduled fine and fails to pay the full amount of the fine within 30 calendar days of the date of the written acceptance of the fine; or (b) fails to notify CPSD of acceptance of a scheduled fine and fails to serve a written notice of appeal on the Director of CPSD in the manner and time required, the Generating Asset Owner shall be in default, and the fine contained in the citation shall become final. Upon default, any unpaid balance of a citation fine shall accrue interest at the legal rate of interest for judgments, and CPSD and the Commission may take any action provided by law to recover unpaid penalties and ensure compliance with applicable statutes and Commission orders, decisions, rules, directions, demands or requirements.

13.3.6 Form and Content of Citations. The Director of CPSD or his/her designee is authorized to draft a citation and present it to the Generating Asset Owner. If after investigation, CPSD finds violations of any of the Specified Violations, CPSD may issue a citation and levy the corresponding fine set forth in Appendix F to this General Order. Citations shall include the following:

13.3.6.1 Citations shall clearly delineate the alleged violations and fine amount and shall summarize CPSD's evidence.

13.3.6.2 Citations shall include an explanation of how to file an appeal, including an explanation of the Generating Asset Owner's right to have a hearing, to have a representative at the hearing, and to request a transcript of the hearing.

13.3.6.3 Citations shall be supported by evidence documenting the alleged violation and this information, if not voluminous, shall be provided with the citation. If the evidence is voluminous, CPSD may summarize the evidence and make it available for timely inspection by the Generating Asset Owner.

13.3.7 Service of Citations. Citations shall be sent by first class mail to the Generating Asset Owner's authorized representative as set forth in the most recent verified statement or certification records on file with the Commission, or the agent for service of process of the corporation or LLC or other business entity filed with the Secretary of State of California.

13.3.8 Appeals. Appeals will be conducted as follows:

13.3.8.1 The appeal shall be brought by Filing a written Notice of Appeal upon the Director of CPSD within 30 days from the date of the citation. The Notice of Appeal must indicate the grounds for the appeal.

13.3.8.2 CPSD shall promptly advise the Chief Administrative Law Judge upon receipt of a timely Notice of Appeal. The Chief Administrative Law Judge shall designate an Administrative Law Judge to hear appeals under this resolution.

13.3.8.3 Upon advice from CPSD that a citation has been appealed, the Chief Administrative Law Judge shall forward the matter to the assigned Administrative Law Judge, who shall promptly set the matter for hearing. The Administrative Law Judge may, for good cause shown or upon agreement of the parties, grant a reasonable continuance of the hearing.

13.3.8.4 Appeals of citations shall be heard in the Commission's San Francisco or Los Angeles hearing rooms on regularly scheduled days. Appeals shall be calendared accordingly, except that a particular matter may be re-calendared at the direction of the Administrative Law Judge.

13.3.8.5 The respondent may order a transcript of the hearing, and shall pay the cost of the transcript in accordance with the Commission's specified procedures.

13.3.8.6 The respondent may be represented at the hearing by an attorney or other representative, but any such representation shall be at the respondent's expense.

13.3.8.7 At an evidentiary hearing, CPSD bears the burden of proof and accordingly shall open and close. The Administrative Law Judge may, in his or her discretion to better ascertain truth, alter the order of presentation. Formal rules of evidence do not necessarily apply, and all relevant and reliable evidence may be received in the discretion of the Administrative Law Judge.

13.3.8.8 Ordinarily, the case shall be submitted at the close of the hearing. The Administrative Law Judge, upon a showing of good cause, may keep the record open for a reasonable period to permit a party to submit additional evidence or argument.

13.3.8.9 The Administrative Law Judge shall issue an order resolving the appeal not later than 30 days after the appeal is submitted, and the order shall be placed on the first available agenda, consistent with the Commission's applicable rules.

13.3.9 Ex Parte Communications. From the date that CPSD issues a citation to and including the date when the final order is issued, neither the Generating Asset Owner nor CPSD staff, or any agent or other person acting on behalf of the Generating Asset Owner or CPSD, may communicate regarding the appeal, orally or in writing, with a Commissioner, Commissioner's advisor, or Administrative Law Judge, except as expressly permitted under these procedures.

14.0 SANCTIONS

14.1 Sanctions. Consistent with prior Commission decisions, the following factors will be considered in determining the sanctions to be imposed against a Generating Asset Owner for violating this General Order:

14.1.1 The diligence and reasonableness demonstrated by the Generating Asset Owner in attempting to prevent a Violation, in detecting a Violation, in disclosing a Violation to CPSD and other requisite government agencies, and in rectifying a Violation.

14.1.2 The seriousness of the Violation in terms of injury, if any, to persons, property, and the integrity of the regulatory process.

14.1.3 The number and seriousness of any prior Violations.

14.1.4 The Generating Asset Owner's financial resources.

14.1.5 The totality of the circumstances in furtherance of the public interest.

14.1.6 Commission precedent.

14.2 Mitigation of Sanctions. The following factors may be considered as mitigation in considering the sanctions to be imposed for violating this General Order:

14.2.1 The Generating Asset Owner's demonstrated, substantial compliance with any guidelines or other guidance issued by the Committee or the Executive Director concerning the Standards and requirements of this General Order.

14.2.2 Conflicting or competing requirements imposed on the Generating Asset Owner by other governmental agencies; warranty requirements; power contract requirements; or requirements imposed by the California Independent System Operator, NERC, or the Western Electricity Coordinating Council.

14.2.3 Penalties already imposed on the Generating Asset Owner by other governmental agencies, contracts, or other regulatory bodies for the same acts or omissions resulting in Violations of this General Order.

14.2.4 The Generating Asset Owner's demonstrated cooperation in assisting the Commission and CPSD in the enforcement of this General Order.

14.3 Enhancement of Sanctions. The following enhancing factors may be considered in increasing the sanctions that would otherwise be imposed for violating this General Order:

14.3.1 The Generating Asset Owner's demonstrated, substantial noncompliance with any guidelines or other guidance issued by the Committee or the Executive Director concerning the Standards and requirements of this General Order.

14.3.2 The Generating Asset Owner's repetitive violations of the Standards, the Public Utilities Code, or this General Order.

14.3.3 The Generating Asset Owner's violations of the Standards or this General Order have resulted in the failure to deliver electricity as scheduled by the Independent System Operator or in actual power outages.

14.3.4 The Generating Asset Owner's failure to report, as required, or cooperate with the Commission and CPSD in any investigation, audit, inspection, test, or technical evaluation.

14.3.5 The Generating Asset Owner's efforts to impede or frustrate CPSD in the enforcement of this General Order. A Generating Asset Owner's lawful and reasonable assertion of its rights under this General Order or state or federal law will not be used to enhance a sanction.

14.4 Not Applicable to Specified Fines. The factors set forth in subsections 14.1, 14.2, and 14.3 do not apply to those specified Violations, set forth in Appendix F, for which a scheduled fine has been assessed against and accepted by a Generating Asset Owner, pursuant to subsection 13.3 of this General Order.

15.0 MISCELLANEOUS PROVISIONS

15.1 Ongoing Reporting Obligations.

15.1.1. Periodic Recertifications. For each Generating Asset not exempted under subsections 5.2, 6.2, 7.4, or 8.4, the Generating Asset Owner shall file a recertification that it continues to maintain logbooks as required under sections 5.0 or 6.0 of this General Order and continues to implement a Maintenance Plan and an Operation Plan, as described in Sections 7.0. and 8.0. of this General Order, in a manner that complies with the Generator Maintenance Standards and Generator Operation Standards. The recertifications will be filed every other year pursuant to a schedule to be determined by CPSD.

15.1.2. Notice of Material Change. A Generating Asset Owner shall notify CPSD of (a) any previously unreported deficiency in its operation or maintenance practices (including logbook practices); or (b) any correction or amendment to the Initial Certification, Recertification, Maintenance Plan Summary or Operation Plan Summary pertaining to a Generating Asset that is required because of a material change in the operation or maintenance of the Generating Asset. A material change is a modification of the characteristics, operation, or maintenance of a Generating Asset when that change reasonably could be expected to significantly improve or degrade the reliability, output, or performance of the Generating Asset. The Generating Asset Owner shall file a Notice of Material Change within 30 days of the known occurrence of the material change.

15.2 Filings and Submissions. All Certifications, Recertifications, Notices, or other submissions of information or data in response to Commission requests and the requirements of this General Order will be filed directly with the CPSD, Electric Generation Performance Program, at 505 Van Ness Ave., San Francisco, CA 94102. Documents must be received by CPSD on the day they are due. In addition to or instead of paper filings, CPSD may require electronic submissions of all filings that reasonably can be created in that format.

15.3 Oath, Affirmation or Verification. Each formal filing with the Commission (i.e., Certification, Recertification, Notice, Contest, Maintenance Plan Summary, Operation Plan Summary, Updates of Plan Summaries) will be under the written oath, affirmation, or verification of a corporate officer of the Generating Asset Owner.

15.4 Confidentiality. All claims of confidentiality related to the implementation and enforcement of this General Order must be based on the provisions of this subsection.

15.4.1 Burden of Establishing Privilege. A Generating Asset Owner has the burden of establishing any privilege that it claims regarding requested documents or information. A Generating Asset Owner has the right to claim an absolute statutory privilege, such as the attorney-client privilege, for information requested. If such a privilege applies, the Generating Asset is not required to provide such information to the Commission. However, the Generating Asset Owner must specify the statutory privilege applicable to particular information. A Generating Asset Owner may also assert a claim of privilege for documents or information provided to the Commission on a confidential basis, such as the trade secret privilege. In such cases, the Generating Asset Owner must assert the specific privilege(s) it believes the Generating Asset Owner and/or the Commission holds and why the document, or portion of document, should be withheld from public disclosure.

15.4.2 Confidentiality Claims Requiring Balancing of Interests. If a confidentiality request is based on a privilege or exemption requiring a balancing of interests for and against disclosure, rather than on a statutory prohibition against disclosure or a privilege held by the Generating Asset Owner, the Generating Asset Owner must demonstrate why the public interest in an open process is clearly outweighed by the need to keep the material confidential. A Generating Asset Owner which is a public utility should not cite

Public Utilities Code § 583 as a sole basis for the Commission's nondisclosure of information since, as noted in D.91-12-019, § 583 does not create for a utility any privilege that may be asserted against the Commission's disclosure of information or designate any specific types of documents as confidential.

15.4.3 Requirements. A Generating Asset Owner desiring confidential treatment of information provided to the Commission shall at a minimum:

15.4.3.1 Specifically indicate the information that the Generating Asset Owner wishes to be kept confidential, clearly marking each page, or portion of a page, for which confidential treatment is requested.

15.4.3.2 Identify the length of time the Generating Asset Owner believes the information should be kept confidential and provide a detailed justification for the proposed length of time. The business sensitivity of information generally declines over time and the balancing of interests for and against disclosure may change accordingly.

15.4.3.3 Identify any specific provision of state or federal law the Generating Asset Owner believes prohibits disclosure of the information for which it seeks confidential treatment and explain in detail the applicability of the law to that information.

15.4.3.4 Identify any specific privilege the Generating Asset Owner believes it holds and may assert to prevent disclosure of information, and explain in detail the applicability of that law to the information for which confidential treatment is requested. For example, if a Generating Asset Owner asserts that information is subject to a trade secret privilege (Evidence Code § 1060 *et seq.*, the Generating Asset Owner must explain how the information fits the definition of a trade secret (*e.g.*, how the information provides the holder with economic value by virtue of its not being generally known to the public and what steps the Generating Asset Owner has taken to maintain the secrecy of the information.

15.4.3.5 Identify any specific privilege the Generating Asset Owner believes the Commission holds and may assert to prevent disclosure of information and explain in detail the applicability of that privilege to the information for which confidential treatment is requested. For example, if the privilege is one that involves a balancing of public interests for and against disclosure, such as the official information privilege in Evidence Code § 1040(b)(2), the Generating Asset Owner must demonstrate that the information at issue falls within the definition of official information and the Commission's disclosure of the information is against the public interest because there is a necessity for preserving the confidentiality of the information that outweighs the necessity for disclosure in the interest of justice.

15.4.3.6 State whether the Generating Asset Owner would object if the information were disclosed in an aggregated format.

15.4.3.7 State whether and how the Generating Asset Owner keeps the information confidential and whether the information has ever been disclosed to a person other than an employee of the Generating Asset Owner.

15.4.4 Duration of Confidentiality Claims. A confidentiality claim, whether or not specifically acted upon by the Commission, expires on the earliest of the following dates: (a) at the end of the period specified by the Generating Asset Owner pursuant to subsection 15.4.3.2; (b) at the end of a period specified in a specific Commission ruling or decision; or (c) two years after the claim was first asserted before the Commission. To reassert the confidentiality claim, the Generating Asset Owner must again satisfy the requirements of this subsection 15.4 before the end of the confidentiality period. Staff may disclose information provided under a claim of confidentiality if the Commission has already authorized disclosure of that class of information.

15.5 Disclosure to Other Agencies. If the Commission provides any information to another governmental agency (whether in response to a request, subpoena, or on the Commission's own initiative), the Commission will ensure that the information is accompanied with a copy of any confidentiality claim that has been submitted pursuant to subsection

15.4 of this General Order. Where appropriate, the Commission may enter into a confidentiality agreement with the other governmental agency. When the Commission obtains information indicating a possible violation of any federal, state, or local law, the Commission may provide that information to the appropriate governmental agency. Even though a claim of confidentiality has been made, the claim of confidentiality will not prevent the Commission from providing that information to the appropriate governmental agency.

15.6 Compliance with Other Laws. Pursuant to California Public Utilities Code § 761.3(f), enforcement of any Standard will not modify, delay, or abrogate any deadline, standard, rule or regulation that is adopted by a federal, state, or local agency for the purposes of protecting public health or the environment including, but not limited to, any requirements imposed by the California State Air Resources Board, an air pollution control district, or an air quality management district pursuant to Division 26 (commencing with section 39000) of the California Health and Safety Code.

15.7 Committee Amendments. The Committee may file any amendment to the Standards, duly adopted by the Committee, with the Commission's Docket Office. The Committee shall serve the amendment on CPSD or its successor. The amendment will become enforceable by the Commission under this General Order on the thirtieth day following publication of the notice of filing in the Commission's *Daily Calendar* (or successor publication). In its filing of any amendment, the Committee shall reference this General Order and request publication of the notice of the filing in the Commission's *Daily Calendar* (or any successor publication). In the case of any amendments, the Executive Director will make the appropriate codification revisions to the appendices to this General Order.

15.8. Duration of Standards. When the Committee ceases to exist pursuant to Public Utilities Code § 761.3(b)(3), the Standards, as on file with the Commission on the date the Committee ceases to exist, will remain effective and enforceable by the Commission under this General Order. The Commission thereafter may amend the Standards in a rulemaking proceeding and enforce the Standards as amended, all in exercise of its responsibilities under the California Constitution, Public Utilities Code, and this General Order.

15.9 Extension of Time. For good cause shown, a Generating Asset Owner may request the extension of any deadline established in or pursuant to this General Order. The request must be in writing and submitted in advance of the deadline to the Executive Director or the Executive Director's designee. Pursuant to the request, the Executive Director may grant one or more extensions, if the Executive Director determines that a good and sufficient reason exists for the extension. The extension will specifically indicate its duration.

15.10 Guidance. The Executive Director may promulgate forms, instructions, advisories, and other guidance to Generating Asset Owners aiding them in achieving compliance with this General Order.

15.11 Severability. If a court of competent jurisdiction determines that any provision of this General Order is void or unenforceable, the Commission will continue to enforce the remainder of the General Order without reference to the void or unenforceable provision.

15.12 Effective Date. This General Order is effective on the third day following the mailing of the Commission's decision adopting this General Order. The initial Commission decision adopting this General Order was mailed May 7, 2004, and the General Order became effective May 10, 2004. Changes to this General Order are effective on the third day following the mailing of the Commission's decision adopting these changes. This includes changes regarding Generator Maintenance Standards and Generator Operation Standards (Sections 7.0, 8.0, Attachment D and Attachment E, plus related parts in Sections 2, 3, 4 and 15), logbook Electronic Database Minimum Requirements (Section 5.7), and Generating Asset Information (Sections 10.3.5 and 10.3.6.)

APPENDIX A: GENERAL DUTY STANDARDS FOR OPERATIONS AND MAINTENANCE

Pursuant to California Public Utilities Code § 761.3, each facility used for the generation of electricity owned by an electrical corporation or located in California (Facility) shall be operated and maintained by its owner(s) and operator(s) in accordance with the following standards:

1. Each Facility shall be operated and maintained in a safe, reliable and efficient manner that reasonably protects the public health and safety of California residents, businesses, employees, and the community.

2. Each Facility shall be operated and maintained so as to be reasonably available to meet the demand for electricity, and promote electric supply system reliability, in a manner consistent with prudent industry practice.

3. Each Facility shall comply with the protocols of the California Independent System Operator for the scheduling of power plant outages.

4. [Reserved.]

5. Each Facility shall maintain reasonable logs of operations and maintenance in a manner consistent with prudent industry practice.

6. Each Facility shall be operated and maintained in a reasonable and prudent manner consistent with industry standards while satisfying the legislative finding that each facility is an essential facility providing a critical and essential good to the California public.

Pursuant to California Public Utilities Code § 761.3(a), the California Public Utilities Commission shall implement and enforce these General Duty Standards for Operation and Maintenance. Pursuant to the provisions of California Public Utilities Code § 761.3(f), nothing in these General Duty Standards for Operations and Maintenance shall modify, delay, or abrogate any deadline, standard, rule or regulation that is adopted by a federal, state, or local agency for the purposes of protecting public health or the environment, including, but not limited to, any requirements imposed by the California State Air Resources Board, an air pollution control district, or an air quality management district pursuant to Division 26 (commencing with Section 39000) of the California Health and Safety Code.

(END OF APPENDIX A)

APPENDIX B: GENERATOR LOGBOOK STANDARDS (THERMAL ENERGY)

I. PURPOSE

The intent of this document is to define the requirements for facility logs for plants generating electricity by the use of thermal energy.

II. GENERAL

Each generating facility shall maintain a Control Operator Log that contains the chronological history of the facility including detailed entries regarding the operations and maintenance of the facility. Where information is unit specific, information for each unit must be recorded and so identified.

The Control Operator Log is a formal record of real time operating events as well as the overall status of the generating units and auxiliary equipment under the purview of the Control Room Operator. The log shall also contain an accurate and concise record of important and/or unusual events involving operations, maintenance, water chemistry, safety, accidents affecting personnel, fires, contractor activities, environmental matters, and any other pertinent information concerning the operation of the facility. The log shall also record communications between the facility and outside entities including but not limited to the Independent System Operator (ISO), scheduling coordinators or headquarters facilities, regulators, environmental agencies, CalOSHA or similar agencies. The log shall be maintained notwithstanding and in addition to any other similar requirements that mandate that events be recorded. The generator must collect and record all information specified in these standards. All such information must be readily available to operators, California Public Utilities Commission staff, and other authorized personnel at all times.

Notwithstanding the above, generators may elect to record certain kinds of information in separate logs, as authorized by either Exception 1 or Exception 2 below. The information specified in Exception 1 may be recorded in an Equipment Out of Service Log. Similarly, the information specified in Exception 2 may be recorded in a Work Authorization log. Information recorded in these separate logs need not be recorded in the Control Operator log.

All required logs entries shall be retained in hard copy, electronic format, or both for a minimum period of five years from the date of the log entry. Each log entry shall start by recording the time of the event. The Generating Asset Owner (GAO) is responsible for maintaining the integrity of the generating facility logs.

Each facility must record a Plant Status Entry at least once each calendar day. If practicable, the control operator shall make that entry at midnight; however, a facility may for operational reasons elect to make that entry at another time. In any case, the

Plant Status Entry must be made at the same time each day, except when emergency conditions require a postponement. In the case of such emergency conditions, the entry for that day shall be made as soon as it is safe to do so.

Information in the Plant Status Entry shall include:

1) Unit status, if on line, including:
   - Current Mega Watt (MW) load.
   - Generator Kilo Volt (KV) and Mega VAR (MVAR) readings.
   - Fuel type and availability.
   - For units equipped with Automatic Generation Control (AGC), the status of AGC equipment, including the availability of AGC, its operational status (on or off), and the normal range of output possible when the unit is operating under AGC.
   - Condenser water box differential pressures, condenser back pressure/vacuum readings, boiler and pre-boiler water chemistry readings (if applicable).
   - Status of environmental monitoring equipment.

   Or if off line:

   - Type of outage with expected return date/time (including the ISO outage ID number).
   - Any other reason the unit is off line.
2) Any unit MW output restrictions (de-rates) including reasons for and expected time/date of release (including the ISO outage ID number).
3) Status of any environmental constraints (for example total annual NOx allowable emissions vs. year to date total emissions or, for jet peakers, total allowable run time vs. current year to date actual run time).
4) Equipment out of service, including any equipment that has been isolated and prepared for an upcoming work authorization with particular emphasis on redundant equipment that if the primary equipment fails, will result in a load restriction or a unit trip (see Exception 1).
5) Any abnormal operating conditions.
6) Outstanding work authorizations commonly referred to as clearances (see Exception 2).
7) Status of any retention/waste basins.
8) Status of any water conditioning equipment such as facility demineralizers and in stream demineralizers.
9) The on hand quantities of large consumables including distilled water, hydrogen, nitrogen and hypochlorite, if applicable.
10) Any other pertinent information regarding the status and reliability of the facility.

The first entry in the Control Operator Log at the start of a shift shall identify each operator on that shift and by some regular means distinguish his/her responsibilities (list in a regular order the identity of the Shift Supervisor(s), Control Operator(s), Assistant Control Operator(s) and Plant Equipment Operator(s)). This initial entry shall indicate that the crew has ascertained the plant status through the shift turnover, review of the log and a check of the indications and alarms in the control room.

Events shall be logged chronologically as they occur. Significant entries will include the control operator's name at the end of the entry preceded by the name(s) of others involved in the activity.

The events recorded in the Control Operator log shall include, but are not limited to, the following:

1) Any changes to generator MW output (except when on AGC). The current load of the unit shall be recorded as well as the new target load and the reason for the load change including:

    a) As directed by the day ahead schedule.
    b) Deviations from the schedule as directed by a scheduling coordinator.
    c) Load reductions for scheduled equipment outages (cleaning condensers, pump repairs, etc.).
    d) ISO directions.
    e) Unplanned unit equipment problems (forced derates) including load restrictions for environmental causes.
    f) Reducing to minimum load.
    g) Any other reason.

2) Starting and stopping of equipment and any associated abnormal conditions.
3) Significant operations and milestones in the process of major operations such as start-ups, shutdowns and heat-treats.
4) During a unit start up, once on line, each generator load increment released to the scheduling coordinator.
5) Each instance where a unit is placed on or removed from AGC, including a notation if the AGC limits are set for a different value than the normal AGC range for that unit.
6) Any changes to the future schedule for generator output.
7) Detailed account of unit trips including any known or suspected causes and remedial action taken.
8) Load limit position anytime it is placed at any value less than full load and reason for such action.

9) All information related to planned outages or de-rates, including but not limited to communications with scheduling coordinators, headquarters, or the ISO regarding such outages (including requests to take an outage; and notification to the facility that such outages have been approved or denied), the nature of the work to be completed during the outage, initial and revised return-to-service dates, completion of milestones in such work, requests to the ISO or others for extension of such outages including the reason for that extension, and completion of such outages. All entries shall include the date, time, duration, reason or explanation and the identities of all involved.

10) All information related to forced outages or de-rates, including but not limited to communications with scheduling coordinators, headquarters, or the ISO regarding such outages; the nature of the problem; progress reports on further diagnosis of the problem or on ongoing repairs; estimated and revised return-to-service dates; the nature of any extended work to be completed during the outage; completion of milestones in such work; and completion of such outages. All entries shall include the date, time, duration, reason or explanation and the identities of all involved.

11) All work authorizations issued and released and the reason for such work.

12) Equipment placed in a not normal status.

13) Equipment declared out of service (OOS) including date and time of initial OOS declaration.

14) Any current or potential fuel-supply problems.

15) Results of performance tests including heat rate tests, hotwell drop tests, turbine stop valve tests, etc.

16) Equipment outages of environmentally sensitive equipment or environmental monitoring devices.

17) All out-of-limit water chemistry conditions including duration and remedial actions, as well as all boiler chemical feeds and boiler drum blowdowns where applicable.

18) Changes in equipment/systems status (such as a suspected boiler tube leak, fouled condensers, or a feedwater heater tube leak).

19) Detailed information regarding environmental limitations exceeded, including the date, time, duration, amount, and any known or suspected cause.

20) Detailed reports of observations related to transmission system or facility trouble involving frequency or voltage deviations.

21) Report of any industrial accident including all details of the incident and the names of all parties involved.

22) All other pertinent information concerning the operation of the facility including names of all individuals involved.

Exceptions:

1. In lieu of logging equipment out of service information in the plant status entry, an Equipment OOS Log may be utilized, at the discretion of the GAO, to track equipment declared out of service. The work authorization program is intended to provide a safe work environment for current maintenance activities. If a delay is encountered in the repair process, the work authorization should be released and the equipment declared OOS. If the OOS designation is expected to be of short duration (five days or less), the OOS entry should be carried forward in the plant status Control Operator Log entry. If a longer period is anticipated, the OOS entry can be recorded in the OOS log to avoid carrying it forward repeatedly in the CO log. Information in the OOS log shall include the following:
   - Equipment description
   - Date declared OOS
   - Reason for being declared OOS
   - Estimated time for equipment to return to service
   - Name of person declaring equipment OOS
   - Maintenance order number or similar tracking mechanism
   - Contact person(s)
   - Date equipment is returned to service
2. In lieu of logging outstanding work authorizations in the plant status entry, a Work Authorization log book may be utilized, at the discretion of the GAO, during periods of construction, overhauls, or major work; and contains work authorizations, commonly referred to as clearances issued, released, and associated with the special activity. All other entries pertaining to the special activity shall be entered in the Control Operator log. Work authorization log entries do not need to be carried forward for each plant status but may remain for the duration of the special activity. Information in the Work Authorization log shall include the following:
   - Date and time the clearance was issued.
   - Name of the Control Operator or Assistant Control Operator issuing the clearance.
   - Identification of clearance.
   - Name of person the clearance is issued to.

III. THERMAL PLANTS TO WHICH THESE STANDARDS ARE APPLICABLE

Thermal Logbook Standards are applicable to each facility that generates electric energy by the use of thermal resources owned by an electrical corporation or located in California that is 50 MW or larger. Thermal Logbook Standards are not applicable in the following cases (see California Pub. Util. Code §§ 761.3(d), 761.3(h)):

1. Nuclear-powered generating facilities that are federally regulated and subject to standards developed by the Nuclear Regulatory Commission, and that participate as members of the Institute of Nuclear Power Operations.

2. Qualifying small power production facilities or qualifying cogeneration facilities within the meaning of §§ 201 and 210 of Title 11 of the federal Public Utility Regulatory Policies Act of 1978 (16 U.S.C. Secs. 796(17), 796(18), and 824a-3), and the regulations adopted pursuant to those sections by the Federal Energy Regulatory Commission (18 C.F.R. Secs. 292.101 to 292.602, inclusive).

3. Generation units installed, operated, and maintained at a customer site, exclusively to serve that customer's load.

4. Facilities owned by a local publicly owned electric utility as defined in California Pub. Util. Code § 9604(d).

5. Any public agency that may generate electricity incidental to the provision of water or wastewater treatment.

6. Facilities owned by a city and county operating as a public utility, furnishing electric service as provided in California Pub. Util. Code § 10001.

Electrical corporation does not include electric plant:

a. where electricity is generated on or distributed by the producer through private property solely for its own use or the use of its tenants and not for sale or transmission to others (§ 218(a)),

b. employing cogeneration technology or producing power from other than a conventional power source solely for one or more of three named purposes (§ 218(b)),

c. employing landfill gas technology for one or more of three named purposes (§ 218(c)),

d. employing digester gas technology for one or more of three named purposes (§ 218(d)), and

e. employing cogeneration technology or producing power from other than a conventional power source for the generation of electricity that physically produced electricity prior to January 1, 1989, and furnished that electricity to immediately adjacent real property for use thereon prior to January 1, 1989 (§ 218(e)).

(END OF APPENDIX B)

APPENDIX C: GENERATOR LOGBOOK STANDARDS (HYDROELECTRIC ENERGY)

I. PURPOSE

The intent of this document is to define requirements for operation logs for attended and unattended hydroelectric generating facilities. These standards are intended to ensure that operating information associated with normal operation, maintenance, and abnormal activities are properly recorded and available for review and analysis by regulatory agencies

II. GENERAL

Owners of hydroelectric generating facilities shall maintain logbooks or other data collection systems that contain the chronological, real-time operational history of the facilities. Logbooks shall include accurate and concise entries regarding the operations and maintenance of the facility and overall status of the generating units and auxiliary equipment. Logbooks shall be maintained at attended facilities, control centers for unattended facilities, and unattended facilities, as described more fully below.

Logbooks shall include, as appropriate, entries of important and/or unusual events relating to safety, accidents, environmental matters, and any other information pertinent to operations. Where information is unit specific, information for each unit must be recorded and so identified**.** Logbooks shall also contain entries noting operations and maintenance communications between the facility operator and outside entities, including but not limited to the Independent System Operator (ISO), scheduling coordinators or headquarters facilities, regulators, environmental agencies, CalOSHA or similar agencies. The logbooks shall be maintained notwithstanding and in addition to any other similar requirements that mandate that events be recorded.

Owners of hydroelectric generating facilities must collect and record, either through automated data collection systems, written logbooks, or both, all information specified in this standard. Such information must be readily available to operators, California Public Utilities Commission staff, and other authorized personnel at all times, and must be kept for a minimum period of five years from the date of collection. The owner of the hydroelectric facility is responsible for maintaining the integrity of the information collected and recorded. Any corrections to logbook entries shall be made in a manner that preserves the legibility or integrity of the original entry, and identifies the date and time of the correction. Each utility (and facility) will maintain a list of any approved abbreviations used by operators in that utility (and that particular facility), along with a definition of each abbreviation.

III. REQUIRED INFORMATION

A. Attended Facilities and Control Centers for Unattended Facilities

Logbooks at attended facilities and control centers for unattended facilities shall be the chronological, real-time record of the operation and maintenance activities that occur either at the attended facility or the unattended facilities within the jurisdiction of the control center, respectively.

Information collected and recorded by automatic devices may be maintained separately and need not be entered in the logbook itself, provided that the information is available for review and shall be maintained in accordance with the standards set forth herein for the daily operations logbooks.

Each logbook shall consist of accurate, concise entries and shall contain at least the information specified below. To the extent any of the information below is not available to the control center operator, it shall be captured either by automated systems or recorded in the Unattended Facilities Log.

1. Orders and other communications received and transmitted by the operator, as appropriate, including but not limited to those from or to the Independent System Operator (ISO); scheduling coordinators, headquarters facilities and/or dispatchers; transmission operating centers; regulators; environmental agencies; CalOSHA; or similar agencies;
2. Actions taken by the operator to change load, derate the unit, or take the unit off line,
3. Operational data, including power production (load) levels, water flows, the availability and operation of automatic generation control (AGC), and any generation limits applicable to AGC operation other than the normal limits specified in the Participating Generator Agreement with the California Independent System Operator;
4. Operation of system protection relays;
5. Water regulation (e.g., downstream water requirements, FERC license requirements);
6. Unit separation and parallel times;
7. Clearances/Work authorizations;
8. Reporting on and off clearances;
9. Start and completion of switching operations;
10. The application, removal, moving, or change in location and/or number of grounding devices;
11. Site emergency activities; including but not limited to accidents, spills and earthquakes;

12. Trouble reports; including but not limited to those involving equipment failures and those from outside persons or entities;
13. Daily operations, including unit outages and de-ratings, Automatic Voltage Regulator/Power System Stabilizer operations, voltage operations, governor operations, and black-start operations, if applicable;
14. Special system setups for hydraulic, mechanical, electrical or pneumatic systems.

Each entry shall include the time, location and description of event, including, as relevant, the equipment involved, loads and other readings, voltage orders, directed load changes, deviations from generation schedules, weather, annunciator alarms or other indications, relay target information including device number, limitations, notifications, and corrective actions. Entries noting communications between the operator and outside parties shall include the names of the persons involved in the communication.

B. Unattended Facilities

Logbooks at unattended facilities shall be the chronological record of operation and maintenance activities that occur when personnel visit an unattended facility. Entries in logbooks at unattended facilities shall be made consecutively and shall include the following information, as applicable:

1. Time and date of entry and exit;
2. Name(s) of personnel entering/exiting the station;
3. Location of event;
4. Text description of event/reason for entering station;
5. All information pertinent to event, including but not limited to equipment involved, loads and other readings, voltage orders, directed load changes, deviations, weather, annunciator alarms or other indications, relay target information including device number, curtailments, limitations, notifications, corrective actions;
6. The application, removal, moving, or change in location and/or number of grounding devices;
7. Clearances/Work authorizations.

(END OF APPENDIX C)

APPENDIX D: MAINTENANCE STANDARDS FOR GENERATING ASSET OWNERS

Maintenance Standards (MS) 1 though 18 apply to each covered generating asset. (See GO 167, §§ 3 and 7.) A separate document containing recommended guidelines may be obtained from the Commission's Consumer Protection and Safety Division (or successor entity). (See GO 167 § 15.2.) The guidelines are intended to assist each generating asset owner determine how it may comply with these MS.

1. MS 1 – Safety

The protection of life and limb for the work force is paramount. The company behavior ensures that individuals at all levels of the organization consider safety as the overriding priority. This is manifested in decisions and actions based on this priority. The work environment, and the policies and procedures foster such a safety culture, and the attitudes and behaviors of individuals are consistent with the policies and procedures.

2. MS 2 - Organizational Structure and Responsibilities

The organization with responsibility and accountability for establishing and implementing a maintenance strategy to support company objectives for reliable station operation is clearly defined, communicated, understood and is effectively implemented. Reporting relationships, control of resources, and individual authorities support and are clearly defined and commensurate with responsibilities.

3. MS 3 – Maintenance Management and Leadership

Maintenance managers establish high standards of performance and align the maintenance organization to effectively implement and control maintenance activities.

4. MS 4 – Problem Resolution and Continuing Improvement

The company values and fosters an environment of continuous improvement and timely and effective problem resolution.

5. MS 5 - Maintenance Personnel Knowledge and Skills

Maintenance personnel are trained and qualified to possess and apply the knowledge and skills needed to perform maintenance activities that support safe and reliable plant operation.

6. MS 6 - Training Support

A systematic approach to training is used to achieve, improve, and maintain a high level of personnel knowledge, skill, and performance.

7. **MS 7 – Balance of Maintenance Approach**
   The maintenance program includes the proper balance of the various approaches to maintenance, e.g., preventive, predictive, or corrective. The approach is adequately documented with consideration of economics and reliability of equipment or components, and their affect on reliable operation of the unit. Operating experience is factored into the program. Maintenance procedures and documents should include the generation equipment and all those components owned by the generation owner directly connected to the plant that are an integral part of delivering power to the grid including fuel supply systems, electrical switchyards, transmissions lines, penstocks, flumes, exhaust system, etc.

8. **MS 8 – Maintenance Procedures and Documentation**
   Maintenance procedures and documents are clear and technically accurate, provide appropriate direction, and are used to support safe and reliable plant operation. Procedures must be current to the actual methods being employed to accomplish the task and are comprehensive to ensure reliable energy delivery to the transmission grid.

9. **MS 9 – Conduct of Maintenance**
   Maintenance is conducted in an effective and efficient manner so equipment performance and materiel condition effectively support reliable plant operation.

10. **MS 10 – Work Management**
    Work is identified and selected based on value to maintaining reliable plant operation. Work is planned, scheduled, coordinated, controlled, and supported with resources for safe, timely, and effective completion.

11. **MS 11 – Plant Status and Configuration**
    Station activities are effectively managed so plant status and configuration are maintained to support reliable and efficient operation.

12. **MS 12 – Spare Parts, Material and Services**
    Correct parts and materials in good condition, are available for maintenance activities to support both forced and planned outages. Procurement of services and materials for outages are performed in time to ensure materials will be available without impact to the schedule. Storage of parts and materials support maintaining quality and shelf life of parts and materials.

13. **MS 13 - Equipment Performance and Materiel Condition**
    Equipment performance and materiel condition support reliable plant operation. This is achieved using a strategy that includes methods to anticipate, prevent, identify, and promptly resolve equipment performance problems and degradation.

14. MS 14 – Engineering and Technical Support

Engineering activities are conducted such that equipment performance supports reliable plant operation. Engineering provides the technical information necessary for the plant to be operated and maintained within the operating parameters defined by plant design.

15. MS 15 – Chemistry Control

Chemistry controls optimize chemistry conditions during all phases of plant operation and system non-operational periods.

16. MS 16 – Regulatory Requirements

Regulatory compliance is paramount in the operation of the generating asset. Each regulatory event is properly identified, reported and appropriate action taken to prevent recurrence.

17. MS 17 – Equipment History

Maintenance standards or procedures clearly define requirements for equipment history for the systems and equipment, including, what information or data to collect, how to record data, and how the data is to be used.

18. MS 18 – Maintenance Facilities and Equipment

Facilities and equipment are adequate to effectively support maintenance activities.

(END OF APPENDIX D)

APPENDIX E: OPERATION STANDARDS FOR GENERATING ASSET OWNERS

Operating Standards (OS) 1 though 28 apply to each covered generating asset. (See GO 167, §§ 3 and 8.) A separate document containing recommended guidelines may be obtained from the Commission's Consumer Protection and Safety Division (or successor entity). (See GO 167 § 15.2.) The guidelines are intended to assist each generating asset owner determine how it may comply with these OS.

1. OS 1 - Safety

The protection of life and limb for the work force is paramount. GAOs have a comprehensive safety program in place at each site. The company behavior ensures that personnel at all levels of the organization consider safety as the overriding priority. This is manifested in decisions and actions based on this priority. The work environment and the policies and procedures foster such a safety culture, and the attitudes and behaviors of personnel are consistent with the policies and procedures.

2. OS 2 - Organizational Structure and Responsibilities

The organization with responsibility and accountability for establishing and implementing an operation strategy to support company objectives for reliable plant operation is clearly defined, communicated, understood and is effectively implemented. Reporting relationships, control of resources, and individual authorities support and are clearly defined and commensurate with responsibilities.

3. OS 3 - Operations Management and Leadership

Operations management establishes high standards of performance and aligns the operations organization to effectively implement and control operations activities.

4. OS 4 - Problem Resolution and Continuing Improvement

The GAO values and fosters an environment of continuous improvement and timely and effective problem resolution.

5. OS 5 - Operations Personnel Knowledge and Skills

Operations personnel are trained and qualified to possess and apply the knowledge and skills needed to perform operations activities that support safe and reliable plant operation.

6. OS 6 - Training Support

A systematic approach to training is used to achieve, improve, and maintain a high level of personnel knowledge, skill, and performance. Each GAO provides a site-specific training program including on-the-job training, covering operations, including reasonably anticipated abnormal and emergency operations. Personnel are trained commensurate with their duties.

7. OS 7 - Operation Procedures and Documentation

Operation procedures exist for critical systems and states of those systems necessary for the operation of the unit including startup, shutdown, normal operation, and reasonably anticipated abnormal and emergency conditions. Operation procedures and documents are clear and technically accurate, provide appropriate direction, and are used to support safe and reliable plant operation. Procedures are current to the actual methods being employed to accomplish the task and are comprehensive to ensure reliable energy delivery to the transmission grid.

8. OS 8 - Plant Status and Configuration

Station activities are effectively managed so plant status and configuration are maintained to support safe, reliable and efficient operation.

9. OS 9 - Engineering and Technical Support

Engineering activities are conducted such that equipment performance supports reliable plant operation. Engineering provides the technical information necessary for the plant to be operated and maintained within the operating parameters defined by plant design. Engineering provides support, when needed, to operations and maintenance groups to resolve operations and maintenance problems.

OS 10 - Environmental Regulatory Requirements

Environmental regulatory compliance is paramount in the operation of the generating asset. Each regulatory event is identified, reported and appropriate action taken to prevent recurrence.

OS 11 - Operations Facilities, Tools and Equipment

Facilities and equipment are adequate to effectively support operations activities.

OS 12 - Operations Conduct

To ensure safety, and optimize plant availability, the GAO conducts operations systematically, professionally, and in accordance with approved policies and procedures. The GAO takes responsibility for personnel actions, assigns personnel to tasks for which they are trained, and requires personnel to follow plant and operation procedures and instructions while taking responsibility for safety. Among other things:

A. All personnel follow approved policies and procedures. Procedures are current, and include a course of action to be employed when an adopted procedure is found to be deficient.
B. All operations are performed in a professional manner. Basic rules of conduct apply throughout the plant at all times.
C. All personnel on-duty are trained, qualified, and capable of performing their job functions. Personnel are assigned only to duties for which they are properly trained and qualified.
D. Personnel take immediate actions to prevent or correct unsafe situations.

13. OS 13 - Routine Inspections

Routine inspections by plant personnel ensure that all areas and critical parameters of plant operations are continually monitored, equipment is operating normally, and that routine maintenance is being performed. Results of data collection and monitoring of parameters during routine inspections are utilized to identify and resolve problems, to improve plant operations, and to identify the need for maintenance. All personnel are trained in the routine inspections procedures relevant to their responsibilities. Among other things, the GAO creates, maintains, and implements routine inspections by:

A. Identifying systems and components critical to system operation (such as those identified in the guidelines to Standard 28).

B. Establishing procedures for routine inspections that define critical parameters of these systems, describe how those parameters are monitored, and delineate what action is taken when parameters meet alert or action levels.

C. Training personnel to conduct routine inspections.

D. Monitoring routine inspections.

OS 14 - Clearances

Work is performed on equipment only when safe. When necessary**,** equipment is taken out of service, de-energized, controlled, and tagged in accordance with a clearance procedure. Personnel are trained in the clearance procedure and its use, and always verify that equipment is safe before any work proceeds. Among other things:

A. The GAO prepares and maintains a clearance procedure. The clearance procedure contains requirements for removing a component from service and/or placing a component back into service.

B. The GAO ensures that personnel are trained in and follow the clearance procedure.

15. OS 15 - Communications and Work Order Meetings

The availability of the generating asset and safety of personnel is ensured during the execution of work orders by adequate communications and meetings, which may be scheduled or as needed, to review work plans with all affected personnel before work begins. Clear lines of communication exist between personnel responsible for operations, maintenance and engineering groups. Among other things:

A. The GAO prepares and maintains a procedure for review of work plans through communications and work order meetings at the facility.

B. Work is analyzed to determine what personnel, components, and systems are affected.

C. Affected personnel meet before work begins to define the work, identify safety issues, to minimize the impact on plant operation, and to determine the need for further meetings.

D. Personnel are trained in and follow the procedure.

16. OS 16 - Participation by Operations Personnel in Work Orders

Operations personnel identify potential system and equipment problems and initiate work orders necessary to correct system or equipment problems that may inhibit or prevent plant operations. Operations personnel monitor the progress of work orders affecting operations to ensure timely completion and closeout of the work orders, so that the components and systems are returned to service. Among other things:

A. Operations personnel identify problems requiring work orders, and initiate work orders to correct those problems

B. The operations manager or other appropriate operating personnel periodically review work orders that affect operations to ensure timely completion and closeout of the work orders, so that components and systems are returned to service.

C. Personnel responsible for prioritizing work orders consult operations personnel to assure that work orders affecting the operations of the plant are properly prioritized.

D. Appropriate personnel are trained in and follow procedures applicable to work orders.

17. OS 17 - Records of Operation

The GAO assures that data, reports and other records reasonably necessary for ensuring proper operation and monitoring of the generating asset are collected by trained personnel and retained for at least five years, and longer if appropriate.

18. OS 18 - Unit Performance Testing

The GAO conducts periodic performance tests as appropriate to identify trends and possible improvements in unit operation. The GAO responds to test results with changes to equipment, policies, routines, or procedures necessary to maintaining unit availability and the unit's ability to support grid operations consistent with the Unit Plan.

19. OS 19 - Emergency Grid Operations

The GAO prepares for conditions that may be reasonably anticipated to occur during periods of stress or shortage on the state's electric grid. During such periods of stress or shortage, the GAO makes operational decisions to maximize each unit's availability and ability to support grid operations. Among other things the GAO:

A. Takes reasonable steps to maintain the ability to communicate with the Control Area Operator all times.

B. In preparing for periods of stress or shortage, takes steps to clarify the regulatory requirements, such as emissions, water discharge temperature, etc., which will apply during emergencies.

C. When emergencies appear imminent, seeks regulatory relief from those regulatory requirements that reduce output.

D. Assists the Control Area Operator in responding to the various kinds of possible problems on the electrical grid, including restoration of service after a disturbance.

E. When practical, during periods of stress or shortage, consults with the Control Area Operator before derating a unit or taking a unit off line and defers outages and derates at the Control Area Operator's request when continued operation is

1. Possible and practical,
2. Safe to plant personnel and to the public,
3. In accordance with applicable law and regulations, and
4. Will not cause major damage to the plant.

20. OS 20 - Preparedness for On-Site and Off-Site Emergencies

The GAO plans for, prepares for, and responds to reasonably anticipated emergencies on and off the plant site, primarily to protect plant personnel and the public, and secondarily to minimize damage to maintain the reliability and availability of the plant. Among other things, the GAO:

A. Plans for the continuity of management and communications during emergencies, both within and outside the plant,

B. Trains personnel in the emergency plan periodically, and

C. Ensures provision of emergency information and materials to personnel.

21. OS 21 - Plant Security

To ensure safe and continued operations, each GAO provides a prudent level of security for the plant, its personnel, operating information and communications, stepping up security measures when necessary.

22. OS 22 - Readiness

Until a change in a unit's long-term status, except during necessary maintenance or forced outages, the GAO is prepared to operate the unit at full available power if the Control Area Operator so requests, after reasonable notice, when such operation is permitted by law and regulation. Among other things, the GAO:

A. Maintains contingency plans to secure necessary personnel, fuel, and supplies, and

B. Prepares facilities for reasonably anticipated severe weather conditions.

23. OS 23 - Notification of Changes in Long-Term Status of a Unit

The GAO notifies the Commission and the Control Area Operator in writing at least 90 days prior to a change in the long-term status of a unit. The notification includes a description of the planned change.

24. OS 24 - Approval of Changes in Long-Term Status of a Unit

The GAO maintains a unit in readiness for service in conformance with Standard 22 unless the Commission, after consultation with the Control Area Operator, affirmatively declares that a generation facility is unneeded during a specified period of time. This standard is applicable only to the extent that the regulatory body with relevant ratemaking authority has instituted a mechanism to compensate the GAO for readiness services provided.

25. OS 25 - Transfer of Ownership

The GAO notifies the Commission and the Control Area Operator in writing at least 90 days prior to any change in ownership.

26. OS 26 - Planning for Long-Term Unit Storage

At least 90 days before a change in the long-term status of an electric generation unit, other than permanent shutdown and/or decommissioning, the GAO shall submit to the Commission plans and procedures for storage, reliable restart, and operation of the unit.

27. OS 27 - Flow Assisted Corrosion

Where circumstances require it, the GAO has a flow-assisted corrosion program, which identifies vulnerable equipment, provides for regular testing of that equipment, and responds appropriately to prevent high energy pipe failures.

28. OS 28 - Equipment and Systems

GAO complies with these Operation Standards (1-27) considering the design bases (as defined in the Appendix) of plant equipment and critical systems. The GAO considers the design basis of power plant equipment when as required by other standards it, among other things:

A. Establishes procedures for the operation of critical systems at each unit (Ref. Standard No. 7).

B. For each system, identifies critical parameters that require monitoring (Ref. Standard No. 8 and 13).

C. For each critical parameter, establishes values at which to increase observation of the system or take actions to protect it (Ref. Standard No. 8 and 13).

D. Assures that systems are monitored and actions are taken (Ref. Standard 8 and 13).

E. Establishes parameters for operation during periods of stress or shortage on the state's electric grid (Ref. Standard No. 9 and 19).

F. Assures that personnel operating critical systems are trained and qualified (Ref. Standard No. 6).

Appendix

A. Definitions

Design Basis Documents – Vendor and engineering documents used in the design, or used to instruct in the correct operation and maintenance, of the systems and equipment used in the power plant. Design basis documents consist of OEM Manuals, vendor documents, industry standards, codes and documented engineering assessments.

Documented deviations from the above documents are also considered part of the design basis documents provided there is documented reasoning for those deviations. Documented reasoning includes the benefit of the deviation and why the deviation is consistent with the Unit Plan.

B. Industry Codes Standards and Organizations

ASME Boiler and pressure vessel code, Section 1, (including all amendments)

ASME Boiler and pressure vessel code, Section V111

ANSI/ASME B 31.1 Power Piping

Note on Codes: Any boiler designed and approved to an earlier issue and amendment of these standards is maintained and repaired to the design as originally issued. However, advances in engineering knowledge and experience reflected in the subsequent issues of the codes are taken into consideration in operation and maintenance of the boiler.

Weld repairs and alterations of boilers designed to ASME Boiler and Pressure Vessel Code, Section 1, is carried out in accordance with the rules of the National Board Inspection Code, published by the National Board of Boiler and Pressure Vessel Inspectors.

These standards are intended to augment and not conflict with other standards, which are pertinent to specific components and systems at each facility such as standards issued by organizations including but not limited to:

A& WMA	Air & Waste Management Association
AAQS	Ambient Air Quality Standard
ABMA	American Boiler Manufacturer's Association
AMCA	Air Movement and Control Association
ANSI	American National Standards Institute
APCD	Air Pollution Control District
API	American Petroleum Institute
ARB	Air Resources Board (see CARB)
ASME	American Society of Mechanical Engineers

ASNT	American Society for Nondestructive Testing
ASTM	American Society for Testing and Materials
AWS	American Welding Society
CAISO	California Independent System Operator
CAL OSHA	California Occupational Safety and Health Administration
CAPCOA	California Air Pollution Control Officers Association
CARB	California Air Resources Board
CPUC	California Public Utilities Commission
CEC	California Energy Commission
CCR	California Code of Regulations
CSA	Canadian Standards Association
EPA	Environmental Protection Administration
GAO	Generating Asset Owner
HEI	Heat Exchange Institute
HI	Hydraulic Institute
IEEE	Institute of Electrical and Electronics Engineers
ISA	The Instrumentation, Systems, and Automation Society
NEC	National Electrical Code
NERC ES-IC	North American Reliability Council Information Sharing and Analysis Center
NEMA	National Electrical Manufacturer's Association
NIPC	National Infrastructure Protection Center
NFPA	National Fire Protection Association
NRTL	Nationally Recognized Testing Laboratories
OSHA	Occupational Safety and Health Administration
PFI	Pipe Fabrication Institute
SSPC	Steel Structures Painting Council
TEMA	Tubular Exchanger Manufacturer's Association
UBC	Uniform Building Code
UL	Underwriters' Laboratories
UPC	Uniform Plumbing Code

C. Summary of Abbreviations and Acronyms

ACC	Air-Cooled Condenser
AODTM	A trademark of Environmental Elements Corporation for a urea to ammonia system
AVG, avg	Average
BACT	Best Available Control Technology
BMS	Burner Management System
BTA	Best Technology Available
BTU, Btu	British Thermal Unit
BCW	Bearing Cooling Water
CA	California
CAM	Compliance Assurance Monitoring
CEM, CEMS	Continuous Emissions Monitoring System (also referred to as CEMs)
CFR	Code of Federal Regulations
CO2	Carbon Dioxide
CO	Carbon Monoxide
CT	Combustion turbine
CTM	Conditional Test Method
CWP, CWS	Circulating Water Pump, Circulating Water System
DC	Direct Current
DLN	Dry Low-Nox
EOH	Equivalent Operating Hour
^{o}F	Degree Fahrenheit
ft3	Cubic Feet
GAO	Generation Asset Owner
gpm	Gallons per minute
H2SO4	Sulfuric Acid
HAP	Hazardous Air Pollutant
HHV	High Heating Value

Hp	Horsepower
HR, hr	Hour
Inj	Injection
kWe	Kilowatt electrical
LAER	Lowest Achievable Emission Rate
LEC	Low Emission Combustor
LB, LBs, lbs	Pound, Pounds
MACT	Maximum Achievable Control Technology
MMBtu	Million British Thermal Units
MW	Megawatt
MWe	Megawatt electrical
MWh	Megawatt-hour
NH3	Ammonia
Nm	Nanometer
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NOx	Oxides of Nitrogen or Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
O&M	Operation & Maintenance
O_2	Oxygen
OEM	Original Equipment Manufacturer
PM10, PM10	Particulate Matter (10 microns or less)
PM2.5 or PM2.5	Particulate Matter (2.5 microns or less)
PM	Particulate Matter
Ppm	Parts per Million
ppmvd	Parts per Million by Volume, Dry
PSD	Prevention of Significant Deterioration
QA/QC	Quality Assurance/Quality Control
RATA	Relative Accuracy Test Audit

RMP	Risk Management Plan
S/S	Startup and Shutdown
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SOTA	State-of-the-Art
SOx	Sulfur Oxides
TDS	Total Dissolved Solids
UPS	Uninterruptible Power Supply
UV	Ultraviolet
VOC	Volatile Organic Compound
Yr	Year
ZAT	Zero Ammonia Technology

(END OF APPENDIX E)

Appendix F: Fines For Specified Violations

Violation	Fine
1. Failure to file a formal document at the time or in the manner required by this General Order. These documents are Initial Certification, Recertification, Notice of Material Change, Maintenance Plan Summary, Operation Plan Summary, Update to Maintenance Plan Summary, and Update to Operation Plan Summary.	$1,000 per incident *plus* $500 per day each day thereafter.
2. Failure to maintain specific documents as required by this General Order. These documents are Maintenance Plan, Operation Plan, Logbook (Thermal), and Logbook (Hydroelectric).	$5,000 per incident.
3. Failure to respond to an Information Requirement set forth in Section 10.0 of this General Order.	$1,000 per incident *plus* $500 per day for the first ten calendar days the Information Requirement was not satisfied after being requested and $1,000 for each day thereafter.
4. Submission of inaccurate information in response to an information request under Section 10.0 of this General Order.	$2,000 per incident *plus* $500 per day for the first ten days the inaccuracy was not corrected and $1,000 for each day thereafter.
5. Repeated violation of any requirement listed in this schedule.	200% of the fine that would be imposed for a first-time violation.

(END OF APPENDIX F)

END OF GENERAL ORDER