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PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ENERGY DIVISION **RESOLUTION E-4214**
December 18, 2008

R E S O L U T I O N

This Resolution formally adopts the 2008 Market Price Referent values for the use in the 2008 Renewable Portfolio Standard solicitations. This Resolution is made on the Commission's own motion.

SUMMARY

2008 Market Price Referent (MPR) values have been calculated for use in the 2008 Renewable Portfolio Standard (RPS) solicitations.

This Resolution formally adopts the 2008 MPR values for use in the 2008 RPS solicitations. This Resolution is made on the Commission's own motion.

Adopted 2008 Market Price Referents[1] (Nominal - dollars/kWh)				
Resource Type	**10-Year**	**15-Year**	**20-Year**	**25-Year**
2009 Baseload MPR	0.10043	0.10537	0.11126	0.11480
2010 Baseload MPR	0.10175	0.10748	0.11390	0.11761
2011 Baseload MPR	0.10400	0.11046	0.11730	0.12110
2012 Baseload MPR	0.10698	0.11405	0.12126	0.12509
2013 Baseload MPR	0.10998	0.11776	0.12527	0.12915
2014 Baseload MPR	0.11278	0.12122	0.12897	0.13290
2015 Baseload MPR	0.11605	0.12503	0.13290	0.13690
2016 Baseload MPR	0.11971	0.12915	0.13706	0.14111
2017 Baseload MPR	0.12367	0.13352	0.14144	0.14549
2018 Baseload MPR	0.12802	0.13814	0.14603	0.15001
2019 Baseload MPR	0.13271	0.14298	0.15080	0.15464
2020 Baseload MPR	0.13776	0.14797	0.15578	0.15937

[1] Note: using 2009 as the base year, Staff calculates MPRs for 2009-2020 that reflect different project online dates. The 2008 MPR model is available at: http://www.ethree.com/MPR.html

BACKGROUND

The RPS Program requires each utility to increase the amount of renewable energy in its portfolio

The California Renewables Portfolio Standard (RPS) Program was established by Senate Bill 1078 (Chapter 516, statutes of 2002, effective January 1, 2003) and codified at California Public Utilities Code Section 399.11, et seq. The statute requires that RPS-obligated investor-owned utilities (IOU), energy service providers (ESP) and community choice aggregators (CCA) meet annual targets by increasing procurement of Eligible Renewable Energy Resources (ERR) by at least 1 percent of annual retail sales per year until 20 percent is reached, subject to the Commission's rules on flexible compliance, no later than 2017.

The State's Energy Action Plan (EAP) called for acceleration of this RPS goal to reach 20 percent by 2010[2]. This was reiterated again in the Order Instituting Rulemaking (R.04-04-026) [3] issued on April 28, 2004, which encouraged the utilities to procure cost-effective renewable generation in excess of their RPS annual procurement targets[4] (APTs), in order to make progress towards the goal expressed in the EAP. On September 26, 2006, Governor Schwarzenegger signed Senate Bill (SB) 107[5], which officially accelerated the State's RPS targets to 20 percent by 2010, subject to the Commission's rules on flexible compliance.[6] California's renewables goal was furthered on November 17, 2008 when Governor Schwarzenegger signed Executive Order S-14-08, which established a 33 percent RPS goal by 2020.[7]

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[2] The Energy Action Plan was jointly adopted by the Commission, the California Energy Resources Conservation and Development Commission (CEC) and the California Power Authority (CPA). The Commission adopted the EAP on May 8, 2003.

[3] http://www.cpuc.ca.gov/Published/Final_decision/36206.htm

[4] APT - An LSE's APT for a given year is the amount of renewable generation an LSE must procure in order to meet the statutory requirement that it increase its total eligible renewable procurement by at least 1% of retail sales per year.

[5] SB 107, Chapter 464, Statutes of 2006

[6] Sec. 399.14(a)(2)(C)

[7] http://gov.ca.gov/index.php?/executive-order/11072/

MPR is an important element in the RPS procurement process

The MPR is a key component of the RPS program. Pursuant to Legislation, the MPR has three functions.[8] The first, expressed in § 399.14(g), is to deem reasonable per se and allow to be recovered in rates those "[p]rocurement and administrative costs associated with long-term contracts entered into by an electrical corporation for eligible renewable energy resources pursuant to this article, at or below the market price determined by the commission pursuant to subdivision (c) of Section 399.15. . ." The second function of the MPR is to establish the basis for the use of Above-Market Funds (AMFs) which are awarded by the Commission pursuant to SB 1036, Statutes 2007, ch. 685.[9, 10] The third function of the MPR is to set limits on the procurement obligations of retail sellers under the RPS program.[11] That is, if the amount of AMFs available to an electrical corporation is insufficient to support the total costs expended above the market price, then the Commission shall allow an electrical corporation to limit its annual procurement obligation to the quantity of eligible renewable energy resources that can be procured with available AMFs.

To establish the market price necessary for implementation of the RPS program, the Legislature directed the Commission, in consultation with the Energy Commission, to:[12]

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[8] The RPS legislation is codified at Pub. Util. Code §§ 399.11-399.20.

[9] The original method for funding above-market costs was the use of Supplemental Energy Payments (SEPs), administered by the CEC. See §§ 399.13(c), 399.15(b)(5). The SEP program was eliminated by SB 1036 (Perata), Stats. 2007, ch. 685. The existing funds were refunded to the three large IOUs (PG&E, SDG&E, and SCE) and, along with the portion of funds which would have been collected through January 1, 2012, will be used to fund above-market costs of their long-term RPS contracts. See Res. E-4160 (April 10, 2008).

[10] In order to carry out this function, D.04-06-015 concluded that the contract price should be compared to the MPR on a net present value basis as calculated over the entire contract term.

[11] §399.15(d)(3)

[12] §399.15(c)

> Establish a methodology to determine the market price of electricity for terms corresponding to the length of contracts with renewable generators, in consideration of the following:
>
> > (1) The long-term market price of electricity for fixed price contracts, determined pursuant to the electrical corporation's general procurement activities as authorized by the Commission.
> >
> > (2) The long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities.
> >
> > (3) The value of different products, including baseload, peaking, and as-available output.

In D.03-06-071, the Commission determined that it was not feasible to employ the first consideration set out in § 399.15(c), "the long-term market price of electricity for fixed price contracts, determined pursuant to the electrical corporation's general procurement activities." Because the existing long-term contracts for electricity were almost exclusively those signed by the Department of Water Resources (DWR) pursuant to Water Code § 80100 et seq., the Commission concluded that there were not a sufficient number of existing, reasonably-priced, long-term power contracts of recent vintage currently in the utilities' resource portfolios to establish an MPR based on the first consideration. The Commission, in D.03-06-071, therefore relied on the second and third considerations, developing a proxy plant to model the long-term costs "associated with fixed-price electricity from new generating facilities," taking into account "the value of different products, including baseload, peaking, and as-available output."

MPR procedural history

The Commission set the initial parameters for the MPR in D.03-06-071. The method for calculating the MPR was first developed in D.04 06-015. In D.04-06-015, the Commission clarified "what the MPR is not: it does not represent the cost, capacity or output profile of a specific type of renewable generation technology. . . [T]he MPR is to represent the presumptive cost of electricity from a non-renewable energy source, which this Commission, in D.03-06-071, held to be a natural gas-fired baseload or peaker plant." (D.04-06-015, mimeo., p. 6, n.10.)

In D.05-12-042, the methodology for calculating the MPR was expanded and stabilized. This methodology has been used for the resolutions implementing the MPR for 2005 and 2006. The 2007 MPR was calculated pursuant to D.07-09-024, wherein the Commission adopted an interim method to account for the costs of the emission of greenhouse gases (GHG adder).

D.07-09-024 authorized the use of the GHG adder for the 2007 MPR only. That decision also authorized an examination of the MPR for 2008 and later years, to determine whether any changes should be made to the MPR methodology, including how the compliance costs of State mandates to reduce GHG emissions should be reflected in the MPR.

MPR methodology was reevaluated in 2008

The 2008 review process[13] began with comments filed on March 6, 2008 in response to the Administrative Law Judge's (ALJ's) February 8, 2008, Ruling requesting pre-workshop comments on the 2008 MPR. On March 27, 2008, Energy Division staff (Staff) held a workshop where parties discussed potential modifications to the MPR methodology, inputs, and assumptions for 2008 and later years. Parties identified several key issues for review:

- Capacity Factor
- MPR Gas Methodology
- GHG Adder
- Installed Capital Costs and Cost Escalation
- Generation Meter Multiplier (Transmission Line Losses)
- MPR Contract Length

A May 20, 2008 Ruling requested post-workshop comments, which were filed on June 6, 2008; reply comments were filed on June 18, 2008. Parties' comments and reply comments, including pre-workshop comments and presentations made at the March 27, 2008 workshop, informed D.08-10-026, the Commission's 2008 Decision on the Market Price Referent for the California Renewables Portfolio

[13] The following parties participated in the 2008 MPR proceeding: California Wind Energy Association (CalWEA), California Cogeneration Council, Concentrated Solar Power Companies, Large-scale Solar Association, and Solar Alliance, jointly (collectively, CalWEA); Center for Energy Efficiency and Renewable Technologies (CEERT); Central California Power (CCP); Energy Producers and Users Coalition (EPUC) and Cogeneration Association of California, jointly (collectively, EPUC); Green Power Institute (GPI); GreenVolts, Cleantech America, and Community Environmental Council, jointly; Shell Energy North America (US), L.P (Shell); Division of Ratepayer Advocates (DRA); Pacific Gas and Electric Company (PG&E); San Diego Gas & Electric Company (SDG&E); Southern California Edison Company (SCE); The Utility Reform Network (TURN); and Union of Concerned Scientists (UCS).

Standard. D.08-10-026 refined the MPR in matters related to the methodology; additionally, several issues were determined to be within the discretion of Staff. Accordingly, we discuss those changes in this Resolution.

MPRs were calculated using a cash-flow simulation methodology

The 2008 MPRs were calculated using the "MPR model", which is based on a cash-flow simulation methodology approved by the Commission.[14] The MPR model requires several types of input data, including natural gas prices, capital costs, operating costs, finance costs, taxes, and power delivery assumptions. The primary input drivers for the MPR calculation are the California (CA) gas price forecast, power plant capital costs, and the capacity factor for a proxy baseload plant. (Refer to 2008 MPR model, tabs; CA_Gas_Forecast, Install_Cap, and CF_Inputs.)

The MPR model calculates what it would cost to own and operate a baseload combined cycle gas turbine (CCGT) power plant over a 10, 15, 20 and 25-year period. The cost of electricity generated by such a power plant, at an assumed technical capacity factor and set of costs, is the proxy for the long-term market price of electricity. To ensure that the MPR represents "the value of different products including baseload, peaking, and as-available output,"[15] the IOUs apply their IOU-specific Time of Delivery (TOD)[16] profiles to the baseload MPR when evaluating RPS renewable facilities. The application of TOD factors to the MPR result in a market price for each product and electric generating unit. (Refer to 2008 MPR model "CF_Data Set" and "Control" tabs.)

Release of 2008 MPR is consistent with prior Commission decisions

Pursuant to D.05-12-042, Staff is required to prepare a draft resolution for the annual MPR, including any relevant supporting materials as attachments to the draft resolution. The draft resolution will be released after all utility solicitations have closed.[17] For 2008, the draft resolution incorporates the methodological

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[14] A list of all relevant MPR documents, with links, is provided at the beginning of this resolution's Discussion section.

[15] Sec. 399.15(c)(3).

[16] TOD factors are based on the forward value of electricity during different TOD periods.

[17] The three large California utilities submitted their letters to the Executive Director notifying the Commission that their solicitations were closed on: Pacific Gas & Electric–

changes adopted in the Commission's recent decision D.08-10-026 and refines several MPR inputs at the recommendation of Staff, as discussed herein. Parties will have the usual opportunity to file comments and reply comments on the draft resolution prior to its formal consideration by the Commission.[18]

DISCUSSION

Please refer to the following documents in the following chronological order for a detailed discussion of the MPR methodology:

- **D.04-06-015**: Opinion Adopting Market Price Referent Methodology http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/37383.doc
- **Resolution E-3942**: Adopts 2004 MPR Values for 2004 RPS Solicitation http://www.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/48242.DOC
- **D.05-12-042**: Interim Opinion Adopting Methodology for 2005 Market Price Referent http://www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/52178.DOC
- **Resolution E-3980**: Adopts 2005 MPR Values for 2005 RPS Solicitation http://www.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/55465.DOC
- **Resolution E-4049**: Adopts 2006 MPR Values for 2006 RPS Solicitation http://www.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/63132.doc
- **D.07-09-024**: Opinion on Petition for Modification of Decision 05-12-042 http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/73031.DOC
- **Resolution E-4118**: Adopts 2007 MPR Values for 2007 RPS Solicitation http://docs.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/73594.doc
- **D.08-10-026**: Decision on Market Price Referent for the California Renewables Portfolio Standard http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/92445.htm

The 2008 MPRs are calculated pursuant to D.08-10-026

In D.08-10-026, the Commission modified the MPR methodology and broadly examined the MPR model inputs. In this section we discuss modifications to the MPR model by Commission decision as implemented by Staff.

May 13, 2008, Southern California Electric– May 5, 2008 and San Diego Gas & Electric– April 30, 2008.

[18] D.04-06-015 (Footnote 21, p.30)

To facilitate party review of 2008 MPR modifications, the 2008 MPR model includes toggle switches or lists on the "Control" tab that allows parties to evaluate MPR values while applying 2007 and/or 2008 inputs.

2008 MPR Gas Methodology and Inputs

The most significant cost during the life a new CCGT is the cost of its natural gas fuel. The MPR models the cost of gas over the entire life of the proxy plant's long-term contract. As the Commission pointed out in D.05-12-042, no new gas-fired plant in California actually enters into a 20-year fixed price contract for physical gas delivery. Therefore, in order to capture the "fixed-price fuel costs associated with fixed-price electricity from new generating facilities," the MPR model creates a forecast of long-term gas prices for purposes of the MPR. As explained in D.05-12-042, the MPR model is based on the fact that California market participants , when considering a power purchase agreement (PPA), "use some mixture of market data (NYMEX prices) and fundamentals forecasts for estimating long-term gas prices in a variety of settings, not only new PPAs for electricity produced from CCGTs".[19]

<u>New York Mercantile Exchange (NYMEX) data</u>

In D.05-12-042, the Commission authorized Staff to use all available NYMEX forward contract data, under this guidance, the 2005, 2006 and 2007 MPRs were calculated using the full six years of NYMEX. In 2008, NYMEX extended its forward gas contract term offering from six to 12 years.

The Commission weighed the pros and cons of extending the MPR methodology to incorporate the additional years of NYMEX data that parties identified in their comments. Specifically, CAlWEA, UCS and PG&E supported the MPRs' continued preference for market data, i.e., full 12 years,[20] while TURN, SCE and SDG&E opposed the use of 12 years NYMEX based on concern about relying on

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[19] D.05-12-042, p. 17.

[20] D.05-12-042 adopted five Guiding Principles for the MPR Gas Methodology: 1) The natural gas prices used to calculate the MPR should reflect the behavior of market participants, 2) Market data should be used to the extent possible, 3) For shorter-term contracts, forecast data should be verified against forward market data; for longer-term contracts that extend beyond available market data, forecasts should be benchmarked against fundamental costs and/or historical market data, 4) The methodology should be consistent with the evaluation of other products and 5) The methodology should be consistent with previous regulatory decision.

the outer years of NYMEX data where minimal or no actual trades had occurred. SCE supported its position stating that for its own operations, they do not enter into NYMEX transactions so far into the future.[21] From a procurement perspective, the opposing parties concerns have merit. In D.08-10-026, however, the Commission highlighted an important distinction about the MPR. That is, "…that gas forecast information for the MPR is part of a modeling exercise, not a procurement transaction".

Thus, D.08-10-026 authorized Staff to use between nine and 12 years (the current maximum) of NYMEX forward price data. In reviewing the applicable NYMEX data set,[22] Staff determined that there was no evidence of a single outlier that would argue for using less than all available NYMEX forward prices. (Refer to 2008 model, "NYMEX_Futures" and "CA_Gas_Forecast" tabs.)

Transition to Fundamental Forecast

The MPR model's long-term gas contract requires the use of fundamental gas forecasts to project gas prices when NYMEX forward prices are not available. The MPR fundamental forecast for years 12 – 25 was developed using three out of four private sector natural gas forecasts (Henry Hub) from Cambridge Energy Research Associates, PIRA Energy Group, Global Insight or Wood Mackenzie. Due to contractual obligations requiring the Commission to keep the forecast confidential, Staff can not reveal which of the four firms the forecasts were purchased from.

The use of fundamental forecasts requires a two-step implementation process. First, a methodology must determine how to utilize the fundamental forecast data, and secondly, a methodology is required to transition from NYMEX data to fundamentals data.

For 2007, the transition between NYMEX forward prices and the MPR fundamental forecast was accomplished by making a straight line interpolation between the last year of NYMEX data (year 2012) and the MPR fundamental

[21] SCE, post-workshop reply comments, p. 13.

[22] The MPR Gas Methodology uses a 22-trading day average of NYMEX forward prices ending with the close of the utilities' solicitations. Accordingly, the 2008 MPR Gas Methodology is derived based on the 22-trading day average of NYMEX forward prices leading up to May 13, 2008.

forecast's year 2016 value to create prices for years 2013, 2014 and 2015. (Refer to 2007 MPR model, "CA_Gas_Forecast" tab.)

D.08-10-026 ordered Staff to continue the use of private fundamental forecasts; however, the methodology now utilizes the annual percentage rate change, rather than the actual values, *per se,* to produce the MPR fundamental forecast. D.08-10-026 also directed Staff to make the transition from NYMEX forward prices to the first year of the MPR fundamental forecast by using a linear trend of the last three to five years of NYMEX forward prices, which mitigates the impact of any one price in the outer years of NYMEX. The first year of the MPR fundamental forecast is then extended using the annual escalation rate for the remainder of the MPR fundamental forecast. (Refer to Appendix C for the 2008 California and Henry Hub gas forecasts (2009 – 2050) and Appendix D for specific inputs used in the 2008 gas forecast.)

California Basis Adjustment

The 2007 MPR used NYMEX Clearport futures data to account for the cost of delivery from Henry Hub to California.[23] Staff averaged PG&E Citygate and SoCal Border Clearport prices for the three years of available data and then fixed the average price in year three for all years throughout the proxy CCGT's contract term.

D.08-10-026 ordered Staff to retain the use of NYMEX Clearport prices for years when NYMEX data is used, but now requires that California Basis data from private fundamental forecasts be used when the MPR Gas Methodology relies on fundamental forecast data. (Refer to 2008 MPR model "CA_Basis_Adj" tab.)

Pursuant to D.08-10-026, Staff continued its use of PG&E Citygate and SoCal Border Clearport prices for the first three years and then fixed the average price in year three through 2020, the last year when the MPR Gas Forecast relies on NYMEX forward prices.[24] The California Basis Adjustment for the remainder of

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[23] "The Henry Hub is the largest centralized point for natural gas spot and futures trading in the United States. The New York Mercantile Exchange (NYMEX) uses the Henry Hub as the point of delivery for its natural gas futures contract." http://www.eia.doe.gov/oiaf/analysispaper/henryhub/

[24] NYMEX Clearport provides SoCal prices for up to six years; however, PG&E Citygate is only available for three; therefore, Staff determined it most reasonable to use the same methodology that was used in prior years.

the proxy CCGT's contract term is based on the average of basis prices from the private fundamental forecasts used to develop the long-term California MPR Gas Forecast. (Refer to 2008 MPR model "CA_Basis_Adj" tab.)

2008 MPR Non-Gas Methodology and Inputs

Installed Capital Cost Data Set

D.05-12-042 adopted criteria for conducting a market survey of plant costs and ordered Staff to use installed capital costs that reflect the actual cost of a range of CCGT projects that have been built in the last few years or are currently under construction in California. Specifically, Staff was ordered to use the following as suggested criteria in selecting plants to survey:

- 500 MW CCGT (approximate)
- Utilizes GE "F-Series" turbine
- Located in California

Using the survey criteria outlined above, Staff identified the following plants that had publicly available cost data; Palomar (SDG&E), and Cosumnes (SMUD).[25] The 2007 MPR model's data set for installed capital cost consists of the Palomar and Cosumnes power plants.

D.08-10-026 examined whether the Colusa power plant, which is currently under construction, would meet the criteria for use in the MPR calculation.[26] CalWEA and Shell argued that Colusa represented a distressed sale, and therefore, did not meet the criteria established in D.05-12-042. [27] Ultimately, D.08-10-026 determined that Colusa does meet the MPR criteria, because the reasonableness for Colusa was approved through formal contested Commission proceedings and moreover, the certificate of public convenience and necessity (CPCN) retained the initial cost cap.[28]

[25] Refer to Resolution E-4049, Appendix C, for a detailed discussion on how the installed capacity cost for the 2006 MPR was developed.

[26] D08-10-026, pp 21-23.

[27] CalWEA, post-workshop comments, pp 3-4; Shell, post-workshop comments, pp 4-5.

[28] D.06-11-048 approved several contracts, including the Colusa plant, which resulted from PG&E's 2004 long-term request for offers; D.08-02-019 granted PG&E's request for a certificate of public convenience and necessity to build the plant itself and reaffirmed Colusa's $684 million cost cap imposed in D.06-11-048.

While D.08-10-026 does not order Staff to incorporate Colusa into the MPR model, based on the decision's findings, Staff determined that the MPR calculation would benefit from adding Colusa to the limited data set for installed capital costs. According to D.08-02-019, the cost to build Colusa is set at $684.4 million, which results in $1,042/kw based on a 2010 operating online date. To incorporate Colusa into the MPR model, Staff de-escalated Colusa's cost cap using USACOE. The adjustment results in overnight installed capital costs of $670.57 million or $1,021/kw. (Refer to 2008 MPR model, "Install_Cap" and "Control" tabs.)

<u>Escalation of Historic Capital Cost</u>

The 2007 MPR model calculated its installed capital cost estimate by applying the annual United States Army Corps of Engineers (USACOE) Construction Cost Index to capital cost data from the Palomar and Consumnes plants.[29]

D.08-10-026 agreed with the majority of parties, that given the MPR model's limited and relatively older data set, combined with a significant increase in power project development costs, that the use of a private index may be warranted, "…to bring the older cost values more into line with 2008 values".[30] D.08-10-026 authorized Staff to determine the most reasonable data source for escalating the MPR model's historic capital costs.

For the 2008 MPR calculation, Staff used Handy-Whitman's Index of Public Utility Construction Costs (Handy-Whitman),[31] which was recommended by several parties,[32] to escalate the historic installed capital costs for Palomar and Consumes. SDG&E described Handy-Whitman's index as an industry standard that has precedent in the utility industry and with regulatory agencies, and is available at a reasonable cost.[33] Applying Handy-Whitman results in

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[29] CWBS Feature Code 07 (Power Plants). Updated March 30, 2007. http://www.usace.army.mil/inet/usace-docs/eng-manuals/em1110-2-1304/toc.htm

[30] D.08-10-026, pp 23-24.

[31] Whitman, Requardt & Associates, LLP publishes the Handy-Whitman Index of Public Utility Construction Costs. http://www.wrallp.com/

[32] CalWEA, UCS and SDG&E

[33] SDG&E post-workshop reply comments, p. 3.

approximately a 7% increase in the MPR model's installed capital costs.[34, 35] (Refer to 2008 MPR model "Install_Cap" and "Control" tabs.)

Escalation of Current Capital Cost

The 2007 MPR model escalated capital costs through 2010 according to the methodology adopted in D.05-12-042, which assumed that in 2010, increased technical efficiencies would offset incremental capital costs (e.g., inflation).

In D.08-10-026, the Commission determined that, "… the record in this proceeding reveals no reason to believe that the dynamic relationship between cost increases and efficiency improvements will suddenly end in 2010".[36] Accordingly, the MPR methodology was revised to provide for the escalation of installed capital costs on a rolling five-year basis. The 2008 MPR values are calculated assuming that capital costs increase through 2013 and then remain fixed throughout the proxy CCGT contract term. (Refer to 2008 MPR model "CF_Data_Set" tab; cells J13:O13) Installed capital cost will continue to be escalated, prospectively, using the USACOE Index.

Capacity Factor

The 2007 MPRs were calculated using an "economic" capacity factor based on the weighted average of the utility's time of delivery (TOD) factors to determine when it was economic for the proxy CCGT to operate. The 2007 MPR methodology produced an economic capacity factor of approximately 71%.[37]

D.08-10-026 determined that the Commission's statutory obligation was best achieved by calculating MPR values based on a technical capacity factor rather than an economic capacity factor. Specifically, D.08-10-026 found that, "The use of the technical capacity factor eliminates the distortions of the weighted average of TOD factors in the current method [and] …results, when properly time-differentiated, in an MPR that better reflects the values of baseload, peaking, and intermittent products".[38]

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34 Assumes Palomar, Consumnes and Colusa.

35 Handy-Whitman's Bulletin 168, July 2008.

36 D.08-10-026, p. 25.

37 See 2007 MPR model "Cap_Fac" tab.

38 D.08-10-026, p. 20

Accordingly, Staff revised the 2008 MPR model so that the proxy CCGT's capacity factor is now based on the proxy plant's technical capacity factor, which is assumed to be 92%. The MPR's capacity factor is now an input on the "CF_Inputs" tab and Staff deleted the "Cap_Fac" tab, which was used expressly for calculating the economic capacity factor.
D.08-10-026 highlighted the necessity that an MPR calculation using a technical capacity factor must be applied to the utility's TODs to ensure that the calculation fully reflects the costs and revenue of the proxy CCGT. That is, the technical capacity derived MPR, when multiplied by the utility's TOD factors, results in the market price. Moreover, applying the utility's TODs is necessary to evaluate RPS bids received in the annual solicitations in order to produce a time-differentiated bid evaluation process. (Refer to Appendix B for review of the utilities TOD periods and factors)

GHG compliance cost

In D.07-09-024, the Commission determined that it was reasonable to include a GHG adder to account for the costs of compliance with recent California climate laws, Assembly Bill (AB) 32 (Statutes 2006, ch. 488 and SB 1368 (Statutes 2006, ch. 598), because the MPR applies to long-term contracts.[39] Pursuant to D.07-09-024,[40] Staff calculated the 2007 MPRs using the $/$CO_2$ ton values and methodology of the Energy and Environmental Economics (E3) Avoided Cost model for calculating a GHG adder.[41] The 2007 MPR model assumed a CO_2 adder of $8/ton for 2004, escalated at 5 percent per year through 2023 and then escalated using a straight line trend of $0.90/ton per year from 2024-2040.

D.08-10-026 revised further the MPR methodology to reflect California's GHG environmental laws. D.08-10-026 made the cost of compliance with GHG

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[39] The Global Warming Solutions Act and Emissions Performance Standard, respectively.

[40] D.07-09-024, Ordering Paragraph 1 states, "The calculation of the 2007 market price referent (MPR) used in the renewables portfolio standard program shall use the model for calculating greenhouse gas emissions costs (GHG adder) developed by Energy and Environmental Economics and adopted in Decision 04-12-048, applied to the MPR's combined cycle combustion turbine proxy plant for GHG emissions costs beginning January 1, 2012. "

[41] The Avoided Cost model developed by E3's was adopted by the Commission in D.04-12-048 (R.04-04-003) and D.05-04-024 (R.04-04-025). The model is available here: http://www.ethree.com/cpuc_avoidedcosts.html

regulation a permanent component of the MPR calculation and because at this time there is no GHG compliance market in California, the decision adopted criteria for Staff to employ in modeling the GHG compliance costs incurred for the MPR proxy CCGT. Specifically, D.08-10-026 identified criteria that Staff must use for selecting a resource for modeling GHG compliance costs for the MPR. The model should be:

- publicly available;
- based on multiple scenarios and sources of information;
- based on realistic and public assessments of policy proposals and scenarios;
- based on the most current reliable information that conforms to the other three criteria.

At the March workshop, Synapse discussed its methodology and explained how it was based on the analysis of multiple state and federal GHG policies, economic models used to determine price impacts, as well as, ranges of CO_2 prices used by utility regulatory commissions and utilities in resource planning.[42] Staff has determined that at this time, the Synapse model best meets the criteria established in D.08-10-026.

The 2008 MPR model uses $/$CO_2$ ton values based on Synapse's most recent report, "Synapse 2008 CO_2 Price Forecasts".[43] Specifically, Staff used the Synapse "mid-case" cost data, which was recommended by CalWEA and UCS.[44] The Synapse report assumes CO_2 prices of $15 in 2013, increasing to $30.80 in 2020 and $53.40 in 2030, which results in a levelized price of $30/ CO_2 ton in 2007$. Staff converted the reports $/$CO_2$ ton values, which are provided in 2007$, to

[42] Synapse presentation materials are available at: http://www.cpuc.ca.gov/NR/rdonlyres/022569BE-516A-4E13-87D8-733C989D8411/0/MPRGHGadder_2008MPR_workshop_Synapse_UCS.ppt#256,1, Greenhouse Gas Adder for Use in Determining the 2008 MPR

[43] http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.2008-Carbon-Paper.A0020.pdf

[44] CalWEA post-workshop reply comments, p. 10; UCS post-workshop reply comments, p. 5.

nominal$ using a 2.5% inflation rate.[45] (Refer to 2008 MPR model "CF_Data_Set" tab; row 9.) The table below identifies MPR GHG compliance costs for 2012, 2015 and 2020 in short tons and its metric tonne (MT) equivalent.

Year	2012	2015	2020
MPR GHG compliance cost in short tons (nominal$ / CO_2 ton)	**\$10.18/ CO_2 ton**	**\$23.76/ CO_2 ton**	**\$42.46/ CO_2 ton**
Conversion to Metric Ton (nominal$ /MT CO_2)	\$11.22/ MT CO_2	\$26.19/ MT CO_2	\$46.80/ MT CO_2

General Meter Multiplier (Transmission Line Losses)

The 2007 MPR model used a General Meter Multiplier (GMM) of 98.5%, which is equivalent to a 1.5% line loss factor, based on a simple average of CAISO's transmission losses.[46]

D.08-10-026 determined that the MPR methodology should be revised to accommodate the likelihood that a PPA between a California LSE and a CCGT would require delivery at the busbar.[47] Accordingly, the 2008 MPR model calculates MPRs based on delivery at the delivery at the busbar. (Refer to "CF_Inputs" tab; cell E34:E35.)

Capital Cost Inputs

The MPR model requires fixed and variable operational and maintenance (O&M) costs to calculate total installed capital costs for the MPR proxy CCGT. The 2007 MPR calculated average fixed and variable O&M costs based on data from Palomar, Gateway (formerly, Contra Costa), and Mountain View facilities, as well as data from the CEC and Energy Information Agency (EIA).

During the evaluation of the 2008 MPR methodology and inputs, parties were asked to comment on the extent to which the MPR model may benefit from

[45] Staff implemented the Synapse values in consultation with David White, one of the principal authors of the report, "Synapse 2008 CO_2 Price Forecasts Report".

[46] http://oasis.caiso.com/

[47] D.08-10-026, pp 25-26.

either inputs or assumptions from the CEC's Comparative Cost of Generation Model (COG).[48] CalWEA supported the use of the COG's fixed and variable O&M and heat rate values and PG&E stated that the COG's fixed O&M and heat rate assumptions seemed reasonable.[49]

Staff determined that the MPR model should update its fixed and variable O&M costs using the CEC's COG report, which is based on a survey of 19 CCGTs built in California, nine of which began operating as recently as 2005 or 2006.[50] See table below for comparison of 2007 and 2008 MPR fixed and variable O&M data sets. The MPR model's heat rate is based on the turbine employed in the proxy CCGT. Because the 2008 MPR model assumes the same turbine used in calculating the 2007 MPR, the 2008 MPR model's heat rate is unchanged. (Refer to 2008 MPR model "CF_Data_Set" and ""Control" tabs.)

MPR Model Data Set	Fixed O&M	Variable O&M
2007 MPR inputs[51]	$13.28/kw-yr	$2.58/Mwh
2008 MPR inputs	$9.70/kw-yr	$4.36/MWh

MPR Contract Length

The 2007 MPR model calculated MPR values based on 10, 15 and 20-year contracts. In D.08-10-026, the Commission found that, "because parties have negotiated and presented for approval RPS contracts with extended terms, it is

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[48] Comparative Cost of California Central Station Electricity Generation Technologies, December 2007. The report is available at: http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF

[49] Respectively, CalWEA, pre-workshop comments, p. 4; PG&E pre-workshop comments, p. 4

[50] Comparative Cost of California Central Station Electricity Generation Technologies, December 2007, Table 11.

[51] These 2007 MPR input values represent the inputs used for calculating the 2007 MPR, escalated to 2008$ for an equivalent comparison to the COG values in 2008$. The 2007 MPR values also reflect a corrected minor error in the 2007 MPR fixed cost data set.

reasonable to allow staff to calculate the MPR so that such contracts can be evaluated consistently with contracts with more standard lengths".[52]

Pursuant to D.08-10-026, Staff revised the MPR model to allow for MPR calculations for a 25-year contract. (Refer to 2008 MPR model, "Control" tab.)

Miscellaneous 2008 MPR Model Updates

- Dry Cooling Cost Inputs
    - Staff updated the 2008 MPR model's dry cooling cost data based on the CEC's most recent COG report. (Refer to 2008 MPR model, "Install_Cap" tab)
- PG&E Gas Delivery Tariff
    - The 2008 MPR model includes PG&E's Backbone transmission tariff rates for delivery from Malin (redwood) and Topock (Baja) as inputs to the MPR model's average gas distribution rate. Including the average of these tariffs increases the 2008 MPR model's average distribution rate by approximately $0.16/MMBtu. (Refer to 2008 MPR model, "Delivery_Tar" tab, cells D21:D22.)

MPRs are calculated to reflect multiple CCGT online dates

Many renewable projects in California typically take 2 – 5 years to construct and are potentially dependent on major transmission upgrades that will not be completed until 2010 or later. Additionally, recent renewable solicitations have included bids with multiple phase build-outs and options for subsequent projects. Consequently, renewable projects that bid into an RPS solicitation could have commercial online dates as late as 2020. To ensure that there is an appropriate MPR for all of the 2008 RPS projects; Staff has calculated the 2008 MPRs assuming a range of project online dates (2009 – 2020).

COMMENTS

Public Utilities Code section 311(g)(1) provides that this resolution must be served on all parties and subject to at least 30 days public review and comment prior to a vote of the Commission. Section 311(g)(2) provides that this 30-day

[52] D.08-10-026, p. 27.

period may be reduced or waived upon the stipulation of all parties in the proceeding.

The 30-day comment period for the draft of this resolution was neither waived nor reduced. Accordingly, this draft resolution was mailed to parties for comments on November 4, 2008.

On November 24, 2008, timely comments were filed by PG&E, SDG&E, SCE, DRA and CalWEA. Reply comments were filed by CalWEA on December 1, 2008.

Parties' comments generally support the draft resolution. The comments primarily focus on minor modeling errors which we discuss below. Some parties' comments address issues already decided in D.08-10-026 and, thus, are outside the scope of this resolution. All comments and reply comments have been carefully considered.

Modeling of GHG compliance costs

CalWEA commented that the 2008 MPR Model incorrectly calculated the GHG compliance costs for the 2008 MPR. Specifically, CalWEA argued that the phase-in approach recommended in D.08-03-037 should not be used in calculating GHG compliance costs for the 2008 MPR because (1) the phase-in approach fails to account for the generator's opportunity cost of buying and selling allowances, (2) the GHG Decision is unclear on how allowances will be allocated to "new entrant" CCGTs, which is how the MPR is classified, and (3) the phasing in of GHG compliance costs was not considered in the 2008 MPR methodology proceeding. No party filed reply comments opposing CalWEA's position.

The issues raised by CalWEA suggest that the draft resolution may have made a calculation of GHG compliance costs that is more precise than the record and the State's current policy can justify. Because D.08-10-037 is a recommendation to the California Air Resources Board, but is not yet State policy, it will not be relied upon for the purposes of calculating GHG compliance costs as they relate to the 2008 MPR.[53] Accordingly, the 2008 MPR GHG compliance costs will be calculated in the same manner as they were for the 2007 MPR.

[53] The California Air Resources Board is responsible for implementating Assembly Bill 32, the State's emissions reduction policy.

Modeling of the MPR fundamental gas forecast

PG&E identified in its comments a minor error in the MPR Model's fundamental gas forecast calculation. Specifically, PG&E noted that the Model transitioned from NYMEX prices to fundamentals in 2020 rather than in 2021. In their reply comments, CalWEA concurred that this error exists and that it should be corrected.

Staff agrees with the PG&E and CalWEA and has revised the MPR Model accordingly. (Refer to 2008 Model, "CA_Gas_Forecast" tab.)

Cost adjustment made for Colusa

SCE noted in its comments that the MPR Model erroneously made an additional cost adjustment for the Colusa power plant. Specifically, the Model increased the Commission approved cost-cap figure to account for dry-cooling, which SCE contends is already reflected in the cost cap.

Staff confirmed that the cost of building Colusa included dry-cooling and has deleted the cost adjustment for Colusa. (Refer to 2008 Model, "Install_Cap" tab, cells H10:I10.)

Escalation of historic capital costs

SCE argued in its comments that Staff exceeded its authority granted by D.08-10-026 for calculating MPR installed capital costs. SCE requested a change in the Model's calculation. No party supports SCE's position. Furthermore, SCE claimed that Staff did not explain the need or rational for its use of Handy-Whitman rather than USACOE.

We disagree with SCE. In D.08-10-026, this Commission did not revisit or change the technical methodology for calculating MPR installed capital costs. Installed capital costs for the 2008 MPR were calculated in this same manner as they were in past years, with the exception that, pursuant to D.08-10-026, Staff escalated installed capital cost (historic) using Handy-Whitman. Accordingly, we reject SCE's request and reaffirm our decision to use Handy-Whitman

Separately, SCE identified an error in the cost estimate date used for the Consumnes power plant. Specifically, SCE commented that the MPR Model incorrectly identified the cost estimate date for Consumnes as September 2005. SCE contends that the Model should be revised to reflect a March 2006 cost estimate date based on documentation for the bond issue which is relied on for the cost estimate for Consumnes.

While we agree with SCE that an error exists, we reach a different conclusion for resolving this discrepancy. Further review of Consumnes' bond documentation, which was issued on January 16, 2006, reveals that the cost estimate of $435 million likely accounts for a delay of project's operational date from September 2005 to March 2006. Therefore, Staff changed the cost estimate date for Consumnes from September 2005 to January 2006 the date of the bond issue. (Refer to 2008 Model, "Install_Cap" tab.)

Modeling of MPR for contracts of greater than 20 years

SDG&E identified an error in the MPR Model's calculation for contracts of greater than 20 years. SDG&E noted that the MPR Model improperly excluded fixed costs and tax expenses for contracts longer than 20 years.

SDG&E suggested several changes to formulas in the MPR Model to implement a 25-year MPR. However, SDG&E recommended changes that impact the MPR for contracts of 20 years and less, which should not be the case. CalWEA in its reply comments agrees that the problem exists but offers a more accurate solution which we adopt with a minor modification.

The MPR methodology provides that the proxy CCGT will recover its fixed costs over 20 years regardless of the length of the contract.[54] The fixed costs for shorter term contracts are levelized over the 10 or 15-year contract term. Consistent with the MPR methodology, the 25-year MPR should also recover its fixed costs over 20 years. However, continuing the escalation of fixed revenues beyond the term of debt and depreciation (20 years) results in extremely high taxes for the last five years of the 25-year MPR. While the MPR methodology specifies a 20-year debt term, in reality, it is likely that the PPA would be structured in such a way as to minimize this tax burden. Assuming a 20-year term for debt and depreciation, Staff finds it more reasonable to limit the fixed revenues escalation to the same terms. Therefore, the 25-year MPR's fixed cost recovery will be limited to the ongoing annual fixed costs over the last five years, which are insurance, fixed O&M, collateral and taxes. (Refer to 2008 Model, "Fixed_Comp" tab.)

[54] MPR variable costs are recovered over the length of the contract.

FINDINGS

1. The 2008 MPRs were calculated and released consistent with D.08-10-026 and prior Commission decisions.
2. The 2008 MPR values for baseload proxy plants have been finalized for use in the 2008 Renewables Portfolio Standard (RPS) solicitations.

THEREFORE IT IS ORDERED THAT:

1. The 2008 MPRs in Appendix A are approved for use in the 2008 RPS solicitations.
2. This Resolution is effective today.

I certify that the foregoing resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held on December 18, 2008; the following Commissioners voting favorably thereon:

/s/ PAUL CLANON
PAUL CLANON
Executive Director

MICHAEL R. PEEVEY
PRESIDENT
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners

APPENDIX A

Adopted 2007 Market Price Referents (Nominal - dollars/kWh)

Operation Date	Baseload MPR	10 year	15 year	20 year	25 year
2009	MPR All-in	**0.10043**	**0.10537**	**0.11126**	**0.11480**
	MPR fixed component	0.02186	0.02262	0.02332	0.02192
	MPR variable component	0.07857	0.08274	0.08794	0.09288
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.00561	0.00844	0.01096	0.01310
2010	MPR All-in	**0.10175**	**0.10748**	**0.11390**	**0.11761**
	MPR fixed component	0.02230	0.02310	0.02381	0.02239
	MPR variable component	0.07944	0.08438	0.09009	0.09522
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.00715	0.01004	0.01264	0.01476
2011	MPR All-in	**0.10400**	**0.11046**	**0.11730**	**0.12110**
	MPR fixed component	0.02274	0.02356	0.02430	0.02284
	MPR variable component	0.08127	0.08690	0.09300	0.09825
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.00894	0.01185	0.01452	0.01657
2012	MPR All-in	**0.10698**	**0.11405**	**0.12126**	**0.12509**
	MPR fixed component	0.02319	0.02403	0.02479	0.02331
	MPR variable component	0.08379	0.09002	0.09646	0.10178
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.01100	0.01389	0.01657	0.01855
2013	MPR All-in	**0.10998**	**0.11776**	**0.12527**	**0.12915**
	MPR fixed component	0.02365	0.02452	0.02530	0.02378
	MPR variable component	0.08633	0.09324	0.09998	0.10536
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.01271	0.01568	0.01838	0.02030
2014	MPR All-in	**0.11278**	**0.12122**	**0.12897**	**0.13290**
	MPR fixed component	0.02367	0.02455	0.02533	0.02382
	MPR variable component	0.08912	0.09667	0.10364	0.10908
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.01425	0.01735	0.02005	0.02193
2015	MPR All-in	**0.11605**	**0.12503**	**0.13290**	**0.13690**
	MPR fixed component	0.02369	0.02458	0.02536	0.02385
	MPR variable component	0.09236	0.10045	0.10754	0.11305
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.01585	0.01909	0.02174	0.02358
2016	MPR All-in	**0.11971**	**0.12915**	**0.13706**	**0.14111**
	MPR fixed component	0.02372	0.02461	0.02540	0.02389
	MPR variable component	0.09599	0.10454	0.11166	0.11723
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.01753	0.02090	0.02346	0.02526
2017	MPR All-in	**0.12367**	**0.13352**	**0.14144**	**0.14549**
	MPR fixed component	0.02375	0.02465	0.02543	0.02392
	MPR variable component	0.09991	0.10888	0.11601	0.12157
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.01928	0.02274	0.02520	0.02696
2018	MPR All-in	**0.12802**	**0.13814**	**0.14603**	**0.15001**
	MPR fixed component	0.02379	0.02468	0.02546	0.02395
	MPR variable component	0.10423	0.11346	0.12057	0.12606
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.02111	0.02459	0.02696	0.02867
2019	MPR All-in	**0.13271**	**0.14298**	**0.15080**	**0.15464**
	MPR fixed component	0.02382	0.02472	0.02549	0.02398
	MPR variable component	0.10889	0.11826	0.12531	0.13066
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.02301	0.02645	0.02873	0.03038
2020	MPR All-in	**0.13776**	**0.14797**	**0.15578**	**0.15937**
	MPR fixed component	0.02386	0.02476	0.02552	0.02401
	MPR variable component	0.11390	0.12321	0.13026	0.13537
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.02500	0.02831	0.03050	0.03208

APPENDIX B
Utility's 2008 Time-of-Delivery (TOD) periods and factors

PG&E[55]

Month	Period	Definition	Factor
June - September	Super-Peak	Hours Ending (HE) 13-20 Monday-Friday (except NERC holidays)	**2.01**
	Shoulder	HE 7-12, 21 and 22 Monday-Friday (except NERC holidays); HE 7-22 Saturday, Sunday and all NERC holidays	**1.14**
	Night	HE 1-6, 23 and 24 all days (including NERC holidays)	**0.72**
October - February	Super-Peak	Defined above	**1.09**
	Shoulder	Defined above	**0.96**
	Night	Defined above	**0.78**
March - May	Super-Peak	Defined above	**1.13**
	Shoulder	Defined above	**0.86**
	Night	Defined above	**0.63**

55 PG&E 2008 RPS Solicitation, pro forma contract, pp. 30-31. http://www.pge.com/includes/docs/word_xls/b2b/wholesaleelectricsuppliersolicitation/AttachmentGAsAvailableFormPPARev022908.DOC

SCE[56]

Season	Period	Definition	Factor
Summer June - September	On-Peak	WDxH[1], noon-6 pm	**3.13**
	Mid-Peak	WDxH, 8-noon, 6-11 pm	**1.35**
	Off-Peak	All other times	**0.75**
Winter October - May	Mid-Peak	WDxH, 8 am-9 pm	**1.00**
	Off-Peak	WDxH, 6-8 am, 9 pm-midnight; WE/H[2] 6 am-midnight	**0.83**
	Super-Off-Peak	Midnight-6 am	**0.61**

1/ WDxH is defined as weekdays except holidays
2/ WE/H is defined as weekends and holidays

SDG&E[57]

Season	Period	Definition[1]	Factor
Summer July - October	On-Peak	Weekdays 11am-7pm	**1.6411**
	Semi-Peak	Weekdays 6am-11am; Weekdays 7pm-10pm	**1.0400**
	Off-Peak	All other hours	**0.8833**
Winter November - June	On -Peak	Weekdays 1pm-9pm	**1.1916**
	Semi -Peak	Weekdays 6am-1pm; Weekdays 9pm-10pm	**1.0790**
	Off-Peak	All other hours	**0.7928**

1/ All hours during National Electric Reliability Council (NERC) holidays are Off-Peak.

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56 SCE 2008 RPS Solicitation, pro forma contract, Exhibit K, p. 2.
http://www.sce.com/nrc/rfp/2008_RPS_Appendix_B_ProForma_Agreement.doc

57 SDG&E 2008 RPS Solicitation, pro forma contract, p. 39.
http://www.sdge.com/documents/rfo/renewablerfo2008/ModelPPA.doc

APPENDIX C

2008 MPR California and Henry Hub Gas Forecast (2009 – 2045)

Year	2008 MPR Henry Hub Forecast (nominal$)	2008 MPR CA Gas Forecast (nominal$)
2009	$10.47	$10.60
2010	$9.69	$9.97
2011	$9.40	$9.68
2012	$9.25	$9.54
2013	$9.14	$9.44
2014	$9.12	$9.43
2015	$9.19	$9.50
2016	$9.27	$9.60
2017	$9.39	$9.73
2018	$9.55	$9.90
2019	$9.72	$10.08
2020	$9.89	$10.27
2021	$10.04	$10.56
2022	$10.39	$10.90
2023	$10.91	$11.41
2024	$11.52	$12.02
2025	$12.05	$12.56
2026	$12.40	$12.91
2027	$12.96	$13.48
2028	$13.48	$14.00
2029	$13.95	$14.48
2030	$14.46	$14.99
2031	$14.95	$15.49
2032	$15.44	$16.01
2033	$15.94	$16.52
2034	$16.17	$16.77
2035	$16.67	$17.28
2036	$17.16	$17.80
2037	$17.65	$18.31
2038	$18.15	$18.82
2039	$18.64	$19.34
2040	$19.13	$19.85
2041	$19.63	$20.37
2042	$20.12	$20.88
2043	$20.61	$21.39
2044	$21.11	$21.91
2045	$21.60	$22.43

APPENDIX D
2008 MPR Gas Forecast Inputs

Row No.	Input Category	Input	Units	Baseload Inputs	Notes
1	**Henry Hub Forecasts /1**	CERA, PIRA, or Global Insight /2	$/MMBtu	N/A	20 yr. Henry Hub forecast (private - purchased)
2	**General Inputs**	Transaction Cost	$/MMBtu	$0.082	D.04-06-015, pg. 26, reafirmed in D.05-12-042 (pg. A-7)
3		Transportation Escalation Rate	Percent-%	1.99%	Average of EIA 2008 GDP Chain-Type Price Index. See 2008 MPR model - Delivery_Tar Tab (Cell E9)
4		20-year WACC	Percent-%	8.51%	2008 MPR model - Cost Cap Tab (Cell D9)
5	**Municipal Surcharge**	SoCal Muni Surcharge	Percent-%	1.462%	Schedule G-MSUR - http://www.socalgas.com/regulatory/tariffs/tm2/pdf/G-MSUR.pdf
6		PG&E Muni Surcharge	Percent-%	0.950%	PG&E Rate Schedule GC-P: (1) http://www.pge.com/rates/tariffs/GCP_Current.xls and (2) http://www.pge.com/rates/tariffs/GSUR_Current.xls
7	**PG&E Gas Distrib. Rate**	Customer Access Charge	$/day	$182	http://www.pge.com/tariffs/pdf/G-EG.pdf
8		Proxy Plant Capacity	MW	500	2008 MPR model - Delivery_Tar Tab (Cell E15)
9		Heat Rate	MMBtu/MWh	6.88	2008 MPR model - Delivery_Tar Tab (Cell E16)
10		Capacity Factor	percent-%	92%	2008 MPR model - Delivery_Tar Tab (Cell E17)
11		Monthly Gas Consumption	MMBtu	75,750	(Row 8 * Row 9* Row 10) * 24 hours
12		Unit Cost of Customer Access Charge	$/MMBtu	$0.0024	Row 7 / Row 11
13		Transportation Charge	$/MMBtu	$0.1827	http://www.pge.com/tariffs/pdf/G-EG.pdf
14	**SoCal Gas Distrib. Rate**	Customer Charge	$/month	$0.00000	http://www.socalgas.com/regulatory/tariffs/tm2/pdf/GT-F.pdf
15		Transmission Charge	$/MMBtu	$0.2936	http://www.socalgas.com/regulatory/tariffs/tm2/pdf/GT-F.pdf
16		Interstate Transportation Cost Surcharge	$/MMBtu	$0.0005	http://www.socalgas.com/regulatory/tariffs/tm2/pdf/GT-F.pdf

1/ The Henry Hub forecasts are inputs for the MPR - Henry Hub forecast - there are no specific baseload values.
2/ Due to contractual obligations requiring the Commission to keep the forecast confidential, staff can not reveal which of the three firms the forecast was purchased from.

APPENDIX E
2007 MPR Non-Gas Inputs

Row No.	Input Category	Input	Units	Baseload Inputs	Escal. Rates/yr.	Notes
1	Capital Inputs	Total capital cost January 1 - 1st operational yr.	$/kw	$1,182	2.15%	Per D.05-12-042, Staff conducted a survey of actual plant costs in CA. Four plants were selected and an average was calculated
2		Fixed O&M	($/kW-yr) 1st operational yr.	$9.70	1.99%	CEC Cost of Generation Report CEC-200-2007-001-SF Table 6, p. 18. Escalated from $2007 to $2009 using EIA GDP Chain-type Price Index.
3		Variable O&M	(mills/kWh) 1st operational yr.	$4.35	1.99%	CEC Cost of Generation Report CEC-200-2007-001-SF Table 6, p. 18. Escalated from $2007 to $2009 using EIA GDP Chain-type Price Index.
4		New & Clean heat rate	Btu/kWh HHV	6704	n.a.	Per D.05-12-042, Staff used the the "new & clean" heat rate for an F-Series (GE S207FA) CC Turbine, adjusted for Higher Heating Value
5		Heat rate degradation factor	Percent-%	1.74%	n.a.	Per D.05-12-042, Staff contacted GE for an appropriate heat rate degradation factor for an F-series CC turbine. GE provide a degradtion curve that calculated the average degradation over the life of the project.
6		Average heat rate	Btu/kWh HHV	6924	n.a.	Average heat rate over life of plant, taking into account the impact of Higher Heating Value, degradation, dry cooling, and starts/stops
7	Finance Inputs	20-year WACC	Percent-%	8.51%	n.a.	Weight-Average Cost of Capital = (Cost of Equity x Equity %) + (Cost of Debt x (1-tax rate) x Debt %)
8		Cost of LT Debt	Percent-%	7.84%	n.a.	Per D.05-12-042, Cost of Debt (industrial firms) = risk free rate (20 year T-Bill) + risk premium (mid point between BBB & B+). http://www.bondsonline.com, May 13, 2008
9		Cost of Equity	Percent-%	12.38%	2.00%	Per D.05-12-042, Cost of Equity = risk free rate (20-yr Tbill) + risk premium (equity) + mid-cap risk premium (equity). http://www.bondsonline.com, May 13, 2008
10		Debt as % of total cost	Percent-%	50%	n.a.	Per D.05-12-042, LT debt ratio for BBB rated company
11		Debt Term	Years	20	n.a.	Adopted in D.04-06-015 and reaffirmed in D.05-12-042
12		Insurance as % of plant cost	Percent-%	0.60%	1.99%	Same value used for 2004 MPR. Energy Division contacted insurance brokers for quotes and calculated an average value.
13	Power Delivery Inputs	Transformer Loss Factor	Percent-%	0.50%	n.a.	Loss factor recommended by parties and used in 2004 MPR calculation
14		Generation Meter Multiplier (GMM) to load center	Percent-%	98.5%	n.a.	Not Used. Pursuant to D. 08-10-026, the MPR Model assumes delivery at the busbar
15		Capacity Factor	Percent-%	92%	n.a.	Per D.08-10-026
16	Tax Rate Inputs	Federal Tax Rate	Percent-%	35%	n.a.	Tax rate proposed by the parties and used in the 2004 MPR calculation
17		State Tax Rate	Percent-%	8.84%	n.a.	Tax rate proposed by the parties and used in the 2004 MPR calculation
18		Total Effective Tax Rate	Percent-%	40.75%	n.a.	Effective Tax = Federal Tax * (1 - State Tax) + State Tax
19		Property taxes as % of plant cost	Percent-%	1.20%	n.a.	Same value used for 2004 MPR. Energy Division averaged the property tax rates for 14 counties in which power plants were constructed (or under construction) in the last 5 years.
20	Gas Forecast	20yr gas forecast - 2009 levelized	$/MMBtu	$10.42	n.a.	Output from CA_Gas_Forecast Tab (Cell N42) in 2008 MPR model
21	GHG	GHG Compliance Cost	$/Ton	$15.00	n.a.	($15 in 2013). Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning. Synapse Energy Economics. March 2, 2007. Updated July 2008, Synapse 2008 CO2 Price Forecast (in $2007). (Table 2, p. 16) http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.2008-Carbon-Paper.A0020.pdf