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PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ENERGY DIVISION

I.D.# 6931
RESOLUTION E - 4118
October 4, 2007

R E S O L U T I O N

This Resolution formally adopts the 2007 Market Price Referent values for a proxy baseload plant for the use in the 2007 Renewable Portfolio Standard solicitations. This Resolution is made on the Commission's own motion.

SUMMARY

2007 Market Price Referent (MPR) values have been calculated for use in the 2007 Renewable Portfolio Standard (RPS) solicitations.

This Resolution formally adopts the 2007 MPR values for a baseload proxy plant for the use in the 2007 RPS solicitations. This Resolution is made on the Commission's own motion.

Adopted 2007 Market Price Referents[1] (Nominal - dollars/kWh)			
Resource Type	**10-Year**	**15-Year**	**20-Year**
2008 Baseload MPR	0.09271	0.09383	0.09572
2009 Baseload MPR	0.09302	0.09475	0.09696
2010 Baseload MPR	0.09357	0.09591	0.09840
2011 Baseload MPR	0.09412	0.09696	0.09969
2012 Baseload MPR	0.09518	0.09844	0.10139
2013 Baseload MPR	0.09605	0.09965	0.10275
2014 Baseload MPR	0.09722	0.10107	0.10430
2015 Baseload MPR	0.09873	0.10274	0.10602
2016 Baseload MPR	0.10054	0.10466	0.10796
2017 Baseload MPR	0.10270	0.10686	0.11131
2018 Baseload MPR	0.10480	0.11018	0.11471
2019 Baseload MPR	0.10820	0.11372	0.11697
2020 Baseload MPR	0.11175	0.11599	0.11926

[1] [1] Note: using 2008 as the base year, Staff calculates MPRs for 2008-2020 that reflect different project online dates. Link to 2007 MPR Model: 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, 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.

MPR is an important element in the RPS procurement process

The MPR is a key component of the RPS program. In setting up the RPS program, the Legislature assigned three functions to the MPR. 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

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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

resources pursuant to this article, at or below the market price determined by the commission pursuant to subdivision (c) of Section 399.15. . ."[6]

The second function of the MPR is to establish the basis for the use of Supplemental Energy Payments (SEP)[7], which are awarded by the Energy Commission. Pub. Res. Code § 25743(b)(1) provides that:

> In order to cover the above market costs of renewable resources as approved by the Public Utilities Commission and selected by retail sellers to fulfill their obligations under Article 16 (commencing with Section 399.11) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code, the [energy] commission shall award funds in the form of supplemental energy payments, subject to. . . criteria. . .

See also §§ 399.15(d)[8] and 399.13(e).[9] 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.[10]

The third function of the MPR is to set limits on certain obligations of retail sellers under the RPS program. One obligation so limited is the obligation to buy energy from renewable resources. As provided in § 399.15(b)(5):

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[6] D.04-06-015 determined that the contract price must be calculated on a net present value basis over the entire contract term.

[7] The funding for SEPs comes from the California Energy Commisssion's New Facilities Program that in turn is funded through the non-bypassable public benefits surcharge that was enacted in 2001.

[8] Sec. 399.15(d) provides that the Energy Commission "shall provide supplemental energy payments from funds in the New Renewable Resources Account in the Renewable Resource Trust Fund to eligible renewable energy resources pursuant to Chapter 8.6 (commencing with Section 25740) of Division 15 of the Public Resources Code, consistent with this article, for above-market costs."

[9] Sec. 399.13(e) provides that the Energy Commission shall. . . "[a]llocate and award supplemental energy payments pursuant to Chapter 8.6 (commencing with Section 25740) of Division 15 of the Public Resources Code, to eligible renewable energy resources to cover above-market costs of renewable energy."

[10] Note: SB 1036, which was approved on September 12, 2007, but still requires the Governor's signature, would rescind the CEC's authority to award SEPs as described per statute. Pursuant to SB 1036 the CEC would refund any available SEP funds to the IOUs and grants the CPUC authority over the IOUs costs-recovery for RPS-eligible procurement that is in excess of market prices.

> If supplemental energy payments from the Energy Commission, in combination with the market prices approved by the commission, are insufficient to cover the above-market costs of electricity procured from eligible renewable energy resources through an electricity purchase agreement of at least 10 years' duration, , 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 supplemental energy payments. A retail seller shall not be required to enter into long-term contracts with operators of eligible renewable energy resources that exceed the market prices established pursuant to subdivision (c).

To establish the market price necessary for implementation of the RPS program, the Legislature directed the CPUC, in consultation with the Energy Commission, to[11]:

> 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 CPUC 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 CPUC 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 CPUC, in D.03-06-071, therefore relied on the second and third considerations, developing a proxy plant

[11] Sec. 399.15(c).

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." As long as the DWR contracts remain the dominant long-term electricity procurement contracts, the CPUC will use the proxy plant method to calculate the MPR.[12]

In D.04-06-015, the CPUC 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.)

MPRs were calculated using a cash-flow simulation methodology

The 2007 MPRs were calculated using the "MPR model", which is based on a cash-flow simulation methodology approved by the Commission in D.04-06-015[13] and modified by Resolution E – 3942[14], D.05-12-042[15], Resolution E-3980[16], and Resolution E-4049.[17] 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. See 2007 MPR model, Tabs; CA_Gas_Forecast, Install_Cap, and Cap_Fac.

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, and 20-year period. The cost of electricity generated by such a power plant, at an assumed 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,"[18] the IOUs apply their

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[12] Documents submitted by DWR in Application (A.) 00-11-038 *et al*. show that DWR contracts account for approximately 30% of the utilities' load.

[13] http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/37383.doc

[14] http://www.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/48242.DOC

[15] http://www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/52178.DOC

[16] http://www.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/55465.DOC

[17] http://www.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/63132.doc

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

IOU-specific Time of Delivery (TOD)[19] 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.

MPRs 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. D.05-12-042[20] orders Staff to calculate nominal MPRs that reflect different project online dates by escalating the non-gas inputs using an inflation index.[21] The Decision also orders Staff to assume that capital costs for the proxy plant should be escalated until 2010 and then held constant to reflect the fact that increased efficiencies will offset incremental capital costs.[22] To ensure that there is an appropriate MPR for all of the 2007 RPS projects; Staff has calculated the 2007 MPRs assuming a range of project online dates (2008 – 2020). See "CF_Data Set" and "Control" Tabs in the 2007 MPR model for the specific calculation.

MPR Gas Forecast Methodology and Inputs

D.04-06-015 noted that there is no transparent, liquid market for natural gas forward products for 10, 15 or 20-year terms, which is necessary in order to fuel a proxy power plant producing fixed-priced electricity over these time periods. Consequently, D.04-06-015 outlined a California gas forecasting methodology for years 1 through 6, and another methodology for years 7 through 20, both of which are based on the forward Henry Hub (HHub) gas price that is basis adjusted to California.[23]

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

[20] D.05-12-042, page 44

[21] Installed capital costs were escalated using the US Army Corp of Engineers Escalation Index (CWBS Feature Code 07 - Updated March 30, 2007). Insurance, FOM, and VOM were escalated using the EIA 2007 GDP Chain-Type Price Index.

[22] D.05-12-042, pg. 55 (FoF #30)

[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/).

D.05-12-042, modified by D.06-01-029, refined the methodology for years 1- 5 by changing the 60-day-averaging period for the NYMEX forward prices to a 22-trading day averaging period, ending with the close of the utilities' solicitations.[24] For years 6 – 20, D.05-12-042 noted that parties criticized the methodology used in 2004 as not yielding consistent and explainable results using data from a variety of time periods and market conditions. Most notably, the gas prices for Years 7-20 were heavily (possibly too heavily) influenced by the forward gas price in the last year of NYMEX data used in the 2004 MPR forecast.

Consequently, D.05-12-042 adjusted the relationship between the end of NYMEX data (no later than Year 6, and possibly Year 5, see D.04-06-015) and the beginning of reliance on the fundamentals forecasts in Year 6 to address the problems with the forecast in 2004. D.05-12-042 determined that, instead of using the escalation forecasting methodology of the 2004 MPR for Years 6-20, Staff should use a three-year straight line blending between the near-term (Years 1-5) and the long-term (Years 6-20), and then use the average of the fundamental forecasts for the remaining years. This method retains the absolute value of the fundamentals-based gas price forecasts and eliminates the escalation process for Years 6-20 that the 2004 MPR used, which was the subject of criticism from the parties.

The fundamental forecast for years 6 – 20 was developed using two private and one public 20-year Henry Hub fundamental forecasts.[25] Specifically, the public forecast was based on the HHub wellhead prices provide in the U.S. Energy Information Administration (EIA) 2007 Annual Outlook.[26] With regard to the two private forecasts, they are a private sector natural gas forecasts from Cambridge Energy Research Associates (CERA), PIRA Energy Group, or Global Insight. Due to contractual obligations requiring the CPUC to keep the forecast confidential, Staff can not reveal which of the three firms the forecasts were purchased from.

It should be noted that the EIA HHub forecast is derived by manipulating the EIA's forecasted wellhead prices. Specifically, EIA examined the relationship between Henry Hub spot prices for natural gas and the U.S. wellhead price for

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[24] PG&E's 2007 RPS solicitation closed on 5/31/07 - after SCE's and SDG&E's 2007 RPS solicitation. Consequently, Staff used 5/31/07 as the last day in the 22-trading day averaging period.

[25] In 2004, 3 public forecasts and 1 private forecast were used, e.g., timely forecasts produced by CERA, PIRA, Global Insight, EIA, and the CEC.

[26] http://www.eia.doe.gov/oiaf/aeo/excel/aeotab_14.xls

the period spanning August 1996 through December 2000.[27] Their analysis determined the extent to which the two price series are linearly correlated and also evaluated the statistical properties of two simple price relationships—the actual difference and the percent difference. The results of the analysis indicated that there was a strong linear relationship between the two price series, to the effect that, on average the Henry Hub spot prices were 32 cents per thousand cubic feet (10.8 percent) higher than wellhead prices. The median value of the actual difference is 24 cents per thousand cubic feet, and the median value of the percent difference is 10.4 percent. Consequently, Staff escalated the EIA wellhead prices by 10.8% to derive a proxy HHub forecast.

Please refer to:

- Appendix B for the 2007 California and Henry Hub gas forecasts (2008 – 2039)
- Appendix C for specific inputs used in the 2007 gas forecast

Release of 2007 MPRs is consistent with prior Commission decisions

Pursuant to D.05-12-042[28], 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. Parties will have the usual opportunity to file comments and reply comments on the draft resolution prior to its formal consideration by the Commission. [29]

The three large California utilities submitted their letters to the Executive Director notifying the Commission that their solicitations were closed on:

- Pacific Gas & Electric (PG&E) – May 31, 2007 [30]
- Southern California Electric (SCE) – May 18, 2007 [31]
- San Diego Gas & Electric (SDG&E) – May 30, 2007 [32]

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[27] U.S. Natural Gas Markets: Relationship Between Henry Hub Spot Prices - EIA Analysis (http://www.eia.doe.gov/oiaf/analysispaper/henryhub/index.html)

[28] http://www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/52178.DOC

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

[30] On 6/5/07, PG&E notified the CPUC Executive Director by letter that its 2007 RPS solicitation had closed.

[31] On 6/7/07, SCE notified the CPUC Executive Director by letter that its 2007 RPS solicitation had closed.

2007 MPRs will include a greenhouse gas adder (GHG adder)

The merits of including a GHG adder for the MPR have been discussed since the initial development of the MPR methodology. In D.03-06-071, the Commission denied requests to adopt a GHG adder based on the "…cost of possible future environmental regulations" (UCS Opening Briefs, pp 12-13), reasoning that in order for the Commission to consider a GHG adder, compliance costs would have to "…become more definite, both in likelihood and value."[33] D.05-12-042 revisited the merits of a GHG adder for the MPR and determined that "The greenhouse gas adder is not currently an element of the long-term market price of electricity in California."[34]

On June 25, 2007, California Wind Energy Association (CalWEA) and Green Power Institute (GPI) filed a Petition for Modification of D.05-12-042 (R.04-04-026) to include a GHG adder in the 2007 MPRs. On September 20, 2007, the Commission approved D.07-09-024[35], which determined that "The mandates of AB 32 and SB 1368 make the present moment – and the future – different from the situation in December 2005.", and therefore, it was reasonable to include GHG emission costs in the 2007 MPR with an assumption that compliance costs begin in 2012.[36] D.07-09-024 clarified that the Petitioners request was granted only to the extent that a GHG adder is included in the 2007 MPRs. Any opinion on the reasonableness for including a GHG adder for future MPRs, or modifying the MPR methodology per se, was not addressed in D.07-09-024**.** See "Discussion" section for details regarding the implementation of a GHG adder for the 2007 MPR.

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[32]On 6/4/07, SDG&E notified the CPUC Executive Director by letter that its 2007 RPS solicitation had closed.

[33] D.03-06-071, page 23

[34] D.05-12-042, Findings of Fact 32.

[35] Opinion on Petition For Modification of Decision D.05-12-042

[36] D07-09-024, page 6

DISCUSSION

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

- D.04-06-015[37]
- Resolution E – 3942[38]
- D.05-12-042[39]
- Resolution E-3980[40]
- Resolution E-4049[41]
- D.07-09-024

Modifications to MPR Non-Gas Methodology and Inputs

For the 2007 MPRs, Staff has made several modifications to the MPR model that specifically address:

- Capital Cost Escalation Rate
- Retail-Sales Weighted Average Time of Delivery (TOD) Profiles
- Forced Outage Rate
- Cost of Operating Collateral
- GHG Adder

To facilitate party review of 2007 MPR modifications, the 2007 MPR model includes toggle switches on the "Control" tab (cells J17:J23) which allows parties to evaluate MPR values while applying 2006 and/or 2007 methodologies.

Capital Cost Escalation

D.05-12-042 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. D.05-12-042 also adopted additional criteria for conducting a market survey of plant costs. Specifically, Staff was ordered to use the following as suggested criteria in selecting plants to survey:

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[37] http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/37383.doc

[38] http://www.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/48242.DOC

[39] http://www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/52178.DOC

[40] http://www.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/55465.DOC

[41] http://www.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/63132.doc

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

Staff identified the publicly available installed capital costs for the 2006 MPR CCGT proxy using the reported capital costs ($ per kW) of comparable CCGT plants. To find comparable plants, Staff started with the list of existing and planned CCGT plants within the Western Electricity Coordinating Council (WECC) found on the CEC's "Energy Facility Status" website.[42] Using the survey criteria outlined above, Staff identified the following plants that had publicly available cost data; Palomar (SDG&E), and Cosumnes (SMUD).[43]

The 2006 MPR model calculated capital cost estimates by applying the annual USACOE Construction Cost Index to capital cost data from the Palomar and Consumnes plants. The initial capital cost estimate for Palomar was $410 million (2006$). For the 2006 MPR, the initial cost estimate was escalated using the USACOE Construction Cost Index (USACOE) at an annual rate of 2.77%, resulting in capital cost estimate of $421 million (2007$). Using the 2007 USACOE annual rate of 3.74% to calculate 2007 MPRs would have increased the capital cost estimate to $435 million (2008$). The analogous values for the Consumnes plant are; initial capital cost $435 million (2006$), the 2006 MPR used a capital cost estimate of $447 million (2007$), and applying the 2007 USACOE annual rate of 3.74% to calculate 2007 MPRs would have increased the capital cost estimate to $462 million (2008$).

However, this methodology does not reflect the increase in power plant construction costs that has occurred since those plant cost estimates were calculated[44]. Therefore, the 2007 MPR model will use quarterly values to calculate capital cost estimates to December 2007, assuming a January 2008 start date. For the 2007 MPR, Palomar capital costs ($410 million) will be de-escalated from 2006 to 2004 at the 1.67% rate reflected in the USACOE index for 2003. This results in a cost of $397 million in 2004 dollars. The cost will then be re-escalated

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

[43] Refer to Resolution E-4049, Appendix C, for a detailed discussion on how the installed capacity cost for the 2006 MPR was developed.
http://www.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/63132.doc

[44] 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

from June 2004 to December 2007 using the USACOE quarterly index, which reflects annual escalation rates of approximately 5%. This methodology results in a capital cost estimate of $460 million for the beginning of 2008. (See 2007 MPR model "Install_Cap" Tab (cell D6)). The Consumnes initial capital costs of $435 million will be escalated from September 2005 to December 2007 using the USACOE quarterly index resulting in a capital cost estimate of $477 million for the beginning of 2008. (Refer to 2007 MPR model "Install_Cap" Tab (cells F6)). See table below for a results comparison of 2006 and 2007 MPR capital cost escalation methodology.

Plant / Escalation Rate	Initial Capital Costs ($ million)	2006 MPR Capital Costs ($ million)	2007 MPR Capital Costs ($ million)
Palomar / annual	$410	**$421**	$435
Palomar / quarterly	$410		**$460**
Consumnes / annual	$435	**$447**	$462
Consumnes / quarterly	$435		**$477**

Capacity Factor - Sales Weighted Average TOD factors

Pursuant to D.05-12-042, the capacity factor for the MPR CCGT is calculated using each utility's TOD profile to estimate a statewide average capacity factor for final MPR calculation.[45] To date, MPR models have used a simple average of IOU TODs which does not accurately reflect a statewide average capacity factor based on the relative size of the IOUs' load. Specifically, SDG&E's retail electric load is approximately 5 percent of SCE and PG&E's retail load, and therefore, SDG&E's TODs should not be weighed equally.

To calculate a more accurate statewide value, the 2007 MPR model will use each utility's retail sales to calculate a statewide weighted average capacity factor in favor of the simple average used in prior years. Retail sales of 76,692,370 MWh, 78,863,139 MWh and 16,846,888 MWh will be used for PG&E, SCE and SDG&E respectively, based on reports made by each utility in the RPS Proceeding (R.06-05-027).[46,47,48] See 2007 MPR model "Cap_Fac" Tab (cell E9 and cells; B13:14, B23:24, B30:31).

[45] D.05-12-042, page 34 -35

[46] Renewables Portfolio Standard Periodic Report of Pacific Gas and Electric (U 39-E), April 3, 2007. (R.06-05-027)

Forced Outage Rate

The 92 percent "technical" capacity factor used in the MPR model is based on the CEC Cost of Generation (COG) Model.[49] The CEC COG Model calculates an availability factor which is (1-Scheduled Outage Factor)*(1-Forced Outage Rate). The result of the formula is (1-3.84%)*(1-4.57%) = 91.77 percent.

The 2006 MPR calculated an "economic" capacity factor using each utility's TOD factors to determine when it is economic for the CCGT to operate. The model then took the minimum of the technical and economic capacity factors.[50] The method failed to use the Forced Outage Rate to account for forced outages when calculating the economic capacity factor. The Forced Outage Rate should properly be applied to all the hours in which the power plant is assumed to be operational in the MPR model.[51] The capacity factor calculation in the 2007 MPR model will therefore apply the Forced Outage Rate of 4.57 percent to reduce the "economic" capacity factor accordingly. See 2007 MPR model, "CF_Inputs" Tab (cell E10).

Operational Collateral for MPR proxy plant

Both renewable and non-renewable RFO's issued by the California IOU's require collateral. The cost of collateral, however, was not reflected in earlier MPR calculations. Collateral requirements fall into three general categories; bid deposit, development collateral and operating collateral.[52,53] The bid deposit and

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[47] 2006 Compliance Filing of Southern California Edison Company (U 338-E): Reporting Performance Pursuant to the California Renewables Portfolio Standard, April 3, 2007. (R.06-05-027)

[48] April 3, 2007 Compliance Filing of San Diego Gas & Electric: Reporting Performance Pursuant to the California Renewables Portfolio Standard, April 3, 2007. (R.06-05-027)

[49] The August 2003 Comparative Cost of California Central Station Electricity Generation Technologies report, www.energy.ca.gov/reports/2003-08-08_100-03-001.PDF Note: At this time, the CEC has not formally adopted an updated Comparative Cost of California Central Station Electricity Generation Technologies report.

[50] See 2006 MPR model, Cap_Fac tab, cells; O20, O27, O34.

[51] The Generation Availability Data System (GADS) definition of Forced Outage Rate is Forced Outage Hours/(Forced Outage Hours + Service Hours). Service Hours include all hours in which the plant is synchronized to the system, even if the output is zero. Service Hours do not include Reserve (aka Economy) Shutdown hours.

[52] Evaluation of Credit and Collateral Requirements for the California Public Utilities Commission: Final Report, February 22, 2007. Vantage Consulting

development collateral are assumed to have a negligible effect on the overall costs of a CCGT. The 2007 MPR model will, however, include assumptions regarding the cost of operating collateral.

Non-renewable RFO's in which a CCGT would participate generally use mark-to-market methods to determine the level of operating collateral required.[54] It is not possible, however, to include such mark-to-market measures in the MPR model given the complexity and lack of transparency of the mark-to-market methodology. Specifically, mark-to-market accounting is a dynamic methodology, which would require sophisticated market price forecasts and regular recalculating of collateral levels. It is therefore necessary to represent collateral costs in the MPR model using simplified assumptions.

Renewable RFO collateral requirements generally require 3-12 months of operating revenue for operating collateral.[55,56,57] Though not typically applied to fossil fueled generation, 6 months of operating revenue will be used as a proxy for the operating collateral requirements of the MPR proxy plant. Furthermore, it is assumed that such operating collateral will be provided through a letter of credit at a cost of 1 percent per year. This increases the MPR by approximately $0.30-0.39/MWh depending on the commercial online date and length of the contract term. Refer to 2007 MPR model, "Var_Comp" Tab (cells C17:V17).

<u>2007 MPRs include a GHG adder</u>

D.07-09-024 determined that because the MPR applies to long-term contracts for RPS-eligible generation, it was reasonable to include a GHG adder to account for the costs of compliance with recent California climate laws, Assembly Bill (AB) 32 (Global Warming Solutions Act) and SB 1368 (Emissions Performance Standard).

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[53] Lowering the Effective Cost of Capital for Generation Projects: California Credit Policies Report. January 2007, CEC 100-2007-001. Aspen Environmental Group & Sentech Inc.

[54] Mark to market is a pricing mechanism based on valuing a commodity or contract at its immediate resale value. http://www.energybuyer.org/glossaryLM.htm

[55]http://www.pge.com/includes/docs/pdfs/suppliers_purchasing/wholesale_electric_supplier_solicitation/2007rpsrfo_protocol_030707.pdf

[56] http://www.sce.com/NR/rdonlyres/CF783D2C-7A42-4D06-A66E-E10D5339DC99/0/200703122007_Procurement_Protocol.doc

[57] http://www.sdge.com/renewablerfo2007/docs/RFO.pdf

Pursuant to D.07-09-024, Ordering Paragraph 1[58], Staff adopted the $/CO2 ton values and methodology of the Energy and Environmental Economics (E3) Avoided Cost model for calculating a GHG adder.[59] In order to forecast the avoided cost of greenhouse gas emissions, the E3 Avoided Cost model includes a CO2 adder of $8/ton for 2004.[60] The CO2 cost is then escalated at 5 percent per year through 2023. An annual percentage growth rate, however, would result in increasingly steep exponential growth in later years. Therefore, the C02 costs in the E3 Avoided Cost model are escalated using a straight line trend of $0.90/ton per year from 2024-2030. The MPR model adopts this approach and continues the straight-line trend through 2040 to accommodate longer MPR contract terms.

The MPR model calculates a gradually deteriorating heat rate for each year of operation, which in turn is used to calculate the natural gas consumption for each year. The MPR model then multiplies the annual gas consumption by the factor of 0.0585 Tons CO2/MMBtu to calculate annual CO2 emissions in tons. This value is multiplied by the annual $/ton CO2 adder to calculate proxy GHG emissions costs, which are included as a variable operating cost. Refer to 2007 MPR model, "Var_Comp" tab (cells C18:V18).

As a result, the $/MWh GHG adders in the 2007 MPRs differ only slightly from the values recommended by CalWEA, GPI and CSPA. Refer to 2007 MPR model, “MPR Matrix” tab, “GHG Adder $/MWh” table.

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

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[58] 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. “

[59] The Avoided Cost model developed by Energy and Environmental Economics (E3) avoided cost model was adopted by the Commission in D.04-12-048 (R.04-04-003) and D.05-04-024 (R.04-04-025).

[60] http://www.ethree.com/cpuc_avoidedcosts.html

The 30-day comment period for this resolution has been reduced in accordance with the provisions of Rule 14.6 (c)(9). Rule 14.6 (c)(9) provides that the Commission may waive or reduce the comment period for a decision when the Commission determines that public necessity requires reduction or waiver of the 30-day period for public review and comment. For purposes of Rule 14.6 (c)(9), "public necessity" refers to circumstances in which the public interest in the Commission's adopting a decision before expiration of the 30-day review and comment period clearly outweighs the public interest in having the full 30-day period for review and comment, and includes circumstances where failure to adopt a decision before expiration of the 30-day review and comment period would cause significant harm to public health or welfare.

The public necessity in this case is that the 2007 RPS solicitations have closed and the MPR is an important component in administering the RPS program. Shortening the comment period for the 2007 MPR draft resolution will ensure that the RPS program moves successfully towards the 20% by 2010 goal, and therefore, clearly serves the public interest. The original draft Resolution E-4118 mailed for comment on August 23, 2007; no party filed comments objecting to the 2007 MPR methodology, and no errors were identified in the MPR model itself. Pursuant to D.07-09-024, the 2007 MPRs originally proposed in draft Resolution E-4118, will include a GHG adder. Including a GHG adder for the 2007 MPRs is not a significant model modification; nonetheless, the modification requires party review. For all the reasons stated above, a modified draft Resolution E-4118 will be mailed for a shortened comment period.

This matter will be placed on the first Commission's agenda 10 days following the mailing of this draft resolution. Comments shall be filed no later than 4 days following the mailing of this draft resolution, reply comments shall be filed no later than 8 days following the mailing, of this draft resolution.

On September 10, 2007, timely comments were filed by San Diego Gas & Electric (SDG&E), and jointly by California Wind Energy Association (CalWEA), Green Power Institute (GPI), and Concentrated Solar Power Alliance (CSPA). Reply comments were filed by Pacific Gas and Electric (PG&E) on September 14, 2007.

Parties support the 2007 MPR methodology

CalWEA, GPI and CSPA (collectively, CalWEA) supported the changes made to the MPR methodology from 2006 to 2007, as well as, the all-in combined cycle gas turbine (CCGT) costs calculated by the 2007 MPR methodology. SDG&E did not challenge the modified MPR methodology used to calculate the 2007 MPRs.

Parties recommend specific GHG adder values for use in 2007 MPRs

The GHG values[61] provided by CalWEA were derived using a single heat rate to calculate the recommended $/MWh GHG adders for the 2007 MPR. The MPR model, however, calculates a gradually deteriorating heat rate for each year of operation, which in turn is used to calculate the natural gas consumption for each year. Staff greatly appreciates parties' efforts to assist in calculating the GHG adder values for the 2007 MPR. However, to be internally consistent with the MPR methodology, Staff does not adopt the values proposed by CalWEA. Refer to 2007 MPR model, "MPR Matrix" tab, "GHG Adder $/MWh" table.

2007 MPRs should be coordinated with the Commission's decision on the Petition for Modification of D.05-12-042

SDG&E recommends the Commission withdraw draft Resolution E-4118 and reissue it after a final decision is reached on the Petition for Modification of D.05-12-042. SDG&E does not oppose the methodology used to calculate the 2007 MPRs, however, finds it difficult to conduct a full review of the 2007 MPRs prior to a final decision on Petition for Modification of D.05-12-042. CalWEA seek assurance that a Commission decision in favor of adopting a GHG adder will be incorporated into Resolution E-4118 and ultimately into the 2007 MPRs.

Staff agrees that the urgency for adopting the 2007 MPRs should not eclipse the importance of providing parties an opportunity to review the 2007 MPRs which now include a Commission adopted GHG adder. Accordingly, this modified draft Resolution E-4118 will be mailed for an abbreviated public comment period.

A robust evaluation of the MPR methodology for future MPRs is necessary.

CalWEA approve of the methodology used to calculate the 2007 MPRs, however, they encourage further refinement of the MPR methodology in 2008. Staff agrees with CalWEA that 2008 is an appropriate time to revisit the MPR methodology and the associated inputs. The Commission intends to examine the MPR in 2008 to determine what refinements should be made to the MPR methodology, including how the costs of GHG emissions should be reflected in the MPR for 2008 and later years.

[61] Comments of the California Wind Energy Association, the Green Power Institute and the Concentrated Solar Power Alliance on Draft Resolution E-4118 (September 10, 2007)

FINDINGS

1. The 2007 MPRs were calculated and released consistent with prior Commission decisions.
2. Decision 07-09-024 determined it is reasonable to include a GHG adder in the 2007 MPR calculation.
3. The 2007 MPR values for baseload proxy plants have been finalized for use in the 2007 Renewables Portfolio Standard (RPS) solicitations.

THEREFORE IT IS ORDERED THAT:

1. The 2007 MPRs in Appendix A are approved for use in the 2007 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 October 4, 2007; the following Commissioners voting favorably thereon:

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Paul Clanon
Executive Director

APPENDIX A

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

Operation Date	Baseload MPR	10 year	15 year	20 year
2008	**MPR All-in**	**0.09271**	**0.09383**	**0.09572**
	MPR fixed component	0.02720	0.02688	0.02679
	MPR variable component	0.06551	0.06695	0.06894
	GHG Adder	0.00271	0.00362	0.00426
2009	**MPR All-in**	**0.09302**	**0.09475**	**0.09696**
	MPR fixed component	0.02763	0.02744	0.02744
	MPR variable component	0.06539	0.06731	0.06952
	GHG Adder	0.00338	0.00423	0.00484
2010	**MPR All-in**	**0.09357**	**0.09591**	**0.09840**
	MPR fixed component	0.02804	0.02802	0.02812
	MPR variable component	0.06553	0.06789	0.07028
	GHG Adder	0.00414	0.00491	0.00548
2011	**MPR All-in**	**0.09412**	**0.09696**	**0.09969**
	MPR fixed component	0.02793	0.02810	0.02829
	MPR variable component	0.06619	0.06886	0.07140
	GHG Adder	0.00498	0.00566	0.00618
2012	**MPR All-in**	**0.09518**	**0.09844**	**0.10139**
	MPR fixed component	0.02783	0.02820	0.02850
	MPR variable component	0.06734	0.07025	0.07289
	GHG Adder	0.00592	0.00648	0.00695
2013	**MPR All-in**	**0.09605**	**0.09965**	**0.10275**
	MPR fixed component	0.02784	0.02824	0.02856
	MPR variable component	0.06822	0.07140	0.07418
	GHG Adder	0.00622	0.00679	0.00727
2014	**MPR All-in**	**0.09722**	**0.10107**	**0.10430**
	MPR fixed component	0.02785	0.02829	0.02863
	MPR variable component	0.06938	0.07278	0.07567
	GHG Adder	0.00653	0.00711	0.00760
2015	**MPR All-in**	**0.09873**	**0.10274**	**0.10602**
	MPR fixed component	0.02788	0.02835	0.02870
	MPR variable component	0.07085	0.07440	0.07732
	GHG Adder	0.00685	0.00745	0.00794
2016	**MPR All-in**	**0.10054**	**0.10466**	**0.10796**
	MPR fixed component	0.02792	0.02840	0.02876
	MPR variable component	0.07263	0.07626	0.07920
	GHG Adder	0.00719	0.00779	0.00828
2017	**MPR All-in**	**0.10270**	**0.10686**	**0.11131**
	MPR fixed component	0.02796	0.02845	0.02979
	MPR variable component	0.07473	0.07840	0.08152
	GHG Adder	0.00753	0.00814	0.00863
2018	**MPR All-in**	**0.10480**	**0.11018**	**0.11471**
	MPR fixed component	0.02801	0.02945	0.03090
	MPR variable component	0.07678	0.08073	0.08381
	GHG Adder	0.00788	0.00849	0.00899
2019	**MPR All-in**	**0.10820**	**0.11372**	**0.11697**
	MPR fixed component	0.02892	0.03052	0.03096
	MPR variable component	0.07928	0.08321	0.08602
	GHG Adder	0.00824	0.00885	0.00935
2020	**MPR All-in**	**0.11175**	**0.11599**	**0.11926**
	MPR fixed component	0.02989	0.03058	0.03102
	MPR variable component	0.08186	0.08541	0.08824
	GHG Adder	0.00861	0.00922	0.00972

APPENDIX B

2007 MPR California and Henry Hub Gas Forecast (2008 – 2039)

Year	MPR Hhub Forecast (nominal$)	MPR CA Gas Forecast (nominal$)
2008	$8.95	$9.10
2009	$8.68	$8.97
2010	$8.32	$8.66
2011	$8.01	$8.36
2012	$7.81	$8.15
2013	$7.72	$8.07
2014	$7.63	$7.99
2015	$7.54	$7.91
2016	$7.45	$7.82
2017	$7.75	$8.13
2018	$7.84	$8.23
2019	$8.07	$8.47
2020	$8.37	$8.78
2021	$8.53	$8.95
2022	$8.79	$9.22
2023	$9.05	$9.49
2024	$9.33	$9.78
2025	$9.54	$10.00
2026	$9.75	$10.22
2027	$9.98	$10.47
2028	$10.25	$10.74
2029	$10.49	$11.00
2030	$10.72	$11.24
2031	$10.97	$11.50
2032	$11.21	$11.76
2033	$11.46	$12.02
2034	$11.46	$12.03
2035	$11.71	$12.29
2036	$11.96	$12.55
2037	$12.21	$12.82
2038	$12.47	$13.08
2039	$12.72	$13.35

APPENDIX C
2007 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		Energy Information Administration (EIA)	$/MMBtu	N/A	EIA (Feb. 2007) - 20 yr.wellhead prices adjusted 10.8% to reflect Henry Hub forecast (public)
3	General Inputs	Transaction Cost	$/MMBtu	$0.082	D.04-06-015, pg. 26, reafirmed in D.05-12-042 (pg. A-7)
4		Transportation Escalation Rate	Percent-%	1.88%	Average of EIA 2007 GDP Chain-Type Price Index. See 2007 MPR model - Delivery_Tar Tab (Cell E9)
5		20-year WACC	Percent-%	8.93%	2007 MPR model - Cost Cap Tab (Cell D9)
6	Municipal Surcharge	SoCal Muni Surcharge	Percent-%	1.553%	Schedule G-MSUR - http://www.socalgas.com/regulatory/tariffs/tm2/pdf/G-MSUR.pdf
7		PG&E Muni Surcharge	Percent-%	1.005%	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
8	PG&E Gas Distrib. Rate	Customer Access Charge	$/day	$182	http://www.pge.com/tariffs/pdf/G-EG.pdf
9		Proxy Plant Capacity	MW	500	2007 MPR model - Delivery_Tar Tab (Cell E15)
10		Heat Rate	MMBtu/MWh	6.87	2007 MPR model - Delivery_Tar Tab (Cell E16)
11		Capacity Factor	percent-%	76%	2007 MPR model - Delivery_Tar Tab (Cell E17)
12		Monthly Gas Consumption	MMBtu	62,690	(Row 8 * Row 9* Row 10) * 24 hours
13		Unit Cost of Customer Access Charge	$/MMBtu	$0.0029	Row 7 / Row 11
14		Transportation Charge	$/MMBtu	$0.2341	http://www.pge.com/tariffs/pdf/G-EG.pdf
15	SoCal Gas Distrib. Rate	Customer Charge	$/month	$0.00000	http://www.socalgas.com/regulatory/tariffs/tm2/pdf/GT-F.pdf
16		Transmission Charge	$/MMBtu	$0.3892	http://www.socalgas.com/regulatory/tariffs/tm2/pdf/GT-F.pdf
17		Interstate Transportation Cost Surcharge	$/MMBtu	$0.0000	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 CPUC to keep the forecast confidential, staff can not reveal which of the three firms the forecast was purchased from.

APPENDIX D
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	$1,054	2.05%	Per D.05-12-042, Staff conducted a survey of actual plant costs in CA. Four plants were selected and an average was calculated
2		Fixed O&M	($/kW-yr) 1st operational yr.	$14.01	1.88%	See Attachement F, Mountainview Application (FERC Docket ER04-316). Highest and lowest values were deleted from Wharton data set, Palomar and CC8 were added, and an average value was calculated
3		Variable O&M	(mills/kWh) 1st operational yr.	$2.48	1.88%	See Attachement F, Mountainview Application (FERC Docket ER04-316). Highest and lowest values were deleted from Wharton data set, Palomar and CC8 were added, and an average value was calculated
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-%	1.64%	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	6916	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-%	8.93%	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-%	7.72%	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+)
9		Cost of Equity	Percent-%	13.28%	2.00%	Per D.05-12-042, Cost of Equity = risk free rate (20-yr Tbill) + risk premium (equity) + mid-cap risk premium (equity)
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%	1.88%	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.	Per CCC recommendation (comments, pg. 13) , Staff calculated the 2005 system annual average for GMMs used data provided by CAISO
15		Capacity Factor	Percent-%	71%	n.a.	Per D.05-12-042, Staff developed a methodology, using the average of IOU TODs, to calculate a range of capacity factors. See Cap_Fac Tab in 2007 MPR model
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 - 2008 levelized	$/MMBtu	$8.64	n.a.	Output from CA_Gas_Forecast Tab (Cell N42) in 2007 MPR model
21	GHG Adder	CPUC Avoided Cost C02 Ader	$/Ton	$8.00	n.a.	cpucAvoided26-1_update3-20-06.xls (http://www.ethree.com/cpuc_avoidedcosts.html) $8/ton in 2004, escalated at 5% per year to 2023, straight-line trend 2024 through 2030. MPR model continues straight-line trend to end of latest MPR contract term.