BEFORE THE PUBLIC UTILITIES COMMISSION OF

THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development.	))))	Rulemaking 01-10-024

JOINT COMMENTS OF THE UTILITY REFORM NETWORK AND SAN DIEGO GAS AND ELECTRIC COMPANY ON THE DISCUSSION ON MARKET PRICE REFERENTS PREPARED BY THE CPUC ENERGY DIVISION AND DIVISION OF STRATEGIC PLANNING

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Pursuant to the Energy Division notification distributed on March 22, 2004, The Utility Reform Network (TURN) and San Diego Gas & Electric Company (SDG&E) hereby provide comments on the white paper discussing market price referents. During 2003, TURN and SDG&E provided the Commission with Joint Principles for implementation of the California Renewables Portfolio Standard (RPS). These comments reflect the joint views of TURN and SDG&E on further refining the process, methodology and input values for calculating market price referents (MPRs) required under §399.15(c) of the Public Utilities Code.

I. MPR process issues

A. No need for formal decision adopting MPR methodology

TURN/SDG&E do not believe that there is any need for the issuance of a separate formal decision adopting the MPR methodology. Instead of waiting for a formal decision, the Energy Division should consider comments from parties, review materials and discussion from the upcoming workshop(s), and circulate both draft and final methodologies (after receiving one additional round of comments) that contain expected input values or data sources to the extent appropriate.[1] Final MPRs should be calculated as part of a utility solicitation and included in any resolution approving contracts with eligible renewable energy resources. The issuance of a formal MPR decision at this time will only encourage parties to file applications for rehearing on any number of aspects of

[1] Some data will necessarily be unavailable until the actual MPR is calculated after a specific utility solicitation.

the methodology and could thereby prevent any utility from conducting an RPS solicitation until all appeals (including state and federal court review) have been exhausted. It would be preferable to circulate the final methodology in a less formal manner and simply include the MPR calculation in a Commission order approving specific resource commitments.

B. Need for second workshop

TURN/SDG&E believe that any determination on the need for a second workshop should be made after the conclusion of the initial workshop on April 15. It is not possible to predict at this time whether additional days will be useful for reaching consensus or would merely result in parties restating existing positions. The Energy Division should poll parties after the first workshop and make a decision based on whether a second round would be helpful.

C. Timing of MPR disclosure

The white paper provides that the applicable MPRs shall be made public at the end of the bid submission period (p. 22). TURN/SDG&E are concerned that the release of the MPRs at the end of bid submission will allow the MPRs to influence the negotiations between the bidders and the utility in regard to pricing terms. The MPRs developed for a particular solicitation should not be disclosed until the utility files its advice letter seeking approval of the proposed RPS contracts.

Section 399.14(a)(2)(A) requires the Commission to determine the MPRs after the closing date of the solicitation but before the utility releases the results of the solicitation. This section, therefore, provides the Commission with the discretion to release the MPRs after the utility has made its advice letter filing. Moreover, this approach would better satisfy the objectives of this Section, which is to avoid the MPRs influencing the price of renewable energy.

II. General Market Price Referent Issues

A. Actual cost and performance data should be used to the extent possible

The Commission previously decided that the California Energy Commission cost of generation report should be the "starting point" for developing proxy plant estimates.[2] While these numbers are appropriate for the purpose of stimulating debate amongst the parties, the Commission should give preference to verifiable data from actual facilities to the extent possible. TURN/SDG&E believe that modifying the CEC report based on actual facility data will yield more accurate real-world results consistent with the directives of SB 1078.

The Commission now has full cost and expected performance data available for several new combined cycle and peaking plants being acquired by major California utilities, including turnkey purchase prices, annual capital and O&M revenue requirements, and heat rates. Many of the adjustments proposed in these comments rely on information from these facilities. Over time, additional comparable plants will be purchased, contracted or constructed by the utilities and could serve as the basis for updates to many of the key assumptions used to calculate the MPR.[3]

[2] D.03-06-071, p.20.

[3] TURN/SDG&E note that although the Commission can and should rely upon confidential data, this information should not become public solely by virtue of its use to calculate the MPRs.

B. MPR should be recalculated for each solicitation

The Commission should recalculate the MPRs for each solicitation. Section 399.14(a)(2)(A) requires the Commission to determine the applicable MPRs after the closing date of the solicitation in order to prevent the MPRs from influencing actual bid prices. This section, therefore, requires MPRs to be determined in response to each solicitation. This approach will avoid the MPRs developed for one utility's solicitation influencing the bid prices submitted in response to the next utility's solicitation. MPRs developed on an annual basis would neither satisfy the requirements of the legislation nor the need to keep the MPRs confidential until contracts are negotiated.

While TURN and SDG&E understand that the MPR may not change significantly between solicitations within the same year, the Commission may continue to adjust and refine the data inputs based on changes in commodity price forecasts or new information relating to capital costs for relevant projects. Even if the final MPRs for two solicitations within the same year do not vary significantly, the Commission should retain the practice of issuing a new referent for each set of renewable contracts.

C. Only one statewide referent should be calculated

In proposing to establish six different MPRs for each solicitation, the white paper does not contemplate additional referents that would be location-specific. (p.18) TURN/SDG&E agree that location-specific referents would not be practical. Particularly during the first years of RPS implementation, the process should not be overly complicated by an infinite number of MPRs for each solicitation. Statewide MPRs offer a more straightforward approach because a utility's renewables solicitation will not be restricted to projects in a particular geographic region.

A switch to location-based MPRs would dramatically expand the number of referents that need to be calculated for each solicitation. In order to anticipate all potential projects that could respond to a solicitation, the Commission would need to develop a comprehensive set of location-specific MPRs for each utility solicitation because the MPRs must be determined before the results of the solicitation are known (§399.14(a)(2)(A)). The Commission should avoid the unduly burdensome and complex process of developing regional adjustments for items such as land costs and emissions credits by determining statewide MPRs for each solicitation. To the extent that costs differ for plants constructed in different regions, these variations should be captured in the statewide MPR by averaging data from a set of actual or proxy facilities incorporating relevant locational pricing, emissions cost, or operational performance differences.

III. Baseload referent cost components

A. Capital Costs

The white paper picks an illustrative number of $650/kw for a new combined cycle plant based on an average of TURN's original testimony and the CEC report. As indicated previously, TURN/SDG&E believe that more recent and real-world data can be substituted for the CEC numbers. Since the submission of TURN's 2003 testimony, evidence submitted in two major proceedings (A.03-07-032 and R.01-10-024 (SDG&E RFP Phase)) provides significant data on new facility costs that should be afforded great weight. In addition to full capital cost data for the two turnkey projects (Mountainview and Palomar) submitted for approval, SCE provided data on a range of projects that have been announced or recently completed.[4] The use of cost estimates for Mountainview, Palomar and Magnolia should be particularly useful because they include transmission internconnection (gen-tie) costs and AFUDC, both of which are excluded from the CEC cost report.

Capital costs for the Mountainview plant (including AFUDC) are projected to be $667/kW.[5] Since Mountainview was recognized by the Commission to be a distressed asset purchased at a below-market price, this plant should serve as the lowest data point for purposes of averaging the cost of multiple facilities. SCE's testimony in that application shows data on comparable facilities that, when averaged together, yield a price of $740/kW.[6]

The Commission should also incorporate capital cost data for facilities at the higher end of the cost spectrum. These include the Palomar plant proposed for purchase by SDG&E and the Magnolia facility being constructed by a consortium of municipal utilities. Although the turnkey data for Palomar is confidential, SDG&E has provided comprehensive information on capital costs in R.01-10-024 that can be included in the MPR calculation. SDG&E is willing to submit this information separately to the Energy Division under confidential seal. Data on the cost of the Magnolia plant, previously estimated by TURN at $856/kW, can be obtained through publicly available sources.[7]

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[4] SCE testimony, A.03-07-032, Ex. 1, p.119-120.

[5] D.03-12-059, attachment with Mountainview costs shows a total of $703.2 million (in $2006), which yields $667/kW when divided into 1054 MW of plant capacity.

[6] See testimony of Kevin Woodruff, R.01-10-024 (SDG&E RFP phase), Ex. RFP-59, p.23. This figure also includes an escalation to $2006.

[7] See testimony of Bill Marcus, April 1, 2003, p.11. This figure excludes duct firing costs. For public sources, see http://www.scppa.org/magnolia.htm, http://www.scppa.org/Downloads/Bonds/magnoliaprobjectbonds.pdf, and Pasadena, City of. City Manager, Agenda Report, "Adopt Resolution and Ordinance Approving the Magnolia Power Project Power Sale Agreement…" April 8, 2002, page 4. http://www.ci.pasadena.ca.us/councilagendas/2002%20agendas/Apr_08_02/5D1.pdf

B. Capital Recovery Factor:

The capital recovery factor model contained in the white paper is overly simplistic and should be replaced with either a fixed charge model or a cash-on-cash model. Fixed charge models are typically used for developing utility capital-related annual revenue requirements. Cash-on-cash models are used to estimate revenue streams needed to generate minimum a fixed return on common equity for a merchant developer. TURN's April 2003 testimony, cited extensively in the white paper, used a cash-on-cash model for developing the TURN-SDG&E MPR methodology previously considered by the Commission. TURN provides examples of both models with illustrative inputs that are attached to these comments.[8]

If the Commission wishes to adopt the model used in the white paper, the cost of capital figures must be adjusted upwards to account for the income tax treatment of utility debt and assume a utility rate of return of between 12 and 13% including income taxes. In the event that the Commission wishes to base the calculation on a merchant (non-utility) financing structure, the revenue requirement for capital recovery would be equivalent or slightly higher. Differences for merchant financing include higher costs of both debt and equity, a greater debt-to-equity ratio and a shorter term on debt repayment (as compared to a utility plant). In addition, the white paper's capital recovery factor model does not take into account accelerated depreciation (which reduces costs) and property taxes (which increase costs). Those factors can be incorporated into the calculation with the use of an alternative model.

[8] The attached spreadsheet produced by TURN (FCR-COC_models.xls) shows these two models on a hypothetical combined-cycle plant with capital costs of $750/kw.

Assuming a current utility cost of capital (12.5%) and 20-year recovery period, a fixed charge rate slightly in excess of 14% would be appropriate. If the Commission adopts the model contained in the white paper, TURN recommends that this fixed charge rate should be used. If the Commission is willing to consider alternatives models, one of the two methodologies shown in the attachment should be used to derive the annual capital cost recovery for a new combined-cycle or combustion turbine unit.

C. Capacity Factor

The white paper cites TURN's 2003 testimony in proposing a capacity factor of 92% for calculating the baseload MPR. TURN/SDG&E support the use of a high capacity factor that reflects baseload operations but excludes forced and maintenance outages along with duct firing operation. A range of 90-94% would be reasonable for this purpose, and the white paper's use of 92% is appropriate.

D. O&M Expenses

The white paper identifies separate values for fixed and variable O&M costs. TURN/SDG&E recommend that these costs not be separated in the calculation because many analysts use different definitions of fixed and variable O&M. In order to avoid double counting of O&M costs or omitting certain costs from the calculation, an estimate of total fixed and variable costs should be utilized.

As indicated previously, TURN/SDG&E believe that more recent and real-world data should be utilized to estimate total O&M costs. This total O&M data is presently available to the Commission in regard to the Moutainview and Palomar turnkey projects proposed by the utilities.

In general, TURN/SDG&E propose that an appropriate estimate of total fixed and variable O&M would be in the range of $3.50-$4.00/MWh. This range reflects the high capacity factor proposed by TURN/SDG&E. It excludes property taxes (which should be included in the fixed charge model) but includes insurance.

E. Fuel Costs

The white paper asks for guidance on data sources for gas commodity costs that will allow for the development of long-term fixed fuel prices required by SB 1078. TURN/SDG&E support the use of several basic long-term forecasts that can be validated with shorter-term forecasts and market pricing data. Since none of the data sources provides perfect clarity, Commission staff will need to exercise some degree of judgment in assigning relative weights to each forecast as part of each final MPR calculation.

The Commission should begin by averaging the forecasts included in the approved long-term procurement plans of all three utilities. Use of these forecasts will help to align the data sources applicable to all procurement activities. Those forecasts should be compared or averaged with recent CEC forecasts.[9] Any other available long-term forecasts applicable to California could be further incorporated into the model.

Long-term forecast data can be checked against shorter-term forecast or market prices (like the NYMEX) so long as the data includes a basis adder to the California border and firm intrastate transportation. In the event that shorter-

[9] Since the CEC calculates a forecast of fuel prices approximately once every two years, that forecast may become stale if the time lapse is too significant between the CEC approval process and the MPR calculation, so that use of a CEC forecast should be encouraged when appropriate but should not be required.

term data sources diverge significantly from the average of long-term forecasts, this data could either substitute for early year pricing or be used to adjust the long-term forecasts as appropriate.

F. Fuel Hedging Costs

TURN/SDG&E believe that the Commission should continue to explore appropriate data sources and methodological approaches that can be used to calculate the cost of hedging fuel supplies over periods of 10-20 years. It is worth noting that several real-world examples demonstrate substantial hedging costs, including SCE's recent expenditures of $0.80/mmBTU to hedge exposure for its Qualifying Facilities in 2002-2003 and expenditures of $2/MCF by the Los Angeles Department of Water and Power to obtain storage capacity for 2004. Research conducted by Lawrence Berkeley Laboratory suggests that it is appropriate to consider a forecast adder of between $0.40 and $0.80/mmBTU to account for the fact that forward gas contracts have been shown to trade above price forecasts.[10] The white paper adopts a value of $0.45/mmBTU, which is at the lower end of this range. TURN/SDG&E believe that this estimate is appropriate for use in the first round of MPR calculations but should be updated and adjusted to reflect the choice of fuel price forecast data, actual utility hedging experience, and emerging research on the quantification of hedging costs.

G. Heat Rate

The heat rate should reflect actual baseload operations rather than cycling and should exclude duct firing, because duct firing is dispatchable capacity used for

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[10] For the most recent iteration of this research, see "Accounting for Fuel Price Risk: Using Forward Natural Gas Prices Instead of Gas Price Forecasts to Compare Renewable to Natural Gas-Fired Generation" by Mark Bolinger, Ryan Wiser and William Golove, Lawrence Berkeley National Laboratory, LBNL-53587, August 2003.

peaking. The average heat rate, however, should be higher than the full load heat rate under new and clean ISO conditions to reflect real world inefficiencies. It should include an adder of about 5%[11] to cover factors such as degradation between overhauls and over time, temperatures different from ISO, partial forced outages, and start-ups and ramp-ups from outages. TURN/SDG&E recommend that the heat rate be in the range of 7200-7400 Btu/kWh at this time based on real-world data of 6900-7000 Btu/kWh from new-and-clean combined cycles without duct firing.

IV. Peaking referent costs

A. Capital Costs

The white paper lists capital costs of $475 kW for a combustion turbine based on the CEC generation report. Capital costs of less than $500 kW, however, are too low to represent actual costs observed in practice. The California Power Authority's (CPA) inability to secure peaking capacity under its $500/kW cap confirms this conclusion.

TURN/SDG&E recommend that more recent real world data be utilized to update the CEC numbers. The cost data filed with the Commission for a new utility project such as the RAMCO CT proposed by SDG&E as part of its recent grid-reliability RFP should be relied upon to update these costs. Given the lack of current utility filings containing data for such units, estimates can be supplemented in the near term through confidential submissions of data from

[11] TURN/SDG&E note that this adder can be refined based on readily available degradation curves from GE to estimate the average heat rate degradation expected over a 20-year operating period assuming normal and customary maintenance, although (as discussed above) degradation is not the only source of higher heat rates that are higher from new and clean conditions. This adder would only need to be derived once unless at some point in the future there is a dramatic change in technology.

the CPA to the Commission. The Commission should utilize its discretion to determine the weight accorded to the data obtained from these sources.

B. Capital Recovery Factor

See the discussion in Section III(B).

C. Capacity Factor

The white paper lists a 10% capacity factor based on the CEC generation report. This number does not accurately represent the expected capacity factors from any economically attractive combustion turbine and fails to reflect the expected deliveries from renewable generation that will be benchmarked against the peaker MPR. TURN/SDG&E believe that the most likely renewable technology to provide peaking power is a solar thermal project. The Commission should therefore set the peaking capacity factor based on the expected utilization of solar thermal generation.[12] An initial capacity factor of 20% is appropriate but should be adjusted to reflect real-world experience with solar plants or other renewable technologies that qualify to deliver power that can be benchmarked against the peaker MPR.

D. O&M Costs

As stated in section III(D), fixed and variable O&M costs should be combined and not estimated separately as proposed in the white paper. TURN/SDG&E also urge the Commission to use recent real-world data, to the extent possible, to estimate total O&M costs. TURN/SDG&E recommend that the MPR peaker

[12] Solar thermal capacity factors should not include any output generated through the combustion of natural gas, since that portion of the plant's output (if any) would not count towards the utility's annual procurement target.

calculation assume total O&M costs of approximately $5/MWh. Although many contracts with peaking units contain variable O&M charges of $5-$10/MWh, the TURN/SDG&E proposal to use a relatively high capacity factor (20%) means that the Commission should focus on the low end of this range to capture expected variable and fixed O&M expenses.

E. Fuel Cost

See the discussion in Section III(E).

F. Fuel Hedging

The white paper proposes to omit a fuel hedging cost from the calculation of a peaker MPR. Although utilities may not typically hedge fuel costs for peaking plants, the Commission cannot certify that the MPR reflects a "fixed-price" source of electricity as required under §399.15(c) unless the fuel costs are fixed for the duration of the calculation. Therefore, the same fuel hedging costs calculated for a baseload plant should be applied to the peaker MPR. For a discussion of the appropriate hedging values, see the discussion in Section III(F).

G. Heat Rate

The heat rate used in the calculation of the peaker MPR should be based on real world data from the newer peaking units that are presently being installed. These units tend to be under 50 MW because units under this size threshold are not subject to California Energy Commission permitting. The units of choice for new peaking facilities are the GE LM 6000 at 42 to 46 MW and the Pratt and Whitney FT8 at just under 50 MW due to their relative ease of compartmentalized construction, favorable operating characteristics and efficiencies. The heat rates for these units are 9900 and 10,400 Btu/kWh. The heat rate of 9300 Btu/kWh listed in the white paper is low relative to these units (p. 17).

Consistent with the newer units, TURN/SDG&E recommend that a heat rate between 10,000 and 10,500 Btu/kWh be used at this time in the calculation of the peaker MPR. The small adder from the specific plant heat rates identified above reflects amortization of fuel used in start-ups over kWh production and slightly higher heat rates experienced on hot days relative to ISO conditions.

Respectfully submitted,

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