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To: David Mohre and Paul McCurley, NRECA
From: Mathew J. Morey and Laurence D. Kirsch, CA Energy Consulting LLC
Re: Review of LECG Analysis of Coordinated Markets
Date: December 19, 2006

As you requested, we have reviewed the recent PJM-sponsored LECG report entitled *Analysis of the Impact of Coordinated Electricity Markets on Consumer Electricity Charges* (hereafter referred to as "Report").¹ This memorandum summarizes our conclusions about the overall quality of the empirical analysis conducted and the weaknesses of the study.

Overview of the LECG Report

The objective of the Report was to examine empirically the impact of coordinated wholesale electricity markets with LMP pricing on retail electricity rates. "Coordinated wholesale markets" refers to the centralized day-ahead and real-time electricity markets run by Regional Transmission Organizations (RTOs). The study intentionally looked only at the impact of restructured *wholesale* markets, not restructured *retail* markets, on retail rates. The purpose of the Report was to respond to those who have questioned whether such coordinated markets have produced net benefits for retail consumers of electricity.

To estimate the impact of coordinated markets, LECG estimated what the residential rates would have been in the New York and PJM RTO regions during the study period if coordinated markets had not been introduced. Coordinated markets would provide a net benefit to retail consumers if the estimated rates *without* restructured wholesale markets are found to be higher than the actual rates *with* restructured wholesale markets during the study period.

The Report analyzes the effects of wholesale market restructuring over the period from 1998 to 2004. In a vain attempt to avoid having the findings influenced by the peculiarities of state regulation, the Report looks only at municipal utilities (munis) and electric cooperatives (coops), as neither of these groups is typically rate-regulated by the state public utility commissions. Thus, no investor-owned electric utilities (IOUs) were included in the study. Furthermore, the Report estimated restructuring impacts only for munis and coops in the New York and PJM RTOs; and it used munis and coops in the Southeastern United States as a control group for

¹ S.M. Harvey, B.M. McConihe, and S.L. Pope, *Analysis of the Impact of Coordinated Markets on Consumer Electricity Charges*, LECG, LLC, November 20, 2006.

setting certain key parameters of the analysis. Restructuring impacts were measured according to the “average annual rates” of the munis and coops.

The study finds that, over the period 1998 to 2004, wholesale market restructuring reduced the average annual residential rates for munis and coops in the New York and PJM RTOs by \$0.50 per MWh to \$1.80 per MWh, relative to what rates would have been absent coordinated markets. Assuming the combined average load of NYISO and PJM is 100,000 MW per hour, the Report notes that the rate reduction of \$0.50 per MWh translates to savings of \$1.2 million per day and \$430 million per year. Estimated rate reductions of \$1.50 per MWh would translate into savings of approximately \$1.3 billion per year.

Critique of the LECG Report

Although the Report does make a serious attempt to estimate the benefits of restructuring, it suffers from so many modeling problems that its estimates cannot be regarded as reliable or accurate. The main modeling problems include the following:

- *The Report implausibly extends the estimated results for muni and coop customers to IOU customers and the entire regional market load of which munis and coops are only a small fraction thereof.* IOUs, which are regulated for-profit organizations, have different incentives and opportunities than munis and coops, which are generally unregulated not-for-profit organizations. Consequently, the results for munis and coops, even if they are valid, are not directly applicable to the customers who are served by IOUs, who happen to be the large majority of customers in the New York and PJM RTOs. Furthermore, munis and coops typically had higher percentages of their load covered by owned generation or longer-term power purchase contracts than many of the IOUs in the period 1998 to 2004, giving munis and coops very different cost and market exposures than IOUs. Long-term contracts and power supply arrangements may have significantly reduced market exposure for some munis and coops during the chosen study period. Indeed, as the Report itself admits, its analysis focused on the munis and coops precisely because they *are* different from the IOUs.
- *The Report incorrectly assumes that cost conditions in New York and PJM are proportional to those in the Southeastern U.S.* To obtain its price estimates without restructuring, the Report’s analysis implicitly assumes that the relationship of the muni and coop rates in NY and PJM to the muni and coop rates in the Southeast during the period 1990-1997 continued into the 1998 to 2004 period. This ignores the likelihood that prices in the high-cost states (of New York and PJM) would have fallen toward those in the low-cost states (of the Southeast) because of the expiration of high-cost legacy obligations in the high-cost states. It also does not address the possibility that restructuring in the high-priced markets may have increased the flow of power from the low-cost states to the high-cost states, thus raising wholesale market prices in the Southeast, raising wholesale supply costs for southern munis and coops, and thus contaminating the “control” data of the Southeastern utilities.
- *The Report implausibly assumes that utilities in New York and PJM have the same need and ability to pass wholesale power costs to residential customers as do utilities in the*

Southeastern U.S. On the contrary, the utilities in the different regions differ in at least the following ways:

- *As previously mentioned, many munis and coops in New York and PJM were procuring power under long-term wholesale power contracts that expired after 2004.* In particular, New York’s munis and coops have for many years obtained up to 100% of their power requirements from the New York Power Authority under low-cost long-term contracts. The Report thus ignores the reality that the rates of these munis and coops could not have been affected by the development of the coordinated markets during the study period, and that their rates largely reflect pre-existing contractual commitments rather than the introduction of coordinated markets.
- *Munis and coops differ in their fuel adjustment clauses (or lack thereof).* This means that some munis and coops automatically pass on to residential ratepayers their increases in fuel costs, while others do not. Consequently, New York and PJM may significantly differ from the Southeast in the portion of fuel cost increases that are automatically reflected in retail rates.
- *Fuel costs and fuel mix have not been adequately considered.* Although the Report used the Southeastern utilities as a proxy for fuel price impacts, that proxy did not account for the facts that fuel costs vary by region and that these regional differences change over time, sometimes significantly. Furthermore, although the Report attempts to control for fuel mix through separate regressions for gas- and oil-dependent states versus other states, each group includes states with very dissimilar gas and oil dependence, thus undermining the value of separate regressions.
- *The Report acknowledges that it has failed to control for many factors.* “Average retail rates vary from year to year for a variety of reasons that are not controlled for in the study such as year to year variations in average and peak load across the regions analyzed in the study, variations in cost recovery practices across the utilities included in the study, major nuclear plant outages within the regions during particular years, variations in the duration, timing and terms of forward hedging contracts, and differences in year to year changes in fuel costs.”² This healthy admission of the limitations of the analysis is sufficient to create a correspondingly healthy skepticism about the resulting estimated rate impacts and about the Report’s far-reaching conclusions about the benefits to electricity consumers.
- *The Report overlooks the interdependence of the Southeastern utilities that comprise the “control” group.* For example, munis and coops in the Carolinas and Georgia often jointly procure power, some through Joint Action Agencies and other times through lead utilities (e.g., Santee Cooper, North Carolina Electric Membership Corporation). Similar arrangements exist in the other southeastern states. This joint procurement means that the

² Report, p. 6.

Report's assumption that the rates of the utilities within the southeastern "control group" sample are independent is violated and thus the model estimates are biased.³

There are also the following anomalies in the reported results:

- *The Report's results for the first year of restructuring are implausible.* The Report acknowledges that LMP-based restructured markets began in New York in November 1999; but the Report predicts that residential customer prices without restructuring in 1999 would have been as different from the actual prices in 1999 as are the predicted and actual prices for the years 2000 to 2004. It is astonishing that the impact of restructuring in a year with only two restructured months would be of roughly the same size as the impacts in years with twelve restructured months. This casts substantial doubt on the veracity of the price estimates for all years.
- *The estimated effects of industrial loads on residential rates are odd.* The Report's detailed quantitative results say that, all else held constant, larger industrial loads reduce residential rates for utilities in gas-dependent regions but increase rates for utilities in non-gas dependent regions. The Report offers no explanation for this strange result. A likely explanation is that the model suffers from specification errors.

Finally, there are the following technical problems with the statistical analysis:

- *The robustness of the quantitative results is questionable.* The Report shows a "good fit" (a high R-squared) for its statistical results; but this is largely an artifact of a "connect the dots" exercise in which numerous time dummy and utility dummy variables account for all the factors left out of the model. Therefore, the good statistical fit is not a reflection of the robustness of the model results or the explanatory power of the estimating equation. Furthermore, while the Report indicates the statistical significance of the parameters of the estimating equation, it fails to indicate the confidence bands around the estimated residential rates. Without knowing these confidence bands, it is not possible to determine whether there was a statistically significant difference between the predicted and actual residential rates: *it is possible that the price differences are nothing more than statistical noise.*
- *The estimating equation included an "Allegheny Impact Variable" that implies that problems may be caused by anomalous data.* The Report's model includes a variable that gives special treatment to utilities that were serving load within the Allegheny control area in 2002 and 2003.⁴ Typically, the reason for introducing a variable so specific to a particular utility or time period is to control for anomalous data that cannot be explained and that would otherwise distort the analytic results.
- *The Report's estimating equations are not robust to changes in the explanatory variables.* The Report presents results for two model types – the Utility Dummy Model and the 1990 Rate Model. The 1990 Rate Model has the same explanatory variables used in the

³ On a technical level, the dependence across "control" group utilities introduces biases into the estimates of the coefficients and their standard errors.

⁴ Report, p. 22.

Utility Dummy Model, plus variables that represent 1990 muni and coop rates.⁵ The significant differences in the estimated coefficients and the rate impacts of these two models suggest that the results are not robust to changes in the set of explanatory variables. Such lack of robustness generally can be attributed to high correlations among the explanatory variables that render the coefficient estimates unstable.

The foregoing list of shortcomings is consistent with the critique of the Report that has been provided by the American Public Power Association, a critique with which we concur.⁶

Conclusions

Quantifying the effects of restructuring on consumer prices is tricky business because these prices are affected by so many factors. Of all of the estimates published these past few years, this Report provides what is perhaps the most serious attempt at quantification of the impacts of coordinated markets on consumer prices. Still, the results presented in the Report are highly questionable since they are based upon a questionable approach and questionable assumptions.

The Report compounds the foregoing analytic problems by extrapolating its questionable predictions for munis and coops to the entire load of the New York and PJM RTOs. This extrapolation is unreasonable because of the significant differences between munis and coops, on the one hand, and the IOUs that serve the majority of load on the other. As LECG takes great pains to explain throughout the Report, it is the differences between the munis, coops, and IOUs that has driven the analysis to focus on the munis and coops in the first place.

Consequently, this Report cannot be relied upon to have reasonably answered the question about whether coordinated markets have in fact produced net benefits for consumers.

⁵ The rate impacts estimated from these two model types are presented in the Report's Tables 10 and 11, and they represent the values of the estimated coefficients on the "coordinated markets" dummy variable included in the two model types. Regression results are presented in Tables B-1 and B-2; but these results are incomplete since the estimates of the coefficients on the utility dummy variables are not reported at all. In the interest of full disclosure, these coefficients should have been reported in an appendix.

⁶ *Statement of the American Public Power Association responding to an analysis commissioned by PJM Interconnection of the Impact of Coordinated Electricity Markets on Consumer Electricity Charges*, December 1, 2006.