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ACTIVITIES RELATED TO THE	§	
IMPLEMENTATION OF A NODAL	§	**PUBLIC UTILITY COMMISSION**
MARKET FOR THE ELECTRIC	§	**OF TEXAS**
RELIABILITY COUNCIL OF TEXAS	§	

COMMENTS OF CAPP AND STAP ON THE ERCOT MARKET RESTRUCTURING COST-BENEFIT ANALYSIS FINAL REPORT FILED DECEMBER 21, 2004

The Cities Aggregation Power Project (CAPP) and the South Texas Aggregation Project (STAP) are both political subdivision corporations and members of ERCOT. Combined, CAPP and STAP represent over 120 members with an aggregated load of over 1.2 billion kWh of usage annually. Most of the members are municipalities that formerly received bundled retail service from an IOU.

Utilizing the current ERCOT five zone model, CAPP members are located in the North, Northeast, and West zones. In particular, a large number of CAPP members are located in the Dallas/Fort Worth metroplex. These members are particularly aware of the current problems in serving loads within this area due to the limitations of the current 138 kV transmission system in this area and the need to import power into the DFW non-attainment area in order to meet the local demand. These CAPP members are concerned about their ability to secure energy at reasonable prices and the impact on regional economic development under a nodal market design.

STAP members are all located in the current South zone and represent many of the larger metropolitan areas within this zone that were traditionally served by Central Power and Light prior to customer choice in 2002. These members have seen the historic costs attributed to both local congestion and reliability must run (RMR) service in the South zone and in some cases, in their individual city. Like CAPP members, they are extremely concerned about the negative economic impact which may be thrust upon this zone by the direct assignment of local congestion costs to this zone. Additionally, there have been discussions in development of the Texas Nodal option that will allow some Non Opt-In Entities (NOIE) to create a zone of their own. If this is allowed, it will

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significantly increase the costs to the non-NOIE loads in the South. Because of the potentially significant impact on some loads in the South zone, the NOIE load zones that have been confirmed in the TNT protocols should be modeled in the Cost Benefit Analysis.

As loads, CAPP and STAP have an extreme interest in the efforts to re-design the ERCOT market and the impacts such a re-design may have, not only on our loads, but on the loads of our members' citizens. CAPP and STAP have reviewed the final edition of the Cost Benefit analysis and offer the following comments concerning the study.

General Observations

One of CAPP and STAP members' major concerns with the ERCOT Market Restructuring Cost Benefit Analysis (Cost Benefit Analysis) prepared by Tabors Caramanis & Associates (TCA) is the disproportionate allocation of costs and benefits, particularly in the South Zone. CAPP is also particularly concerned about the future development of a DFW zone and the impact it may have on the future allocation of costs and net benefits (if any) to CAPP members within this zone. In examining the load impacts of the Cost Benefit Study, as shown in Table 3-20 of the Costs Benefit Analysis, it is clear that the vast majority of alleged benefits to be derived from the application of nodal will be to loads within the Houston zone. The majority of benefits to load in the remaining four zones is miniscule in comparison to those of the Houston zone and often times the majority of the benefits to the other four zones occurs in the later years of the analysis. The results shown in these later years (2012-2014) are subject to error and not reliable since, by the admission of TCA in the Cost Benefit Analysis study, they are influenced by the transmission system assumptions used in the analysis (CBA, page xii). Indeed, the consultants that developed the Cost Benefit Analysis provided the following warning in their October 27, 2004 presentation of initial results of the Cost Benefit Analysis:

> "TCA believes that specific predictive conclusions should not be based on TCA results obtained for the out years (2013, and especially 2014). Massive addition of new generating resources modeled for out years is not supported by transmission upgrades." (Preliminary Report on EIA Results, October 27, 2004. Slide 7)

Thus, it is very possible that unless a more detailed and perfected set of transmission system assumptions is used in the later years of the analysis, there may be little to no net benefit to loads located outside of the Houston zone.

CAPP and STAP are also concerned about the extreme changes in the results of the final Cost Benefit Analysis as compared to the preliminary results presented in September 2004. TCA presented an update of preliminary results of the Energy Impact Analysis (EIA) at the September 10, 2004 meeting of the Cost Benefit Concept Group. In this presentation, TCA stated that while they were still investigating some zonal results for years after 2007, they felt their results for the time period from 2005 through 2007 were "solid" for both the zonal and nodal cases. (TCA Presentation titled Cost Benefit Study Update, dated September 10, 2004.) Slide 8 of this presentation shows that the total cost of serving load under the nodal case as compared to the zonal case is greater in the nodal case by $3.2 billion in 2005, $2.9 billion in 2006, and $4.5 billion in 2007 (prior to congestion rent refund). While it is noted in the presentation that these are preliminary results and are subject to change, CAPP and STAP find it hard to believe that the differential costs between the nodal and zonal cases change so drastically to a net benefit to the nodal case of $0.37 billion in 2005, $0.45 billion in 2006, and $0.56 billion in 2007 (prior to congestion rent refund), as shown in Table 3-11 of the final report.

$ in Millions	**Total Costs of Serving Demand (Nodal – Base(Zonal))**		
Year	**September 10, 2004 Preliminary Results** (TCA Cost-Benefit Study Update 9/10/2004)	**November 30, 2004 Final Results** (ERCOT Cost Benefit Study Final Report, Table 3-11)	**Difference**
2005	$3,239	($370)	$3,609
2006	$2,980	($449)	$3,429
2007	$4,574	($561)	$5,135

CAPP and STAP also find it hard to be confident in a final analysis that is preliminarily declared to be "solid" over this three year period on September 10, 2004, yet changes by an average of $4 billion by November 30, 2004. CAPP and STAP believe that the radical changes that occurred in the conclusions of the consultant between September and November are attributable to bias on the part of certain members of the Commission Staff who compelled a pro-nodal report. At a point in time when public policy makers, including the Commissioners, have a lack of confidence in the leadership of ERCOT, the Commission should refrain from reaching any conclusions about fundamental market change based on a study that flip-flops its conclusions after discussion with Staff members who desired an outcome different than that preliminarily reached by "independent" consultants. At the least, the September to November variance suggests that this cost benefit analysis needs a major review and should not serve as the justification of changing ERCOT's fundamental market design. At the least, the Cost Benefit Analysis presented in the November 30, 2004 final report should be discarded and a new and thorough cost benefit analysis performed prior to determining the need for a new market design.

Overall, the ERCOT Market Restructuring Cost-Benefit Analysis is based upon a methodology that can generally be described as flawed, unverified and applied inconsistently between the Base Case and the nodal Change Case. The factors leading to these weaknesses are so fundamental and pervasive in the conduct of the study that the resulting final report cannot be used as a reliable projection of the benefits of converting the current zonal market design (Base Case) to the proposed nodal market design (Change or Nodal Case). In particular, the result of applying the flawed and inconsistently applied study methodology results in an extreme overstatement of the potential benefits of the nodal market design compared to the zonal market. In the following comments, CAPP and STAP will detail their concerns with the Cost Benefit Analysis.

Methodology Flawed

The basic modeling methodology of the Cost Benefit Analysis is flawed in important respects that tend to overstate the payments for market energy in the existing zonal case, and understate the cost of congestion management in the nodal case. This results in an overestimate for zonal and an underestimate for nodal of the Generator Net Revenues. This in turn produces an exaggerated estimate of the difference in the Cost to Serve Load between nodal and zonal, one of the primary metrics of the nodal benefits cited in the Cost Benefit Analysis.

In the case of the model of the existing zonal market, the Cost Benefit Analysis prices all energy to serve load at the projected Market Clearing Price of Energy (MCPE). MCPE is defined as "(t)he highest price associated with a Congestion Zone for a Settlement Interval for Balancing Energy deployed during the Settlement Interval" (ERCOT White Paper – Calculation of Market Clearing Price for Energy 12/10/04, p. 1).

By assuming that all energy to serve load is priced at this highest price surrogate, the Cost Benefit Analysis completely ignores the more economical prices that are prevalent in the existing zonal market associated with bilateral contracts and term purchases that provide the bulk of the energy consumed by load in ERCOT, leaving in many intervals only the more expensive, marginal production units available and priced for Balancing Energy. (Another way to look at this is that if MCPE were the most attractive energy price in the current market, it would represent nearly 100% or market transactions, rather than approximately 5% of market transactions.) Thus, using MCPE as the means to estimate future prices for payments for market energy if the existing zonal market is continued, overestimates the payments to generators shown for the zonal case in Table 3-5 of the Cost Benefit Analysis.

While CAPP and STAP believe that modeling assumptions lead to overstated costs in the zonal analysis, CAPP and STAP are also concerned about modeling assumptions that may lead to understated costs in the nodal analysis. In particular, in the modeling of the proposed nodal market, OOME is assumed to be zero in all years. In the description of the method for estimating OOME in the zonal market in Section 3.3.2.4, TCA explains the reasons that its model of the existing zonal model greatly overestimates OOME compared to recent actual amounts of OOME in ERCOT. One of the reasons given is that historic payments that ERCOT makes to Reliability Must Run (RMR) units are not included in OOME, whereas TCA models these units as dispatchable which has the effect of including payments to RMR units in total OOME.

However, the TCA model for nodal assumes that OOME is zero under nodal, and thus there are no such payments to RMR units under the nodal analysis. Candidates for RMR contracts in ERCOT are those units that are least efficient with resulting very low capacity factors or dispatch rates that would otherwise be retired or mothballed without RMR contracts and payments. These units would logically be the units in the nodal market with some of the highest bid prices based on marginal production costs and continued low dispatch rates. If these RMR units were required to recover all of their fixed and variable costs via infrequent dispatch into the market they will not be able to recover all of their costs by only collecting energy payments priced at their LMP. Thus, the expected outcome for these plants is that they will cease to operate and thus cease to provide ERCOT with the reliability they currently support.

TCA indirectly deals with this shortcoming in treating likely retirements in Section 3.3.2.9 on page 3-54. It "had to estimate a capacity price in the market in each year as if some form of the installed capacity market" existed, which TCA admits does not presently exist. It established an assumed maximum loss level that units would be assumed to incur and still remain in operation.

If the zonal model includes RMR energy and fixed payments as OOME as claimed by TCA, the capacity payments for RMR are included. However, there are no corresponding capacity payments in the nodal model. The zonal model suggests that RMR units would operate indefinitely at slightly below the assumed maximum loss level without additional compensation. But the Cost Benefit Study reflects bias toward nodal by continuing to pay the RMR capital component as part of OOME.

In summary, CAPP and STAP believe that the Cost Benefit Analysis, as presented in the final report, understates the costs of serving load under the nodal model by ignoring RMR fixed costs. RMR units exist because they are needed to maintain system reliability, however they do not possess the inherent economics to be competitive in the market without some financial incentive. A move to a nodal market design will not change this fact or insure that a RMR unit owner will be willing to keep their plant available without some guarantee of a revenue stream. Thus, CAPP and STAP feel it is reasonable to assume that if a non-competitive plant currently requires some form of capacity payment to maintain operations for overall system reliability, it will continue to need this payment in a nodal market and the current Cost Benefit Analysis does not include these costs.

Methodology Applied Inconsistently between Zonal and Nodal Cases

A key driver of the future cost to serve load in either the zonal or nodal market design is the assumptions used for siting and technology selection of new generation additions. Nodal proponents think that the projected profitability and investment attractiveness of new types and locations of generation additions will be different between the two different market structures. Indeed, an analysis of the impact on differences in costs of serving load due to different patterns of new generation addition is a legitimate component of the Cost Benefit study. The problem in the Cost Benefit Analysis is that the decision rules established by TCA to project future generation additions patterns between the two cases often result in unrealistic additions and are so tilted to the benefit of the nodal case as to make the comparison between the cases invalid. In particular, TCA used different selection rules for locating new additions for the zonal and nodal cases, and the resulting impact of these new additions on the future costs and congestion are misleading and not useful for cost-benefit comparison.

In both the zonal and nodal cases, the "new entry logic is, all else equal, to site generators where they will be most profitable given system payments" (p. 3-10). In the case of the zonal market, all new additions are assumed to be made only at existing generation busses. The specific existing generation busses are selected by projecting profitability components of spark spread and OOME payments. This would appear to site new generation additions where current generation is needed most to relieve congestion by the indication of highest relative OOME payments.

As admitted in Footnote 29 on p. 3-11, however, there was a major flaw in the application of this decision rule for the years until 2012. Prior to 2012, TCA's analysis included OOME Down payments in this profitability projection. OOME Down is an indicator of which existing generators are contributing the **most** to congestion costs, as evidenced by the need to make payments to them to reduce output from the level scheduled to better manage congestion. As described in this footnote "siting based on OOME Down payments creates a positive feedback loop" increasing congestion leading to the need for even greater OOME Down payments in the following years.

This inherent flaw in TCA's methodology for zonal was pointed out to them and TCA "stopped using OOME Down payments as a criteria for siting for the 2012 – 2014 years," but apparently did not correct the results for the earlier years of the study nor correct for the artificial penalty that those additions based on this rule through 2011 embedded into the zonal case for all years. The impact of this flaw is demonstrated clearly in Figure 3-7, p. 3-26, that shows that total OOME Down is much greater than OOME Up during the study horizon.

By contrast, in the nodal case, the siting decision rule employed by TCA calculates the spark spread available based on the projected Locational Marginal Pricing (LMP) at each high voltage bus. Generation additions are then made where the projected profitability is highest as a result of selling at these highest LMP bus locations. In general, load bus LMPs are higher than generation bus LMPs, otherwise the huge congestion rents and congestion rents refunds would not be produced in the nodal case. The highest load bus LMPs will tend to be at locations where congestion is most prevalent or expensive to solve, leading to high LMP premiums compared to other load busses.

The result of applying this decision rule is that most (perhaps all) new generation locations are right on top of the load busses where LMPs are the highest and congestion is the worst. Although it is not directly acknowledged in Section 3.2.6 (Adding Economic Resources in the Base and Change Cases), this result is confirmed in work papers provided to participants to support the preliminary findings presented on October 26, 2004. Of course, the most effective theoretical way to reduce congestion costs is to locate new generation right where load is concentrated the most and/or transmission infrastructure is the most insufficient. This decision rule for the nodal methodology is, however, by and large completely unrealistic. Locations where load bus LMPs are the highest will tend to be where the residential and commercial load sources are the most concentrated, and necessary land availability and other infrastructure required for generation is the least available.

In summary, the discussion of the results of the study in Section 3.3 indicating the reduction in Annual Generation Cost that supposedly would be produced by the nodal market states "(t)his demonstrates that the nodal system is more efficient in managing congestion than the zonal system resulting in lower generation costs" (p. 3-21). Of course, a study methodology that assumes new generation is located in the most disadvantageous locations for zonal and the most advantageous (and unrealistic) locations for nodal will artificially produce this indicated outcome. In reality, the results in this study for the important metric of Annual Generation Cost cannot be used as a decision basis for justifying a nodal market when it is produced with such inconsistent and illogical methodology.

Other Inequities in the Study

Although the following are not strictly inconsistencies between zonal and nodal methodologies, the Cost Benefit study highlights some major inequities between consumers located in different zones in the proposed nodal market that should be mentioned here. These inequities adversely and inordinately impact consumers in the North and South zones. One of these inequities involves the redistribution of the congestion rents collected in the North zone and refunded in other zones. The other involves the ignoring in the study of the proposed creation of special protected load zones for certain large municipal utilities and coops in the South zone at the expense of remaining South zone loads.

The study describes the congestion rent collection method which will be averaged on a load zone basis in the proposed nodal design. On p. 3-30 of the Cost Benefit Analysis, however, the study states that "the congestion rent refund ... is based on load ratio share over the entire ERCOT region." This results in a cost shift between zones in nodal compared to zonal that adversely impacts loads in the North zone. As described by TCA, "if one zone – the North zone, for example, - experiences significant local congestion in the nodal case, then loads in the North will pay higher nodal prices to cover the cost of the congestion, but the congestion rent associated with those payments will be refunded to loads across ERCOT." The highest amount of congestion is indeed currently in the North zone and will continue to be if a nodal market is installed. It is obviously inequitable to collect a majority of the costs of this congestion from consumers in the North zone and then refund it to consumers in other parts of ERCOT that did not pay it and already reaped benefits of lower LMP prices due to the lack of congestion in their zone.

The inequity that the nodal market is projected to subject on South zone consumers is due to what the study calls more efficient congestion management that results in more energy flows from the South to the Houston zones. As summarized on p. xiii, "(t)his increases the cost of energy to buyers in the South Zone." This inequity under nodal is not projected to be alleviated until 2010 in the study.

The study also acknowledges in footnote 42 on p. 3-49 the proposed creation of special Non-Opt In Entity (NOIE) loads zones for major portions of South zone load in the proposed nodal design. It ignores, however, that these protected load zones will concentrate this impact on a limited subset of consumers in the rest of the South zone, making this an even more inequitable effect. Should the NOIEs in the South zone, which could include the two largest municipal utilities in the state, a river authority, and possibly several coops be allowed to create their own load zone(s), the only remaining load of any significance to absorb both local congestion and RMR costs in the South zone will be the parties who received bundled service from AEP-Central Power & Light prior to deregulation. This is a large burden for these customers to bear and may have dire consequences on economic development within the region. Those customers are already paying the highest price to beat rates in the State, and retail customers in the South can already look forward to significant non-bypassable surcharges associated with recovery of CPL's stranded cost.

Conclusion

In conclusion, it is clear that the problems detailed above provide overwhelming evidence of the uncertainty of potential benefits to the consumers and residents in ERCOT of switching to a nodal market design as demonstrated by the following:

1. Extreme variations in results achieved between the first set of preliminary results, which the consultants felt were "solid" and the results shown in the final report point to the need for Texas to take a more cautious approach and continue to study and refine the analysis of the current market and a potential future nodal market. Indeed, a recent report from another nodal market, PJM, suggests that wholesale customers are not seeing the savings promised to them when the nodal market was being formulated and implemented in that region (PJM Industrial Customer Coalition Whitepaper: What Large Commercial and Industrial Customers Need from a PJM Marketplace).

2. One of the often purported benefits of the nodal market is that it will send effective price signals to generators as to the best places to site future generation. What the Cost Benefit Analysis continually failed to address is the costs to individual loads that will be paid to send these price signals. Developing a system that grossly over-collects dollars from loads beyond that necessary in order to pay generators, then re-allocating these excess collected dollars under a scheme which is different from that used to collect them is a sign of a poorly designed market which will result in favored loads versus disadvantaged loads. This, combined with the proposed NOIE zone(s) that will basically insulate the largest municipal utilities, coops and any other non-opt-in entities from this statewide re-allocation scheme, results in a further division of winners and losers. Existing loads chose their current location based on an entirely different set of market conditions. To penalize them now for decisions they made in the past is unduly harsh.

3. The current proposed nodal market design developed for Texas provides no assurance that there will be a fair and equitable benefit to all loads and market participants of a better market in the future. Indeed, using Table 3-17 of the Cost Benefit Analysis, which shows the net impact on costs to serve load before congestion rent refund shows no net benefit to the North zone, South zone, and West zone, with a minimal benefit to the Northeast zone, and a large benefit to the Houston zone. Table 3-19 of the Cost Benefit Analysis, which shows the net impact on costs to serve load after the congestion rent refund shows a very marginal benefit to the Northeast, West and South zones, with the

majority of the benefit still occurring in the Houston zone. In the case of the South zone, no net benefit is achieved until 2010.

4. Given the numerous flaws in the study methodology and poorly developed assumptions mentioned previously in these comments, it is highly doubtful that actual benefits will be as positive as those shown in this report. Further study is needed to refine both the zonal and nodal cases, replace poorly developed assumptions with actual market dynamics (such as utilizing an assumption that more closely resembles actual market pricing in the zonal case), and insuring there are no artificial limitations imposed that may restrict adverse impacts prior to determining anticipated costs under each market design and comparing net costs and benefits to consumers. Given the feedback coming from other nodal markets that customers are concerned that they are not seeing the promised benefits of a nodal market design, Texas needs to move cautiously in adopting such a market design.

5. If a cost benefit analysis cannot demonstrate with a high level of confidence substantial, immediate, and sustained benefits to all market participants, including all consumers, other alternatives to the nodal market design should be pursued.

Respectfully submitted,

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