PROJECT NO. 26376

RULEMAKING PROCEEDING ON WHOLESALE MARKET DESIGN ISSUES IN THE ELECTRIC RELIABILITY COUNCIL OF TEXAS	§ § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

PROPOSAL FOR PUBLICATION OF NEW §25.501 AS APPROVED AT THE MAY 9, 2003 OPEN MEETING

The Public Utility Commission of Texas (commission) proposes new §25.501, relating to Wholesale Market Design for the Electric Reliability Council of Texas. Project Number 26376 is assigned to this proceeding.

The proposed new rule will set forth basic principles for the ancillary service markets operated by the Electric Reliability Council of Texas (ERCOT), including both energy and ancillary capacity service markets. The rule includes requirements for ERCOT to: allow market participants to self-schedule and bilaterally contract for energy and ancillary capacity services, to the extent consistent with system reliability; require the submission of resource-specific bid curves for energy and ancillary capacity services that ERCOT competitively procures a day ahead of an operating day or in the operating day; directly assign all congestion rents to the resources causing the congestion; and use nodal energy prices for resources and zonal energy prices for loads.

Dr. Eric S. Schubert, Senior Market Economist in the commission's Market Oversight Division, has analyzed the effects of the proposed rule. Dr. Schubert is an economist, an expert on competitive electricity markets and the design of those markets, and is intimately familiar with the details of the rule and its implications. Dr. Schubert has determined that the public benefits expected as a result of adoption of the proposed rule will largely begin to accrue during the third year after the rule takes effect, because ERCOT is required to fully implement the requirements of the rule approximately three years after it is scheduled to take effect. The public benefits will be more effective competition in the sale of electricity at wholesale, resulting in increased market efficiency; reduction in certain local congestion costs; increased price transparency; and increased liquidity, as well as improved siting of generation and transmission resources. In addition, more accurate wholesale prices will be apparent to retail electric providers and retail customers, facilitating better-informed price responses by customers. More accurate pricing will lead to more efficient consumption decisions, and the rule may lead to the deployment of advanced demand-response technologies, distributed generation resources, more sophisticated services, and increased efficiency in the consumption of electricity.

Currently, end-users of electricity in ERCOT are paying between $25 million to $30 million per year in fees paid to induce power generation companies to reduce their production at specific generation resources (referred to as out of merit order down energy or OOME Down costs). These costs easily could double over time as electricity prices rise, local transmission congestion increases, or market participants exploit the market rules. Dr. Schubert estimates that the net cost of these OOME Down payments would decline substantially as a result of implementation of the rule, based on the experience of the implementation of direct assignment of congestion fees between ERCOT zones in February 2002. Direct assignment of local congestion fees, as part of a nodal congestion management system required by the rule, could reduce these costs by at least $20 million per year for every year in the future. Using an estimate of $20 million to $30 million of uplifted OOME Down payments per year and assuming that OOME Down costs would be eliminated starting in the fourth year that the rule is in effect, the estimated net present value of the savings in uplifted OOME Down payments over the first five years of implementing this rule ranges from $30 million to $50 million. This net present value may understate the benefit, because the market design proposed in this rule eliminates the risk of an unexpected sharp increase in OOME Down costs, to which the current market design does not have countermeasures. In addition, these savings will continue to accumulate beyond the five-year horizon analyzed here.

As noted in comments filed in this proceeding by a number of interested persons, direct assignment of congestion fees and zonal pricing have improved siting of large-scale, gas-fired generation resources, reducing the need to build 345 kilovolt (Kv) lines to transport power long distances within ERCOT. The commission sees a comparable benefit of direct assignment of local congestion fees as part of a nodal congestion management system for 69 Kv and 138 Kv lines, by encouraging better siting of new generation resources and more location-specific demand-side resources and distributed generation. In addition, Dr. Ross Baldick of the University of Texas at Austin presented in this proceeding the results of his study that shows that the current zonal system distorts price signals relative to major transmission constraints, therefore distorting business decisions on where to locate new generation. Based on STP-Dow shadow prices for the whole of 2002, Dr. Baldick estimates the error in incentive is approximately 10% of the capital carrying cost of new generation. In addition to operational inefficiencies, such a large distortion in price signals will cause unnecessary construction of transmission lines because of poor siting decisions based on inaccurate price signals. Presently, ERCOT is planning roughly $650 million of upgrades and construction of transmission lines (excluding the construction to relieve the McCamey constraint discussed separately below). This figure is a snapshot, as over time ongoing transmission projects are completed and new ones are added. For purposes of this analysis, Dr. Schubert assumes that this $650 million figure is a typical snapshot of transmission construction in ERCOT. If direct assignment of local congestion fees improves the siting of new generation resources relative to major transmission constraints, prevents wind farms from making poor siting decisions that create another new and expensive local transmission constraint in West Texas, increases the use of site-specific demand-side resources and distributed generation resources, then Dr. Schubert anticipates that the rate of transmission construction costs in ERCOT will be permanently reduced by 20% to 30%. Assuming that these reduced costs start appearing in the fourth and fifth years after the rule's effective date, the savings from reduced transmission construction to end-use customers has a net present value of roughly $45 million to $65 million over five years and will continue to accumulate beyond the five-year horizon, especially in response to load growth in urban areas.

As Staff discussed in its filing on September 9, 2002 in this proceeding, the McCamey area saw a large-scale overbuilding of wind farms behind a local transmission constraint as a result of inadequate locational price signals. ERCOT estimates the cost of upgrading the transmission system to accommodate the wind farms to be $150 million, and as much as $300 million to double that export capacity so that ERCOT could accommodate the target in the renewable resources mandate in the Public Utility Regulatory Act (PURA) almost solely from the McCamey area. Because of the lack of sufficiently granular pricing within a congestion management zone, the commission and ERCOT are faced with over $100 million of transmission upgrades, which are eventually paid by end-use customers, resulting from the actions of a handful of market participants. With a nodal congestion management system combined with long-term transmission planning at ERCOT and the commission, wind farms will site in areas of sufficient transmission export capacity or pay substantial congestion fees if they decide to locate in an area that is congested, greatly reducing the chances of a wind farm getting financing to build in a congested area. Dr. Schubert estimates the savings to end-use customers of electricity in ERCOT will amount to a net present value of $80 million in the first five years after the effective date of the rule, because nodal pricing for resources will encourage wind farms to locate to places on the ERCOT grid other than McCamey.

For the first five years after the effective date of the rule, Dr. Schubert estimates the net present value of the quantified benefits of converting to a Texas Nodal market design ranges from $155 million to $195 million in reduced uplift of local congestion costs and reduced transmission construction. For the first ten years after the effective date of the rule, Dr. Schubert estimates that the net present value of the quantified benefits of converting to a Texas Nodal market design ranges from $320 million to $445 million. Other benefits not quantified here include a greater range of new supply resources more efficiently interconnected with the ERCOT grid such as distributed generation and demand-side resources as well as increased efficiency in real-time operational dispatch of resources in ERCOT.

Dr. Schubert has determined that for each year of the first five years that the rule will be in effect, there will be economic costs to entities that are required to comply with the rule. These costs are associated with modification of software used in the ERCOT wholesale market and changes in certain business practices, which are likely to vary from business to business. As part of this proceeding, Staff asked two qualified scheduling entities (QSEs) to estimate the economic impact on their businesses of having ERCOT implement a nodal congestion management system. The estimated costs, which involved upgrades in their software and communications infrastructure as well as changed businesses practices, were filed in August 2002 as part of this proceeding. The overall costs of implementing a nodal system was disputed by stakeholders, but based on experience in other jurisdictions and these estimated QSE costs, Dr. Schubert concludes that the net present value of the costs to be between $130 million and $140 million for all entities required to comply with the rule in the first five years of the implementation of this rule. Dr. Schubert also estimates that the net present value of the costs to be between $255 million to $265 million in the first ten years of implementation of this rule. Dr. Schubert developed these estimates by taking ERCOT's estimate of $50 million to revise its software stated in its filing of April 18, 2003 and the estimates of QSE conversion costs (both initial implementation and increases in operation and maintenance expenses) listed in filings by the Lower Colorado River Authority and Reliant Resources filed in August 2002. Dr. Schubert anticipated that the one-time conversion expenses by the QSEs and ERCOT would take place in the second and third years and that the ongoing operation and maintenance costs would take place in the fourth and fifth years. Dr. Schubert also notes that the Competitive Power Advocates (CPA) in its filing on January 31, 2003 assumed that only half of the QSEs in ERCOT would need to make a full conversion of their software and business practices, as many of the QSEs based outside of Texas already had software that would be compatible with the implementation of the market design in the proposed rule. Dr. Schubert in his estimate assumed all QSEs would have the full conversion costs, so his estimate likely overstates the true cost of conversion to the market design proposed in this rule. Nevertheless, these costs are less than the benefits in the first five years that the rule will be in effect.

The overall benefits of implementing a nodal congestion management system go well beyond the first five years, and as Dr. Schubert has estimated, the benefits increasingly outweigh the costs when looking at a ten-year horizon. The benefits of implementing this rule are not "one-off" benefits; they will continue to provide end-users of electricity with savings well into the future. The new market design will sharply reduce OOME Down payments and transmission construction costs in every year after implementation, not just in the first five years. In contrast, the bulk of the costs of the new market design will take place in the first five years of the market, as a result of QSEs implementing new software and instituting new business practices. The operating and maintenance costs for QSEs in years six and further will be much smaller than the benefits gained from implementing this rule. Thus the ten-year analysis shows an even higher net benefit to end-use customers than the five-year analysis does.

Dr. Schubert has determined that the economic effects on small businesses or micro-businesses as a result of the rule will not be proportionately larger than impacts to the largest businesses. Dr. Schubert has determined that converting ERCOT to a nodal congestion management system would directly impact QSEs. Implementing a day-ahead market may have an impact on QSEs, but the commission is not requiring a mandatory day-ahead market and may decide to endorse a voluntary power exchange, so those entities that do not want to use the day-ahead market need not incur user expenses. Dr. Schubert has reviewed the list of QSEs in ERCOT and found that none of them qualify as small businesses or micro-businesses as defined in Texas Government Code §2006.001 (Vernon 2000, Supplement 2003). Certain retail electric providers (REPs) or power generation companies (PGCs) in ERCOT may be micro-businesses or small businesses.

The costs of converting ERCOT market software and the software of some QSEs to handle a nodal congestion management system likely will be passed along to REPs and QSEs in the form of fees or charges, using cost for each $100 of sales of electricity as the standard. The great majority of these charges will be passed along to end-use customers.

In the public benefits section above, Dr. Schubert has analyzed the potential costs and savings resulting from the rule. Market participants have provided the commission with a range of costs of changing software and business practices of implementing a nodal system, as would be required by the rule. Dr. Schubert has reviewed data from ERCOT and stakeholder comments that suggest that small businesses and micro-businesses that are consumers of electricity will save money by paying less as a result of the rule, by virtue of reduced transmission costs, improved real-time economic dispatch, reduced local congestion costs, and the benefit from having a greater range of viable electric services such as demand-side response programs and distributed generation available to end-use customers. As indicated above in the public benefits section, the commission believes that the savings and benefits of implementing a nodal congestion management system will more than offset the costs to small businesses and micro-businesses, so implementing the rule should save money for small businesses and micro-businesses.

Dr. Schubert states that, generally, for the state and for local governments for each of the first five years that the rule will be in effect: there is no additional estimated direct cost expected as a result of enforcing or administering the rule; there are no estimated direct reductions in costs as a result of enforcing or administering the rule; there is no estimated direct loss or increase in revenue as a result of enforcing or administering the rule; and enforcing or administering the rule does not have foreseeable direct implications relating to cost or revenues. The exception to this statement is that local governments that participate in the ERCOT wholesale market may incur costs to comply with the rule; the costs to market participants are described above. The effect of the rule on the state will be that the commission will administer and enforce the rule using existing resources. There will be no direct effects of the rule on local governments, other than as market participants. Local governments are expected to be indirectly affected due to the public benefits described above; in particular increased market efficiency will increase disposable income throughout the ERCOT power region and promote expansion of businesses, which will in turn increase the tax revenues of local governments. However, the increased tax revenues resulting from the rule would be very difficult to accurately quantify. As stated above, the rule will also improve siting of new generation resources and will reduce the need for new transmission facilities. The changed sites for new generation resources will mean that some local governments will receive more tax revenues while others will receive less, with respect to new generation resources. Local governments at or near areas of large electric consumption will be more likely to see new generation resources sited in their jurisdictions, because the rule will provide generation resources a stronger incentive than currently exists to avoid congestion costs by locating near areas of large electric consumption. With respect to new transmission facilities, the rule will reduce the need for new transmission facilities, because more, new generation resources will locate at or near areas of large electric consumption. New transmission facilities will be needed to interconnect new generation facilities to the transmission system, but fewer transmission lines will be needed to transfer power within areas of large electric consumption. Therefore the new rule will also mean that local governments at or near areas of large electric consumption likely will see a different mix of new transmission facilities sited in their jurisdictions than under the current market design. The indirect revenues and costs to local governments resulting from the rule's effects on new generation resources and new transmission facilities would be very difficult to accurately quantify.

Dr. Schubert states that the rule will not have a direct effect on a local economy, including for each of the first five years that the rule will be in effect. However, the rule may have indirect effects. As explained above with respect to the effects of the rule on local governments, the rule will improve siting of new generation resources and will reduce the need for new transmission facilities. The changed sites for new generation resources will mean that some local economies will have increased employment while other local economies will have less employment, with respect to new generation resources. Local economies at or near areas of large electric consumption will be more likely to see new generation resources sited in their areas, because the rule will provide generation resources a stronger incentive than currently exists to avoid congestion costs by locating near areas of large electric consumption. With respect to new transmission facilities, the rule will reduce the need for new transmission facilities, because more, new generation resources will locate at or near areas of large electric consumption. New transmission facilities will be needed to interconnect new generation facilities to the transmission system, but fewer transmission lines will be needed to transfer power within areas of large electric consumption. Therefore, the new rule will also mean that local economies at or near areas of large electric consumption likely will see a different mix of new transmission facilities sited in their jurisdictions than under the current market design. The indirect employment effects on local economies resulting from the rule's effects on new generation resources and new transmission facilities would be very difficult to accurately quantify.

The commission staff will conduct a public hearing on this rulemaking under the Administrative Procedure Act, Texas Government Code §2001.029 at the commission's offices, located in the William B. Travis Building, 1701 North Congress Avenue, Austin, Texas 78701, on Tuesday, June 24, 2003, at 9:30 a.m.

Comments on the proposed new section (16 copies) may be submitted to the Filing Clerk, Public Utility Commission of Texas, 1701 North Congress Avenue, PO Box 13326, Austin, Texas 78711-3326, on or before June 23, 2003. Reply comments may be submitted on or before June 26, 2003. Comments should be organized in a manner consistent with the organization of the proposed rule. All comments should refer to Project Number 26376.

The commission invites specific comments regarding the costs associated with, and benefits that will be gained by, implementation of the proposed section. The commission will consider the costs and benefits in deciding whether to adopt the section. In addition, the commission invites comments on the following questions:

Question 1: In subsection (e) of the proposed rule, the implementation date for this new market design is March 1, 2006. The commission seeks comment on the appropriateness and feasibility of this date.

(a) Is this deadline feasible? If not, why not, and what is your alternative implementation date?

(b) Is having the new market design implemented before the end of the price-to-beat period important?

(c) If you believe that the new market design should be implemented in 2007 or later, what "no regrets" interim measures should be taken to address the existing problems in the current wholesale market design, such as operational inefficiency, stability of zonal boundaries, the DEC game, the uplift of local congestion costs, and inadequate price signals for siting resources?

Question 2: The commission has stated its intention to have most of the implementation of this rule take place through the ERCOT stakeholder process. Nevertheless, are there additional issues not addressed by the rule that the commission should address?

Question 3: On what timeline should the following issues be addressed?

(a) Congestion rights

(b) Zonal boundaries for settling load imbalance charges

(c) Day-ahead market / power exchange

(d) Market mitigation

Question 4: The proposed rule requires ERCOT to implement a day-ahead energy market. One option for such a market is an ERCOT-operated voluntary (but financially binding) day-ahead market based on security-constrained, least-cost dispatch. Such a market would require that all bilateral transactions become financially binding at the resource level in the day-ahead period. Alternatively, a day-ahead market can take the form of a third-party-operated voluntary power exchange, as is used in the United Kingdom and NordPool markets. Power exchanges would permit trading at a limited number of trading hubs, with possible hedging of real-time congestion rents, but could also provide a wider variety of contracts (e.g., forwards, futures, options) and products (e.g., electricity, natural gas) than an ERCOT-operated day-ahead market of the type seen in the northeastern United States. A power exchange could increase liquidity and price discovery in the bilateral market without requiring submission of financially binding schedules in a day-ahead energy market run by ERCOT. Bilateral transactions not traded through the exchange could become financially binding at the time of congestion settlement, which could take place close to real time.

(a) Would a third-party operated power exchange meet the needs for liquidity and price discovery in the ERCOT wholesale market?

(b) Would incorporating such an energy market into the market design be preferable to relying on a voluntary but financially binding day-ahead energy market based on security-constrained, least cost dispatch?

Question 5: When ERCOT files the Protocols to implement the rule, should it also file a cost-benefit analysis that supports the manner in which ERCOT chose to implement the rule, including evaluation of major options?

This new section is proposed under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (Vernon 1998, Supplement 2003) (PURA), which provides the Public Utility Commission with the authority to adopt and enforce rules reasonably required in the exercise of its powers and jurisdiction; §35.004(e), which requires that the commission ensure that ancillary services necessary to facilitate the transmission of electric energy are available at reasonable prices with terms and conditions that are not unreasonably preferential, prejudicial, discriminatory, predatory, or anticompetitive; §39.001(d), which requires the commission to order competitive rather than regulatory methods to achieve the goals of PURA Chapter 39 to the greatest extent feasible; §39.151(a)(1), which requires that ERCOT ensure access to the transmission and distribution systems for all buyers and sellers of electricity on nondiscriminatory terms;

§39.151(a)(2), which requires that ERCOT ensure the reliability and adequacy of the regional electrical network; §39.151(a)(4), which requires that ERCOT ensure that electricity production and delivery are accurately accounted for among generators and wholesale buyers in the ERCOT power region; §39.151(c), under which the commission certified ERCOT to perform the functions prescribed by §39.151 for the ERCOT power region; §39.151(d), which requires ERCOT to establish and enforce procedures, consistent with PURA and the commission's rules, relating to the reliability of the regional electrical network and accounting for the production and delivery of electricity among generators and all other market participants, and which makes these ERCOT procedures subject to commission oversight and review; §39.151(i), which permits the commission to delegate authority to ERCOT to enforce operating standards within the ERCOT regional electrical network and to establish and oversee transaction settlement procedures, and which permits the commission to establish the terms and conditions for ERCOT's authority to oversee utility dispatch functions after the introduction of customer choice; and §39.151(j), which requires a retail electric provider, municipally owned utility, electric cooperative, power marketer, transmission and distribution utility, or power generation company to observe all scheduling, operating, planning, reliability, and settlement policies, rules, guidelines, and procedures established by ERCOT.

Cross Reference to Statutes: PURA §§14.002, 35.004(e), 39.001(d), and 39.151.

§25.501. Wholesale Market Design for the Electric Reliability Council of Texas.

(a) **General.** The protocols and other rules and requirements of the Electric Reliability Council of Texas (ERCOT) shall be consistent with established economic principles, including marginal cost pricing and minimizing social costs; support wholesale and retail competition; support the reliability of electric service; and reflect the physical realities of the ERCOT electric system.

(b) **Bilateral markets and default provision of energy and ancillary capacity services.** ERCOT shall permit market participants to self-schedule and bilaterally contract for energy and ancillary capacity services except to the extent that doing so would adversely impact ERCOT's ability to maintain reliability. To the extent that a market participant does not self-schedule or bilaterally contract for the energy and ancillary capacity services necessary to meet its obligations, ERCOT shall procure energy and ancillary capacity services to cover the shortfall and charge the market participant ERCOT's procurement costs.

(c) **Day-ahead energy market**. ERCOT shall operate a voluntary day-ahead energy market, either directly or through contract.

(d) **Develop a Texas Nodal Model.** By January 1, 2004, ERCOT shall use a stakeholder process to develop a wholesale market model that includes the following characteristics:

(1) **Adequacy of operational information.** ERCOT shall require resource-specific bid curves for energy and ancillary capacity services that it competitively procures in the day-ahead or operating day, and ERCOT shall use these bid curves in its operational decisions and financial settlements.

(2) **Congestion pricing.** ERCOT shall directly assign all congestion rents to those resources that caused the congestion. A resource shall be considered to have caused congestion if it was in the position to relieve congestion but did not do so. Congestion rents shall be consistent with the nodal prices used to financially settle resource imbalance charges and the zonal prices used to financially settle load imbalance charges.

(3) **Nodal energy prices for resources.** ERCOT shall use nodal energy prices for resources. Nodal energy prices for resources shall be based on security-constrained, economic dispatch.

(4) **Energy trading hubs.** ERCOT shall provide information for energy trading hubs by aggregating nodes and calculating an average price for each aggregation, for each financial settlement interval.

(5) **Zonal energy prices for loads.** ERCOT shall use zonal energy prices for loads that consist of an aggregation of the individual load node prices

within each zone. ERCOT shall maintain stable zones and shall notify market participants in advance of zonal boundary changes in order that the market participants will have an appropriate amount of time to adjust to the changes.

(6) **Congestion rights**. ERCOT shall provide congestion revenue rights (CRRs), but shall not provide physical transmission rights. ERCOT shall auction all CRRs, using a simultaneous combinatorial auction, except as otherwise ordered by the commission for any preassigned CRRs approved by the commission. CRRs shall not be subject to "use-it-or-lose-it" or "schedule-it-or-lose-it" restrictions and shall be tradable.

(7) **Market power mitigation**. ERCOT shall apply ex ante market power mitigation methods to energy and ancillary capacity services that it procures.

(8) **Simultaneous optimization of ancillary capacity services**. For ancillary capacity services that it competitively procures in the day-ahead or operating day, ERCOT shall use simultaneous optimization and shall set prices for each service to the corresponding shadow price.

(9) **Multi-settlement system for procuring energy and ancillary capacity services**. For any energy and ancillary capacity services that it competitively procures in the day-ahead or operating day, ERCOT shall set a separate market clearing price for each procurement of a particular service.

(e) **Implementation.** ERCOT shall file with the commission a petition to approve the protocols to implement the requirements set forth in this section by July 1, 2004. Concurrent with that filing, ERCOT shall present to the commission a cost-benefit analysis of the proposed Texas Nodal wholesale market design. ERCOT shall fully implement the requirements of the wholesale market design approved by the commission by March 1, 2006.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's authority to adopt.

ISSUED IN AUSTIN, TEXAS ON THE 12th DAY OF MAY 2003 BY THE PUBLIC UTILITY COMMISSION OF TEXAS
RHONDA G. DEMPSEY