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PROJECT NO. 54335

REVIEW OF MARKET REFORM ASSESSMENT PRODUCED BY ENERGY AND ENVIRONMENTAL ECONOMICS, INC. (E3)	§ § §	**BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS**

COMMENTS BY ERCOT STEEL MILLS IN RESPONSE TO COMMISSION QUESTIONS REGARDING THE E3 MARKET REFORM ASSESSMENT

TO THE HONORABLE COMMISSIONERS:

NOW COMES the ERCOT Steel Mills ("Steel Mills") and submits these comments as requested in the Commission's Request for Comments in this project.

I. INTRODUCTION, GENERAL COMMENTS & RECOMMENDATIONS

We appreciate the opportunity to submit this response to the Commission's request for comments regarding the market reform assessment produced by Energy and Environmental Economics, Inc. ("E3").

The Steel Mills are very large users of electricity and providers of demand response to ERCOT via our participation in the Emergency Response Service ("ERS") program and through voluntary price and demand response. As such, we have a keen interest in any changes to the ERCOT wholesale market that may affect the market's long-term success, our overall energy costs, our continued ability to operate our facilities in a safe and efficient manner, and our ability to optimally engage in active and passive demand response. The Steel Mills consider the continued availability, preservation, and expansion of robust demand response opportunities in ERCOT to be critical to the future reliability of the ERCOT grid under any ERCOT market construct, as well as very important to the competitiveness of Texas industry. We think the continuation of the energy-only market, with real time price signals reflecting scarcity, is a critical component to this objective.

Our comments on some of the questions below regarding the Performance Credit Mechanism (PCM) are more limited than we would prefer at this stage. This is because we have had no involvement in the analysis conducted by E3 and Astrapé Consulting and have not had sufficient time and resources to examine and evaluate the reasonableness and validity of many of the assumptions and models used. Furthermore, much of the detail surrounding the development, implementation, and operation of the PCM (or the other market reform options) has yet to be spelled out. The full impact of the market reform proposals on the overall market, on various market participants, and especially on retail consumers, cannot be determined without at least a lot more detail and critical examination. As with any new market design construct, the devil is invariably in the details. This seems to especially be the case with PCM.

The Independent Market Monitor ("IMM") and certain market participants have identified what they believe to be a number of errors and other issues with the E3 analysis, including the use of some unrealistic assumptions that significantly impact the validity the overall conclusions in the E3 report. To the extent that the IMM and other market participants have correctly identified legitimate concerns with E3's analysis, it is of critical importance that feedback be solicited from all stakeholders and a corrected, revised analysis be provided to stakeholders and the Commission. In the Senate Committee on Business and Commerce meeting of November 17, the IMM asserted that E3 had erroneously modeled the impact of the operating reserve demand curve ("ORDC") on generator revenues and had assumed that an existing dispatchable generator would retire in any year when fixed cost recovery was less than the cost of new entry. Such modeling issues will likely have a considerable impact on the study's results.

Based on our present understanding of the modeling, it seems as though a more realistic set of assumptions would fall somewhere between the present base case and the "Low Cost of Retention Equilibrium" scenario, once any necessary corrections to the modeling of the ORDC are made. That is, many (generally, older) existing resources may not need to fully recover Cost of New Entry ("CONE") in 2026, while some resources may need to. A survey of generation owners regarding their retirement plans may also help to inform this analysis.

Before the Commission adopts an extremely complex and costly program such as PCM or any of the other market reform options studied by E3, it is important to consider all reasonable alternatives. As a result, we strongly suggest that an additional alternative to those evaluated by E3 be considered. At the same Senate hearing referenced above, representatives from the Texas Association of Manufacturers ("TAM") and the IMM discussed, as an alternative to PCM, the use of a potential new ancillary service that would be used as a tool for ERCOT operations to manage reliability concerns. Since that hearing, the Coalition for Dispatchable Reliability Reserve Service ("Coalition") filed comments on December 14, 2022, in Project No. 52373 requesting the Commission consider this new ancillary service option, referred to as Dispatchable Reliability

Reserve Service ("DRRS"), in lieu of capacity-based market design options such as the PCM concept evaluated in the E3 Report.

The ERCOT Steel Mills generally agree with many of the overall conclusions outlined in the Coalition's filing (with some minor reservations concerning the details of the proposed DRRS product). We believe that all options should be weighed to find the most reliable way of improving the ERCOT system as required by SB3 while also minimizing the cost to consumers and best maintaining the benefits of the energy-only market. DRRS would not only help manage the production volatility seen in daily solar and wind generation, but also provide a new market for fast-start dispatchable generation to manage the "uncertainty" caused by forced outages of generation and other unforeseen events, while at the same time dispatching the future generation fleet in ERCOT at potentially lower costs to consumers than any of the market reform options evaluated by E3.

Providing a new ancillary service market for fast-start dispatchable generation can provide solutions to both short- and long-term constraints and is worthy of careful consideration. This approach can be implemented by ERCOT much faster than the market reform options evaluated by E3 and significantly reduce the financial risk to new generation providers by supporting a new market for dispatchable generation. The Commission could order ERCOT to immediately begin developing protocols for DRRS while also asking ERCOT to develop the ancillary service plan that would provide the range of MWs of DRRS to be purchased in the Day Ahead markets. Presumably, DRRS would only be needed during the forecasted hours of highest reliability risk and thus be limited to only a few hours during a day. The plan would also outline how the new service would be dispatched (deployed) in future operations, which will provide the basis for potential new dispatchable generation providers to design new plants to meet those requirements.

The Coalition's filing is submitted by a large coalition of stakeholders who have a vested interest in ensuring ERCOT systems are robustly reliable while at the same time maintaining low costs to consumers in Texas, thereby facilitating strong business opportunities for our state. The ERCOT Steel Mills urge careful consideration of the DRRS product outlined by the Coalition as an alternative to the market reform options evaluated by E3.

Regardless of the market reform option selected, it is very important that the market design promote and not undercut demand response. In this regard, beyond preserving energy-market scarcity pricing to the degree possible, we recommend that any market reform option adopted, such as PCM, be designed in a manner that ensures that non-firm interruptible loads do not pay

PCM-type capacity charges. The E3 Report recognizes this in part by noting that demand-responsive interruptible load can avoid PCM, FRM or BRS charges by curtailing during hours of the highest reliability risk. However, relying on this approach alone requires many unnecessary curtailments (at a significant production cost to demand responders) and risks discouraging such response since it will be very difficult and costly for loads to accomplish. As a result, this approach should be supplemented by exempting loads in ERCOT demand response programs, such as Load Resources and participants in the ERS program, from such charges. This principle could be also extended as well to non-ERCOT load management programs, such as those operated by TDUs. Finally, ERCOT should establish an interruptible registration program for other "non-firm" loads, such as Large Flexible Loads, which are willing to be curtailed for reliability purposes under specified conditions and consequently would also not be responsible for such charges.

II. QUESTIONS & ANSWERS

The ERCOT Steel mills offer the following initial responses to the questions posed by the Commission in this project (we reserve the right to change our views set forth in these comments as we review additional information).

1. The E3's report observes that the Performance Credit Mechanism (PCM) has no prior precedent for implementation, does this fact present a significant obstacle to its operation for the ERCOT market?

Naturally, we are concerned that the lack of precedent and operational experience in other markets with the PCM construct will present a significant obstacle to its successful operation for the ERCOT market, particularly when you consider that it is estimated to generate over $5.6 billion in annual consumer charges for the program in 2026. Although these costs are projected by E3 to be offset in large part by suppressed market prices, we cannot say with any certainty that this will happen, and we are concerned that any resultant market price suppression will also suppress demand responsiveness within ERCOT.

Given that the PCM is an entirely new and wholly untested concept, it will take years to draft rules, write protocols, design, and implement and could thereafter require multiple revisions before it is likely to work in the manner intended and achieve intended results. Until perfected, consumers could be paying enormous sums in the form of performance credits without commensurate benefit. We also fear that the lengthy implementation timeline itself would create generation investment uncertainty until such time as PCM is actually implemented and perfected.

Further, we are concerned that if the PCM construct does not eventually work as intended, the process of dismantling PCM could be problematic and could itself create additional future market uncertainty, all increasing the investment risk associated with new dispatchable generation construction desired by this Commission.

It should be noted that these concerns also apply to the FRM and LSERO market constructs. For these reasons, we would prefer that any market design changes desired by the Commission be implementable over a much shorter time horizon, have some operational precedent, and adhere as closely as possible to existing ERCOT energy-only market principles.

2. Would the PCM design incentivize generation performance, retention, and market entry consistent with the Legislature's and the commission's goal to meet demand during times of net peak load and extreme power consumption conditions? Why or why not?

If the goal is to meet demand during times of net peak load and extreme weather conditions, then PCM "events" should coincide with those conditions. As presented, PCM events would be hours associated with the highest reliability risks. Although high net peak load hours are typically the hours of highest reliability risks, high reliability risks may also occur when net demand is low and there is nonetheless a power plant ramping problem, a fuel shortage problem, or a unit commitment scheduling problem (for example, winter storm Uri).

Properly designed and implemented, based on E3's assessment, the PCM construct, at least in concept, appears capable of meeting the Commission's goal of having more capacity available for dispatch during times of extreme power consumption conditions. However, the same can be said of a number of other market redesign alternatives. We are not convinced at this point that the PCM (or other somewhat similar constructs such as FRM and LSERO) is the optimal choice from the standpoints of efficient market function, maintenance of the energy-only-market structure, stimulation of new market entry, speed of implementation and lowest cost to consumers.

Whether the PCM design is consistent with the Legislature's vision is another question. Based on legislative history regarding the initial implementation and subsequent legislative action with respect to Texas' longstanding energy-only market structure, we believe the Legislature has historically preferred to meet reliability and capacity sufficiency goals by means that are more consistent with an energy-only market construct. PCM may be closer to this goal than FRM and LSERO, but by substantially suppressing market prices, all of these designs depart from the design of the energy-only market, by failing to provide accurate real-time energy price signals to both generators and load. The Lieutenant Governor has indicated that market design legislation will be a major priority for the upcoming legislative session. It seems like the Legislature will have the opportunity in the upcoming session to provide additional clarity as to which market design reform is consistent with their thinking and direction.

Regardless of the market reform option chosen, we believe that demand-side resources, such as ERCOT Load Resources, consumers participating in the ERS program, and other ERCOT interruptible programs (including a new "registered non-firm load" construct), as well as demand response programs operated by TDUs, retailers or non-opt-in entities (NOIEs), are key to achieving that goal. Demand response is an important market component and can go a long way in meeting ERCOT's operational reliability and capacity sufficiency objectives, provided it is appropriately encouraged and incentivized. Most importantly, care needs to be exercised to avoid undercutting demand response. Implementation of any new market mechanism needs to encourage and preserve participation by the demand side of the market, consistent with prior Commission commitment to robust and expanded demand response.

In our view, at a minimum, if PCM (or any other market reform reliability option) is adopted, the following four categories of demand-responsive loads should be exempted from PCM-type charges, given that their demand response greatly mitigates rather that exacerbates reliability-threatening events:

(1) The first demand response category would be those loads that, through passive response, reduce consumption during PCM event hours (the hours of highest reliability risk). (The E3 Report recognizes this response and suggests that the market design of these reforms would support this type of response. This type of

response is similar to passive response to market prices that currently occurs in the ERCOT energy-only market.)

(2) The second category would be those non-firm loads participating in current ERCOT facilitated demand response services, such as ERS and Load Resources providing Responsive Reserve Service ("RRS").

(3) The third category would consist of non-firm loads registered in demand response programs (to the degree that the programs would result in curtailment to meet ERCOT reliability needs under terms and conditions to be developed by ERCOT) operated by TDUs, retailers and non-opt-in entities ("NOIEs").

(4) The fourth category would be those loads that agree to register with ERCOT as an interruptible non-firm load in a new interruptible load registration program to be established by ERCOT, building upon the Interim Voluntary Curtailment Program for Large Flexible Loads implemented by ERCOT on December 6, 2022. (In the Senate Committee on Business and Commerce meeting on November 17, ERCOT and Oncor representatives expressed significant concern for the overall reliability of ERCOT systems in light of the desire of Large Flexible Loads (LFLs) to be quickly added to the grid. If the LFLs are registered as non-firm loads and agree to curtail certain load when called upon under certain conditions, they could potentially avoid negative impacts on reliability and instead provide a valuable resource for ERCOT operations to call on these loads to interrupt at times of need.)

While the E3 Report addresses the first category, it is not clear from the report that E3 recognizes the need to exempt the latter three categories if they are available for dispatch but are not actually dispatched.[1] Excluding the latter three categories of non-firm load from PCM-type charges would create additional incentive for these loads to participate in desired demand response activity and would allow ERCOT to instruct the loads to drop off the grid during times of shortages in a manner consistent with their various contractual demand reduction obligations. Formal registration of these loads as non-firm load would also allow ERCOT to reflect such in its publication of the SARA and CDR reports.

[1] Note that Table 45 on p. 90 under the heading for PCM suggests that a demand-side resource must actually be "dispatched" in order to earn performance credits. Yet, this contradicts the assertion in that same table that demand-side resources are "able to compete on a level playing field to provide reliability relative to other resources," since supply-side resources may earn a performance credit by simply being *available* to be dispatched.

Loads in a new ERCOT interruptible registration program could be subject to interruption by dispatch instruction from ERCOT Operations regardless of their actual energy consumption at any time when necessary for reliability. While the specific details would need to be worked out, in concept, loads who have registered as non-firm and agree to interrupt when requested by ERCOT Operations should be excluded from PCM charges for the reliability reserve hour(s), provided they properly perform when requested.

If the PCM (or other market reform option) is adopted, we believe that providing useful historical, real-time, and forecast PCM information to the market will also be a key to increased demand response within the ERCOT market. ERCOT should continuously update and post the historical data and forecasts related to minimum reliability reserve hours (in accordance with how PCM events will be declared) on their website and show all year-to-date hours of reserve, highlighting the top minimum hours of reserve (equal to the number of event hours specified by the PCM) that have occurred to date during the monthly or year-to-date postings. This information is clearly needed so that non-firm loads in ERCOT can better anticipate an action by ERCOT operations and be ready to assist in providing demand response quickly to resolve any issues that may arise on the ERCOT system. Similarly, ERCOT should also develop a mechanism to forecast, for each day, month, and balance of the year, the potential hours of highest reliability risk in advance (potential event hours) in order to facilitate optimal load management by demand response providers.

3. **What is the appropriate reliability standard to achieve the goals stated in Question 2? Is 1-in-10 loss of load expectation (LOLE) a reasonable standard to set, or should another standard be used, such as expected unserved energy (EUE). If recommending a different standard, at what level should the standard be set (e.g., how many MWh of EUE per year)?**

If a reliability standard is to be adopted by the Commission, the "1 event in-10 years" standard (0.1 LOLE), seems to be a reasonable and appropriate general objective.

4. **The E3 report examines 30 hours of highest reliability risk over a year. Is 30 the appropriate number of hours for this purpose? Should the reliability risk focus on a different measure?**

At the technical workshop on December 2nd, E3 stated that the Commission could reasonably use a range of as few as 10 hours to as many as 100 hours in a year. Our preference would be to choose from the lower end of the range (i.e.,10-20 hours total in a year) in order to enable large industrial loads with demand response capability to reasonably manage their operations around projected performance credit events and minimize the number of false events where consumers interrupt their operations only to later find out that the hour in question was indeed not a performance event. Note that unnecessary excess curtailments would lead to substantial operational inefficiencies and loss of production by manufacturers, at a significant cost.

We note that 20 hours per year is presently used to assign capacity values to energy efficiency programs under the Commission's oversight.[2] Moreover, ERCOT uses 20 hours to determine the capacity value of wind generation, hydroelectric generation, and solar generation for the purpose of preparing capacity, demand, and reserves (CDR and SARA) tables.[3] Thus, the use of 20 hours would be more consistent with the manner used to establish a capacity value for other resources in Texas.

It is our understanding that the Commission hopes that the demand side of the market will try to lower energy usage during performance credit events to reduce their exposure to performance credit costs, which would also improve reliability during such events. We note that the suggestion that there might be four performance credit hours each month – for a total of 48 performance hours per year – may present problems for responsive loads. Because the actual events would not be known until a given month is over, consumers would need to respond to a far larger number of events, in hopes of responding during the actual hours of low reliability. The larger the number of hours, the less value responding during any hour would provide, since PCM costs would be incurred over a larger number of hours.

Additionally, it becomes impractical to try to reduce energy use during potentially hundreds of hours – after all, industry locates its operations in Texas to produce products and any demand response is consequently a secondary consideration to production requirements.

[2] See Technical Reference Manual, p. 13 at: http://texasefficiency.com/images/documents/RegulatoryFilings/DeemedSavings/PY2023%20TRM%2010.0%20Vol%201%20Overview%202022-11-08%20FINAL.pdf

[3] See ERCOT Protocols, Sec. 3.2.6.2.2.

Thus, limiting the number of hours to 10 to 20 total per year would be better if robust demand response is to be encouraged.

We also think consideration should be given to whether using shorter intervals than an hour would be beneficial and more precise. For example, we note that real-time energy prices in the ERCOT market are based on 15-minute intervals, not hourly intervals.

5. **Over what period should the hours of highest reliability risk be determined? A year, a season, a month, or some other interval? At what point in time should that determination be made?**

We believe that a year would be a reasonable period, given that it would avoid the problems inherent in determining how to reflect the relative value of resources in shorter periods. The downside to using a monthly period and a pre-determined number of hours per month is that it would fail to reward resources for being available when they are most needed, which tends to be in summer and winter months. If a monthly period were used, then the months would need to be somehow weighted, so that performance credits sold or purchased in more-critical months are assigned a higher weight to reflect the greater value of capacity in those months. Certainly, the value of a resource to the ERCOT market in August or February is greater than the value of a resource in November or April.

The use of well-defined seasons (such as summer and winter) and apportioning the annual hours among the seasons (such as 10 hours for summer and 10 hours for winter), could also prove to be a reasonable option. A summer season could be defined using the four months of June-September, and a winter season might be defined as the three-month period from December 1 through the end of February. These two seasons would include the periods where capacity had its greatest value.

Moreover, reliability metrics in recent years suggest that resource availability in both the summer and winter seasons is of critical importance. A potential benefit of seasonal periods would be the calculation of performance credit costs twice per year, shortly after each season. Thus, payments and costs could be settled in a timelier fashion after each season, rather than waiting for the completion of a calendar year. If a year were used as the period, the value of a resource during a reliability event in January would not be recognized until at least the following January, following year-end calculations.

Of course, if DRRS is adopted instead of PCM, the ERCOT Ancillary Service Plan would provide complete flexibility for ERCOT to specify the hours in the year of greatest importance, affording potential providers and consumers greater ability to optimally assist in managing the uncertainty in the ERCOT system.

6. **Would a voluntary forward market for generation offers and a mandatory residual settlement process for Load Serving Entity procurement provide additional generation revenue sufficient to incentivize resource availability in a way that improves reliability?**

We assume this question refers to the PCM market option. Such a process should incentivize more generation. However, the issue is whether the incentive comes at a reasonable cost, whether it promotes robust demand response, whether it is necessary and the best option available. As discussed above, we think other options available appear to better achieve these goals.

7. **Does a centrally cleared market through ERCOT sufficiently mitigate the risk of market power abuse? Should additional tools be considered?**

A centrally cleared market would help. However, market power problems could nonetheless emerge if a single supplier controlled too large a share of the resources eligible for performance credits.

8. **If the commission adopts a market design with a multi-year implementation timeline, is there a need for a short-term "bridge" product or service, like the Backstop Reliability Service (BRS), to maintain system reliability equivalent to a 1-in-10 LOLE or another reliability standard? If so, what product or service should be considered?**

To the degree that there is a concern about short-term reliability and the possible need for a "bridge" solution, it would be best to adopt a market design which can be implemented quickly and can meet both short- and long-term system needs – for example, implementation of DRRS proposed by the Coalition. Implementing a bridge product and then changing the market design again a few years later after a PCM-type market construct is fully devised and fit for implementation, for example, would add complexity and uncertainty into the ERCOT market that itself would likely reduce and/or delay new investment in dispatchable generation.

9. If implementing a short-term design as a "bridge" delays the ultimate solution, should it be considered? Is there an alternative to a bridge solution that could be implemented immediately, using existing products, such as a long-term commitment to buy the additional 5,630 MW of Ancillary services necessary to achieve the 1-in-10 LOLE reliability standard?

See the answer above. The Commission should carefully evaluate the Coalition's DRRS proposal as a potentially viable vehicle for simultaneously meeting both short- and long-term ERCOT system reliability objectives.

10. What is the impact of the PCM on consumer costs?

We cannot answer this question with any certainty (we have not conducted an independent study). Given the uncertainties, we are not sure that anyone can. That said, we are concerned that, if the assumptions employed in the E3 report prove invalid, then the cost to consumers could be far more than the net $460MM/yr suggested by E3. It should be kept firmly in mind that the PCM approach results in new market charges of more than $5.6 billion and relies on suppressed market energy and ancillary service prices to mitigate the impact of these charges. This seems like a major risk. Even assuming all of the assumptions in the E3 report are indeed correct, then it appears from the report that consumer costs would not be lowest for the PCM construct. The BRS design, for instance, at $360MM in 2026 per E3's estimate, would cost consumers less than for the PCM proposal. DRRS may cost even less.

11. What is the fastest and most efficient manner to build a "bridge" product or service, such as the BRS, in order to start sending market signals for investment in new and dispatchable generation, while a multi-year market design is implemented by ERCOT? Please provide specific steps.

No comment at this time.

12. In what ways could the Dispatchable Energy Credit design be modified through quantity and resource eligibility requirements, e.g., new technology such as small modular nuclear reactors, in such a way that it incentivizes new and dispatchable generation?

No comment at this time.

III. CONCLUSION

The Steel Mills urge the Commission to carefully consider our comments herein in the Commission's review and development of potential market design changes and other programs to improve the reliability of ERCOT's market design and its ongoing operations.

Respectfully submitted,

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PROJECT NO. 54335

REVIEW OF MARKET REFORM ASSESSMENT PRODUCED BY ENERGY AND ENVIRONMENTAL ECONOMICS, INC. (E3)	§ § §	**BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS**

EXECUTIVE SUMMARY

COMMENTS BY ERCOT STEEL MILLS IN RESPONSE TO COMMISSION QUESTIONS REGARDING THE E3 MARKET REFORM ASSESSMENT

- Before the Commission adopts an extremely complex and costly program such as PCM or any other market reform option studied by E3, all reasonable alternatives should be considered and carefully evaluated. We are concerned that the lack of precedent and operational experience in other markets with the PCM construct will present a significant obstacle to its successful operation for the ERCOT market, particularly when the projected $5.6 billion in annual consumer charges for the program in 2026 are considered, and the lack of certainty that projected levels of offsetting consumer energy and ancillary service market cost savings will be realized.

- We strongly urge that the Coalition for Dispatchable Reliability Reserve Service's DRRS proposal as outlined in December 14 comments in Project No. 52373 be carefully considered. We generally agree with many of the overall conclusions outlined in the Coalition's comments. We believe their proposal may be the most reliable way of improving the ERCOT system as required by SB3 while also minimizing the cost to consumers. DRRS could potentially greatly assist ERCOT in managing the production volatility seen in daily solar and wind generation while at the same time providing additional incentive for new investment in fast-start dispatchable generation, all at potentially lower cost to consumers than the market reform options evaluated by E3. Further, it would preserve ERCOT's longstanding energy-only market construct, which we believe to be essential to long-term market stability and efficiency. The proposal could also be implemented by ERCOT far faster than the other market reform options evaluated by E3, and significantly reduce the financial risk associated with new investment in dispatchable generation during the lengthy time period required to develop and implement a much more complex and administratively burdensome market redesign.

- Regardless of the market reform option selected, it is very important that the market design promote and not undercut demand response. In this regard, energy-market scarcity pricing should be preserved to the degree possible. We also recommend that any market reform option adopted, such as PCM, be designed in a manner that ensures that non-firm interruptible loads do not pay PCM or similar capacity charges. The E3 Report recognizes this in part by noting that demand-responsive interruptible load can avoid PCM, FRM or BRS charges by curtailing during hours of the highest reliability risk. However, relying on this approach alone requires many unnecessary curtailments (at a significant production cost to demand responders) and risks discouraging such response since it will be very difficult and costly for loads to accomplish. As a result, this approach should be supplemented by exempting ERCOT demand response programs, such as Load Resources and participants in the ERS program, from such charges. This principle could be extended as well to load management programs operated by TDUs. Finally, ERCOT should establish an interruptible registration program for other "non-firm" loads, such as Large Flexible Loads, which are willing to be curtailed for reliability purposes under specified conditions and consequently would also not be responsible for such charges.