Filing Receipt

Received - 2022-12-14 04:11:21 PM
Control Number - 54335
ItemNumber - 49

PROJECT NO. 54335

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

COMMENTS OF SIERRA CLUB, LONE STAR CHAPTER

The Lone Star Chapter of the Sierra Club respectfully submits these Comments, which build on previous comments, and in response to the study and memo filed on November 10th. We would note the very short time afforded the public and stakeholders to respond to what is essentially a completely new proposal - the Performance Credit Mechanism - and a document of some 135 pages. We do acknowledge the steps the PUCT made to hold a technical conference and the additional time provided beyond the usual 30-day response period. We also acknowledge the efforts made by the Chairman and other commissioners to hold space for stakeholder input.

The Lone Star Chapter of the Sierra Club has nearly 30,000 members throughout Texas, most of whom are located in the ERCOT region. We and our members have long advocated at the PUC, ERCOT, the Legislature, and at local utilities and cities for clean energy, demand response and other distributed energy technologies, energy efficiency, and adoption of building codes, as ways to reduce energy demand.

As we will make clear in our comments, we believe that the PUC would be well served in implementing the approaches laid out in Phase 1 - some of which have still not been implemented - and conducting further analysis on some of the approaches laid out in the E3 memo, as well as at least two other options: the **Dispatchable Reliability Reserve Service (**Uncertainty Product), and a peak-ahead market such as a MIRTRM. Separately, the Sierra Club has signed onto a stakeholder letter urging adoption of a DRRS.

Thus, we would urge the Commission not to adopt any of the Phase 2 approaches on January 12th, but instead conduct some additional analysis on the PCM and several alternative approaches and hold public hearings before committing to all or some of these approaches. We also understand that the Legislature has indicated a preference to also provide additional input before any final decision is made. Because any new construct like the PCM could not actually be implemented for several years, we think taking more time to deliberate and study both the PCM and other alternatives is wise.

We understand that the Commission has legislative and gubernatorial direction to take action, but we also believe it is reasonable to further involve the stakeholders, the public and analysts before making fundamental changes to our market that would increase costs to consumers, and in our view may not be the most cost-effective approaches to assuring resiliency and reliability, which we believe is a shared goal of all Texans.

Phase 1 Changes Still Must be Fully Implemented

As we have made clear in previous comments, the Sierra Club has been largely supportive of Phase 1 changes, even though some of those changes such as the ORDC changes and Firm Fuel Supply products have or will increase costs to consumers. While we had expected that all of the Phase 1 changes could be implemented by the end of 2022 - with the exception of ERCS which is dependent upon system changes at ERCOT and is likely to be implemented by June of 2023 – the reality is that several important changes have yet to be implemented. We do recognize the important efforts made in increasing ERS, implementing FFRS, changing the ORDC and the price cap, and especially in requiring more robust weatherization standards.

As a reminder, the Blueprint required the Commission to "set higher performance for energy efficiency standards." We agree, but the best way to achieve this would be to open up a rulemaking on the TDU Efficiency and Load Management Program, invite comments, and then adopt a rulemaking to expand these programs to make our grid more reliable and resilient through consumer-friendly investments in small business and residential buildings. Again, looking only at supply solutions to our reliability and operational issues is only looking at half the equation.

As is well known, the Sierra Club, with the support of many Texans, and many allied organizations, filed a rulemaking petition earlier this year that would have required utilities both inside of and outside of ERCOT to increase their energy efficiency and demand response programs by nearly doubling the peak demand goals, and quadrupling the energy savings goals (approximately). That petition was denied in October, but with a promise of opening up rulemaking in the future on energy efficiency and load management programs. Again, we restate that this Phase 1 change has yet to be implemented, and would be an important tool to significantly improve reliability, resiliency and lower costs to consumers.

Second, Phase I changes require nodal pricing for demand response, but we are still waiting a year later for ERCOT to implement these changes, which would be important to incentivize more demand response in our market.

We do want to recognize the important efforts by the PUCT and many stakeholders to implement changes - and a pilot - to increase the use of distributed energy resources, which can be a new dispatchable energy solution to our reliability issues. It will be important to more fully implement this change through future rulemaking so that these resources can contribute to energy, ancillary services, price formation and reliability.

Recent Data From ERCOT Show A Capability Issue not a Capacity or Resource Issue

The most recent ERCOT CDR report shows some important developments. First, the November CDR indicates that over 1,500 MWs of new dispatchable gas plants are expected to be operational in the next two years, along with approximately 3,000 MWs of dispatchable battery storage resources. Even greater amounts of solar and some important wind energy capabilities are expected in the coming years, which helps raise our overall reserves and capacity, though we recognize these resources are not yet dispatchable. It is important to recognize that solar and in particular coastal wind do provide important megawatt hours during peak summer days that will assist in keeping the lights on.

Second, that same CDR indicates that under normal conditions, Texas will have sufficient reserves. According to ERCOT, the Planning Reserve Margin for summer 2023 is forecasted to be 22.2%, while the Reserve Margin rises to 39.9% for summer 2024, largely reflecting solar capacity additions, much of which represents project delays from prior years. Again, under normal circumstances, ERCOT expects the planning reserve margin to remain around 40 percent for several years. Planning reserves during winter peaks are similarly robust, hovering in the 30 percent range.

The issue facing Texas then is due not to our electric grid not having enough capacity, or even dispatchable capacity, but to having resources that are capable of delivering energy when there are sudden changes in demand, changes in the weather, forced outages/mechanical failures of fossil fuel plants, or sudden shifts in renewable output when again the weather suddenly shifts. These are the problems that we as a state must focus on to avoid another situation like Winter Storm Uri, and avoid the crisis mode in which we have found ourselves as climate extremes become the reality.

Preventing some of these scenarios - better weatherization requirements is certainly a help - while also designing a grid that is *capable* of providing energy and electricity during these shifts is the problem that the PUCT must solve. The PCM discussed in the E3 report and Commission memo is an approach worth considering, but we are not convinced that it will actually lead to the operational improvements needed to assure Texans the lights will stay on.

Don't Forget a New Reality that Didn't Exist in 2022: The IRA of 2022

In addition, we would note the new tax incentives and grants passed by Congress as part of the Inflation Reduction Act of 2022 continue incentives to traditional renewable resources like wind and solar - and in fact increase those incentives depending on location and supply chain - but also to new types of energy, from nuclear, to fossil fuel plants with carbon capture, to hydrogen, to storage, to geothermal and significant incentives for demand response. There are also vast pots of money for energy efficiency, better buildings and demand response. Any analysis or consideration of new market mechanisms must acknowledge this new reality. Wind and solar would have been built even without passage of the IRA of 2022, but now they are likely to increase, but other resources like storage, nuclear, hydrogen, geothermal and carbon capture technologies are also more likely even without any changes in our market structure.

Additional Solutions that Could Be Implemented and Should be studied

Peak-Ahead Market

ERCOT and the Commission should reconsider an idea that has stakeholder support but has never been implemented: multi-interval SCED --also known as MIRTM -- a Multi-Interval Real Time Market. Essentially a peak-ahead market in-between the day-ahead market and the real-time market would that allow bids into several time periods such as 30 minutes, an hour or even two hours before the actual events would facilitate and encourage more robust participation by demand response, distributed resources, and quick start resources like battery storage (and certain gas plants), thereby improving system reliability and reducing overall costs. A MIRTM would improve the efficiency of the short term commitment decisions, dispatch and pricing of resources such as storage and distributed generation, combustion turbine Generation Resources and Load Resources providing demand response by coordinating the commitment and honoring the resources' temporal constraints and by reflecting the physical realities of the system. A MIRTM would be an extra cost on the system because new software and ERCOT operations and monitoring would be required, but compared to other proposals it is pennies on the dollar.

Dispatchable Reliability Reserve Service (Uncertainty Product)

We have been supportive of looking at creating an additional reliability product service, known as the **Dispatchable Reliability Reserve Service, but also** often referred to as Uncertainty Product. A separate letter of support from multiple stakeholders is being submitted in Project Number 52373 and Sierra Club is a signatory to that proposal. Because we believe that most reliability issues in ERCOT are operational in nature - due to sudden changes in demand, forced outages or sudden changes in weather that undermine the predictability of renewable resources - a **Dispatchable Reliability Reserve Service** built precisely for those two to four hour periods when ERCOT faces such risks, such a product - which is in keeping with our existing market structure - could be a solution less costly than a PCM, BRS, DEC or other options being considered. While we are supportive of the development of an Uncertainty Produce, we do believe that at the very least, the PUCT should model an energy-only market construct with an added reliability service product like the "Uncertainty Product" before considering additional more costly solutions.

PCM is an unknown mechanism and we support additional study

In general, the Sierra Club is opposed to longer-term administrative solutions such as the LSE Reliability Obligation, a Forward Capacity Market, or physical firming requirements on generators, which will be expensive and time-consuming, will fail to ensure reliability, and will undermine the incorporation of new technologies and approaches. We were happy to see that firming requirements have been taken off the table. An LSE Reliability Obligation approach will tend to pick winners and losers because it will inevitably favor large retail companies that also own generation. In addition, we are very concerned about how the capacity factors of various resources would be administratively set. As an example, ERCOT in its most recent CDR gives storage a capacity factor of zero even though storage clearly can provide energy at peak. Moreover, it will not incentivize the type of new technologies and resources we need to incorporate and efficiently utilize existing and anticipated renewable energy resources on our system. The market should reward flexibility, dispatchability, and resilience, not just the capacity contemplated in the LSE obligation approach. An LSE obligation -- unless very targeted to net-peak seasonal needs and actual use -- will tend to favor those generators with large dispatchable resources. It is also unclear how demand response and distributed generation would be incorporated into an LSE approach.

While we can not at this time endorse the PCM ***we do think it is a better approach than the LSERO or FCM discussed in the memo*** because it avoids the issue of assigning capacities to different resources, and would reward performance.

Still, we would note some serious concerns about the way that E3 modeled all of the scenarios, including the PCM, which has led to conclusions that may be overstated.

First, we found the unique approach to consider storage as a resource to subtract from total load along with renewables to arrive at peak net load to be baffling. This decision undermines the analysis since it changes the consideration of which hours would count toward those hours facing reliability or capacity issues. At the very least, E3 should be directed to rerun their analysis with storage counting as a dispatchable not a variable resource, which changes the components of net-peak load.

Second, we fundamentally disagreed with the analysis that led to an assumption of a sudden retirement of more than 11,500 MWs of coal and gas resources in 2026 under the energy-only scenario. In essence, E3 simply removed those resources in 2026, thus increasing scarcity prices and leading to reliability issues in their modeling. Again, in the recently published CDR, the only resource that was retired in 2022 was the Decker Steam Turbine unit owned by Austin Energy - 420 MWs of rarely used older inefficient gas, while approximately 2,000 MWs of additional gas and coal capacity have announced they could retire in the coming years (see table). In the case of Decker the unit only ran infrequently, and a directive from Austin City Council to retire Austin's oldest and most inefficient gas plants was the impetus for retirement, as opposed to a reaction to the energy-only market itself.

Announced Retirements, 2023-2028

	2023	2024	2025	2026	2027	2028
Unit Name						
V H BRAUNIG STG 1	-	-	217	217	217	217
V H BRAUNIG STG 2	-	-	230	230	230	230
V H BRAUNIG STG 3	-	-	412	412	412	412
COLETO CREEK *	-	-	-	-	655	655
O W SOMMERS STG 1	-	-	-	-	420	420
TOTAL	**-**	**-**	**859**	**859**	**1,934**	**1,934**

Source: ERCOT, CDR, November 2022.

While we acknowledge there are some upcoming EPA federal environmental rules which could put pressure on some older coal and gas units to retire in the coming years, as of today, there have been no additional retirement announcements within ERCOT that would approximate anywhere near 11,650 MWs.

Third, we would note that the analysis of the DEC proposal changed the proposal itself by assuming that DEC resources would need to be available for 48-hours, as opposed to the 4-hour requirement in the initial proposal, again undermining DEC as a viable option.

Fourth, we think to actually consider a PCM proposal, significant backcasting and a look at actual hours in recent years where a PCM would have been generated will be important. What is the appropriate number of hours that is reasonable? What are the causes of reliability issues that we are trying to fix through a PCM? Are they actually do the lack of capacity or forced outages that could have not have been avoided?

We believe that Texas would be well served by requiring E3 to look at further analysis around these issues.

If the PCM is ultimately adopted, we would ask that;

1. The PUCT consider a seasonal or monthly approach, which would be more refined than an annual obligation;
2. Unlike the E3 proposal, when implementing PCM, keep storage as a resource to provide the PCM, and not subtract it from total peak load as if it were akin to a renewable resource, which would discount storage's contribution, and increase costs.
3. Allow all resources - fossil fuel, storage, renewables, distributed resources and loads through demand response – to qualify for PCMs. In other words, if the PUCT were to adopt a PCM construct, it will be important to have any resource that can meet the PCM by either providing a megawatt hour <u>or</u> negawatt hour to be qualified to be paid the PCM, which will in turn keep costs low and assure that the market remains non-discriminatory.

DEC or DERC?

We are also interested in further discussions on the DEC proposal filed by Commissioner McAdams and supported by Commissioner Glotfelty and believe it merits further review. We appreciate that the proposal as envisioned would be self-correcting, meaning that as new investments in newer dispatchable technologies like batteries and fast-responding gas resources occurred, the cost of the DECs would likely decrease, creating a buffer to any higher prices. This is very similar to the RPS obligations, which were met long ago, though a voluntary market in RECs has helped retailers and other load serving entities provide some guarantee of renewable energy to consumers who desire green energy. Having a longer-term goal with yearly obligations to create newer investments in generation that is flexible, fast, and can provide energy for at least two hours is a novel approach. We agree generally with the five-minute requirement for dispatchability and focusing on new growth. Again, we must consider how possible expansion of energy efficiency programs could work with this load growth requirement, but would note with Texas growing even if we were to reach a one percent savings goal in energy efficiency program, there would still likely be a growth of one to two percent in total load each year, and assuring that we have fast acting dispatchable resources will be important.

To the extent that the Commission pursues the DEC, we suggest the following approaches.

First, the Commission should initiate a rulemaking or issue a directive to ERCOT to allowing distributed generators to qualify for full participation in the market (i.e. SCED-qualified), thereby allowing them to qualify for the DEC program. If the Commission creates a new market for Dispatchable Energy Credits, any resource that can dispatch energy should be eligible to earn the credit and participate. We understand that it may take time to get those DG resources qualified but would not want to limit participation in the program. Consumers would benefit from allowing distributed resources that can meet the criteria of the program, including storage plus local solar.

Second, while the purpose of the DEC is to create a signal for new dispatchable generation -- in part to meet the requirements of Section 18 of SB 3 -- the concept can and should be expanded to include loads through creation of a Demand Reduction Energy Credit. In other words, if we are going to require loads to contract with generators, or purchase DECs through the market or pay Alternative Compliance Payments, why not give them the option of investing in demand response as a way to meet their obligation? As an example, if the yearly obligation for DEC for ERCOT were 4,000 MWs, the PUC could allow up to 25% -- 1,000 MWs of the obligation to be met with DREC, or some similar number. This would help spur a market in demand response, thus keeping the costs to consumers of the DEC lower.

Finally, we reiterate our support for a future public hearing on these changes that would allow for any stakeholder or member of the public to address the Commission. In other words, whether the Commission decides to pursue a PCM, an Uncertainty Product, a Peak-Ahead Market, a DEC, a BRS or some combination of these, there should, at the very least, be a public hearing required before adoption of such an approach.

Answers to Specific Questions

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

The PCM would be a completely new construct and therefore does present some challenges. First, there are no existing models exactly like a PCM in other markets. Second, as opposed to the day-ahead ancillary market approach, generators are being qualified and assessed after the appropriate hours of highest net-peak load are determined, whether annually, seasonally or monthly. Defining which hours qualify for "PCM" will need to be determined administratively. Would hours that had high peak net loads due to an outstanding weather event like a hurricane or another polar vortex "count" or should it only be hours of relatively normal operations? If a generator qualified to provide PCM does not perform due to an exceptional event, should they be penalized? There would be many challenges in implementing such an approach.

That being said it is perhaps easier administratively than an LSERO or FCM - two of the other capacity constructs -since it would initially set prices administratively through a centralized clearing house, looks back and does not require the determination of carrying capacity. In the PCM approach you either provided energy during the hours or you didn't.

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?

It is unclear. As it is a look-back mechanism, clearly performance can be determined and incentivized. However, as a look back mechanism, it relies on the promise of extra payment during these times to provide the incentive, but the actual price paid for such a service would largely depend on the number of hours it was in effect, and the load serving entities responsible for paying for the credits. Unlike a day-ahead or real-time market, or even a bilateral market, there would be no guarantee the additional revenues would be enough to encourage the development of new generations absent the mechanism. In fact, generators - existing or future - would not know the incentives paid for PCM until after the season, month or year were over. We are not clear this would provide enough incentive for new market entry, even though we recognize the price and curve could be changed administratively to encourage such investment.

Again, as mentioned, E3 analysis makes an assumption that absent some sort of capacity market that there would be significant retirements of some 11,560 MWs of dispatchable generation because of the lack of incentives in the market, while stating that with a capacity construct, there would be no significant retirements, and instead the development of significant additional generation. The retirement data is based solely on those generators not being expected to earn CONE, but there is no reason to believe that all of those generators would decide to retire within three years.

In fact, while there was significant retirements of coal and gas resources between 2017 and 2021, the recent changes made by ERCOT and the PUCT in the last year, as well as the rising gas prices have stopped the pace of retirements and have already led to actual investments in gas and storage, which are dispatchable. As far as we can tell, there was only one retirement in 2022 - the Decker 2 Steam plant - and that retirement was a decision due a municipal utility generation plan as opposed to a market decision. This is without any promise of a PCM or capacity construct, meaning the energy-only market and expanded ancillary services have led to additional dispatchable resources without the need for a new expensive capacity construct like the PCM.

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)?

We think the 1-in-10 loss of load expectation (LOLE) is worth considering as a useful tool to see the results of analysis, but in reality what consumers want is a reliable system that can withstand sudden events like climate extremes that can lead to cold weather equipment failures, problems in fuel delivery or issues with available water or derates (especially during hot events). Thus LOLE may not be the appropriate tool to assess such events. ERCOT does not seem to have a capacity or adequacy issue, but a capability/operational issue.

For consumers, a better measure for reliability could well be the measurements of hours of unserved energy. This could be a less costly approach than a blunter instrument like LOLE. Thus, we would be in favor of examining a different reliability standard based on EUE, though we do not have specific recommendations in terms of MWhrs.

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?

Without looking at actual data - say for the past several years in which we have had both climate extremes, rising demand and increasing renewable energy penetration - it is hard to justify 30 hours as the appropriate number of hours to consider. Actually looking at previous years and seeing what caused real issues for our grids - be it fossil fuel operators having outages, a sudden change in demand or change in weather impacting renewables - would be useful to determine on a seasonal or monthly basis when ERCOT actually faces reliability issues, and for what causes. This might help reveal whether a PCM would actually incentivize the solutions, or indeed other solutions - such as demand response, better maintenance, or fast operating ancillary services - might be a better solution.

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 do believe that if a PCM is implemented, having seasonal or even monthly hours as opposed to annual would be a superior and more refined approach. It may be that it is only a few hours in shoulder season where the reliability risk is highest, while many of the other hours in the winter and summer can be handled operationally through the use of ancillary service products. Again, without additional backcasting and analysis, it is very difficult to determine if the PCM would help mitigate against reliability issues present in the ERCOT market.

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

No response.

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

There is little to prevent a generation company from withholding power in the likely operating hours of the PCM to increase scarcity or prices, nor from Generation companies with retail affiliates from providing preferential treatment to those entities by running their plants at certain hours. That being said, we do believe the PCM is less likely to be abused than a forward market mechanism or LSERO.

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?

We are not in favor of a bridge product like the BRS because it will impose additional costs on consumers and we do not believe it is necessary. Instead, we would favor as previously mentioned putting more emphasis on consumer-friendly options like energy efficiency and demand response, which by their nature will decrease the need for both the proposed bridge products and ultimately the size of any other product like the PCM. Doubling or quadrupling the energy efficiency demand and savings goals could lower the risks to the systems, and directly benefit consumers.

If there is a need to “bolster” larger generation sources that might otherwise retire due to market economics, then one could instead consider the use of RMRs for longer periods of time. In addition, we would be in favor of assessing and potentially adopting an additional ancillary service like the Uncertainty Product favored by the IMM, while also finally moving toward co-optimization of energy and ancillary service markets. Indeed, if we were to combine additional ancillary service procurements, real-time co-optimization and expanded EE and DR products, and the potential for more robust RMR procurements as needed, then the existing market structure may actually meet the reliability standards that the PUCT and legislature is looking for.

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?

Again, we believe the best “Bridge” and indeed long-term solution is to focus on the demand side, and assure that utilities have more robust energy efficiency and demand response programs. We would also favor some requirements that retail electric providers and other load serving entities with direct sales to customers offer residential and small commercial demand response programs. A simple requirement like all LSEs must have the capability to reduce residential and small commercial demand by one percent in 2024, and perhaps 3-5 percent in 2026, could be implemented relatively easily, especially if it were partially paid for by the utility energy efficiency programs.

In addition, we should not ignore the incredible volume of federal funds that could be utilized to lower demand. From the $174 million that Texas is receiving for the federal WAP (Weatherization Assistance Program) in the coming years, to potentially more than

$650 million for appliance rebates, as well as money for better building code implementation and revolving loans for energy efficiency, the PUCT could design programs and work with other state agencies (TDHCA, SECO) to assure that Texas is driving down or at least mitigating the growth in electric demand. Much of our demand is caused by inefficient heating and cooling systems and older building stock, and focusing on this side of the occasion is a way to delay or even prevent the need for a relatively expensive solution like the PCM.

What is the impact of the PCM on consumer costs?

It is largely unknown. The E3 study assumes that the cost of the PCM will "only" be $5.6 billion and as it assumes much lower prices in the energy market, will only lead to roughly half-a-billion in additional costs. But as these questions make clear, even the exact number of hours, and whether the PCM would be paid on a monthly, seasonal or annual basis is unclear. In essence the PCM would pay an incentive for all MWhs served during that hour, but at what price that would clear and be assigned to load serving entities is still unknown.

The E3 analysis made the assumption that the energy-only market would lead to massive retirements, leading to higher and higher scarcity prices. Thus, when comparing the two - PCM vs. Energy-Only Market - E3 assumed that the PCM would not lead to those retirements and therefore energy prices would be much lower, mitigating the cost of the PCM. Again, as previously mentioned, the retirement assumptions in the E3 analysis seem to be very high given the actual dynamic we are seeing in the market today.

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

Again we would favor solutions like expanded energy efficiency, continued development of the DER framework, and specific steps to expand residential DR as a better way to assure reliability. In addition, as mentioned we would support creation of a Dispatchable Reliability Reserve Service, also known as an Uncertainty Product. This would fit into our existing market design and be easy to implement.

In what ways could the Dispatchable Energy Credit (DEC) 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?

We believe that the DEC could be a useful tool, but were surprised by the E3 analysis as it modeled it as a 48-hour product, when the DEC as envisioned was a four hour capable product. We think the original design as laid out by Commissioner McAdams may be sufficient to incentivize new and dispatchable generation. We do not think incentivizing small modular nuclear reactors is something we need to ensure through a market mechanism - rather setting a performance standard in a technologically-neutral way is better. As mentioned earlier, the PUCT could also consider a mechanism to ensure that demand response becomes part of the market through credits for DRs (such as a Demand Energy Reduction Credit) or an actual obligation on retail electric providers and other load serving entities.

The Sierra Club appreciates the opportunity to file these comments in Project 54335.

Sincerely,

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Executive Summary

The Sierra Club does not endorse any of the specific Phase 2 solutions looked at by E3 in its analysis. Instead, we believe that the PUCT should fully implement Phase 1 of the Blueprint by paying demand response nodal pricing, and significantly expanding energy efficiency and demand response, similar to the rulemaking petition we filed. We acknowledge the significant work done in implementing other aspects of Phase 1 such as weatherization requirements and the Distributed Energy Resources pilot.

In addition, we are one of many stakeholders asking the PUCT at the very least to consider the development of a new Dispatchable Reliability Reserve Service like the Uncertainty Product as a more refined solution to our operational issues. We also think that an in-between "Peak-Ahead" Market (or MIRTM) could be worthy of further consideration and should be considered.

We have concerns about several of the assumptions made in the E3 report, including the decision to subtract storage from the calculation of peak-load, the assumption that an energy-only market would lead to about 11,650 MWs of retirement, which impacts the underlying analysis, and a misrepresentation of the DEC proposal, which then undermines that potential solution.

The Sierra Club believes that backcast analysis of the PCM is needed to assess how it would actually have impacted hours found to be problematic, which would help determine if the PCM would actually help solve the issues by providing the additional incentive. Again, in this way a capacity construct like the PCM could be compared to a more operational construct like the Uncertainty Product to see which would actually help improve reliability at a reasonable cost.

We do want to acknowledge that the PCM does have some advantages over other capacity constructs and could be designed in a way that would make it less discriminatory to technologies. If the PCM is ultimately adopted, we would ask that:

- **The PUCT consider a seasonal or monthly approach, as opposed to an annual approach;**
- **Unlike the E3 proposal, keep storage as a resource to provide the PCM, and not subtract it from load as if it were akin to a renewable resource.**
- **Allow all resources - fossil fuel, storage, renewables, distributed resources and loads – to qualify for PCMs. In other words, if the PUCT were to adopt a PCM construct, it will be important to have any resource that can meet the PCM by either providing a megawatt hour <u>or</u> negawatt hour to be able to qualify, which will keep costs low and assure that the market remains non-discriminatory.**