Control Number: 40000

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OPEN MEETING COVER SHEET

MEETING DATE: **November 15, 2013**

DATE DELIVERED: November 15, 2013

AGENDA ITEM NO.: 19

CAPTION: **Project No. 40000** – Commission Proceeding to Ensure Resource Adequacy in Texas.

ACTION REQUESTED: Memo from Commissioner Anderson

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Public Utility Commission of Texas

Memorandum

TO: Chairman Donna L. Nelson
Commissioner Brandy D. Marty

FROM: Commissioner Kenneth W. Anderson, Jr. KWA/kwp

DATE: November 15, 2013

RE: **Project No. 40000, Item No. 19** – *Commission Proceeding to Ensure Resource Adequacy in Texas*

In anticipation of the upcoming workshop to address resource adequacy in Texas, I would like to add the following questions for parties to address in our discussion of alternatives to an energy-only market (EOM) in the Electric Reliability Council of Texas (ERCOT) region and implementation of a mandatory reserve margin for generation capacity in ERCOT.

Questions of General Applicability

- What is the legal basis for adopting a resource adequacy mechanism? What restrictions exist on the Public Utility Commission of Texas' (PUCT) authority? Does the PUCT have the legal authority to implement any mandatory generation obligation outside of an energy-only market (EOM) construct?

- Does the PUCT have the authority to require municipal utilities and electric cooperatives to share the cost of any resource adequacy construct?

- How does the cost of paying all capacity a clearing price at the cost of incremental capacity compare to traditional utility rate of return regulation?

- How does pricing energy market revenues based on the market clearing price of energy compare to traditional utility fuel recovery?

- For a backstop procurement or in a capacity market, is it appropriate to price both capacity and energy based on a market clearing price?

- For a backstop procurement or in a capacity market, is it appropriate to pay the resources a market clearing price for energy if capacity payments guarantee return on and off capital?

- What extra capacity (in MW) would be required over and above the economic equilibrium reserve capacity provided by an energy-only market?

- How many hours per year would that incremental extra capacity be called upon to be available?
- How much would it cost for ERCOT to have that amount of capacity built?
- What is the average value of lost load (in $/MWh) in the ERCOT market?
- Is the average value of lost load in the ERCOT market appropriate as liquidated damages for capacity generation that has been purchased but is not available when called upon?
- What is the net present value of the $400 million per year cost of a capacity market as described in Charles River Associates study commissioned by NRG?
- What would be the cost to reduce transmission and distribution related outages per MWh?
- What is the cost of eliminating resource adequacy related outages per MWh under each of the following:

  (1) a capacity market;

  (2) EOM plus construction of state-owned generation; and

  (3) any other backstop or supplemental generation mechanism?

<u>Backstop Generation as an Ancillary Emergency Reserve Service in EOM</u>

- Could new ancillary services be used to address resource adequacy? Why or why not?
- If a new ancillary service were created as a resource adequacy backstop, how far forward would it need to be applied?
- If a backstop ancillary service were created, what resources would be able to provide the service?
- On what basis should backstop resources be selected?
- What requirements would be needed to ensure that backstop resources were available to meet the need for which they were procured?
- Would deployment of the backstop ancillary service cause inappropriate price reversal?
- How should backstop service payments be billed to the market? As all other ancillary services are billed?

- What is the appropriate trigger for a backstop ancillary service procurement to occur?

<u>Reserve Margin Obligation on load serving entities (LSEs)</u>

- How could a mandatory reserve margin be imposed on LSEs?
- How do you ensure sufficient transparency so as to prevent affiliated generation and LSEs from exercising undue price influence in the market?

<u>Centralized Forward Capacity Market</u>

- How should the demand curve be implemented so as to avoid the boom and bust cycle?
- If a sloped curve is used, how is a minimum margin achieved?
- What should be the forward and commitment periods? Why?
- What products should be permitted to participate in a capacity market?
    - What performance requirements should be imposed on capacity bidders beyond an obligation to bid in the day ahead market (DAM)?
    - What additional measures should be imposed to prevent market power abuse by large generators and independent power producer (IPP) generators that are affiliated with LSEs?
    - How should the market be designed so as to avoid the problem of large incumbent IPPs keeping out small generators? Should the PUCT market power abuse rules be modified to lower the generation ownership limit to less than 10% of installed capacity?
    - To minimize capacity market manipulation, should generators participating in any capacity auction be required to divest themselves of any LSE? Should non opt-in entities (NOIEs) be exempt from this obligation? Alternatively, is it sufficient to require non-NOIE generators to prove that they offer non-affiliated retail electric providers (REPs) bilateral contracts that are no less favorable than the terms that they offer their affiliated LSEs? Should they be required to offer more favorable terms to avoid market concentration problems?
    - Should generation successfully bidding in the capacity auction be required to submit bids in the DAM? If so, how is withholding of power to be determined? Should short-run marginal cost be required with respect to their bids?
    - Does the PUCT need to define what constitutes a violation of its market power abuse rules for purposes of a capacity market? Should each MW bid for each

hour above short-run marginal cost be deemed to be a violation for purposes of the PURA penalty provisions?

  - To minimize capacity market manipulation, should generators participating in any capacity auction be required to divest themselves of any LSE. Should NOIEs be exempt from this obligation? Alternatively, is it sufficient to require non-NOIE generators to prove that they offer non-affiliated REPs bilateral contracts that are no less favorable than the terms that they offer their affiliated LSEs? Should they be required to offer more favorable terms to avoid market concentration problems?

- Should any working group at ERCOT which recommends protocols to implement any mandatory capacity construct be composed at a minimum equally between resources and load?

- How would the costs of a mandatory capacity market be allocated?

- If a mandatory capacity market contains a forward component, how are payments to be applied to customers who switch? How do REPs allocate their capacity charge? Will REPs be left with what amounts to a stranded cost?