**DOCKET NO. 33672**

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| **COMMISSION STAFF'S PETITION FOR THE DESIGNATION OF COMPETITIVE RENEWABLE ENERGY ZONES** | **§ § § §** | **PUBLIC UTILITY COMMISSION OF TEXAS** |

**THIRD TECHNICAL CONFERENCE**
**ERCOT'S RESPONSES TO PARTIES' FOLLOW-UP QUESTIONS**

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Parties may treat ERCOT's responses as if sworn. A sponsoring witness or witnesses is identified for each response.

Respectfully submitted,

By:________________________________

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ATTORNEYS FOR THE ELECTRIC
RELIABILITY COUNCIL OF TEXAS

## CERTIFICATE OF SERVICE

I certify that a copy of this document was served on all parties of record in this proceeding on May 15, 2008, in the following manner: by email, first-class U.S. mailing or facsimile.

________________________________

Michael G. Grable

**PUC Docket No. 33672**

**ERCOT'S RESPONSES TO PARTIES' FOLLOW-UP QUESTIONS FROM THE THIRD TECHNICAL CONFERENCE**

**April 24, 2008**

**Luminant Energy Company, LLC and Luminant Generation Company, LLC**:

**Follow-up Question to Luminant's Initial Question No. 2:**

**Please provide, for the base case and each CREZ scenario, the average annual locational marginal price at the following 345 kV buses: Tomball and Tricorner.**

Response:

| Average Annual Nodal Prices ($/MWh) | | |
|---|---|---|
| **Scenario** | **Tricorner** | **Tomball** |
| **1 Plan A** | 40.87 | 42.68 |
| **1 Plan B** | 40.00 | 42.46 |
| **2** | 36.54 | 38.91 |
| **Base Case** | 45.32 | 49.09 |

Sponsoring Witness: Warren P. Lasher

**Follow-up Question to Luminant's Initial Question No. 3:**

**For the base case and each CREZ scenario, what are the five hours of highest percentage of wind penetration? At what hour of the study do these occur? For each of these hours, what is the percentage of wind penetration, what is the load, what is the amount of wind generation, and how much non-wind generation capacity is on-line? Additionally, how much of the reported load is private network load?**

Response:

| Five Hours of Highest Penetration for Each Case | | | | | | |
|---|---|---|---|---|---|---|
| Scenario | Time | Wind | Load | Private Network | Penetration | Non-Wind Capacity |
| Base Case | 9/26/12 3:00 | 4,208 | 32,814 | 5,522 | 12.82% | 37,971 |
| | 9/26/12 4:00 | 4,229 | 33,028 | 5,522 | 12.80% | 37,971 |
| | 9/26/12 2:00 | 4,143 | 33,171 | 5,522 | 12.49% | 37,971 |
| | 12/18/12 3:00 | 4,219 | 33,962 | 5,522 | 12.42% | 40,342 |
| | 10/14/12 3:00 | 3,927 | 31,825 | 5,522 | 12.34% | 36,616 |
| Scenario 1 Plan A | 12/11/12 1:00 | 10,715 | 33,622 | 5,522 | 31.87% | 34,742 |
| | 3/13/12 3:00 | 9,877 | 31,346 | 5,522 | 31.51% | 34,340 |
| | 12/11/12 2:00 | 10,609 | 33,759 | 5,522 | 31.43% | 33,324 |
| | 12/11/12 0:00 | 10,657 | 33,926 | 5,522 | 31.41% | 35,582 |
| | 3/13/12 2:00 | 9,838 | 31,542 | 5,522 | 31.19% | 34,813 |
| Scenario 1 Plan B | 3/17/12 3:00 | 10,011 | 32,505 | 5,522 | 30.80% | 32,319 |
| | 3/17/12 1:00 | 10,125 | 33,323 | 5,522 | 30.38% | 32,319 |
| | 11/22/12 1:00 | 10,084 | 33,196 | 5,522 | 30.38% | 32,135 |
| | 3/12/12 3:00 | 9,557 | 31,475 | 5,522 | 30.36% | 33,704 |
| | 3/12/12 4:00 | 9,668 | 31,875 | 5,522 | 30.33% | 33,704 |
| Scenario 2 | 3/12/12 3:00 | 14,912 | 31,475 | 5,522 | 47.38% | 27,222 |
| | 3/12/12 4:00 | 14,987 | 31,875 | 5,522 | 47.02% | 35,037 |
| | 3/12/12 2:00 | 14,856 | 31,835 | 5,522 | 46.67% | 27,031 |
| | 11/29/12 1:00 | 15,827 | 34,509 | 5,522 | 45.86% | 29,573 |
| | 3/12/12 1:00 | 14,923 | 32,654 | 5,522 | 45.70% | 28,517 |

The load and non-wind capacity listed above includes the private network load and generation.

Sponsoring Witness: Warren P. Lasher

**Clarifying Response to Luminant's Initial Question No. 8:**

**Yes, Luminant wants implied heat rate of the base case and each CREZ option, based on the forecasted natural gas price, as employed in the CTO Study.**

Response:

Implied Heat Rate from Scenarios (All values in MMBtu/MWh) based on $7.MMBTU average annual gas price

| Scenario | Average Implied Heat Rate (Based on Production Cost) | Marginal Implied Heat Rate (Based on Generator Revenue) | Marginal Non-Wind Implied Heat Rate (Based on Non-Wind Generator Revenue) |
|---|---|---|---|
| Base Case | 4.97 | 6.78 | 7.51 |
| 1 Plan A | 4.56 | 6.07 | 7.16 |
| 1 Plan B | 4.57 | 6.08 | 7.16 |
| 2 | 4.38 | 5.54 | 7.01 |

Sponsoring Witness: Warren P. Lasher

**1. What is the total congestion cost in the base case (*i.e.* no CREZ wind, no transmission upgrades), and each CREZ scenario?**

Response:

| **Scenario** | **Aggregate Annual Shadow Prices ($/MW)** |
|---|---|
| Base Case | 6,178,605 |
| Scenario 1 Plan A | 1,882,941 |
| Scenario 1 Plan B | 3,271,508 |
| Scenario 2 | 2,926,117 |

Sponsoring Witness: Warren P. Lasher

**7. Please list the generator capacity factor grouped by technology type for the base case and each CREZ scenario.**

Response:

| | **Scenario 1 Plan A** | | | **Scenario 1 Plan B** | | |
|---|---|---|---|---|---|---|
| **Technology** | **MW** | **GWh** | **CF (%)** | **MW** | **GWh** | **CF (%)** |
| CT | 4,528 | 6,928 | 17.4 | 4,528 | 6,921 | 17.4 |
| CC | 34,486 | 155,604 | 51.4 | 34,486 | 156,100 | 51.5 |
| Coal | 20,854 | 153,949 | 84.0 | 20,854 | 153,290 | 83.7 |
| Gas Steam | 20,709 | 12,025 | 6.6 | 20,709 | 11,992 | 6.6 |
| Hydro | 469 | 957 | 23.2 | 469 | 957 | 23.2 |
| Nuclear | 5,007 | 38,247 | 87.0 | 5,007 | 38,277 | 87.0 |
| Wind | 12,136 | 41,836 | 39.2 | 12,136 | 41,773 | 39.2 |

| | Scenario 2 | | | Start Case | | |
|---|---|---|---|---|---|---|
| **Technology** | **MW** | **GWh** | **CF (%)** | **MW** | **GWh** | **CF (%)** |
| CT | 4,528 | 7,006 | 17.6 | 4,528 | 6,870 | 17.3 |
| CC | 34,486 | 149,276 | 49.3 | 34,486 | 169,576 | 56.0 |
| Coal | 20,854 | 139,822 | 76.3 | 20,054 | 154,372 | 87.6 |
| Gas Steam | 20,709 | 11,627 | 6.4 | 20,709 | 13,958 | 7.7 |
| Hydro | 469 | 957 | 23.2 | 469 | 958 | 23.2 |
| Nuclear | 5,007 | 36,983 | 84.0 | 5,007 | 38,346 | 87.2 |
| Wind | 18,538 | 63,931 | 39.3 | 18,538 | 25,590 | 15.7 |

Sponsoring Witness: Warren P. Lasher

**9. What is the annual capacity factor of the wind farms in the base case and each CREZ scenario, separately grouped into three categories:**

**a. CREZ-related wind farms;**

**b. Existing wind farms; and**

**c. Non-CREZ wind farms with generator interconnect agreements that were not operational when the study started.**

Response:

| Annual Capacity Factor (%) | | | |
|---|---|---|---|
| **Scenario** | **CREZ** | **Existing** | **IA Not Operational** |
| 1 Plan A | 40.8 | 40.5 | 36.3 |
| 1 Plan B | 41.6 | 39.1 | 36.2 |
| 2 | 40.9 | 38.9 | 34.6 |
| Base Case | 0.0 | 36.3 | 30.6 |

Sponsoring Witness: Warren P. Lasher

## Electric Transmission Texas, LLP, AEP Texas North Company and AEP Texas Central Company

**4. In response to ERCOT's request for RPG-CREZ meeting participants to depict potential CREZ plans on maps provided by ERCOT at the 8/31/07 CREZ meeting, AEP provided a conceptual plan for the application of 765 kV transmission on 8/26/07 in an e-mail to Warren Lasher and again in presentation form on 9/28/07 at the RPG-CREZ meeting. Please identify all 765 kV plans evaluated by ERCOT in response to AEP's 7656 kV backbone and transport line proposal. Please explain each such 765 kV plan evaluated by ERCOT and provide any drawing of such plan.**

Response: Please see Attachment A to this filing for the requested maps.

Sponsoring Witness: Warren P. Lasher

**<u>Denton Municipal Electric and Oncor Cities</u>**

**<u>DME 1 and 2 and Oncor Cities 1 and 4</u>**

1. **<u>DME</u>: In ERCOT's December 2006 Analysis of Transmission Alternatives for Competitive Renewable Energy Zones in Texas, Table 5 at page 46 summarized economic modeling results. Please provide a similar table for the scenarios in ERCOT's April 2008 CREZ Transmission Optimization Study.**

2. **<u>DME</u>: If ERCOT does not have the data necessary to update Table 5, please provide as much comparable data as is available for each scenario.**

1. **<u>Oncor Cities</u>: Will ERCOT provide input assumptions and summary output reports for the production cost savings analysis prepared for each of the scenarios and plans evaluated?**

Response:

| Scenario | New Wind Capacity (MW) | Transmission Capital Cost ($M) | Annual System Production Cost Savings ($M/yr) | Annual System Generator Revenue Reductions ($M/yr) | New Wind Average Capacity Factor (%) | Average New Wind Generator Revenue ($/MWh) | Annual System Production Cost Savings per kW New Wind ($/kW-yr) | Annual System Generator Revenue Reductions per kW New Wind ($/kW-yr) | Transmission Capital Cost per kW New Wind ($/kW) |
|---|---|---|---|---|---|---|---|---|---|
| | A | B | C | D | | | 1000*C/A | 1000*D/A | 1000*B/A |
| Scenario 1 (Plan A) | 5,150 | 2,950 | 1,150 | 1,931 | 40.8% | 30.1 | 223 | 375 | 573 |
| Scenario 1 (Plan B) | 5,150 | 3,779 | 1,140 | 1,931 | 41.6% | 29.1 | 221 | 375 | 734 |
| Scenario 2 | 11,552 | 4,931 | 1,677 | 3,356 | 40.9% | 25.1 | 145 | 290 | 427 |

Sponsoring Witness: Warren P. Lasher

4. **<u>Oncor Cities</u> - Please provide the assumed annual capital and operating costs and capacity factors for wind generation projects evaluated in the CTO Study.**

Response:

| CREZ Zone | Wind Input Capacity Factor (%) |
|---|---|
| Panhandle A | 42.4 |
| Panhandle B | 43.3 |
| Central | 39.7 |
| Central West | 33.7 |
| McCamey | 44.5 |

ERCOT did not make any assumption of capital or operating costs associated with the CREZ wind generation projects for the purposes of the CTO Study.

Sponsoring Witness: Warren P. Lasher

## <u>Public Utility Commission - Staff</u>

**BA-7 Please provide a breakdown in MW for each CREZ zone (Central West, Central, McCamey, Panhandle A, and Panhandle B) of the wind generation with currently signed interconnection agreements that was not used in the CTO Study.**

Response:

| CREZ Zone | MW |
|---|---|
| Central | 1,622 |
| Central West | 269 |
| McCamey | 300 |
| Panhandle A | 150 |

Sponsoring Witness: Warren P. Lasher

## <u>BP Wind Energy North America Inc.</u>

1. **How balanced is each of the transmission expansion proposals? In other words, how evenly are the 2% curtailments were distributed among all the CREZ zones? Can ERCOT provide the annual curtailment percentages for each of the CREZ zones?**

**Q: Walter Reid: Whenever providing a capacity factor or percentage, also provide the ratio input values.**

Response:

| Wind Curtailment | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Scenario** | | **CENTRAL** | **WEST** | **MCCAMEY** | **NON-CREZ** | **PHA** | **PHB** | **OVERALL** |
| **Scenario 1 Plan A** | Maximum Energy | 21,576,293 | 2,537,720 | 6,174,160 | 1,871,780 | 6,168,264 | 4,085,151 | 42,413,369 |
| | Actual Energy | 21,436,910 | 2,510,730 | 6,155,410 | 1,862,870 | 5,702,740 | 4,082,190 | 41,750,850 |
| | Curtailment | **0.65%** | **1.06%** | **0.30%** | **0.48%** | **7.55%** | **0.07%** | **1.56%** |
| **Scenario 1 Plan B** | Maximum Energy | 21,576,293 | 2,537,720 | 6,174,160 | 1,871,780 | 6,168,264 | 4,085,151 | 42,413,369 |
| | Actual Energy | 21,103,210 | 2,537,490 | 5,974,000 | 1,868,240 | 6,154,930 | 4,050,750 | 41,688,620 |
| | Curtailment | **2.19%** | **0.01%** | **3.24%** | **0.19%** | **0.22%** | **0.84%** | **1.71%** |
| **Scenario 2** | Maximum Energy | 27,413,194 | 4,226,297 | 10,168,178 | 1,871,780 | 12,760,951 | 9,102,378 | 65,542,780 |
| | Actual Energy | 26,574,570 | 4,213,640 | 9,745,590 | 1,821,390 | 12,632,400 | 9,043,310 | 64,030,900 |
| | Curtailment | **3.06%** | **0.30%** | **4.16%** | **2.69%** | **1.01%** | **0.65%** | **2.31%** |

Energy listed in MWh.

Sponsoring Witness: Warren P. Lasher

**Shell WindEnergy, Inc.**

**1-15 To the extent that you can do so without revealing confidential information, please describe on what basis ERCOT located wind collection gathering points in Randall and Castro counties and on what basis ERCOT has proposed single circuit 138 kV and 345 kV transmission elements for Randall, Castro, and Swisher counties. Want the generation amounts in the scenarios at that bus.**

Response: The following amounts of wind capacity were located at these buses in the ERCOT cases (in MW).

| | | Scenario | | | | |
|---|---|---|---|---|---|---|
| | Bus# | 1A | 1B | 2 | 3 | 4 |
| Randall | 10914 | 400 | 400 | 600 | 938 | 938 |
| Castro | 10913 | 200 | 200 | 200 | 311 | 435 |

Transmission elements were sized to meet the 2% overall wind curtailment goal at minimum capital cost. For each plan, engineers simulated several plan modifications (line additions, removals, upgrades, and downgrades) in an effort to find the lowest capital cost solution which meets the 2% curtailment goal.

Sponsoring Witness: Warren P. Lasher

**<u>Lone Star Transmission, LLC</u>**

**8. In scenarios 3 and 4, the modeling assumptions changed from one of a maximum specified amount of curtailment (nominally 2% in Scenarios 1 and 2) to one of transfer capability.**

**b. Did ERCOT assume that two transmission plans with similar transfer capabilities would have similar levels of wind curtailment? Transfer capabilities?**

Response: No. However, given the limitations in analytical methods, transfer capacity was the method utilized to determine the adequacy of solutions for Scenarios 3 and 4.

Sponsoring Witness: Warren P. Lasher

**16. Can ERCOT provide data to support cost estimates for the specific applications of series compensation used in the CTOS? Please provide ABB/Oncor materials, presentation, etc.**

Response: This question will be addressed in a second follow-up document.

Sponsoring Witness: Warren P. Lasher

**18. Please describe ERCOT's planning and operational experience with series compensation. Series compensation info**

Response: ERCOT staff has had limited experience planning series compensation, but members of the Regional Planning Group, whose input informs ERCOT, have had significant experience. The use of series compensation in the 345kV-based plans was discussed at several RPG meetings during 2008. ERCOT has been operating the system with series compensation on the 345kV lines to the lower Rio Grande Valley since its inception.

Sponsoring Witness:

**33. Operating Costs: We would like to have the composition – that is, cost of generation by type, transmission losses and other costs (e.g., ancillary services) – and totals for the operating costs with both plans, including the transmission losses if possible.**

Response:

| UNIT TYPES | SCENARIO 2 ($1,000) | SCENARIO 2 HVDC ($1,000) |
|---|---|---|
| DC TIES | $117,150 | $117,554 |
| NUCLEAR | $259,452 | $259,442 |
| COAL & LIGNITE | $2,197,311 | $2,205,829 |
| GAS STEAM BOILER | $815,514 | $808,985 |
| SIMPLE CYCLE | $565,999 | $564,118 |
| COMBINED CYCLE | $8,700,171 | $8,723,395 |
| TOTAL GEN COSTS | $12,655,597 | $12,679,323 |
| Losses | 7,832 GWh | 9,157 GWh* |

* This does not include losses on the HVDC lines.

As a point of clarification, the total productions cost for the HVDC scenario is $23.7 million more than the total production cost for the all AC scenario. This number was previously stated to be $30.49 million in response to Lone Star question 6 (filed as Third Technical Conference ERCOT Responses to Parties Questions). The change in this number is the result of corrections applied to the cases.

Sponsoring Witness: Warren P. Lasher

Q: Lone Star 8(b): Explain the methodology used to determine adequacy of transfer capacities for Scenarios 3 and 4.

Response: The tool used for calculating first-contingency incremental transfer capability is MUST. MUST requires four input files: a case model, a subsystem definition file, a list of contingencies, and a list of what elements should be monitored for overloading, and for under- and over-voltages.

This process started with a PSS/E spring high-wind case.

- Loads were scaled to match the 4-2-2018 4AM forecast.
- Non-wind generation was based on an unconstrained 24 GW wind UPLAN run for April. Individual unit dispatch was required to be between Pmin and Pmax. Pmin was reduced to no more than 50%Pmax for coal units and for self-serve units.
- Non-CREZ wind was set to 70% of nameplate (3,831 MW dispatched of 5,511 MW).
- CREZ wind was set to about 87% of nameplate (16,394 MW dispatched of 18,791 MW).

(Note: Almost 1,400 MW existing wind generation units were reconnected to CREZ facilities and thereafter treated as if CREZ units.)

Next, a list of contingencies was developed beyond the single-element default list to include all single-events involving multiple elements. The contingency lists (varying for CREZ topology) added nearly 700 events to the default.

The FCITC was calculated by MUST with a 2% cutoff level for transfers from all wind units to all the rest of ERCOT. The case was modified until the FCITC was above zero for the starting dispatch described above. We required the MUST contingency calculations to produce no voltage collapse, but tolerated over- and under-voltages that could reasonably be cured by appropriate local voltage control (i.e. 138kV and below capacitor banks and reactor banks).

Sponsoring Witness: Warren P. Lasher

**AES Seawest, Inc. and FPL Energy, LLC**

**1. Can ERCOT please cite the policy regarding Special Protection Schemes referenced by Mr. Woodfin in his response to AES Question 1?**

Response: The following is from the current ERCOT Operating Guides:

## 4.3.1 Remedial Action Plans

Generating plants or constrained transmission elements that would otherwise be subject to restrictions can operate to full rating if appropriate Special Protection Systems (SPS) or Remedial Action Plans (RAP) are in place. See Section 7.2.2, Design and Operating Requirements for ERCOT System Facilities, for SPS requirements. A RAP refers to predetermined operator actions to maintain reliability in a defined adverse operating condition. Normally, it is desirable that TDSP constructs Transmission Facilities adequate to eliminate the need for any RAP; however, in some circumstances, such construction may be unachievable in the available time frame. A RAP may be proposed by any ERCOT Market Participant, but must be approved by ERCOT prior to implementation. Any ERCOT RAP must meet the following requirements:

a. Coordinated and approved with the owners and operators of facilities included in the RAP.
b. Use is limited to the time required to construct replacement Transmission Facilities. However, the RAP will remain in effect, if replacement Transmission Facilities have been determined by the Control Area Authority to be impractical.
c. Complies with all applicable ERCOT and NERC requirements.
d. ERCOT develops and posts a methodology to include the RAP in the Total Transfer Capability (TTC) calculations, if appropriate.
e. Clearly defines and documents operator actions.
f. Includes the option for the transmission operator to override the procedures if the RAP will not improve system reliability.
g. Operators must be trained in RAP implementation.

And from section 7.2.2

13. Special Protection Systems (SPS) are protective relay systems designed to detect abnormal ERCOT System conditions and take pre-planned corrective action (other than the isolation of faulted elements) to provide acceptable ERCOT System performance. SPS actions include among others, changes in demand, generation, or system configuration to maintain system stability, acceptable voltages, or acceptable Facility loadings. An SPS does not include under-frequency or under-voltage Load shedding. A Type 1 SPS is any SPS that has wide-area impact and specifically includes any SPS that a) is designed to alter generation output or otherwise constrain generation or imports over DC Ties, or b) is designed to open 345 kV transmission lines or other lines that interconnect TDSPs and impact transfer limits. Any SPS that has only local-area impact and involves only the Facilities of the owner-TDSP is a Type 2 SPS. The determination of whether an SPS is Type 1 or Type 2 will be made by ERCOT upon receipt of a description of the SPS from the SPS owner. Any SPS, whether Type 1 or Type 2, shall meet all requirements of NERC Standards relating to SPSs, and shall additionally meet the following ERCOT requirements:

- The SPS owner shall coordinate design and implementation of the SPS with the owners and operators of Facilities included in the SPS, including but not limited to Generation Resources and HVDC ties.
- The SPS shall be automatically armed when appropriate.
- The SPS shall not operate unnecessarily. To avoid unnecessary SPS operation, the SPS owner may provide a real-time status indication to the owner of any Generation Resource controlled by the SPS to show when the flow on one or more of the SPS's monitored facilities exceeds 90% of the flow necessary to arm the SPS. The cost necessary to provide such status indication shall be allocated as agreed by the SPS owner and the Generation Resource owner.
- The status indication of any automatic or manual arming of the SPS shall be provided as SCADA alarm inputs to the owners of any facility(ies) controlled by the SPS..
- When a Transmission Operator (TO) removes a SPS from service, the TO shall immediately notify ERCOT operations. ERCOT shall modify its reliability constraints to recognize the unavailability of the SPS and notify the Market. When a SPS is returned to service, the TO shall immediately notify ERCOT operations. ERCOT shall modify its reliability constraints to recognize the availability of the SPS.

14. The owner(s) of an existing, modified, or proposed SPS shall submit documentation of the SPS to ERCOT for review and compilation into an ERCOT SPS database. The documentation shall detail the design, operation, functional testing, and coordination of the SPS with other protection and control systems.

- ERCOT shall conduct a review of each proposed SPS and each proposed modification to an existing SPS. Additionally, it shall conduct a review of each existing SPS every five years, or sooner as required by changes in system conditions. Each review shall proceed according to a process and timetable documented in ERCOT Procedures and posted on the ERCOT website.

- For a proposed Type 1 SPS, the review must be completed before the SPS is placed in service, unless ERCOT specifically determines that exemption of the proposed SPS from the review completion requirement is warranted. The timing of placing the SPS into service must be coordinated with and approved by ERCOT. The implementation schedule must be confirmed through submission of a Service Request to ERCOT.
- For a proposed Type 2 SPS, the SPS may be placed into service before completion of the ERCOT review, with advanced prior notice to ERCOT in the form of a Service Request. The timing of placing the SPS into service must be coordinated with and approved by ERCOT. Existing SPSs that have already undergone at least one review shall remain in service during any subsequent review, and proposed modifications to existing SPSs may be implemented, upon notice to ERCOT, and approval of ERCOT before completion of the required ERCOT review.
- The process and schedule for placing an SPS into service must be consistent with documented ERCOT Procedures. The schedule must be coordinated among ERCOT and the owners of any facility(ies) controlled by the SPS, and shall provide sufficient time to perform any necessary testing prior to its being placed in service.
- An ERCOT SPS review shall verify that the SPS complies with ERCOT and NERC criteria, guides, and Reliability Standards. The review shall evaluate and document the consequences of failure of a single component of the SPS, which would result in failure of the SPS to operate when required. The review shall also evaluate and document the consequences of misoperation, incorrect operation, or unintended operation of an SPS, when considered by itself, and without any other system contingency. If deficiencies are identified, a plan to correct the deficiencies shall be developed and implemented. The current review results shall be kept on file and supplied to NERC on request within thirty (30) days.
- As part of the ERCOT review and unless judged to be unnecessary by ERCOT, the appropriate ROS working groups such as the Steady State Working Group, the Dynamics Working Group, and/or the System Protection Working Group shall review the SPS and report any comments, questions, or issues to ERCOT for resolution. ERCOT may work with the owner(s) of facilities controlled by the SPS as necessary to address all issues.
- ERCOT shall develop a methodology to include the SPS in the Commercially Significant Constraint (CSC) limit calculations, if appropriate.
- ERCOT's review shall provide an opportunity for and include consideration of comments submitted by Market Participants affected by the SPS.

15. SPS owners shall notify ERCOT of all SPS operations. Documentation of SPS failures or misoperations shall be provided to ERCOT using the Relay Misoperation Report located in Section 6 of these Operating Guides. ERCOT shall conduct an analysis of all SPS operations, misoperations, and failures. If deficiencies are identified, a plan to correct the deficiencies shall be developed and implemented.

16. For each SPS, the owner shall either identify a preferred exit strategy or explain why no exit strategy is needed to ERCOT. This shall take place according to a timetable documented in ERCOT Procedures and posted on the ERCOT website. Once an exit strategy is complete and a SPS is no longer needed, the owner of an existing SPS shall notify ERCOT, using a Service Request, whenever the SPS is to be permanently disabled, and shall do so according to a timetable coordinated with and approved by ERCOT and the owners of all facilities controlled by the SPS.

Sponsoring Witness: Dan Woodfin

**2. Can ERCOT please list the number of SPSs currently active on the ERCOT system?**

Response: There are seven in-service Special Protection Schemes for generation units.

Sponsoring Witness: Dan Woodfin

**3. Can ERCOT please list the number of SPSs which have been removed from the ERCOT system in the past five years?**

Response: Nine

Sponsoring Witness: Dan Woodfin

**4. It is FPLE's understanding that some SPSs currently installed on the ERCOT systems have been active for decades. What is the oldest active SPS on the system today? How many SPSs can reasonably be construed to be "permanent" installations?**

Response: The Mt. Enterprise SPS for Tenaska Gateway is permanent by its own description. None of the documentation on the active SPSs predates 2005, however the China Grove – Morgan Creek reactor SPS is more than 10 years old.

Sponsoring Witness: Dan Woodfin

**5. Of the number of SPSs currently active on the ERCOT system, how many can reasonably be described to fit the criteria mentioned in ERCOT's response to AES? (i.e., how many only primarily affect one entity and do not have regional impacts?)**

Response: Only the Valley + Kiamichi SPS does not meet the criteria because it involves two separate plants. This SPS is much bigger than any of the others and is close to a heavy load center.

The Golden SPS can also trip two plants, but they are at the same location and owned by the same company.

All the other active SPSs are smaller in scope, and do fit the criteria in the question. Note that each active SPS affecting generation initiates a ramp down instruction and only trips generation if the plant does not respond in an acceptable time period.

Sponsoring Witness: Dan Woodfin

**6. What is the basis for Mr. Woodfin's assertion that a hypothetical SPS at Bluff Creek as proposed by AES would likely have significant regional impacts? Please share any ERCOT studies performed which inform Mr. Woodfin's view.**

Response: As stated in the Operating Guides (provided above), SPSs are separated into two groups. A Type 1 SPS is any SPS that has wide-area impact and specifically includes any SPS that a) is designed to alter generation output or otherwise constrain generation or imports over DC Ties, or b) is designed to open 345 kV transmission lines or other lines that interconnect TDSPs and impact transfer limits.

ERCOT believes that any SPS involving a DC tie from the West Zone to the North or South zone would impact transfer limits between zones.

Sponsoring Witness: Dan Woodfin

**7. Regarding Question 5 above, can ERCOT please characterize in more detail the "significant regional impacts" Mr. Woodfin envisions may result from implementation of a hypothetical SPS as proposed by AES Question 1.**

Response: See response to question 6.

Sponsoring Witness: Dan Woodfin