DOCKET NO. 42511

COMPLAINT OF CALPINE CORPORATION AND NRG ENERGY, INC. AGAINST THE ELECTRIC RELIABILITY COUNCIL OF TEXAS AND APPEAL OF DECISION CONCERNING THE HOUSTON IMPORT PROJECT	§ § § §	PUBLIC UTILITY COMMISSION OF TEXAS

CALPINE CORPORATION'S AND NRG ENERGY, INC.'S COMPLAINT AGAINST THE ELECTRIC RELIABILITY COUNCIL OF TEXAS AND APPEAL OF DECISION CONCERNING THE HOUSTON IMPORT PROJECT

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TABLE OF CONTENTS

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CALPINE CORPORATION'S AND NRG ENERGY, INC.'S COMPLAINT AGAINST THE ELECTRIC RELIABILITY COUNCIL OF TEXAS AND APPEAL OF DECISION CONCERNING THE HOUSTON IMPORT PROJECT

TO THE HONORABLE CHAIRMAN AND COMMISSIONERS OF THE PUBLIC UTILITY COMMISSION OF TEXAS:

Calpine Corporation ("Calpine") and NRG Energy, Inc., ("NRG")(collectively, "Complainants"), each on its own behalf and on behalf of its subsidiaries that own or operate generation facilities in ERCOT, respectfully submit this Complaint against The Electric Reliability Council Of Texas ("ERCOT") and Appeal of Decision Concerning the Houston Import Project (hereafter, "the Complaint"). By this proceeding, Complainants seek review of the ERCOT Board of Directors' April 8, 2014 Resolution ("Resolution") endorsing the need for the Houston Import RPG Project ("Project").[1]

Complainants seek a good cause exception to the requirement to enter into the Alternative Dispute Resolution ("ADR") process with ERCOT,[2] and also request that the case be retained at the Commission and not transferred to the State Office of Administrative Hearings.

[1] This Complaint is filed within 35 days of the completion of the ERCOT action in question and is therefore timely. Complainants have attached copies of documents relevant to the dispute.

[2] PUC PROC. R. 22.251 (c)(2) allows a person presenting a complaint against ERCOT to submit a written request for waiver of the requirement for using the Applicable ERCOT Procedures (which require pursuing the Alternative Dispute Resolution Procedures), and the Commission may grant the request for good cause.

I. INTRODUCTION AND SUMMARY

Calpine and NRG are each publicly-held companies with headquarters in Houston, and each, acting through their direct and indirect subsidiaries, own and operate electric generation facilities in ERCOT that provide power to millions of Texas residents and businesses, and employ thousands of Texans. Combined, Calpine and NRG represent approximately 20,000 MW of generation in ERCOT, and each has invested a substantial amount of capital to participate in the Texas electric market. As promoters of competitive markets, Complainants have long supported a robust transmission system that operates reliably and efficiently. Through participation in the ERCOT stakeholder processes, including the Technical Advisory Committee ("TAC") and its various subcommittees, as well as the Regional Planning Group ("RPG"), Calpine and NRG have supported ERCOT's efforts to maintain and improve system reliability and security.

However, the need for the Houston Import Project ("Project") has not been validly demonstrated. ERCOT's determination to support it is the result of inadequate and incomplete study and regulatory-based policies with the potential to exacerbate the very localized resource adequacy concerns this Project intends to remedy. Many inconsistencies and untenable assumptions have led to ERCOT's findings that the Project is warranted. These collectively amount to an abuse of ERCOT's discretion, which constitutes conduct that is in violation of law the Commission has jurisdiction to administer, orders and rules of the Commission, and Protocols and procedures that ERCOT has adopted pursuant to laws the Commission has jurisdiction to administer.[3]

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[3] PUC PROC. R. 22.251 (b).

- ERCOT did not conduct a full economic analysis that includes examination of both Resources[4] and transmission costs and their expected benefits. ERCOT therefore failed to comply with the Protocols requirement to attempt to meet reliability criteria "as economically as possible," and the Planning Guides requirement to do so in a "cost-efficient" manner. ERCOT's analysis and methodology inherently biases in favor of using transmission solutions, suppressing the locational marginal price ("LMP") signals needed to direct resource investment to those locations where it is needed. ERCOT only considered which of the suggested transmissions solutions had the lowest cost. Without applying some rational set of economics-based factors to evaluate the costs of solving putative "reliability" issues, the Commission risks creating a precedent in which no transmission cost is considered too great if it "solves" a reliability issue, and leading to Texas customers bearing economically unjustifiable costs and constraints on resource pricing signals. Sound transmission planning should foresee and work in harmony with new Resource investment.

- ERCOT has not even established that a real reliability problem exists. ERCOT ignored the latest load forecasting methodology that has been utilized in the two most recent Capacity, Demand, and Reserves Reports ("CDR"), and its own 90/10 extreme weather forecasts developed previously. ERCOT instead used interested transmission service provider ("TSP") forecasts. The TSP-provided forecasts show significantly higher Coastal region load growth than any of ERCOT's load forecasts using either the new or

[4] This Complaint uses the term "Resource" consistently with its ERCOT Protocols meaning, including both generation and load resources. *See* ERCOT Protocols §2 Definitions and Acronyms. Resource – the term used to "refer to both a Generation Resource and a Load Resource."

the previous methodologies. Using either of the ERCOT load forecasts (either the new CDR methodology or the 90/10 forecasts) shows that no reliability problem exists.

- ERCOT then found an even greater problem exists within the Coastal zone[5] by using very restrictive criteria for determining the resources available in 2018. In the nodal, energy-only market, instances where load may at certain times exceed local resources will create price pressure and signals that incentivize new resource investment, generation and demand response, in those areas. But ERCOT did not consider the likelihood of expanded Coastal zone resource investment as market prices increase to reflect this scarcity. It further did not include certain planned resources included within the ERCOT CDR, and made no allowance for likely cogeneration and repowerment developments.

- Yet, at the same time, ERCOT utilized a very pro-generation view with regard to the North Central zone to which the Project would interconnect. It simply asserted without any explanation that building a $590 million transmission line would lead to sufficient new or expanded resources developing in the North Central zone capable of exporting power to supply the Coastal zone's needs. ERCOT did not address the question why such resource investment will occur in the North Central zone, but not the Coastal zone, or explain why it used a very conservative approach to Coastal zone resource development but not the North Central zone. Without such analysis, ERCOT cannot demonstrate that the Project will resolve the Coastal zone reliability issues it identifies.

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[5] This includes the Coastal weather zone ERCOT identified in its Independent Review, which covers the Houston and Galveston metropolitan areas. ERCOT Independent Review of Houston Import RPG Project, ERCOT System Planning, 2014 at 3.

- Because sufficient generation to supply ERCOT's assumed Coastal zone load growth does not exist in the transmission planning cases, ERCOT turned to scaling methodologies not described in the Protocols or Planning Guides. This uses power flow models in which the load in the western and northern parts of ERCOT was artificially reduced to mimic new generation additions in amounts capable of adequately serving the Coastal zone.[6] To justify these load reductions, ERCOT considered an average of the 10 peak hours between the two regions it identified, rather than the one hour system peak that is the standard practice for transmission planning.
- The Project could potentially exacerbate any long-term Coastal zone generation resource adequacy problem that it purports to remedy, because it could lead many generators or other resource owners now developing Coastal zone projects to delay or even abandon those efforts, and further cause existing resources to shut down as the Project distorts locational price signals. This represents a risk anytime ERCOT imposes a transmission solution in an instance in which resource expansion would normally be expected to follow from the increased load growth-driven pricing signals. Muting those signals by building unneeded transmission projects is therefore antithetical to the Commission's current scarcity pricing-based policy of promoting resource investment in an energy-only market. What ERCOT calls a "reliability problem" and proposes to solve with $590 million worth of socialized transmission costs, is in reality a need for additional Houston area resource investment. Adding unnecessary transmission has adverse consequences, suppresses necessary price signals and revenues needed to sustain generation and load

[6] Independent Review at 37.

response resource investment, imposing hundreds of millions in costs on Texas customers and landowners, and creating other environmental impacts, neighborhood disruptions, and other impacts from aggressive transmission buildout.

As a result of these deficiencies, ERCOT's determination of a reliability need cannot be sustained, and cannot be relied upon as a basis for a Certificate of Convenience and Necessity ("CCN"). Collectively, ERCOT's methodology and choices amount to an abuse of ERCOT's discretion that is contrary to the protocols and procedures that ERCOT has developed, as well as the law of the Commission, and proffers a completely unreasonable result.

The Complainants have brought this proceeding to raise these issues to the Commission's attention, rather than waiting to challenge need issues in a subsequent certification case lest the issue be determined to have been resolved by ERCOT and gone unchallenged. A proceeding directly addressing ERCOT's Resolution provides the most efficient means to review ERCOT's determinations and one that saves ERCOT electric customers from incurring potentially unnecessary CCN application preparation costs, not to mention the approximately $600 million in Project costs and market-distorting pricing effects.

The Commission should direct ERCOT to re-examine its recommendation for the Project without the erroneous methodologies, assumptions, and determinations identified in this Complaint. Such a directive would be consistent with the ERCOT Board of Directors' April 8, 2014 direction to ERCOT management to conduct a formal review of its own transmission planning processes with strong stakeholder input and regular reports to the Board. This review and implementation of modifications to address flaws in the processes should be completed and then applied to evaluate the Project *prior* to proceeding with a $590 million dollar project.

Complainants therefore ask the Commission to find that ERCOT's Board of Directors Resolution of April 8, 2014 is contrary to law and protocols and order ERCOT permanently to suspend the Project's implementation.

II. COMPLAINANTS AND PARTIES AGAINST WHOM RELIEF IS SOUGHT

The Complainants are:

1. **Calpine Corporation**, appearing by and through its representatives:

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The Complainants seek relief against ERCOT. ERCOT's contact information is set forth below:

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The Complainants are serving ERCOT a copy of this Complaint through Mr. Magness, contemporaneously with filing it.

III. STATEMENT OF THE CASE[7]

A. Underlying Proceedings. Several transmission utilities proposed projects that the RPG studied over several months, and for which ERCOT Staff prepared an independent review. The ERCOT Board of Directors adopted a resolution on April 8, 2014 endorsing the need for the Project, and also finding that the Limestone-Gibbons Creek-Zenith 345kV double circuit line component of the Project was of "critical" status.

B. Identity of Directly Affected Entities or Classes. Both Calpine and NRG are "affected entities" with standing to present this Complaint. ERCOT's Resolution will affect the ERCOT generation market economics, both within the Houston area and outside it, by altering price signals that would ordinarily incentivize new resource investment (or affect facility retirement decisions). The Project would also affect the market for electricity generated by the Complainants' facilities, by altering the prevailing prices paid for such electricity. Assuming that the Commission granted the Complainants' requested relief, the decision could affect the transmission providers whom ERCOT has assigned responsibility to develop the Project. On information and belief, those include CenterPoint Energy ("CenterPoint"), the City of Garland, and Cross Texas Transmission, LLC.[8] Also, consumers who will bear higher transmission charges needed to finance the Project are a class that the Complaint may affect.

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[7] *See* PUC PROC. R. 22.251 (d)(1)(B).

[8] *See* Docket No. 42424, Complaint of CenterPoint Energy, Inc. Against the Electric Reliability Council of Texas at 2.

C. Concise Description of Conduct From Which Relief is Sought. The ERCOT Board of Directors' Resolution of April 8, 2014 endorsing the Project.

D. Statement of Applicable ERCOT Procedures. The following ERCOT protocols and standards are relevant to this Complaint. As stated below, the Complainants have not used Applicable ERCOT Procedures for challenging or modifying ERCOT's challenged conduct or decision. The Complainants have requested to be excused from following those procedures for good cause.[9] The Complainants likewise have not pursued the modification of ERCOT Protocols as a remedy.[10] Such revisions would not address the abuse of discretion in the analyses of the Project, under ERCOT Procedures, or address the harm resulting from ERCOT's adoption of the Resolution in question and therefore would not provide any relief for the conduct specified herein.

Protocols §3.11.2 (3), (4), and (5)

Planning Guide §§3.1.1.2 (1); 3.1.2.1 (6); 3.1.4.1 (1); 3.1.4.2 (1); 4.1.1.1; 6.9

ERCOT RPG Charter

E. Statement Related to Suspension. Complainants do not request the Commission to suspend the Resolution while this case is pending. After hearing, however, Complainants request that the Commission's final order suspend the Resolution and its implementation, and instruct ERCOT that any further consideration of the Project should adhere to standards that do not constitute an abuse of discretion.

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[9] PUC PROC. R. 22.251 (c)(2), (d)(1)(A)(iv).

[10] *Id.*

F. *Commission Jurisdiction.* The Commission possesses jurisdiction over this Petition under PURA §§14.001, 39.001, 39.003, and 39.151. Specifically, that jurisdiction includes the authority to "adopt and enforce rules relating to the reliability of the regional electrical network" or delegate such authority to the independent organization (ERCOT).[11] If the Commission delegates authority over reliability,

> Any such rules adopted by an independent organization and any enforcement actions taken by the organization are subject to commission oversight and review. An independent organization certified by the commission is directly responsible and accountable to the commission. The commission has complete authority to oversee and investigate the organization's finances, budget, and operations as necessary to ensure the organization's accountability and to ensure that the organization adequately performs the organization's functions and duties.[12]

The Commission may also "resolve disputes between an affected person and an independent organization and adopt procedures for the efficient resolution of such disputes."[13]

This proceeding seeks relief under P.U.C. PROC. R. 22.251, which allows an "affected entity" to file a complaint against ERCOT, setting forth "any conduct" that violates any law the Commission has jurisdiction to administer, any order or rule of the Commission, or any Protocol or procedure adopted by ERCOT pursuant to any law that the Commission has jurisdiction to administer. "Conduct" under the rule includes "a decision or an act done or omitted to be done," which would cover the ERCOT Resolution.

IV. STATEMENT OF ALL ISSUES AND POINTS PRESENTED

This Complaint presents the following issues:

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[11] PURA §39.151 (d).

[12] *Id.*

[13] *Id.*, subs. (d-4)(6).

1. The Planning Guides require ERCOT to use the SSWG base cases, but allow it to use "reasonable variations of the Load Forecast." Does a load forecast provided by the interested transmission providers not subject to public review, and not the latest ERCOT load forecasting methodologies used in evaluating resource adequacy, represent such a "reasonable variation" sufficient to demonstrate a "reliability" problem exists?

2. ERCOT must determine available resource amounts when evaluating a transmission project.

a. May it utilize different assumptions and methodologies for transmission planning than in assessing resource adequacy?

b. May ERCOT employ one set of assumptions for one region of ERCOT, assuming that insufficient resources will develop and excluding consideration of known generation projects and likely demand response, cogeneration, repowering, and uprating additions, while assuming without explanation that sufficient generation will develop in a different area of ERCOT?

3. Can ERCOT utilize superseded load scaling techniques that will be replaced shortly, including splitting the state into two regions and using inconsistent generation investment assumptions for each, to justify a project when load flow cases indicate a localized Resource shortage?

4. By failing to perform a full economic analysis[14] of the Project, and examine the Project's effects on the resource market and consider whether the resource market would resolve any reliability issues more economically and cost-effectively than the Project, did ERCOT ignore the Protocols requirement that it attempt to meet applicable reliability criteria as economically as possible and the Planning Guides' requirement that it do so in a cost-efficient manner?

5. Was ERCOT's Resolution and the process and methodology used to derive it reasonably supported or did it constitute a completely unreasonable result?

V. STATEMENT OF FACTS

A. The Complainants

Calpine Corporation is a Commission-registered power generation company.[15] Other Calpine companies doing business in ERCOT's wholesale markets are Calpine Energy Services, L.P., a Commission-registered power marketer, and Calpine Power Management LP, an ERCOT-registered qualified scheduling entity ("QSE"). NRG Energy, Inc. is a publically held corporation that owns and operates power generation companies, power marketers, QSEs, and retail electric providers in ERCOT.[16]

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[14] ERCOT purported to conduct an "economic analysis", but ERCOT's analysis simply "compare[s] the relative performance of each select option in terms of production cost savings." Independent Review at 32

[15] Calpine generating facilities in ERCOT are Baytown Energy Center, LLC, Brazos Valley Energy, LLC, Calpine Hidalgo Energy Center, L.P., Channel Energy Center, LLC, Clear Lake Cogeneration Limited Partnership, Corpus Christi Cogeneration, LLC, Deer Park Energy Center, LLC, Freestone Power Generation, LLC, Magic Valley Generating Station, Pasadena Cogeneration, L.P., and Texas City Cogeneration, LLC. Some of this generation is "behind the fence" capacity not currently available to the ERCOT market, specifically cogeneration whose output is contractually committed to the facility's thermal steam host. 25% of Freestone Energy Center is owned by Rayburn County Electric Cooperative, Inc. and 21.5% of Hidalgo Energy Center is owned by the City of Brownsville. Freeport Energy Center is owned by Calpine but contracted and operated by the Dow Chemical Company.

[16] NRG generation entities include Langford Wind Power LLC, Elbow Creek Wind Project LLC, NRG Texas Power LLC, Sherbino I Wind Farm LLC, NRG Cedar Bayou Development Company LLC, NRG South Texas LP, Petra Nova Power I LLC

B. ERCOT Transmission Planning Process

Commission rules delegate to ERCOT the primary responsibility to plan the transmission system. [17] The rules obligate ERCOT to issue recommendations to the Commission on transmission line projects during certification cases, and to submit transmission planning guides and procedures to the Commission for approval.[18] The ERCOT Protocols and Planning Guides outline the transmission planning process and criteria.

ERCOT must annually prepare a Regional Transmission Plan ("Plan"), as noted earlier, for projects needed on a six year planning horizon. The Plan lists forecasted transmission needs, but does not approve specific projects. The Plan represents the primary basis for all ERCOT transmission planning reviews.[19]

Whether included in the Plan or not, the RPG must review and issue a recommendation for nearly every proposed transmission project.[20] The RPG is an open stakeholder group comprised primarily of ERCOT staff and TSP representatives.[21] Projects that exceed $50 million require an independent ERCOT Staff evaluation and approval of the ERCOT Board of Directors. [22] Commission rules provide that the recommendations of the ERCOT Board

[17] PUC SUBST. R. 25.361 (b)(9).

[18] PUC SUBST. R. 25.101 (b)(3)(A)(ii), (D); 25.361 (d)(1).

[19] There are periodic transmission studies and analyses performed for unforeseen circumstances that are not included in the Plan.

[20] RPG submittal is not required for certain "Tier 4" projects, those in which the projected capital cost is under $15 million and that do not require a CCN, or that are otherwise classified as "neutral" projects. ERCOT Protocols §3.11.4.4

[21] ERCOT Protocols §§3.11.3, 3.11.4.

[22] ERCOT Protocols §3.11.4.7. These include so-called "Tier 1" projects.

concerning a transmission project's need are "given great weight" in a related certification case.[23]

ERCOT must use the Steady State Working Group ("SSWG") "base cases" (power flow studies based on observed load flows and load/resource projections) in preparing the Plan, and in most transmission planning studies and reviews. The Planning Guides allow ERCOT to make "reasonable variations in the load forecast."[24]

In addition to the Plan's results and findings, the Protocols and Planning Guides set forth the assumptions and required performance criteria ERCOT may employ in evaluating proposed transmission projects and in transmission planning more broadly.[25] ERCOT also applies individual TSP planning criteria, but must make such criteria public.[26] ERCOT must also adhere to applicable NERC criteria.

The Planning Guides provide that ERCOT will "approve" (endorse or recommend) a transmission project when the proposed project will "ensure that the system is able to meet applicable reliability criteria in a cost-effective manner."[27] This carries forward the Protocols' transmission planning requirement that in meeting applicable reliability criteria, ERCOT must attempt to do so "as economically as possible."[28]

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[23] PUC SUBST. R. 25.101(b)(3)(A)(ii)

[24] ERCOT Planning Guides §4.1.1.1 (5)

[25] ERCOT Protocols §3.11.2; ERCOT Planning Guides §4 (generally).

[26] ERCOT Planning Guides §4.1 (8).

[27] *Id.* §3.1.3

[28] ERCOT Protocols §3.11.2 (3).

C. Houston Import Project Description

The Project that the Board approved included construction of a new transmission line and several substation upgrades. These include:

- A new Limestone-Gibbons Creek-Zenith 345kV double circuit line (2,988 MVA of emergency rating/circuit);
- Upgrade the Limestone, Gibbons Creek, and Zenith substations to accommodate the terminations of the new circuits; and
- Upgrade of the existing T.H. Wharton-Addicks 345kV line to 1,450 MVA of emergency rating.

ERCOT's Independent Review estimated the Project's capital cost as $590 million in 2018 dollars, but stated that the estimate may vary from actual results based on the designated transmission providers' actual designs and cost analyses.[29] ERCOT designated CenterPoint, City of Garland, and Cross Texas Transmission as co-providers of the new transmission line and associated equipment upgrades. CenterPoint is the designated provider of the T.H. Wharton-Addicks 345kV line, and the Limestone and Zenith substation upgrades. Cross Texas Transmission and City of Garland were designated to provide the Gibbons Creek substation upgrade.[30]

D. ERCOT Processing and Review

1. Earlier Version of the Project

CenterPoint proposed an earlier version of the Houston Import Project in 2010 as an "economic" transmission line through five counties connecting the Fayetteville and Zenith substations. CenterPoint secured ERCOT Board approval for that Project. In June 2011,

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[29] Independent Review at 1.

[30] CenterPoint has filed a complaint against ERCOT challenging these designations. Docket No. 42424, *supra.*

CenterPoint filed comments with the Commission arguing that while a definite reliability need for additional import capacity into Houston had not been established, an ERCOT study on proposed environmental regulation impacts showed that such a project may be needed, that the then-current energy-only market design will not support adequate reserve margins, and additional transmission pathways into Houston are necessary to support reserve margins. It described its "import project" as a means to address this generation adequacy problem.[31] Notably, however, in seeking ERCOT Board approval of the Project earlier this year, ERCOT's presentation stated that "ERCOT long-term transmission planning has consistently indicated a need for additional import capacity into the Houston region since 2008."[32] This is inconsistent with CenterPoint's contemporaneous representation (during 2010), that a reliability case did not support an additional Houston import path. Overwhelming public and official opposition eventually led CenterPoint to withdraw its 2010 proposal.[33]

2. ERCOT's Review and Methodology

By mid-2013, CenterPoint and other transmission providers returned to ERCOT proposing to develop additional transmission paths into Houston. Between them, they submitted three separate proposals. The RPG evaluated each proposal, and ERCOT staff conducted an independent review. As part of the independent review, ERCOT staff reviewed 21 separate options, all involving new transmission development.

[31] Project No. 37978, Comments of CenterPoint Energy.

[32] ERCOT Presentation to the Board of Directors at 2, April 8, 2014.

[33] See *Comments Concerning CenterPoint Energy's Proposed 345-kV Transmission Line From the Fayetteville Substation to the Zenith Substation*, Project No. 39380.

a. No Economic Analysis or Consideration

ERCOT did not perform any analysis to quantify the economic benefits or effects that the Project would create. Instead, the Independent Review examined only the costs of each proposed transmission option, and recommended selecting the lowest cost options that solved the supposed reliability issue.[34] As a consequence of not studying the Project's economic benefits and effects, ERCOT also did not weigh any economic benefits against the Project's costs to determine that the Project met the planning criteria "as economically as possible." ERCOT did not address the Project's effect on LMPs and congestion charges at the end of the constrained path and the corresponding effect on pricing signals to resource investors and customers. Nor did ERCOT analyze whether the Project meets reliability criteria in a "cost-effective" way. It did not assess the Project's impact on localized resource investment (either in the Coastal zone or in the North or North Central zones) to determine whether the combination of the Project and additional North Texas resources (if they indeed materialize) represents a more economical or cost-effective means of meeting the reliability criteria than relying on pricing signals to bring about the same amount of Coastal zone resources, but without the Project's minimum $590 million price tag.[35] Nor did ERCOT consider other non-capital costs, such as annual cost of service, potential RMR contracts required when the Project alters LMPs and renders marginal generation uneconomic, or costs imposed on landowners or others.

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[34] ERCOT Independent Review at 34-35. ERCOT did include a brief section entitled "Economic Analysis," but that section simply studies "annual production costs" for the eight options it considered in detail to determine which of the selected options resulted in the lowest production costs. ERCOT did not perform an economic analysis as described in Protocol §3.11.2 (4) in which ERCOT determines the "net societal benefit" of a project *Id.* at 32.

[35] The ERCOT Independent Review quantifies the Project's cost at $590 million, but gives no consideration to other costs, such as annual operating costs, the suppressing effect on generation investment and possible expansion of reliability must run ("RMR") contracts as certain resources become uneconomical, costs imposed on landowners, and likelihood of cost overruns.

b. Widely Varying Load Forecasts

ERCOT did not rely on its recently revised CDR "neural network" forecasting model in evaluating the Project's need. Instead, ERCOT used the "higher of" the TSP-supplied load forecast or ERCOT's own 90/10 extreme weather forecast in the SSWG base cases.[36] While the TSP load forecasts were available to RPG members who knew to look for them embedded in SSWG information, the TSP forecasts do not receive the same vetting and scrutiny applied to ERCOT's load forecasts. ERCOT did not post them with a Market Notice, for example, while ERCOT's own load forecasts have been publicly debated and scrutinized in numerous market participant meetings and during Commission open meetings. As examples of the differences, the TSP-provided SSWG 2018 Coastal weather zone peak load forecast is 1,880 MW higher than ERCOT's own 90/10 extreme weather forecast for the same region and same year. Conversely, the TSP-provided SSWG 2018 North Central weather zone (which includes the Dallas/Ft. Worth metroplex) is 3,617 MW lower than ERCOT's 90/10 extreme weather forecast. [37]

In light of differences in the loads used in the Project's study cases, it is useful to compare the load forecasts used in the Project analysis with the peak load value in the primary resource adequacy planning tool, the ERCOT CDR. The sum of the loads in 2018 in the base case used by ERCOT to evaluate the Project shows a system-wide coincident peak of 80,965 MW. ERCOT's CDR shows a coincident peak summer load in 2018 of 69,888 MW. Allowing the use of the TSP's load forecasts rather than depending on ERCOT's new load forecasting

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[36] Independent Review at 3-5.

[37] The North Central figures presented here incorporate ERCOT's 85% "scaling" methodology, although the Complainants challenge that as well.

functionality creates a very large 15 percent difference between transmission planning and resource adequacy planning.

c. Consideration of Coastal Resource Development Prospects

While adopting a higher Coastal zone load forecast than any of ERCOT's load forecasting methodologies. ERCOT also employed a highly conservative approach to determining available 2018 Coastal zone resources. It found that very little generation development would occur, offering without evidence only that "while the load growth in the [Houston] region is expected to continue, a significant challenge is also anticipated in developing new resources in the increasingly urban area due to restrictions such as air quality standards and site availability inside the city."[38] It assumed resource growth would not keep pace with Coastal zone load expansion, but through a load scaling technique that is not described in either the Planning Guides or the Protocols, assumed resource growth can occur to keep pace with load expansion in other regions of ERCOT. ERCOT also conceded that generation projects develop closer in time to the point of scarcity than transmission. But stating that it "lacks control" over generation, ERCOT did not analyze future Coastal zone generation beyond considering facilities that had signed interconnection agreements and provided financial security.[39] It did include several new generators within the Coastal zone, but did not include several announced generation projects with interconnection agreements, including the 1,469MW Pondera King unit (which ERCOT included in its February 2014 CDR report as available in summer 2018, but has been recently accelerated by the developer to be available in summer 2017).

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[38] Independent Review at 1.

[39] *Id.* at 37

It also did not address possible cogeneration development. A comparison of the SSWG's 2014 and 2018 Base Cases reveals that numerous bus loads in the Houston area's industrial pockets show TDSP forecasted peak load increases in excess of 150 percent. These immense peak load differences can only be explained as part of Texas' Gulf Coast recognized industrial expansion, which CenterPoint has touted in ERCOT stakeholder meetings.[40] This is an important point because ERCOT relies on CenterPoint's expertise and data in the RPG process. Industrial expansion is normally accompanied by local cogeneration development due to the frequent need for both electricity and process steam, which cannot practically be provided from another region. ERCOT made no assumptions that any cogeneration would develop at industrial sites to serve this increased load.

In one of its sensitivity cases, ERCOT assumed the retirement of 1,939 MW of greater than 50 year old Houston area generation units by 2018 and ran power flow studies excluding these existing resources.[41] However, ERCOT ignores any possibility that these assumed retirements would be offset by repowering projects at those sites, and more importantly, ERCOT assumed there would be no retirements of greater than 50 year old generation in other regions of ERCOT that would be required to import the power needed across the Project's transmission lines to serve the Houston area load.

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[40] CenterPoint presentation to the ERCOT Scenario Development Stakeholder Workshop, January 23, 2014, lists the following proposed industrial projects in the Houston area: Exxon Mobil (Baytown), Chevron Phillips (Baytown), Chevron Phillips (Old Ocean), Dow Chemical (Freeport), Freeport LNG (Freeport), LyondellBasell (Channelview), LyondellBasell (La Porte), INEOS (Chocolate Bayou), Celanese (Clear Lake), Linde (La Porte), Enterprise Products (HSC) and Enterprise Products (Mont Belvieu). *CNP Discussion Points for Long-Term Scenarios (2014-2029) January 23, 2014, slide 10,* *www.ercot.com/.../meetings/lts/keydocs/2014/0123/CNP_Discussion_Points_for_Long_Term_Scenarios.ppt.*

[41] ERCOT Independent Review at 28, 34.

d. Assumed North Central Generation Expansion

While adopting a very conservative approach to forecasting 2018 Coastal zone resource levels, ERCOT merely assumed without any explanation that the North Central zone would experience resource expansion at levels adequate to flow over the Project and meet the Coastal zone's supposed resource deficiency. The Independent Review concedes, as noted below, that the North Central zone does not presently contain adequate resources to serve the zonal load and have spare capacity to flow south.[42] Nor does the Independent Review offer any insight into why ERCOT believes that the Project itself will alter resource investment economics in the North Central region of the state to stimulate such investment by 2018. At most, it merely opines that a possibility exists the Project will incentivize additional resource investment: "Furthermore, a new import path into the Houston area may open the market for new, more efficient generation sources to construct outside of the area and sell power by importing into Houston which will introduce additional competition for the legacy generation resources in the area."[43]

e. "Scaling" of Loads

In addition to the use of questionable and inconsistent load forecasts, ERCOT further employed a "scaling" methodology to reduce the load outside the Coastal weather zone. ERCOT's stated reason for doing so was not enough generation exists in the base case to "meet the summed non-coincident peak load of all areas of the system."[44] ERCOT further stated that to solve this challenge it had to "split the 2018 summer peak case into two study areas, the so-

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[42] *Id.* at 3-4.

[43] *Id.* at 28.

[44] *Id.* at 3.

called NW and SE areas,"[45] and that "for each study area the load level was set to the forecasted peak load for that area while load outside of the area was scaled down until there was enough generation to meet the load plus an operational reserve of approximately 1,375 MW."[46] The Project study area was the SE area.[47] In the SE study case, ERCOT scaled the load down in the north, north central, and western regions of the state, while holding the loads at their highest peak forecast levels in the Houston, south, and south central regions of the state.

This scaling technique (scaling load down from the questionable load assumptions described previously) ultimately resulted in an electrically equivalent 15 percent North Central weather zone generation addition, approximately 2,000 MW.[48] Conversely, by holding the Coastal region loads at their peaks with no scaling, ERCOT assumed no resources can be added in the Coastal zone. ERCOT justified the scaling by comparing the coincident peaks of the Coastal and North Central weather zones to the top ten hourly peak load conditions,[49] rather than utilizing the customary peak hour that is typically used in transmission planning and always used in the CDR.

3. ERCOT's Decision and Recommendation

Based on the methodology and assumptions described herein, ERCOT's independent analysis found that loading would exceed N-1 standards for one 345kV line, and G-1 + N-1 would be violated for multiple 345kV lines. It therefore recommended approving the list of

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[45] *Id.*

[46] *Id.*

[47] *Id.* at 3-4.

[48] *Id.*

[49] *Id.* at 4.

upgrades and construction identified as "Option 4," and approve it as a reliability-driven project.[50] RPG approved the Project and sent it to TAC and later to the Board of Directors, both of which endorsed it, although not unanimously. Calpine and NRG representatives participated in the RPG study process. Calpine and NRG both also submitted comments and made presentations to the TAC and the Board of Directors.[51]

E. ERCOT Board Questions RPG Review Process, Directs Review

In the ERCOT Board discussion about the Project, several Board members expressed concern about ERCOT's planning methodologies. Specifically, Board members raised concerns, with no public objection by any other Board member, about the lack of fidelity between transmission planning load forecasts provided by TSPs and the new neural model load forecasts ERCOT has developed and now uses for evaluation of ERCOT resource adequacy, including the ERCOT CDR.[52] The ERCOT Board directed ERCOT to work with the RPG to address those concerns, and as appropriate, revise the transmission planning process. In the discussion, ERCOT Vice President for Operations, Kenneth McIntyre, acknowledged the validity of the concerns that must resolved, such as addressing "is there significant difference between how we do it in a CDR or how we do it in the planning cases and let's look that and see if we need to adjust that." [53] Mr. McIntyre further conceded the need for ERCOT to begin "working with the

[50] Independent Review at 38.

[51] The Complainants attach the presentations that they made to the Board of Directors (attached).

[52] ERCOT Board of Directors Meeting, April 8, 2014, Transcript pp. 88 – 92, 96 – 101 (attached).

[53] *Id.* at 91.

experts and the Regional Planning Working Group itself to challenge [the planning methods used]."[54]

Emphasizing that a simple RPG discussion about the matter does not satisfy these concerns, Board member Mark Dreyfus observed that "there's a lot of other things going on in our environment and in our market, and issues have been raised about the consistency of the load forecast with our new approach, the load scaling methodology."[55] Mr. Dreyfus urged that the process to resolve these inconsistencies should be "more formal than you [Mr. McIntyre] might have suggested in your comment that we have a working group." Mr. Dreyfus requested a review with a "strong stakeholder involvement" and with routine Board updates.[56] Mr. McIntyre agreed to Mr. Dreyfus' recommendations.[57] This reflected the controversial and exceptional nature of the Project, for greater resource adequacy and investment implications than the typical project RPG usually reviews.

VI. SUPPORT FOR CONTENTIONS[58]

The Houston Import Project amounts to ERCOT's classification of temporary intra-zonal generation shortfalls as a transmission reliability issue. ERCOT controls transmission, not generation, and as a consequence it has employed study methodologies, such as using a load forecast provided by interested TSPs rather than ERCOT's own load forecast, that point ERCOT toward deploying transmission solutions to resolve localized resource adequacy issues. Transmission takes longer to develop than generation, as modern combined cycle generation or

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[54] *Id.* at 92.

[55] *Id.* at 96 .

[56] *Id.* at 96-97

[57] *Id.*

plant repowerment and refurbishment options can be developed within two to three years. The temporal ambiguity this presents to transmission planners seems to create a bias to see the transmission they control as the solution for every forecasted system shortfall. This distorts and suppresses resource pricing signals critical to an energy-only market's viability. In this case, this premature resort to transmission options will impose nearly $600 million in additional transmission costs and construction risk on Texas customers rather than private generation investors. It creates conflicting positions on whether ERCOT possesses sufficient resources. ERCOT's faulty assumptions and methodologies are erroneous, as is its overall recommendation. Both amount to an abuse of its discretion.

A. Legal Standards

Although it is a private entity, ERCOT exercises governmental authority. Accordingly, it may do so only when an administrative agency reviews its activities.[59] ERCOT therefore possesses reasonable discretion to accomplish the duties delegated to it, but may not abuse its discretion. The Commission bears a statutory and constitutional duty to oversee ERCOT's application of discretion, not simply to defer in all cases to its actions.[60] While some measure of deference may be warranted in many cases, oversight requires active review and scrutiny, and not merely ensuring that ERCOT appeared to follow a process on the books. The Commission's applicable Procedural Rule sets forth this standard, providing that "if the factual determinations supporting the conduct complained of have not been made in a manner that meets the procedural

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[58] PUC PROC. R. 22.251 (d)(1)(E).

[59] *Texas Boll Weevil Eradication Foundation, Inc. v. Lewellen*, 952 S.W.2d 454, 472 (Tex. 1997)(important factor in approving delegation is whether "the private delegate's actions subject to meaningful review by a state agency or other branch of state government").

standards specified in this subsection, or if factual determinations necessary to the resolution of the matter have not been made, the commission will resolve any factual issues on a *de novo* basis."[61]

An abuse of discretion may occur in several different ways, such as by applying a factor or standard not called for in the applicable rule or statute, applying inconsistent standards by acting without "substantial evidence" or without explaining how facts support conclusions, employing unjustified or legally impermissible factors, acting contrary to an express statutory requirement, or following legally relevant factors but reaching a completely unreasonable result.[62]

B. ERCOT's Errors

ERCOT has abused its discretion in several ways. Specifically, ERCOT: (1) failed to verify that that the Project meets the reliability criteria "as economically as possible" and cost-effectively; (2) used TSP-sponsored load forecasts within the Coastal zone rather than either ERCOT's 90/10 extreme weather cases underlying the Plan or its later adjusted CDR methodology, which was not a "reasonable variation in the load forecast"; (3) erroneously excluded known generation projects and likely cogeneration development and refurbishment and repowering options within the Coastal zone, and did not explain its refusal to assume Coastal zone resources would expand, while making the opposite assumption about the North Central

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[60] *FM Properties Operating Co. v. City of Austin*, 22 S.W.3d 868, 880 (Tex. 2000)(finding actual governmental review an important factor in approving delegation to private entities).

[61] PUC PROC. R. 22.251 (l). The "procedural standards specified in this subsection" denote facts determined in a proceeding to which the parties have voluntarily agreed to participate and by an impartial third party under circumstances that are consistent with the due process standards inherent in the Administrative Procedure Act (i.e. notice of a hearing, right to present and cross-examine witnesses, and right to present evidence).

[62] *City of El Paso v. Public Utility Comm'n*, 883 S.W.2d 179, 184 (Tex. 1994)

zone; (4) used "scaling" techniques not described in the Protocols or Planning Guides to reduce North Texas loads, thereby relying on "virtual generation" and flows along the Project to Houston; and (5) without any explanation or evidence, assuming that generation adequate to resolve the alleged reliability problems would actually develop in North Texas.

As demonstrated below, these decisions and assumptions amount to an abuse of discretion. ERCOT has ignored factors set forth in the Protocols and Planning Guides, relied upon factors not included in the Protocols and Planning Guides, made unreasonable and erroneous factual determinations, and reached a completely unreasonable result.

1. Failure to Conduct Required Full Economic Analysis

ERCOT posits high load growth within the Coastal zone that local resources cannot solve, which will overload existing import capacity and create a reliability issue. By labeling the Houston Import Project a "reliability project," and failing to quantify the economic benefits it offers, ERCOT concludes, without analysis of any resource options or effect on generation or resource investment, that the project is "economical" or "cost-effective" and the amount of economic benefits can be ignored. Import limits, to the extent they are present, have economic implications in the form of congestion charges and changed LMPs when the limit is binding. If a reliability-related upgrade is made, it would reduce congestion charges over the import interface that was limiting, and change LMPs on both side of the limit interface. Economic benefits accruing from the changed LMPs need to be quantified and compared with the cost of the proposed reliability upgrades. ERCOT did not perform this analysis, however.

Without such analysis, ERCOT cannot verify that the proposed upgrade meets reliability criteria as economically as possible or cost-effectively. It can only conclude that the option proposed for the Project is the least cost means for increasing the import capacity from among those it studied.

Failing to conduct such analyses at all risks a future in which ERCOT recommends extremely high cost projects to solve similar reliability/resource adequacy concerns as they may develop throughout the ERCOT system. The Project here provides a precedent that ERCOT can repeat. Indeed, through a scaling analysis such as performed for the Project, ERCOT could always divide the ERCOT region into any two separate areas, "scale" the load down in one region as much as necessary and apply a generous load forecast for the other, and inevitably show transmission overloads between the two just as it did here. The techniques used in the Project can always be repeated to show a "reliability problem" without requiring ERCOT to conduct a full economic analysis, and there is nothing that would prevent ERCOT from supporting unlimited transmission development that supplants resource investment.

ERCOT essentially reclassified the Houston Import Project from an economic project designed to increase the societal benefit on an ERCOT-wide basis through reduced congestion and improved generator dispatch, to a reliability project. ERCOT's interpretation is that doing so meant that it would not have to justify the $590 million price tag, except to show that it had the lowest cost of several options to address the "constraint" caused by assuming that future "virtual North Texas generation" would flow to Houston to serve interested TSP-forecasted load growth. By ERCOT's reasoning, it would never have to justify the cost of any "reliability" project, even when the "reliability" issue is really a local resource adequacy problem. Under this reasoning, no cost would ever be considered excessive, as long as other transmission projects cost even more. That cannot be a desired policy outcome, yet that represents the logical conclusion of ignoring the Protocols' requirement that ERCOT must attempt to meet reliability criteria "as economically as possible."

2. Unjustified Use of a Different Load Forecast for Transmission Planning versus the CDR and RTP process

ERCOT has recently and extensively revised its load forecasting methodology, which is intended to improve the accuracy of its load forecasts as well as the CDR utilized by policy makers and others. ERCOT Director of System Planning Warren Lasher stated, for example, that "[a]lthough population and the economy continue to grow in the ERCOT region, the relationship between economic growth and peak electric demand has changed in the past several years....We believe recent improvements to our load forecasting methodology are providing a more realistic view of the future electric demand we need to be prepared to serve."[63] In that same release, ERCOT offered that industry experts have concluded that peak demand has grown more slowly than economic growth due to energy efficiency measures, and the new load forecasting methodology focuses on customer premises growth rather than general economic and employment growth figures.[64] Yet, ERCOT did not use this new forecasting methodology, or its own prior forecasts using the previous methodology.

No reasonable basis exists for using two different types of load forecasts, or for rejecting ERCOT's load forecast in favor of interested TSP load forecasts. For several of the weather zones, including most importantly the Coastal and North Central zones, not only did ERCOT not use the 90/10 extreme weather forecasts derived with the previous methodology, which showed thousands of MWs difference compared to the load forecast provided by the TSPs, but it also

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[63] ERCOT News Release, "New Report shows peak demand for electricity growing more slowly than in previous years" (Feb. 28, 2014). http://www.ercot.com/news/press_releases/show/26597

failed to apply the newly refined load forecasting methodology at all. ERCOT offered no evidence to justify doing so. Though the Planning Guides provide that ERCOT may make *reasonable* load adjustments, ERCOT did not explain why the TSP's forecasts constituted such a reasonable adjustment.

3. Excluding Coastal Zone Resources

ERCOT used a much more conservative approach to forecasting Coastal zone resource development than in the North Central zone. It excluded the 1,469MW Pondera King facility ("Pondera"), assumed in a sensitivity case that all 1,939 MW identified for possible retirement in the Coastal zone would in fact retire and not undergo repowerment or refurbishment, yet retirements would not occur in other regions, and made no consideration for cogeneration development. ERCOT has stated that it assumed this conservative view because it lacks control over resource development.[65] Ignoring resource development's closer in time development horizon, ERCOT concluded it must act with a transmission project.

ERCOT's approach was unreasonable. ERCOT's February 2014 CDR lists Pondera, for example, as available in 2018,[66] the same year ERCOT claims the Project is needed, but Pondera has informed ERCOT the plant will be operational by June 2017. Pondera is included in the CDR based on belief it can be counted for resource adequacy. ERCOT has not expressed a meaningful reason to distinguish between the certainty of resources for purposes of transmission planning versus resource adequacy.

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[64] *Id.*

[65] Independent Review at 37.

[66] The May 2014 CDR Update actually omits Pondera King from the latest assessment, based on it not having presented adequate documentation of water rights, but that is expected to be cured shortly.

ERCOT's refusal to consider likely cogeneration development accompanying industrial load growth similarly was unreasonable. Houston's industrial corridor is expecting load growth at several large industrial busses in the 2018/2019 time frame.[67] This industrial load will require the support of process steam generated by combined heat and power resources in the Coastal Zone because process steam simply cannot be provided by resources located in the North Central Zone.

ERCOT's sole rationale supporting this approach was that environmental limits and site availability restrictions prevent adequate Coastal zone resource development. The empirical record, including Pondera King's development and at least two new Calpine units going into service within the Coastal zone this summer, belies ERCOT's assertion.[68]

4. Inappropriate Scaling of Loads In the North

ERCOT's load scaling assumption finds no mention in the Planning Guides or Protocols. Even accepting their use, the standards ERCOT used exceeded reasonable limits and thus drive the unrealistic Project results. By reducing the load in the North Central region to an 85 percent coincident peak value relative to the Coastal region, ERCOT has made an "electrically equivalent" generation assumption that approximately 2,000 MW of generation will be added in the North Central weather zone by 2018, while assuming that none will be added in the Coastal zone. Again, it failed to show that this represents a reasonable assumption.

To help understand the huge economic impacts these types of load scaling assumptions can have on customers, consider the other planning case utilized to study 2018. In the NW case,

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[67] February 2014 CDR

[68] ERCOT Monthly System Planning Report, March 2014 at 5-6 (attached).

ERCOT utilized load scaling assumptions that are completely opposite from the SE case. In the NW case, ERCOT scaled down the load in the Houston, south, and south central regions, while holding the loads at their highest peak forecast levels in the north, north central and western portions of the state. This is a complete reversal of the load assumptions in two different regions of the state and they both cannot be right. In the SE case, ERCOT made an electrically equivalent assumption that excess generation will be available from the north that can be imported into Houston, but in the NW case it reversed the load scaling and therefore made the opposite assumption that excess generation will be available in the Houston region that can be imported into the Dallas/Ft. Worth/north central area of the state. This "flip-flopping" of the load scaling assumptions across two separate regions, which ERCOT has already conceded will likely be modified in the future, does not solve the real issue, a shortage of generation in 2018. It will instead impose unnecessary and significant costs on Texas consumers.

ERCOT further erred in comparing the 10 peak hours between its seemingly arbitrarily drawn load zones, rather than the normal one hour period. As NRG showed in the table included in its Board comments[69], the 10 hour average values show a greater disparity between Houston and North Texas peak loads than the coincident peak, artificially finding that more virtual generation resources would be available to flow south into the Coastal zone than a standard peak analysis would allow.

[69] NRG Comments/Concerns with Houston Import Project at 5 (attached).

As for ERCOT's oft-repeated insistence that even without using scaling a reliability case supports the Project, that is true only if one uses the faulty load forecasts and generation assumptions described above.

5. Assumption of North Central Zone Resource Expansion

ERCOT does not explain its seemingly conflicting assumption that the LMPs reflecting Coastal zone scarcity will not lead to the development of 1,800 MW of resources within the Coastal zone, but once the Project is built, adequate investment incentives will lead investors to develop resources in the North Central zone.

For the Project to achieve its stated reliability goals, there has to be sufficient available generation to transfer from the North Zone into the Coastal Zone; a transmission line by itself cannot power homes and businesses. ERCOT, however, cited no data indicating more generation investment will occur in the northern and western portions of the state than in the coastal and southern regions. ERCOT merely observed that the Project "may open the market" for such generation additions. ERCOT did not act reasonably in making that assumption. Certainly, no reason exists to assume that additional North Texas resource capacity will develop at the same time one assumes it will not develop within the Coastal zone. Resource development costs simply do not vary materially between these regions.

ERCOT was unwilling to believe that the higher LMPs prevalent in a resource constrained area like the Coastal zone would lead to sufficient resource growth, but for some reason it just assumes that building a $590 million transmission line will lead the same investors that are not developing Coastal zone resources despite higher LMPs to do so in the North Central zone. Just as the CDR shows slower Houston load growth than the interested TSP's load forecasts on which ERCOT relied, the CDR shows lower generation expansion in North Texas than the 2,000 MW ERCOT assumed will develop to justify this Project.[70] Interconnection applications and agreements similarly refute any reasonable belief that that amount of generation will develop in North Central zone on the 2018 horizon.[71] Had ERCOT employed the same set of assumptions and treatments to the North Central zone it employed in the Coastal zone, the Project would not solve the reliability issue ERCOT identified.

C. Taken in its Entirety, ERCOT's Supporting Analysis and Resulting Action Constitutes An Unreasonable and Abusive Exercise of Discretion, Creating Adverse Market Results.

ERCOT abused its discretion or demonstrated an unreasonable exercise of discretion by using several key, but unreasonable assumptions that pointed the decision toward approving the Project as a critical reliability project. The Project finds its justification solely as the result of a broad-view transmission planning function that will result in front-running resource development and mute the ability of the ERCOT energy-only market to effectively send investment signals for additional resource capacity. It will also produce at least $590 million in cost imposed on customers and additional costs on landowners.

In large part, ERCOT's inconsistent use and application of load and resource data accounts for the "reliability" problem that allegedly justifies the Project. Consider the following realistic example of how these load forecast differences and load scaling assumptions can skew the Project's study results. If ERCOT had used its 90/10 extreme weather load forecast for 2018 instead of the TSP-provided load forecasts, and even if ERCOT retained the questionable load

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[70] February 2014 CDR, Executive Summary (showing no Metroplex additions to the CDR) (attached).

scaling assumptions that were mentioned previously, it would "lower" the Coastal (Houston) load by 1,880 MWs (26,355 MW load forecast from the TSPs minus 24,475 MW in ERCOT's extreme weather forecast) and "increase" the North Central load by 3,074 MW (a scaling down to 85% of 29,512 MW in ERCOT's extreme weather forecasts minus a scaling down to 85% of the 25,895 TSP provided load forecast). This is a total swing in the load scaling assumptions of 4,954 MW in a direction that would completely modify the Project's conclusions and show that the Project cannot solve the perceived 2018 reliability issue.

ERCOT's methodology also upends the relationship between transmission planning and resource development. As noted earlier, transmission planning should foresee new generation and resources. The point of the nodal market was to institute more granular pricing that would send accurate price signals to add new resources at the points where they are needed. ERCOT's "reliability" issue truly recasts an underlying mismatch between load and resource growth that Resource suppliers can be expected to close in an energy market as they respond to heightened price signals. Responding through regulatory fiat with a costly transmission project, however, distorts those price signals and reduces the pricing incentive to add or enhance resources in the resource deficient area. This may "even out" and reduce the incentive to locate resources in any particular area, thereby creating a situation where still more transmission is required to connect resource short areas with areas that may become long on capacity.

Transmission projects should be market-neutral. They should not deter resource investment or artificially direct it to inefficient or unneeded locations. As described above, the

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[71] See attached excerpts from the March ERCOT System Planning Monthly Status Reports at 5-9 (showing no interconnection agreements or applications for the four county Metroplex area).

Project demonstrates that transmission expansion planning and resource adequacy planning are not balanced. In the case of the Project, ERCOT's assumptions and unbalanced methodologies have led to transmission planning front-running generation development.

The Complainants urge the Commission to consider that ERCOT's pursuit of reliability projects like the Houston Import Project – which CenterPoint initially advanced as an economic project – is unfairly displacing generation solutions using the false premise that reliability requires doing so. The energy-only market is being relied on – for the foreseeable future – to support generation as warranted by market signals. Any inherent bias against generation and load response or for transmission undercuts the energy-only market's ability to meet its intended goal. In the case of the Project and all future instances where ERCOT uses transmission to solve local resource adequacy situations, it seems highly likely such a policy will mute the very signal the energy-only market should be sending to support the build-out of needed generation in the Coastal Zone. Allowed to continue, this bias toward transmission solutions over generation development will become a self-perpetuating process with no apparent circuit breaker in sight.

Therefore, in its entirety, ERCOT has abused its discretion by:

1. Ignoring Protocols and Planning Guides requirements that it attempt to meet reliability criteria as economically as possible and in a cost-efficient manner;

2. Utilizing inconsistent, unreasonable, and conflicting assumptions concerning the 2018 load forecasts, and not using its own reasonable and widely vetted variations of the load forecasts;

3. Using inconsistent, unreasonable, and conflicting standards and assumptions about resource development within different parts of ERCOT;

4. Employing scaling methodologies not sanctioned by the Protocols or Planning Guides; and

5. Reaching a completely unreasonable result, by confounding a potential and localized resource adequacy characteristic of the normal workings of nodal market scarcity pricing and forcing a regulatory transmission solution that will likely depress price signals to resource investors in the region most in need of investment, and impose at least $590 million in costs on Texas customers and others in the process.

VII. QUESTIONS OF FACT FOR EVIDENTIARY HEARING

At this time, Complainants believe that the dispute involves several factual issues concerning the appropriate application of relevant Protocols and Planning Guides provisions. These are more specifically described in Section IV, and include:

1. Was ERCOT's failure to conduct an appropriate economic analysis inconsistent with its authority or an abuse of discretion?

2. Did ERCOT err in using inconsistent and questionable load forecasts?

3. Should ERCOT have included known and reasonably anticipated generation and cogeneration development in its reliability analysis?

4. Was ERCOT's load scaling methodology consistent with its authority and applied reasonably?

   a. Was its decision to compare 10 hour average coincident peaks appropriate to use in a peak planning case?

b. Whether the magnitude of load scaling employed was reasaonable.

The Complainants reserve the right to supplement this statement should ERCOT's response or subsequent discovery reveal further disputed factual issues.

VIII. WAIVER OF ADR

The Complainants request that the Commission waive any applicable ADR requirement. ADR would represent a waste of the parties' time and resources. The ERCOT RPG has studied this Project and debated it in several meetings. ERCOT Staff performed an independent review. Both the TAC and the Board of Directors considered the Project at their regular meetings, and market participants were allowed to present competing views. No purpose is served by requiring the Complainants to negotiate with ERCOT officials, who likely will feel bound to support the Resolution in its entirety. Accordingly, the Complainants request that they be excused from pursuing ADR.

IX. REQUEST FOR COMMISSION HEARING

The considerations set forth above for why the Commission should excuse the parties from pursuing ADR also warrant retaining this proceeding at the Commission. The Complaint speaks directly to Commission policies and ERCOT standards, over which the Commission possesses unique expertise. Similarly, the case is part of a broader context in which both ERCOT and the Commission are re-examining resource adequacy, reliability and planning standards, and considering those broader issues in a hearing directly before the Commissioners will greatly enhance review of these issues. The Commission therefore should retain this case and hold an evidentiary hearing.

X. CONCLUSION

Based on the foregoing, the Complainants request that the Commission enter an Order granting its Complaint, and finding that ERCOT's Resolution was an abuse of discretion and otherwise contrary to law, Protocols, and standards. The Complainants request that the Commission declare the Resolution invalid, and instruct ERCOT to study the matter further using justified assumptions that do not abuse its discretion. The Complainants further request the Commission award any all such further relief to which they may be entitled.

Respectfully submitted,

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ATTORNEY FOR NRG ENERGY, INC.

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of this pleading has been forwarded by fax, U.S. first class mail, hand-delivery, or by courier service to ERCOT on the 13th day of May, 2014.

Chris Reeder

Attachment 1

Affidavit of Randy Jones

&

Affidavit of Adrian Pieniazek

AFFIDAVIT OF RANDY JONES

COUNTY OF HARRIS	§
	§
STATE OF TEXAS	§

I, Randy Jones, first being duly sworn, do hereby state as follows:

"1. I am over the age of 18 and am competent to make this affidavit and testify.

2. My name is Randy Jones. I am employed as Vice President, Government and Regulatory Affairs, Calpine Corporation. I affirm that I have reviewed the Complaint of Calpine Corporation Against the Electric Reliability Council of Texas Concerning the Houston Import Project ("Complaint"), including all attachments. I further affirm that I have personal knowledge of the facts stated in this Complaint based on my employment, and that I have the authority to verify the factual statements in this Complaint on behalf of the Calpine Corporation.

3. I certify that the factual allegations contained within this Complaint are true and accurate to the best of my knowledge, information, and belief, and that all documents attached to the Complaint are true and correct copies of the originals."

Further Affiant sayeth not

Randy Jones

Randy Jones

Given under my hand and seal of office this 12th *day of* May, *A.D.,* 2014

Regina Kaye Ellis

Notary Public in and for the State of Texas

REGINA KAYE ELLIS
Notary Public, State of Texas
My Commission Expires
July 11, 2015

My Commission Expires On: July 11, 2015

AUS-5971637-1

AFFIDAVIT OF ADRIAN PIENIAZEK

COUNTY OF TRAVIS §
§
STATE OF TEXAS §

I, Adrian Pieniazek, first being duly sworn, do hereby state as follows:

"1. I am over the age of 18 and am competent to make this affidavit and testify.

2. My name is Adrian Pieniazek. I am employed as Director of Market Policy-ERCOT Region, for NRG Energy, Inc. I affirm that I have reviewed the Complaint of Calpine Corporation and NRG Energy, Inc. Against the Electric Reliability Council of Texas Concerning the Houston Import Project ("Complaint"), including all attachments. I further affirm that I have personal knowledge of the facts stated in this Complaint based on my employment, and that I have the authority to verify the factual statements in this Complaint on behalf of NRG Energy, Inc.

3. I certify that the factual allegations contained within this Complaint are true and accurate to the best of my knowledge, information, and belief, and that all documents attached to the Complaint are true and correct copies of the originals."

Further Affiant sayeth not

Adrian Pieniazek
Adrian Pieniazek

Given under my hand and seal of office this 13 day of May, A.D., 2014.

Lisa J Porter
Notary Public in and for the State of Texas

My Commission Expires On: 01-13-2018

Attachment 2

ERCOT Presentation to the ERCOT Board

ERCOT

Item 8: Houston Import RPG Project

Jeff Billo
Manager, Transmission Planning

Board of Directors Meeting
ERCOT Public
April 8, 2014

Study Overview

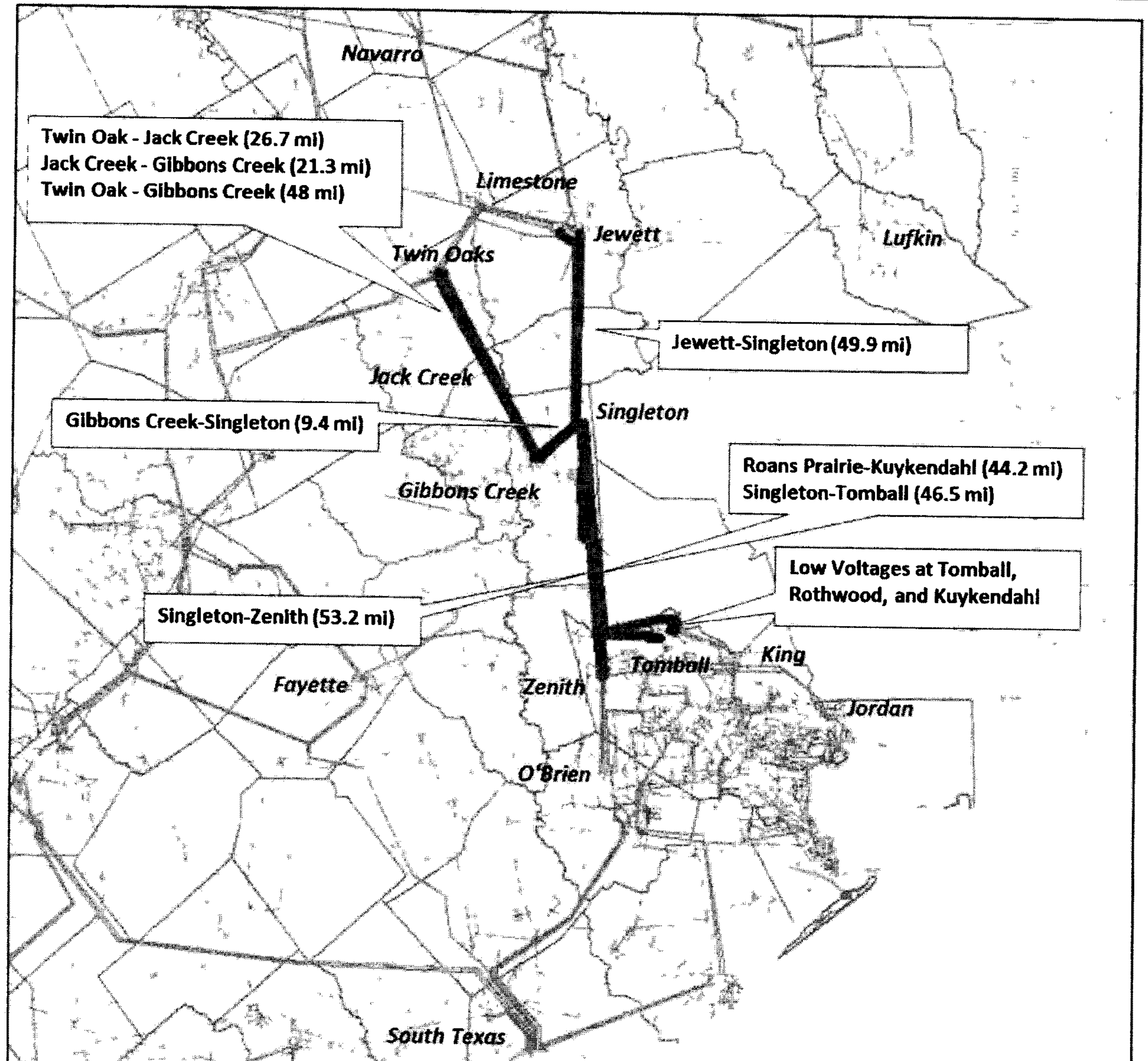
- ERCOT has determined that there will be a need for additional import capacity into the Houston region by 2018
  - Houston is the fifth most populous metropolitan area in the U.S.
  - Population in the Houston region is expected to grow at a rate of over 100,000 new residents per year.
  - Gross area product in the Houston metro area is projected to grow at an average annual rate of 3.5%.
  - The Houston metro area has almost 40% of the nation's petrochemical manufacturing capacity.
  - The Port of Houston has ranked first among U.S. seaports in terms of import tonnage for 22 consecutive years.
  - The Houston region represents approximately ¼ of the total ERCOT peak system load.
  - ERCOT long-term transmission planning has consistently indicated a need for additional import capacity into the Houston region since 2008. A Houston import project was found to be economically justified based on the generator revenue test in 2010.

ERCOT Study Approach

- In mid-2013, CenterPoint Energy, City of Garland and Cross Texas Transmission, and Lone Star Transmission separately identified a reliability need to increase the import capability into the Houston area by 2018
  - Each Transmission Service Provider submitted a project proposal to the Regional Planning Group (RPG) for review and comment
  - ERCOT conducted a single, combined Independent Review of the proposals
- ERCOT Independent Review study assumptions are consistent with the 2013 and previous Regional Transmission Plans
  - Used the 2018 summer peak load transmission planning case
- Generation assumptions followed Planning Guide Section 6.9
- Load assumptions followed Planning Guide Section 4.1.1.1(5)
- ERCOT conducted AC contingency analysis following Planning Guide criteria

Project Need Study Results

- Several ERCOT planning criteria violations were found in the 2018 peak load planning case
- The Singleton-Zenith 345 kV lines are overloaded under N-1 (contingency loss of one transmission element)
- Multiple 345 kV lines are overloaded (total length ~200 miles) and low voltage conditions in G-1 + N-1 analysis (G-1 is the outage of one generation unit)



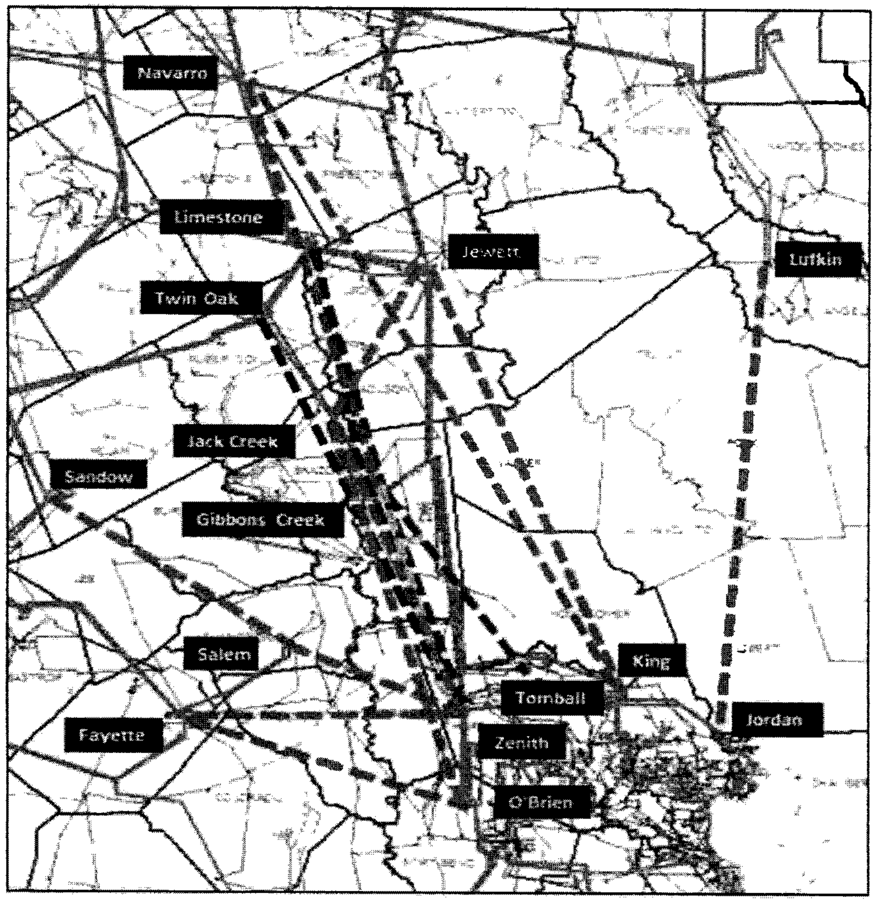
Stakeholder Comments

- Stakeholders had questions regarding the load assumptions for the Houston region used in the study.
  - Loads used in transmission planning include the impact of hot weather (different from the CDR which includes a 50/50 load forecast).
  - Non-coincident regional peak demands can occur at times when system-wide scarcity and resulting price-responsive demand are not present.
- Stakeholders commented on the use of load scaling in the study.
  - ERCOT studied the system with loads outside the study area scaled down to reflect typical non-coincidence of regional loads.
  - Stakeholders asked if ERCOT's load scaling methodology could exacerbate the North-Houston line loading in the 2018 study case.
  - To address stakeholder comments ERCOT ran three sensitivity cases with reasonable variations in load (including a case with no load scaling). Overloaded circuits were noted in all three sensitivity cases.

Worst overload	Case 1	Case 2	Case 3
Singleton-Zenith double circuit	122%	128%	137%

Project Alternatives Evaluation

ERCOT evaluated 21 project alternatives



ERCOT performed the following analysis to determine which option would best meet the long-term needs of the system:

- Assessment of potential future system upgrades and time value of money analysis of those upgrades
- Voltage stability margin analysis
- System needs analysis if older generation in the Houston area were to retire
- NERC Category C and D contingency analysis
- Production cost savings analysis
- System loss analysis

ERCOT Recommendation

- **ERCOT requests Board of Director endorsement of the need for the following project (Study Option #4), which was found to be the best alternative to address both the near-term and long-term reliability needs in the Houston area:**
  - Construction of a new Limestone-Gibbons Creek-Zenith 345 kV double circuit to achieve approximately 2988 MVA of emergency rating for each circuit
  - Upgrade of the substations at Limestone, Gibbons Creek and Zenith to accommodate the terminations of new transmission lines
  - Upgrade of the existing T.H. Wharton-Addicks 345 kV line to achieve approximately 1450 MVA of emergency rating
- **ERCOT requests that the Limestone-Gibbons Creek-Zenith 345 kV line be deemed critical to reliability pursuant to Public Utility Commission of Texas Substantive Rule 25.101(b)(3)(D)**

Questions?

000055

ERCOT

Date: April 1, 2014
To: Board of Directors
From: Jeff Billo, Manager, Transmission Planning
Subject: ERCOT Independent Review of the Houston Import Regional Planning Group Project

Issue for the ERCOT Board of Directors

ERCOT Board of Directors Meeting Date: April 8, 2014
Item No.: 8

Issue:
Whether the Board of Directors (Board) of Electric Reliability Council of Texas, Inc. (ERCOT) should accept the recommendation of ERCOT staff to: (1) endorse the need for the Houston Import Regional Planning Group (RPG) Project to meet the reliability requirements for the ERCOT System, which ERCOT staff has independently reviewed and which the Technical Advisory Committee (TAC) has voted to support, and (2) deem the Limestone-Gibbons Creek-Zenith 345 kV double circuit line critical to reliability of the ERCOT System pursuant to Public Utility Commission of Texas Substantive Rule 25.101(b)(3)(D).

Background/History:
Load growth in the Houston area is projected to cause the need to import power to the area to exceed the current capability of the transmission system by 2018. In 2013, three groups of Transmission Service Providers (TSPs; CenterPoint Energy, City of Garland and Cross Texas Transmission, and Lone Star Transmission) independently identified this need and submitted three separate proposals to solve the reliability criteria violation. ERCOT performed a single Independent Review of the proposals and confirmed the reliability need for a project by 2018. ERCOT analyzed the submitted proposals as well as several alternative projects.

Following a comprehensive analysis, ERCOT determined that the following set of improvements would be the most cost-effective solution to meet the near-term and long-term reliability needs for the Houston area:

- Construction of a new Limestone-Gibbons Creek-Zenith 345 kV double circuit to achieve approximately 2,988 MVA of emergency rating for each circuit
- Upgrade of the substations at Limestone, Gibbons Creek and Zenith to accommodate the terminations of new transmission lines; and
- Upgrade of the existing T.H. Wharton-Addicks 345 kV line to achieve approximately 1,450 MVA of emergency rating (~10.7 miles).

The cost estimate for these improvements is $590 million.

The ERCOT Independent Review of the Houston Import RPG Project is attached as Attachment A.

Key Factors Influencing Issue:

1. Transmission system improvements are needed to meet reliability criteria in the ERCOT System related to the import of power into the Houston area.

ERCOT

2. The recommended set of improvements was found to be the most cost-effective solution for meeting the reliability criteria.
3. The Limestone-Gibbons Creek-Zenith 345 kV double circuit line is critical for system reliability for summer peak 2018.
4. TAC has voted to recommend that the Board of Directors endorse the project.

Conclusion/Recommendation:

ERCOT Staff recommends that the Board of Directors: (1) endorse the need for the Houston Import RPG Project to meet the reliability requirements of the ERCOT System which ERCOT staff has independently reviewed and with the support of TAC; and (2) deem the Limestone-Gibbons Creek-Zenith 345 kV double circuit line critical to reliability of the ERCOT System pursuant to Public Utility Commission of Texas Substantive Rule 25.101(b)(3)(D).

ERCOT

ELECTRIC RELIABILITY COUNCIL OF TEXAS, INC.
BOARD OF DIRECTORS RESOLUTION

WHEREAS, staff of Electric Reliability Council of Texas, Inc. (ERCOT) has prepared the Independent Review of the Houston Import Regional Planning Group (RPG) Project, which is attached hereto as *Attachment A*;

WHEREAS, after due consideration of the alternatives, the Board of Directors (Board) of Electric Reliability Council of Texas, Inc. (ERCOT) deems it desirable and in the best interest of ERCOT to accept ERCOT staff's recommendation, to: (1) endorse the need for the Houston Import RPG Project to meet the reliability requirements for the ERCOT System which ERCOT staff has independently reviewed and which the Technical Advisory Committee (TAC) has voted to support; and (2) deem the Limestone-Gibbons Creek-Zenith 345 kV double circuit line critical to reliability of the ERCOT System pursuant to Public Utility Commission of Texas Substantive Rule 25.101(b)(3)(D); and

THEREFORE, BE IT RESOLVED, that ERCOT is hereby: (1) endorses the need for the Houston Import RPG Project to meet the reliability requirements for the ERCOT System which ERCOT staff has independently reviewed; and (2) deem the Limestone-Gibbons Creek-Zenith 345 kV double circuit line critical to reliability of the ERCOT System pursuant to Public Utility Commission of Texas Substantive Rule 25.101(b)(3)(D).

CORPORATE SECRETARY'S CERTIFICATE

I, Vickie G. Leady, Assistant Corporate Secretary of ERCOT, do hereby certify that, at its April 8, 2014 meeting, the ERCOT Board passed a motion approving the above Resolution by ______.

IN WITNESS WHEREOF, I have hereunto set my hand this ___ day of April, 2014.

____
Vickie G. Leady
Assistant Corporate Secretary

Attachment 3

ERCOT Independent Review

Attachment A

ERCOT Independent Review of Houston Import RPG Project

ERCOT System Planning

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Document Revisions

<table>
<tr><th>Date</th><th>Version</th><th>Description</th><th>Author(s)</th></tr>
<tr><td rowspan="2">02/20/2014</td><td rowspan="2">1.0</td><td>Final</td><td>Sun Wook Kang,
Jesse Boyd,
Ying Li</td></tr>
<tr><td>Reviewed by</td><td>Prabhu Gnanam, Jeff Billo</td></tr>
</table>

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TABLE OF CONTENTS

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1. Executive Summary

The load in the Houston metropolitan area is currently served by the generation in the area and the power imported through 345 kV lines from the north and south into the Houston area (Figure 2.1). Over the past ten years, a significant amount of generation has been retired in the Houston area, while the load in the region continues to grow. The continuous load growth and lack of new generation additions in the load center has resulted in the Houston system relying more on power imports through the existing 345 kV lines into the area. In addition, increasing dependence on power imports causes significant challenges in scheduling a planned outage with a sufficient duration on any of the major 345 kV lines along the Houston import path.

Identifying the reliability need to improve the import capability into Houston, CenterPoint Energy, Lone Star Transmission, and Garland Power & Light and Cross Texas Transmission submitted three different Regional Planning Group (RPG) proposals in July and August 2013. For the three RPG submittals, ERCOT has conducted a combined single independent review and determined that the import paths from the north into Houston are vulnerable to thermal overloads under various contingency conditions by 2018. The review also revealed post-contingency low voltage issues at certain 345 kV buses in the region.

Based on the result of the independent review, ERCOT concludes that transmission reinforcement is needed to meet the reliability criteria under the 2018 summer peak condition. Among various options evaluated, ERCOT prefers Option 4 (new Limestone-Gibbons Creek-Zenith 345 kV double-circuit line) as the best solution for the area and recommends the project to be in-service by 2018. The project will address the reliability need, improve the import capability into Houston, and provide additional benefits to the system in both the near-term and long-term transmission planning horizons.

The project preferred by ERCOT requires

- Construction of a new Limestone-Gibbons Creek-Zenith 345 kV double-circuit line to achieve approximately 2988 MVA of emergency rating for each circuit. The approximate length of the new line is estimated to be 129.9 miles.
- Upgrade of the existing substations at Limestone, Gibbons Creek and Zenith to accommodate the terminations of the new 345 kV line.
- Upgrade of the existing T.H. Wharton-Addicks 345 kV line to achieve at least 1450 MVA of emergency rating (~10.7 miles).

The construction cost for the preferred project is estimated to be approximately $590 million in 2018 dollars. The estimate may vary as the designated providers of the new transmission facilities (CenterPoint Energy, Garland Power & Light and Cross Texas Transmission) perform more detailed cost analysis.

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2. Introduction

The Houston metropolitan area is one of the major load centers in Texas, serving more than 25% of the entire load in the ERCOT system. While the load growth in the region is expected to continue, a significant challenge is also anticipated in developing new resources in the increasingly urban area due to restrictions such as air quality standards and site availability inside the city. Historical data indicates that approximately 1,800 MW of new generation has been added in the Houston region over the past ten years (2004 to 2013), while approximately 3,800 MW of generation has been retired over that time. Such continuous load growth and lack of new generation additions in the load center resulted in the Houston system relying more on power imports through the existing 345 kV lines into the area. These issues have been the primary focus of various studies in the past such as the DOE long-term transmission planning study and the annual ERCOT voltage stability study.

Recently, four Transmission Service Providers (TSPs) including CenterPoint Energy (CNP), Lone Start Transmission (LST), and jointly Garland Power & Light and Cross Texas Transmission (GPL & CTT) independently submitted three Regional Planning Group (RPG) proposals, identified a reliability need and proposed new transmission reinforcement to address the need and to improve the import capability into Houston by 2018.

For the three RPG proposals submitted, ERCOT has conducted one combined independent review. ERCOT performed various studies to address the reliability need and identified a best solution that significantly improves the import capability into Houston, which is currently relying on the power import through the existing 345 kV lines:

- Existing import paths from North to Houston
  - Singleton-Zenith 345 kV line #98
  - Singleton-Zenith 345 kV line #99
  - Singleton-Tomball 345 kV line #74
  - Roans Prairie-Bobville-Kuykendahl 345 kV line #75

- Existing import paths from South to Houston
  - Hillje-W.A. Parish 345 kV line #72
  - Hillje-W.A. Parish 345 kV line #64
  - South Texas-W.A. Parish 345 kV line #39
  - South Texas-DOW 345 kV line #18
  - South Texas-DOW 345 kV line #27

Increasing dependence on the power import through the above import paths is also expected to cause significant challenges in scheduling a planned outage with a sufficient duration on any of the 345 kV lines. As the load continues to grow in Houston, it is expected that these outages (forced or planned) will cause significant reliability issues and become increasingly more costly.

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The figure below shows the system map of the study area indicating the key 345 kV substations connecting the major import paths into the Houston area.

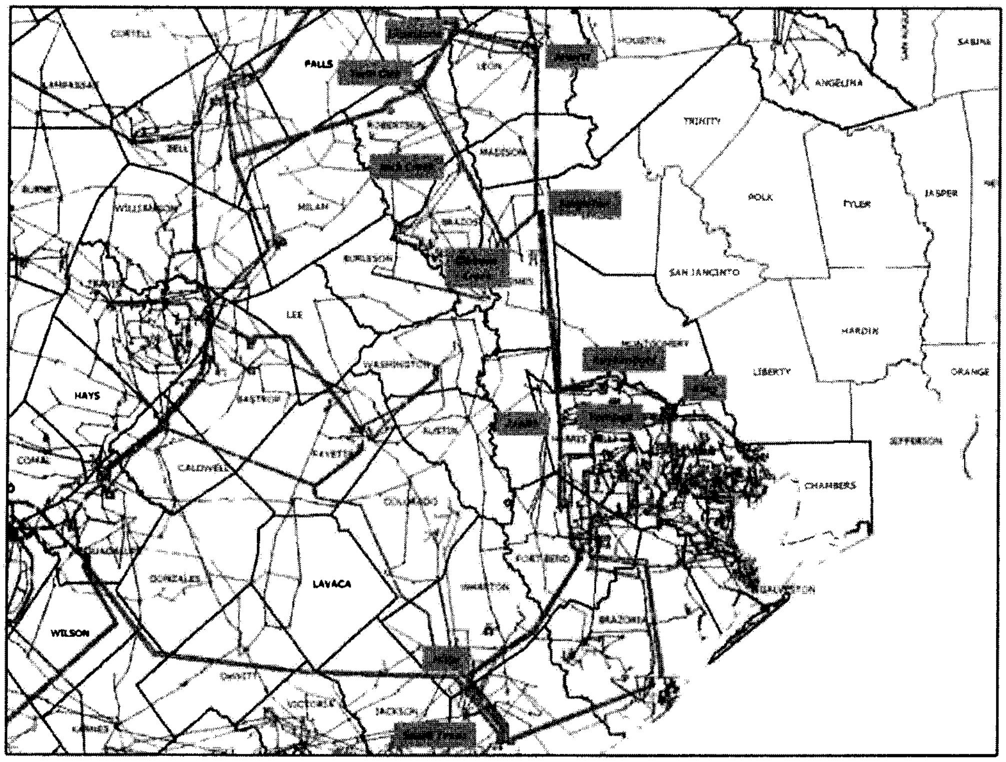

Figure 2.1 System map of study area with key substations

3. Criteria, Study Assumptions and Methodology

ERCOT performed studies under various system conditions to evaluate the reliability need and to find a robust and cost-effective solution from both near-term and long-term transmission planning perspectives. The study criteria, assumption and methodology for the ERCOT independent review are described in this section and are consistent with the NERC reliability standards, ERCOT Protocols, and ERCOT Planning Guide. The study scope and approach was also presented to the RPG at the September 2013 RPG meeting.

3.1 Study Criteria and Monitored Area

The criteria applied for the AC power flow analyses are consistent with the ERCOT Planning Guide 4.1.1.2 and the ERCOT 2013 Regional Transmission Plan (RTP). For the reliability analysis, the following thermal and voltage limits were enforced:

- Rate A under pre-contingency conditions for 60 kV and above transmission lines and transformers with a low side voltage of 60 kV and above

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- Rate B under post-contingency conditions for 60 kV and above transmission lines and transformers with a low side voltage of 60 kV and above
- 0.95 pu voltage under pre-contingency conditions for 100 kV and above transmission lines and transformers with a low side voltage of 100 kV and above
- 0.90 pu voltage under post-contingency conditions for 100 kV and above transmission lines and transformers with a low side voltage of 100 kV and above

The area monitored in the study is the system in the ERCOT Coast weather zone and in the East weather zone (electrically close to the Houston metropolitan area).

3.2 Study Assumptions and Methodology

3.2.1 Study Base Case

Two 2018 summer peak cases that were created as part of an ERCOT stakeholder driven process were available for use at the beginning of the study. The first is the 2018 summer peak case from the 2013 Dataset B as developed by the Steady-State Working Group (SSWG) in accordance with the Reliability and Operations Subcommittee approved SSWG Procedure Manual. This is the case that was used by each of the TSPs when developing the results in the three project proposals submitted to the RPG.

The second 2018 summer peak case was developed for use in the ERCOT 2013 RTP. This case started with the SSWG 2018 summer peak case and then modified it in accordance with the 2013 RTP scope and process document which was presented to the RPG for comments. For this analysis, ERCOT elected to use the 2018 RTP summer peak case as the base case as this is the typical practice for independent reviews. As described in later sections of this report, ERCOT also used the SSWG case to perform sensitivities on the analysis.

When the summer peak cases are created by the SSWG or modified by ERCOT for use in the RTP, it is recognized that the load level for each area on the system is set to its non-coincident peak. That is, the load for an area will be set according to the maximum load that area is expected to experience during the summer which may be greater than the load for that particular area when the ERCOT system as a whole reaches its maximum load. Hence, the summed load that is modeled in the base cases when looked at from a system-wide perspective is much greater than the expected ERCOT system-wide load for a given year. Generation, which is provided by the market based on economic considerations, is assumed to be planned to meet the expected ERCOT system-wide load for a given year plus a reserve margin.

In transmission planning analysis the amount of generation available in the base case may not be enough to meet the summed non-coincident peak load of all areas of the system. In order to solve this challenge in the 2013 RTP, ERCOT split the 2018 summer peak case into two study areas, the so-called NW and SE areas. For each study area the load level was set to the forecasted peak load for that area while load outside of the area was scaled down until there was enough generation to meet the load plus an operational reserve of approximately 1375 MW (equal to the largest single unit on the ERCOT system).

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In the 2018 SE summer peak case from the 2013 RTP, the load levels for the East, Coast, South Central, and Southern weather zones were set to their forecasted peak load levels. The load levels in the North, North Central, West, and Far West weather zones were set to approximately 85% of the peak load levels from the SSWG base case. ERCOT used 2018 SE summer peak case for the analysis in this review since the Houston area is located within the Coast weather zone and the facilities that were shown to be overloaded in the three RPG project submittals were wholly contained within the East and Coast weather zones.

In order to ensure that the load scaling did not adversely affect the results of the study by disproportionately modeling power flows from the scaled down weather zones to the Coast weather zone, ERCOT analyzed historic weather zone peak data. To do this ERCOT looked at the top ten peak load hours for the Coast weather zone for each of the last three years. For each of the other weather zones ERCOT assessed the percentage of their annual peak for those ten hours and then averaged the results. The data is presented in the below table.

Average % of peak load of each weather zone during the top ten hourly peak load conditions at the Coast Weather Zone							
Year	East	South	South Central	Far West	West	North	North Central
2011	97.46%	98.21%	96.38%	93.75%	83.70%	67.86%	93.37%
2012	96.32%	95.58%	96.08%	93.23%	92.93%	78.55%	85.56%
2013	76.77%	98.62%	97.42%	95.81%	78.23%	90.88%	88.81%

The results show that, with the exception of 2013, the East weather zone was near its peak when the Coast weather zone was at its peak. If the 2013 exception were to be taken into account it would likely increase flows along the North to Houston import path. Both the South and South Central weather zones were near their peaks (95% to 98%) when the Coast weather zone was at its peak. In all three years the Far West weather zone was above the assumed 85% loading, however, since the Far West weather zone is electrically far from the Coast weather zone and has a relatively small amount of load this difference is not considered meaningful for this study. Both the West and North weather zones have two years where the average is below the 85% assumption and one year where the average is above the 85% assumption. Therefore, the assumption seems reasonable. In all three years the North Central weather zone was slightly above the 85% assumption, but in 2012 the average was just 0.56% above and 85% can reasonably be assumed to occur.

Based on this analysis ERCOT concluded that the load levels in the 2018 SE summer peak case from the 2013 RTP represent a reasonable variation of load forecast in accordance with Planning Guide Section 4.1.1.1(5)(a), and decided to use the 2018 SE summer peak case as the base case of this ERCOT independent review.

Based on the result of the 2013 RTP studies, several transmission upgrades inside Houston were modeled to create the study case. ERCOT considers these upgrades not relevant to the Houston import project review as the upgrades listed below do not significantly change power flows on the import paths.

- Three new projects were identified in the 2013 RTP for the study area:

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- Project to loop Roans Prairie-King into Rothwood 345 kV substation
- Project to upgrade the system in the Katy area, which includes
  - ✓ A new second 345/138 kV transformer at Zenith
  - ✓ A new 138 kV line from Zenith to Franz and reconfiguration of existing 138kV lines in the Katy area
- Project to upgrade the Dickinson-League City 138 kV line

The load level of the Coast weather zone assumed in the 2018 SE study base case is identical to the load level of the same weather zone in the SSWG case. This assumption is consistent with the study scope of the 2013 RTP, and the total load assumed for the year 2018 in the Coast weather zone is 26,355 MW.

Several future generators were modeled in the case based on the model-building requirement in Planning Guide Section 6.9 and the input from stakeholders:

- Future generators modeled online in the study area based on the above ERCOT planning criteria:
  - Deer Park Energy G6, Channel Energy GT3, Deepwater Energy (later cancelled)

- Future generators modeled offline based on the above ERCOT planning criteria and the input from ERCOT stakeholder:
  - A new W.A. Parish unit, Pondera King, Cobisa

3.2.2 Study Methodology

The purpose of the independent review of the Houston import project is first, to determine whether the system in the study area needs transmission reinforcement; and second, if it does, to evaluate options and develop a solution that performs best to meet the reliability criteria under various system conditions. The ultimate goal, if the system needs reinforcement, is to find a best value solution among various options from both system performance and cost perspectives.

To evaluate the reliability need described in the TSP's RPG submittals, ERCOT studied the 2018 study base case by applying the planning criteria in Section 3.1. In addition to the 2018 study base case, ERCOT also performed additional sensitivity studies with and without varying the load levels for all weather zones except the Coast weather zone. The additional studies were done to incorporate the comments from ERCOT stakeholders and to ensure the reliability need also existing in the SSWG case.

Once the reliability need was identified, ERCOT developed a number of options based on the RPG submittals, input from the stakeholders, and past ERCOT studies including the DOE long-term transmission planning study. For the various options developed, ERCOT took a two-step approach to screen and select options for more detailed analyses. First, ERCOT performed a contingency analysis to identify options that mitigate the reliability concerns under the ERCOT N-1 conditions. Then, as a second step, ERCOT studied G-1+N-1 (generator unit outage plus a contingency) conditions for the options that passed the N-1 criteria. If an option addressed the

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reliability issues under both N-1 and G-1+N-1 conditions, the option was selected for further evaluation.

For the options selected based on the result of the G-1+N-1 analysis, ERCOT performed additional studies to determine the most robust and cost-effective solution that is the best for both the near-term and the long-term (the next 15 years) planning horizons. For each select option, ERCOT conducted a power transfer analysis to evaluate the thermal and voltage stability limits. For transfer analysis, ERCOT gradually scaled up the load in the Coast weather zone, while scaling down the loads in the North, North Central, West and Far West weather zones to balance supply and demand. The purpose of the transfer analysis was to identify additional future upgrades that may be needed for each select option beyond the project in-service year (2018) up to year 2028 and quantify the benefits of each select option from reliability and cost perspectives.

ERCOT also studied the impact of the potential retirement of older generation units (listed in Section 7.3) located inside the Houston area. An AC power flow analysis was performed for each select option using the 2018 study base case with the old units assumed offline. ERCOT also performed a generation reduction analysis to estimate the amount of generation that might be retired without causing any thermal issues on the major import paths. ERCOT compared the system performance of each select option under the potential system conditions.

Severe contingencies such as NERC Category C and D conditions were tested using the 2018 study base case for each of the selected options.

Transmission efficiency was also analyzed for each select option by computing system loss reduction using the 2018 system peak condition.

Although the project discussed in this RPG report is purely driven by reliability need, ERCOT also conducted an economic analysis of each select option using the 2013 RTP economic case developed for study year 2018 in order to compare the relative annual production cost savings of each option.

Finally, ERCOT performed various sensitivity analyses as discussed in Section 8. ERCOT performed a transfer analysis by using a different load-scaling approach to check if there is any significant impact on the result of the transfer analysis (discussed in Section 7.1).

3.2.3 Tools

ERCOT utilized the following software tools for the independent review of the Houston import project:

- PowerWorld version 17 with SCOPF was used for AC power flow analysis
- VSAT and PSAT version 11 were used to perform power transfer analysis
- UPLAN version 8.12.0.9073 was used to perform security-constrained production cost analysis

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3.2.4 Contingencies

All NERC Category A and B and ERCOT double circuit contingencies were evaluated for the AC power flow analyses. For G-1+N-1 analysis, the following generator outages were considered to identify the worst G-1 conditions:

- South Texas U1 (1378 MW),
- Cedar Bayou N2 (749 MW),
- Frontier G4 (374 MW),
- Gibbons Creek L1 (470 MW)

In accordance with Planning Guide Section 4, following the outage of a generator (G-1), the system was adjusted (redispatched) before applying the N-1 contingency.

For the power transfer analysis, ERCOT tested roughly 450 contingencies (300 kV and above in Coast, East and South Central weather zone in ERCOT system) using the 2018 study base case. As a result, ERCOT identified 45 key contingencies. These key contingencies were tested for each select option in order to identify future transmission upgrades during the transfer analysis.

For the NERC Category C and D analysis, ERCOT tested 23 severe events selected based on past ERCOT experience and also based on the annual ERCOT stability analysis.

4. Project Need

ERCOT conducted an AC power flow analysis using the 2018 SE study base case. The result indicated the overload of the Singleton-Zenith 345 kV double circuit under N-1 contingency conditions. This issue was aggravated further under G-1+N-1 conditions causing other additional thermal overloads of the import paths and low voltages at certain 345 kV buses in the area.

The result also indicated that the worst G-1+N-1 issues would occur during the outage of South Texas Project (STP) U1. The issues under other G-1+N-1 conditions (i.e. N-1 under Frontier, Gibbons Creek, or Cedar Bayou outage condition) were found to be the subset of the N-1 issues under the STP U1 outage condition (G-1).

The key reliability issues identified in the study are listed below and also illustrated in Figure 4.1. Among various contingencies causing the reliability issues, the worst contingency is the loss of the Singleton-Tomball & Roans Prairie-Bobville 345 kV double circuit.

- Key reliability issues identified under N-1 conditions are
  - Overload (~116.6%) of the Singleton-Zenith 345 kV double circuit
  - Heavy flow (~98.9%) on the Jewett-Singleton 345 kV double circuit

- Key reliability issues under the worst G-1 (STP U1)+N-1 conditions are
  - Overload (~145%) of Singleton-Zenith 345 kV double circuit both under system intact and under contingency conditions
  - Overload (~124%) of Jewett-Singleton 345 kV double circuit

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- Overload (~124%) of Jack Creek-Twin Oak 345 kV circuit #1
- Overload (~115%) of Roans Prairie-Bobville-Kuykendahl 345 kV circuit #75
- Overload (~115%) of Gibbons Creek-Twin Oak 345 kV circuit #1
- Overload (~112%) of Gibbons Creek-Singleton 345 kV double circuit
- Overload (~106%) of Gibbons Creek-Jack Creek 345 kV circuit #2
- Overload (~105%) of Singleton-Tomball 345 kV circuit #74
- Low voltage (below 90%) at Tomball, Rothwood, Bobville and Kuykendahl 345 kV buses

More detailed results on the reliability issues are presented in Appendices A and B.

The result of the power flow analysis also showed the overload of the 345/138 kV transformers at DOW substation and certain 138 kV lines inside the Houston area. ERCOT considered these issues as local issues not relevant to the Houston import capability study.

Based on the study result, ERCOT confirmed the reliability need to improve the import capability into Houston.

During the course of the independent review ERCOT provided study updates to the RPG at regularly scheduled monthly RPG meetings and received comments on the study at these meetings. NRG and other stakeholders commented that the load scaling methodology that ERCOT used in the creation of the 2013 RTP base cases may exacerbate the overloads on the North to Houston import pathways. As discussed in Section 3.2.1 of this report ERCOT validated the assumptions used in the study case in response to these comments. In addition ERCOT performed several sensitivities using the latest 2018 summer peak base case built by the SSWG from the 2014 Dataset B which was not available at the beginning of the analysis.

In order to incorporate the comments from the ERCOT stakeholders and ensure that the reliability need exists regardless of the load or generation assumptions used in the 2018 study base case, ERCOT evaluated the following cases (Appendix E has a more detailed description of each case):

Case 1: *2018 SSWG case (2018 SUM1 Final 10/15/2013) with no changes to load or generation*

Case 2: *2018 SSWG case with weather zone load scaled to the highest average percentage load level between 2011 and 2013 when the Coast weather zone was at its peak as presented in section 3.2.1 of this report.*

Case 3: *2018 SSWG case with weather zone load scaled to the average percentage of load level when the Coast weather zone was at its peak in 2013 as presented in section 3.2.1 of this report.*

These cases were evaluated under G-1 (STP U1) + N-1 conditions. As a result of the evaluation, ERCOT found either overloads or heavy flows of the 345 kV lines identified in the 2018 study

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base case. The details of the results can be found in Appendix F (for Case 1), Appendix G (for Case 2) and Appendix H (for Case 3). The results are summarized in the table below.

Overload Element	Study Case	Case 1	Case 2	Case 3*
Singleton-Zenith double circuit	145%	122%	128%	137%
Roans Prairie-Bobville #75	115%	99%	104%	110%
Bobville-Kuykendahl #75	115%	99%	103%	110%
Jewett North-Singleton #1	124%	93%	99%	106%
Jewett South-Singleton #1	123%	91%	97%	103%
Gibbons Creek-Singleton #75	113%	92%	94%	101%
Gibbons Creek-Singleton #99	113%	92%	94%	101%
Jack Creek-Twin Oak #1	124%	92%	100%	102%
Singleton-Tomball #74	105%	Below 90%	93%	99%
Gibbons Creek-Twin Oak #1	115%	Below 90%	92%	95%
Gibbons Creek-Jack Creek #2	106%	Below 90%	Below 90%	Below 90%

* Low voltage issue (below 90%) at the Tomball 345 kV bus was also found in Case 3 under G-1+N-1 conditions.

The results showed that while overloads were generally less than in the study case, the project need was confirmed in all of the evaluated cases. Based on the results, ERCOT confirmed that the reliability need identified in this section is an imminent issue irrespective of the assumptions used in the 2018 study base case.

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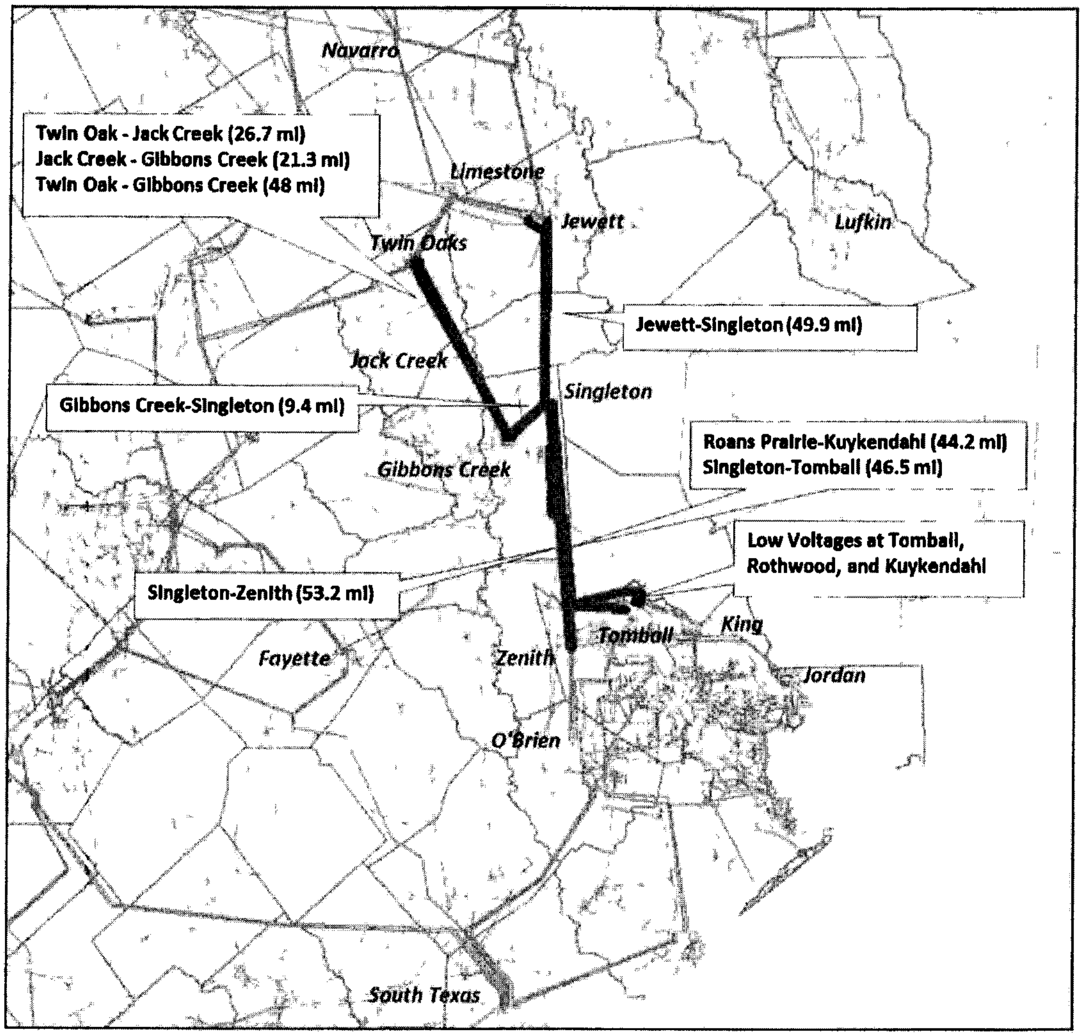

Figure 4.1 Map of system reliability issues related to Houston import capability

Table 4.1 Key thermal overloads identified in 2018 SE Study Base Case under N-1

Thermal Issues	Worst Contingency	Percent Loading
Singleton-Zenith 345 kV #98	Singleton-Tomball 345 kV and Roans Prairie-Bobville 345 kV	116.6
Singleton-Zenith 345 kV #99	Singleton-Tomball 345 kV and Roans Prairie-Bobville 345 kV	116.6

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Table 4.2 Key thermal overloads identified in the 2018 SE Study Base Case under G-1+N-1

Overloaded Element	Percent Loading Under Worst Contingency			
	South Texas G-1	Cedar Bayou G-1	Gibbons Creek G-1	Frontier G-1
Singleton – Zenith 345 kV #98	145.5	136.0	114.2	114.7
Singleton – Zenith 345 kV #99	145.6	136.1	114.2	114.7
Gibbons Creek – Twin Oak Switch 345 kV #1	115.3	107.0	103.1	100.9
Gibbons Creek – Singleton 345 kV #75	112.6	104.7	N/A	N/A
Gibbons Creek – Singleton 345 kV #99	112.6	104.7	N/A	N/A
Jack Creek – Twin Oak Switch 345 kV #1	124.1	115.1	110.9	108.7
Jewett South – Singleton 345 kV #1	123.2	115.5	104.1	109.2
Jewett North – Singleton 345 kV #1	124.1	115.4	102.6	108.7
Roans Prairie – Bobville 345 kV #75	115.7	108.9	N/A	N/A
Bobville – Kuykendahl 345 kV #75	115.4	108.7	N/A	N/A
Gibbons Creek – Jack Creek 345 kV #2	106.1	N/A	N/A	N/A
Singleton – Tomball 345 kV #74	105.6	N/A	N/A	N/A

Table 4.3 Key low voltage issues identified in the 2018 SE Study Base Case under G-1+N-1

Bus Name	Bus Voltage Under Worst Contingency			
	South Texas G-1	Cedar Bayou G-1	Gibbons Creek G-1	Frontier G-1
Tomball 345 kV	0.87	0.89	> 0.90	> 0.90
Bobville 345 kV	0.89	> 0.90	> 0.90	> 0.90
Kuykendahl 345 kV	0.89	> 0.90	> 0.90	> 0.90
Kuykendahl 345 kV	0.89	> 0.90	> 0.90	> 0.90
Rothwood 345 kV	0.89	> 0.90	> 0.90	> 0.90

5. Initial Options

Based on the reliability analysis ERCOT identified that multiple 345 kV lines including Singleton-Zenith, Jewett-Singleton, Jack Creek-Twin Oak, Singleton-Tomball, Gibbons Creek-Singleton and Gibbons Creek-Twin Oak (more than 200 miles of double-circuit 345 kV lines) would overload under either N-1 or G-1+N-1 conditions in 2018. In addition to the overloads, ERCOT also identified other 345 kV low voltage issues under contingency conditions.

ERCOT does not consider upgrading all of the existing 345 kV import lines as a viable option. CNP, the owner of the Singleton-Zenith 345 kV line, estimated that it would take 12 to 18 months to rebuild this line alone. ERCOT's analysis showed that it would not be possible to take any of the lines out of service for construction when load levels in the Houston area are high because the next contingency would place the system at risk of voltage collapse. This would likely lead to high congestion costs because a significant portion of the generation in the Houston area would be required to run during the construction outage in order to maintain system

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security. Much of this generation is older, less efficient generation that is not typically economic to run in the off peak times when the construction would likely occur. Further, since generators require maintenance outages as well it may not be possible to take all of the required outages for transmission construction and generator maintenance. Since there are over 200 miles of overloaded lines it is not feasible that all of the lines would be rebuilt by 2018. Lastly, the estimated cost (over $700 million) of upgrading all of the lines is more than most of the options studied in this analysis, but would not provide a comparable level of reliability.

ERCOT evaluated twenty-one options to address the identified need and improve the import capability into Houston. All twenty-one options require constructing a new transmission line into Houston area on a new right of way.

Among the options evaluated, three options were preferred by CNP, four options by LST and another three options by GPL & CTT. The remaining options were developed by ERCOT considering new transmission sources from various directions into Houston or modifying certain options from the TSPs. These options are listed in Table 5.1 through 5.4. ERCOT evaluated these options under N-1 and G-1+N-1 conditions. Figure 5.1 shows the system map of the study area overlapped with these options.

Table 5.1 CenterPoint's preferred options

Option ID	CenterPoint Options	Approximate Line Length Modeled in study (mi)
C1	– Construct a new Twin Oak-Zenith 345 kV double circuit	117.0
C2	– Construct a new substation, called Ragan Creek, adjacent to the existing double-circuit 345 kV line running between Gibbons Creek and Jack Creek – Loop the adjacent to the existing double-circuit 345 kV line between Gibbons Creek and Jack Creek into Ragan Creek – Construct a new Ragan Creek-Zenith 345 kV double circuit	69.0
C3	– Construct a new substation, called Ragan Creek, adjacent to the existing double-circuit 345 kV line running between Gibbons Creek and Jack Creek – Loop the adjacent to the existing double-circuit 345 kV line between Gibbons Creek and Jack Creek into Ragan Creek – Construct a new Limestone-Ragan Creek-Zenith 345 kV double circuit	130.2

Table 5.2 Lone Star's preferred options

Option ID	Lone Star Options	Approximate Line Length Modeled in study (mi)
L1	– Construct a new Navarro-Gibbons Creek-Zenith 345 kV double	165.0

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	circuit	
L2	– Construct a new Navarro-King 345 kV double circuit	186.0
L3	– Construct a new 500/345 kV substation at Navarro – Install two new 500/345 kV transformers at Navarro – Construct a new 500/345 kV substation at King – Install two new 500/345 kV transformers at King – Construct a new Navarro-King 500 kV double circuit	186.0
L4	– Construct a new Navarro-King 345 kV double circuit with 50% Series Compensation	186.0

Table 5.3 Cross Texas and Garland Power & Light's preferred options

Option ID	Cross Texas & Garland Power and Light Options	Approximate Line Length Modeled in study (mi)
T1	– Construct a new Gibbons Creek-Tomball 345 kV double circuit	50.0
T2	– Construct a new Gibbons Creek-Zenith 345 kV double circuit	60.0
T3	– Construct a new Limestone-Gibbons Creek-Zenith 345 kV double circuit	122.0

Table 5.4 Other options developed by ERCOT

Option ID	ERCOT and Other Options	Approximate Length Modeled in study (mi)
E1	– Construct a new Jewett-King 345 kV double circuit	142.5
E2	– Construct a new Lufkin-Jordan 345 kV double circuit	126.0
E3	– Construct a new Fayette-Zenith 345 kV double circuit	65.6
E4	– Construct a new Fayette-O'Brien 345 kV double circuit	73.9
E5	– Construct a new Jewett-Jack Creek-O'Brien 345 kV double circuit – Loop the existing Twin Oak-Gibbons Creek 345 kV line into Jack Creek	154.6
E6	– Construct a new Jewett-Jack Creek-Zenith 345 kV double circuit – Loop the existing Twin Oak-Gibbons Creek 345 kV line into Jack Creek	134.1
E7	– Construct a new Sandow-Salem-Zenith 345 kV double circuit	113.4
E8	– Construct a new Jewett-Jack Creek-Zenith 345 kV double circuit with 25% Series Compensation	134.1

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	– Loop the existing Twin Oak-Gibbons Creek 345 kV line into Jack Creek	
E9	– Construct a new Jewett-Jack Creek-Zenith 345 kV double circuit with 50% Series Compensation – Loop the existing Twin Oak-Gibbons Creek 345 kV line into Jack Creek	134.1
E10	– Construct a new Twin Oak-Zenith 345 kV double circuit with 25% Series Compensation	117.0
E11	– Construct a new Twin Oak-Zenith 345 kV double circuit with 50% Series Compensation	117.0

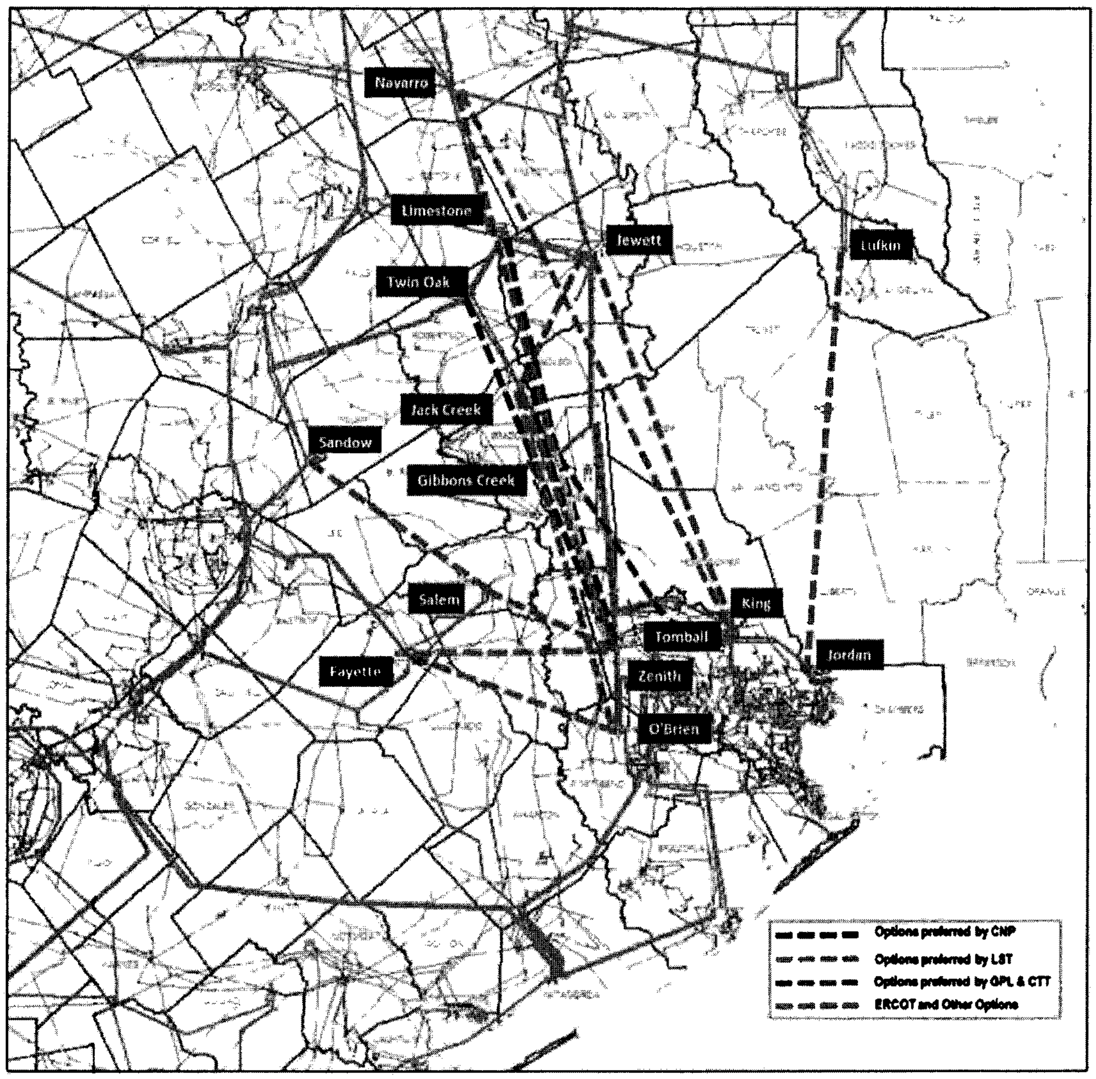

Figure 5.1 System map with initial options

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5.1 Result of N-1 and G-1+N-1 Analysis of Each Initial Option

5.1.1 Result of N-1 Contingency Analysis

As described in the study methodology in Section 3, ERCOT tested each option under N-1 contingency conditions by using the 2018 SE study base case to identify options addressing the reliability need under N-1.

Among the initial twenty-one options evaluated, ERCOT found six options that did not meet the N-1 criteria. ERCOT eliminated these six options from further consideration because these options did not address the overload on the existing Houston import paths. ERCOT concluded that the total project cost in 2018 for these six options including the upgrade of existing 345 kV lines along the Houston import path would be significantly higher than other options that resolved all N-1 overloads. In addition, the upgrade of existing 345 kV lines along the Houston import would pose a reliability risk and add significant outage cost. These six options and the reason for the elimination are as follows.

- C2: Ragan Creek-Zenith 345 kV double circuit
  - Overload of Twin Oak-Ragan Creek 345 kV
  - Overload of Jack Creek-Twin Oak 345 kV
  - Heavy flow* on Jewett-Singleton 345 kV
- T1: Gibbons Creek-Tomball 345 kV double circuit
  - Overload of Jack Creek-Twin Oak 345 kV
  - Heavy flow* on Jewett-Singleton 345 kV
  - Heavy flow* on Gibbons Creek-Twin Oak 345 kV
- T2: Gibbons Creek-Zenith 345 double circuit
  - Overload of Jack Creek-Twin Oak 345 kV
  - Heavy flow* on Jewett-Singleton 345 kV
  - Heavy flow* on Gibbons Creek-Twin Oak 345 kV
- E2: Lufkin-Jordan 345 kV double circuit
  - Overload of ~50 miles of 138 kV lines in the Lufkin area
- E3: Fayette-Zenith 345 kV double circuit
  - Overload of Singleton-Zenith 345 kV
- E4: Fayette-O'Brien 345 kV double circuit
  - Overload of Singleton-Zenith 345 kV

* **Note:** Heavy flow means post-contingency loading greater than 95%

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Table 5.1.1 Key thermal issues of Option C2 (Ragan Creek-Zenith) under N-1

Thermal Issues	Worst Contingency	Percent Loading
Twin Oak-Ragan Creek 345 kV	Jewett-Singleton 345 kV double circuit	100.0
Jack Creek-Twin Oak 345 kV	Jewett-Singleton 345 kV double circuit	106.9
Jewett North-Singleton 345 kV #1	Jack Creek-Twin Oak 345 kV and Twin Oak-Ragan Creek 345 kV #1	95.1
Jewett South-Singleton 345 kV #2	Jack Creek-Twin Oak 345 kV and Twin Oak-Ragan Creek 345 kV #1	96.8

Table 5.1.2 Key thermal issues of Option T1 (Gibbons Creek-Tomball) under N-1

Thermal Issues	Worst Contingency	Percent Loading
Jack Creek-Twin Oak 345 kV	Jewett-Singleton 345 kV double circuit	102.4
Gibbons Creek-Twin Oak 345 kV	Jewett-Singleton 345 kV double circuit	95.5
Jewett South-Singleton 345 kV #2	Jack Creek-Twin Oak 345 kV and Gibbons Creek-Twin Oak 345 kV	95.7

Table 5.1.3 Key thermal issues of Option T2 (Gibbons Creek-Zenith) under N-1

Thermal Issues	Worst Contingency	Percent Loading
Jack Creek-Twin Oak 345 kV	Jewett-Singleton 345 kV double circuit	104.1
Gibbons Creek-Twin Oak 345 kV	Jewett-Singleton 345 kV double circuit	97.2
Jewett North-Singleton 345 kV #2	Jack Creek-Twin Oak 345 kV and Gibbons Creek-Twin Oak 345 kV	95.2
Jewett South-Singleton 345 kV #2	Jack Creek-Twin Oak 345 kV and Gibbons Creek-Twin Oak 345 kV	96.9

Table 5.1.4 Key thermal issues of Option E2 (Lufkin-Jordan) under N-1

Thermal Issues	Worst Contingency	Percent Loading
Lufkin SS-Lufkin 138 kV	Stryker Creek SES-Lufkin 345 kV	166.11
Nacogdoches SE- Nacogdoches S 138 kV	Stryker Creek SES-Lufkin 345 kV	105.4
Nacogdoches SE- Henry North 138 kV	Stryker Creek SES-Lufkin 345 kV	120.0
Cushing-Gresham Road Switch 138 kV	MT Enterprise-Nacogdoches 345 kV	102.8
Nacogdoches S Tab-Lufkin 138 kV	Stryker Creek SES-Lufkin 345 kV	116.9

Table 5.1.5 Key thermal issues of Option E3 (Fayette-Zenith) under N-1

Thermal Issues	Worst Contingency	Percent Loading
Singleton-Zenith 345 kV #98	Singleton-Tomball 345 kV and Roans Prairie-Bobville 345 kV	106.0
Singleton-Zenith 345 kV #99	Singleton-Tomball 345 kV and Roans Prairie-Bobville 345 kV	106.0

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Table 5.1.6 Key thermal issues of Option E4 (Fayette-O'Brien) under N-1

Thermal Issues	Worst Contingency	Percent Loading
Singleton-Zenith 345 kV #98	Singleton-Tomball 345 kV and Roans Prairie-Bobville 345 kV	106.7
Singleton-Zenith 345 kV #99	Singleton-Tomball 345 kV and Roans Prairie-Bobville 345 kV	106.7

The remaining fifteen options addressed the N-1 reliability issue and moved to the G-1+N-1 analysis.

5.1.2 Result of G-1+N-1 Contingency Analysis

ERCOT conducted the G-1+N-1 analysis (G-1: STP U1 offline) for the fifteen options that met the N-1 criteria. As a result of the analysis, ERCOT found seven options that did not address the reliability issues under the G-1+N-1 conditions. Although these seven options reduced the contingency loadings on the 345 kV import paths from the north into Houston, there are still overloads or impending overloads on the Singleton-Zenith 345 kV double circuit or the Jewett-Singleton 345 kV double circuit. These seven options are

- C1: Twin Oak-Zenith 345 kV double circuit
  - Heavy flow* on Singleton-Zenith 345 kV
- E1: Jewett-King 345 kV double circuit
  - Overload of Singleton-Zenith 345 kV
- E5: Jewett-Jack Creek-O'Brien 345 kV double circuit
  - Overload of Singleton-Zenith 345 kV
- E7: Sandow-Salem-Zenith 345 kV double circuit
  - Overload of Singleton-Zenith 345 kV
  - Heavy flow* on Jewett-Singleton 345 kV
- L2: Navarro-King 345 kV double circuit
  - Overload of Singleton-Zenith 345 kV
  - Heavy flow* on Jewett-Singleton 345 kV
- L3: Navarro-King 500 kV double circuit
  - Overload of Singleton-Zenith 345 kV
- L4: Navarro-King 345 kV double circuit with 50% series compensation
  - Heavy flow* of Singleton-Zenith 345 kV

* **Note:** Heavy flow means contingency loading greater than 95%

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Table 5.2.1 Key thermal issues of Option C1 (Twin Oak-Zenith) under G-1+N-1

Thermal Issues	Worst Contingency	Percent Loading
Singleton-Zenith 345 kV #98	Singleton-Tomball 345 kV and Roans Prairie-Bobville 345 kV	97.0
Singleton-Zenith 345 kV #99	Singleton-Tomball 345 kV and Roans Prairie-Bobville 345 kV	97.0

Table 5.2.2 Key thermal issues of Option E1 (Jewett-King) under G-1+N-1

Thermal Issues	Worst Contingency	Percent Loading
Singleton-Zenith 345 kV #98	Singleton-Tomball 345 kV and Roans Prairie-Bobville 345 kV	106.3
Singleton-Zenith 345 kV #99	Singleton-Tomball 345 kV and Roans Prairie-Bobville 345 kV	106.3

Table 5.2.3 Key thermal issues of Option E5 (Jewett-Jack Creek-O'Brien) under G-1+N-1

Thermal Issues	Worst Contingency	Percent Loading
Singleton-Zenith 345 kV #98	Singleton-Tomball 345 kV and Roans Prairie-Bobville 345 kV	101.7
Singleton-Zenith 345 kV #99	Singleton-Tomball 345 kV and Roans Prairie-Bobville 345 kV	101.7

Table 5.2.4 Key thermal issues of Option E7 (Sandow-Salem-Zenith) under G-1+N-1

Thermal Issues	Worst Contingency	Percent Loading
Singleton-Zenith 345 kV #98	Singleton-Tomball 345 kV and Roans Prairie-Bobville 345 kV	117.3
Singleton-Zenith 345 kV #99	Singleton-Tomball 345 kV and Roans Prairie-Bobville 345 kV	117.3
Jewett South-Singleton 345 kV	Gibbons Creek-Singleton 345 kV double circuit	98.7
Jewett North-Singleton 345 kV	Gibbons Creek-Singleton 345 kV double circuit	99.4

Table 5.2.5 Key thermal issues of Option L2 (Navarro-King 345) under G-1+N-1

Thermal Issues	Worst Contingency	Percent Loading
Singleton-Zenith 345 kV #98	Singleton-Tomball 345 kV and Roans Prairie-Bobville 345 kV	112.2
Singleton-Zenith 345 kV #99	Singleton-Tomball 345 kV and Roans Prairie-Bobville 345 kV	112.3
Jewett South-Singleton 345 kV	Gibbons Creek-Singleton 345 kV double circuit	97.7
Jewett North-Singleton 345 kV	Gibbons Creek-Singleton 345 kV double circuit	98.5

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Table 5.2.6 Key thermal issues of Option L3 (Navarro-King 500) under G-1+N-1

Thermal Issues	Worst Contingency	Percent Loading
Singleton-Zenith 345 kV #98	Singleton-Tomball 345 kV and Roans Prairie-Bobville 345 kV	105.3
Singleton-Zenith 345 kV #99	Singleton-Tomball 345 kV and Roans Prairie-Bobville 345 kV	105.4

Table 5.2.7 Key thermal issues of Option L4 (Navarro-King 345 with 50% SC) under G-1+N-1

Thermal Issues	Worst Contingency	Percent Loading
Singleton-Zenith 345 kV #98	Singleton-Tomball 345 kV and Roans Prairie-Bobville 345 kV	99.4
Singleton-Zenith 345 kV #99	Singleton-Tomball 345 kV and Roans Prairie-Bobville 345 kV	99.5

6. Description of Options Selected for Further Evaluation

Among the initial twenty-one options, ERCOT found eight options effectively addressing the reliability issues under the N-1 and G-1+N-1 conditions. These eight options are

- E10: Twin Oak-Zenith 345 kV double circuit with 25% series compensation
- E11: Twin Oak-Zenith 345 kV double circuit with 50% series compensation
- C3: Limestone-Ragan Creek-Zenith 345 kV double circuit
- T3: Limestone-Gibbons Creek-Zenith 345 kV double circuit
- E6: Jewett-Jack Creek-Zenith 345 kV double circuit
- E8: Jewett-Jack Creek-Zenith 345 kV double circuit with 25% series compensation
- E9: Jewett-Jack Creek-Zenith 345 kV double circuit with 50% series compensation
- L1: Navarro-Gibbons Creek-Zenith 345 kV double circuit

Due to the injection of the new high voltage transmission source designed in the above options, several additional upgrades were needed to the existing lines located near the termination point(s) of each selected option. The upgrades of the existing lines are listed below:

- For all selected options listed above,
  - o Upgrade the T.H. Wharton-Addicks 345 kV line (~10.7 miles)
- For E8 and E9,
  - o Upgrade the Jack Creek-Twin Oak 345 kV double circuit (terminal upgrade)
- For L1,
  - o Upgrade the Jack Creek-Twin Oak 345 kV line #1 (terminal upgrade)

With the few existing line upgrades included, the select options were updated, renamed, and listed below. The total estimated construction cost[1] provided for each select option is discussed further in Section 7.2, and the details of the estimates can be found in Appendix I.

[1] The line length of new line assumed for the cost estimate includes a 20% of uncertainty added to the straight length of the new line.

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- Option 1:
  - Construct a new Twin Oak-Zenith 345 kV double-circuit line with 25% series compensation to achieve 2988 MVA of emergency rating for each circuit. The line length assumed for the cost estimate is approximately 117 miles.
  - Upgrade the existing T.H. Wharton-Addicks 345 kV line to achieve 1450 MVA of emergency rating (~10.7 miles).
  - The estimated cost for Option 1 is approximately $555 million in 2018 dollars.

- Option 2:
  - Construct a new Twin Oak-Zenith 345 kV double-circuit line with 50% series compensation to achieve 2988 MVA of emergency rating for each circuit. The line length assumed for the cost estimate is approximately 117 miles.
  - Upgrade the existing T.H. Wharton-Addicks 345 kV line to achieve 1450 MVA of emergency rating (~10.7 miles).
  - The estimated cost for Option 2 is approximately $572 million in 2018 dollars.

- Option 3:
  - Construct a new Limestone-Ragan Creek-Zenith 345 kV double-circuit line to achieve 2988 MVA of emergency rating for each circuit. The line length assumed for the cost estimate is approximately 130 miles.
  - Upgrade the existing T.H. Wharton-Addicks 345 kV line to achieve 1450 MVA of emergency rating (~10.7 miles).
  - The estimated cost for Option 3 is approximately $610 million in 2018 dollars.

- Option 4:
  - Construct a new Limestone-Gibbons Creek-Zenith 345 kV double-circuit line to achieve 2988 MVA of emergency rating for each circuit. The line length assumed for the cost estimate is approximately 129.9 miles.
  - Upgrade the existing T.H. Wharton-Addicks 345 kV line to achieve 1450 MVA of emergency rating (~10.7 miles).
  - The estimated cost for Option 4 is approximately $590 million in 2018 dollars.

- Option 5:
  - Construct a new Jewett-Jack Creek-Zenith 345 kV double-circuit line to achieve 2988 MVA of emergency rating for each circuit. The line length assumed for the cost estimate is approximately 128.9 miles.
  - Upgrade the existing T.H. Wharton-Addicks 345 kV line to achieve 1450 MVA of emergency rating (~10.7 miles).
  - The estimated cost for Option 5 is approximately $596 million in 2018 dollars.

- Option 6:
  - Construct a new Jewett-Jack Creek-Zenith 345 kV double-circuit line with 25% series compensation to achieve 2988 MVA of emergency rating for each circuit. The line length assumed for the cost estimate is approximately 128.9 miles.
  - Upgrade the existing T.H. Wharton-Addicks 345 kV line to achieve 1450 MVA of emergency rating (~10.7 miles).

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- Upgrade the Jack Creek-Twin Oak 345 kV double-circuit line (terminal upgrade) to achieve 1606 MVA of emergency rating.
- The estimated cost for Option 6 is approximately $617 million in 2018 dollars.

- Option 7:
  - Construct a new Jewett-Jack Creek-Zenith 345 kV double-circuit line with 50% series compensation to achieve 2988 MVA of emergency rating for each circuit. The line length assumed for the cost estimate is approximately 128.9 miles.
  - Upgrade the existing T.H. Wharton-Addicks 345 kV line to achieve 1450 MVA of emergency rating (~10.7 miles).
  - Upgrade the Jack Creek-Twin Oak 345 kV double-circuit line (terminal upgrade) to achieve 1606 MVA of emergency rating.
  - The estimated cost for Option 7 is approximately $629 million in 2018 dollars.

- Option 8:
  - Construct a new Navarro-Gibbons Creek-Zenith 345 kV double-circuit line to achieve 2988 MVA of emergency rating for each circuit. The line length assumed for the cost estimate is approximately 177.9 miles.
  - Upgrade the existing T.H. Wharton-Addicks 345 kV line to achieve 1450 MVA of emergency rating (~10.7 miles).
  - Upgrade the existing Jack Creek-Twin Oak 345 kV circuit #1 (terminal upgrade) to achieve 1606 MVA of emergency rating.
  - The estimated cost for Option 8 is approximately $806 million in 2018 dollars.

The estimates provided for Option 2, Option 3, Option 6 and Option 7 assumed series compensation with a 4000 Amp rating per circuit.

7. Evaluation of Selected Options

As described in the study methodology, ERCOT performed extensive studies to find the most robust and cost-effective solution among the select options. These studies include:

- power transfer analysis (both thermal and voltage stability analysis),
- long-term cost analysis (NPV analysis),
- impact of potential retirement of older generation units inside Houston,
- transmission efficiency in terms of system loss reduction,
- impact of severe events (NERC Category C and D contingency), and
- review of the congestion-related impact.

In this section, ERCOT presents the results of various studies done for each select option, and compares the overall performance of each select option based on the decision metrics in Section 7.8.

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7.1 Power Transfer Analysis

Assuming each select option will be in service by 2018, ERCOT performed power transfer analysis (both steady-state thermal and voltage stability analysis) to identify additional future transmission upgrades that might be needed over the next 15 years (up to 2028) to serve the import needs of the Houston area.

Using VSAT and the 2018 SE study base case, ERCOT performed a screening analysis by testing roughly 450 contingencies (300 kV and above) in the Coast, East and South Central weather zones. As a result of the screening analysis, approximately 45 contingencies were found to be significant to the Houston import project study. ERCOT tested these 45 significant contingencies under the worst G-1 condition (STP U1) for each select option in the transfer analysis. ERCOT monitored transmission facilities (100 kV and above) in the Coast weather zone and the vicinity of the entire 345 kV import path into Houston.

For the transfer analysis, ERCOT incrementally scaled the load in the Coast weather zone up to the 2028 load level in order to simulate the continued load growth in the region and to identify what additional thermal issues would occur by 2028 assuming each select option is in-service by 2018.

ERCOT estimated the load level of the year 2028 based on the 2013 ERCOT 90/10 load forecast for 2018 and the 1.3% of annual load growth rate noted in the RPG report submitted by CNP. As demonstrated in Figure 7.1, ERCOT compared the assumed load growth rate against the historical data, and confirmed that it is very close to the historical load growth rate (~1.4%). Thus, ERCOT considered the assumption valid for the power transfer analysis. As shown in the figure, the future load projection estimated for the Coast weather zone is closely aligned with the trend of the historical peak loads of the weather zone.

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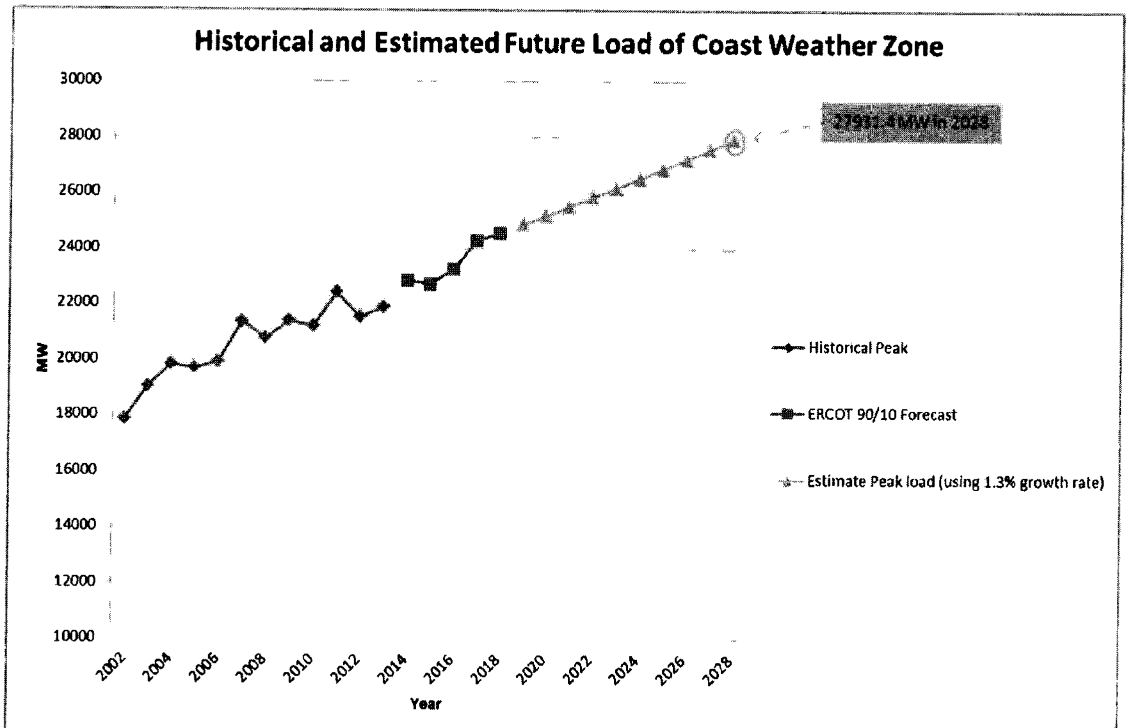

Figure 7.1 Historical load and estimated future load of Coast weather zone

Table 7.1 shows the results of the transfer analysis from a steady-state thermal perspective. The results indicated that some of the major import paths into Houston would need to be upgraded between 2025 and 2028. The result also indicated that the need year of the same line upgrade might vary depending on what option is in service by 2018. As an example, each select option requires the upgrade of the Singleton-Zenith 345 kV double-circuit line in the future, but the upgrade is needed by 2027 under Option 3 and Option 4, and by 2025 under Option 5. Therefore, Option 3 and Option 4 provide a benefit over Option 5 by deferring the need to upgrade the same line by two years. In order to capture such benefit of each select option, ERCOT performed a Net Present Value (NPV) analysis in Section 7.2 by considering not only the construction cost of each select option but also the construction cost of the future transmission upgrades identified in Table 7.1 taking into account the time value of money.

For this analysis ERCOT assumed that the net generation in the Houston area (existing generation plus generation additions minus generation retirements) stayed the same between 2018 and 2028. If more generation were to retire than be added to the area the upgrades identified may need to be accelerated. If more generation were to be added than retired in the area the upgrades identified may be deferred. Future planning analyses will determine the exact timing of upgrades.

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Table 7.1 Result of power transfer analysis from a steady-state thermal perspective

Option		by 2025	by 2026	by 2027	by 2028
Option 1	Twin Oak-Zenith w/ 25% compensation plus TH Wharton-Addicks upgrade		Singleton-Zenith 345 kV (53.2 mi)	Big Brown-Jewett 345 kV (32.8 mi)	Zenith-TH Wharton 345 kV (15.1 mi)
Option 2	Twin Oak-Zenith w/ 50% compensation plus TH Wharton-Addicks upgrade		Big Brown-Jewett 345 kV (32.8 mi)		Singleton-Zenith 345 kV (53.2 mi), Zenith-TH Wharton 345 kV (15.1 mi)
Option 3	Limestone-Ragan Creek-Zenith plus TH Wharton-Addicks upgrade			Singleton-Zenith 345 kV (53.2 mi), Jack Creek-Twin Oak #1 (26.7 mi), Big Brown-Jewett 345 kV (32.8 mi)	Gibbons Creek-Ragan Creek 345 kV (9.6 mi)
Option 4	Limestone-Gibbons Creek-Zenith plus TH Wharton-Addicks upgrade			Singleton-Zenith 345 kV (53.2 mi), Big Brown-Jewett 345 kV (32.8 mi)	Jack Creek-Twin Oak #1 (26.7 mi)
Option 5	Jewett-Jack Creek-Zenith plus TH Wharton-Addicks upgrade	Singleton-Zenith 345 kV (53.2 mi)	Big Brown-Jewett 345 kV (32.8 mi), Twin Oak-Jack Creek 345 kV (26.7 mi)		Jewett-Singleton 345 kV (49.9 mi), Zenith-TH Wharton 345 kV (15.1 mi), Gibbons Creek-Singleton 345 kV (9.4 mi), Gibbons Creek-Jack Creek 345 kV (21.3 mi)
Option 6	Jewett-Jack Creek-Zenith w/ 25% compensation plus TH Wharton-Addicks & Twin Oak-Jack Creek upgrade		Big Brown-Jewett 345 kV (32.8 mi)	Singleton-Zenith 345 kV (53.2 mi)	Zenith-TH Wharton 345 kV (15.1 mi), Twin Oak-Jack Creek 345 kV (26.7 mi)
Option 7	Jewett-Jack Creek-Zenith w/ 50% compensation plus TH Wharton-Addicks & Twin Oak-Jack Creek upgrade		Big Brown-Jewett 345 kV (32.8 mi)		Singleton-Zenith 345 kV (53.2 mi), Zenith-TH Wharton 345 kV (15.1 mi), Twin Oak-Jack Creek 345 kV (26.7 mi)
Option 8	Navarro-Gibbons Creek-Zenith plus TH Wharton-Addicks & Twin Oak-Jack Creek upgrade		Jewett-Singleton 345 kV (49.9 mi), Gibbons Creek-Twin Oak & Gibbons Creek-Jack Creek-Twin Oak 345 kV (48 mi)	Singleton-Zenith 345 kV (53.2 mi)	

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Item 8

ERCOT also reviewed the performance of each select option from a voltage stability perspective. Figure 7.2 shows the load level of the Coast weather zone at the point of voltage collapse under each select option without any future transmission upgrades. The results indicated that the voltage collapse conditions would occur beyond 2028 under every select option except Option 5.

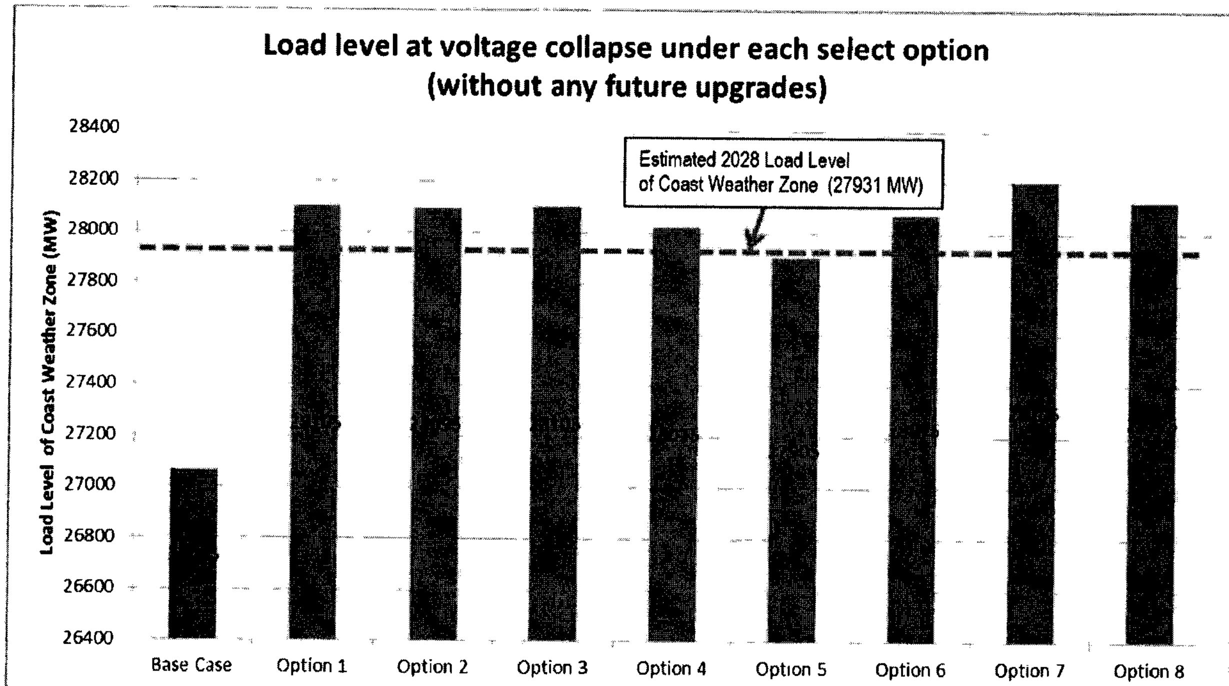

Figure 7.2 Results of power transfer analysis from a voltage stability perspective

7.2 Cost Analysis

This section presents the overall reliability impact of each select option on a NPV basis when considering the potential for Houston import needs out to 2028. For the NPV analysis, ERCOT considered the construction costs of each select option and future transmission upgrades to capture the long-term reliability benefit of each select option. ERCOT assumed 3% of escalation rate[2] and 8% of discount rate[3] to calculate the present value of each set of future upgrades in 2018 dollars, which is associated with each select option.

Based on cost estimates of each select option provided by each TSP, ERCOT found differences in the cost per mile of a new transmission line. CNP and TMPA used approximately $3.78 million per mile and $2.15 million per mile, respectively. Lone Star and Oncor used approximately $1.93 million per mile and $1.83 million per mile, respectively. Among the different cost-per-mileage assumptions for a new line, ERCOT assumed $3.78 million per mile

[2] The 3% escalation rate is consistent with the rate used by TSPs for their cost estimates.

[3] The 8% discount rate is from the report "Update on the ERCOT Nodal Market Cost-Benefit Analysis" prepared by CRA International for the Public Utility Commission of Texas in December 18, 2008, http://www puc texas gov/industry/electric/reports/31600/PUCT_CBA_Report_Final.pdf

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for the purpose of comparing the construction cost of each select option in 2018 dollars for the following reasons:

- The project in this report is driven by reliability need, not by economic benefit. Therefore, the cost estimate is not a driver for project justification and is only useful for comparing options.
- An analysis was performed by ERCOT using different cost-per-mileage assumptions (\$2.2 mm/mi or combination of \$2.15 mm/mi and \$3.78 mm/mi) for a new transmission line. The results showed no significant impact in selecting the best solution recommended in this report. The results of the analysis can be found in Appendix D.

Appendix I has more details of the cost estimates of each select option and future upgrades. Shown in Table 7.2.1, the results of the cost analysis were summarized in 2018 dollars. The results of the cost analysis are further discussed in Section 7.8.

Table 7.2.1 Result of NPV analysis

Unit. $ Million

Option	Estimated Cost of Each Select Option (in 2018 dollars)	Net Present Value (NPV) of Estimated Cost of the Set of Future Upgrades (in 2018 dollars)	Overall Cost (in 2018 dollars)
Option 1	554.8	387.0	941.8
Option 2	572.0	390.6	962.6
Option 3	610.2	399.5	1,009.7
Option 4	590.1	383.1	973.3
Option 5	596.3	652.9	1,249.3
Option 6	617.1	419.5	1,036.6
Option 7	629.1	435.2	1,064.4
Option 8	805.9	537.5	1,343.4

Table 7.2.2 Estimated cost of each future upgrade at the potential need year

Unit: $ Million

Option	Construction Cost of Future Upgrades Under Each Option			
	2025	2026	2027	2028
Option 1		279.6	76.5	78.8
Option 2		74.2		375.4
Option 3			416.2	16.4
Option 4			364.5	53.3
Option 5	271.5	123.3		372.7
Option 6		74.2	288.0	130.9
Option 7		74.2		427.5
Option 8		313.8	288.0	

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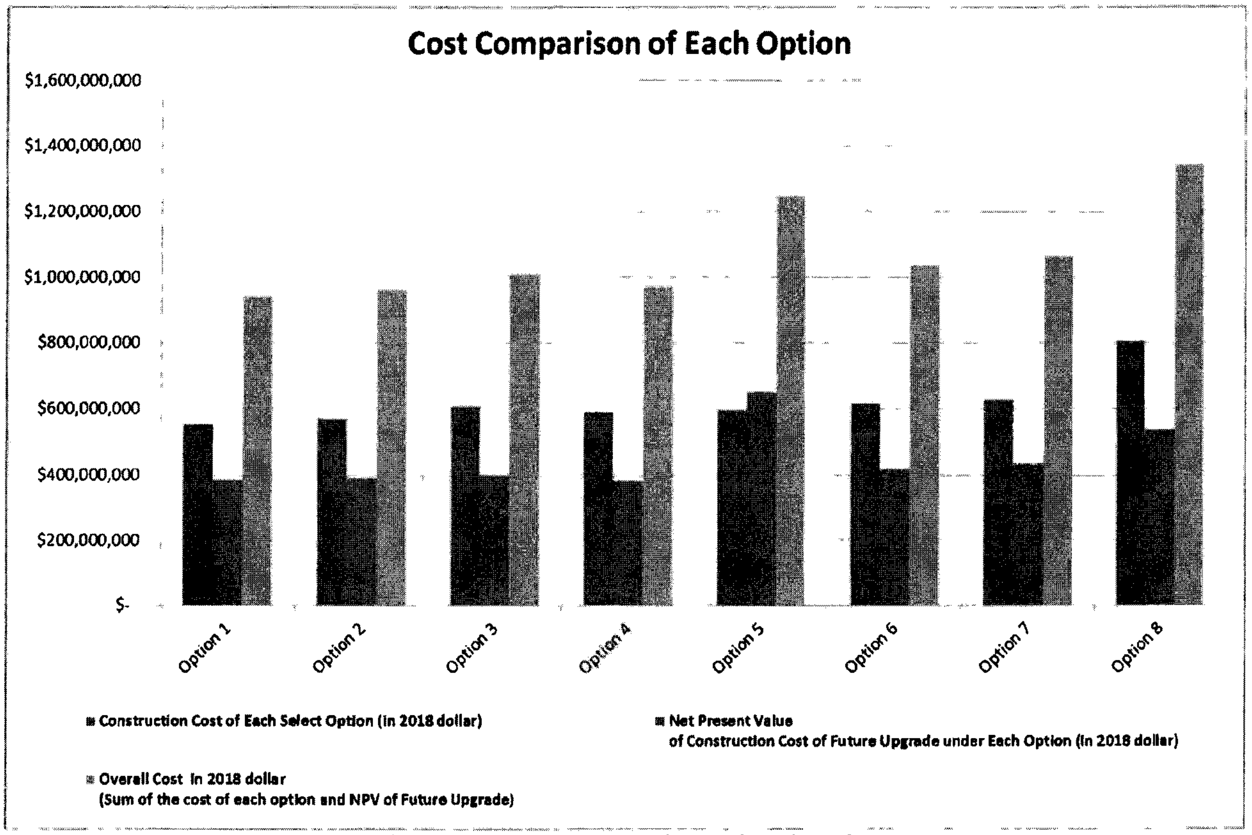

Figure 7.2.1 Cost comparison of each option

7.3 Impact of the Potential Retirement of Older Generation Units inside Houston

Including the Houston area, existing urban load centers in ERCOT rely on legacy generation resources located within the area and power imports from outside of the region to serve their load. Some generation units within the load centers were built approximately fifty years ago. Nearing the end of their useful life, these units are generally less efficient when compared to the overall generation fleet within ERCOT and may be retired relatively sooner than other newer generation units. As pointed out by Luminant Energy in submitted comments, natural gas units of similar vintage throughout ERCOT have retired or mothballed over the last ten years. Examples of these units include Atkins units 4, 5, and 6, Newman unit 5, H.O. Clarke units 1, 2, 3, 4, 5, and 6, J. L. Bates units 1 and 2, Lake Creek unit 2, Lon Hill units 3 and 4, Morgan Creek units 5, 6, 7, and 8, North Lake units 1, 2, and 3, North Texas units 1, 2, and 3, Nueces Bay unit 6, Oak Creek unit 1, P.H. Robinson units 1, 2, 3, and 4, Paint Creek unit 3, Permian Basin units 5 and 6, Rio Pecos units 5 and 6, San Angelo units 1 and 2, Spencer units 4 and 5, Tradinghouse units 1 and 2, Valley units 1, 2, and 3, Tuttle units 3 and 4, and Webster unit 3.

In addition, rapid urbanization has surrounded many of the legacy resources with residential, commercial and industrial development. With increasing urban density and environmental

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regulations typically it is not as feasible to site generation within a major load center. The siting difficulty is expected to put an increasing demand through the transmission import paths into the Houston area in the future. Furthermore, a new import path into the Houston area may open the market for new, more efficient generation sources to construct outside of the area and sell power by importing into Houston which will introduce additional competition for the legacy generation resources in the area.

To assess the robustness of each select option, ERCOT studied a hypothetical condition for the older generation units inside Houston. Within the Houston area, there are approximately 1939 MW of generation units that will be more than fifty years old by 2018. For the older units shown in Table 7.3.1, ERCOT performed two studies for each select option:

- AC power flow analysis under N-1 conditions with the old units assumed offline
- Generation reduction study using VSAT to compare the amount of generation output that may be retired without causing thermal issues under G-1+N-1 conditions

Table 7.3.1 Generation units more than fifty years old within the Houston area

Generation Unit	(MW)
S.R. Berton GT2	13
S.R. Berton 1	118
S.R. Berton 2	174
S.R. Berton 3	230
S.R. Berton 4	230
T. H. Warton 1	13
W.A. Parish GT1	13
W.A. Parish 1	169
W.A. Parish 2	169
W.A. Parish 3	258
W.A. Parish 4	552
Total MWs for Units fifty Years or more in service	1939

For the AC power flow analysis, ERCOT conducted the N-1 contingency analysis using the 2018 SE study base case with and without each option, assuming all of the old units offline.

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The result of the study indicated a number of system issues. The key issues identified in the 2018 SE study base case are

- Under system intact conditions with the units offline,
  - Overload of Singleton-Zenith 345 kV double circuit
  - Overload of Jewett-Singleton 345 kV double circuit
  - Low voltage around Tomball, Kuykendahl, Bobville, and Rothwood

- Under N-1 contingency conditions,
  - Overload of Jewett-Singleton 345 kV double circuit
  - Overload of the bus ties at Twin Oak/Oak Grove
  - Overload of Singleton-Zenith 345 kV double circuit
  - Overload of Gibbons Creek-Twin Oak 345 kV line
  - Overload of Jack Creek-Twin Oak 345 kV line
  - Overload of Gibbons Creek-Singleton 345 kV double circuit
  - Overload of Roans Prairie-Bobville-Kuykendahl 345 kV line
  - Heavy flow on Singleton-Tomball and Gibbons Creek-Jack Creek 345 kV line
  - Low voltages at 15 345 kV buses and 38 138 kV buses in Houston area

Based on this analysis, ERCOT found no system problems under system intact conditions and no low voltage issues under N-1 conditions for each of the selected option. Table 7.3.2 shows the result indicating overloads or heavy flows on certain 345 kV lines under N-1 conditions that might still exist even with each option if all of the old units were retired. Among options, Option 3, Option 4 and Option 7 showed no overload issues although a few heavy flow issues on certain 345 kV lines were found under N-1 conditions with the older units offline.

Table 7.3.2 Performance of each select option under N-1 conditions with the older units offline

Elements	**Jewett S-Singleton 345 kV line #1**	**Jewett N-Singleton 345 kV line #1**	**Twin Oak-Oak Grove 345 kV bus tie**	**Twin Oak 345 kV bus tie**	**Singleton-Zenith 345 kV line #98**	**Singleton-Zenith 345 kV line #99**	**Gibbons Creek-Twin Oak 345 kV #1**	**Gibbons Creek-Jack Creek 345 kV #2**	**Jack Creek-Twin Oak 345 kV #1**	**Jack Creek-Twin Oak 345 kV #2**
Option 1			Overload	Overload	Overload	Overload				
Option 2			Overload	Overload						
Option 3			Heavy flow	Heavy flow	Heavy flow	Heavy flow			Heavy flow	
Option 4			Heavy flow	Heavy flow	Heavy flow	Heavy flow				
Option 5			Overload	Overload	Overload	Overload			Overload	Overload

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Option 6			Overload	Overload	Heavy flow	Heavy flow				
Option 7			Heavy flow	Heavy flow					Heavy flow	Heavy flow
Option 8	Overload	Overload	Heavy flow	Heavy flow	Heavy flow	Heavy flow	Overload	Heavy flow	Heavy flow	

ERCOT also performed a generation reduction analysis under G-1+N-1 conditions. Using the 2018 study base case with each select option modeled and with the STP U1 offline (G-1), ERCOT gradually reduced the MW output from the older units using VSAT while testing the G-1+N-1 conditions. Table 7.3.3 shows the result of the generation reduction analysis. As an example, if Option 3 or Option 4 is assumed in service, a thermal overload start to occur when approximately 1000 MW from the older units is retired.

Table 7.3.3 Results of generation reduction study

Option	**Description**	**Approximate MW generation reduction that starts causing overloads under G-1+N-1**
Option 1	Twin Oak-Zenith with 25% series compensation plus TH Wharton-Addicks upgrade	900.6
Option 2	Twin Oak-Zenith with 50% series compensation plus TH Wharton-Addicks upgrade	911.1
Option 3	Limestone-Ragan Creek-Zenith plus TH Wharton-Addicks upgrade	1061.3
Option 4	Limestone-Gibbons Creek-Zenith plus TH Wharton-Addicks upgrade	1020.0
Option 5	Jewett-Jack Creek-Zenith plus TH Wharton-Addicks upgrade	400.0
Option 6	Jewett-Jack Creek-Zenith with 25% series compensation plus TH Wharton-Addicks upgrade and Twin Oak-Jack Creek upgrade	773.8
Option 7	Jewett-Jack Creek-Zenith with 50% series compensation plus TH Wharton-Addicks upgrade and Twin Oak-Jack Creek upgrade	662.6
Option 8	Navarro-Gibbons Creek-Zenith plus TH Wharton-Addicks upgrade and Twin Oak-Jack Creek upgrade	652.6

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7.4 Impact of NERC Category C and D Contingencies

NERC Category C and D contingency conditions are rare events, but the consequences of the events can be severe. To check if each select option provides any benefit to the system under the severe events, ERCOT tested twenty-three NERC Category C and D events selected based on the annual ERCOT voltage stability analysis and knowledge of the system in the area.

Table 7.4.1 shows the result of the analysis, indicating that every option provides better system conditions under the severe events compared to the 2018 SE study base case with no Houston Import project. Particularly, under the NERC Category D events, the number of unsolved contingencies was reduced from six to one under every option. (ERCOT has analyzed the one remaining unsolved contingency in past studies and has taken steps to minimize the likelihood of the occurrence of this event.) This indicates that the new transmission sources designed in each select option will provide significant improvement in the reliability of the system of the area even under the extreme system conditions. It should be noted that the Houston area under-voltage load shedding (UVLS) scheme was not modeled in this analysis.

Table 7.4.1 Impact of NERC Category C and D conditions with each select option

Options	Number of Unsolved Contingencies (NERC Cat. D)	Number of Thermal Overload On 345 kV (115% above)	Number of Low Voltage at 345 kV Buses (below 0.9 pu)
w/o Option	6	6	5
Option 1	1	1	4
Option 2	1	0	3
Option 3	1	0	5
Option 4	1	0	5
Option 5	1	1	6
Option 6	1	0	5
Option 7	1	0	3
Option 8	1	0	5

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7.5 System Loss Reduction

When a new transmission line is added to a system, transmission efficiency will be improved due to a decrease in the system impedance and improvement in the system voltage profile. The transmission efficiency improved by a new line can be measured by system loss reduction.

ERCOT performed the system loss analysis with and without each option, using the 2018 SE study base case (summer peak case), in order to capture the benefit of transmission efficiency improved by each select option. The amount of loss reduction is shown in Table 7.5.1 indicating significant loss reduction realized for each of the select options during the peak hour.

Table 7.5.1 System losses reduced by each select option (2018 summer peak condition)

Option	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8
System Loss Reduction (MW)	44.7	38.8	47.6	31.2	38.2	44.8	35.0	32.7

7.6 Economic Analysis

Although this RPG project is driven by reliability need, ERCOT also conducted an economic analysis to compare the relative performance of each select option in terms of production cost savings.

Using the 2018 economic case built for the 2013 RTP, ERCOT modeled each select option and performed production cost simulations for the year 2018. The annual production cost under each select option was compared to the option yielding the highest annual production cost in order to obtain a relative annual production cost saving for each option.

As shown in Table 7.6.1, the result indicates that none of the options provides significantly better production cost savings than others.

Table 7.6.1 Relative annual production cost savings (referenced to Option 8)

Unit: $ Million

Option	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8
Relative Annual Production Cost Savings (referenced to Option 8)	4.3	3.4	3.2	1.7	2.1	2.2	1.7	0.0

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7.7 Sub-Synchronous Resonance due to Series Compensation

Four of the eight select options (Option 1, Option 2, Option 6, and Option 7) require series compensation. The series compensation is the capacitor connected in series with a transmission line, used typically to increase power flow by reducing line impedance, to relieve bottlenecks, to increase stability and to reduce voltage variation. However, series capacitors can create a sub-synchronous resonance (SSR) condition in the system under some circumstances, typically when the series capacitor is radially connected to nearby generation. The SSR condition due to a series compensated transmission line may cause damage to the generator shaft and failure of insulation of the windings of the generator. The damage can be extremely costly and require a significant amount of time for repair.

There are existing generators in the area including the conventional units at Gibbons Creek, Twin Oak, Frontier, TNP One, and Limestone that are connected to the major 345 kV import paths. These units may be at risk due to SSR introduced by the series compensation designed in Option 1, Option 2, Option 6 and Option 7. Although no SSR study was performed for the options with series compensation, ERCOT considered the following issues associated with series compensation in comparing each select option:

- Significant time and resources may be needed to perform detailed SSR studies for each generator in the area, which may jeopardize the in-service year of the project. Due to the nature of the study, accurate generator data will be needed for each unit. It may take 3 to 6 months for data gathering, and an additional 6 to 12 months will be needed to complete the SSR studies.
- As mentioned in Section 6, the overall project cost of Option 1, Option 2, Option 6, and Option 7 by TSPs assumed series compensation with a 4000 Amp rating. This cost will increase further for 5000 Amp series compensation if required to match the conductor rating of the new line (5000 Amp conductor).
- Thyristor Controlled Series Capacitors (TCSC) may be used to mitigate the potential SSR issues. The cost of the TCSC will be significantly higher (roughly 1.5 to 5 times more expensive than the fixed series compensation assumed in the given cost estimates).
- Relatively high cost filters may be required to protect area generators from the effects of SSR.
- For Option 1, Option 2, Option 6, and Option 7, the units in the area may become radially connected to a series capacitor under some contingency conditions.
- As pointed out in comments submitted by Edison Mission Marketing and Trading, at the time of this analysis, there were still open policy questions in ERCOT regarding which entities are responsible for paying for SSR mitigation measures when required.

Further discussion of these options with series compensation can be found in Section 7.8.

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7.8 Overall Comparison of Selected Options

ERCOT performed various studies to evaluate the options selected as discussed in the previous sections. The results of the studies done for each select option were compared in Table 7.8.1, and summarized as follows:

- All eight selected options addressed the reliability need identified in the 2018 study base case, and met the reliability criteria.
- There are differences in the estimated cost per mile of a new transmission line. ERCOT assumed $3.78 million per mile based on the reasons listed in Section 7.2. The result of the cost analysis indicates:
  - Option 1 as the least cost option, followed by Option 2 and 4.
  - Option 1, followed by Option 2 and Option 4, as the least cost options if the NPV of the future upgrades is considered.
- Except Option 5, each select option performed similarly from a voltage stability perspective. The results indicated that the voltage stability limit exceedance would occur beyond 2028 under every select option except Option 5.
- AC power flow analysis was performed under N-1 conditions with the units 50-years old or older inside Houston assumed offline. As a result of the analysis, potential overloads on certain 345 kV facilities were found under Option 1, Option 2, Option 5, Option 6, and Option 8. Although several heavy flow issues (see Table 7.3.2) were found under Option 3, Option 4 and Option 7, no immediate N-1 overloads on the 345 kV facilities were expected even if the older units inside Houston are assumed to be retired in 2018.
- In addition to the AC power flow analysis, the generation reduction analysis was performed under G-1+N-1 conditions by gradually reducing the MW generation from the older units inside Houston. The results indicated Option 3 and Option 4 as the best performers causing no thermal issues on the 345 kV lines under G-1+N-1 conditions even with significant MW reduction (~1000 MW) from the older units.
- Severe system conditions (NERC Category C and D contingencies) critical to the area were evaluated. The results showed that every select option significantly improved the reliability of the system and equally reduced the number of unsolved events.
- The results of economic analysis indicated no significant difference in the relative annual production cost savings between the options.
- The system loss analysis done using the 2018 peak load condition demonstrated significant system loss reduction under every option resulting in substantial improvement in transmission system efficiency.
- All of the eight select options require new right of way, ranging from 117 miles to 178 miles.
- As discussed in Section 7.7, the series compensation in Option 1, Option 2, Option 6 and Option 7 may introduce potential risk of SSR to the existing conventional thermal units in the area.

Based on the overall comparison above, Options 1 through 4 provided better overall reliability benefits and lower overall project costs compared to the remaining options. Options 1 through 4 performed very similarly in terms of reliability and overall project cost. Although Options 1 and 2 had slightly lower overall costs compared to Options 3 and 4, Options 3 and 4 performed the

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best under the scenario with the older generation units in the Houston area assumed to be retired. In addition to the reliability benefits, Options 3 and 4 will not cause the potential issues (as discussed in Section 7.7) associated with series compensation required by Options 1 and 2. Therefore, Options 3 and 4 are significantly better options to the system in the area despite the slightly higher project cost.

Based on these overall comparisons, ERCOT narrowed the eight options to Option 3 and Option 4 as the potential solutions to best meet the overall reliability need for the area. The two options are very similar except that Option 3 requires constructing a new 345 kV substation roughly 9 to 10 miles north of the existing Gibbons Creek substation. Between Option 3 and Option 4, ERCOT considers Option 4 as the best alternative for meeting the near-term and future transmission reliability needs in the Houston area based on the comparison of the capital cost estimates of Option 3 and Option 4, and the fact that Option 4 utilizes the existing Gibbons Creek 345 kV substation while Option 3 requires building a new substation. Hence, Option 4 may have slightly less public impact than Option 3.

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Table 7.8.1 Overall comparison of each select option

Description	Option 1 (TWZ-25comp-TA)	Option 2 (TWZ-50comp-TA)	Option 3 (LRZ-TA)	Option 4 (LGZ-TA)	Option 5 (JJZ-TA)	Option 6 (JJZ-25comp-TATJ)	Option 7 (JJZ-50comp-TATJ)	Option 8 (NGZ-TATJ)
System Performance (2018) (All options addressed the reliability need)	Met criteria	Met criteria	Met criteria	Met criteria	Met criteria	Met criteria	Met criteria	Met criteria
Capital cost in 2018 dollar ($ Million), (Based on $3.78 million per mile for T-cost)	554.8	572.0	610.2	590.1	596.3	617.1	629.1	805.9
NPV of the set of future upgrades under each option in 2018 dollar ($ Million)	387.0	390.6	399.5	383.1	652.9	419.5	435.2	537.5
Overall cost impact Sum of the cost of each option and NPV of future upgrades in 2018 dollar ($ Million)	941.8	962.6	1009.7	973.3	1249.3	1036.6	1064.4	1343.4
Voltage stability Analysis (Estimated 2028 load level in Coast zone = 27931 MW)	28105 MW (beyond 2028)	28095 MW (beyond 2028)	28105 MW (beyond 2028)	28025 MW (beyond 2028)	27905 MW (2028)	28075 MW (beyond 2028)	28205 MW (beyond 2028)	28125 MW (beyond 2028)
Performance with the old units offline (AC power flow under N-1)	4 overloads	2 overloads	0 overload	0 overload	6 overloads	2 overload	0 overload	3 overloads
Amount of generation reduction from the old units without causing overload under G-1+N-1 (MW)	900.6	911.1	1061.3	1020.0	400.0	773.8	662.6	652.6
NERC Category C and D performance	Good	Good	Good	Good	Good	Good	Good	Good
Economic Benefit (Relative annual production cost savings in $ million, referenced to Option 8)	4.3	3.4	3.2	1.7	2.1	2.2	1.7	0.0
System Loss Reduction at Peak (MW)	44.7	38.8	47.6	31.2	38.2	44.8	35	32.7
New Right of Way	117 mi	117 mi	130 mi	129.9 mi	128.9 mi	128.9 mi	128.9 mi	177.9 mi
Sub-Synchronous Resonance (SSR) concern	Yes	Yes	No	No	No	Yes	Yes	No

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8. Sensitivity Analysis

8.1 Transfer Sensitivity Analysis

Based on the feedback from RPG meetings regarding the load scaling approach assumed in the power transfer analysis in Section 7.1, ERCOT conducted an additional study to check if there would be any significant impact on the results of the power transfer analysis due to a different load scaling approach. ERCOT tested the following two load scaling approaches under N-1 conditions for some of the select options.

- Approach #1: Scaling load down in North, North Central, West and Far West, while scaling load up in the Coast weather zone
- Approach #2: Scaling all load down except the load in Coast weather zone, while scaling load up in the Coast weather zone

As a result, ERCOT found that:

- reliability criteria violations still exist in 2018 regardless of which approach is used and,
- the need for the next set of future upgrades (in the 2025 to 2028 timeframe) may be deferred by one or two years if the all-load-scaling approach (#2) is used. For example, ERCOT found roughly 220~300 MW difference in the transfer capability when the future overload issue on the Singleton-Zenith 345 kV double circuit occurs with each option.

8.2 Non-Transmission Alternative Sensitivity Analysis

A high-level sensitivity analysis was performed to estimate the impact of new future generation or demand response within the Coast weather zone.

To perform this sensitivity the load was scaled down from the base case level in the study case for 2018 in the entire Coast weather zone to mimic the new generation addition or demand response. The results indicated that approximately 1800 MW of new generation and/ or demand response would reduce the G-1 + N-1 overload to 100%. Hence, if a net of 1800 MW of generation were to be added in the Houston area it would defer the need of the project until 2019. However, should this amount of new generation materialize ERCOT would not recommend deferring the project due to the risk of retirement of existing generation within the area as described in Section 7.3. It should be noted that ERCOT cannot compel generation or demand response to locate in a certain area and participate in the ERCOT market. Therefore, ERCOT must plan transmission projects when reliability criteria violations are found.

Since there is currently not a mechanism in ERCOT to call on demand response for a transmission security issue this is not considered a feasible alternative.

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9. Conclusion and Recommendation

ERCOT identified a reliability need to increase the Houston import capability by 2018 and based on the independent review selected Option 4 as the preferred option to meet the reliability need.

The following facilities constitute the preferred option:

- Construction of a new Limestone-Gibbons Creek-Zenith 345 kV double circuit to achieve 2988 MVA of emergency rating for each circuit. The line length assumed for the cost estimate is approximately 129.9 miles.
- Upgrade of the substations at Limestone, Gibbons Creek and Zenith to accommodate the terminations of new transmission lines.
- Upgrade of the existing T.H. Wharton-Addicks 345 kV line to achieve 1450 MVA of emergency rating (~10.7 miles).
- The estimated total cost for Option 4 is approximately $590 million in 2018 dollars. The estimate may vary as the designated providers of the new transmission facilities perform more detailed cost analysis.

9.1 Critical Energy Infrastructure Information (CEII) Considerations *(This section redacted from public version)*

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10. Designated Provider of Transmission Facilities

In accordance with the ERCOT RPG Planning Charter and Procedures Section 2.3.4, ERCOT staff is to designate transmission providers for projects reviewed in the RPG. The default providers will be those that own the end points of the new projects. These providers can agree to provide or delegate the new facilities or inform ERCOT if they do not elect to provide them. If different providers own the two ends of the recommended projects, ERCOT will designate them as co-providers and they can decide between themselves what parts of the recommended projects they will each provide.

Both CenterPoint Energy and Texas Municipal Power Agency (TMPA) own endpoints of the new 345 kV transmission line from Limestone to Gibbons Creek to Zenith listed in the project scope of this recommendation. TMPA has delegated their portion of the project to Cross Texas Transmission and Garland Power & Light. Therefore, ERCOT designates CenterPoint Energy, Cross Texas Transmission and Garland Power & Light as co-providers of the new 345 kV transmission line. CenterPoint Energy is the designated provider of the T.H. Wharton-Addicks 345 kV line, Limestone substation, and Zenith substation upgrades. Cross Texas Transmission and Garland Power & Light are the designated providers of the Gibbons Creek substation upgrades.

The designated TSPs have indicated that it is unlikely for the project to be in-service before summer peak of 2018 unless ERCOT designates the project critical to reliability per PUCT Substantive Rule 25.101(b)(3)(D). Since there is a reliability need to have the project in place before summer 2018 ERCOT deems the project critical to reliability.

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11. RPG Process of Houston Import Project Review

The following table details significant milestones in the Regional Planning Group review of the project:

Date	Description
7/26/2013	Project proposal submitted by CenterPoint Energy to RPG
7/29/2013	Project proposal submitted by Garland Power & Light and Cross Texas Transmission to RPG
8/16/2013	End of comment period for CenterPoint Energy proposal
8/19/2013	End of comment period for Garland Power & Light and Cross Texas Transmission proposal
8/19/2013	Project proposal submitted by Lone Star Transmission to RPG
8/27/2013	The three project proposals were presented in the RPG meeting by the TSPs
9/9/2013	End of comment period for Lone Star Transmission proposal
9/24/2013	Approach for ERCOT Independent Review of the Houston import project was presented for comment in the RPG meeting
10/22/2013	ERCOT presented and took comments on the results of the 2018 study base case including the reliability need at the RPG meeting
12/17/2013	ERCOT presented the status of the ERCOT Independent Review of the Houston import project at the RPG meeting, which included a list of options under evaluation, the results of various studies (power flow, transfer analysis, impact of older units, NERC C and D contingency analysis, loss analysis and other sensitivity analyses)
11/1/2013	End of project study mode (responses to comments)
1/16/2014	Lone Star submitted late comments concerning the project evaluation to RPG
1/21/2014	ERCOT presented the result of various studies (cost analysis, congestion-related impact analysis, sensitivity analysis, other consideration) at the RPG meeting
1/21/2014	NRG presented comments/concerns with the study assumptions at the RPG meeting
1/30/2014	ERCOT informed RPG of extending the review period to February 20, 2014 in order to review and address the additional comments received from ERCOT stakeholders
2/12/2014	ERCOT sent a response to the Lone Star's January 16 comments to the RPG
2/18/2014	ERCOT addressed the NRG comments/ concerns from the January RPG meeting and presented the final results at the RPG meeting. ERCOT also verbally addressed the Calpine comment/concern at the RPG meeting by referring to the results of the sensitivity analysis presented in the January RPG meeting
2/20/2014	ERCOT posted the independent review

Comments from stakeholders that were received by ERCOT during RPG meetings or formally submitted through the RPG process have been taken into account and included as appropriate in

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the analysis presented in this report. The following entities formally submitted comments during the official comment phase for one of the three submitted project proposals:

Bay Area Houston Economic Partnership
Galveston County Economic Alliance
The Woodlands Area Economic Development Partnership
Humble Independent School District
The Economic Development Alliance for Brazoria County
Baytown – W. Chambers County Economic Development Foundation
Galveston Economic Development Partnership
Pearland Economic Development Corporation
City of Waller Economic Development Corporation
Economic Alliance Houston Port Region
City of Houston
Texas Medical Center
Pasadena Second Century Corporation
Tomball Economic Development Corporation
Greater Fort Bend Economic Development Council
Shriners Hospital for Children
Uptown Houston
City of Missouri City, Texas
Calpine
Waller County EDP
NRG Texas Power LLC
Lone Star Transmission
Edison Mission Marketing & Trading
Luminant Energy Company LLC
Texas Industrial Energy Consumers (TIEC)
LCRA Transmission Services Corporation
Cross Texas Transmission (CTT) [and Garland Power & Light]
F to Z Coalition
Oncor Electric Delivery
Mercuria Energy America

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12. Appendices

Appendix A: AC Contingency Result of 2018 SE Study Base Case (N-1 analysis)	Houston_Import_BaseCase_N-1.xlsx
Appendix B: AC Contingency Result of 2018 SE Study Base Case (G-1+N-1 analysis)	Houston_Import_BaseCase_G-1_STX_N-1.
Appendix C: AC Contingency Result of 2018 SE Study Base Case with Option 4 (N-1 analysis)	Houston_Import_CTT-LGZ-TA_N-1.xlsx
Appendix D: Result of cost analysis using different cost-per-mileage for new transmission line in each select option	Summary of Cost Analysis using differe
Appendix E: Description of the SSWG Cases, and Summary of the study result	Appendix E.docx
Appendix F: AC Contingency Result of the 2018 SSWG Case 1 (G-1+N-1 analysis)	Contingency Result - Case 1 2018 SSWG (
Appendix G: AC Contingency Result of the 2018 SSWG Case 2 (G-1+N-1 analysis)	Contingency Result - Case 2 2018 SSWG v
Appendix H: AC Contingency Result of the 2018 SSWG Case 3 (G-1+N-1 analysis)	Contingency Result - Case 3 2018 SSWG v
Appendix I: Estimates of selected options and future upgrades in 2018 dollars	Cost Estimates of Selected Options and

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Attachment 4

NRG Comments to the ERCOT Board

The power to change life.
The energy to make it happen.

NRG Comments/Concerns with Houston Import Project

April 8, 2014 ERCOT Board of Directors Meeting

Item 8
ERCOT Public

nrg.

Introductory Remarks

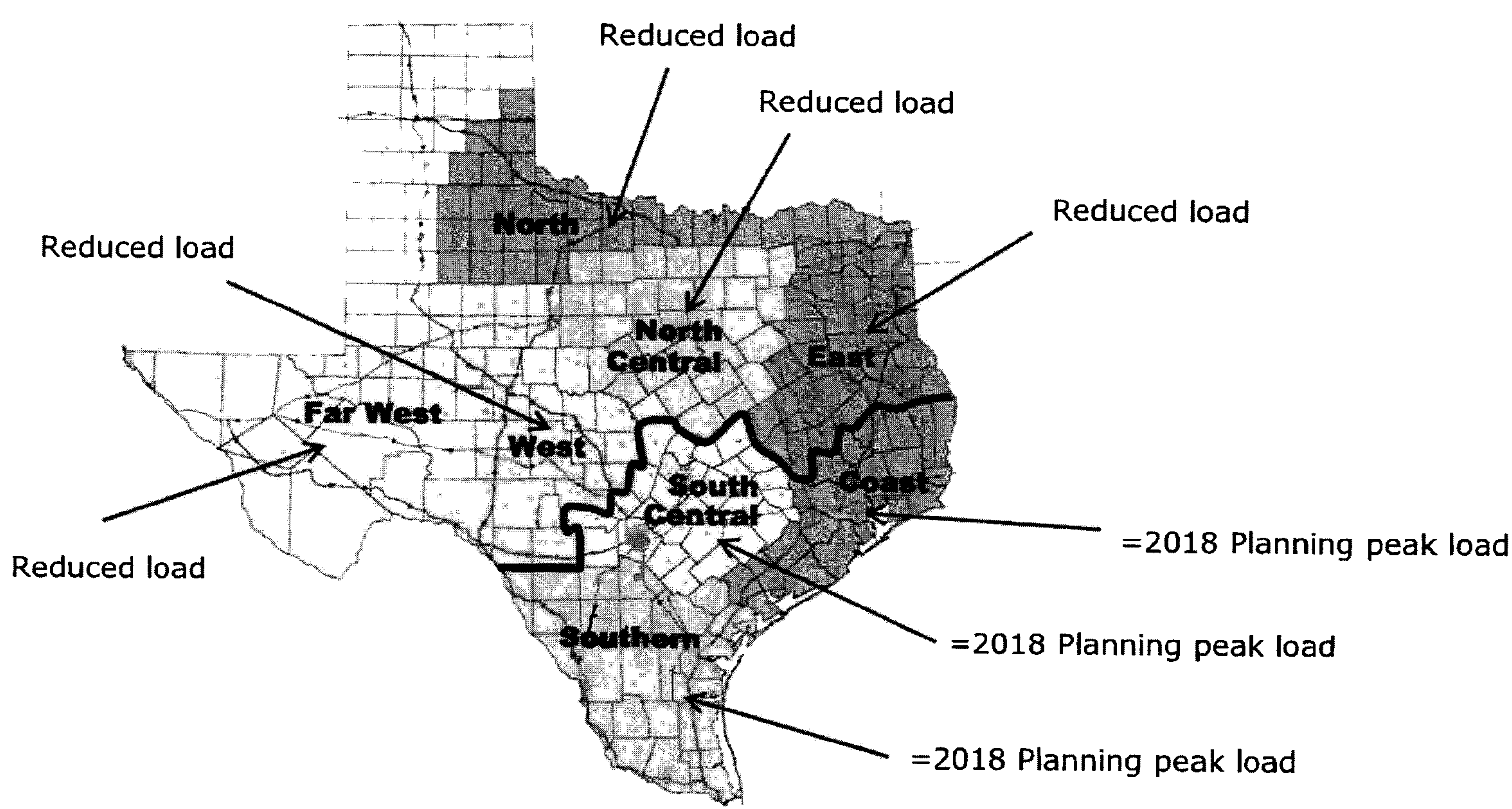
- The Houston Import Project ("HIP") being recommended by ERCOT is the most expensive transmission expansion project since CREZ. The estimated cost is $590 million, and if approved it is scheduled to be in service in 2018.
- NRG and others, as witnessed by the TAC vote and the numerous comments filed during the HIP's Regional Planning Group process, have voiced their concerns with the ERCOT recommendation to proceed with the HIP transmission addition.
- Commenters have stated they believe the assumptions used in the HIP analysis are leading to a result that could lead to significant and unnecessary costs being placed on consumers.
- The goal of this presentation is to try and simplify ERCOT's extremely detailed and voluminous HIP analysis in order to highlight some of the planning assumptions that are driving the results.

nrg.

Concerns with the HIP Analysis

- NRG believes ERCOT's analysis shows the problem being addressed in 2018 by the HIP is a lack of generation, not a lack of transmission infrastructure.
- In fact, ERCOT's final report states there is not enough generation to meet the SSWG Planning non-coincident peak load in 2018, so ERCOT utilized a "load reduction" scaling methodology to handle the problem. From ERCOT's HIP Final Report:
  - *"In transmission planning analysis the amount of generation available in the base case may not be enough to meet the summed non-coincident peak load of all areas of the system. In order to solve this challenge… ERCOT split the 2018 summer peak case into two study areas, the so-called NW and SE areas. For each study area the load level was set to the forecasted peak load for that area while load outside of the area was scaled down until there was enough generation to meet the load plus an operational reserve of approximately 1375 MW."*
  - *"In the 2018 SE summer peak case…the load levels for the East, Coast, South Central, and Southern weather zones were set to their forecasted peak load levels. The load levels in the North, North Central, West, and Far West weather zones were reduced…from the peak load levels of the SSWG base case."*
- The "SE" (Southeast) case was used in the HIP analysis. Because of their relative sizes, the loads in the Houston (Coastal) and Dallas/Ft. Worth (North Central) weather regions are the load assumptions that drive the HIP results. Loads in the Coastal region were held at peak, while loads in the North Central region were reduced.
- A planning assumption of reduced load in one area of the state is electrically equivalent to adding that same amount of generation in that area.

SE Case: Weather Zones with Load Reduced and Weather Zones with Load Equal to 2018 Planning Peaks



nrg.

Load Scaling Assumptions Used in the HIP Analysis

- ERCOT justified the North Central load reductions based on a "top ten" table that calculated the coincident peaks of the other weather zones relative to the top ten hourly Coastal peak conditions in 2011, 2012 and 2013.

Average % of peak load of each weather zone during the top ten hourly peak load conditions at the Coast Weather Zone							
Year	East	South	South Central	Far West	West	North	North Central
2011	97.46%	98.21%	96.38%	93.75%	83.70%	67.86%	93.37%
2012	96.32%	95.58%	96.08%	93.23%	92.93%	78.55%	85.56%
2013	76.77%	98.62%	97.42%	95.81%	78.23%	90.88%	88.81%

- Using this table, ERCOT decreased the North Central (D/FW) load to approximately 85% of the forecasted 2018 peak load for that region, even though the above table indicates 85% is too low. A swing of 7.8% in the North Central peak load (93.37%-85.56%) equates to approximately 1,950 MWs.
- NRG and others questioned ERCOT as to why they used a 10 hour average peak when historical planning has always been concerned with a peak hour.
- The data on the next slide shows how multi-hour averages can skew the results when compared to the hourly peak conditions.

nrg.

Why a 10 Hour Average Instead of the Coincident One Hour Peak?

- The data below shows how the one hour coincident peaks are almost always a higher percentage relative to the Coastal one hour peak than are the 10 hour average values used in the HIP analysis, especially in the North Central zone, which has the greatest load scaling impact.

Average % of peak load of each weather zone during the top ten hourly peak load conditions at the Coastal weather zone

Year	East	South	South Central	Far West	West	North	North Central
2011	97.46%	98.21%	96.38%	93.75%	83.70%	67.86%	93.37%
2012	96.32%	95.58%	96.08%	93.23%	92.93%	78.55%	85.56%
2013	76.77%	98.62%	97.42%	95.81%	78.23%	90.88%	88.81%
avg.	**90.18**	**97.47**	**96.63**	**94.26**	**84.95**	**79.10**	**89.25**

Average % of peak load of each weather zone during the top HOUR peak load condition at the Coast Weather Zone

2011	97.60%	95.30%	96.70%	91.20%	92.00%	88.30%	95.50%
2012	97.60%	98.70%	97.90%	95.10%	97.70%	90.30%	94.60%
2013	92.70%	98.10%	98.10%	98.60%	95.20%	87.10%	90.20%
avg.	**95.97**	**97.37**	**97.57**	**94.97**	**94.97**	**88.57**	**93.43**

Source for Peak Hour data: 2011, 2012 and 2013 ERCOT Demand and Energy Report nrg

What do these Assumptions Mean?

- NRG understands that when there is not enough generation in a study case, assumptions have to be made to solve the load flow analysis. In the HIP case, load reduction techniques were used, but only in certain regions of the state. By automatically scaling the load in only one region, while keeping the load at peak in another, the load flow analysis will undoubtedly lead to a conclusion that major transmission infrastructure is needed across the two regions. NRG doesn't believe these types of assumptions are realistic.
- By reducing the load in the North Central region to an 85% coincident peak value relative to the Coastal region, ERCOT has made an "electrically equivalent" generation assumption that approximately 2,000 MWs of generation will be added in the North Central weather zone by 2018, while none will be added in the Coastal region.
- NRG believes the scaling models were beyond reasonable limits and thus drive the unrealistic HIP results. For the HIP project to work there has to be something to transfer from the North into Houston, and there is no available data indicating more generation will be built in the northern and western portions of the state than in the coastal and southern regions.

Additional Issues with Load Forecasts

- The recent resource adequacy debate has resulted in significant changes being made to ERCOT's load forecast methodology.
- NRG and others have noticed a substantial difference in the load forecasts used in the HIP analysis (provided by TSPs) vs. the ERCOT load forecasts used for other purposes, like the CDR.
- For example, the peak load in 2018 for the Coastal region in the HIP analysis is 26,355 MWs. ERCOT's 90/10 (extreme weather) forecast from the 2013 Regional Transmission Plan ("RTP") shows a 2018 peak load in the Coastal region of 24,475 MWs.
- The North Central weather zone peak load in 2018 in the HIP analysis is 25,895 MWs, while ERCOT's 90/10 forecasted peak in the RTP is 29,512 MWs.
- These differences in the load forecasts exacerbate the load scaling issues described in this presentation (an example is provided on the next slide).
- Should one load forecast be used when discussing generation reserve margins in the CDR, while another load forecast is used to plan transmission?
- NRG believes the answer is No.

nrg.

Using ERCOT's Load Forecast Indicates No Need for the HIP in 2018

- The data on the previous slide can help illustrate how the various load forecasts impact the HIP analysis.
- If the ERCOT 90/10 (extreme weather) load forecast for 2018 is used instead of the TSP's HIP load forecasts, and even retaining the questionable load scaling assumptions used in HIP (coast at peak and north central at 85% of its peak), it would "lower" the coastal load by 1,880 MWs (26,355-24,475) and "increase" the North Central load by 3,074 MWs (85% of 29,512 vs. 85% of 25,895).
- This is a total swing in the load scaling assumptions of 4,954 MWs in a direction that would completely negate the need for the HIP!
- ERCOT's final HIP report states an addition of only 1,800 MWs in the Coastal region alone could defer the HIP project to at least 2019. As shown above, simply using ERCOT's 90/10 extreme weather load forecast in the coastal weather zone only, instead of the HIP coastal weather zone forecast, provides over 1,800 MWs.

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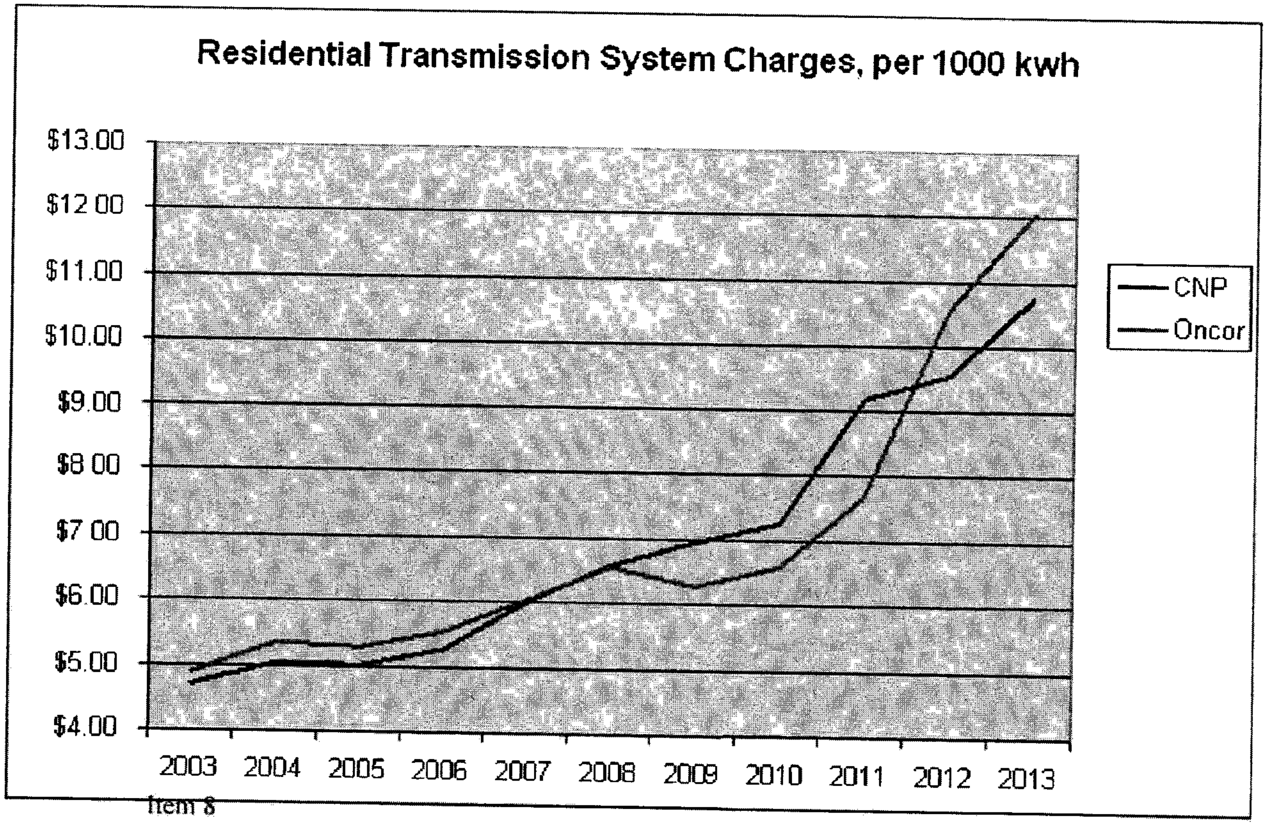
Residential Transmission Charges for Oncor and CNP



- Transmission System Charges are the sum of the distribution tariff Transmission Charge and the Transmission Cost Recovery Factor
- CNP is up 127% from 2003
- Oncor is up 146% from 2003
- 2014 transmission costs will be even higher as all of CREZ costs are captured in the TCRF

Item 8
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Conclusions

- Load scaling in one region is electrically equivalent to adding that same amount of generation in that region.
- NRG believes ERCOT's assumption to scale the weather zones in the north and western portions of the state while the Coast is peaking, based on an average of the "top ten" hours, is not a realistic load scaling assumption. Peak planning cases should be based on the peak hour, not averages.
- The historical coincident peak hour for the North Central weather zone when the Coastal weather zone is at peak has been as high as 95% (in 2011), and has averaged over 93% from 2011-2013. This is much higher than the assumed 85% level used in the HIP analysis.
- Even assuming an 85% load scaling assumption is correct, using ERCOT's 90/10 extreme weather load forecast, instead of the TSP's transmission planning forecasts, would completely negate the need for the HIP project in 2018.
- More logical, realistic assumptions for the load reduction (electrically equivalent to generation addition) scenarios in the HIP analysis across the regions, combined with a consistent use of ERCOT's load forecast, would provide a vastly different result and will lead to a more cost-effective utilization of consumer dollars.

nrg.

Recommendations

- NRG recommends the Board defer consideration of the HIP project and direct ERCOT to:
  - reconcile the differences in the ERCOT CDR and transmission planning load forecasts;
  - reconsider whether the HIP assumptions based on multi-hour coincident peak averages, instead of a coincident peak hour, is appropriate; and
  - determine whether the use of load scaling in only one region, while keeping the load at peak in another, is an appropriate technique.

Attachment 5

Calpine Comments to the ERCOT Board

CALPINE®

NYSE CPN

Houston Import Project Observations for the Technical Advisory Committee's Consideration

TAC Meeting
March 27th, 2014

CLEAN MODERN EFFICIENT FLEXIBLE POWER GENERATION

Overview

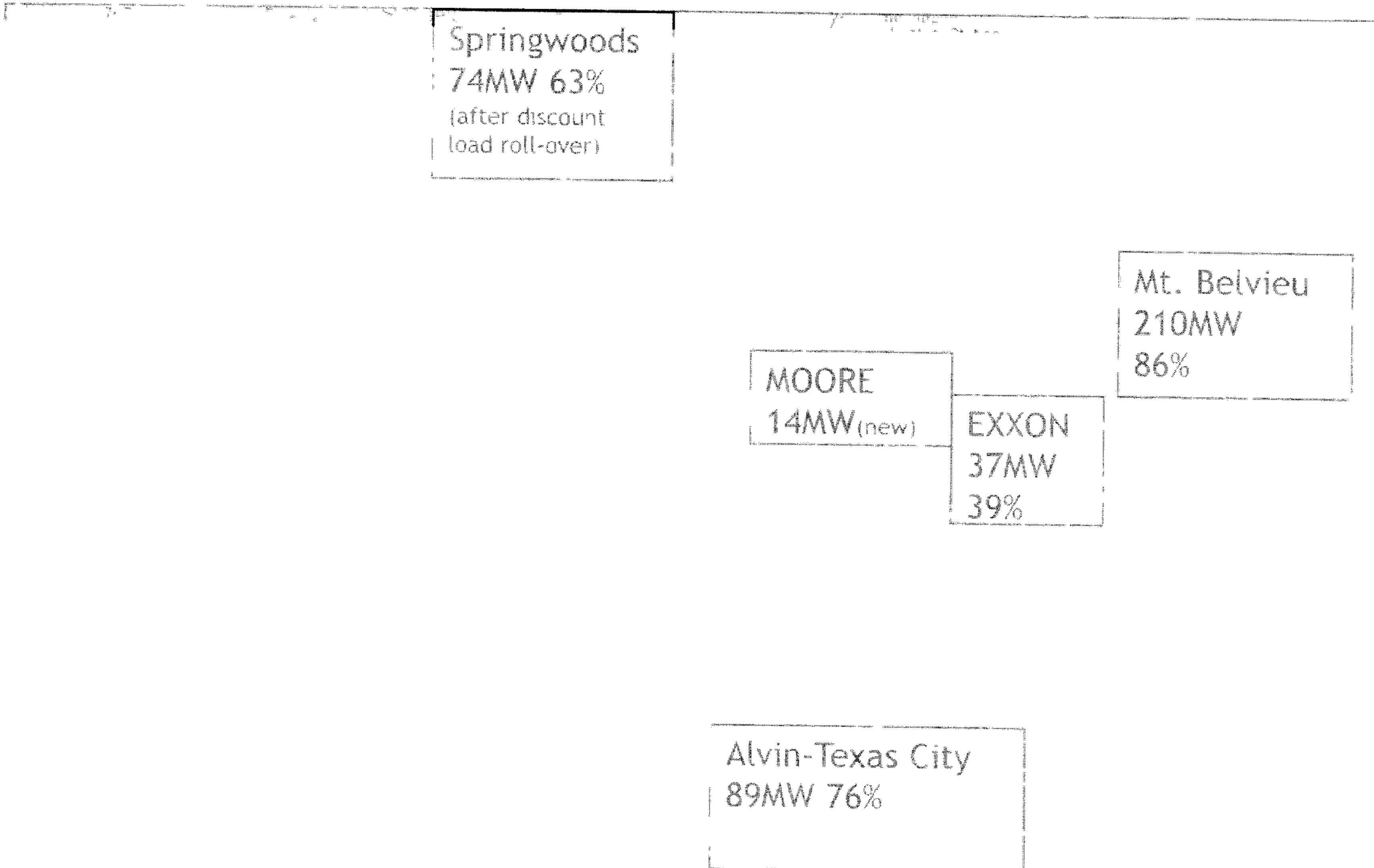
CALPINE

Calpine asks the Technical Advisory Committee to consider two significant issues that have recently surfaced relative to the Houston Import Project:

1) Several load buses in the 2018 SSWG's Base Case show very large percentage changes from the 2014 peak loads for those buses; percentage changes that are unlikely to be residential or commercial development and are likely industrial development requiring cogeneration development not accounted for in the HIP studies,

2) ERCOT's latest CDR shows the Pondera King Power Project's capacity available for 2018 yet it is not considered in the HIP studies.

Possible Cogen Load Locations in Houston (SSWG 2018 vs. 2014)



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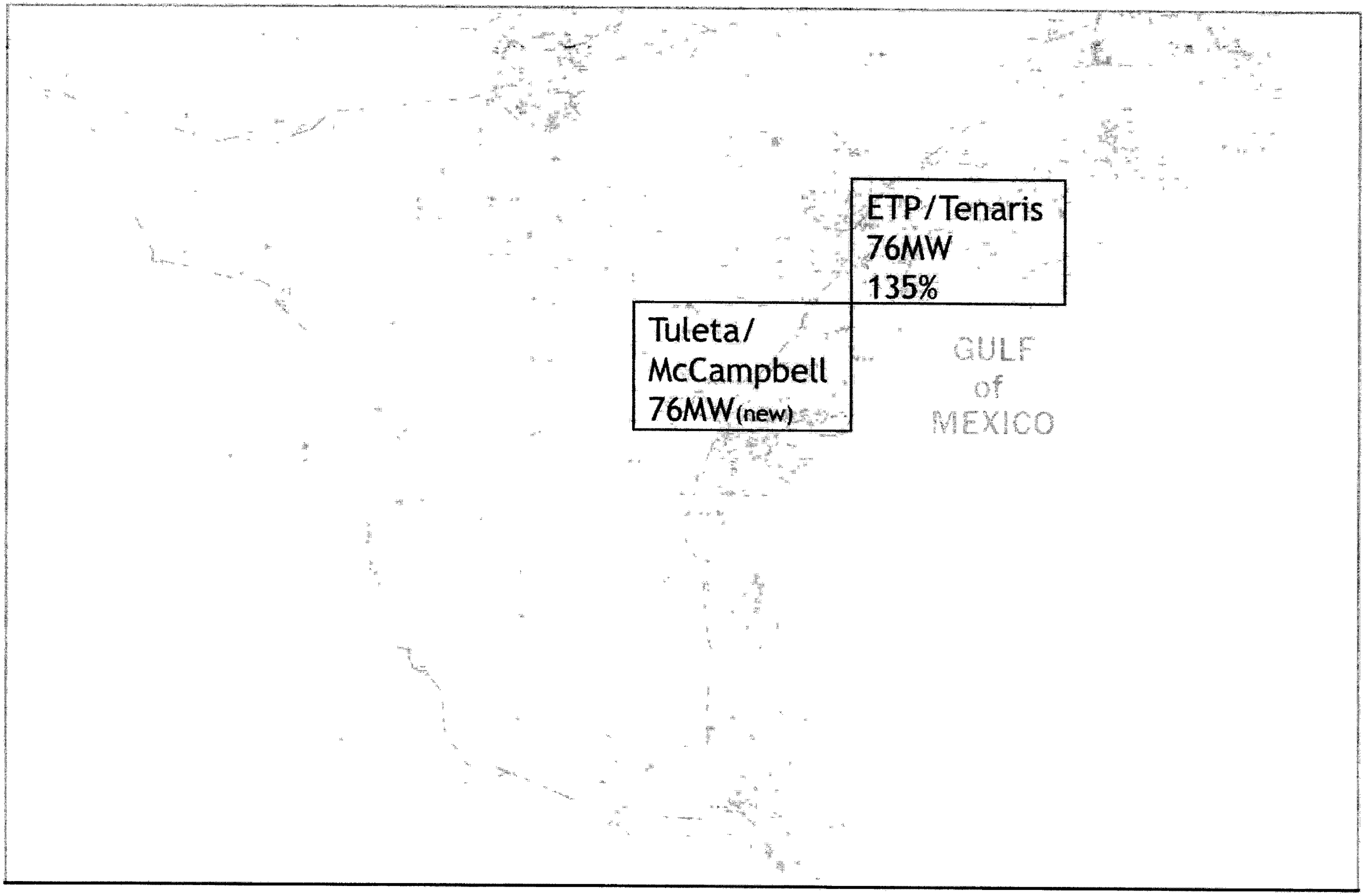
Bus List of Possible Cogen from SSWG 2018 vs. 2014

CALPINE

Bus #	Bus Name	2018 Load (MW)	2014 Load (MW)	18 vs. 14 change	% changed	Region
38920	TNLEAGCITY1	123	101	22	22%	Alvin-Texas City
38990	TNSEMINOLE1	45	31	14	46%	Alvin-Texas City
38900	TNHDNLAKES1	22	0	22		Alvin-Texas City
38930	TNUTMB____1	20	0	20		Alvin-Texas City
38830	TNMAINLAND1	11	0	11		Alvin-Texas City
39015	TNNALVIN__1	11	0	11		Alvin-Texas City
40570	EXXON___138A	131	94	37	39%	EXXON
40555	MOORE___138X	14	0	14		MOORE
40665	CONNOR__138X	25	1	24	2370%	Mt. Belvieu
41611	TRNITY__138B	32	8	24	281%	Mt. Belvieu
40764	WINFRE__138X	53	30	23	78%	Mt. Belvieu
41111	MT_BEL__138A	129	95	34	36%	Mt. Belvieu
40760	NORTON_138X	77	51	26	50%	Mt. Belvieu
40770	HACHER__138X	80	47	33.00	71%	Mt. Belvieu
41610	TRINTY__138A	61	14	47.00	338%	Mt. Belvieu
46270	SPRINGWOODS	212	130	82	64%	Springwoods
Total		**1046**	**602**	**444**	**74%**	

000123

Possible Cogen Load Locations in South WZ (SSWG 2018 vs. 2014)



000124

Bus List of Possible Cogen in South WZ (SSWG 2018 vs. 2014)

CALPINE

Bus #	Bus Name	2018 Load (MW)	2014 Load (MW)	18 vs. 14 change	% changed	Region
5523	ETPSUB8	98	56	42	43%	ETP/Tenaris
5562	TENARISSUB8	34	0	34		ETP/Tenaris
8590	TULETA4EA	38	0	38		Tuleta/ McCampbell
80470	MCCAMPB4	38	0	38		Tuleta/ McCampbell
Total		**208**	**56**	**152**	**271%**	

Pondera King Power Project

CALPINE

From the Winter 2014 CDR

SITE_NAME	GINR_NUM	UNIT_CODE	COUNTY	FUEL	ZONE	YEAR	2014	2015	2016	2017	2018
New Resources with Signed IA and Air Permit											
PANDA SHERMAN CTG1	10INR0021	PANDA_S_SHER1CT1	GRAYSON	GAS	NORTH	2014	-	192.8	192.8	192.8	192.8
PANDA SHERMAN CTG2	10INR0021	PANDA_S_SHER1CT2	GRAYSON	GAS	NORTH	2014	-	192.8	192.8	192.8	192.8
PANDA SHERMAN STG	10INR0021	PANDA_S_SHER1ST1	GRAYSON	GAS	NORTH	2014	-	334.7	334.7	334.7	334.7
PANDA TEMPLE CTG1	10INR0020a	PANDA_T1_TMPL1CT1	BELL	GAS	NORTH	2014	-	191.2	191.2	191.2	191.2
PANDA TEMPLE CTG2	10INR0020a	PANDA_T1_TMPL1CT2	BELL	GAS	NORTH	2014	-	191.2	191.2	191.2	191.2
PANDA TEMPLE STG	10INR0020a	PANDA_T1_TMPL1ST1	BELL	GAS	NORTH	2014	-	334.7	334.7	334.7	334.7
DEER PARK ENERGY CENTER	14INR0015	DDPEC_GT6	HARRIS	GAS	HOUSTON	2014	-	165.0	165.0	165.0	165.0
FERGUSON REPLACEMENT CTG1	13INR0021	FERGCC_FERGGT1	LLANO	GAS	SOUTH	2014	-	161.9	161.9	161.9	161.9
FERGUSON REPLACEMENT CTG2	13INR0021	FERGCC_FERGGT2	LLANO	GAS	SOUTH	2014	-	161.9	161.9	161.9	161.9
FERGUSON REPLACEMENT STG	13INR0021	FERGCC_FERGST1	LLANO	GAS	SOUTH	2014	-	186.0	186.0	186.0	186.0
TEXAS CLEAN ENERGY PROJECT	13INR0023		ECTOR	COAL	WEST	2018	-	-	-	-	-
PANDA TEMPLE II	10INR0020b		BELL	GAS	NORTH	2015	-	-	717.0	717.0	717.0
PONDERA KING POWER PROJECT	10INR0022		HARRIS	GAS	HOUSTON	2018	-	-	-	-	1,468.6

From the ERCOT Planning Update to the RPG on 1/21/2014

Study Base Case

- Total Load in Coast Weather Zone in the 2018 SE case
  - ~ 26,355 MW (CNP load = ~ 22800 MW)
  - The load is identical to the SSWG case load in the Coastal weather zone
- Status of future generators in the study case

  Online:
  - Deer Park Energy G6, Channel Energy GT3,
  - Deepwater Energy,

  Offline:
  - New W.A. Parish unit, Pondera King, Cobisa

000126

Our Conclusions

CALPINE

1) If you believe that the bus load growths we've identified are likely industrial development and will require power and/or steam, then you should also believe that they will be supplied locally and not from the North Central Weather Zone. New cogeneration development in the Houston Area will be needed to match these loads yet no such assumption was used in the HIP studies.

2) It may be useful to exclude the Pondera King Power Project from the HIP studies in order to support an apparent need for new North-Houston transmission, and it may also appropriate to include that same facility in the CDR for resource adequacy purposes but doing both raises an obvious question about the discontinuity between resource adequacy planning and transmission planning.

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NYSE CPN

Attachment 6

Transcript, ERCOT Board of Directors, Meeting, Apr. 8, 2014
(*Partial*)

TRANSCRIPT OF PROCEEDINGS

BEFORE THE

ELECTRIC RELIABILITY COUNCIL OF TEXAS

AUSTIN, TEXAS

BOARD OF DIRECTORS MEETING

EXCERPT OF AGENDA 8

Tuesday April 8, 2014

BE IT REMEMBERED THAT at 9:02 a.m, on Tuesday, the 8th day of April 2014, the above-entitled matter came on for hearing at the Electric Reliability Council of Texas, 7620 Metro Center Drive, Austin, Texas, before CRAVEN CROWELL, Chairman; JUDY WALSH, Vice Chair; TRIP DOGGETT, CEO; MARK DREYFUS; NICK FEHRENBACH; CLIFTON KARNEI; MICHEHL GENT; REED COMSTOCK (for SHANNON BOWLING); TONY BAER; KEVIN GRESHAM; JEAN RYALL-PORTER; MARK CARPENTER and KARL PFIRRMANN, Members of the Board; and the following proceedings were reported by Lou Ray, Certified Shorthand Reporter.

northwest case where they reversed it. The Singleton-Zenith loading in the southeast case, which is what used to justify the HIP project, the loading on Singleton-Zenith was 3200 megawatts or something. It was overloaded in an N-1 and G-1. The northwest case they reversed the assumption. The loading went to 300 megawatts for the same planning year, the same peak time frame, but they reversed the assumption and the load -- if you believe the northwest case, you wouldn't need any Houston import for 30 years. Which is correct? And I think that probably both need to be looked at.

MR. KARNEI: Okay. Thank you.

CHAIRMAN CROWELL: Kevin, did you have some questions? I can't remember whether you wanted to be recognized again or not.

MR. GRESHAM: Yeah, I will. You want to recognize me now?

CHAIRMAN CROWELL: I recognize you now.

MR. GRESHAM: Good deal. Appreciate that. I want to tag onto something that Phillip said and that was in Calpine's presentation, and a question for Jeff. And that is, you know, as Phillip noted, the petrochemical industry and expansion, you know, future growth, you know, one of the things having been in Houston for a very long time before moving to the fair hills of Austin is that, you know, there's an awful lot of co-gen associated with those types of facilities. Was there an assumption, you know, based on the load growth that, you know, there would be some -- some amount of co-gen that would also develop within the Houston area, the coastal zone?

MR. BILLO: Yes. So the way we did the analysis is we followed the planning guide Section 6.9, the guidelines there on what generation to include. We did, however, go back and do a sensitivity analysis and determined that even if 100 percent of that additional load that Randy pointed out, even if 100 percent of that had cogeneration to meet that demand, that we would still have a need for the project.

MR. GRESHAM: Okay. The -- I think you noted it up front -- I think the speakers noted it also -- Mr. Chairman, this is a comment part.

CHAIRMAN CROWELL: That's quite all right.

MR. GRESHAM: And I appreciate Phillip offering this up because, you know, there is -- in a competitive market there is a tension naturally between reliability and market function and getting the incentives right to spur generation. I think, you know, the questions that are being raised here about what generation is being included in the CDR versus what's in planning case, you know, the impact of load forecasts in each. You know, those types of questions, even, you know, the last point that I was making, you know, there can be other future generation.

The question to me is have -- you know, in the changes that we've made, have we tipped the balance? And it's a careful balance and it's a careful tension. So, you know, I'm not sure what the process is.

But, you know, if ERCOT and stakeholders, you know, would, you know, sit down and look at the guides to ensure that that tension is not being -- you know, the scale isn't being tipped towards, you know, transmission, that we're allowing for adequate incentives for generation to be built, I think that would be a very useful process in all of this. And I think that's one of the things that in the issues that NRG and Calpine are raising, I think that's certainly -- you know, that's the question I think that's hanging out there.

CHAIRMAN CROWELL: Trip?

MR. DOGGETT: I was just going to recognize that we -- ERCOT are certainly interested in going back and evaluating whether any changes are needed, and I guess I'll ask Ken -- I know Ken's looked at this. We'll let Ken make any specific comments he may have in the area.

MR. McINTYRE: Yeah, Ken McIntyre, VP of Grid Planning and Operations.

You know, to your comments, Kevin, and also Phillip's previous ones, we received a lot of good comments through this process. Many comments at RPG as Jeff was alluding to, and then during our independent review. And I think we're prepared to evaluate any suggestions. And there is a process to do that at the Regional Planning Group and the Planning Working Group. They continuously look at the transmission planning process and is there things that we need to adjust or do differently to approve that.

We think the process is good now. We trust the process. We've been using it for a number of years, as Jeff alluded to, but it doesn't mean that we can always look at this, consider things as to your comments, are we considering generation correctly. You know, is there significant difference between how we do it in a CDR or how we do it in the planning cases and let's look at that and see if we need to adjust that.

Is there a way to look at future distributed generation, demand response programs or cogeneration and how do we firm that up to get that into planning cases? Is there a way to better do?

So we definitely are on board in working with the experts and the Regional Planning Group and the Planning Working Group itself to challenge those.

CHAIRMAN CROWELL: Kevin, you still have the floor if you still want --

MR. GRESHAM: I'm done for right now.

CHAIRMAN CROWELL: Okay. Let's go to Karl first and then over to Mark.

MR. PFIRRMANN: Thank you, Mr. Chairman. I think the point's been made that we could add generation in the Houston area and resolve the issue. Right?

MR. BILLO: Yeah.

MR. PFIRRMANN: With regard to the needs within the Houston zone?

MR. BILLO: Right. We looked at analysis with that and determined we would need 1800 megawatts to defer the project to 2019.

MR. PFIRRMANN: Right. And that would be constrained to just that zone because of congestion coming into the Houston area. By building this line, we remove that congestion and, therefore, increase the area in which new generation could be built, that 2,000 megawatts could be built not just in Houston but now maybe up in Dallas-Fort Worth or some other area. Is cogeneration, it's not just real power we're talking about. You can't transfer steam from the Dallas-Fort Worth area to Houston. And so it has to be local generation for a lot of that industrial development that requires steam as well as electric. Thank you.

MR. PFIRRMANN: Thank you.

CHAIRMAN CROWELL: Okay. Mark?

MR. DREYFUS: Thank you, Mr. Chairman. I want to agree with and support Kevin's point that this process and this dialogue has raised a number of issues in our assumptions and approach. And the transmission planning process has been in place for quite a while. It is, after all, a transmission planning process, but there's a lot of other things going on in our environment and in our market, and issues have been raised about the consistency of the load forecast with our new approach, the load scaling methodology.

And Ken mentioned there's new demand-side technologies and opportunities, and I think it -- it's reasonable that we take a kind of refresh of the transmission planning process, taking all those issues into account. And so I agree and support with Kevin's point. I appreciate Ken stepping up to undertake that. I'd just like to see it be a little more formal than you might have suggested in your comment that we have a working group. Somehow under the regional transmission planning process groups, and that we have -- assure that we have strong stakeholder involvement and that the Board be routinely updated on how that's going.

CHAIRMAN CROWELL: You want to respond to that, Ken?

MR. McINTYRE: Yeah. I appreciate that, Mark, and we can definitely do that. So we'll work with Regional Planning Group and the Planning Working Group to set that up.

CHAIRMAN CROWELL: Okay. Reed?

MR. COMSTOCK: Yes, I've got a question for Jeff.

So NRG had two points. The first had to do with the load scaling, and I think I understand ERCOT's response to that issue.

The second was the use of a significantly higher load forecast for the HIP project compared to the CDR. And I just want to make sure I understand ERCOT's response to that issue.

CHAIRMAN CROWELL: Okay. Jeff?

MR. BILLO: Yeah, let me call my boss up, Warren Lasher. He's much more familiar with the CDR process than I am. So I'm going to let him answer that.

CHAIRMAN CROWELL: Okay. Reed, Warren's

down here.

MR. LASHER: Yeah, I'm down here. Warren Lasher for ERCOT. So, you know, a little bit more familiarity with the CDR process than Jeff.

Obviously we've talked a lot about load forecasting the last few months associated with the CDR. So there are some notable changes and notable differences between the analysis we do for the Houston Import Project and what we are doing in essence in the CDR process, and let me go through some of those.

First of all, like Jeff mentioned, the CDR process fundamentally is built on an assumption of average weather conditions. And there is a separate study that's done, loss of load study, which indicates how much additional generation reserve margin you need to have in order to cover for weather differences for abnormally hot conditions. We don't have that in the transmission planning process. So in essence, that component of the -- of the analysis has to go in up front into the transmission planning process. The variability of weather has to be incorporated into your assumptions when you're doing transmission planning. That's the first thing.

The second thing is when we look at -- one of the big changes that -- improvements that Calvin made going into this year, his new model analysis does a much better job of incorporating the non-coincidence of loads across the Houston region -- I mean across the ERCOT region. So that does a better job of accounting for the fact that when Houston is hot, it's not hot in West Texas. And when Houston's hot, it's not hot in some other regions of the system.

And so when we look across the system now, Calvin's new load forecast does a much better job of, under average weather conditions, looking at the -- the impact of the variability of weather across the different regions. And that, in essence, is leading to lower systemwide load forecasts, but not lower region-specific load forecasts. So that's another big issue.

Another issue that is very important to note here is one of the big things that we're seeing, one of the big changes that we're seeing in loads going forward, are the impacts of some of the scarcity pricing changes that we see coming out of regulatory changes here in ERCOT. Most notably, the increases to the systemwide offer cap, the upcoming implementation of the operating reserve demand curve, and also the 4CP impacts.

All of those impacts are really targeted at systemwide scarcity conditions. So those are the top 10 to 15 hours in which systemwide we see scarce resources. When we do a transmission study like this, there are going to be hours of the year every year in which loads are very high in the Houston region because it's very hot in Houston, but it's not hot in the rest of the system. So those exact same scarcity conditions associated with 4CP and associated with systemwide peak loading conditions aren't going to be present in those hours and aren't going to have an impact on Houston loads in those hours because it's only hot in the Houston region under those conditions.

So all of these factors together put us in a position where the assumptions and the considerations that go into a systemwide load forecast analysis have to be very different from the considerations that go into a region specific -- in this case just looking at the Houston region -- and the needs of the Houston region.

MR. COMSTOCK: I do have a quick follow-up.

CHAIRMAN CROWELL: Yes.

MR. COMSTOCK: So I just want to confirm that to the extent the load forecast that is used for the transmission planning process, if the TDSPs submit a load forecast, does ERCOT have the authority within the process to revise that number if it deems that appropriate?

MR. LASHER: I don't look at it in terms of authority. But we work with the transmission system providers to make sure that their load forecasts are reasonable and appropriate for their regions. We have a -- you know, we have a strong working relationship that goes back many years. In some cases we felt that some of the regions had load forecasts that were a little bit too low; and some cases we felt that there were load forecasts that were a little too high depending on regions and stages of kind of our relationship with the transmission service providers.

In this case for the Houston Import Project, our transmission analysts determined that the load forecasts were appropriate for this analysis.

CHAIRMAN CROWELL: Okay. Adrian, I can only recognize you if a Board member has a question. But out of an abundance of fairness, I'll give you -- I'll recognize you for a quick response since I -- you have been trying to be recognized here.

MR. PIENIAZEK: Just again point out that, yes, there are times when it's really hot in Houston and it's not hot in Dallas. But there are also times -- as I pointed out -- where it's all over the state. And

Attachment 7

ERCOT System Planning Report
March 2014
(*Excerpt*)

System Planning

Monthly Status Report March 2014

Report Highlights

- ERCOT is currently tracking 230 active generation interconnection requests totaling over 58,100 MW. This includes over 26,700 MW of wind generation.
- ERCOT is currently reviewing proposed transmission improvements with a total cost of $962.5 Million.
- Transmission Projects endorsed in 2013 total $349.8 Million. No transmission projects endorsed in 2014 (Jan. through March, 2014).
- All projects (in engineering, routing, licensing and construction) total approximately $4.4 Billion.
- Transmission Projects energized in 2014 total about $123.3 Million.

1.5 Projects with Interconnection Agreements

Generation Interconnection Agreements as of March 31, 2014							
INR	Site Name	County	COD	Fuel	MW For Grid	Change from Last Report	Sufficient Financial Security Received by TSP
11INR0013	Goldthwaite Wind Energy	Mills	4/2014	WIND	149		Yes
13INR0048	Spinning Spur Wind Two	Oldham	6/2014	WIND	161		Yes
13INR0021	Ferguson Replacement Project	Llano	7/2014	GAS	570		Yes
14INR0012a	Miami Wind 1 Project	Gray	7/2014	WIND	289		Yes
14INR0015	Deer Park Energy Center	Harris	7/2014	GAS	190		Yes
14INR0030a_2	Panhandle Wind	Carson	7/2014	WIND	218		Yes
10INR0020a	Panda Temple Power	Bell	8/2014	GAS	717		Yes
10INR0021	Panda Sherman Power	Grayson	8/2014	GAS	720		Yes
11INR0050	Moore Wind 1	Crosby	8/2014	WIND	149		No
13INR0040	Rentech Project	Harris	8/2014	GAS	15		Yes
14INR0024	OCI Alamo 4	Kinney	8/2014	SOLAR	38		Yes
14INR0059	Forney Power Plant Upgrade	Kaufman	8/2014	GAS	34		No
13INR0059a	Hereford Wind	Castro	9/2014	WIND	200		Yes
11INR0094	White Camp Solar	Kent	10/2014	SOLAR	100	PRJ COD	No
12INR0034a	Stephens Ranch Wind Energy Phase 1	Borden	10/2014	WIND	201		Yes
13INR0010a	Mariah Wind	Parmer	10/2014	WIND	232		No
12INR0059	Barilla Solar	Pecos	11/2014	SOLAR	30		Yes
06INR0022c	Baffin (Penascal Wind Farm 3)	Kenedy	12/2014	WIND	202		Yes
11INR0079a	South Clay Windfarm	Clay	12/2014	WIND	200		No
13INR0005	Conway Windfarm	Carson	12/2014	WIND	600		Yes
13INR0052	Los Vientos III	Starr	12/2014	WIND	200		Yes
13INR0057	Windthorst 2	Archer	12/2014	WIND	65		No
14INR0023	Longhorn Energy Center	Briscoe	12/2014	WIND	361		Yes
14INR0032a	Route66 Wind	Randall	12/2014	WIND	150		Yes
14INR0049_2	Keechi Wind 138 kV Joplin	Jack	12/2014	WIND	102		Yes
14INR0053	Spinning Spur Wind Three	Oldham	12/2014	WIND	194		Yes
09INR0051	Mesquite Creek	Borden	1/2015	WIND	249		Yes
12INR0068	Sendero Wind Energy Project	Jim Hogg	2/2015	WIND	78		Yes
12INR0070	Green Pastures	Knox	2/2015	WIND	300		Yes
12INR0034b	Stephens Ranch Wind Energy Phase b	Borden	4/2015	WIND	177		No
13INR0059b	Jumbo Road Wind	Castro	4/2015	WIND	300	SFS	No
14INR0038	PHR Peakers	Galveston	4/2015	GAS	390		No
14INR0047	Wake Wind Energy	Floyd and Crosby	4/2015	WIND	299	New	Yes
13INR0020a	CPV Rattlesnake Den Ph 1	Glasscock	5/2015	WIND	201		Yes
13INR0050	Logans Gap Wind I	Comanche	5/2015	WIND	200		No
11INR0057	Cameron County Wind	Cameron	6/2015	WIND	165		Yes
14INR0039	Goldsmith Peaking Facility	Ector	6/2015	GAS	408		No
14INR0025a	South Plains Wind I	Floyd	7/2015	WIND	200		No
08INR0018	Gunsight Mountain	Howard	8/2015	WIND	120		No

Interconnection Database Reference Number	County	Fuel	Capacity to Grid (MW)	Commercial Operation Date (as specified by the resource developer)
16INR0039	Reeves	Solar	100.00	6/2016
14INR0011	Swisher	Storage	270.00	7/2016
08INR0019b	Gray	Wind	250.00	7/2016
16INR0013	Nacogdoches	Gas	215.00	7/2016
16INR0024	Hidalgo	Wind	200.00	10/2016
16INR0037	Floyd	Wind	400.00	10/2016
16INR0019	Coke/Sterling	Solar	100.00	12/2016
16INR0018	Upton	Solar	40.00	12/2016
16INR0017	Culberson	Solar	70.00	12/2016
08INR0019c	Gray	Wind	250.00	12/2016
13INR0006	Gray	Wind	750.00	12/2016
16INR0029	Hill & Limestone	Wind	100.00	12/2016
16INR0030	Young & Jack	Wind	201.00	12/2016
16INR0028	Jack	Wind	100.00	12/2016
16INR0027	Grayson & Fannin	Wind	100.00	12/2016
16INR0026	Erath, Somervell & Bosque	Wind	100.00	12/2016
16INR0025	Sterling	Solar	30.00	12/2016
13INR0010f	Parmer	Wind	200.00	12/2016
12INR0002b	Briscoe	Wind	200.00	12/2016
16INR0011a	Cameron	Wind	18.00	12/2016
16INR0031	Zapata & Starr	Wind	100.00	12/2016
15INR0013	Anderson	Storage	324.00	5/2017
17INR0003	Jackson	Gas	965.00	6/2017
17INR0002	Henderson	Gas	489.00	6/2017
17INR0005	Starr	Wind	200.00	6/2017
17INR0009	Hood	Gas	1042.00	7/2017
17INR0007	Wharton	Gas	1141.00	7/2017
16INR0011b	Cameron	Wind	132.00	12/2017
11INR0040	Freestone	Gas	640.00	3/2018

Attachment 8

ERCOT Feb 2014 CDR
Executive Summary

Executive Summary

The methodology for developing this report is defined in Chapter 3 of the ERCOT Protocols (see: http://www.ercot.com/content/mktrules/nprotocols/current/03-040213_Nodal.doc). ERCOT has developed this report using data provided by resource owners and by transmission service providers. Although ERCOT works to ensure that the data provided are as accurate and current as possible, we cannot independently verify all of the information provided to us. **Information available to ERCOT as of February 21, 2014, is included in this report.**

accurate as of 2/21/2014

The load forecast included in this assessment has been developed with a revised load forecast methodology that uses customer accounts (residential, commercial and industrial) that relate to relevant economic indicators for each of those customer classes within the ERCOT region. This load model forecasts peak loads and total annual customer demand based on an average of the past 12 years of weather conditions. In contrast, the next Seasonal Assessment of Resource Adequacy (SARA) reports, which will be released on March 5, 2014, cover a range of scenarios including extremely high load and generation outages. The new model also accounts for energy efficiency impacts on the historical summer peaks, and therefore a separate energy efficiency line item is no longer included in this report to avoid double-counting the load impacts. Additional information regarding the revised load forecasting methodology is available at: http://www.ercot.com/gridinfo/load/

Uses customer account numbers instead of non farm employment

12 years of weather

Energy efficiency data is part of peak load forecast now and not a separate line item

Currently available information indicates that the planning reserve margin in the ERCOT region will be approximately 13 percent at the start of the 2014 peak season and will rise to 16 percent when the Panda Sherman (720 MW), Panda Temple I (717 MW), Ferguson (510 MW), and Deer Park Energy Center (165 MW) combined-cycle gas plants are completed and brought into service later in the summer season. (The commercial operations date for the Deer Park plant is currently July 1, 2014, while the date for the Panda and Ferguson plants is currently August 1, 2014).

Summer starts at 13% and raises to 16% at end of summer when Panda Sherman, Panda Temple [Aug 1st COD], Ferguson [Aug 1st COD] and Deer Park [COD July 1st] are completed.

The expected wind capacity availability for coastal and non-coastal resource locations is being reported separately due to their differing operational characteristics. For example, the availability of coastal resources is typically significantly higher than non-coastal resources during peak load conditions due to the prevailing coastal wind patterns during late summer afternoons. Note that capacity for all wind generation resources are being included in the report at 8.7 percent of the total nameplate capacity. ERCOT acknowledges that the 8.7 percent peak load capacity availability is conservative. Recent analysis indicates that wind generation resources in ERCOT can be expected to serve peak demand at levels of approximately 27 percent of nameplate capacity for wind generation resources located along the Texas Gulf Coast, and 14 percent of nameplate capacity for other wind generation resources. ERCOT is also considering other methods of estimating the capacity availability of wind, such as using historical operational availability, and will adopt the most desirable method for future CDR reports.

Wind ELCC used is 8.7% of nameplate

The ERCOT protocols were modified in NPRR 550 (approved by the ERCOT Board of Directors on November 19, 2013) to include a requirement that thermal power plants have received their greenhouse-gas air emissions permit to be included in the CDR report. Currently five natural gas-fired powerplants have received an interconnection agreement for transmission service, but have not completed their air permitting requirements. Therefore, those facilities are not included in this report. Those future power plants are: Antelope facility (394 MW, currently scheduled to be completed July 2016); Goldsmith Peaking facility (380 MW, currently scheduled to be completed June 2015); P.H. Robinson Peaking facility (388 MW, currently scheduled to be completed April 2015); Friendswood Energy Generation (316 MW, currently scheduled to be completed September 2015); FGE Texas facility (799 MW, currently scheduled to be completed June 2016).

Units not in CDR due to NPRR 550 requires Greenhouse Gas Permitting along with signed IA

Project	Nameplate	Projected COD
Antelope	394	Jul-16
Goldsmith Peaking	380	Jun-15
PH Robinson Peaking	388	Apr-15
Friendswood Energy Center	316	Sep-15
FGE Texas	799	Jun-16
Tot:	2,277	

000150

10INR0020b	Panda Temple Power II	Bell	8/2015	GAS	717	Project Name	Yes
11INR0062	Patriot (Petronilla) Wind	Nueces	8/2015	WIND	178		Yes
14INR0012b	Miami Wind 1 Project	Gray	8/2015	WIND	111		No
13INR0049	Friendswood Energy Generation	Harris	9/2015	GAS	316		No
11INR0054	Midway Farms Wind	San Patricio	10/2015	WIND	161		Yes
14INR0030b	Panhandle Wind 2 (Phase 2)	Carson	11/2015	WIND	182		Yes
13INR0010b	Mariah Wind	Parmer	12/2015	WIND	200		No
13INR0031	Mustang Solar Project	Travis	12/2015	SOLAR	30		No
14INR0025b	South Plains II	Floyd	12/2015	WIND	300		No
14INR0072	Briscoe Wind Farm	Briscoe	12/2015	WIND	300		Yes
13INR0020b	CPV Rattlesnake Den Ph 2	Glasscock	5/2016	WIND	150		No
13INR0028	Antelope Station	Hale	6/2016	GAS	359	SFS	Yes
16INR0010	FGE Texas 1	Mitchell	6/2016	GAS	799		No
15INR0032	Antelope Station CT1	Hale	7/2016	GAS	197		No
15INR0033	Antelope Station CT2	Hale	7/2016	GAS	197		No
06INR0006	Cobisa-Greenville	Hunt	12/2016	GAS	1792		No
12INR0029	Comanche Run Wind	Swisher	12/2016	WIND	500		No
13INR0010c	Mariah Wind	Parmer	12/2016	WIND	168		No
12INR0018	Pampa Wind Project	Gray	3/2017	WIND	500		No
10INR0022	Pondera King Power Project	Harris	6/2017	GAS	1629		No
16INR0003	Freeport LNG PreTreatment Facility	Brazoria	6/2017	GAS	11		No
13INR0023	Texas Clean Energy Project	Ector	6/2018	COAL	240		No

1.6 Projects Undergoing Full Interconnection Studies with Confidentiality Waived

INR	Site Name	County	COD	Fuel	MW for Grid	Change from Last Report

1.7 Generation Projects Undergoing Full Interconnection Studies

Interconnection Database Reference Number	County	Fuel	Capacity to Grid (MW)	Commercial Operation Date (as specified by the resource developer)
14INR0076	Galveston	Gas	5	6/2014
14INR0069	Milam	Coal	30	8/2014
14INR0077	Smith	Gas	10	8/2014
14INR0013	Cameron	Wind	103	10/2014
13INR0036	Hidalgo	Wind	200	10/2014
14INR0066	Lamar	Gas	130	11/2014
10INR0085	Ector	Solar	57	12/2014
14INR0009	Kent	Wind	248	12/2014
14INR0043	Sterling	Solar	40	12/2014

Interconnection Database Reference Number	County	Fuel	Capacity to Grid (MW)	Commercial Operation Date (as specified by the resource developer)
15INR0074	Deaf Smith/Randall/Castro	Wind	156	12/2014
14INR0057b	Erath	Wind	48	12/2014
13INR0010d	Parmer	Wind	200	12/2014
14INR0048_2	Wilbarger	Wind	250	12/2014
14INR0045a	Webb	Wind	502	12/2014
14INR0057a	Erath	Wind	48	12/2014
14INR0048_1	Wilbarger	Wind	114	12/2014
14INR0056	Mills	Wind	101	12/2014
12INR0045	Kleberg	Wind	135	12/2014
14INR0049_1	Jack	Wind	102	12/2014
14INR0014	Val Verde	Solar	100	1/2015
15INR0069	Pecos	Solar	110	3/2015
15INR0070_1	Pecos	Solar	110	3/2015
14INR0050	Uvalde	Solar	40	3/2015
15INR0070_2	Pecos	Solar	110	3/2015
15INR0036	Uvalde	Solar	105	3/2015
14INR0020	Floyd & Motley	Wind	150	3/2015
10INR0009	Castro	Wind	300	3/2015
15INR0055	Austin	Gas	142	5/2015
15INR0054	Reeves	Gas	123	5/2015
15INR0053	Winkler	Gas	123	5/2015
15INR0021	Starr	Wind	200	5/2015
14INR0041a	Willacy	Wind	115	6/2015
14INR0074	Williamson	Gas	92	6/2015
13INR0026	Oldham	Wind	201	6/2015
15INR0027	Hidalgo	Gas	79	6/2015
15INR0028	Freestone	Gas	160	6/2015
14INR0040	Hidalgo	Gas	225	6/2015
15INR0023	Wharton	Gas	700	6/2015
13INR0054	Bee	Gas	25	7/2015
12INR0055	Baylor	Wind	40	7/2015
11INR0082a	Val Verde	Wind	50	8/2015
14INR0026	Presidio	Solar	30	9/2015
13INR0025	Randall	Wind	150	9/2015
14INR0062	Gray	Wind	200	9/2015
15INR0068	Sterling	Solar	20	10/2015
13INR0055	Zapata	Wind	250	10/2015
11INR0082b	Val Verde	Wind	150	11/2015
14INR0030a_1	Carson	Wind	322	11/2015
15INR0034	San Patricio	Wind	201	12/2015

Interconnection Database Reference Number	County	Fuel	Capacity to Grid (MW)	Commercial Operation Date (as specified by the resource developer)
15INR0035	Kenedy	Wind	200	12/2015
14INR0041b	Willacy	Wind	115	12/2015
11INR0065	Nueces	Wind	350	12/2015
08INR0019a	Gray	Wind	250	12/2015
12INR0060	Schleicher	Wind	58	12/2015
14INR0044	Reeves	Solar	100	12/2015
15INR0042	Hood	Gas	460	12/2015
15INR0051	Castro	Wind	200	12/2015
14INR0060	Haskell	Wind	400	12/2015
15INR0073	Armstrong/Carson	Wind	170	12/2015
13INR0032	Andrews	Solar	30	12/2015
12INR0002a	Briscoe	Wind	200	12/2015
13INR0010e	Parmer	Wind	200	12/2015
13INR0038	Swisher	Wind	300	12/2015
15INR0049	Zapata / Webb	Wind	250	12/2015
14INR0045b	Webb	Wind	251	12/2015
11INR0093	San Patricio	Wind	41	12/2015
14INR0033	Armstrong	Wind	500	12/2015
14INR0018	Nolan	Solar	20	12/2015
15INR0044	Webb and Duval	Solar	200	12/2015
13INR0045	Castro	Wind	288	12/2015
15INR0059	Pecos / Crane	Solar	102	12/2015
15INR0037	Starr	Wind	200	12/2015
14INR0028	Live Oak	Wind	300	4/2016
16INR0036	Nolan	Gas	280	4/2016
16INR0009	Calhoun	Gas	510	4/2016
13INR0056	Scurry	Wind	366	5/2016
16INR0008	Grimes	Gas	687	5/2016
16INR0023	Dawson	Solar	100	5/2016
15INR0057	Wharton	Gas	142	6/2016
16INR0004	Cameron	Gas	730	6/2016
16INR0007	Hidalgo	Gas	95	6/2016
16INR0006	Angelina	Gas	785	6/2016
16INR0005	Cameron	Gas	871	6/2016
14INR0027	Guadalupe	Gas	471	6/2016
16INR0038	McLennan	Gas	471	6/2016
17INR0004	Hale	Gas	202	6/2016
16INR0041	Pecos	Solar	100.00	6/2016
16INR0040	Reeves	Solar	50.00	6/2016