Control Number: 37897

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PROJECT NO. 37897

PUC PROCEEDING RELATING TO RESOURCE AND RESERVE ADEQUACY AND SHORTAGE PRICING	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

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PROJECT NO. 40268

PUC RULEMAKING TO AMEND PUC SUBST. R. §25.505, RELATING TO RESOURCE ADEQUACY IN THE ELECTRIC RELIABILITY COUNCIL OF TEXAS (ERCOT) POWER REGION	§ § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

SUBMISSION OF THE BRATTLE GROUP'S "ERCOT INVESTMENT INCENTIVES AND RESOURCE ADEQUACY" REPORT

COMES NOW, Electric Reliability Council of Texas, Inc. (ERCOT), and files a copy of the *ERCOT Investment Incentives and Resource Adequacy Report* prepared by The Brattle Group (Attachment A).

In March 2012, ERCOT selected the Brattle Group to conduct a study to inform ERCOT's and the Commission's actions on resource adequacy issues in the ERCOT market. ERCOT asked Brattle Group to focus on three major topics:

1. Investors and their Investment Criteria: Identify, describe and rank the relevant factors that influence investment decisions by the development and financial community related to new capacity additions, capacity retirements and repowering projects in ERCOT.

2. Market Outlook for Investment and Resource Adequacy: Evaluate the current drivers from both a wholesale and retail respective that influence Resource investment decisions in the ERCOT market.

3. Evaluation of Policy Options: Provide suggestions for ways to enhance favorable investment outcomes for long-term Resource adequacy in ERCOT.

The Brattle Group report is posted on ERCOT's website on the Reports and Presentations webpage, under Operations and System Planning, at http://www.ercot.com/news/presentations.

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Respectfully submitted,

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Attachment A

The Brattle Group

ERCOT Investment Incentives and Resource Adequacy

June 1, 2012

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Prepared for

ERCOT

Electric Reliability Council of Texas

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Acknowledgements and Disclaimer

The authors would like to thank ERCOT staff for working with us closely to provide data, insights, and input for our analysis, including Joel Mickey, John Dumas, Warren Lasher, Paul Wattles, Kenneth Ragsdale, Sai Moorty, Bob Spangler, Calvin Opheim, Haso Peljto, Resmi Surendran, Bill Blevins, and Kittipong Methaprayoon. We would also like to thank the PUCT Commissioners, the Independent Market Monitor, and market participants for their responsiveness to our many questions and for their valuable insights. We would also like to thank *The Brattle Group*'s Frank Graves, Bin Zhou, and Metin Celebi for their helpful comments, and acknowledge Khanh Nguyen and Stephen Fang for their research and analytical contributions. Opinions expressed in this report, as well as any errors or omissions, are the authors' alone. The examples, facts, results, and requirements summarized in this report represent our interpretations. Nothing herein is intended to provide a legal opinion.

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EXECUTIVE SUMMARY

The Electric Reliability Council of Texas's (ERCOT's) energy-only market has worked well for many years to support efficient operations and to attract sufficient generation investment to maintain resource adequacy. Now, despite reserve margins declining with load growth and retirements, investment appears to have stalled. Many projects have been postponed or cancelled and no major new generation projects are starting construction. As a result, ERCOT projects that reserve margins will fall to 9.8% by 2014, substantially below its current reliability target of 13.75%. Reserve margins will decline even further thereafter unless new resources are added. Generation investors state that a lack of long-term contracting with buyers, low market heat rates, and low gas prices in ERCOT's energy-only market make for a uniquely challenging investment environment.

In response to these concerns, the Public Utility Commission of Texas (PUCT) has implemented a number of actions to ensure stronger price signals to add generation when market conditions become tight. The PUCT has enabled prices to reach the current $3,000/MWh offer cap under a broader set of scarcity conditions and is considering raising offer caps to as high as $9,000/MWh, among other measures. Following the PUCT's initiatives, forward prices have increased and more than 2,000 MW of relatively low-cost capacity additions have been announced, including uprates and reactivations of mothballed units. The critical question remains whether the recent and proposed reforms will be adequate and what other measures might be necessary to attract sufficient investment.

To inform the Commission's and ERCOT's actions, ERCOT commissioned *The Brattle Group* to address three questions:

1. **Investors and their Investment Criteria**. Identify, describe, and rank the relevant factors that influence investment decisions made by the development and financial community related to new capacity additions, capacity retirements, and repowering projects in ERCOT.
2. **Market Outlook for Investment and Resource Adequacy**. Evaluate the current drivers from both a wholesale and retail perspective that influence resource investment decisions in the ERCOT market.
3. **Evaluation of Policy Options**. Provide suggestions for ways to enhance favorable investment outcomes for long-term resource adequacy in ERCOT.

Our approach to addressing these questions and our findings are summarized as follows:

Investors and their Investment Criteria

To understand the factors affecting suppliers' willingness to invest, we interviewed a broad spectrum of generation developers and lenders and analyzed relevant financial indicators, as described in Section II. We found that investors are generally cautious after a history of investment losses. However, many could and would invest in ERCOT if revenue levels were expected to be adequate to earn a return on the investment that is commensurate with perceived risks.

The lack of long-term power purchase agreements (PPAs) in Texas's retail choice environment generally leaves much of the investment risk with investors, similar to other retail restructured markets. A number of generators also stated that the ERCOT's energy-only market design is more volatile, harder to model, and riskier overall than energy-and-capacity markets (though they acknowledged that generator revenues in ERCOT are more stable than spot prices, since most power is sold at least several months forward at prices that average out weather and other unexpected effects). Some also worried that energy-only markets can lead to extreme outcomes that might induce future regulators to intervene in the market. However, they expressed that the current Commission has demonstrated a strong commitment to markets and regulatory certainty. Overall, we believe that ERCOT's energy-only market may be only marginally riskier than energy-and-capacity markets, a view consistent with the statements of a subset of merchant investors. Both types of markets place much more risk on investors than do regulated environments without retail choice.

Considering these risk factors, some generation developers state that they will require projected returns exceeding the 9.6% after-tax weighted-average cost of capital (ATWACC) assumed by ERCOT.[1] Large, diversified investors with hedging options and the ability to finance plants on their balance sheet might be able to invest at lower returns. We estimate an ATWACC as low as 7.6% for efficiently hedged and diversified merchant generation investments.

Risk tolerances and revenue needs vary considerably by type of investor. To underwrite project-finance loans with no upside opportunities, lenders must be confident that the borrowing entity will have sufficiently stable net revenues to cover the total amount borrowed with ample margin for error. Larger borrowers can partially diversify project-specific risks and can borrow more cost-efficiently against a larger corporate balance sheet. Such investors may be able and willing to weather some bad years for a few good years as long as the discounted expected value is high enough. These are likely to be the most robust investors in a market with high price volatility. Smaller, undiversified borrowers relying on high leverage through project-specific, non-recourse debt financing with little equity, however, might ultimately be uncompetitive and pushed out of the market unless they can secure long-term PPAs with public power or other entities.

Market Outlook for Investment and Resource Adequacy

In Sections III and IV, we examine whether new and proposed rules are likely to produce prices that are high enough often enough to attract sufficient investment. Our approach includes: (1) assessing ERCOT's market and operational processes to understand how new and proposed rules will affect scarcity prices; (2) analyzing forward curves; (3) conducting economic simulation modeling to project future prices, including the frequency of scarcity prices; and (4) comparing projected energy margins to capital costs and investors' cost of capital. We conduct this analysis for a broad range of potential planning reserve margins, showing how suppliers' energy margins will increase as reserve margins fall and the market becomes tighter, or decrease as reserve margins rise. The key question is whether market prices will be high enough to support entry at an acceptably high reserve margin and associated reliability level. We address this question in the context of several major uncertainties that investors face.

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1 See PUCT (2012b), Item Number 87, p. 1. We note that ERCOT's ATWACC estimate was developed a year ago and that the cost of capital has decreased since then, as we discuss further in Section II.D.3.

We find that generators' energy margins have been low because of low gas prices and low market heat rates, except during rare price spikes. Market heat rates have been low because an efficient generating fleet and new wind generation form a very low and flat supply curve. However, current and proposed market rule changes will increase the frequency and level of scarcity prices. Forward curves have risen correspondingly, but they are still not high enough to support investment in new generation, notwithstanding recent success in attracting relatively low-cost plant reactivations and uprates.

Our simulation analysis finds that the Commission's proposals to further raise the offer cap would stimulate greater investment, but investment would still fall short of what is needed to meet ERCOT's current reliability target of "one load-shed event in 10 years," at least under current market conditions and demand response penetration. Scarcity prices would be too infrequent to support the target because if reserve margins are high enough to make load shedding very rare, scarcity pricing events would also be quite rare. This is compounded by the long "tails" of the load distribution, including rare, extreme extended heat waves such as the one in 2011. Having high enough reserves to limit load shedding even under even such challenging conditions would eliminate scarcity in most years.

We estimate that the current market design and the \$3,000 offer cap would achieve a reserve margin of only 6% on a long-term average basis under current market conditions. If the offer cap is increased to \$9,000, a reserve margin of approximately 10% could be achieved without reducing the frequency of scarcity prices below the level needed to support investment. This is approximately five percentage points less than the 15.25% reserve margin we estimate would be needed to achieve ERCOT's reliability target. Our 15.25% estimate is higher than ERCOT's current 13.75% reliability target because we assumed a 1-in-15 chance of extreme 2011 weather occurring, whereas ERCOT's target reserve margin study could not account for 2011 weather because it had not been experienced at the time. On average, the 10% reserve margin achieved with a \$9,000 offer cap would result in approximately one load-shed event *per year* with an expected duration of two-and-a-half hours, and thirteen such events in a year with a heat wave as severe as the one in 2011. In years with less extreme weather than 2011, however, load shedding would be expected to occur less than once in ten years.

Reserve margins would differ on a year-to-year basis due to the lead times required to respond to supply shocks, such as simultaneous environmentally-driven generation retirements. Moreover, even our long-term average estimates are highly uncertain due to underlying uncertainties about market conditions, weather, regulatory risk, and investors' perceptions of these risks. The range of uncertainties we analyzed could result in average reserve margins that fall between one and seven percentage points below the 1-in-10 target reserve margin on average. For example, with only a 1-in-100 chance of extreme 2011 weather, the reserve margin achieved with a \$9,000 offer cap would fall only three percentage points below the reserve margin needed to achieve the reliability target and load shedding would be expected only once every three years on average.

An important qualification to these simulation results is that they assume only the current level of demand response (DR). If several thousand megawatts (MW) of price-responsive demand were added, those resources could prevent involuntary load shedding and set prices at customers' willingness to pay, thereby increasing reliability and softening (but not eliminating) price spikes. With this much demand response, ERCOT's energy-only market design could support the current bulk power reliability target under a \$9,000 price cap. However, achieving such a high demand response penetration would take years, not months, as we explain further in Section V.B.

Evaluation of Policy Options

Our finding that the energy-only market will not dependably support ERCOT's current reliability target until sufficient demand response penetration is achieved suggests that either the market design needs to be adjusted or the reliability objectives have to be revised. We present a broad analysis of policy options, preceded by a discussion of reliability objectives.

The "1-in-10" reliability standard has been used in the industry for decades, but has rarely been evaluated from an economic perspective, as we explain in Section VI. ERCOT's "1 load-shed event in 10 years" interpretation of the 1-in-10 standard is more stringent than the "1 outage day in 10 years" interpretation used in the Southwest Power Pool (SPP). Other regions use entirely different approaches based on the economic value of reliability. We also note that distribution outages cause customers to lose power 100 times more often than do generation resource shortages, suggesting that the 1-in-10 target could be too high. Even if reserve margins fall to a 10% equilibrium reserve margin, load shedding would occur approximately two-and-a-half hours per year, averaging only three minutes per customer; this compares to an average of a few *hundred* minutes per customer per year from distribution outages. Moreover, critical loads that are not behind a single distribution feeder may enjoy even less exposure to power outages, assuming load shedding protocols are designed properly. We therefore recommend that the PUCT and ERCOT evaluate their resource adequacy objectives in the context of delivered reliability, load shedding protocols, and informed by an analysis of marginal costs and benefits. We recommend determining the *desirable* reserve margin target and, separately, a *minimum acceptable* reserve margin needed to avoid extremely adverse consequences under worst-plausible weather and outage conditions.

This report does not recommend a specific course of action because the best path forward depends on policy objectives, which only stakeholders, regulators, and other policymakers can assess. To inform the choice among policy options, we describe five available options and present the advantages and disadvantages of each in Section VI:

1. Energy-only with market-based reserve margin;
2. Energy-only with adders to support a target reserve margin;
3. Energy-only with backstop procurement at minimum acceptable reliability;
4. Mandatory resource adequacy requirement for load serving entities (LSEs); and
5. Resource adequacy requirement with a centralized forward capacity market.

The evaluation criteria assessed for each option include both the reliability implications of letting the market determine the level of reliability and the market implications of having regulators determine the level of reliability. We also assess economic efficiency, compatibility with investment, regulatory stability, and the extent and complexity of necessary market design changes. Table 1 summarizes our evaluation of these policy options.

Table 1
Comparison of Policy Options

Option	How Reliability Level is Determined	Who Makes Investment Decisions	Risk of Low Reliability	Investor Risks	Economic Efficiency	Market Design Changes	Comments
1. Energy- Only with Market-Based Reserve Margin	Market	Market	High in short-run; Lower in long-run w/ more DR	High	May be highest in long-run	Easy	- Depends on substantial DR participating to set prices at willingness-to-pay; ERCOT does not yet have much DR
2. Energy-Only With Adders to Support a Target Reserve Margin	Regulated	Market	Medium	High	Lower	Easy	- Not a reliable way to meet target - Adders are administratively determined
3. Energy- Only with Backstop Procurement at Minimum Acceptable Reliability	Regulated (when backstop imposed)	Regulator (when backstop imposed)	Low	High	Lower	Easy	- Attractive as an infrequent last resort, but long-term reliance is inefficient, non-market based, and slippery-slope
4. Mandatory Resource Adequacy Requirement for LSEs	Regulated	Market	Low (with sufficient deficiency penalty)	Med-High	Medium (due to regulatory parameters)	Medium	- Well-defined system and local requirements and resource qualification support bilateral trading of fungible credits, and competition - Cannot be a forward requirement - Flexibility: DR is like opting out; customers not behind a single distribution feeder could pay for higher reserves and reliability
5. Resource Adequacy Requirement with Centralized Forward Capacity Market	Regulated	Market	Low	Med-High (slightly less than #4)	Medium (due to regulatory parameters)	Major	- Working well in PJM - Forward construct can efficiently respond to retirements and meet needs with sufficient lead time - Transparency valuable to market participants and market monitor - Many administrative determinations

"Energy-only with market-based reserve margins" is theoretically the most efficient option because it allows customers to choose the level of supply based on prices and their value of avoiding curtailment, without having to pay for costly reserves they may not want. It also provides strong incentives for resources to be available when they are needed most. We believe that energy-only, perhaps with rare backstop procurement of short-term resources as needed to support a very minimal reserve margin, might be the most aligned with the Commission's demonstrated philosophy to let the market work. However, this would require managing public expectations about reliability implications and the potential for periodic high spot prices. Energy-only will deliver less reliability than the current target until more price-responsive demand is developed.

If the Commission and ERCOT want to maintain a higher level of reliability, the four other options we present differ in their effectiveness, efficiency, and complexity. Price adders or backstop procurement may seem appealing because they require the least modification to the existing design in the short term. However, price adders will not dependably achieve any particular reserve margin. The backstop procurement option introduces market inefficiencies and could threaten the viability of market-based investments unless it is used very sparingly to maintain only a minimum-acceptable level of reserves that is well below the "desirable" target. If policymakers decide that a higher target reserve margin must be met every year, imposing a resource adequacy requirement on LSEs is the most market-based, efficient option. Implementing such a reserve margin requirement through a forward capacity market could further increase forward competition, price transparency, and efficient investments, but these markets are quite complex and increase the importance of administrative parameters such as the load forecast.

Recommendations

Our primary recommendations are that the PUCT and ERCOT: (1) evaluate and define resource adequacy objectives for the bulk power system; and then (2) choose a policy path to meet those objectives, informed by the advantages and disadvantages of each option we have identified. We recommend defining the long-term resource adequacy framework expeditiously. Committing to a definitive course of action will resolve regulatory uncertainty and support investment. However, we urge caution about implementing major changes too quickly or without sufficient analytical support or stakeholder consideration. Complex market design changes will likely take more than a year to implement, and market participants need to be allowed ample time to prepare for the implementation of any changes.

The year 2014 poses a particular challenge because it may be approaching too quickly to add some types of new capacity, even if market conditions would support such investments. However, we anticipate that more low-cost resources will enter the market before 2014 than are currently reported in ERCOT's Report on the Capacity, Demand and Reserves (CDR) Report, yielding reserve margins that are at least somewhat above the 9.8% currently projected.[2] If the 2014 planning reserve margin outlook fails to improve sufficiently to meet a minimum acceptable level of reliability before new generation can be added, the PUCT and ERCOT could consider soliciting additional Emergency Response Service resources as a short-term solution. However, we stress that such a backstop mechanism should be implemented with great restraint to avoid introducing a perpetual dependence on backstops or displacing market-based resources that would otherwise be developed.

In addition, and regardless of the overarching policy path selected by the Commission, we recommend enhancing several design elements to make the ERCOT market more reliable and efficient, as discussed in Section V: (1) increase the offer cap from the current $3,000 to $9,000, or a similarly high level consistent with the average value of lost load (VOLL) in ERCOT, but impose this price cap only in extreme scarcity events when load must be shed; (2) for pricing during shortage conditions when load shedding is not yet necessary, institute an administrative scarcity pricing function that starts at a much lower level, such as $500/MWh when first deploying responsive reserves, and then increase gradually, reaching $9,000 or VOLL only when

[2] ERCOT (2012n).

actually shedding load; (3) increase the Peaker Net Margin threshold to approximately $300/kW-year or a similar multiple of the cost of new entry (CONE), and increase the low system offer cap to a lever greater than the strike price of most price-responsive demand in Texas; (4) enable demand response to play a larger role in efficient price formation during shortage conditions by introducing a more gradually-increasing scarcity pricing function (as stated above) so loads can respond to a more stable continuum of high prices, by enabling load reductions to participate directly in the real-time market, and by preventing price reversal caused by reliability deployments; (5) adjust scarcity pricing mechanisms to ensure they provide *locational* scarcity pricing signals when appropriate; (6) avoid mechanisms that trigger scarcity prices during non-scarcity conditions; (7) address pricing inefficiencies related to unit commitment but without over-correcting; (8) clarify offer mitigation rules; (9) revisit provisions to ensure that retail electric providers (REPs) can cover their positions as reserve margins tighten and price caps increase; and (10) continue to demonstrate regulatory commitment and stability. We recommend considering these ten suggestions no matter which resource adequacy framework the Commission and ERCOT select.

I. BACKGROUND

The Electric Reliability Council of Texas (ERCOT) engaged *The Brattle Group* to analyze the ability of its energy-only market to attract and retain sufficient resources to reliably power Texas. This study comes two years before reserve margins are projected to fall significantly below target levels. Concerns that wholesale prices have been too low to attract the needed investments led to a number of ongoing wholesale market reforms by ERCOT, the Public Utility Commission of Texas (PUCT), and stakeholders. This study is intended to support and inform that ongoing effort.

A. STUDY MOTIVATION AND APPROACH

1. Motivation

Since deregulation, ERCOT's energy-only market has successfully attracted substantial investment without the need for regulatory intervention to maintain resource adequacy. In the early 2000s, investors added more than 20,000 MW of efficient gas-fired combined-cycle (CC) plants. Toward the middle of the decade, investors began developing approximately 4,000 MW of coal plants that are now online or about to come online. Additionally, more than 9,000 MW of wind capacity was developed over the past half-decade. Now, however, no other major new generation is under construction.[3] The handful of permitted projects that were planned to begin construction has been postponed.[4] Developers state that prices are not high enough to support new generation, due to the combination of low gas prices, an efficient fleet, and the recent influx of wind generation.

With few new resources and expected load growth, ERCOT is projecting a planning reserve margin of only 9.8% by 2014, compared to a reliability target of 13.75%.[5] Thereafter, further load growth and potential environmentally-driven retirements would push reserves even lower unless new resources come online.

The prospect of declining reserve margins concerns ERCOT and the PUCT, particularly after experiencing supply shortages in 2011. The year 2011 presented extreme weather conditions, including very cold weather in February that disabled generation and froze some gas delivery equipment, leading to 8 hours of load shedding.[6] Extraordinarily hot weather in August pushed the system into shortages that required emergency actions, while drought conditions threatened to derate or disable capacity.[7] These events occurred when the planning reserve margin was

3 See ERCOT (2011f), p. 16, Total Future Non-Wind Resources. We exclude Sandy Creek, which completed construction but experienced an accident during testing in 2011. See further discussion in Section III.D.

4 See ERCOT (2011b), p. 6. Pondera King Power Project, Las Brisas Energy Center, and Coleto Creek Unit 2 have delayed their commercial operations dates.

5 See ERCOT (2012n), p. 7.

6 See Potomac Economics (2011a), p. 5.

7 See ERCOT (2012c) and ERCOT (2012h).

14%, which suggests vulnerability if the reserve margin were to fall to the much lower projected levels.[8]

In this context, stakeholders and policy makers are concerned about the current lack of construction and the possibility that price signals may not be sufficient to attract needed investments, even as the reserve margin outlook becomes tighter. The PUCT and ERCOT have implemented a number of measures to address these concerns, and they are considering several additional proposed enhancements. They sponsored this study to provide an analytical and objective foundation to help ensure that ongoing reforms will be adequate and efficient.

2. Approach

To inform ERCOT's and the PUCT's efforts, we analyze three aspects of attracting investment and maintaining resource adequacy in ERCOT, consistent with ERCOT's request for proposals (RFP) for this study:

1. **Investors and their Investment Criteria**. The RFP required that we "*identify, describe, and rank the relevant factors that influence investment decisions by the development and financial community related to new capacity additions, capacity retirements, and repowering projects in ERCOT.*"[9] We review financial indicators and report our findings from interviews with numerous generation developers and lenders. Section II characterizes the spectrum of investors and their investment criteria, and provides an estimate of the returns they will require to build new generation in ERCOT.
2. **Market Outlook for Investment and Resource Adequacy**. The RFP required that we "*evaluate the current drivers from both a wholesale and retail perspective that influence resource investment decisions in the ERCOT market.*" We examine whether new and proposed rules are likely to produce prices that are high enough often enough to attract sufficient investment. Our approach includes: (1) assessing market and operational processes to understand how the new and proposed rules will affect scarcity prices; (2) analyzing forward curves; (3) conducting economic simulation modeling to project future prices, including the frequency of scarcity prices; and (4) comparing projected energy margins to capital costs and investors' cost of capital. We conduct this analysis for a broad range of potential planning reserve margins, showing how suppliers' energy margins will increase as reserve margins fall and the market becomes tighter, or decrease as reserve margins rise. The key question is whether returns on investment will be high enough to support entry at an acceptable reserve margin and reliability level. We address this question in the context of several major uncertainties that investors face. Sections III and IV summarize our analysis of the current and long-term market outlook for investment, respectively.

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8 The CDR report released in June 2011reported the planning reserve margin at 17.5% for the Summer of 2011, however, ERCOT advised the PUCT during its February 2012 Open Meeting that the Summer 2011 CDR reserve margin would have been 14% based on a revised analysis subject to the: (1) application of the hotter "normal" weather profile being used post 2011 to produce the peak load forecast; (2) use of actual peak net generation from private-use networks, rather than survey results; and (3) improved tracking of the expected availability of new generation, see ERCOT (2011b) and (2012d).

9 See ERCOT (2012g), Section 2.3.

3. **Design Recommendations and Policy Options.** The RFP required that we "*provide suggestions for ways to enhance favorable investment outcomes for long-term resource adequacy in ERCOT.*" We evaluate options for improving the efficiency and effectiveness of ERCOT's market design for resource adequacy. In Section V, we present an analysis of market design improvements that we recommend pursuing regardless of overall policy objectives. These refinements to the wholesale market design, many of which are already under review within ERCOT or PUCT initiatives, would increase the efficiency of market signals and enhance resource adequacy. In Section VI, we present a broader analysis of policy options, starting with a question of objectives: should regulators determine the level of reliability instead of the market and, if so, what level of reliability is optimal and what level is minimally acceptable? We then describe five market constructs for meeting those objectives, and evaluate each option's advantages, disadvantages, and implementation issues.

In conducting this analysis of resource adequacy in ERCOT, we examine major concerns identified by regulators, generators, load representatives, and market observers in public comments and private interviews.

B. ERCOT Energy-Only Market Design

Between 1996 and 2002, the Texas legislature and the PUCT restructured the electricity system to create the competitive wholesale and retail markets that exist today.[10] ERCOT has made a number of enhancements to its market since inception, including transitioning to a nodal market in late 2010, and increasing the system-wide offer cap.[11] However, the core principals have not changed. ERCOT is an "energy-only" market in which both operations and investment are driven primarily by energy price signals.

ERCOT's design as an energy-only market distinguishes it from all other regions in the U.S. Other U.S. markets maintain a minimum reserve margin through regulated planning, resource adequacy requirements, or capacity markets. These other markets support investment through either long-term contracts or market-based payments that recognize suppliers' contributions to resource adequacy.[12] In ERCOT and other energy-only markets such as those in Alberta, Australia, and Nord Pool, realized reserve margins are the aggregate outcome of private investment decisions based on wholesale prices. ERCOT does have a target reliability standard of "1 loss of load event in 10 years" that currently translates into a 13.75% reserve margin, but this target is not enforced through any specific requirements or market structures.[13] ERCOT's realized reserve margin may be higher or lower than this target.

Spot prices in energy-only markets are characterized by moderate prices most of the time and occasional severe price spikes during shortage conditions. Price spikes are essential to a well-functioning energy-only market because they signal resource shortages and provide revenues that can attract new investments. Few suppliers would be able to recover their capital costs and

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[10] See ERCOT (2012e); Kiesling and Kleit (2009).

[11] See ERCOT (2012e); Potomac Economics (2011a), p. 15.

[12] For a more comprehensive discussion of various market design approaches to resource adequacy, see Pfeifenberger, Spees, and Schumacher (2009).

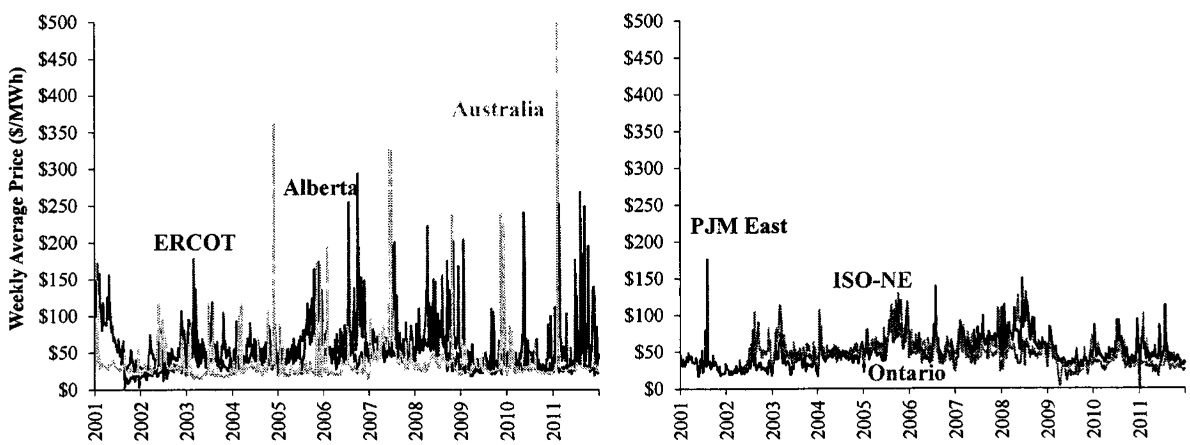
[13] See ERCOT (2010a).

justify a new investment without these price spikes, except under the fortuitous condition in which new generation has substantially lower operating costs than existing price-setting generation (which was the case in ERCOT at times in the past decade, as discussed below).

Some energy-only markets set price caps at a high level tied to customers' value of lost load (VOLL), which is approximately \$3,000 – \$12,000.[14] A high VOLL-based price cap is a theoretically efficient market price during load-shed events because it reflects the price that customers would have been willing to pay to avoid curtailment.[15] ERCOT does not currently base its \$3,000 offer cap on a VOLL estimate but has historically maintained a higher price cap than other non-energy only markets.

Similar price spikes may be avoided in most markets with a resource adequacy standard, because those markets' high reserve margins reduce the likelihood of scarcity events. In addition, those markets generally apply lower price caps when scarcity occurs. However, over the past few years, and particularly since a Federal Energy Regulatory Commission (FERC) mandate in Order 719, even non-energy-only markets have begun to revise their scarcity pricing mechanisms to allow for more efficient high prices during shortage events.[16] The different character of prices in these markets is highlighted in Figure 1. The figure shows that energy-only markets such as ERCOT, Australia, and Alberta periodically produce much higher prices than those markets with resource adequacy standards such as PJM, ISO-NE, and Ontario.

Figure 1
Prices in Energy Only Markets (Left) and Markets with a Reliability Requirement (Right)



Sources and Notes:

Weekly average prices from Ventyx (2012); Weekly average prices for Australia from AEMO (2012).

Historical prices shown for ERCOT are at the North Hub; Australia prices are at New South Wales; PJM prices are at the Eastern Hub; and ISO-NE prices are at the System Hub.

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14 For example, Australia's National Energy Market has a VOLL-based price cap of \$12,500 AUD (\$12,200 USD), see AEMC (2009). Estimates of VOLL range widely by study and especially by customer segment, at \$1,500 – \$3,000/MWh for residential, \$10,000 – \$50,000/MWh for commercial, and \$10,000 – \$80,000/MWh for industrial loads according to a MISO survey conducted in 2005, see MISO (2006). Exchange rate assumed is USD/AUD = \$1.02 from Bloomberg (2012).

15 Note that this high price should also make customers indifferent as to whether they were actually curtailed or stayed online but were required to pay a high price.

16 See FERC (2008), and, for example, PJM (2010).

The cyclical periods of high prices or low reliability that characterize energy-only markets can also make them susceptible to regulatory intervention, depending on the political context. Political pressures may arise in response to price shocks even if *average* customer costs are no higher than all-in costs in markets with resource adequacy standards.[17] If public officials were to succumb to the pressure and intervene in the market (*e.g.*, by changing the rules or sponsoring out-of-market supplies), they would not only depress in-market investment but also undermine investor confidence generally. Resisting political pressures to intervene is essential if an energy-only market is to attract investment. Over the past decade, regulators in ERCOT have demonstrated a sustained commitment to market principles, leading at least two analysts to rank the Texas regulatory environment as more favorable for investment than most other states.[18] However, at least one agency does not rank the PUCT as attractive for investors, noting a less constructive, higher-risk regulatory climate from an investor viewpoint.[19]

In addition to its energy and ancillary services (A/S) markets, ERCOT also maintains two non-market reliability mechanisms that support resource adequacy. One is the Emergency Response Service (ERS), formerly known as Emergency Interruptible Load Service (EILS). ERS is a demand curtailment program in which approximately 350 MW of medium-large commercial and industrial (C&I) customers earn a capacity payment to be callable as a last resort during system emergencies.[20] The other non-market reliability mechanism is ERCOT's option to sign reliability-must-run (RMR) contracts to induce mothballed generation to reactivate or remain online.[21] Many market commentators have rightly observed that these mechanisms deviate from a true "energy-only" market because they use non-market mechanisms to attract sufficient capacity for resource adequacy purposes.

Similar out-of-market reliability mechanisms are common in many energy-only and other markets to safeguard reliability, even though they invariably introduce tensions with market efficiency.[22] Resources supported by out-of-market means such as RMR contracts can depress efficient wholesale prices when they are dispatched, and in the worst extremes can supplant in-market investments. The potential for such outcomes is a concern that ERCOT has addressed by requiring RMR generation to offer its energy at the system-wide offer cap.[23] We examine this topic further in Sections V.A and VI.B.3.

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17 For example, a recent high-price period in Alberta initiated by an unexpected plant retirement caused a wave of unfavorable press articles and consumer complaints, even though average long-term rates remained below the Canadian average according to an industry-sponsored study, see London Economics (2011), p. 25. However, regulators have resisted pressures to intervene, and reaffirmed their commitment to the energy-only design.

18 See UBS (2012), p. 2; TCPA (2011).

19 See SNL (2012).

20 See ERCOT (2012a).

21 See ERCOT (2012k), Section 3.14.1.

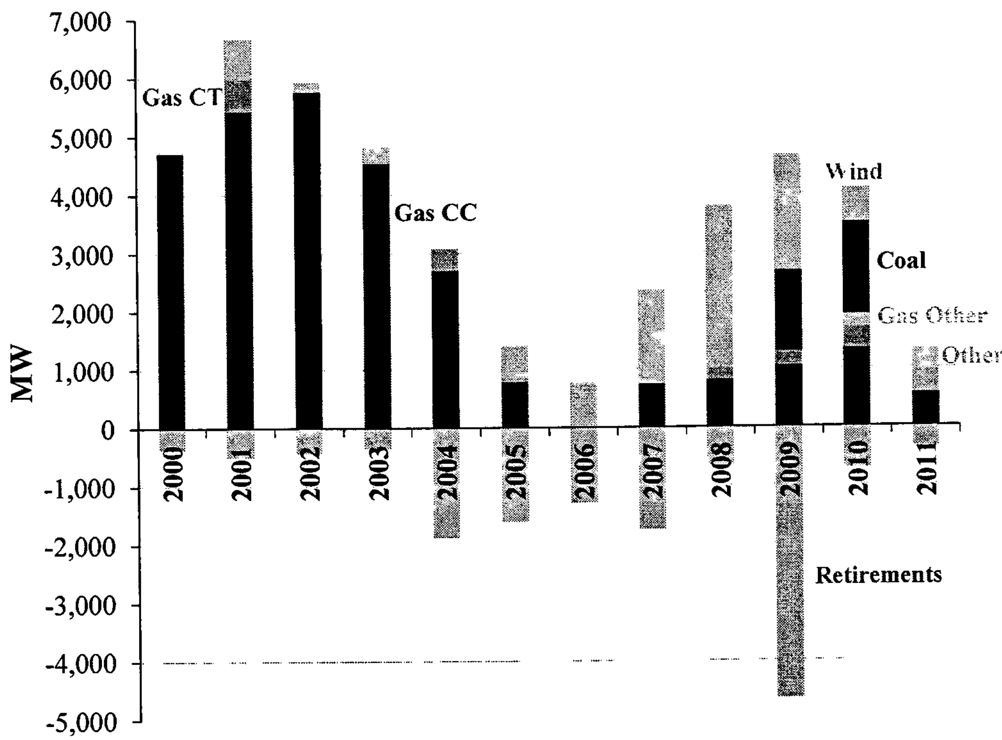
22 Some type of RMR or other reliability backstop mechanism exists in almost all markets, but the frequency with which these mechanisms are implemented and the corresponding level of inefficiency that they introduce varies widely. For a few examples, see Pfeifenberger, Spees, and Schumacher (2009), Section IV.

23 See ERCOT (2012f), NPRR442, approved 5/15/2012.

C. INVESTMENT TRACK RECORD SINCE MARKET IMPLEMENTATION

Since ERCOT deregulated its wholesale electricity market, it has attracted substantial quantities of investment as shown in Figure 2. The first and largest wave of investment started before the beginning of the decade. Between 2000 and 2005, more than 20,000 MW of gas-fired CCs came online. Investors sought to capitalize on new opportunities brought by deregulation and the efficient new generation technology. New combined cycles appeared economic because energy prices were often set by less efficient older units.[24] However, in Texas as in many other regions, the investment boom led to excess capacity and lower prices, causing many of these investors to lose money.

Figure 2
Historical Investment and Retirement Activity in ERCOT



Sources and Notes:
Wind investments reported at nameplate capacity.
Total quantities may not exactly match those reported in ERCOT sources because we rely on a separate data source for unit capacities, see Ventyx (2012).

Toward the middle of the decade as gas prices rose, solid fuels became more economic. Investors began developing nearly 4,000 MW of coal plants. Approximately 3,000 MW are already online, and the 925 MW Sandy Creek Energy Station is scheduled to come online in

[24] See Kiesling and Kleit (2009), p. 100.

2013 due to construction delays.[25,26] In addition, the new 100 MW wood-fired Nacogdoches Station is scheduled to come online later this year.[27]

In the second half of the decade, developers brought more than 9,000 MW of wind generation online, supported by high gas prices as well as state and federal policies. In 1999, the PUCT had instituted Electric Substantive Rule 25.173, *Goal for Renewable Energy*, which established a renewable portfolio standard (RPS), a renewable energy credit (REC) trading program, and renewable energy purchase requirements for competitive retailers in Texas.[28] In 2005, Texas updated the RPS, increasing the renewable-energy mandate to 5,880 MW by 2015 and a target of 10,000 MW by 2025.[29] Other states' renewable portfolio standards have also contributed to wind investments in ERCOT because developers can benefit from the superior wind resources in Texas while selling RECs into other states that allow external resources to qualify.[30]

The federal production tax credit (PTC) is another major driver of wind development in ERCOT and elsewhere. The PTC is a $22/MWh tax credit for electricity generated by qualified renewable resources.[31] The PTC was originally enacted in 1992 with a planned expiration date in 1999. It has since been extended several times, most recently in February 2009, when it was extended to include wind resources that are completed and in-service by the end of 2012.[32] Political efforts are underway to extend the credit again, but it is unclear whether these will succeed.[33]

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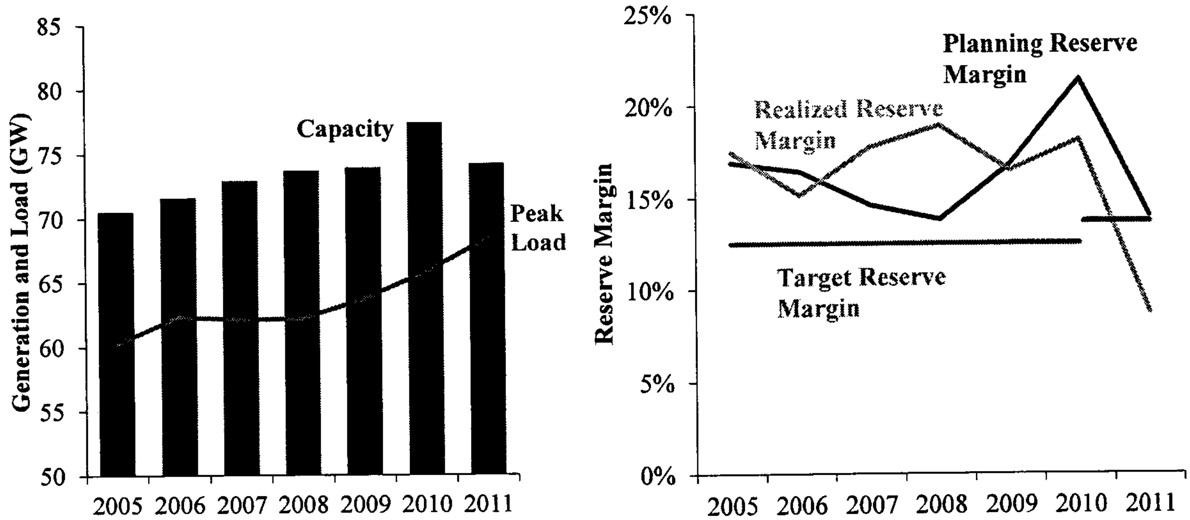
[25] The 3,000 MW already online includes the 785 MW JK Spruce plant, the 1,616 MW Oak Grove Station, and the 570 MW Sandow 5 unit, see Ventyx (2012).
[26] See ERCOT (2012n), p. 19.
[27] See ERCOT (2011f), p. 16.
[28] See PUCT (1999).
[29] See Texas State Legislature (2005).
[30] Many wind assets developed in Texas may be able to sell renewable energy credits to meet other states' RPS standards. See RPS program descriptions at DSIRE (2012a).
[31] See DSIRE (2012b).
[32] See Internal Revenue Code (2012), Section D.1.
[33] See American Renewable Energy Production Tax Credit Extension Act (2011).

The energy-only market was able to attract sufficient market-based investments to maintain resource adequacy over the past decade, as Figure 3 shows. The left chart shows that net capacity additions kept pace with substantial load growth even in the face of moderate retirements; the right chart shows that planning and realized reserve margins were always above the reliability target except under the extreme load conditions in 2011.

Figure 3
ERCOT Capacity and Load Growth (Left) and Reserve Margins (Right)



Sources and Notes:

Capacity includes generation and load resources from ERCOT's 2005 – 2011 CDR Reports. Year 2011 data account for revisions from the original CDR, see ERCOT (2012d).

Peak load is from ERCOT's 2012 Long-Term Demand and Energy Forecast, see ERCOT (2012b), p. 2.

Planning reserve margins are based on peak load expected with normal weather, from ERCOT's CDR reports.

"Realized reserve margins" are calculated based on actual peak load rather than the weather-normalized forecast. In a year such as 2011, with severe weather and an actual peak load much higher than forecast, the realized reserve margin was lower than the planning reserve margin.

The target reserve margin increased from 12.5% to 13.75% for years starting 2011, see ERCOT (2011g), p. 27.

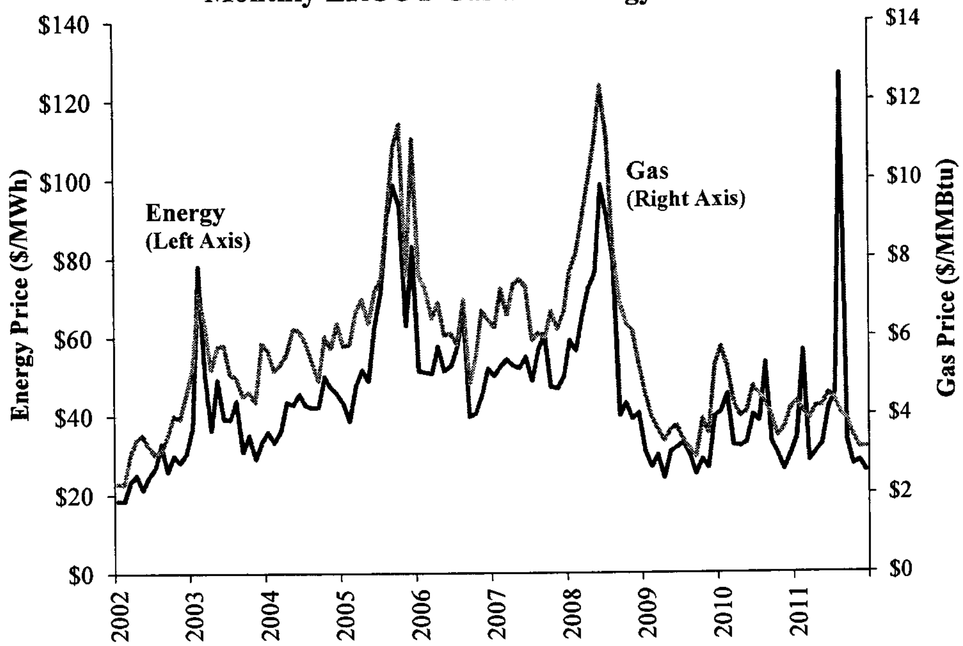
D. RECENT MARKET CONDITIONS

Although ERCOT has maintained sufficient reserve margins since deregulation, recent market conditions raise resource adequacy concerns. Existing generators will face retirement pressures from new environmental rules at a time when operating margins are already depressed by low electric prices. ERCOT's low electric prices are driven primarily by low natural gas prices and by the composition of ERCOT's generation fleet including a large number of efficient combined cycles and growing wind supply. We describe these challenges and the impact they have had on generator energy margins.

1. Low Gas Prices

The price of natural gas directly affects the production cost and offer prices of gas generators in the wholesale electricity market. Because natural gas-fired generators are the price-setting suppliers in most hours, the price of natural gas strongly affects the market-clearing price for electricity.[34] Figure 4 shows recent North Hub electricity prices and Houston Ship Channel gas prices, demonstrating the close relationship between natural gas and electricity prices.

Figure 4
Monthly ERCOT Gas and Energy Prices



Sources and Notes:
Electricity prices for North Hub from Ventyx (2012).
Gas prices for Houston Ship Channel from Platts (2012).

More recently, rapid increases in shale gas production and the economic downturn have depressed natural gas and electricity prices.[35] Over 2009 – 2011, average Houston Ship Channel prices dropped to $4.01/MMBtu, from an average of $6.27/MMBtu in 2002 through 2008. Coincident with falling natural gas prices, electric prices have also decreased to $36/MWh in 2009 through 2011, from an average of $49/MWh over 2002 – 2008. Given the changed fundamentals of the natural gas industry due to shale gas development, low gas prices are expected to continue for the foreseeable future and are reflected in low futures prices, as discussed in Section III.

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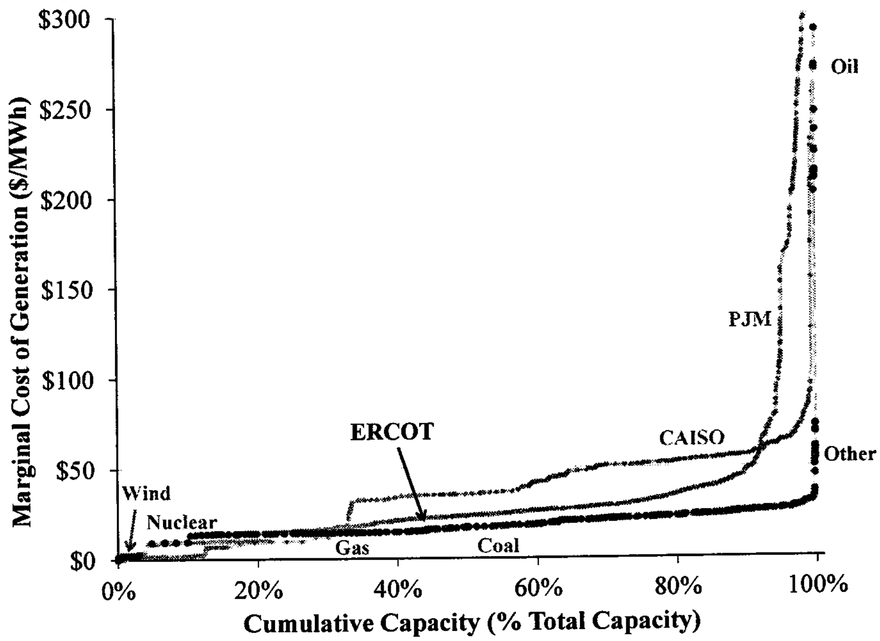
[34] For example, in 2007 – 2010 in the Houston Zone, gas generation was marginal in more than 70% of hours in almost all months, and was marginal in more than 90% of hours in some months. See Potomac Economics (2011c), p. 10.

[35] See, for example, Saur and Wallace (2011).

2. Fleet Makeup and Supply Stack

With more than 20,000 MW of new, efficient combined-cycle generation, as well as low-cost coal, wind, and nuclear generation, much of ERCOT's fleet has uniformly low marginal costs compared to other regions' fleets. Figure 5 shows the marginal cost of ERCOT's supply stack compared to PJM and CAISO. In ERCOT, the low marginal costs of much of the supply stack cause low prices in most hours, with the sharp increase at the end of the stack leading to severe price spikes only when generation supplies are almost completely exhausted.

Figure 5
ERCOT Supply Stack vs. Other Markets



Sources and Notes:

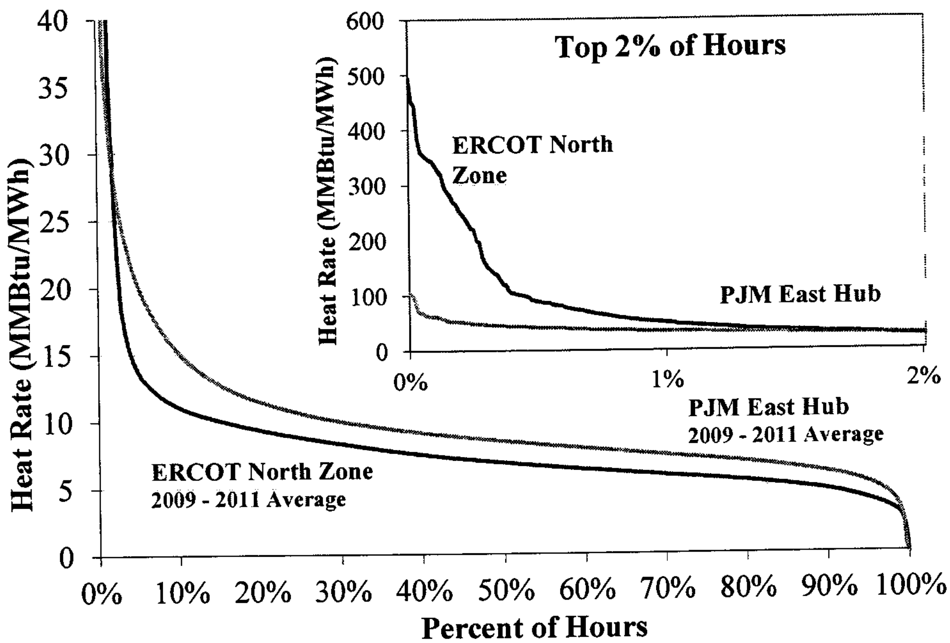
Individual plants' marginal costs obtained from Ventyx (2012).

To calculate plant marginal costs, Ventyx estimates VOM, fuel, and emissions prices. To calculate fuel costs, Ventyx estimates coal prices based on the last 3 months' delivered cost, natural gas prices based on 5/10/2012 spot prices via Intercontinental Exchange, and petroleum prices based on the 4/2012 ENERFAX price.

Imports are not accounted for. Wind is derated to 20% of installed capacity.

The impact of ERCOT's distinctly "hockey-stick" shaped supply stack on market prices is highlighted in Figure 6. The figure compares market heat rate duration curves in ERCOT's North Zone to those in PJM East.[36] Heat rates in ERCOT are lower across almost the entire duration curve due to its efficient fleet and flat supply stack, whereas heat rates in the top one percent of hours are substantially higher due to the sharp bend in ERCOT's supply stack, its higher price cap, and its scarcity pricing mechanisms. As a result, ERCOT's generators face low energy prices and margins under normal conditions and earn a disproportionate share of their total revenue in super-peak hours. The extremely high prices during super-peak hours (up to $3,000 in some hours) is illustrated by the spike in the monthly average price to over $120/MWh during the heat wave of August 2011, as shown in Figure 4 above.

Figure 6
ERCOT vs. PJM Market Heat Rate Duration Curves from 2009 - 2011



Sources and Notes:

Shows market heat rates, calculated as hourly energy price divided by daily gas price; each year's 8,760 hours are sorted from highest to lowest; the three years' duration curves are averaged into a single curve.

Energy Prices at PJM East Hub and ERCOT North Zone from Ventyx (2012).

Gas prices are at Transco Zone 6 Non-NY for PJM and Houston Ship Channel for ERCOT, from Platts (2012).

3. The Impacts of Wind Penetration

Because wind is an intermittent resource, it provides little resource adequacy value. ERCOT currently discounts the installed capacity of wind by 91.3% to establish its capacity value in its reserve margin accounting.[37] While not contributing substantially to resource adequacy, wind generation does have a substantial impact on the energy market because it enters the supply stack

[36] The figure shows hourly market heat rates calculated as the hourly electric price divided by the daily gas price; this measure can be thought of as the electric price after normalizing for changes in gas prices.

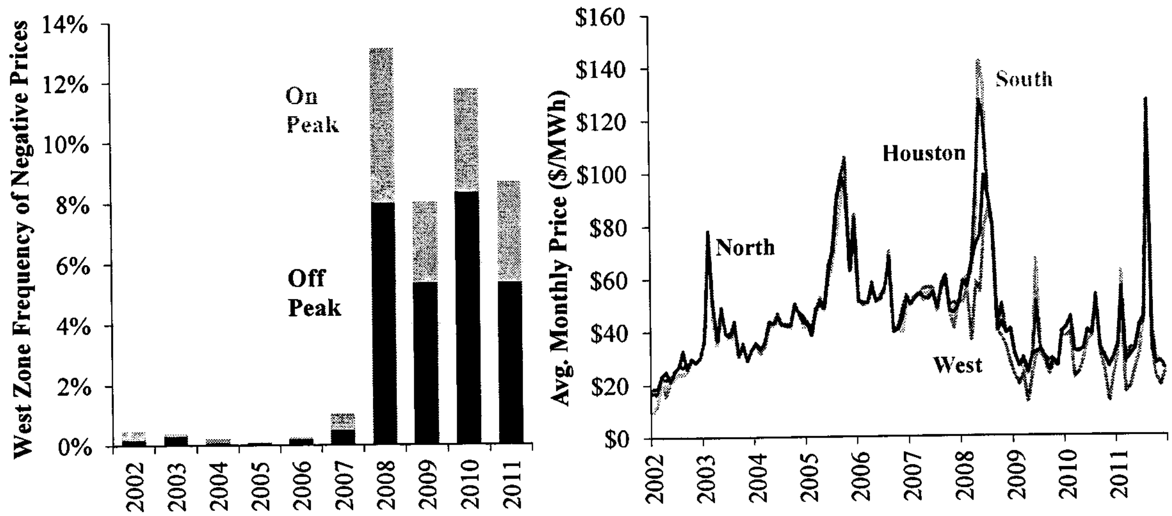
[37] See ERCOT (2011f), p. 3.

at zero or negative-priced offers. Wind generators may offer their output at negative values if not generating would forego PTC value or REC payments.[38]

Wind generation puts downward pressure on energy prices in all parts of ERCOT whenever the wind blows. However, the effect is greatest in the West Zone, where more than 70% of ERCOT's wind capacity is located.[39] In the West Zone, wind generation has caused negative prices in many off-peak periods when wind generation was high, zonal load was low, and transmission capacity was insufficient to export the excess. The left panel of Figure 7 shows the growing incidence of negative prices in the West Zone as the amount of wind generation increased there.[40] Negative prices have largely been confined to the ERCOT's West Zone, while the other 3 zones have not had more than 0.4% of hours with negative prices.[41] Wind growth has therefore depressed West Zone prices relative to the other zones, as shown in the right panel of Figure 7.[42]

Figure 7

Frequency of Negative Prices in the West Zone (Left) and Average Prices by Zone (Right)



Source:

Hourly zonal real-time prices from Ventyx (2012).

Owners and investors in non-wind generation have expressed concern about the energy market impacts of the PUCT's Competitive Renewable Energy Zones (CREZ) Transmission Program.[43] The CREZ project is primarily designed to move electricity generated by wind and other renewable resources from remote parts of Texas (*i.e.*, West Texas and the Texas Panhandle) to the more heavily-populated areas of Texas (*e.g.*, Austin, Dallas-Fort Worth, and San Antonio). This transmission expansion will also increase Texas's ability to build more wind generation, but

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38 See Potomac Economics (2009), p. xxxii.

39 See ERCOT (2011f), pp. 14-16.

40 For a further discussion of the impact of wind generation on prices in the West Zone, see Potomac Economics (2009), pp. iv, xxxi–xxxii, and 87–90.

41 See Ventyx (2012).

42 See Potomac Economics (2009), p. iv.

43 See PUCT (2010).

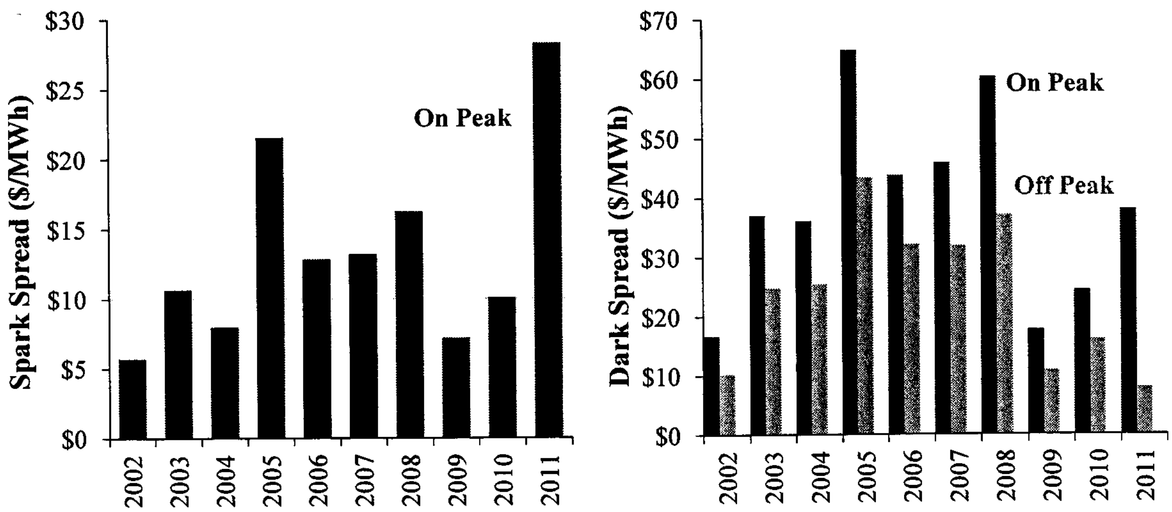
may in the future erode non-wind generator economics more by depressing energy prices in the other three zones.

In addition, large wind penetration levels can introduce a variety of operational challenges, as the system operator must develop wind forecasting capability and operate the power grid with a highly intermittent generation resource. The risk of sudden reductions in wind output increases the need for operating reserves. Unexpectedly high wind output during low load periods can also create operational challenges by creating over-generation conditions when baseload generators are operating at minimum output, and the system operator must order further involuntary generation reductions or shutdowns. These operational challenges are the subject of an ongoing market design effort by ERCOT and stakeholders to address increasing wind penetration in the near term and longer term.

4. Historical Generator Returns

The combination of ERCOT's efficient supply stack, low gas prices, and high wind penetration has greatly reduced the operating margins of existing and potential new generators. Figure 8 shows trends in spark and dark spreads since 2002, indicating the approximate per-MWh profitability of a continuously-operating gas CC or coal unit, respectively.[44] Spark spreads declined in 2009 and 2010, then increased in 2011 because of price spikes caused by extreme weather and scarcity conditions. Similarly, dark spreads have declined sharply since 2008, with the exception of 2011.

Figure 8
ERCOT On-Peak Spark Spreads (Left) and Dark Spreads (Right)



Sources and Notes:
- Hourly energy prices from Ventyx (2012).
- Gas and coal prices from Ventyx (2012). Gas prices at Houston Ship Channel, coal prices as reported by Ventyx on average across ERCOT's coal units.
- Spark spreads calculated based on a 7,000 Btu/kWh heat rate. Dark spreads calculated based on a 9,500 Btu/kWh heat rate.

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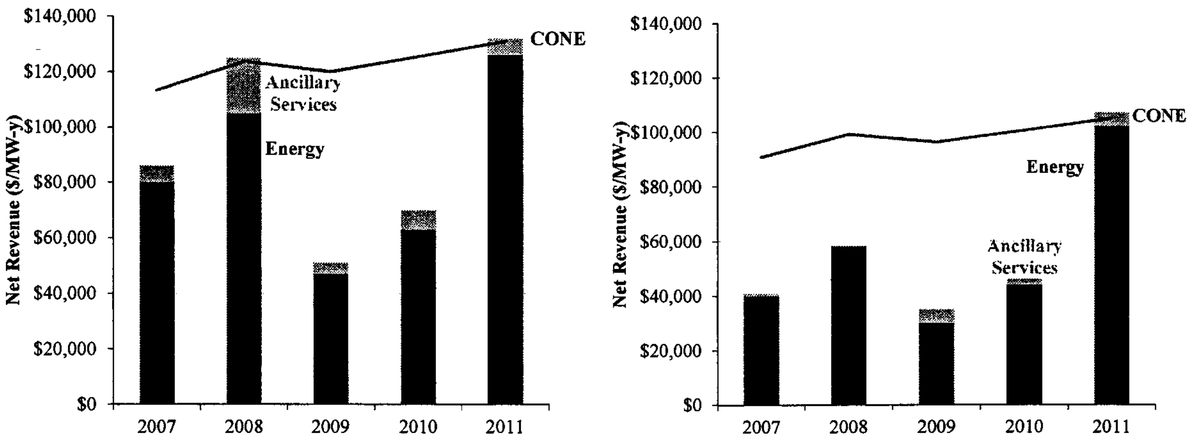
44 Spark and dark spreads show the difference between power prices and fuel costs. On-peak spark spreads show the difference between the electricity price and fuel price for a unit with a 7,000 Btu/kWh heat rate. Similarly, dark spreads fuel prices are based on coal prices at a 9,500 heat rate.

Figure 9 shows the historical energy margins for simple-cycle combustion turbine (CT) and combined-cycle units. Both technologies have been uneconomic relative to their levelized investment costs since 2007, with the exception of 2008 and 2011 for CCs, and 2011 for CTs. Even though the extreme weather and shortage events of 2011 approximately doubled the profitability of CCs and CTs relative to previous years, these technologies still earned only marginally more than their annualized revenue requirements. Suppliers would have to expect returns at 2011 levels on average in every year in order to invest; therefore, it appears that recent market conditions have been insufficient to attract new generation.

Figure 9
ERCOT Combined Cycle (Left) and Simple Cycle (Right) Energy Margins



Sources and Notes:

"CONE" is a Brattle estimated CONE based on an overnight cost of $667/kW and a 9.6% ATWACC. CONE is deflated by Handy Whitman (2011). See Section II below for discussion of estimated CONE.

Net revenue estimates are from the Independent Market Monitor, see Potomac Economics (2011c).

E. Current Resource Adequacy Concerns

Investors' basic requirement is that they can expect future revenues to be high enough, often enough, to cover the costs of building a plant, including a return on capital commensurate with risk. Because the wholesale market conditions in ERCOT have not been favorable due to the fleet makeup and low electric prices, investment appears to have stalled. This lack of investment threatens resource adequacy in the near future.

1. Recent and Projected Shortages

Since deregulation, ERCOT has maintained sufficient levels of investment and reserve margins. However, reserve margins are deteriorating due to retirements and relatively low new entry, combined with rapid, economically-driven load growth at an average rate of 2.3% a year since 2002.[45] By 2011, the planning reserve margin was 14%, and system reliability was stressed by weather conditions at or beyond the range of possibilities that had been considered when establishing target reserve margins.

45 *Brattle* calculated average load growth for 2002 – 2011, data from Ventyx (2012).

On February 2, 2011, ERCOT experienced extreme cold weather, causing a record winter peak demand of 56,493 MW, and the loss of numerous generating facilities used to help meet demand. Cold ambient temperatures combined with high winds caused problems with plant control systems and caused 82 generating units representing more than 8,000 MW to go offline, or never come online.[46] Additionally, some gas units were derated due to fuel availability problems.[47] The combination of record demand and unit outages caused ERCOT to shed up to 4,000 MW of load across an 8-hour period.[48]

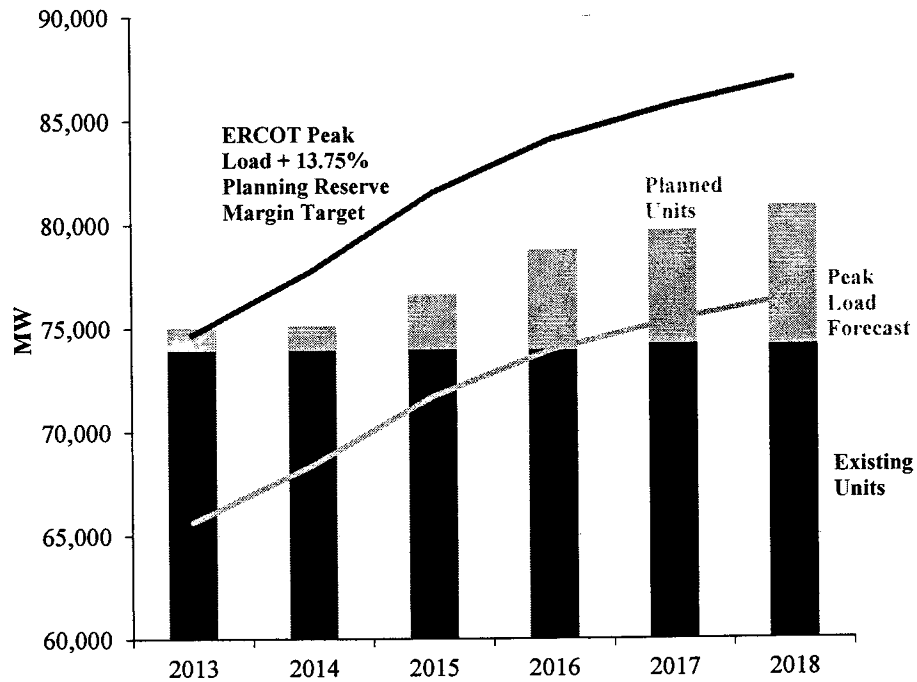
In addition to the cold snap in February, ERCOT experienced unusually hot weather in 2011. Average June – August temperatures were the hottest recorded by the National Weather Service since recordkeeping began in 1895.[49] The August heat wave led to the use of energy emergency procedures 6 times and 19 hours of prices at the $3,000 price cap, although no load shedding was needed.[50] With the extreme weather in August, the realized reserve margin was only 9%, compared to the 14% reserve margin that would have been realized under normal weather conditions.

As 2011 has shown, reliability outcomes in Texas depend heavily on the weather. ERCOT estimates that a 13.75% reserve margin is needed to maintain the "1 loss-of-load event in 10 years" reliability target.[51] However, this target was established in 2010, before considering the possibility of outlier weather events as extreme as those witnessed in 2011. ERCOT is currently updating its target reserve margin based on updated weather data which includes 2011.

46 See ERCOT (2012b).
47 See ERCOT (2011a).
48 See Potomac Economics (2011a).
49 See ERCOT (2012f).
50 See ERCOT (2012c), Ventyx (2012).
51 See ERCOT (2010a).

As shown in Figure 10, projected planning reserve margins are headed for a low 9.8% by 2014, even if no incremental generation retirements occur.[52] Thereafter, load growth and potential retirements could depress reserve margins much further if new capacity is not added.

Figure 10
Projected Load Growth, Reserve Margin Target, and Capacity Additions



Sources and Notes:
ERCOT does not currently project any retirements in its CDR Report as reflected here, although it has identified some units at risk to retirement in future years as discussed in Section I.E.2, see ERCOT (2012n).

2. Potential Impacts of Environmental Regulations

Several impending environmental regulations will further challenge resource adequacy in ERCOT. ERCOT has analyzed the impact of four different potential rules, including the: (1) Cross-State Air Pollution Rule (CSAPR); (2) Mercury and Air Toxics Standards (MATS); (3) Clean Water Act (CWA) – Section 316(b); and (4) Coal Combustion Residuals Disposal Regulations.

Cross-State Air Pollution Rule — When the EPA finalized CSAPR in July 2011, it included Texas although the state was not included in the earlier proposed rules.[53] The rule was to be implemented within five months, by January 2012. However, on December 30, 2011,

[52] See ERCOT (2012n).
[53] See Environmental Protection Agency (2011a).

the U.S District Court of Appeals stayed CSAPR.[54] The Court is currently hearing oral arguments and is expected to make a decision as early as June or July 2012.[55]

CSAPR is being implemented in order to address the interstate transport of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).[56] Under CSAPR, generating units in Texas would be regulated for annual emissions of SO_2 and NO_X, as well as emissions of NO_X during the peak season. Each unit will be awarded a set allocation of emissions allowances. At the end of the calendar year, resource owners must turn in one allowance for each ton of emissions or be subjected to penalties. Interstate allowance trading will be allowed among states in the same group, but if any one state exceeds its awarded allowances plus a variability limit, then suppliers contributing to the excess will face a penalty. Compliance would likely require a combination of allowance purchases, reduced unit output, the use of low-sulfur fuel, or capital-intensive retrofits.

Mercury and Air Toxics Standards — The EPA finalized the Mercury and Air Toxics Standards rule in December 2011, requiring coal and oil-fired power plants to reduce emission rates of mercury, acid gases, and non-mercury metals below specific limits by April 2015.[57] In addition to the three-year statutory requirement, the EPA allows a potential 1-year extension of the deadline if approved by state permitting agencies, and a further 1-year extension under the circumstances where a power plant would need to continue operations in order to maintain reliability.[58] The MATS rule will require coal plants to install various combinations of controls depending on the unit's existing controls, boiler type, type of coal used, and economic factors. The control equipment needed to comply with MATS may include wet or dry flue gas desulfurization (FGD), selective catalytic reduction (SCR), fabric filter (or baghouse), dry sorbent injection (DSI), or activated carbon injection (ACI).[59]

Clean Water Act 316(b) — Section 316(b) of the Clean Water Act requires that cooling-water intake structures utilize best available technology, and that these structures minimize adverse environmental impacts to fish populations.[60] The EPA announced proposed revisions to the requirements for cooling-water intake structures for existing facilities on March 28, 2011.[61] These regulations are designed to reduce fish entrainment and impingement caused by the use of cooling water by industrial facilities and electric generation plants. While the proposed regulations provide for flexibility and development of site-specific solutions, the strictest implementation of these revised regulations could require that closed-loop cooling tower systems be installed at all

54 See United States Court of Appeals (2011).
55 See Power Magazine (2012).
56 See Environmental Protection Agency (2011a).
57 The compliance deadline is 60 days plus 3 years from the date of publication in the *Federal Register*, which was February 16, 2012. See *Federal Register* (2012), p. 9407.
58 EPA states that it expects that few or no reliability exceptions of this type will be needed, see EPA (2011b).
59 See Celebi, *et al.* (2012), p. 7
60 See EPA (2011c).
61 See EPA (2011d).

existing facilities that currently utilize once-through cooling.[62] A final rule will be issued by July 27, 2012.[63]

Coal Combustion Residuals Disposal Regulations — Under section 3001(b)(3)(A)(i) of the Resource Conservation and Recovery Act (RCRA) (known as the Bevill exclusion), ash products generated from the combustion of coal are excluded from the handling and disposal requirements in the Act pending a determination from the EPA that such requirements are justified.[64] In 1993 and 2000, the EPA determined that regulation of ash from coal combustion under RCRA was not justified.[65] However, in June 2010, the EPA issued a new proposal to address the risks associated with coal ash disposal by either reversing its earlier Bevill regulatory determinations and classifying coal ash as a "special waste," or maintaining its previous Bevill determinations, but issuing national minimum criteria regarding the proper disposal of coal ash waste. In either case, the EPA proposal would limit ash disposal options and require additional monitoring of ash disposal facilities. The EPA proposal could also limit options for the beneficial use of coal ash products.[66]

To evaluate the impact of each regulation, ERCOT reviewed published studies of the nation-wide impacts, and met with environmental experts from several ERCOT generators. ERCOT then developed scenarios based on likely compliance requirements and future market conditions. Units that ERCOT did not project to earn sufficient market returns to justify the cost of a controls upgrade were assumed to retire. These retirement decisions were based solely on market economics; ERCOT did not consider any reliability-based reserve margin requirement and did not consider whether any generation expansion might materialize.

62 See ERCOT (2011c), p. 2.
63 See EPA (2011d).
64 See EPA (2000), p. 2.
65 See EPA (2000b).
66 See EPA (2010).

Table 2 shows the results of ERCOT's evaluation on the impact of CSAPR under three different scenarios. ERCOT could expect to lose 1,200 – 1,400 MW during peak summer months.

Table 2
Environmental Impacts of CSAPR

Scenario		Capacity Reductions Fall *(MW)*	Spring *(MW)*	Summer *(MW)*
Low	Based on compliance plans from resource owners	3,000	3,000	1,200-1,400
Mid	Based on compliance plans + additional maintenance of coal due to daily dispatch	5,000	3,000	1,200-1,400
High	Based on compliance, additional maintenance, and limited imported low-sulfur coal	6,000	3,000	1,200-1,400

Source:
ERCOT (2011e).
Assumed rule implementation by January 2012.

Table 3 shows the retirement impacts of MATS, CWA 316(b), and the Coal Ash regulations. Given ERCOT's relatively small number of coal units that would require major controls upgrades for MATS, it will be much easier for Texas to comply than other parts of the country such as MISO and PJM. ERCOT projects 1,200 MW of coal retirements in the base scenario. Among gas capacity, ERCOT deems that no units are at risk unless the EPA imposes a once-through cooling mandate, in which case nearly 10,000 MW of gas-fired capacity will likely retire. These retirements are from old gas steam units that are less efficient and less flexible than quick-start gas-fired generation. Many of these older units are nearing the end of their economic lives and any requirement to upgrade will likely cause retirement.

Table 3
Combined Environmental Impacts
(Includes MATS, CWA 316(b), and CCR Regulations)

Scenario	w/o Closed-Loop Requirement		w/ Closed-Loop Requirement	
	Coal-Fired Retirements *(MW)*	Gas-Fired Retirements *(MW)*	Coal-Fired Retirements *(MW)*	Gas-Fired Retirements *(MW)*
Base Case	0	0	1,200	9,800
High Gas Price	0	0	0	9,800
$25/ton Carbon Price	4,400	0	5,600	9,800
High Gas Price w/Carbon Price	0	0	0	9,800

Sources and Notes:
ERCOT (2011c).
Assumes the retirements listed in the tables occur by 2016.
Base case gas price is $5.1/MMBtu, high gas price is $8/MMBtu.
This study also included the Clean Air Transport Rule, which was the proposed version of CSAPR at the time. However, the study found no incremental impacts from CATR on ERCOT because it only included Texas in the peak season NO_X program, see ERCOT (2011e), p. 1.

F. Recent and Ongoing Efforts to Address Resource Adequacy

In response to emergency conditions faced in 2011 and projections that reserve margins will fall below the target level by 2014, the PUCT convened Project 37897 to address resource adequacy challenges and scarcity pricing.[67] Since then, ERCOT, the PUCT, and stakeholders have worked through a number of important efforts to analyze resource adequacy challenges and implement market reforms. To date, key approved reforms include the following measures that will prevent price suppression from administrative reliability interventions, or otherwise work to increase prices during scarcity conditions:

- Implementing a price floor at the System Wide Offer Cap for energy deployed from Responsive Reserves and Regulation Up;[68]
- Implementing a price floor at the System Wide Offer Cap for energy deployed from Reliability Unit Commitment (RUC) and RMR units operating between their low sustained limit (LSL) and high sustained limit (HSL);[69]
- Implementing a price floor for deployments of Non-Spinning Reserves, including a floor of $120/MWh for Online Non-Spin, and $180/MWh for Offline Non-Spin;[70]
- Expanding Responsive Reserves by 500 MW with a corresponding reduction in non-spin;[71] and
- Expanding Emergency Interruptible Load Service (EILS) into Emergency Response Service (ERS).[72]

Resource adequacy challenges are also the subject of ongoing market design efforts by the PUCT and ERCOT. Several additional reforms are in progress or under consideration, including:

- Raising the System Wide Offer Cap, possibly as high as $9,000/MWh, with corresponding increases to the Low System Wide Offer Cap and Peaker Net Margin Threshold;[73]
- Raising the high end of the Power Balance Penalty Curve and adjusting its slope and width;[74]
- Eliminating price distortions caused by deployments of load resources;[75]
- Eliminating price distortions caused by 0-LSL energy from ONRUC, RMR, quick-start, and offline non-spin resources;[76]
- Initiating an ERS Demand Response Pilot, and Load Management Initiatives;
- Posting non-binding near real-time forward prices; and
- Sponsoring this study to analyze the resource adequacy challenge.

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[67] See PUCT (2012b).
[68] See ERCOT (2012f), NPRR427.
[69] See ERCOT (2012f), NPRR435 and NPRR442.
[70] See ERCOT (2012f), NPRR428.
[71] See ERCOT (2012f), NPRR434.
[72] See ERCOT (2012f), NPRR451.
[73] See, for example, PUCT (2012a), Item Number 106.
[74] See PUCT (2012a), Item Number 125.
[75] See ERCOT (2012f), NPRR444.
[76] See ERCOT (2012f), NPRR444.

We further discuss the implications of these recent and potential changes where relevant in the remainder of this study. In particular, we examine the implications of recently-implemented and proposed changes on generator margins in Section IV and discuss the efficiency of individual market design elements further in Section V.

II. GENERATION INVESTMENT CRITERIA BY INVESTOR CLASS

To understand the factors affecting investors' willingness to invest in ERCOT, we interviewed a broad spectrum of generation developers and lenders and analyzed relevant financial indicators. We found that investors are generally cautious after a history of investment losses but that many could and would invest in ERCOT if revenue levels were expected to be adequate to earn a return commensurate with risks.

The lack of long-term PPAs in Texas's retail choice environment means that investment risks usually remain with suppliers rather than buyers. This places more risk on investors in restructured markets than in regulated markets where long-term PPAs are standard. A number of generators also state that the wholesale energy-only market design is riskier than other restructured markets where capacity payments are a major revenue stream. However, investors also noted that revenues in ERCOT are more stable than spot prices, since they sell most power at least a few months forward at prices that average out short-term risks such as weather effects. Overall, we believe that the energy-only markets are somewhat riskier and harder to model from a revenue-forecast perspective than capacity markets.

Investors also worry that energy-only markets can lead to extreme outcomes that might induce future regulators to intervene in the market even though they expressed that the current Commission has demonstrated its commitment to markets and regulatory certainty. Considering all of these factors, at least some investors state that they may require returns exceeding the 9.6% after-tax weighted-average cost of capital (ATWACC) assumed by ERCOT last year.[77] Large, diversified investors with hedging options and the ability to finance plants on their balance sheets might be able to accept lower returns on incremental investments in ERCOT, perhaps closer to our current ATWACC estimate of 7.6% for merchant project investments. We also note that some investors believe the ATWACC required for projects in ERCOT is higher than for merchant projects in other locations.

Revenue requirements and risk tolerances vary considerably by type of investor. Lenders of project-finance loans with no upside opportunities must be confident that the borrowing entity will have sufficiently stable net revenues to cover the total amount borrowed with ample margin for error. Larger borrowers can partially diversify project-specific risks and borrow more cost-efficiently against their corporate balance sheet while also absorbing equity risks. Such investors may be able and willing to weather some bad years for a few good years as long as the discounted expected value is high enough. These are likely to be the most robust type of

[77] See PUCT (2012a), Item Number 87, p. 1.; Note that this estimate is a year old, and required rates of return have decreased since then. The ATWACC is defined as the capital-structure weighted average of: (1) the cost of equity; and (2) the after tax cost of debt (*i.e.*, the cost of debt multiplied by one minus the marginal tax rate). See Brealey, *et al.* (2011), p. 216.

investors in a market with high price volatility. Smaller, undiversified borrowers, particularly those relying on high leverage through project-specific, non-recourse debt financing with little equity, might be pushed out of the market unless they can secure PPAs with public power entities.

A. Classes of Generation Investors

Several classes of generation investors are active in ERCOT, with each investor class differing in size, preferred financing model, financial profile, and risk tolerance. In this section, we describe: (1) investment criteria considered by various types of entities that may be involved in new generation investments; (2) the market share of generation owners and investors currently active in ERCOT; and (3) the varying ability of different classes of investors to move ahead with new investment projects in ERCOT, based on their risk exposure, diversification level, and credit ratings.

1. Classes and Criteria of Entities Involved in Generation Development

A number of different types of entities can be directly involved in developing and building new power plants. We will refer loosely to "generation developers" as a group, but note that it is important to understand that each type of entity has a different role and investment considerations:

Unaffiliated Generation Developers — The power industry has a large number of small companies that actively scout for power generation development opportunities. These developers are generally small enterprises without substantial equity or assets to diversify against. To move ahead with an attractive generation investment opportunity, an unaffiliated developer will need to secure financial commitments from major equity investors and lenders. They also need to secure a long-term contract with a buyer to reduce investment risk. Once such a generation project is developed, it is often sold to a variety of companies who own and operate power plants.

Privately-Held Independent Power Producers (IPPs) — Privately-held IPPs span a broad range from smaller, less diversified generation companies to larger, more diversified interests including for example: (a) Topaz, which currently has 2,000 MW generation investment in ERCOT; (b) Panda Power Funds, which is proposing 2,000 MW of new generation in ERCOT and has developed other projects elsewhere in the past; and (c) Tenaska, which has developed almost 3,000 MW in ERCOT and 9,000 MW of generation nationally and internationally.[78]

Publicly-Held IPPs — There are a number of publicly-traded merchant generation companies that currently do or may in the future invest in ERCOT, including: (a) companies that primarily invest in merchant generation, such as NRG and Calpine; (b) merchant affiliates of regulated utilities located in other regions, such as Exelon; or (c) merchant generation investors who are highly diversified or have primary interests in industries other than power, such as Hess. These investors vary widely in size, credit ratings, and diversification, and not all investors from among these types currently have

[78] Tenaska also participates in marketing of gas, power and biofuels, and provides risk management and fuel procurement. For asset information see Topaz (2012); Panda Power Funds (2012); Tenaska (2012).

interests in ERCOT. Many merchant generation companies, such as NRG and Exelon, have partially vertically integrated into retail services to hedge a portion of their generation output as discussed below.[79]

Municipalities and Cooperatives — Municipalities and cooperatives are directly owned by their customers and, as a result, are driven directly by the interests of end users. These entities do not require the same return on investment as merchant investors, because the costs of a generation investment are borne by their end-user customers regardless of prevailing market conditions. These entities engage in long-term planning for power supply and may directly invest in new generation projects or may sign long-term contracts to buy power from other generation owners When signing a long-term PPA, munis and coops take on the risk that a particular generation project may ultimately become uneconomic; these PPAs therefore reduce investment risks to the merchant PPA counterparty. However, munis and coops will face pressure from members to restructure if any investments turn out to be out-of-the-money.

Partially Reintegrated REPs — Unlike munis and coops, REPs are generally unwilling to sign long-term PPAs that would support generation investments. However, there are some large REPs, such as Direct Energy, that have a strategy to hedge a portion of their retail positions with direct ownership in generation assets. These partially-reintegrated entities may purchase existing assets to attain their desired hedging position. As discussed above, there are also many publicly-held merchant generators that hedge their generation position through a retail position in ERCOT as is the case with NRG and its REP subsidiary Reliant.[80]

Large Customers — There are a small number of end-user customers that are large enough to invest in generation assets for self-supply. The majority of these investments would be in small on-site generation with a special economic situation, including cogeneration opportunities and backup power.

Lenders — Large financial institutions provide the project-specific debt used to finance new investments. As discussed further in Section 0 below, the size and terms of any loan will depend on the risk of the investment it supports as well as the equity position and financial health of the company making the investment.

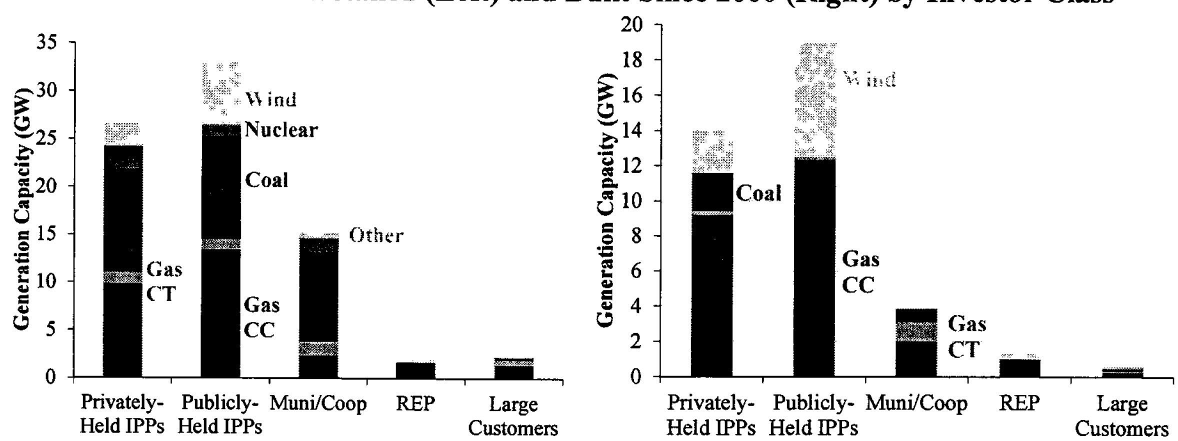
[79] For further discussion of partial vertical integration trends, see Pfeifenberger and Newell (2011).
[80] See Reliant (2012).

2. Market Share of Current ERCOT Asset Owners

To illustrate the relative importance of each investor class in ERCOT, we summarize the current asset holdings by ownership for new generation investments since 2000 and for the entire fleet in Figure 11. Since 2000, ERCOT has attracted roughly 34,000 MW of new generation investments.[81]

The largest market share and recent investments in ERCOT are from privately-held IPPs such as Tenaska and Topaz, and from publicly-held IPPs such as Calpine and NextEra. About 10% of new generation investments have come from municipalities and cooperatives. While municipalities and cooperatives have an important role in enabling some investments, their relatively small market share means that resource adequacy in ERCOT will ultimately depend on IPPs developing assets based on market returns.

Figure 11
Total Generation Installed (Left) and Built Since 2000 (Right) by Investor Class



Sources and Notes:
All capacity reported at summer nameplate rating, from Ventyx (2012).
Ownership categorized based on the identity of the primary owner.

[81] Roughly 10,000 MW of the investment since 2000 was wind generation as shown in Figure 11.

Table 4 summarizes the current asset holdings of all of the largest generating entities in ERCOT, including total generation and generation built since 2000. IPPs account for the largest share of the market: the largest is Luminant, owning approximately 17% of the total fleet in ERCOT, the majority of which are coal plants.[82] NRG has the second largest portfolio, with approximately 14%. Calpine and NextEra Energy are smaller in terms of total generation, but are the two companies that have made the largest investments since 2000. In ERCOT, munis and coops such as CPS, Lower Colorado River Authority, Austin Energy, and Brazos have the largest market share and recent investment activity. Munis and coops own less generation than their 25% combined share of ERCOT load because much of their supply is contracted. As shown, REPs (not counting merchant generators who vertically integrated into retail supply) and large customers make up a small portion of ERCOT generation investment.

Table 4
Total ERCOT Generation Assets by Investor Class and Company

	Total Fleet		Since 2000	
	MW	%	MW	%
Privately- Held IPPs	**18,444**	**23%**	**6,613**	**17%**
Luminant	13,682	17%	2,186	6%
Tenaska Inc	2,901	4%	2,901	7%
Topaz	1,861	2%	1,526	4%
Publicly- Held IPPs	**27,258**	**34%**	**13,480**	**35%**
NRG Energy Inc	10,896	14%	483	1%
Calpine Corp	4,985	6%	4,571	12%
NextEra Energy Inc	5,204	7%	5,061	13%
International Power (GDF Suez)	3,148	4%	2,508	6%
Exelon Corp	3,026	4%	857	2%
Muni/Coop	**12,886**	**16%**	**3,441**	**9%**
CPS Energy	5,829	7%	1,607	4%
Lower Colorado River Authority	3,067	4%	694	2%
Austin Energy	2,546	3%	575	1%
Brazos Electric Power Coop	1,445	2%	565	1%
REP	**2,014**	**3%**	**1,318**	**3%**
Direct Energy	1,227	2%	988	3%
AEP	787	1%	330	1%
Large Customers	**1,774**	**2%**	**394**	**1%**
Dow Chemical	1,033	1%	100	0%
Formosa Plastics Corp	740	1%	294	1%

Sources and Notes:
Capacity reported at summer nameplate rating, from Ventyx (2012).
Percentages for each category will be more than the individual companies because not all companies are included in the above table.

[82] Luminant is currently a privately-owned subsidiary of Energy Future Holding Corporation. EFH acquired Luminant in 2007 with a private-equity acquisition of Kohlberg Kravis Roberts & Co. TPG and Goldman Sachs Capital Partners. EFH also owns TXU Energy and Oncor. See Energy Futures Holdings Corporation (2012).

3. Ability to Finance Investments by Investor Class

In addition to characterizing ERCOT investors in terms of their qualitative differences and market shares, we separately categorize these companies based on their relative ability and willingness to make new generation investments in ERCOT. The ability and willingness of investors to make these investments relates principally to their projected returns (which depend on the market prices they all face) and ability to absorb or diversify risk.

Table 5 ranks these investor types in order of their ability to absorb risk. Generally, a company's willingness and ability to invest in ERCOT has more to do with their size, diversification, and credit quality as discussed below than their ownership type as discussed above. Organized by their ability to manage risk, these investor classes include:

Self-Suppliers — Self-suppliers, such as municipalities, cooperatives, and a select number of large customers, are positioned differently from other generation investors. Retail power consumers are simultaneously constituents or member-owners of the generation entity, with an alignment of economic interests. Public power entities have their own load and usually build or contract far in advance to cover it, consistent with a long-term resource plan. While these entities consider the same market dynamics of price levels and volatility that affect other investors, they are not subject to the same risks because even uneconomic investment costs may be recovered from their retail customers. This protection against losses enables public power entities to enjoy lower financing costs than merchant investors. Public power entities may also enable PPA counterparties to achieve lower financing costs by taking on the risk that the investment may become uneconomic.

Diversified IPPs with Investment-Grade Credit Ratings — These investors are large national or international entities with diversified portfolios, nearly all of them publicly-held companies such as Exelon, NextEra, GDF Suez, and Hess. Such diversified entities have substantial, but not infinite, ability to absorb cash flow timing and volatility challenges posed by individual project investments. Investment-grade credit ratings also provide the ability to borrow on a corporate or balance sheet basis on terms more favorable than those available under project-specific, non-recourse financing.

Diversified IPPs with Below-Investment-Grade (or No) Credit Ratings — Companies in this category include some large publicly-held merchant generation companies and private equity firms with diverse asset portfolios. Their diversification makes them reasonably well-positioned to meet the challenges associated with cash flow volatility of individual plant investments. Their portfolios enable them to issue corporate debt, but their lower credit ratings mean that they face higher interest rates on bank loans and public bonds. Companies in this category may have low credit ratings due to a poor company outlook, but in some cases the companies may intentionally manage to a sub-investment grade credit rating in order to optimize equity returns. In the latter case, the companies may boost equity returns by taking on large amounts of debt. This debt will, in turn, necessarily translate into a lower credit rating and higher required returns regardless of other indicators of financial well-being.

Undiversified IPPs — Undiversified investors are typically privately-held project development or acquisition companies with narrow asset portfolios and insufficient critical mass to attract public-market debt or equity financing. The equity portion of these undiversified companies is typically funded by private equity firms, while the debt portion typically requires non-recourse or "project" financing, as further discussed in Section 0 below. Though some cash flow timing and volatility risks can be managed through third-party hedges and insurance, to make sufficient debt financing possible, these undiversified investors are more reliant on long-term PPAs than any of the other investor classes. They are therefore likely to be excluded from the market if long-term PPAs are unavailable.

Table 5
Investors' Investment Criteria from Most Able to Least Able to Absorb Risk

	Type of Investor	Investment Criteria
Most Able to Absorb Risk	**Self-Suppliers** Municipalities and Cooperatives (Including their Long-Term PPA Counterparties) Select Large Customers	– **Long-Term Planning** — Interests driven by end-use customers who are the ultimate owners. Self-suppliers will own or contract for long-term supplies to meet projected demand. – **Prices and Volatility** — Will plan for lowest long-term costs and preventing price volatility, but will recover investment costs from ratepayers even if a project becomes uneconomic with changing market conditions.
	Diversified IPPs with Investment-Grade Credit Publicly-Held IPPs	– **Expected Price Levels** — Must project returns commensurate with risk. Cautious due to history of investment losses. – **Market Price Volatility** — Can diversify against larger portfolio. – **Debt Financing** — Able to borrow against balance sheet (but will often prefer project financing with a long-term PPA, if available). – **Regulatory Uncertainty** — Concern that upside could be curtailed through regulatory change or intervention.
	Diversified IPPs with Below Investment-Grade Credit Publicly-Held IPPs Privately-Held IPPs	– **Expected Price Levels** — Must project returns commensurate with risk. Cautious due to history of investment losses. – **Market Price Volatility** — Can diversify against portfolio. – **Debt Financing** — May or may not be able to borrow against balance sheet; ability to invest may depend on securing project financing supported by long-term PPA. – **Regulatory Uncertainty** — Concern that upside could be curtailed through regulatory change or intervention.
Least Able to Absorb Risk	**Undiversified IPPs** Unaffiliated Developers	– **Expected Price Levels** — Must project returns commensurate with risk. Cautious due to history of investment losses. – **Market Price Volatility** — Limited portfolio to diversify against. – **Debt financing** — Only able to invest under project financing model supported by steady and certain cash flow, which could be achieved through long-term PPAs or long-term hedges with power marketers, but these are both difficult to secure. With less risk shifting, required returns can exceed those of other investor classes, thereby possibly precluding investment. – **Regulatory Uncertainty** — Concern that upside could be curtailed through regulatory change or intervention.

Table 6 summarizes the size, debt characteristics, and credit ratings of a number of important investors in ERCOT. As previously explained, municipalities and cooperatives usually have strong credit ratings, given their ability to pass risk through to customers. This puts them in a favorable position to invest even if they are small relative to other investors. Some large customers also have favorable credit ratings that could enable them to invest in self-supply, but it is likely that their interest will be limited to a small number of specific cogeneration or backup power opportunities.

Table 6
Investors' Balance Sheets and Credit Quality

	Assets *($B)*	Debt *(%)*	Equity *(%)*	Project Debt *(%)*	S&P Rating
Self-Suppliers					
Municipalities and Cooperatives					
CPS (City of San Antonio)	$10	60%	40%	n/a	AA
Brazos	$2.7	83%	17%	n/a	A-
Austin Energy	n/a	n/a	n/a	n/a	A+
Large Customers					
Dow Chemical	$69	48%	52%	7%	BBB
Publically Held IPPs					
Utility Affiliates					
Exelon	$55	48%	52%	n/a	BBB-
International Power (GDF Suez)	$62	40%	60%	>10%	BBB-
NextEra	$57	59%	41%	26%	A-
Merchant Generators					
NRG	$27	56%	44%	18%	BB-
Calpine	$17	71%	29%	16%	B+
Privately Held IPPs					
Luminant (EFH)	$44	128%	-28%	n/a	CCC
Tenaska	$2.8	49%	51%	n/a	n/a

Sources and Notes:
Investor information from Bloomberg (2012).
Debt and equity percentages calculated based on "capitalization" (except for Tenaska which is based on "total assets"
International Power is a subsidiary of GDF Suez whose current S&P rating is A
Data for CPS is for the year ending 1/31/2011
Data for Brazos is for 2010
Rating for Austin Energy is the rating of its electric utility system revenue bonds.
For additional credit rating explanations see S&P (2012).

IPP affiliates of regulated utilities can sometimes also benefit from the higher credit ratings of their parent companies (which reflect a mix of regulated and IPP operations). Pure merchant generation companies often have below investment-grade credit ratings, although, as noted earlier, this may be intentional to optimize equity returns. Finally, private equity firms cover a range of sizes and credit ratings although these entities are usually not required to publicly report their financial information. In particular, the large Energy Future Holdings (EFH), which owns Luminant, TXU, and Oncor, has a very poor credit rating caused by a $45 billion leveraged buyout that it has not been able to recover since its coal fleet's energy margins fell along with the drop in natural gas prices.[83] Overall, there are a number of entities that are well-positioned to make additional generation investments in ERCOT as long as anticipated returns are commensurate with their risk and financing costs.

B. Debt Financing Models for Power Plant Investments

There are two general debt financing models used to develop power plants: (1) project financing, and (2) balance sheet financing. For many years IPPs have built generating plants using project financing with revenues stabilized through long-term PPAs. In the presence of long-term PPAs, project financing has been attractive to developers because it limits investor risk, allows greater debt leverage, and therefore reduces financing costs.

In recent years, however, declining market prices and the expansion of retail competition have reduced the number of buyers willing to sign long-term PPAs to support new generation plants. Further, since the financial crisis, power marketers have been reluctant to sell long-term hedges (*e.g.*, 10 years) that could otherwise be used to support project-specific debt. These changes have reduced project financing opportunities. As a result, generation development has been shifting toward balance sheet financing and a greater reliance on equity investment.

In this context it is important to understand that lenders have first claim on cash flows (and, if necessary, liquidation value) for the purpose of repaying principal and interest. Lenders have no stake in the residual value of the investment after their principal is repaid, nor any claim to project "upside" in the event of asset appreciation. Leveraging equity investments with debt conserves equity investors' funds and increases their returns, along with their financial risks. Lenders bear less risk than equity investors, making the required return on debt less than the required return on equity. However, with no upside potential, lenders require that their first claim be substantially insulated from default risk and therefore impose corresponding requirements on borrowers.

1. Project Financing

Project financing refers to the use of project-specific, "non-recourse" debt, along with a required portion of equity, to finance the construction of a power plant. Non-recourse debt is not backed by a guarantee from the equity investor (likely a larger parent company) beyond the value of the individual power plant. This means if the project becomes insolvent, the creditors will be unable to recover their investment from any other entity than the project itself. Non-recourse debt is riskier for the lender and consequently more expensive than corporate debt secured through a guarantee associated with the more diversified revenues and assets of a larger parent company.

While usually more expensive than corporate debt, non-recourse debt is still attractive to developers because: (1) it is often the only form of debt financing available for small generation developers; (2) it may be less expensive than corporate debt for companies with below-investment grade ratings; (3) it limits the equity investor's risk to the value of the equity originally invested in case the project proves to be a bad investment; and (4) the leverage project financing provides is attractive to many equity investors who prefer the higher-risk, higher-return investment options it creates.

[83] See Lattman (2012).

Because lenders, unlike equity investors, generally have no possibility of earning "upside" beyond the stipulated debt interest rate, they must apply conservative criteria in a project finance credit evaluation. Generation developers can only secure project financing if lenders are highly confident that cash flows from the plant will be sufficient to repay principal plus interest. The most important factor that can provide this confidence is a long-term PPA to sell power at a known revenue stream. Having a PPA reduces project risk to the owner and lender by shifting market risks to the buyer. With a PPA, even relatively small entities with limited borrowing capacity may be able to build a plant through project financing. Without a PPA, the share of a project that lenders are willing to support through project financing drops substantially. For example, some projects supported by PPAs are able to employ non-recourse debt for 70% or more of total project capital. Conversely, the higher volatility and uncertainty in projected cash flows of projects without PPAs may reduce the portion that can be financed with non-recourse debt to 30% or less of total project capital. By shifting most of the project risk to a long-term buyer, project financing with a PPA will reduce financing costs and the overall cost of building a new plant.

2. Balance Sheet Financing

In addition to project finance, some larger and diversified developers are able to use "balance sheet" financing for power projects. Balance sheet financing employs debt backed by the repayment obligation of the project owner itself, which may have significant, diverse resources and assets beyond the individual project. Corporate debt provides creditors much greater certainty because repayment is no longer solely reliant on the success of any one project but is instead tied to the solvency of a large, diversified company. Corporate debt backing means that the loan will not go into default due to transitory periods of cash flow shortfall that may result from merchant project operations in volatile markets. Therefore, balance sheet financing will tend to increase the amount of debt financing effectively available to a given project without a PPA, *e.g.*, to 50% or 60%.

Balance sheet financing requires an investor with sufficient scale and diversity to provide this security to the lender. This will exclude a number of smaller investors and project developers from a market with few or no PPAs available. Finally, balance sheet financing is not cost-free to investors. Rather, when a company increases its corporate debt through issuing bonds or taking on large bank loans, it reduces its financial flexibility and risks lowering its credit rating because it will have more debt on its balance sheet.

C. Capital Market Conditions

The ability to make investments in ERCOT is driven not only by expected market revenues, but also by overall debt and equity market conditions. The cost of financing depends on the state of the debt and equity markets, which have changed substantially over the past ten years. We outline the state of both debt and equity markets for potential investors in ERCOT.

1. Debt Markets

In the wake of the worldwide financial crisis starting in 2008, financing costs for corporate debt in the U.S. shot up. Corporate debt rates have since dropped back to pre-crisis levels, but the spread to treasuries remains wider than before 2008 due to the ongoing European sovereign debt crisis, low demand for high-risk securities, and new regulatory capital requirements on financial market participants.[84] The project-financing sector has also been adversely affected by the reduction in availability of long-term contracts, with numerous financial institutions refocusing on financing renewable generation investments (which frequently have long term PPAs) or ceasing power industry lending altogether.[85]

Treasury rates and the London Interbank Offering Rate (LIBOR) are now at historic lows, reflecting current policies of the Federal Reserve and investors' continued "flight to safety." However, the cost of debt for power project investors has not dropped as far. Figure 12 shows that even though yields on 20-year Treasury bonds are low relative to pre-crisis levels, yields on corporate bonds are relatively unchanged. We show 20-year BB utility bonds as a rough proxy for borrowing costs facing power projects because this credit rating is in line with the credit rating of some potential ERCOT investors. The spread between BB utility bonds and Treasuries increased after 2006 when it was approximately 2%, escalated dramatically up to 8% during the financial crisis, and has since dropped to current levels in the 3-4% range. While below the spreads experienced during the 2008 financial crisis, today's spreads are as high as they were immediately prior to the crisis. Borrowing spreads have not dropped further due to lower demand for corporate bonds relative to higher-rated securities and the more stringent regulatory standards imposed on financial institutions (*e.g.*, capital requirements).[86]

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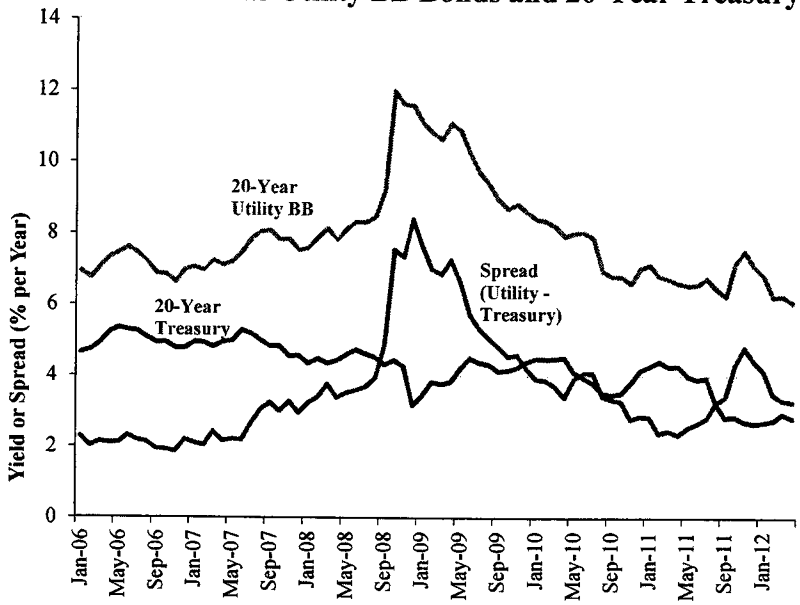
[84] See Krishnan (2012).

[85] See, for example, Wigglesworth and Dombey (2012).

[86] See, for example, Lonski (2012).

Figure 12
Spread Between 20-Year Utility BB Bonds and 20-Year Treasury Notes



Sources and Notes:
Yield is the annual return that a bond-holder will earn.
Spread is the difference in yield between 20-Year Utility BB Bonds and 20-Year Treasuries.
Bloomberg (2012).

Additionally, while in the pre-crisis era it was typical for project-financed plants to be structured with maturities in excess of 15 years, lenders' interest in such long maturities has waned in recent years, and is now strictly bounded by PPA and or hedge availability.

2. Public Equity Markets

The cost of equity has returned to levels similar to those before the financial crisis and lower than a year ago. A readily visible indicator of this reduction is the estimated cost of equity for publicly-held IPPs. For example, Figure 13 shows the cost of equity for NRG, Calpine, and GenOn (including its predecessor companies RRI and Mirant).[87] While each company has a number of idiosyncratic issues that have affected its cost of capital, we see that overall for the group, the cost of equity reached the mid-teens in 2008 during the financial crisis. Now, these companies' equity costs have receded to pre-crisis levels of approximately 10% to 12%, thereby improving the prospects for investments in ERCOT.[88]

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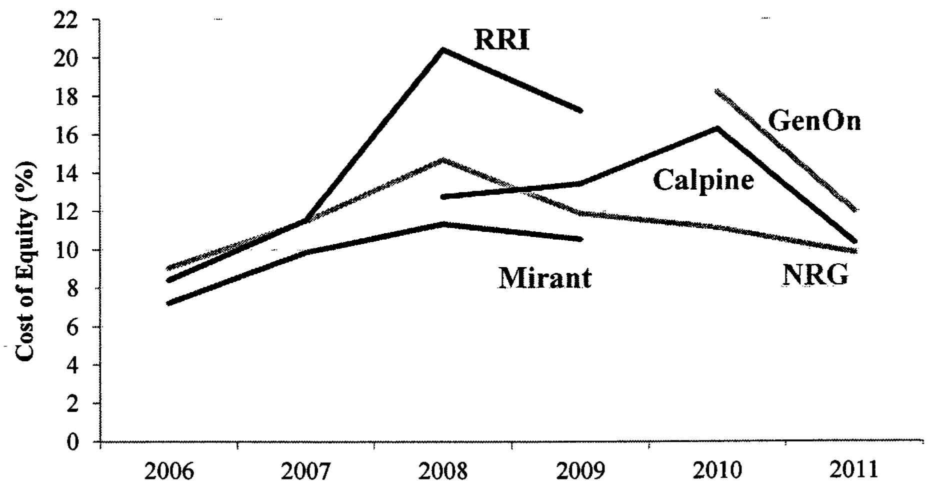
87 As estimated by Bloomberg (2012).

88 The companies' share prices and price-to-earnings ratios, however, have been held down by current and expected low energy margins, see, for example, Dow Jones (2012).

Figure 13
Estimated Cost of Equity for Calpine and NRG



Sources and Notes:

Cost of equity estimated by Bloomberg by using the capital asset pricing model with the current risk-free rate, standard beta estimates, and the most recent market risk premium provided by Ibbotson.

RRI and Mirant merged to form GenOn in 2010, see GenOn (2010).

Data from Bloomberg (2012), as of May 15, 2012.

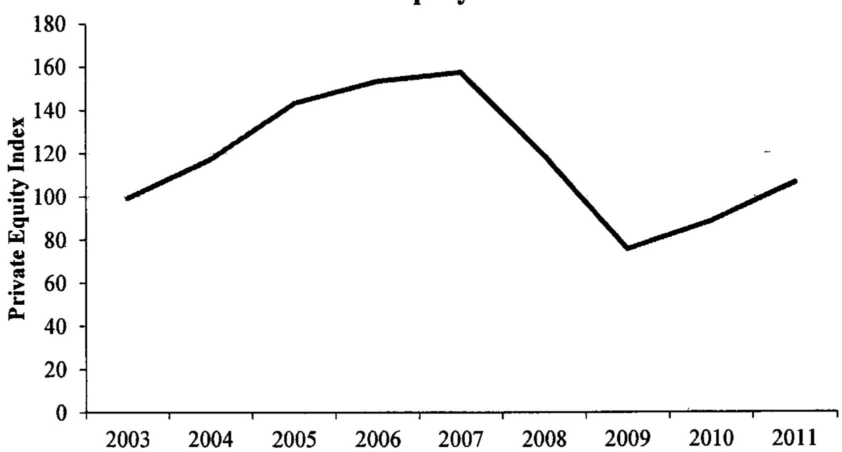
3. Private Equity

Similar to these trends in public equity markets, investment interest from private equity firms has started to recover since the financial crisis in 2008, albeit less robustly than for public shareholders The Private Equity Growth Capital Council, a private equity trade organization, reported approximately $120 billion in private equity investment volume over the four quarters ending in March 2012, up from approximately $55 billion in 2010, and down from approximately $220 billion in 2006.[89] Private equity investments in electric generation have been relatively prolific, and some in the industry now observe an excess of investor interest relative to the number of attractive investment opportunities.[90] Figure 14 shows a private equity index that tracks the health of the private equity sector incorporating measures such as private equity deal volume, equity contributions, private equity fundraising, and exit volumes. The index shows that although investment dropped steeply after the financial crisis, it has been recovering since 2009.

89 See Private Equity Growth Capital Council (2012), p. 2.

90 See Power Intelligence (2011).

Figure 14
Private Equity Index



Source:
Private Equity Growth Capital Council (2012).

Private equity investors are generally oriented to higher risks and returns than are public shareholders and may therefore have greater sensitivity to debt availability. This means that the current anemic state of debt markets may be the greatest challenge for private equity investments.

D. Implications for Generation Investment in ERCOT

1. Ability to Finance Plants without Long-Term Contracts

The ERCOT portion of Texas transitioned from a cost-of-service regulated market to a deregulated market over 1996 to 2002.[91] This is important for resource adequacy, because retail market design affects LSEs' willingness to sign long-term contracts with generators. In regulated markets, the vertically-integrated utility has a long-term obligation to serve load and will procure supply in a portfolio that includes direct ownership and long-term contracts. Municipalities and cooperatives in Texas, which account for approximately 25% of ERCOT load, will plan supplies in this way and so are likely to support some generation development through ownership or long-term contracts.[92]

However, in the restructured retail space covering 75% of ERCOT load represented by approximately 179 REPs, customers are no longer bound to a specific REP and may switch suppliers at any time, subject to contractual terms.[93] Small retail customers typically sign contracts with a particular REP for up to a year or occasionally two; the largest commercial and industrial (C&I) customers typically sign contracts with 1- to 5-year durations. Without captive load, REPs in Texas similarly limit most of their procurement to less than 3 years, and only to the extent they have promised fixed rates to their customers (as opposed to indexed rates). Signing longer-term supply contracts would put the REP at risk of having above-market

91 Kiesling and Kleit (2009), pp. 28–36.
92 See ERCOT (2012i), p. 6.
93 See ERCOT (2012c), p. 15.