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Valuation of an Advanced Combined Cycle Power Plant and its Cost of New Entry (CONE) Into the ERCOT Market

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Valuation of an Advanced Combined Cycle Power Plant and its Cost of New Entry (CONE) Into the ERCOT Market

by

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Dedication

To Randi, Zoe and Phoebe

Acknowledgements

I need to thank numerous people who helped guide my efforts throughout my two year at the forty acres. First, hearty thanks go to my Committee, Michael Webber, Ross Baldick, and Michael McCluskey. They provided strong, yet constructive criticism in a way that improved the final product and bolstered the author's aspirations. Thanks go to John McLeod for offering up Reader suggestions. I also need to thank Tanya Andrien, the young John Butler, and Rob Jones from the McCombs School, who provided valuation guidance, and who always made themselves available.

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Abstract

The Cost of New Entry (CONE) for an Advanced Combined Cycle Power Plant Into the ERCOT Market

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The Texas ERCOT market is one of the most open, deregulated electricity markets in the world. This open market brought electricity costs down for Texas residents and businesses, creating a much more competitive economic climate. However, these low prices currently generate insufficient revenue for generators to finance construction of new or replacement generation assets. In the instance of combined cycle advanced natural gas, the Independent Market Monitor 2012 annual report estimated that a plant needed to generate 2.5 times as much as revenue it did in 2012 to incent new generation.

This author argues that while the gap is still significant, the continuous changes to the ERCOT market since its inception make an historical examination like that used by the IMM less accurate. New market rules such as price caps or changes in fuel markets through new technologies like hydraulic fracturing create a very different valuation gap than a model based on historical activity alone. This analysis attempts to get a more accurate approximation of the gap through the use of publicly traded futures contracts for natural gas and electricity. Electricity futures reflect market expectations of revenue

based on current and future market rules. Gas futures reflect price expectations in light of market changes like fracturing, potential LNG exports, and other changes. Financial positions can be maintained in both markets to give a fixed rate of return. Using this method, one can create a very conservative valuation model that still more accurately reflects market sentiment.

This thesis starts with a brief history of ERCOT deregulation from the early 2000s to present in order to clarify for the reader the changes that have taken place in the market. It then demonstrates the futures-valuation model using an advanced combined cycle power plant as an example.

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Chapter 1: Introduction

This study explores the impact historically low gas prices are having on ERCOTs electrical grid. Specifically, it values a hypothetical combined cycle power plant project and examines the gap between capital and operations costs and market revenues. It starts with a history of deregulation in Texas' electricity market and a brief explanation of its current structure. It then discusses some of the proposed changes facing the market. It then moves a hypothetical power plant valuation. Chapter three outlines the methodology for the valuation; 10-year gas and electricity futures market prices are used as low-risk proxies for actual spot prices that have yet to occur. Using this methodology, chapter four provides the results from this analysis, including what futures prices for both natural gas and electricity must be for new investment.

The move by the Electric Reliability Council of Texas' (ERCOTs) to a deregulated market has largely been successful at achieving ERCOTs goal; electricity prices slowed or fell for most areas and industries in Texas. High participation rates of end-users, especially commercial and industrial users, in selecting their preferred retail electric provider (REP) rather than their default REP was seen as another indicator of the new market's success.

Renewable generators, wind power in particular, substantially altered market pricing due to government incentives and the fact they do not have fuel costs. As Newell notes, it is estimated that wind accounts for 9 percent of Texas capacity, on average.[1] However, at off-peak periods, it has produced as much as 40 percent of systemwide

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1 Newell, Samuel et al., The Brattle Group, ERCOT Investment Incentives and Resource Adequacy, June, 2012. Available from: http://www.ercot.com/content/news/presentations/2012/Brattle%20ERCOT%20Resource%20Adequacy%20Review%20-%202012-06-01.pdf. Accessed 22 October 2012, pp15-16.

demand.[2] Because of this, many natural gas plants that often may have provided base-load regularly now fulfill the role of peaking facilities, quickly ramping up generation in times of need from the grid and ramping back down when redundant. Natural gas' moderately low price at this time, unique role as the main fuel source for Texas electricity generation – 45.4 percent of Texas's electricity came from natural gas in 2010[3] – and its relatively low emissions also increase the importance of gas-fired power plants to the state[4].

Gas' unique position in Texas electricity also creates a very strong correlation in pricing between electricity and natural gas prices. History demonstrates this phenomenon; as natural gas prices rose and fell in response to events like Hurricane Katrina, electricity prices showed similar price spikes[5]. Wind, nuclear, and coal, usually the cheapest generation sources, provide the base load for Texas. As power demands increase, gas plants come online. The newest, most advanced combined-cycle gas power plants can reach full generation capacity in less than fifteen minutes, compared to more than 24 hours for some coal-fired power plants. Base-load have fairly consistent costs, keeping the market steady, but these natural gas plants at the margin have very different heat rates from one another. When demand rises, the less efficient, more expensive generation assets ramp up, raising electricity prices. For these reasons, it is important to understand the impact of low natural gas prices and current ERCOT market forces on the ability to build new generation to meet demand.

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[2] http://www.ercot.com/news/press_releases/show/26611

[3] U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor forms. Table 5. Electric Power Industry Generation by Primary Energy Source, 1990 Through 2010 (Megawatthours). Available from: http://www.eia.gov/electricity/state/Texas/. Accessed 23 November 2012.

[4] Newell, Samuel et al., 2012, pp.15-16.

[5] Ibid., p17.

Chapter 2: A Brief History of the Relationship between Natural Gas and Texas' Deregulated Electricity Market

CALIFORNIA DEREGULATION

Prior to market reform in 1998, three integrated investor-owned utilities (IOUs) owned or controlled 75 percent of California's power market. Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E) provided integrated power services, from wholesale power generation to transmission and distribution to individual customers. Subject to California Public Utility Commission's (CPUC) rate-of-return regulation that allows IOUs to charge rates high enough to recoup costs as well as a reasonable rate of return. While California electricity had very high reliability, it also had the highest retail electric costs in the country. Prices in the early 90s averaged $60 per megawatt hour (MWh) for embedded generation costs in California, compared to $17/MWh at the California-Oregon Border for out-of-state power.[6]

In an effort to address high electricity costs, the CPUC phased in deregulating policies, injecting market forces into the industry to create competition and reduce prices. Over the course of the early 90s, CPUC implemented a competitive bidding process for all new generation capacity. In 1995, they required all IOUs unbundle generation from transmission and distribution services. All generators would have access to the California transmission and distribution (T&D) network for a fee approved by the CPUC. Generators would compete on generation price for business. The cheapest generation plants would be the first to energize the grid while the plants demanding the highest prices would only come on for peaking needs.

[6] Woo, Chi-Keung. "What went wrong in California's electricity market?" *Energy*., 26 (2001). 747-758.

Finally, in 1996, the California Legislature passed Assembly Bill 1890 (AB1890), legislating some of the rules put in place by CPUC. AB1890 included the following elements:

(a) A retail rate freeze at the 1996 level so that the difference between the average embedded cost for generation and the wholesale market price would help pay for the IOUs' stranded generation cost. The freeze for an IOU would last till March 31, 2002; unless the IOU had fully recovered its generation stranded cost before this date.
(b) An immediate rate reduction of 10 percent for residential and small commercial ratepayers. The financing of the rate reduction is through the issuance of 'rate reduction bonds' to be repaid by a charge on retail consumption.
(c) Continued funding for low-income ratepayer assistance programs, public purpose programs for public goods research, development and demonstration, demand-side management and renewable electric generation technologies.
(d) Incentives for the IOUs to divest their fossil-fuel generation units.
(e) Retention of ownership (but not control) of T&D assets by the IOUs.
(f) Creation of a non-profit [Power Exchange] PX to operate the wholesale energy markets.
(g) Creation of a non-profit ISO to manage and operate the California grid.[7]

In the end, it changed California's grid system from a collaboration of regulators and vertically-integrated IOUs into a non-integrated 5-level system. With the new system, (1) regulators created a (2) wholesale energy market where buyers and generators bought and sold power on a trading floor. (3) Independent system operators (ISOs), formerly the State's IOUs, made these wholesale energy transactions on the market. (4) T&D companies, still regulated by rate-of-return (now called price cap) regulation, managed transmission infrastructure and ensured open access to their power lines. Finally, at the consumer end of the distribution chain, (5) they created a retail market that allowed retail customers to freely choose their preferred power provider. While the system was undoubtedly more complicated, it injected competition into two different

[7] Ibid, pp. 751-752.

areas – generator trading and retail choice – allowing free market forces to influence the major components of power. .

Once fully phased in, the new system initially improved costs without substantially hurting reliability. The incentive to divest power generation was initially effective, inducing the big three IOUs to sell off 10 percent of their generating capacity by May of 1999. Two power exchanges (PX) markets were created, one for present-day pricing (the day-of market) and one for pricing the next day (the next-day market). Between 1998 and 2000, customers mainly noticed nothing but price stabilization in their electricity bills. While prices continued to rise, they did so at a flattened rate.

However, in January 2001, clear issues with the system arose. The rate freeze initially helped the IOUs, especially PG&E and SCE, to pay off some of their stranded costs. However, summer prices during 2000 spiked, straining PG&E and SCE capital reserves and eventually causing them both to become financially insolvent by January 2001. Although incenting divesture of generating capacity attracted new power companies to the California generation market beyond the big three, it still had only 10 primary wholesalers with a tight demand market, ensuring generators nearly any price demanded in trading. Since PG&E and SCE were still such dominant generators and continued to operate under rate freezes, and since electricity demand is largely price insensitive, the power demands of the overall market were consequently price-insensitive as well.

The IOUs were also required by the CPUC to buy from the PX and ISO markets. These purchasing requirements combined with a largely inelastic electricity demand market and ever-dwindling reserve capacity made the market incredibly vulnerable to price spikes. Even mild shortages caused heavy competition by IOUs seeking additional capacity on the PX and ISO markets. This situation caused prices to spike much earlier in the demand curve than was sustainable for IOUs. Additionally, as Stoft notes, California's exchange-only operated in energy quantity and price and did not account for startup and no-load costs, causing gaming to the system.[8]

The market was made even more vulnerable to sustained price hikes because it lacked any forward market. Without the option to lock in pricing agreements for extended periods of time, IOUs were unable to hedge against changes in fuel prices, market dynamics, etc. If contracts had been allowed, utilities might have been able to lock in $60/MWh pricing rather than the spikes plaguing the market that reached as high as $750/MWh for non-peak power.

Finally, the trading options limitations of either day-of or next-day pricing in direct sequence made the next-day trading all but useless. Sellers would offer high next-day prices, knowing that if the offers were not accepted they would be able to go back the next day and offer it on the day-of exchange. If the offer was accepted, it usually did not provide strong price hedging.

DEREGULATED TEXAS

Much like California, ERCOT historically consisted of a few major, vertically-integrated power providers that dominated the market.[9] These included Texas Utilities Electric Company (now TXU), Houston Lighting and Power Company (now split into Reliant Energy and CenterPoint Energy), Central and Southwest Corporation (now merged with American Electric Power Company), and Texas-New Mexico Power Company. In addition to these private companies, 60 electric cooperatives and nearly 50

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[8] Stoft, *Power System Economics*. p. 88

[9] Zarnikau, Jay. "A Review of Efforts to Restructure Texas' Electricity Market." *Energy Policy* 33, no. 1
(January 2005): 15–25. doi:10.1016/S0301-4215(03)00193-9. p. 15.

municipalities were permitted to provide Transmission/Distribution Service providers (TDSP) and Retail Electric Providers (REP) services, respectively.

The majority of Texas power is managed by the Electric Reliability Council of Texas (ERCOT). Texans established ERCOT to manage reliability and cost of the state's electrical grid. It does so by encouraging interconnectedness, coordinating power provider activities, and facilitating power transfers between generators during emergencies.[10]

Even as California began to face challenges with their deregulated system in the late 90s, Texas enacted legislation in 2002 that mirrored California's framework in a lot of ways. Under Senate Bill 7 (SB7), most retail electricity providers (REPs) were allowed to choose their investor-owned utilities (IOUs). Vertically integrated providers were required to separate operations into distinct business units for generation, transmission and distribution service providers(TDSP), and REP. TDSP operations still required regulation in acknowledgement that of their natural monopolistic role.[11] Municipalities, rural electric cooperatives and other non-IOUs were granted the ability to continue their existing monopolistic position, but with the caveat that should they decide to open their retail power market to competition in the future they would be unable to go back to a monopolistic market. These operators were labeled non opt-in entities (NOIEs).

Price caps and market rules were used for both generation and REP in order to ensure a certain level of reliability and reduce market manipulation. Without price caps for instance, generators could be incented to intentionally withhold capacity until such a time as prices spike to lucrative levels. However, beyond these basic safeguards, REP and

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10 Ibid, p. 16.

11 Zarnikau, Jay, and Doug Whitworth. "Has Electric Utility Restructuring Led to Lower Electricity Prices for Residential Consumers in Texas?" *Energy Policy* 34, no. 15 (October 2006): 2191–2200. doi:10.1016/j.enpol.2005.03.018. p. 2191.

generation ran mainly unregulated to ensure market influences acted as the main price determinant.[12]

The Public Utility Commission (PUC) reviewed and approved rate cases from these utilities in an effort to control costs until deregulation legislation took full effect in 2001-2002, at which point rate cases only applied to TDSP services. Rate cases would be approved at prices that would "permit utilities a reasonable opportunity to recover their reasonable and necessary costs of business and earn a reasonable return on prudent investments".[13]

While California and Texas shared many parts of their electricity deregulatory policy, it is useful here to discuss some major differences. In deregulating, California saw a risk of destabilizing reliability. They felt a competitive market would demonstrate an increased willingness to accept greater load-release events in exchange for greater returns. There is nothing deceptive or criminal in this calculus – it is simply rational behavior for a company seeking to maximize profits. As Milstein and Tishler note, "instead of building new capacity that will be idle during most of the year, electricity producers let the electricity price spike."[14] This allows greater profits on existing assets rather than moderate profits on a greater number of assets. California therefore instituted a reserve capacity requirement, internalizing the cost of reliability that the market might rationally avoid. REPs were required to incorporate a portion of their rate to use for development or access to additional reserve capacity.

Texas regulators also saw reliability challenges in deregulation. In contrast however, ERCOT relied on an "energy-only" market to both lower operations costs and

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12 Ibid, p. 2191.

13 Ibid, p. 2192.

14 Milstein, Irena, and Asher Tishler. "The inevitability of capacity underinvestment in competitive electricity markets" *Energy Economics.*, 34, (2012): 62-77.

drive additional capital investment. This model utilizes the price spikes on the spot market as an incentive to attract additional generation investment. While undoubtedly more volatile than a market with regulated reserves, the hope was that overall prices would be lower as the market determined more accurate cost structures than the regulator, no matter how sophisticated, may derive. While a few other markets around the globe operated under similar principles (notably Alberta, Canada and Australia), ERCOT is unique in the United States. In this way ERCOT acted as a test-case for the country.

As such, Texas' deregulatory framework was heavily praised from the onset. It had one of the highest switchover rates of any state. By October 2004, about 67 percent of industrial load users, 54 percent of commercial users, and nearly 20 percent of residential users offered the choice had switched to a different retail provider.[15]

In addition to heavy adoption by residents and especially businesses, cost savings have materialized. In the Annual Baseline of Choice in Canada and the United States, ERCOT has been recognized as the most competitive retail market in North America for the last three years (2009-2011).[16] The evidence suggests the new framework has been particularly advantageous for large power users. This is intuitive. Large users demand significant load and require significantly less support from power companies relative to residential customers. They are more sophisticated users and more open to new cost-cutting methods. It is less expensive to pursue these customers rather than market to a wide residential audience. The effort to attract the power load of a single industrial plant versus the thousands of homes using the equivalent power make it clear the most competition between REPs will come in trying to land these big customers. Indeed, larger

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15 Zarnikau, 2006, p. 2192.

16 2011 Scope of Competition in Electric Markets in Texas, Public Utility Commission of Texas, January 2011, p. 49.available from: http://www.treia.org/assets/documents/reports-and-studies/puc.scopeofcompetitionreport2011.elec.pdf. Accessed 8 December 2012

users frequently had as many as 10 REPs providing competitive pricing options to lure their business and secure a major portion of REP load.[17] Only a few retailers targeted residential load.

As deregulation began to take root in Texas, retailers did not compete as much for smaller users, especially residential customers. This is in part due to market forces discussed above, but it is also due to Price to Beat (PTB) rules regarding switching to other REPs. PTB rules limit the ability to garner substantial savings. Texas restructuring rules required an automatic 6 percent discount as the PTB benchmark for potential competitors for the first five years (until January 1, 2004). Affiliate REPs (AREPs) were permitted to charge lower rates after 36 months or once they lost at least 40 percent of their residential and small commercial load to competitors. Only at this point did the PTB become a ceiling rather than a benchmark, allowing AREPs to offer lower prices.[18] Any consumer purchasing over 1 MW annually received no price cap protection. The 2003 PUC Scope of Competition report detailed the smaller success of deregulation on residential rates, estimating that of the $902 million in savings realized by residential users in 2002, one fourth was due to the 6 percent discount and the remainder was due solely to lower fuel costs.[19] Even after the 6 percent discount expired, REPs found the transaction and marketing costs to reach this cohort price them out of the market. Even so, the report confirmed that deregulation had a net positive effect on pricing. Changes in the fuel market compounded those savings.

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17 Zarnikau, 2006, p. 2192.

18 Ibid, p. 2193.

19 2003 Scope of Competition in Electric Markets in Texas, Public Utility Commission of Texas, January 2004, p. 83. available from: http://www.hks.harvard.edu/hepg/Papers/Texaspuc_Comp.elec.markets.report_1-03.pdf. Accessed 8 December 2012

THE IMPACT OF FRACKING ON ELECTRICITY PRICE

The newfound ability to extract natural gas from unconventional sources such as the tight shale found in the Bend arch-Fort Worth basin dramatically increased domestic natural gas production, completely changing commodity market forces, especially so in the US.

Before hydraulic fracturing (fracking) matured, United States imports of liquid natural gas (LNG) grew steadily (see Figure 2.1), reaching a high of 4.6 tcf in 2007. Since that year, even as GDP grew, US imports of natural gas declined roughly 6.8 percent annually, on average, equal to approximately 288 bcf less in natural gas imports per year.[20] In 2010, imports equaled only 3.5 tcf. At this rate, it is projected that the United States could become a net exporter by 2035.[21] In fact, in contrast to most developed countries and regions throughout the world, the impact of fracking suggests that North America as a whole may become net exporters of both oil and gas by 2030 (see Figure 2.2).

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20 EIA, 2012.

21 International Energy Agency (2012), *World Energy Outlook 2012*, OECD Publishing. doi: 10.1787/weo-2012-en , p.76.

Figure 2.1. Annual natural gas imports, 1973-2011[22]

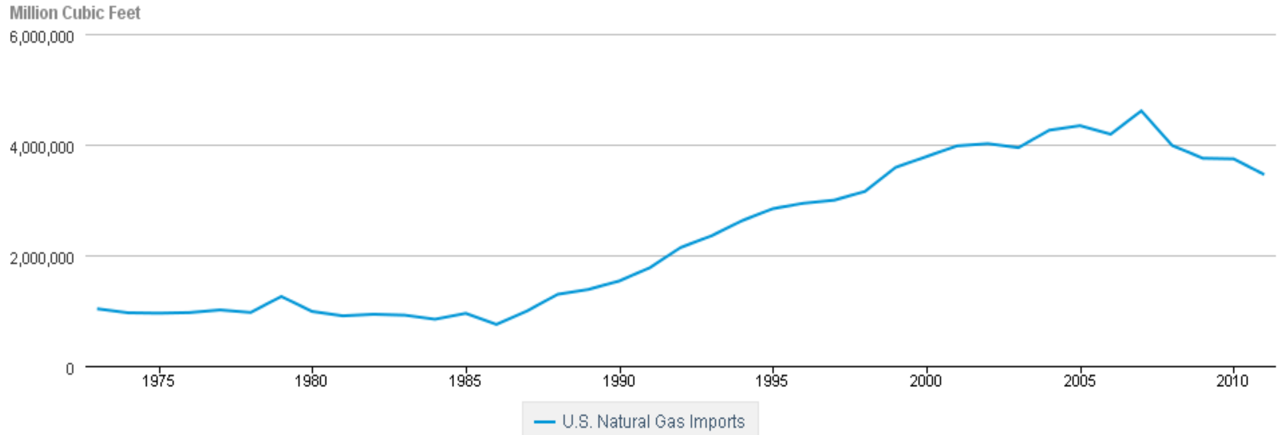
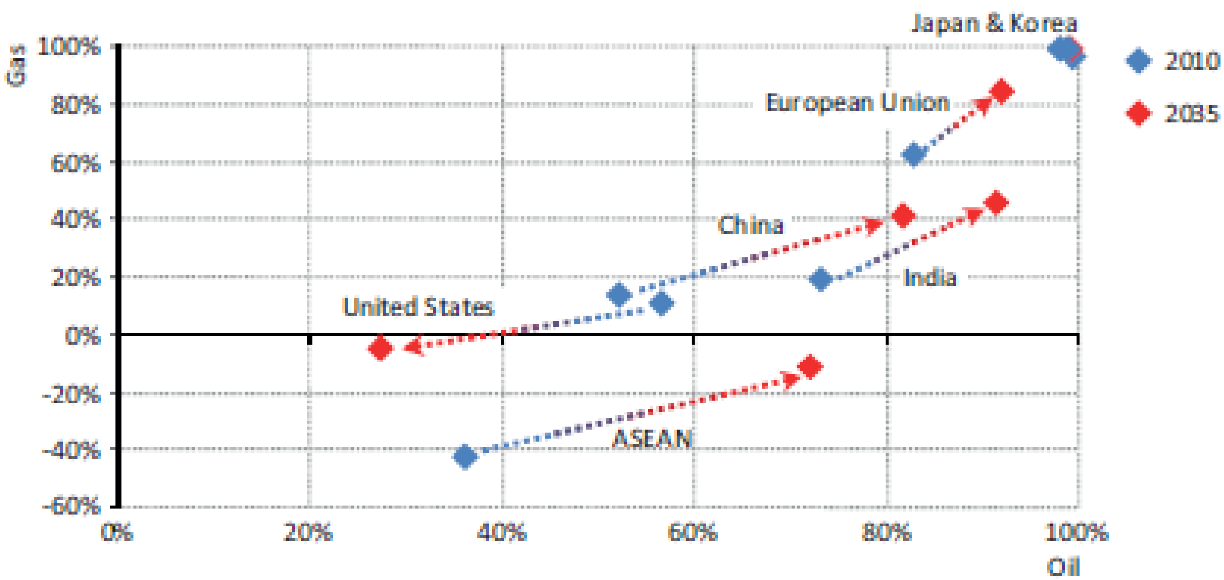


Figure 2.2. Net oil and gas import dependency in selected countries projects[23]



Natural gas prices declined dramatically as a consequence of the growing domestic supply. Before fracking began substantially impacting prices, natural gas cost

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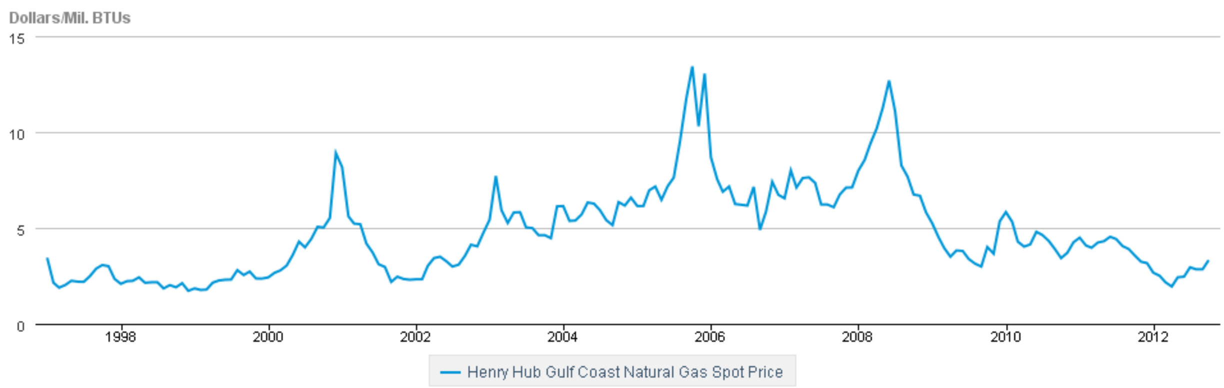
[22] U.S. Energy Information Administration, "US Natural Gas Imports". Available from: http://www.eia.gov/dnav/ng/hist/n9100us2A.htm. Accessed 24 November 2012.

[23] International Energy Agency (2012), *World Energy Outlook 2012*, OECD Publishing. doi: 10.1787/weo-2012-en. p. 76.

between $5 and $7 dollars per MMBtu with natural disasters such as Hurricane Katrina causing sporadic spikes as high as $13.42 (see Figure 2.3). In contrast, the highest spike since 2009 was January 2010's average price of $5.83/MMBtu. Prices have stayed well below this price point since then, hitting historic lows of $1.95/MMBtu in April 2012 and staying below $4.00/MMBtu for over a year. As of October 2012, spot prices averaged $3.32/MMBtu.[24]

Figure 2.3. Henry Hub gulf coast natural gas spot price by month, 1997-2012[25]



As spot prices declined and forward contracts expired for national utilities, natural gas costs in electricity generation also declined (see Figure 2.4.) After hitting an average high of $9.01 for the year 2008, prices have more than halved, with a 2012 year-to-date average of $3.16. Additionally, over the same 2008-2012 time period, natural gas generation capacity grew 3.9 percent, or 15.6 gigawatts. The only other fossil fuel-based generator to grow was coal (by 5.9 gigawatts) over that same time period, but only by 1.9 percent (see Figure 2.5).

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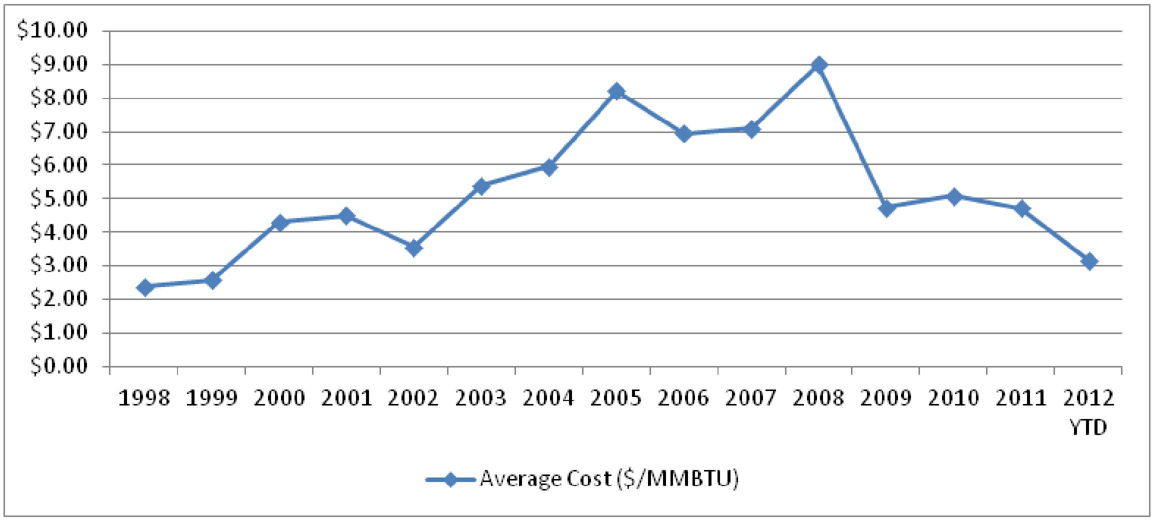
24 EIA, 2012.

25 U.S. Energy Information Administration, "Henry Hub Gulf Coast Natural Gas Spot Price". Available from: http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm. Accessed 24 November 2012.

Figure 2.4. Average natural gas costs for electricity and heat production, 1998-2012[26]



Low gas prices continue to impact Texas. After generation using natural gas peaked at 199.5 gigawatt hours (GWh) in 2007, it declined until 2011 when new facilities came online to take advantage of new pricing (see Figure 2.6). Between 2010 and 2011, 13.6 additional GWh of natural gas-fired power was generated, bringing the state's total natural gas generation in 2011 to 200.5 GWh.

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[26] U.S. Energy Information Administration, "Electric Power Monthly June 2012". Available from: http://www.eia.gov/electricity/monthly/pdf/chap4.pdf. Accessed 24 November 2012.

Figure 2.5. Electric net summer capacity, 1949-2011[27]

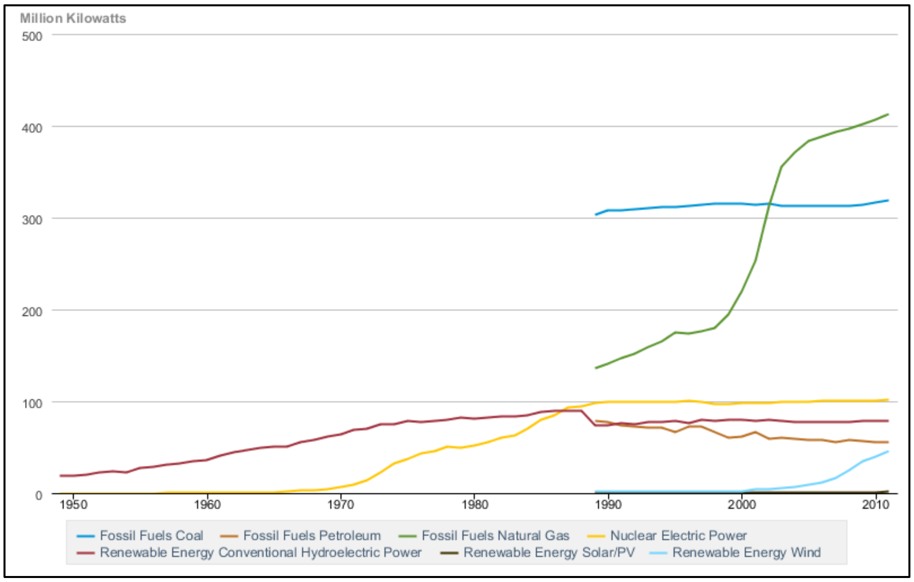
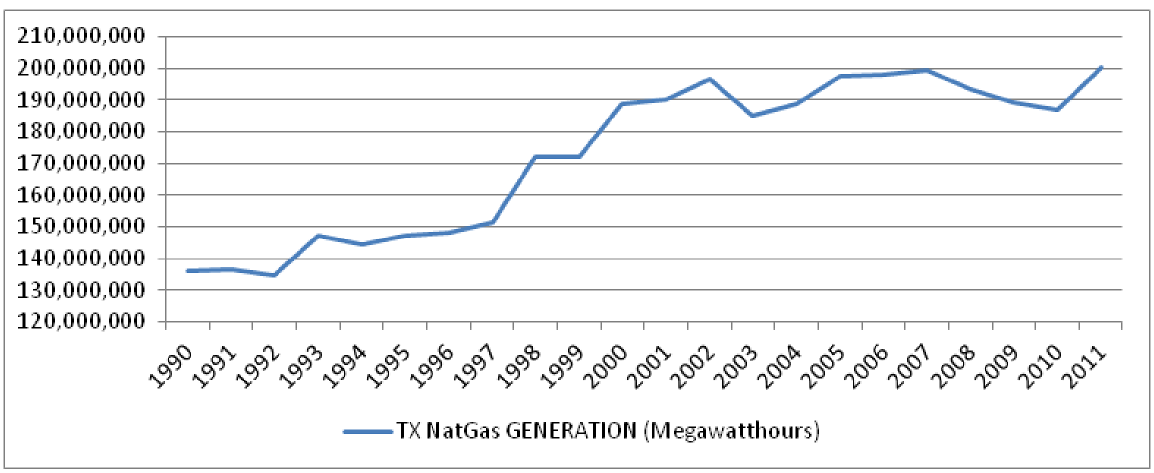


Figure 2.6. Texas electricity generation from natural gas[28]

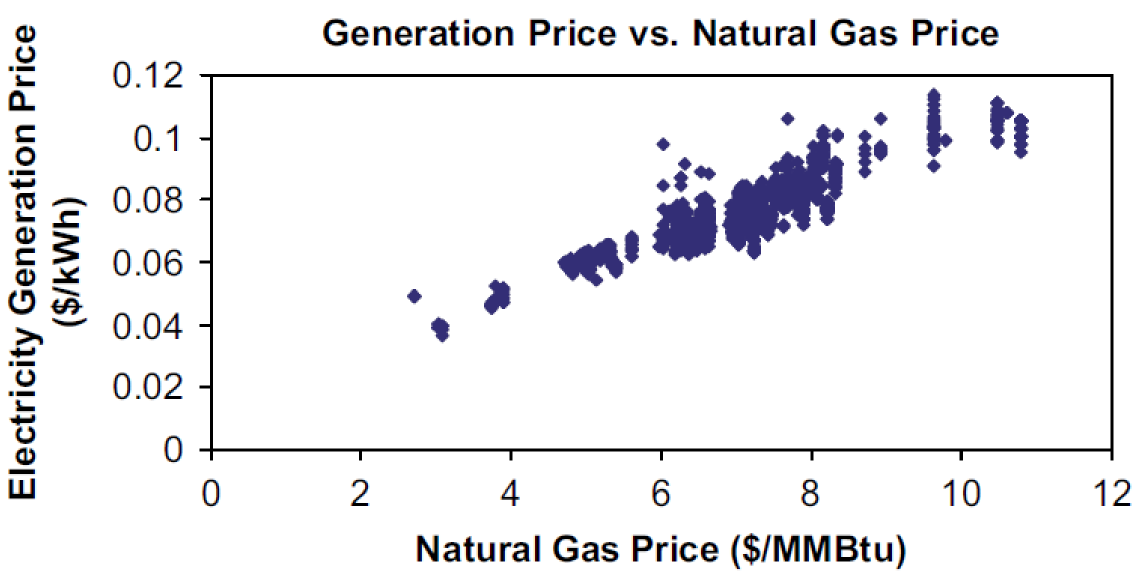


27 U.S. Energy Information Administration, "Annual Energy Review, Table 8.11a Electric net summer capacity: Total (all sectors), 1949-2011 (sum of tables 8.11b and 8.11d; million kilowatts)". Available from: http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb0811a. Accessed 24 November 2012.

28 U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor forms. Table 5. Electric Power Industry Generation by Primary Energy Source, 1990 Through 2010 (Megawatthours). Available from: http://www.eia.gov/electricity/state/Texas/. Accessed 23 November 2012.

As Zarnikau et al. points out, "it is difficult to analyze trends in the retail prices paid by commercial [or any other] sector electricity consumers in the ERCOT market because there is no public survey of retail prices quoted to commercial [or any other] sector electricity consumers."[29] However, by examining price quotes by competitive retail electric providers (CREPs) to load aggregators, a comparison of generation price and natural gas price can be made. Figure 2.7 demonstrates that this comparison shows a strong correlation between electricity generation and natural gas prices in Texas. Through regression it suggests that for every $1/MMBTU increase in natural gas price there is a corresponding wholesale electricity rate increase of $0.0054/kWh for Texas commercial users.[30]

Figure 2.7. Texas commercial electricity generation price versus natural gas price[31]



[29] Zarnikau, Jay, Marilyn Fox, and Paul Smolen. "Trends in Prices to Commercial Energy Consumers in the Competitive Texas Electricity Market." *Energy Policy* 35, no. 8 (August 2007): 4332–4339. doi:10.1016/j.enpol.2007.02.024. p. 4334.

[30] Zarnikau et al, 2007, p. 4335.

[31] Ibid, p.4335.

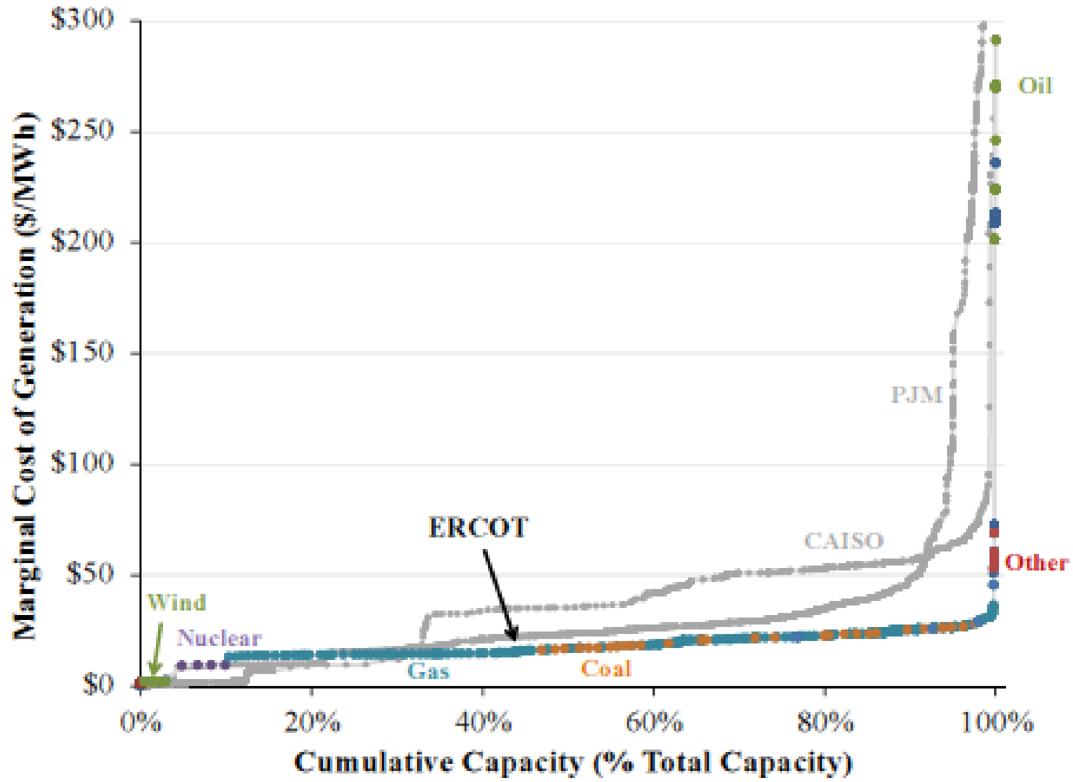
REGULATORY EFFORTS TO INCREASE RESERVE

Even though savings were not as great as expected for residential users, the market has become much more efficient and cost-effective overall. As Figure 2.8 demonstrates, the marginal cost of generation for wholesale generators operating within the ERCOT market stays below the cost curve of other major markets, notably the Pennsylvania-New Jersey-Maryland Interconnection (PJM) and the California Independent System Operator (CAISO). The marginal cost of generation simply forecasts how price changes relative to supply. Generally, generation costs stay flat until they approach the last 5%-10% of capacity, at which point they quickly balloon. Whereas these other markets have to charge greater than $50/MWh as early as 70 percent of capacity for CAISO and 90 percent of capacity for PJM, the ERCOT cost curve does not go above $30/MWh until the market approaches 98 percent of capacity. This hyper-efficiency is great for market efficiency and consumer pricing but it impacts reliability. Energy pricing margins have been so dramatically impacted that analysts in 2012 felt equilibrium (the amount of generation the market would support) would only create an 8 percent reserve (see Figure 2.9).

To keep ERCOT reliably meeting Texas power demand, some level of reserve capacity must exist to maintain power in times of need. This means that in any given day, a portion of generation capacity sits prepared to produce power. This is done primarily to manage unusually high demand on the system or unexpected plant drop-offs. Extremely cold or hot days often are the culprit, pushing heating or air conditioning systems to draw additional load from the system. When this happens, the reserve margin is there to meet it. Otherwise, rolling blackouts would need to be instituted to keep ERCOTs grid from collapsing under the additional demand. This is exactly what happened in January 2011 as an unusually cold day froze controls on some natural gas pipelines, shutting down

7,000 megawatts of power generators at the same time as demand for power to heat homes escalated.[32]

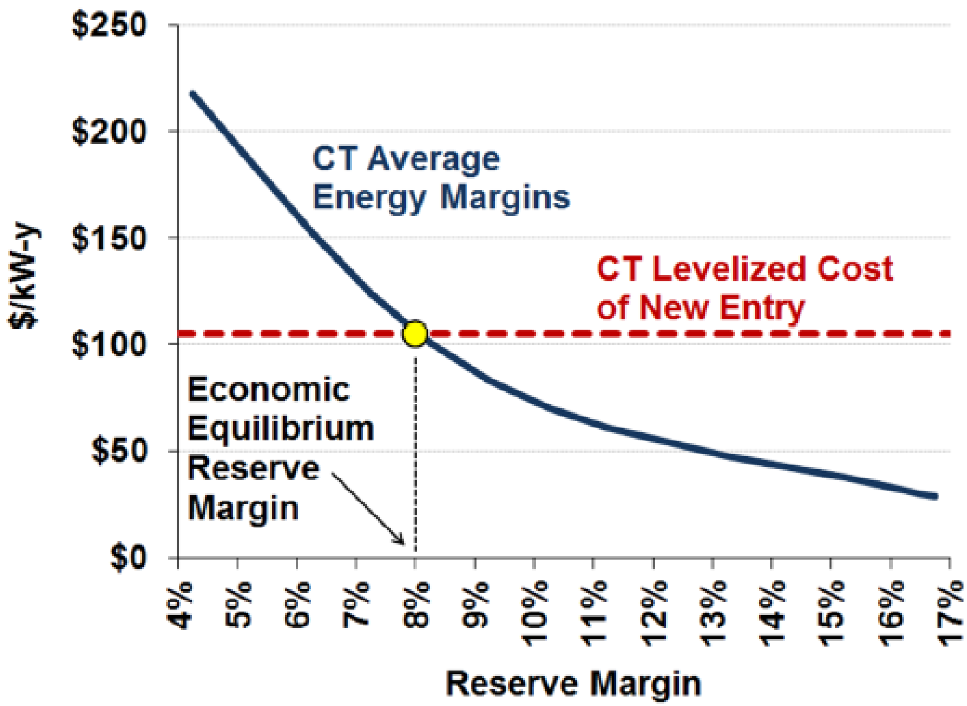
Figure 2.8. ERCOT power generator supply and price versus the Pennsylvania-New Jersey-Maryland Interconnection (PJM) and California Independent System Operator (CAISO)[33]



[32] Baltimore, Chris. Texas weathers rolling blackouts as mercury drops, February 2011. Reuters. Available from: http://www.reuters.com/article/2011/02/02/us-ercot-rollingblackots-idUSTRE7116ZH20110202. Accessed 26 November 2012.

[33] Newell, Samuel et al., The Brattle Group, ERCOT Investment Incentives and Resource Adequacy, June, 2012. Available from: http://www.ercot.com/content/news/presentations/2012/Brattle%20ERCOT%20Resource%20Adequacy%20Review%20-%202012-06-01.pdf. Accessed 22 October 2012. p.18.

Figure 2.9. Reserve margin equilibrium, June 2012[34]



However, since reserve margin power generation supply generates infrequently, higher energy prices are required to recoup costs. As of early 2013, ERCOTs regulatory market, efficient power generation portfolio and low gas prices were not providing energy prices high enough to support ERCOT's target reserve margin of 13.75 percent. In fact, Newell and the Brattle Group forecast that current policy and peak offer price caps of $3,000 are only sufficient for maintaining a reserve margin of only 6 percent. With the price cap now raised to $9,000, the reserve margin is estimated at 10 percent, still well below the target of ERCOT. A 10 percent reserve margin translates roughly into "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."[35] Needless to say,

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34 Ibid, .p. 5.

35 Newell, Samuel et al., The Brattle Group, ERCOT Investment Incentives and Resource Adequacy, June, 2012. Available from:

outages of this magnitude could dramatically impact the Texas economy as well as public welfare.

ERCOT and the PUC are well aware of the unique challenges facing the Texas electricity market. In 2012, the Brattle Group completed a study commissioned by ERCOT. ERCOT tasked them with determining the major factors discouraging generation investment, forecasting the market outlook on resource adequacy, and providing policy options for encouraging investment that meets long-term resource adequacy.[36] This led to the aforementioned price cap increase for peak power from $3,000 to its current rate of $9,000. In all, Brattle gave five policy recommendation options that ranged from heavily market-based solutions to heavily regulation-oriented solutions (see Figure 2.10). They found that in addition to the efficiency of generation resources and the low cost of fuels, investors saw heightened risk due to the inability of generators to lock in long-term contracts.

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http://www.ercot.com/content/news/presentations/2012/Brattle%20ERCOT%20Resource%20Adequacy%20Review%20-%202012-06-01.pdf. Accessed 22 October 2012. p. 3.

[36] Newell, Samuel et al., The Brattle Group, Summary of "ERCOT Investment Incentives and Resource Adequacy", July, 2012. Available from: Newell, Samuel et al., The Brattle Group, ERCOT Investment Incentives and Resource Adequacy, June, 2012. Available from: http://www.ercot.com/content/news/presentations/2012/Brattle%20ERCOT%20Resource%20Adequacy%20Review%20-%202012-06-01.pdf Accessed 26 November 2012.

Figure 2.10. Brattle Group policy scenarios for ERCOT[37]

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

Power plants are multi-decade investments and any change to the market can create huge stranded costs for the generator, limiting their ability to meet their debt obligations. This volatility is causing investors to exact greater returns, shorter payoff terms, and higher capitalization thresholds from owners. To surpass the 10 percent reserve PUC achieved by increasing the peak price cap, Brattle suggests two investor-

37 Newell, Samuel et al., The Brattle Group, ERCOT Investment Incentives and Resource Adequacy, June, 2012. Available from: http://www.ercot.com/content/news/presentations/2012/Brattle%20ERCOT%20Resource%20Adequacy%20Review%20-%202012-06-01.pdf. Accessed 22 October 2012. p. 118.

oriented solutions; that is, two solutions reduced investor risk and encouraged additional investment.

The first option creates a mandatory resource adequacy requirement for load serving entities (LSEs). In this scenario the PUC determines the appropriate adequacy requirements needed within each area of the state and requires the generators in that area to provide additional supply to meet those reserve requirements. These costs are ultimately born by the consumer.

Generators could either buy or build the necessary capacity.[38] In this scenario, regulators do not determine the retail price needed to meet reserve adequacy requirements. They take the reserve margin equation that already exists system-wide and calculate it regionally, accounting for transmission bottlenecks and differences in demand. The strength in this strategy is it still leaves the electrical system largely to market forces. LSEs are responsible for determining the best way to meet requirements while maintaining market competitiveness.

This option would undoubtedly increase costs as generators either build or buy additional capacity. It would also add implementation and management costs. A multi-year phase-in approach would be essential for lowering risk of stranded costs for investors and thereby encourage them to support additional generation development. However, it could prove a challenge to accurately develop multi-year resource adequacy parameters. Before 2010, ERCOT supported a 13.75 percent reserve margin. After the hot summer experienced in 2011, Brattle now estimates ERCOT would recommend a

[38] Newell, Samuel et al., The Brattle Group, ERCOT Investment Incentives and Resource Adequacy, June, 2012. Available from: http://www.ercot.com/content/news/presentations/2012/Brattle%20ERCOT%20Resource%20Adequacy%20Review%20-%202012-06-01.pdf. Accessed 22 October 2012. p. 112.

reserve of 15.25 percent just to maintain previous reliability standards.[39] Passing this change onto LSEs creates a moving target for capacity reserves. Changes like this could keep investor risk high and discourage generation growth. Without very accurate phase-in allowances, investors might see returns eaten up by new margin requirements. The PUC would need to periodically review and adjust its policy, which would be complicated and likely politically-fraught.

Even with the political and administrative challenges, this option is perhaps the least invasive from a regulatory perspective while still incenting additional generation capacity for the state. It acknowledges the rational and reasonable self-interested nature of competitive market forces, namely that of efficiency. It injects reliability into a system that favors price, creating a second system priority. It leaves self-interested businesses in the market alone to figure out the most profitable methods for following the rules.

Brattle's second option that lowers investor risk recommends adding a centralized forward capacity market to the resource adequacy requirement.[40] In this scenario, ERCOT would not only require generators to meet reliability requirements but would also create an auction to support a forward capacity market. ERCOT would hold auctions to secure obligations from generators for power needs three to four years into the future. Within a given year, generators would provide power for the agreed price and volume. LSEs would still have the flexibility to produce that power themselves or to purchase it from another, lower cost provider. Incremental auctions would take place to manage unforeseen changes to demand.

This is a useful system for many reasons. LSEs would be able to hedge for costs by self-supply or through bilateral forward contracting. This allows them to create

39 Ibid, p.3.
40 Ibid, p. 115.

longer-term plans and continues the exertion of market forces on the system. Investors could get multi-year forward contracts without causing stranded costs risks for REPs lacking captive load. Multi-year contracts lessen investor risk, spurring investment. Eliminating concerns regarding stranded costs reduces the regulatory expenses and phase-in periods often required to accommodate the need to amortize the costs of infrastructure built under a different paradigm. Creating a centralized, long-term auction makes monitoring and managing the system more straightforward and reduces risk of unforeseen events. With three to four years of planning ahead, ERCOT can maintain awareness of retiring plants or maintenance cycles well in advance of them causing curtailments. A centralized auction also increases transparency and limits the market power any individual or small group of businesses can exert on the market.

Even with all the positives, this option would face many of the same disadvantages of the previous one. Administration costs would undoubtedly rise to support the addition of an auction market. Implementation costs such as phase-ins, scheme design and development, and market adaptation costs will also contribute to higher costs for a time. Market forces will also be muted to a degree. A guaranteed price combined with locking in fuel rates for a specific period of time could guarantee a generator a rate of return higher than a regulated market would typically allow with reasonable rate of return rules. ERCOT would have little or no recourse to adjust for these changes, though. It would provide another market mechanism for the industry, offsetting some of the cost and inefficiencies imposed by a regulatory scheme, but they do not appear to outweigh the burdens.

That being said, the basic question still remains: what is the market gap for building a new power plant in ERCOT?

Chapter 3: Methodology

IMM Methodology for Valuing New Generation

Volatility in fuel prices and market rule changes create challenges for generators. As fuel prices rise, older, less efficient plants must bid higher prices to allow for the greater spark-spread on their costs and power prices. They pay more for fuel just like their competitors, but they must also purchase more fuel than their competitors to compensate for their lower efficiency. This added cost of production therefore widens the bid price gap between the most and least efficient plants, or those with strong real or financial fuel hedges. This widened price difference at the margin makes bidding more difficult in this area – bid too low and generate at a loss, but bid too high and pay carrying costs without any generation revenue.

A generator can mitigate this pricing challenge through long-term power-purchasing contracts. A power purchasing agreement (PPA) between a buyer and generator creates consistent, predictable revenue for generators and predictable power costs for buyers. A PPA contract can be for 5, 10 or even 20 years, creating a very stable price for both parties. However, the generator still risks losses. Its plants operate in ERCOTs competitive real-time and day-ahead markets. If the bid prices in those markets are lower than is profitable for its plants to produce, the wholesale generator will buy from the market rather than generate. If the sum of the market price or producing power and the company's carrying costs, overhead, etc. exceed the PPA, the company faces a loss. This reality keeps the long-term contract from eliminating all risk for the wholesale power generator and consequently, the debt holder. Even so, the PPA does still offer substantial, albeit not absolute, risk mitigation.

ERCOTs Independent Market Monitor (IMM) recognizes these challenges and provides an estimate of required revenues to incent new generation investment by various generation types. In its 2012, it lays out its methodology for determining whether net revenue suffices to incent new power generation in the following manner:

Although most suppliers are likely to receive the bulk of their revenues through bilateral contracts, the spot prices produced in the real-time energy market should drive the bilateral energy prices over time and are appropriate to use for this evaluation. For purposes of this analysis, heat rates of 7 MMBtu per MWh for a combined cycle unit, 10.5 MMBtu per MWh for a combustion turbine, and 9.5 MMBtu per MWh for a new coal unit were assumed. Variable operating and maintenance costs of $4 per MWh for the natural gas units and $5 per MWh for the coal unit and fuel and variable operating and maintenance costs of $8 per MWh for the nuclear unit were assumed. For purposes of this analysis, a total outage rate (planned and forced) of 10 percent was assumed for each technology.
The energy net revenues are computed based on the generation weighted settlement point prices from the real-time energy market. Weighting the energy values in this way masks what may be very high locational values for a specific generator location. Some generators may also receive uplift payments because of their specific reliability contributions, either as a reliability must run, or through the reliability unit commitment. This source of revenue is not considered in this analysis. The analysis also includes simplifying assumptions that can lead to over-estimates of the profitability of operating in the wholesale market. The following factors are not explicitly accounted for in the net revenue analysis: (i) start-up costs, which can be significant; and (ii) minimum running times and ramp restriction, which can prevent the natural gas generators from profiting during brief price spikes. Despite these limitations, the net revenue analysis provides a useful summary of signals for investment in the wholesale market.[41]

Spot prices are a clear driver of bilateral energy prices. Platts and other forecasters use them in their models. Investors use these forecasted prices to drive their forward contracts appetite. This in turn moves the contract prices towards forecasted prices, which were developed in part through spot price history.

In regulated, stable markets, this is the best data to use to build valuation models. On the cost side, it shows proven operations and maintenance expenses, taxes and fuel costs. The majority of costs are fixed, especially with very efficient generation assets. For

[41] Potomac Economics, Ltd., *2012 State of the Market Report for the ERCOT Wholesale Electricity Markets*. Pp 73-74.

instance, the EIA estimates that excluding fuel, an advanced combined cycle power plant built in 2013 would only have $3.27/MWh in variable operations and maintenance costs, compared to $15.37/kW-yr in fixed O&M costs. Additionally, power plants are becoming modular, with installable components, reducing unexpected site-specific engineering and design costs. Companies like General Electric accurately estimate the incremental cost of one more S107H combined cycle turbine system. Besides some site preparation and shipping and handling, costs are very predictable.

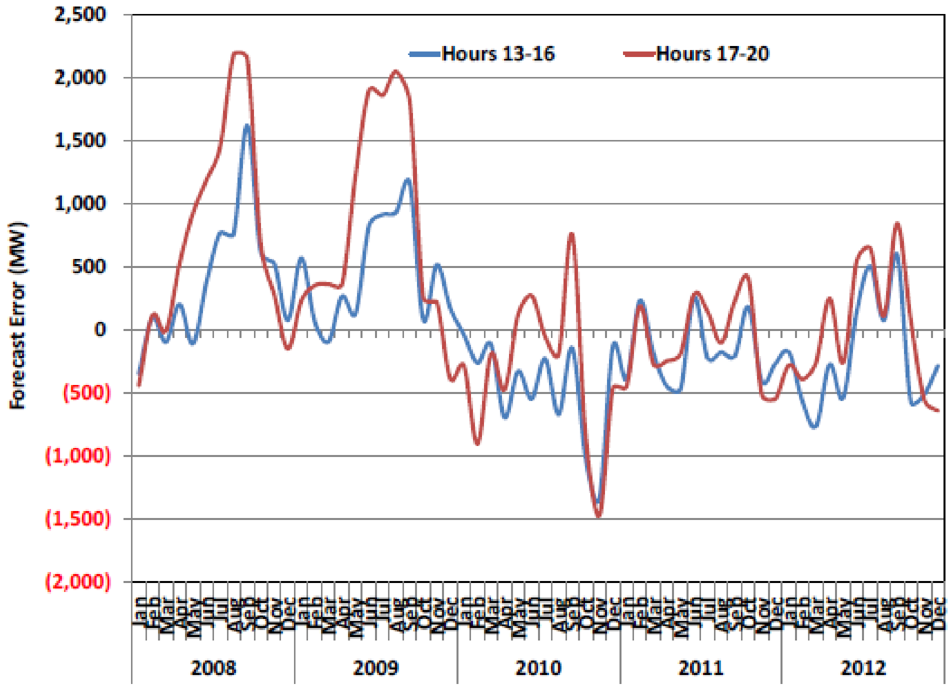
Perhaps more important, historical market performance provides revenue-side data, especially heat rate, capacity factor, and electricity price data. It is one thing to estimate capacity factor using the plant's expected competitiveness in the market, but it is altogether more useful to consider historical performance of a similar plant within ERCOT. Historical electricity prices are even more important. Electricity price varies widely between off-peak periods and times of scarcity. Due to congestion pricing, it can also vary widely between locations within Texas. Historical data within a specific load zone provides an exact data set for calculating generation revenues for a proposed generation asset. It captures both average pricing as well as the significant revenue generated from the $2,000 or $3,000 price spikes.

USING A FUTURES-BASED VALUATION MODEL

Historical performance carries many strengths, but especially within the ERCOT market, it is important to acknowledge some limitations. First, inefficient transmission management can create scarcity pricing situations in the market, causing price spikes. Note Figure 3.1 below.

Additionally, IMM research determined that a new combined cycle unit would need to generate net revenue of $105-$135 per kW-year, but only had revenues of approximately $42 per kW-year in 2012.[42]

Figure 3.1. ERCOT Load Forecast Error[43]



The IMM method also fails to account for market changes. ERCOT was deregulated over a decade ago, but it made many substantive changes to the market over the past five years, including adding an emergency response service in 2012 and incrementally raising the system-wide offer cap from $3,000/MWh in 2011 to its current price of $5,000. This cap will rise to $9,000 in summer 2015.[44] Additionally, ERCOT created an operating reserve demand curve (ORDC) adder that started operating June

42 Ibid., Page 77.
43 Ibid., p.70
44 ERCOT, "ERCOT News Release."

2014. All of these changes add risk to any valuation of new construction using models based upon historical ERCOT pricing.

Bondholders seek high risk-weighted returns. The more a generator can control risk, the easier it is to attract creditors. Contracting PPAs or selling financial positions guarantees a certain return, even if it falls well below the average spot price. Therefore, the IMMs estimate, while illustrative, fails to fully capture the ability of generators to control risk, and consequently their ability to attract capital.

Furthermore, the IMM report only considers data from the past five years. Not only do each of these years operate under different market rules, but they also require some modeling to create enough time series data to amortize the high upfront capital costs of new entry. Some modeling is needed for any method – even futures only provide 10 years of market trades, whereas debt service for generating assets can easily span 20, 30 or even 40 years – but a short historical period that does not reflect the current market scheme brings challenges.

This thesis instead uses futures contracts to determine cost of new entry (CONE) for an advanced combined cycle power plant. This model uses futures contracts rather than historical market activity for three reasons 1) it still provides a conservative, "guaranteed" rate of return for generators through a financial hedge while 2) incorporating investor sentiment on current market rules and ones that will be phased in shortly, and 3) adjusting for future natural gas prices, which are likely to change as the full impact of hydraulic fracturing becomes apparent.

Especially at this point in the market's history, this is a more reasonable approach to valuation in the ERCOT market. ERCOTs current market structure is less than four years old; the current nodal market began December, 2010. There is therefore little historical spot-price data to build ERCOTs price performance. This provides little data to calibrate the IMM model. Additionally, the discussion on capacity and the future of ERCOT injects uncertainty. Will there be new revenue streams? Will the market structure change? I propose that this uncertain environment necessitates the estimation of revenues through forward contracts rather than historical spot prices. Future spot prices may not reflect historical prices. Indeed, if capacity is to increase the spot price must rise. The question then becomes, “what is the gap?” How far are current prices from those necessary to incent new generation?

Admittedly, all of these weaknesses make it hard for any market participant to accurately estimate spot prices in the ERCOT market. Futures traders use all of these data and more to try and accurately price futures contracts, but they are still likely to be conservative because of the limited history of data from which to build their models.

Note here that this thesis does not attempt to find the true value of a new power plant in ERCOT. It ignores many aspects of the assets true costs and revenues, including ancillary services, peak/off-peak generation, plant downtime for maintenance, and ramp up costs, to name a few. Instead, this thesis seeks to frame the problem in its simplest terms – if a generator bought futures to hedge all expected generation, what price must those futures be for the plant to be “in the money,” and what is the gap?

METHODOLOGY

The futures-based valuation model used in this analysis calculates free cash flows (FCF) over the life of the plant.

$$FCF_t = (EBIT_t)(1 - T) + DA_t - CAPEX_t$$

Where:

FCF = free cash flows

t = time

EBIT = earnings before interest and taxes

T = tax rate

DA = depreciation and amortization

CAPEX = capital expenditures (overnight cost)

Taxes are assumed at 35% of earnings and property value. The Advanced Combined Cycle (ACC) power plant is assumed to have a 20-year life span. The model calculates FCFs over the ten years of ERCOT futures contracts currently traded.

DA is amortized over the useful 20-year lifespan of the plant, or five percent per annum. *CAPEX* uses capital cost estimates provided by the 2012 EIA overnight cost estimate of $1,023 per kW constructed, with a nominal capacity of 400MW.[45]

The author calculates *EBIT* as:

$$EBIT_t = (PO_t \times CF_t \times P_t) - (F_t \times HR_t \times PO_t \times CF_t) - (FOM_t \times 1000 \times PO_t) - (VOM_t \times PO_t \times CF_t)$$

Where:

PO = potential plant output (MWh)

CF = capacity factor

[45] U.S. Energy Information Administration, "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants."

P = electricity price (MWh)

F = fuel price ($/mmbtu)

HR = heat rate

FOM = fixed operations and maintenance, selling, general and admin expenses ($/kw-y)

VOM = variable operations and maintenance, selling and general and admin expenses ($/MWh)

The author calculates potential plant output by multiplying the theoretical generating capacity of the plant (400MW) by the number of hours in a year: 365.25×24. Average capacity factor equals the total power produced by a plant as a percent of its maximum annual output. In this case, it is 44 percent, based on EIA peak and off-peak national estimates.[46] Electricity prices equal the annual average of monthly futures settlement prices for each year *t* within ERCOTs northern load zone. The load zone, which covers the Dallas/Fort Worth area, was used because it has the highest volume of trading within ERCOT, making it most reflective of actual market sentiment.

Fuel prices are annual averages of monthly futures contract settlement prices at Henry Hub. There are likely some small price differentials between the northern load zone and Henry Hub due to transportation costs, but again the volume of trading at Henry Hub was preferable for market pricing purposes.*HR, FOM, and VOM* are also provided by EIA estimates.[47]

Heat rate is calculated as mmbtu used divided by MWh produced. It calculates the amount of natural gas needed to generate one MWh of electricity with a given generation

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[46] U.S. Energy Information Administration, "Average Utilization of the Nation's Natural Gas Combined-Cycle Power Plant Fleet Is Rising."
[47] U.S. Energy Information Administration, "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants."

unit. An ACC power plant is assumed to have a heat rate of 6.43mmbtu/MWh, with fixed costs of $15.37/kW-y) and variable costs of $3.27/MWh.

The Gordon Growth model is used to calculate the terminal value in year ten. WACC is used for the discount rate, where terminal value equals $EBITDA_{10}$/WACC, where *EBITDA* is earnings before interest, taxes, depreciation and amortization and WACC is the weighted average cost of capital.

$$WACC = \frac{E}{V} \times Re + \frac{D}{V} \times Rd \times (1 - T)$$

Where:

E = market value of the plant's equity

D = market value of the plant's debt

V= E+D, or total market value of the firm

Re = cost of equity

Rd = cost of debt

E/V = percentage of financing that is equity

D/V = percentage of financing that is debt

T = tax rate

The plant's market value (CAPEX) is calculated using the EIA overnight capital cost estimate of $1,023 per kW installed: $CAPEX = EIACE(IC)$ where EIACE is the EIA cost estimate and IC is the installed capacity of the generation asset.[48]

It was assumed that 70% of the project would be financed with debt. For the cost of debt, the Federal Reserve corporate debt rating for a baa-rated company of 4.69% as of May 29, 2014 was used. For the cost of equity, the author used the 10-year performance

[48] Ibid., Table 1

of the Vanguard Utilities Index Fund Admiral Shares (10.27%)[49] and added the 20-year Treasury bill interest rate on June 2, 2014 (3.1%) as a risk premium, for a total cost of equity of 13.37%.[50] Tax rate is assumed to be 35%.

Once FCF for each year is calculated, they are used to determine net present value (NPV) and internal rate of return of the project:

$$NPV = \sum_{t=1}^{N} \frac{FCF_t}{(1 - WACC)^t} - FCF_0$$

Net present value calculates the return on all cash flows as if they occurred today, putting them in current-day dollars. The author uses the WACC as the discount rate for the project. In other words, the NPV will only be positive if its financial gains surpass not only the physical project costs, but also the financial costs, namely the opportunity costs of equity and actual costs of debt. If the NPV is positive, it suggest that futures markets for natural gas and electricity see ACC power plant investment as currently viable. If negative, as suspected, it calculates in present day dollars the gap in value.

The NPV provides the net value for the project with assumptions laid out above. To calculate the precise gap between financial market expectations and current market realities, the discount rate will be set to zero. This provides the value of the project if there are no debt or equity costs and if there are not expectations on rate of return. At this point the NPV equation will be used to find the internal rate of return (IRR). Rather than solve for NPV the author sets the NPV equal to zero and solves for the discount rate (WACC). In this way we will calculate the NPV, IRR and dollar-value equivalent of the IRR.

49 Vanguard, "Vanguard Utilities Index Fund Admiral Shares (VUIAX) Price & Performance."

50

In addition to determining the valuation gap for the project to be "in the money" using the above assumptions, it calculates the required change in either natural gas or ERCOT futures prices for the project to come into the money. A modifier is included in the model that can increase or decrease fuel and electricity futures prices as a ratio of their market price. The electricity price modifier does not affect any other model prices. In contrast, the natural gas modifier adjusts electricity prices anytime it approaches a price that matches or exceeds the revenues that electricity prices can return. For instance, if natural gas prices reached $20/MMBTU, electricity would not be produced at $40/MWh because it would cost money. The model could assume that electricity would stop being produced at this point. However, as natural gas accounts for 61 percent of Texas electricity generation capacity, it is likely generation would continue, but at a higher price to account for fuel costs. For this reason, the modifier adjusts electricity prices as natural gas prices approach a break-even scenario so that the plant always has revenues that exceed fuel expense, variable and fixed costs.[51] In the base model, revenues exceeded these costs by 19 percent in the most recent year of operations. To stay cash-flow positive, the natural gas modifier therefore keeps the EBITDA from dropping below 19 percent of total revenues. Using Excel's Goal Seek function, this analysis shows the "in the money" price required for either natural gas prices or electricity prices. A two-way table is created to consider scenarios from both electricity and natural gas staying in line with futures to one or both doubling. This gives greater insight into the impact of both prices on the model.

While calculations up to this point provide a clear net present valuation of the proposed project, they have yet to calculate the revenue needed on a per megawatt-hour

[51] Electric Power Industry Capability by Primary Energy Source, Back to 1990, Texas, http://www.eia.gov/state/search/#?1=103&2=224&r=false

or kilowatt-year basis. In order to calculate kw-y, annual revenue generated by the plant is divided by the total capacity of the plant.

Base inputs for the financial model are outlined in Figure 3.2.

Figure 3.2. Base Model Inputs

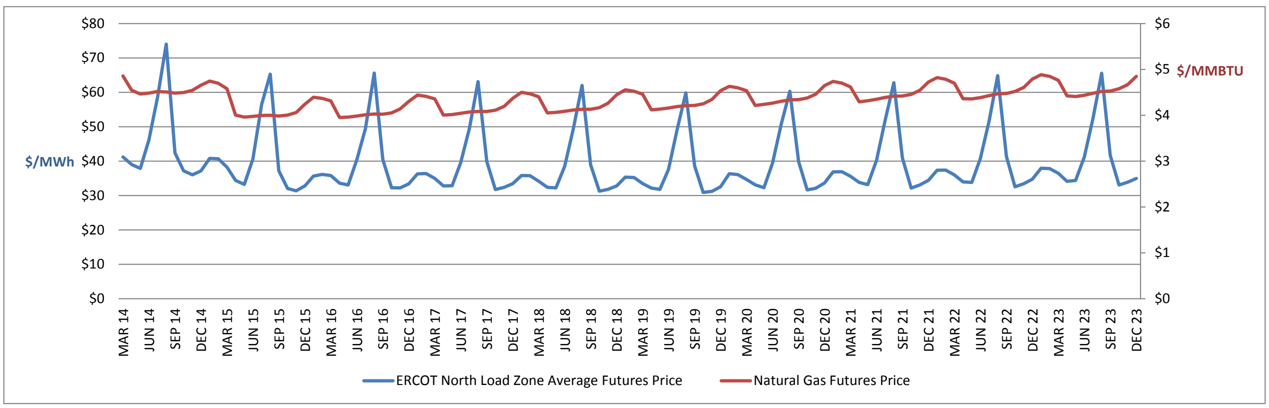
Assumptions	
Fuel costs	See Appendix A
Electricity prices	See Appendix A
Heat Rate (mmbtu/MWh)	6.43
Plant capacity (MW)	400
Capacity factor	44%
Variable O&M ($/MWh)	$3.27
Fixed O&M ($/kW-y)	$15.37
Capital cost ($/kW)	$1,023
Property taxes	1%
% of capital in debt	70%
% of capital in equity	30%
Cost of debt	4.69%
cost of equity	13.70%
Depreciation (years)	20
Tax rate	35%
Gas Futures Modifier	1
Electricity Futures Modifier	1
WACC	6.24%
Plant cost	$409,200,000

Chapter 4: Findings

THE RELATIONSHIP OF ELECTRICITY AND NATURAL GAS FUTURES

While causation is not part of this analysis, it is worthwhile to note the correlation between natural gas and ERCOT futures strike prices. As Figure 4.1 demonstrates, there is cyclicality to prices. Both natural gas and ERCOT futures rise in winter months as energy demand for heating increases. Summers cause dramatic spikes in ERCOT strike prices and a negligible bump in natural gas prices.

Figure 4.1. Comparison, ERCOT NLZ Average Futures Price v. Natural Gas Futures Price[52]



Over ten years of monthly strike prices, gas futures routinely equal 6-7 percent of ERCOT futures prices in summer and 12-13 percent in off-peak months. In fact, when annualizing both sets of data, natural gas futures fluctuate from a low of 10.13 percent to a high of 11.53 percent of the average annual ERCOT future price (see Table 4.1).

[52] Bloomberg L.P., “Natgas Futures Curve.” & Bloomberg L.P., “ERCOT NLZ Average Futures Price.”

Table 4.1. Annualized ERCOT and Natural Gas Futures comparison[53]

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Average Annual ERCOT Future Price	$ 44.98	$ 40.27	$ 39.02	$ 38.59	$ 37.93	$ 37.35	$ 38.36	$ 39.32	$ 39.83	$ 40.29
Average Annual Henry Hub Futures Price	$ 4.55	$ 4.19	$ 4.13	$ 4.18	$ 4.24	$ 4.31	$ 4.41	$ 4.50	$ 4.56	$ 4.61
Market Implied Heat Rate	9.87	9.62	9.46	9.23	8.95	8.67	8.69	8.74	8.74	8.73

Natural gas and ERCOT prices clearly follow related price pathways in Texas. Due to natural gas generators falling at the margin of the bid stack, they effectively set the price. Therefore, as natural gas increases, the price for generation increases. As noted above and elsewhere in this analysis, the price of natural gas plays a critical factor in the viability of constructing new natural gas generation infrastructure.

Another interesting note is the limited variance in futures prices. As Table 4.2 demonstrates, over the next ten years, a buyer can lock in natural gas prices varying less than one dollar, from $3.95 to a high of $4.88. The greatest price fluctuation is observed in electricity prices, likely at least in part due to the dramatic price differences during summer/peak periods versus non-peak periods.

Table 4.2. Futures Descriptive Statistics

	Average	Median	Max	Min	SD
ERCOT NLZ Monthly Futures	$ 39.50	$ 36.13	$ 74.00	$ 30.90	$ 9.43
ERCOT NLZ Unweighted Annualized Futures	$ 39.59	$ 39.17	$ 44.98	$ 37.35	$ 2.13
Henry Hub Monthly Futures	$ 4.36	$ 4.39	$ 4.88	$ 3.95	$ 0.25
Henry Hub Unweighted Annualized Futures	$ 4.37	$ 4.36	$ 4.61	$ 4.13	$ 0.18
Natural Gas as % of ERCOT Price Monthly	11.53%	12.47%	13.93%	6.09%	2.15%
Natural Gas as % of ERCOT Price Annualized	11.05%	11.30%	11.53%	10.13%	0.52%

Annualizing the data reduces standard deviation, but ultimately the averages shifted minimally less than 0.2 percent; ERCOT futures skewed down 9 cents and natural gas averages increased by a penny.

53 Ibid.

MODEL RESULTS

This model forecasts a minimum of $153.96/kw-Y is needed to make the project attractive to investors. The project would require $102/kW-Y just to break even, and this fails to provide a return to investors above their initial capital outlay. It would be better for investors to place their capital in a utility index fund rather than take the risk of building a combined cycle power plant in the ERCOT market. Using the methodology outlined in Chapter 3, we find this project deeply “out of the money.” See Table 4.3 below.

Table 4.3. Free Cash Flows, NPV, IRR and $/kW-Y

In 000s	Startup	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
+Generation EBITDA		**$ 13,013**	**$ 9,401**	**$ 8,067**	**$ 6,863**	**$ 5,305**	**$ 3,699**	**$ 4,221**	**$ 4,854**	**$ 5,044**	**$ 5,188**
-Depreciation		$ 20,460	$ 20,460	$ 20,460	$ 20,460	$ 20,460	$ 20,460	$ 20,460	$ 20,460	$ 20,460	$ 20,460
EBIT		$ (7,447)	$ (11,059)	$ (12,393)	$ (13,597)	$ (15,155)	$ (16,761)	$ (16,239)	$ (15,606)	$ (15,416)	$ (15,272)
-Property TAXES		$ (3,887)	$ (3,683)	$ (3,478)	$ (3,274)	$ (3,069)	$ (2,864)	$ (2,660)	$ (2,455)	$ (2,251)	$ (2,046)
-TAXES		$ 2,606	$ 3,871	$ 4,337	$ 4,759	$ 5,304	$ 5,866	$ 5,684	$ 5,462	$ 5,395	$ 5,345
TAX CARRY FORWARD		$ -	$ 188	$ 1,047	$ 2,532	$ 4,768	$ 7,769	$ 10,793	$ 13,800	$ 16,945	$ 20,244
NOPAT		$ (8,728)	$ (10,683)	$ (10,486)	$ (9,579)	$ (8,152)	$ (5,989)	$ (2,422)	$ 1,201	$ 4,674	$ 8,272
+Depreciation		$ 20,460	$ 20,460	$ 20,460	$ 20,460	$ 20,460	$ 20,460	$ 20,460	$ 20,460	$ 20,460	$ 20,460
-CAPEX	$ (409,200)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Free Cash Flow	$ (409,200)	$ 11,732	$ 9,777	$ 9,974	$ 10,881	$ 12,308	$ 14,471	$ 18,038	$ 21,661	$ 25,134	$ 28,732
+Terminal Value											$ 204,600
DCF	$ (409,200)	$ 11,732	$ 9,777	$ 9,974	$ 10,881	$ 12,308	$ 14,471	$ 18,038	$ 21,661	$ 25,134	$ 233,332
NPV	$ (186,436)										
IRR	-1.3%										
$/kW-Y	$ 91.83										

In this scenario, earnings before interest, taxes, depreciation and amortization (EBITDA) are low enough that depreciation of the plant allows for a tax benefit that cannot be fully realized by this project alone. To get full benefit from the tax benefit carrying forward, this plant must be associated with a larger firm that can fully capitalize on the loss.

This model also assumes the company can get ten full years of generation revenues and sell the asset for the full value minus depreciation, or the terminal value at the end of year 10 (2023). At $204 million, this is nearly 56 percent of the entire positive free cash flows generated from the project. In a real market setting, there is no guarantee that this terminal value will be the realized value, and the fact that it accounts for nearly 56 percent of the FCFs raises a legitimate question.

Net $/kW-Y after cash flows is $91.83. Note this is much higher than the net revenue of $24/kW-Y estimated by the IMM, but still below the $105 - $135/kW-Y threshold it argues is the entry point. Note this comparison is not 1:1, as the IMM study examines net revenue including carrying costs, whereas this model is showing $/kW-Y after all free cash flows.

Even with these differences, however, this model does not appear to be inconsistent with the IMM findings. The internal rate of return is negative, but it is close to break even. In fact, if one sets the $/kW-Y to $105 and uses Goal Seek in Excel to determine the IRR, it produces a positive result of 0.3 percent, or nearly break-even. This is less than required to overcome the weighted average cost of capital – NPV is still negative $140 million – and return a reasonable profit, but it does show a certain level of agreement between the IMM model built on historical prices in the ERCOT market and this model, which is built on the opinions of speculators in the futures market.

HOW GAS AND ELECTRICITY FUTURES AFFECT NPV

In this analysis, electricity prices are the main drivers of profitability. To become profitable based on natural gas prices alone, they need to increase by a factor of 5.3, from the current average of $4.37/MMBTU to $23.29/MMBTU, raising the revenue to $153.96/kW-Y, the break-even revenue. Electricity, while still valuing the project as negative in the current market, only has to rise by a factor of 1.8 of current average strike prices. See Table 4.4.

Table 4.4. Two-variable Table, NPV at Different Electricity and Natural Gas Prices

		Natural Gas Futures Modifier										
		1	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.8	1.9	2
ERCOT Future Price Modifier	1	$ (186,436)	$ (176,427)	$ (199,364)	$ (193,102)	$ (188,313)	$ (183,525)	$ (178,736)	$ (173,947)	$ (169,159)	$ (164,370)	$ (159,581)
	1.1	$ (196,504)	$ (192,673)	$ (173,449)	$ (178,795)	$ (195,030)	$ (183,525)	$ (178,736)	$ (173,947)	$ (169,159)	$ (164,370)	$ (159,581)
	1.2	$ (176,817)	$ (193,467)	$ (195,056)	$ (183,062)	$ (179,492)	$ (193,032)	$ (178,736)	$ (173,947)	$ (169,159)	$ (164,370)	$ (159,581)
	1.3	$ (147,814)	$ (168,228)	$ (188,643)	$ (194,534)	$ (189,376)	$ (181,440)	$ (190,725)	$ (182,873)	$ (169,159)	$ (164,370)	$ (159,581)
	1.4	$ (118,811)	$ (139,225)	$ (159,640)	$ (180,055)	$ (192,707)	$ (192,219)	$ (179,688)	$ (190,240)	$ (183,598)	$ (175,185)	$ (159,581)
	1.5	$ (89,807)	$ (110,222)	$ (130,637)	$ (151,052)	$ (171,467)	$ (188,953)	$ (192,565)	$ (186,079)	$ (187,496)	$ (183,720)	$ (170,361)
	1.6	$ (60,804)	$ (81,219)	$ (101,634)	$ (122,049)	$ (142,464)	$ (162,878)	$ (183,293)	$ (191,023)	$ (189,383)	$ (190,081)	$ (184,636)
	1.7	$ (31,801)	$ (52,216)	$ (72,631)	$ (93,046)	$ (113,460)	$ (133,875)	$ (154,290)	$ (174,705)	$ (188,193)	$ (190,596)	$ (182,782)
	1.8	$ (2,798)	$ (23,213)	$ (43,628)	$ (64,043)	$ (84,457)	$ (104,872)	$ (125,287)	$ (145,702)	$ (166,117)	$ (184,439)	$ (189,054)
	1.9	$ 26,205	$ 5,790	$ (14,625)	$ (35,039)	$ (55,454)	$ (75,869)	$ (96,284)	$ (116,699)	$ (137,114)	$ (157,528)	$ (177,943)
	2	$ 55,208	$ 34,793	$ 14,379	$ (6,036)	$ (26,451)	$ (46,866)	$ (67,281)	$ (87,696)	$ (108,110)	$ (128,525)	$ (148,940)

Note in the model that when gas prices are twice futures prices (with a modifier of 2), ERCOT futures prices do not influence the valuation model until the modifier is 50 percent greater than base (1.5). The natural gas modifier automatically rises to maintain positive EBITDA cash flows. It is only when ERCOT prices have risen by 50 percent that their revenues exceed the modifier and being to influence the two-variable table. Likewise with a 1.5 natural gas modifier, it is not until an ERCOT futures modifier of 1.2 is applied that the 19 percent EBITDA adjustment stops influencing the model.

As Figure 4.5 demonstrates, until the average price of electricity futures reaches between 1.8 and 1.9, or approximately $71.27, on average, a plant could not be built “in the money” using financial risk management instruments alone. The gap between current futures prices is too great. $71.27 is not an unreasonable price for a market that has a $5,000 market cap. However, futures do not currently come close to this price. Over 118 months of futures, only a single month had futures prices greater than $71 and only eight had electricity prices exceed $60. The current average monthly price of $39.50 is not even enough to make the project viable if its capacity factor was 100 percent. Even at 100 percent capacity factor, the average futures price would need to rise 23 percent to $48.95. 20 months, or 16.9 percent of all observations, met or exceeded this price. The ability for a plant to achieve 100 percent capacity factor within a single year, let alone 10, is unrealistic. Routine maintenance, off-peak prices that fall below the plants clearing price, and other factors keep capacity factors well below theoretical limits.

Chapter 5: Conclusions

New natural gas extraction methods have dramatically reduced electricity costs. As a state heavily invested in natural gas electricity generation, this new paradigm affects Texas greater than most. Texas is growing. Substantial capacity has been built over the past decade, albeit not enough to meet reserve demand. However, the relatively young age of much of ERCOTs generation capacity makes it much more efficient. Combined with low gas prices, the generation cost curve only increases when demand nearly reaches full capacity. A lean, deregulated market contributes to keeping the prices as low as possible.

These parameters also work against the essential need that ERCOT be reliable. Lower prices at the cost of reliability raise brownout or rolling blackout risk for businesses and residents. This downtime risk, if great enough, will become a factor in business decisions. Clearly a balance needs to be struck between reliability and costs; a perfectly reliable system would cost far too much to recoup the benefits to business, industry and the Texas economy, while an unreliable system would cost far too much in downtime and unpredictability.

ERCOTs moves to raise peak power pricing to $9,000/MWh by 2015 and the ORDC which went into effect in June 2014 have reduced the revenue gap while preserving the benefits of a deregulated market. Generators have greater ability to recoup costs even as the market is left mainly untouched. This study's author hypothesized that the futures market offered a better determinant of the revenue gap for new generation investment. Multiple market changes meant to bolster generator's returns were passed by the PUC and are being instated over the next 2 years. Assuming these changes would be reflected in market prices, the author believed they might offer a way to conservatively estimate future generation revenues in the ERCOT.

This hypothesis in many ways was validated. Although this study was consistent with the IMM analysis in that it found a significant gap between expenses and revenues, it found the gap was indeed smaller than IMM estimates. This model forecasts a minimum of $105/kW-Y is needed to break even for CONE for an ACC, and $154/kw-Y is needed to attract investment, similar to the IMM estimates of $105-$135 per kW-year. Unlike the IMM analysis, this model found expected revenues to average roughly $92 per kW-year compared to the IMM estimate of $42.

Another validation of this method comes from current market activity. In spite of the gap in market capacity, there has been little new investment, the recent Panda project in Temple being a notable exception. If traditional power plant financing was viable, and the current lack of capacity was as great as ERCOT and its analysts believe, new generation would get built. With the limited investment taking place in ERCOT, one must conclude one or both of these assumptions is incorrect. From the analysis set forth in this thesis, we can conclude the first premise – traditional power plant financing is currently viable – is not a valid statement. While traditional financing is not viable however, it is much closer than the IMM analysis, which estimates revenues exceeding 2.6 times current revenue are needed to incent new construction. From this analysis, revenues 1.14 times current anticipated revenues would be break-even and 1.7 times current anticipated revenues would be sufficient to provide adequate returns to draw investment. This may explain how projects like Panda, which had “an uphill battle, in a very difficult financial market” were only able to finance the project through unusual equity financing methods.[54] It is doubtful financing would occur if anticipated revenues were so far out of the money as the IMM forecasts.

A number of market changes could shrink or eliminate this gap – natural gas or electricity futures could rise, capacity factor could increase, or revenues from ancillary services or the new adder, to name a few – but the most powerful thrust will likely come from higher average electricity prices. Revenues are insufficient to incent new generation capacity. Barring out-migration from the state, significant success from demand response, or some other event or technology that reduces or levels power demand, new generation units need built in Texas. If nothing else is done, scarcity will increase the frequency of $7,000/MWh prices for power, eventually drawing the economics up to the point where new generation capital investment becomes feasible.

[54] Panda PowerFunds, "Panda PowerFunds Press Release."

Chapter 6: Future Analysis

FUTURE MARKET CHANGES

ERCOT is continuing to develop as a market. As it experiences a year with the new ORDC and it moves from a $7,000/MWh to a $9,000/MWh cap in 2015, market dynamics will correspond. These changes will directly influence electricity prices in real-time, DAM, and futures markets, most likely upward. While futures markets still show a gap between generation revenues and the amount needed to attract new investment, this author expects that gap to narrow within the year.

In addition to new market rules that may drive up revenues, natural gas is likely to increase in price and volatility as exports grow and new markets, such as transportation, are explored for their growth opportunities. This will affect the bid stack, increasing the price for electricity throughout ERCOT.

In addition to the benefit of repeating the study a year from now once new market rules have more strongly influenced futures, it would be advantageous to incorporate ancillary services into future studies. Ancillary services were left out of this study because they add little to the overall revenues for gas-fired generation in ERCOT.[55] Even so, as the gap narrows between CONE and potential investment returns, these additional revenue sources will require a closer look.

MODEL CHANGES

This model uses an advanced combined cycle power plant for its analysis. ACCs have much higher heat rates than simple-cycle turbines, giving them high revenue

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[55] Potomac Economics, Ltd., *2012 State of the Market Report for the ERCOT Wholesale Electricity Markets*.p 79.

relative to their heat rate. The assumption was the higher capital cost would be outweighed by the more efficient heat rate. A simple-cycle turbine, however, may offer improved ROI as capital costs are lower. Additionally, something that was not considered in this study, a simple-cycle turbine takes much less time to build, reducing the capital at risk until that asset starts generating.

This model also assumes a flat bid price for futures contracts. The natural gas market trades at sufficiently high volumes as to make this reasonable. However, energy contracts at the volume needed to hedge an entire power plant would undoubtedly affect market prices. That is to say, initial bids would push the sales price upwards. Even so, this model uses futures contracts as a proxy for future price, not as an actual transaction. It is used to account for investor sentiment in light of new market rules.

Finally, to stay conservative, this model uses average daily contract prices and average capacity factor. A less conservative, but possibly more accurate, method would be to compare peak and off-peak contracts to peak and off-peak capacity factors, as ACC capacity differs substantially between these two periods, as do energy prices.

FEDERAL RULES

In addition to the considerations outlined above, new federal rules on CO2 prices and emissions targets for power plants are likely to dramatically change the market. TCEQ and other State level bodies are still determining how to implement these rules. Once they are established, it would be useful to re-examine this model.

Appendix A: ERCOT North Load Zone Average Future Electricity price and Henry Hub Natural Gas Future price[56]

PERIOD	ERCOT NLZ Avg Future $	Nat Gas Futures $	PERIOD	ERCOT NLZ Avg Future $	Nat Gas Futures $	PERIOD	ERCOT NLZ Avg Future $	Nat Gas Futures $
MAR 14	41.2	4.855	MAY 17	32.85	4.016	JUL 20	50.8	4.306
APR 14	39	4.541	JUN 17	39.6	4.041	AUG 20	60.3	4.336
MAY 14	37.9	4.464	JUL 17	49.55	4.069	SEP 20	39.9	4.339
JUN 14	46.15	4.484	AUG 17	63.1	4.084	OCT 20	31.65	4.375
JUL 14	58.7	4.519	SEP 17	39.9	4.082	NOV 20	32.1	4.461
AUG 14	74	4.508	OCT 17	31.75	4.11	DEC 20	33.65	4.645
SEP 14	42.4	4.482	NOV 17	32.4	4.195	JAN 21	36.9	4.737
OCT 14	37.2	4.495	DEC 17	33.45	4.37	FEB 21	36.95	4.702
NOV 14	36.05	4.544	JAN 18	35.8	4.499	MAR 21	35.6	4.617
DEC 14	37.15	4.653	FEB 18	35.75	4.469	APR 21	33.8	4.292
JAN 15	40.8	4.744	MAR 18	34.2	4.404	MAY 21	33.2	4.315
FEB 15	40.7	4.697	APR 18	32.4	4.049	JUN 21	40.2	4.348
MAR 15	38.25	4.58	MAY 18	32.25	4.064	JUL 21	51.8	4.389
APR 15	34.4	4.005	JUN 18	38.5	4.087	AUG 21	62.8	4.416
MAY 15	33.25	3.96	JUL 18	49.35	4.115	SEP 21	40.9	4.421
JUN 15	40.65	3.974	AUG 18	62	4.13	OCT 21	32.15	4.457
JUL 15	56.5	3.996	SEP 18	38.95	4.132	NOV 21	33.05	4.543
AUG 15	65.25	4.001	OCT 18	31.3	4.164	DEC 21	34.45	4.727
SEP 15	37.2	3.984	NOV 18	31.8	4.26	JAN 22	37.35	4.819
OCT 15	32.05	4.005	DEC 18	32.8	4.448	FEB 22	37.4	4.784
NOV 15	31.4	4.057	JAN 19	35.35	4.553	MAR 22	36	4.699
DEC 15	32.8	4.241	FEB 19	35.25	4.523	APR 22	33.95	4.359
JAN 16	35.65	4.393	MAR 19	33.5	4.458	MAY 22	33.8	4.355
FEB 16	36.15	4.368	APR 19	32.2	4.118	JUN 22	40.75	4.385
MAR 16	35.8	4.311	MAY 19	31.8	4.135	JUL 22	51.65	4.426
APR 16	33.6	3.951	JUN 19	37.6	4.159	AUG 22	64.85	4.466
MAY 16	33.05	3.961	JUL 19	49.35	4.189	SEP 22	41.4	4.474
JUN 16	40.5	3.985	AUG 19	59.85	4.211	OCT 22	32.55	4.52
JUL 16	49.45	4.011	SEP 19	38.65	4.215	NOV 22	33.45	4.605
AUG 16	65.6	4.026	OCT 19	30.9	4.251	DEC 22	34.75	4.79
SEP 16	40.45	4.023	NOV 19	31.2	4.345	JAN 23	37.95	4.882
OCT 16	32.3	4.051	DEC 19	32.55	4.533	FEB 23	37.85	4.847
NOV 16	32.25	4.138	JAN 20	36.35	4.629	MAR 23	36.45	4.762
DEC 16	33.4	4.299	FEB 20	36.1	4.599	APR 23	34.15	4.422
JAN 17	36.3	4.44	MAR 20	34.65	4.534	MAY 23	34.4	4.407
FEB 17	36.4	4.413	APR 20	33.1	4.214	JUN 23	41.2	4.437
MAR 17	35	4.355	MAY 20	32.3	4.237	JUL 23	52.3	4.478
APR 17	32.8	4.005	JUN 20	39.4	4.266	AUG 23	65.55	4.517
						SEP 23	41.7	4.527
						OCT 23	33.05	4.579
						NOV 23	33.85	4.664
						DEC 23	35	4.849

56 Bloomberg L.P., "Natgas Futures Curve." & Bloomberg L.P., "ERCOT NLZ Average Futures Price."

Appendix B: EBITDA Calculations

Appendix A shows the results of base assumptions. Note the price w/fuel modifier line only applies to the model when creating scenarios that test various fuel prices.

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Potential Plant Output (MWh)	3,506,400	3,506,400	3,506,400	3,506,400	3,506,400	3,506,400	3,506,400	3,506,400	3,506,400	3,506,400
Capacity Factor	44%	44%	44%	44%	44%	44%	44%	44%	44%	44%
Actual Plant Output (MWh)	1,542,816	1,542,816	1,542,816	1,542,816	1,542,816	1,542,816	1,542,816	1,542,816	1,542,816	1,542,816
Annual Avg Elect Price ($/MWh)	$ 44.98	$ 40.27	$ 39.02	$ 38.59	$ 37.93	$ 37.35	$ 38.36	$ 39.32	$ 39.83	$ 40.29
Price w/fuel modfier	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Annual Avg Fuel Price ($/MMBTU)	$ 4.55	$ 4.19	$ 4.13	$ 4.18	$ 4.24	$ 4.31	$ 4.41	$ 4.50	$ 4.56	$ 4.61
Merchant Energy Revenue	$ 69,388,150	$ 62,130,486	$ 60,195,538	$ 59,539,841	$ 58,511,297	$ 57,624,178	$ 59,179,850	$ 60,658,382	$ 61,442,647	$ 62,156,200
Merchant Fuel Expense	$ (45,182,038)	$ (41,536,325)	$ (40,935,320)	$ (41,483,417)	$ (42,013,326)	$ (42,731,722)	$ (43,765,914)	$ (44,611,620)	$ (45,205,185)	$ (45,774,776)
VOM Cost	$ (5,045,008)	$ (5,045,008)	$ (5,045,008)	$ (5,045,008)	$ (5,045,008)	$ (5,045,008)	$ (5,045,008)	$ (5,045,008)	$ (5,045,008)	$ (5,045,008)
FOM Cost	$ (6,148,000)	$ (6,148,000)	$ (6,148,000)	$ (6,148,000)	$ (6,148,000)	$ (6,148,000)	$ (6,148,000)	$ (6,148,000)	$ (6,148,000)	$ (6,148,000)
EBITDA	$ 13,013,103.6	$ 9,401,152.8	$ 8,067,209.6	$ 6,863,415.9	$ 5,304,962.2	$ 3,699,447.4	$ 4,220,928.2	$ 4,853,754.0	$ 5,044,453.8	$ 5,188,415.3
Gross Revenue/kW-Y	$ 173.47	$ 155.33	$ 150.49	$ 148.85	$ 146.28	$ 144.06	$ 147.95	$ 151.65	$ 153.61	$ 155.39

Glossary

AREP	Affiliate retail electricity provider
CAISO	California Independent System Operator
CPUC	California Public Utility Commission
CREP	Competitive retail electric providers
ERCOT	Electric Reliability Council of Texas
GDP	Gross Domestic Product
GWh	Gigawatt hours
IOU	Investor-owned utilities
ISO	Independent system operators
kWh	kilowatt hours
LNG	liquefied natural gas
LSE	load serving entities
MMBtu	1 million British thermal units
MWh	megawatthours
PG&E	Pacific Gas and Electric
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PTB	Price-to-Beat
PUC	Public Utility Commission
PX	Power Exchange
REP	Retail electricity provider
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
T&D	Transmission and distribution

TDSP	Transmission and distribution service provider
TXU	Texas Utilities Electric Company

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