McCullough Research

# Review of the ERCOT December 18, 2008 Nodal Cost Benefit Study

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## Overview

On December 18, 2008, CRA International and Resero Consulting released a study that concluded that the benefits of continuing the shift to "nodal" markets from the existing "zonal" system significantly outweighed the costs. They reported benefits in two different forms. First, the area of Texas served by ERCOT would experience a $520 million cost reduction, while requiring only $222 million in additional computer programming costs. Second, the new market design would reduce costs to ERCOT's consumers by $5.6 billion.

A careful review reveals serious questions concerning its accuracy and craftsmanship. The scope of the new study is 2011 to 2020, although only the first two years are actually modeled. The period from 2013 through 2020 is simply a repeated "cut and paste" from the results for 2011 and 2012. Moreover, the benefits due to the siting of new generation are simply assumed from the results of the 2004 cost benefit study. Overall, only 17% of the $520 million savings actually results from the computer model described in the report. The remaining 83% of the benefits are the product of various ad hoc adjustments.

Similarly, the $5.6 billion in consumer benefits are also based on modeling that stops in 2012 even though results are reported through 2020. This surprising result – that a shift in computer algorithms will dramatically reduce revenues for electric generators – reproduces the conclusions of the 2004 study. In both cases, the result relies on the assumption that generator bids are fixed at short term marginal costs. Unfortunately, this is not the case in Texas and other areas that have adopted nodal pricing. Strategic bidding (bids vastly higher than marginal costs) is a central feature in ERCOT. In any market where bids can be easily changed to recapture the assumed revenue loss, such gains for the consumer are both speculative and easily corrected by adjusting the bids. The $5.6 billion estimate also contains a significant error – a critical ratio used in the calculation is based on values taken from years before nodal markets are actually implemented. Overall, the $5.6 billion traces only 17% to computer modeling and with the residual 83% representing poorly documented ad hoc adjustments.

No attempt was made to calibrate the study to actual conditions (known as backcasting). Nor did the authors estimate the sensitivity of their results to their assumptions. Since some assumptions were unusual, the lack of sensitivity testing is particularly problematic. The cost reduction in the two years actually modeled is only .04% of annual production costs, a slender margin in a world where the cost of oil increased 100% in 2008 before falling 75% by the end of the year.

The estimate of $222 million in additional computer programming costs is also problematic. In actuality, the December 18, 2008 study assumes $429 million in additional computer programming costs that are offset by $207 million of additional computer programming costs to "refresh" the existing market design. While the December study estimates maintenance costs for the new computer program as $14 million a year, it also appears to assume maintenance costs for the significantly simpler zonal program at $40 million a year. This appears to be a significant discrepancy.

Overall, the results can most kindly be described as speculative. It is an example of a complex model with opaque underpinnings being presented as a clear direction in an important policy decision. Given that the costs of going ahead with nodal markets are a surprising $429 million, a more detailed analysis is appropriate.

## Production Cost Savings

Stripped of its jargon, this issue is simple. ERCOT operates a real time market for approximately 5% of its energy requirements. The market is "zonal" – it is divided into four areas, and each potentially has a different price for electricity. The proposed nodal system replaces the four zones with hundreds of separate markets. Potentially, it can produce hundreds of different prices.

It is important to understand that these "markets" and "prices" are very different from those in the rest of the economy. In fact, the markets and prices represented by the computer programs used in both the zonal and nodal examples are highly stylized simulations of a real market, and the prices do not represent negotiations between willing buyers and willing sellers. Instead, the program simulates the process and determines the prices on its own. ERCOT's current system has relatively little transparency, making it difficult to track prices back to system conditions and bids. The lack of transparency is even greater for the nodal system given the relatively larger complexity of the computer program and the multitude of prices.

The December 2008 update to the November 2004 cost benefit study is surprisingly sketchy. The estimate of production cost savings comprises a ten-year analysis where only two of the ten years are modeled, and within the two years, only one of the two major components is analyzed.

The primary annual operating cost results of the December 2008 study is summarized in Table 5: [1]

[1] Final Report, December 18, 2008, page 26.

Table 5: Annual Production Cost by Scenario (in real 2008 dollars)

| | Zonal Case ($Million) | Nodal Case ($Million) | Benefit (Zonal- Nodal) ($Million) |
|---|---|---|---|
| *2009* | *12,928.6* | *12,892.0* | *36.6* |
| *2010* | *12,319.2* | *12,277.1* | *42.1* |
| 2011 | 12,212.8 | 12,163.6 | 49.2 |
| 2012 | 12,211.2 | 12,164.4 | 46.8 |
| **Average Annual (2011-2012)** | 12,212.0 | 12,164.0 | 48.0 |
| **Projected NPV (2011-2020)** | 86,378 | 86,039 | 339 |

At first glance, this table appears to represent an editorial decision to omit the full set of results in the interest of brevity. A closer reading makes clear that these years are the only years used in the updated study:

> The NPV from 2011 to 2020 is estimated to be $339 million, assuming that production costs and resulting benefits observed for the first two years of operation remain at the same level on average through 2020.[2]

The complete table can be reverse engineered from the projected NPV on the final lines of Table 5:

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| 2012 | 12,212.0 | 12,164.0 | 48.0 |
| ***2013*** | ***12,211.2*** | ***12,164.4*** | ***46.8*** |
| ***2014*** | ***12,212.0*** | ***12,164.0*** | ***48.0*** |
| ***2015*** | ***12,211.2*** | ***12,164.4*** | ***46.8*** |
| ***2016*** | ***12,212.0*** | ***12,164.0*** | ***48.0*** |
| ***2017*** | ***12,211.2*** | ***12,164.4*** | ***46.8*** |
| ***2018*** | ***12,212.0*** | ***12,164.0*** | ***48.0*** |
| ***2019*** | ***12,211.2*** | ***12,164.4*** | ***46.8*** |

[2] Final Report, December 18, 2008, page 9.

| | | | |
|---|---|---|---|
| ***2020*** | ***12,212.0*** | ***12,164.0*** | ***48.0*** |
| **Average Annual (2011-2012)** | 12,211.6 | 12,164.2 | 47.4 |
| **Projected NPV (2011-2020)** | 86,378 | 86,039 | 339 |

The rows added in italics were not modeled in the December study, which instead modeled 2011 and 2012, and then the same results were simply cut and pasted for the remaining 80% of the study horizon. This unusual methodology is surprising given the problems that arose in the 2004 study in modeling ERCOT's production costs after 2012:

> TCA believes that specific predictive conclusions should not be based on TCA results obtained for 2013, and especially 2014. This is because the massive addition of new generating resources modeled for out years is not supported by transmission upgrades.[3]

This same conclusion also occurs later in the 2004 report:

> The mid-term trend continues for another year (2012), but is reversed in 2013 and 2014 due to difficulties associated with the modeling of further capacity expansion decisions in the absence of transmission upgrades.[4]

Table 3-4 in the November 2004 report clearly shows the problem:

[3] Final Report, November 24, 2004, page 3-16.
[4] Final Report, November 24, 2004, page 3-22.

**Table 3-4 ERCOT System Generation Costs Differences (Nodal – Zonal)**

| Year | Generation Cost Reduction ($M) | Generation Cost Reduction Relative to Base Case Generation($/MWh) | Percentage of Generation Cost Reduction Relatively to Base Case |
|---|---|---|---|
| 2005 | 27.3 | 0.08 | 0.19% |
| 2006 | 58.6 | 0.17 | 0.42% |
| 2007 | 81.6 | 0.23 | 0.60% |
| 2008 | 99.5 | 0.27 | 0.73% |
| 2009 | 109.4 | 0.29 | 0.84% |
| 2010 | 46.4 | 0.12 | 0.36% |
| 2011 | 152.0 | 0.39 | 1.17% |
| 2012 | 147.8 | 0.37 | 1.07% |
| 2013 | 68.1 | 0.17 | 0.47% |
| 2014 | (28.1) | (0.07) | -0.19% |
| Total | 762.7 | — | — |
| Average | 76.3 | 0.20 | — |
| NPV | 586.6 | — | — |

In 2013, the benefits of moving to a nodal system are reduced by over 50%. In the following year the results actually indicate that the zonal system is superior to the nodal system. Although it may merely be a coincidence, it is interesting that the December 2008 study stops modeling in the year where problems arose in the November 2004 study.

The second component of nodal benefits is the potential additional precision of data for power plant siting. The December 2008 study assumes the value of improved generation siting by a particularly arbitrary procedure:

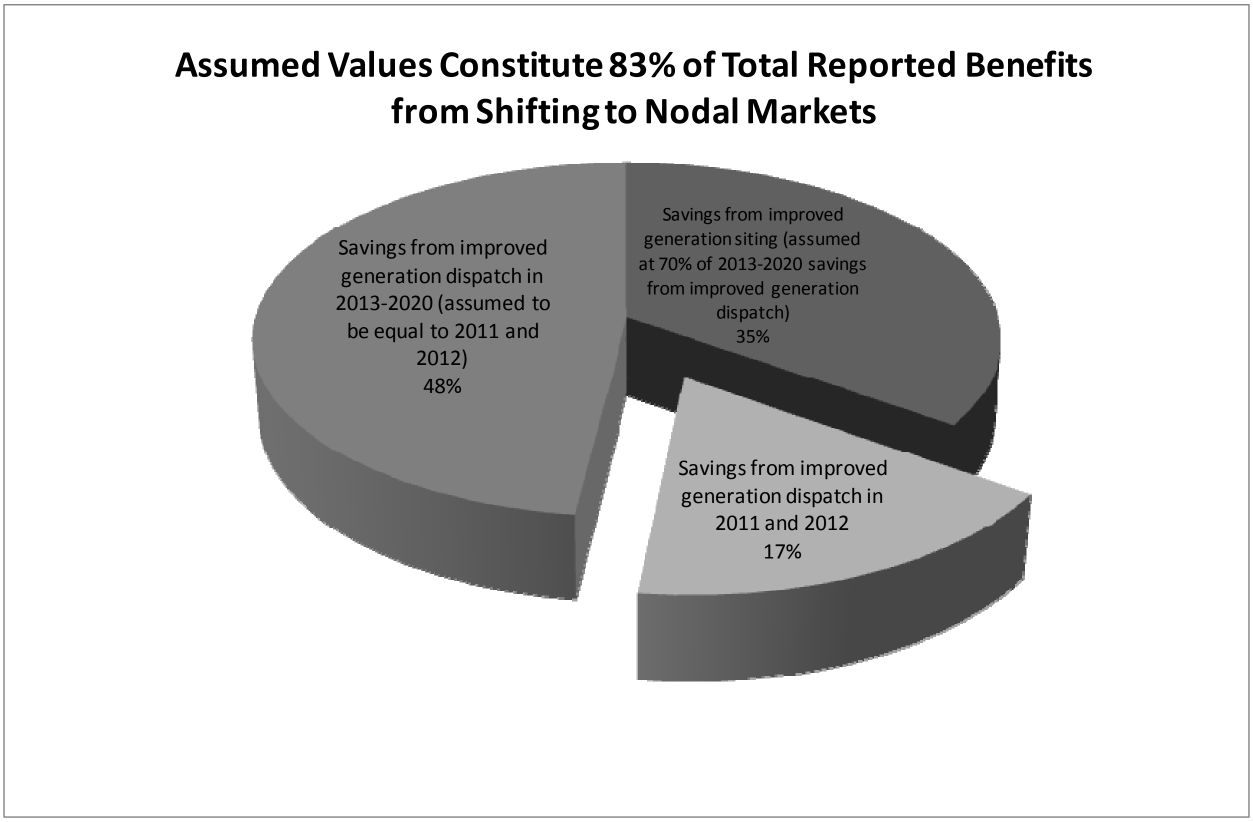
> Assuming 70% in additional benefits attributable to improved generation siting over a period of 2013 through 2020 (when generation capacity will be needed in addition to

> the new entry included in the analysis through 2012), the NPV of these additional benefits amounts to $184 million.[5]

The actual calculation is to take the $339 million in benefits derived by modeling two years, assume that nothing will change for the ensuing eight years, and multiply this number by 1.7 to get $520 million. There is no reason to believe that a ratio arrived at in the November 2004 report using different data for fuel prices, transmission capacity, and resources would be appropriate for an entirely different study period. As the December study states:

> This projection is based on the assumption that siting benefits in relative terms are not reduced by recent transmission upgrades nor are they reduced by changes in any of the other assumptions - such as fuel price and load growth - in the updated CBA.[6]

The following pie chart shows the two years where actual modeling took place and the components that are primarily estimates. Overall, only 17% of the reported results reflect actual modeling calculations.




[5] Final Report, December 18, 2008, page 33.
[6] Ibid., page 9.

Only a small fraction of the reported results come from modeling using current loads, fuel prices, generation, and transmission. The vast majority of the results come from ad hoc adjustments – the reuse of earlier years' results in lieu of completing the modeling and proration of results from the November 2004 study.

## Consumer Payment Savings

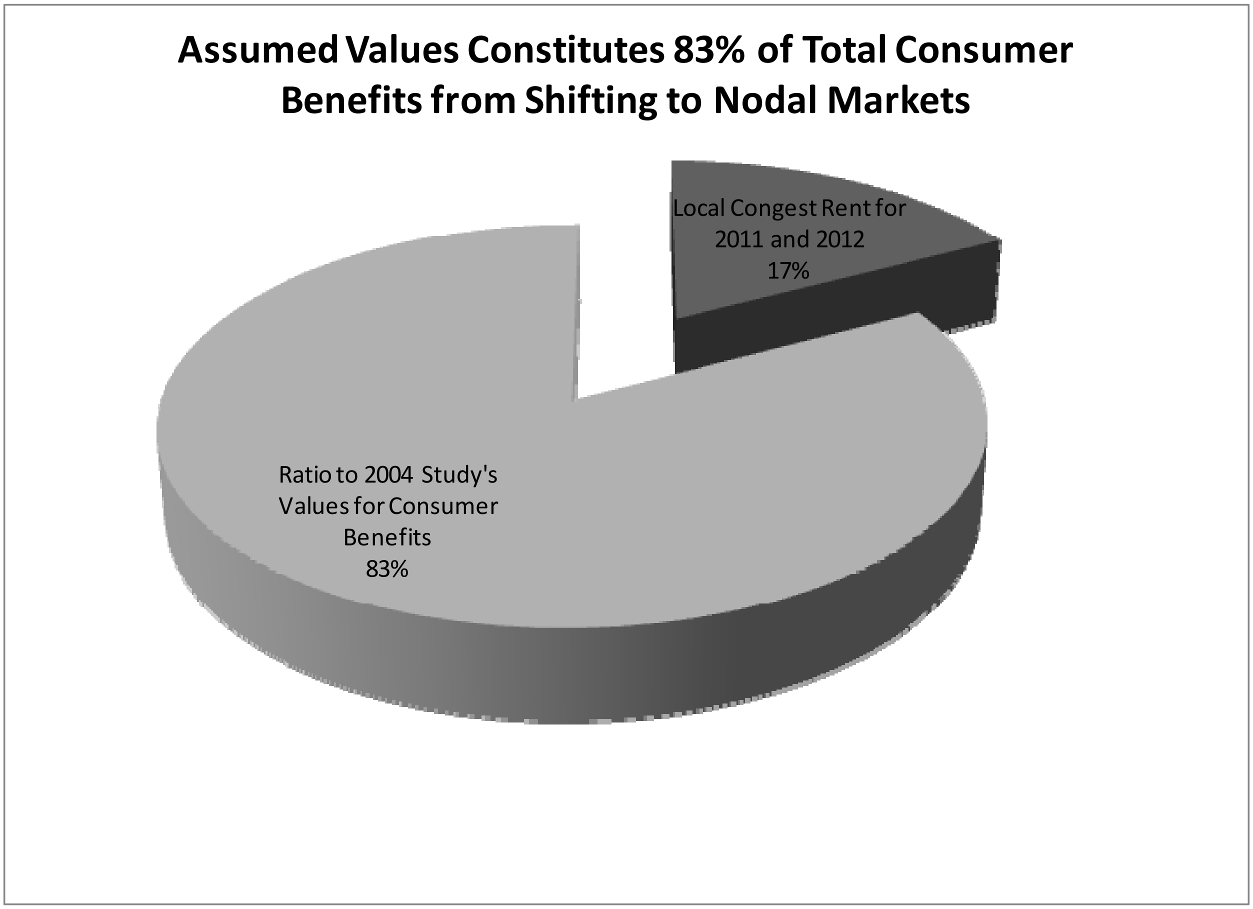
The most significant numbers in the December 2008 study concern consumer benefits. The authors indicate that between 2009 and 2012 consumers will see an annual average $576.6 million in savings due to the reimbursement of "congestion rents" and other benefits. This value is then "ratioed up" by the fraction that the average benefits had between 2005 and 2008 to total benefits estimated in November 2004.

This approach is extremely speculative. As noted above, the new study represents different years, different resources, different fuel prices, and different transmission capabilities. To compound the problems, the ratio used is based on two years when the nodal market will not be operating, so the ratio itself, regardless of its legitimacy, is in error. Finally, the assumption addressed below, that ERCOT generators will restrict their bids to short term marginal cost, is both unrealistic and likely to lead to a massive overestimate of the consumer payment savings.

The calculation described on page 34 of the December 2008 report is:

1. Identify the consumer payment savings for 2005 through 2014 from the November 2004 report – $7.3 billion.
2. Average the congestion rents for 2009 through 2012 from the revised model used in the December 2008 study.
3. Average the congestion rests for 2005 through 2008 from the original model used in the November 2004 report.
4. Divide the 2004 model result by the 2008 model result – getting a factor 1.29.
5. Divide the 2004 value for consumer payment savings by 1.29 to get $5.6 million.

This calculation is so unusual that it is difficult to see any economic logic in its derivation. There is no reason to believe that there is any logical comparison between market conditions in 2005 through 2008 – as estimated four years ago – and the current forecast for 2009 through 2012. Even if the markets were similar, despite the changes in generation, fuel prices, and transmission, the appropriate comparison would use years in which the nodal market was actually operating, not 2009 and 2010 when it has not yet started.




Aside from the illogic of the calculation, the economics of this argument are also suspect. ERCOT is characterized by a severely oligopolistic market structure of many buyers and few sellers. Strategic bidding is a continuing feature of ERCOT's markets with bids and prices often at multiples of short term marginal cost. If, as the authors assume, local congestion rents reduced the revenues of producers, economic theory would lead one to expect that strategic bidding may increase to recover the generators' revenues.

The major generator in ERCOT, Luminant, routinely submits bids at $300/MWh. When investigated by the Texas Public Utilities Commission, Luminant defended its strategic bidding practices by arguing that such high bids were required to cover its total costs of generation. While its argument might have had a poor grounding in economics, it was a perfectly logical argument for a price leader in an oligopolistic market. If Luminant's actual costs increased after nodal markets were adopted by ERCOT, it is logical that it would add the costs to its strategic bids, not passively accept a reduction in income.

## Backcasting

An important feature of the November 2004 report was an attempt to test its accuracy against actual prices and operations for 2003. This is a standard step for any complex computer model. Backcasting results for the November 2004 model were poor: overall ERCOT forecasts were 25.4 $/MWh against actual prices of $29.1/MWh. This represents an error on the order of 15%, a fairly poor showing for forecasting the previous year.

The December study dispenses with backcasting altogether. This omission is puzzling since the December 2008 model forecasted two years (2009 and 2010) of no special interest to the pending policy decision. These two years are not used in the calculations (with the exception of their erroneous inclusion in the ratio used to assume consumer benefits) since the nodal market is not forecasted until 2011. Below is an explanation by year:

| | |
|---|---|
| 2007 | Not modeled as a backcast |
| 2008 | Not modeled as a backcast |
| 2009 | Nodal market not in operation – modeled but not used in the present value of production cost savings |
| 2010 | Nodal market not in operation – modeled but not used in the present value of production cost savings |
| 2011 | Nodal market in operation – modeled and used in present value of production cost savings |
| 2012 | Nodal market in operation – modeled and used in present value of production cost savings |
| 2013 | Nodal market in operation – not modeled and results assumed to be equal to 2011-2012 |
| 2014 | Nodal market in operation – not modeled and results assumed to be equal to 2011-2012 |
| 2015 | Nodal market in operation – not modeled and results assumed to be equal to 2011-2012 |
| 2016 | Nodal market in operation – not modeled and results assumed to be equal to 2011-2012 |
| 2017 | Nodal market in operation – not modeled and results assumed to be equal to 2011-2012 |
| 2018 | Nodal market in operation – not modeled and results assumed to be equal to 2011-2012 |
| 2019 | Nodal market in operation – not modeled and results assumed to be equal to 2011-2012 |

2020 Nodal market in operation – not modeled and results assumed to be equal to 2011-2012

In the absence of a backcast, there is no evidence that the December study is able to reproduce prices and operations in ERCOT with any accuracy whatsoever.

## Assumptions

The authors state on page 68:

> A. Marginal Cost Bidding: All generation units are assumed to bid marginal cost (opportunity cost of fuel plus non-fuel VOM plus opportunity cost of tradable permits). To the extent that real markets are not perfectly competitive, the model tends to underestimate prices.[7]

This decision to make this assumption is not surprising. The original November 2004 report made a similar assumption:

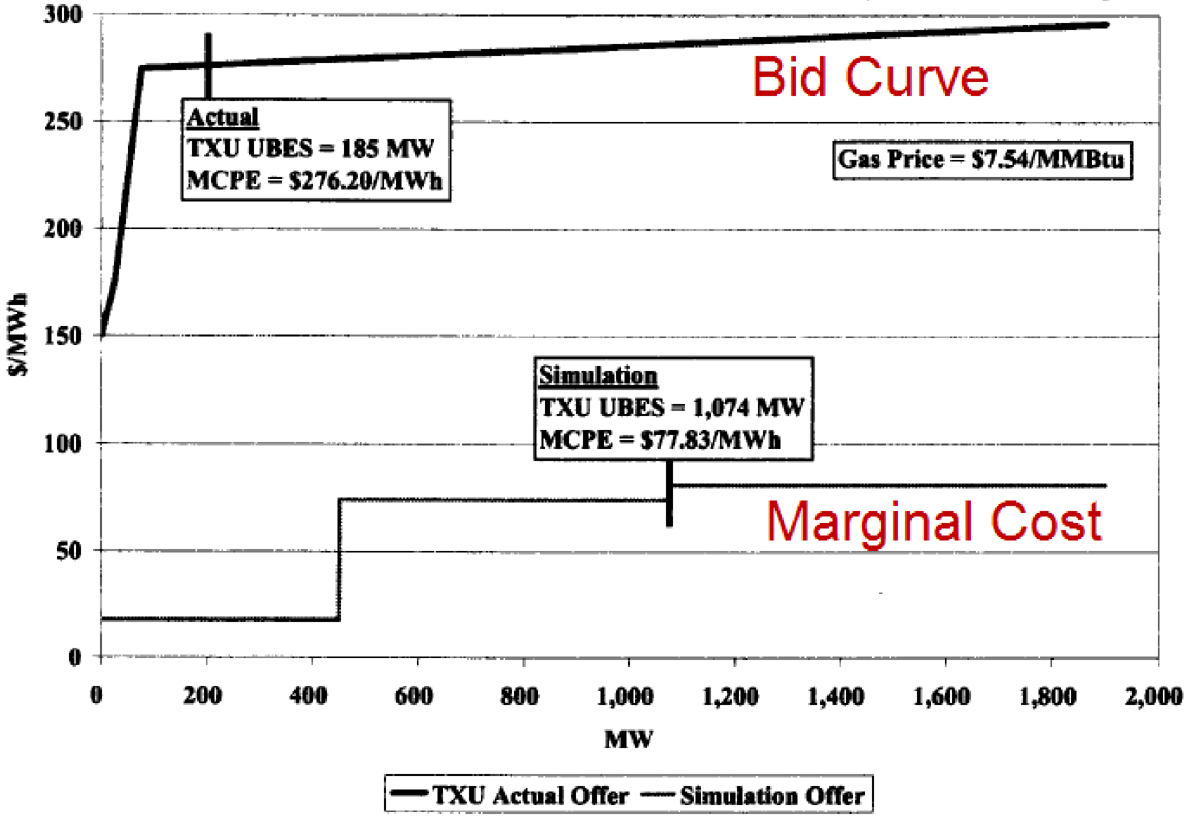
> The assumption of short-run marginal cost bidding can be overridden, implementing strategic bidding behavior, but the effort required to do this is considerable; prior to the contracting process, the CBCG chose not to pursue this approach. Note that throughout this report the use of the term "marginal cost" means refers to short-run marginal costs.[8]

Unfortunately, this is a poor assumption for a model designed to simulate market prices. In a condition of perfect competition, bids will approximate marginal cost. The critical condition precedent is "perfect competition". ERCOT meets few of the conditions of perfect competition, and strategic bidding is a continuing problem in ERCOT-administered markets.

Recently, Luminant settled a complaint by Texas regulators for strategic bidding.[9] At the heart of the investigation was the appropriateness of TXU's exercise of market power. In practice, TXU tends to bid the vast majority of its resources at $300/MWH regardless of the marginal cost of the units.[10]

[7] Final Report, December 18, 2008, page 68.
[8] Final Report, November 24, 2004, page 3-3.
[9] Notice of Violation, Docket 34061, March 28, 2007.
[10] Ibid., page 26. The terms "bid curve" and "marginal cost" were added.

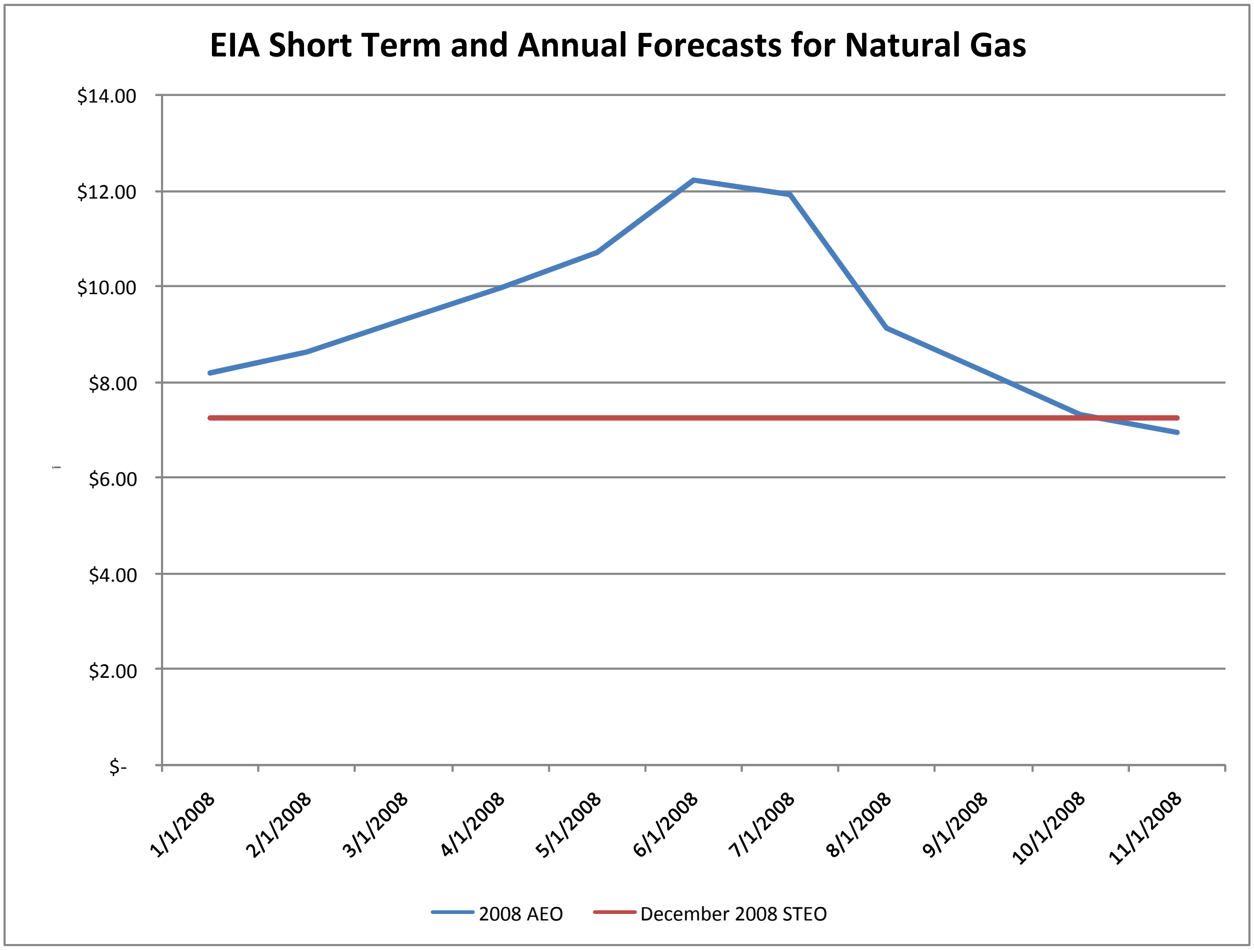
**Figure 10 – TXU Actual and Simulated Offer Curves (July 20, 2005, 5:30 p.m.)**




TXU's strategic bidding was obviously important – witness the complaint filed by PUC staff. Moreover, the deviation between the marginal cost of coal units and $300/MWh bids dwarfs any possible efficiency advantages likely to result from more precise pricing in the nodal model.

Modeling of strategic bidding is a challenge. Oligopolistic pricing decisions are complex and vary with circumstances. As noted above, when the largest single market participant makes strategic bids for thousands of megawatts, it is imprudent to ignore this information when modeling. In the example taken from the PUC complaint, the significant difference in prices is a difference of $200/MWh. The bias this assumption will create in the modeling dwarfs the relatively small production cost differences in the December 2008 report.

The most important operational assumption after bidding behavior is the cost of natural gas. The authors do not include detailed information on natural gas and coal prices used in their model. There is, however, a short discussion of the sources of the natural gas forecasts on pages 68 and 69. Prepared in a year of unprecedented fuel price volatility, the authors make the decision to base forecasts on the 2008 EIA's natural gas forecast published a year ago. The Energy Information Administration makes forecasts on both an annual and a monthly basis. EIA's annual forecasts are released in mid-December, thus making the 2008 forecast a full year out of date. While using forecasts from a year ago would normally be defensible, 2008 was hardly a normal year. Within 2008 prices for natural gas used for electric generation increased over 50% by July 2008 and in the latter portion of the year, they fell even more precipitously.




Forecasting fossil fuel prices has become increasingly difficult over the past few years and the use of superannuated forecasts is an extremely bad step in any modeling exercise. Notwithstanding, the dated natural gas forecast, the use of a single – relatively optimistic – point forecast is no longer appropriate regardless of its source or age. The standard approach to this problem is to prepare sensitivities for high, medium, and low fossil fuel prices so that decision-makers can see the impact of unpredictable fossil fuel prices on the model results.

Additional assumptions and calculations are poorly documented or missing, including:

1. NPV calculations for system costs
2. NPV calculations for customer savings

3. UPLAN results
4. GE MAPS results
5. SOx and NOx requirements and forecasted costs
6. Plant assumptions.

The authors also never address the real discount rate, a value that often drives results in models where costs and benefits occur at very different times in the future. This is true of the December study where computer programming costs largely occur before the onset of the nodal market. The estimated benefits, of course, result only after nodal market implementation. It should be noted also that the authors adopt the discount rate from the November 2004 study in spite of the turmoil in the world's financial markets and the global recession.

## Computer Programming Costs

Perhaps most mysterious is the expected cost to complete the computer programming for the nodal market. Although not explicitly stated, the total expected bill is on the order of $750 million, of which $322.1 has already been spent.[11] Table 13 identifies a present value of future expenditures of $430 million.[12] While beyond the scope of this review, the price for this relatively straightforward computer program is quite high by industry standards, especially for a single state with limited interties to the surrounding markets. Table 15 shows the full cost of the computer programming exercise:

**Table 15: Summary of net costs of TNM implementation through 2020 – 2008 dollars, 4.85% real discount rate**

| Item | Cost | Notes |
|---|---|---|
| ERCOT remaining TNM implementation cost through 2020 (NPV) | $362,294,601 | |
| MP remaining TNM implementation through 2020 (NPV) | $ 67,488,211 | |
| ERCOT demobilization & refresh costs (NPV) | $167,186,524 | Unwinding costs, if relevant, were assumed to occur in the 2009, upon TNM program termination |
| MP demobilization & refresh costs (NPV) | $ 40,573,107 | Unwinding costs, if relevant, were assumed to occur in the 2009, upon TNM program termination |
| Net cost to continue TNM implementation through 2020 | $222,023,181 | |

[11] Final Report, December 18, 2008, page 11.
[12] Ibid., page 40.

Translating this table requires some explanation. The first two lines are positive. The second two lines are actually negative, even though they are reported as positive values. They represent the costs of remaining with ERCOT's existing zonal market. The net cost line at the end is the sum of the positive and negative lines. Inserting the correct signs in the table shows:

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The actual calculation indicates that paying $422 million on the nodal computer program will only have a net impact of $222 million, since over $200 million will need to be spent to retain the existing, already written, computer program. A footnote provides the only documentation of this surprisingly large amount:

> This represents approximately $160 million in deferred zonal market ("refresh") costs and $15 million in costs to "unwind" the TNM.[13]

The scale of deferred costs for the zonal computer program, a less complex program than that needed for the nodal market, makes the estimate of the ongoing maintenance costs for the nodal program appear too low.

Since these large numbers are undocumented, it is only possible to note that the zonal program's maintenance has most likely only been neglected since the beginning of the nodal program four years ago. If this supposition is correct, ERCOT has foregone $40 million annually in computer program maintenance costs over the last four years. The report forecasts maintenance costs for the nodal

[13] Ibid., page 41.

program as a relative bargain at $14.1 million per year over the first decade of its operation, which is approximately one-third of the maintenance costs for the existing program. Assuming that the zonal programs maintenance costs have been overstated by a factor of three, this would increase the net cost to continue the nodal program by $106 million, yielding a net going ahead cost of $326 million, as opposed to $222 million. Alternatively, if maintenance costs of the nodal program are assumed to match the costs of the zonal program, the total go ahead costs would increase to $452 million dollars, instead of the reported $222 million.

In either case, the conclusion in Table 15 appears vastly understated.

## Conclusions

The December 18, 2008 study has a number of problems. These appear significant enough that the conclusions of the study are effectively speculative. In addition, the study is poorly documented and depends on a number of unusual assumptions.

1. The study has only modeled two years of the ten year period under analysis. This failing affects both the estimate of production costs and consumer benefits. The current modeling ends before the year when the 2004 model appeared to have significant problems.
2. The study has not verified their methodology by doing a backcast. In the absence of a backcast, the results cannot be depended upon to even remotely reproduce conditions in ERCOT markets.
3. Several assumptions are highly questionable. The study assumes marginal cost bidding by market participants even though this is not present in ERCOT. In addition, the study uses a natural gas forecast from a year ago -- a curious choice in such volatile times. Other assumptions are undocumented or simply copied from a study four years out of date – the discount rate, for example.
4. The costs of the additional computer programming appear high – very high – and the assumptions appear inconsistent. The high maintenance costs assumed for the existing operational zonal model appear to be just a fraction of the assumed maintenance costs of the new, unfinished and vastly more complex, nodal model.