Total	**37,050**	**160,302,375**

1. Projects to replace EMS and MMS systems would be required. Existing versions are no longer supported by vendor (Areva) on Tru64 platform. Total replacement of these systems is likely.

2. IMM Recommendations

3. IMM - 2007 State of the Market Report

Future Incremental Operating Costs

If ERCOT continues its implementation of the nodal market, there are incremental operating costs that it will incur after the transition from the zonal to the nodal market. These costs result from the increased complexity and size of the nodal market, and the need for additional staff.

ERCOT estimates it will need to employ the equivalent of approximately 50 new FTEs to operate the nodal market. These employees would be needed throughout the organization; there will be significant additions in operations, administration, and engineering. These new personnel make up roughly half of the incremental costs going forward, and their associated costs are estimated to relatively constant. Based on our discussions with ERCOT staff, each employee is estimated to cost approximately $110,000 per year, including salary and benefits.

In addition, the data storage and operational requirements of the nodal market are estimated to be higher than those of the current zonal market, leading to significantly increased costs for hardware and software licenses and support. This cost difference was projected to be $2.8 million in 2011 and $5.9 million in 2012. Hardware and software costs are expected to stabilize at approximately $15.2 million per year in 2012 based on the current design, up from current nodal operational cost of approximately $9.5 million. Based on discussions with ERCOT, we have estimated the average of these incremental increases to be persistent, and the overall incremental increase in operating costs for hardware and software would remain constant at $4.4 million per year.

The numbers presented by ERCOT in its budget of increased costs between 2011 and 2012 do not coincide precisely with these numbers because of the way in which some costs are characterized. Table 17: Summary of ongoing increased incremental TNM operating costs below summarizes which incremental cost increases have been characterized as overall net increases to ERCOT costs in the new nodal market.

Table 17: Summary of ongoing increased incremental TNM operating costs

	Incremental Increase	2011 vs. 2008	2012 vs. 2008	Average difference	Adjusted difference	Notes
Labor & Benefits	Yes	7,542,605	11,886,451	9,714,528	7,285,896	1
Contract Labor - Base Projects	No					2
Contract Labor - Nodal Program	No					2
Support Allocations - Nodal Program	No					2
Backfill Allocations - Nodal Program	No					2
Facilities Allocations - Nodal Program	No					2
Material, Supplies, Tools & Equipment	Yes	90,700	116,215	103,458	103,458	
Special Reviews	No					
Outside Services	Yes	3,376,477	(2,823,690)	276,394	276,394	
Utilities, Maintenance & Facilities	Yes	1,076,830	1,504,813	1,290,822	1,290,822	
HW/SW Renewable License & Maint.	Yes	2,827,924	5,929,620	4,378,772	4,378,772	
Insurance	Yes	(124,631)	(79,998)	(102,314)	(102,314)	
Employee Expenses	Yes	(129,883)	(92,233)	(111,058)	(111,058)	
Interest & Fees	Yes	(2,512)	387,094	192,291	192,291	
NERC Dues	No					3
Other	Yes	1,120,339	757,140	938,740	469,370	4
Property Taxes	Yes	400,000	431,500	415,750	415,750	
	Total	**16,177,849**	**18,016,912**	**17,097,381**	**14,199,379**	

Notes:

1. Based on conversations with ERCOT, ongoing cost has been estimated at 75% of the average difference between 2011 and 2012.

2. These line items in the nodal budget represent primarily changes in the base operating budget resulting from allocations to the TNM program. Based on the CRA/Resero analysis and conversations with ERCOT, they have been excluded from this calculation because they represent no *net* change to ERCOT's *overall* (i.e. TNM + zonal) costs.

3. The large increase in NERC dues in 2011 and 2012 is largely the result of changes in the way that ERCOT participates in NERC processes and programs. These dues would have increased regardless of whether ERCOT was operating a nodal or zonal market, and thus represent no net difference between the operational costs of the TMN and current zonal market.

4. Based on conversation with ERCOT, ongoing miscellaneous costs are estimated to persist at 50% of their average difference between 2011/2012 and 2008.

Interdependent Zonal Costs

In the course of the nodal implementation there are certain costs that ERCOT has incurred that are of use under either market design. These include hardware, software, networking, and infrastructure purchases.

Table 18: Interdependent TNM/Zonal Costs

Project	Total
NMMS	$12,700,000
EMS	$8,900,000
Infrastructure	$18,100,000
Total	$39,700,000

These recent cost estimates were supplied to CRA/Resero by ERCOT. Assuming that the decision facing ERCOT and the Commission is between the options of continuing and halting development, these costs are not relevant because if the TNM is implemented, there is no opportunity to recover these costs without a zonal infrastructure.

Distribution of remaining costs

ERCOT supplied us its monthly expenditure rate and distribution of remaining direct (non-interest) costs. The expenditure rate supplied to by ERCOT did not include a distribution of finance charges, nor did the total summary of yearly costs align with the November 8 budget presentation to the board of directions. This appears to be a consequence of different reports being generated at different times. The following distribution of remaining implementation costs to schedule total implementation costs were assumed.

Table 19: Scheduling of remaining direct and financing costs

	Remaining non-financing costs by year supplied by ERCOT as of 11/14/08	Percentage of total remaining costs incurred per year
2009	$122,049,114	63.6%
2010	$69,270,082	36.1%
2011	$604,365	0.3%
2012		
2013		
2014		

The same time distribution was assumed for remaining implementation costs for market participants' costs.

3.3.2. Market Participants

While ERCOT's TNM implementation costs are the largest contributor to the total cost, market participants' costs are substantial. Estimating of market participants' costs is considerably more complex than estimation of ERCOT's costs. The market contains many different types of entities, from large IOUs to IPPs to small co-ops, and each operates in a relatively unique fashion. The purpose of this CBA update was explicitly not to re-do the 2004 CBA cost estimates, but rather to update and verify costs. CRA/Resero conducted its analysis by interviewing seven different market participants from the following segments: IOUs, munis, co-ops, IPPs and IPMs. Several of the participants we interviewed operate retail operations in Texas, but we were not able to obtain sufficient information from Retail Energy Provider (REP) -only market participants; several were contacted, but did not have detailed nodal implementation data that they could share with us, although their anecdotal comments indicate that their costs are considerably lower than those of market participants who operate ERCOT generation. These REP-only implementation costs have not included in our estimated costs. These market participants spoke to CRA/Resero under a confidentiality agreement that requires divulging neither their identity nor their cost data in anything other than aggregate form.

The market participants interviewed came from a wide spectrum of entities, including some of the largest market participants in ERCOT to multi-state generation fleet owners to small, local companies. Costs varied considerably size of the generation fleet and number of units, but costs were found to be highly dependent upon whether the market participant had prior experience operating in other nodal markets.

Those market participants who operate in other nodal markets such as PJM, or NYISO were able to take considerable advantage of existing equipment and knowledge by re-using systems, re-purposing equipment and leveraging existing institutional knowledge.

After compiling market participant data, and categorizing market participants by number of generation units, amount of capacity in ERCOT and whether they had prior nodal experience, the following estimates were used to extrapolate costs for all market participants.

Table 20: Market participant cost by other-market participation

	Average cost per generation unit	Average cost per MW of installed capacity
No prior Nodal experience group	$673,469	$2,796
Prior Nodal experience	$51,563	$225

The top 20 largest market participants in ERCOT were then used for cost extrapolation as follows:

Table 21: Top market participants used for market participant cost extrapolation

Owner Name	Market Segment	Market Entity	Number of Units	Sum of Capacity
Luminant	IOU	QSE	60	18579
NRG Texas LLC	IPP	QSE	44	14637
FPL Group	IPM	QSE	24	6236
CPS Energy	Muni	QSE	24	5741
Calpine Corp	IPP	QSE	9	4995
Austin Energy	Muni	QSE	18	2591
Lower Colorado River Authority	Co-op	QSE	20	2431
Exelon Generation Co LLC	IPM	QSE	10	2392
American National Power Inc	IREP	QSE	7	1927

Topaz Power Group LLC	IOU	QSE	10	1645
Tenaska Energy	IREP	QSE	2	1370
Brazos Electric Power Coop	Co-op	QSE	9	1315
Midlothian Energy LP	IREP	QSE	4	1156
Guadalupe Power Partners LP	IPP	QSE	2	1142
PSEG Energy	IPM	QSE	2	1135
Navasota Energy	IPP	QSE	4	1100
Tenaska Gateway Partners Ltd	IPP	QSE	1	940
Rio Nogales Power Project LP	IPP	QSE	1	825
Shell Oil Energy	*IPP*	*QSE*	*5*	*332*
Reliant Energy Renewables Inc	IPM	QSE	20	25
Total Nameplate Capacity - Top Companies				70,513
Total ERCOT Nameplate Capacity				96,879

CRA/Resero used the cost ratios detailed earlier in Table 20: to estimate implementation costs for these 20 market participants. Several of the market participants listed above were interviewed; in those cases, actual implementation costs as supplied by those market participants were used.

Estimates of the already-spent implementation costs varied widely, as did estimates of interdependent costs incurred by market participants. Based on the interviews, the average amount of total nodal implementation cost incurred by market participants was 59% of the total costs.

Most market participants interviewed were unable to supply reliable estimates of unwinding and zonal refresh costs, principally because they had not devoted the resources to study this differentiation of costs. In the absence of these data, ERCOT cost ratios were used to estimate this division for the market participants. ERCOT's refresh costs were 24% of its overall system implementation cost ($160 million / $660 million). Using 24% for market participant refresh costs resulted in an estimated unwinding/refresh cost for market participants of $42 million.

The market participants interviewed also provided widely ranging estimates of ongoing incremental operational costs that would result from the TNM implementation. The data supplied were not sufficient to come to a reasonable and consistent estimate of ongoing operational costs, and as a result no market participant incremental TNM operating costs have been included. This has the likely effect of slightly understating the NPV of the market participant implementation costs.

The 20 largest market participants comprise 73% of the installed capacity in ERCOT. After estimating the implementation costs for these market participants, CRA/Resero extrapolated the costs to cover the entire installed capacity base in ERCOT and arrived at the following summary.

Table 22: Summary of market participant (MP) implementation costs, 2008 dollars

Item	Cost	Notes
Estimated TNM implementation costs for top 20 ERCOT MP	$127,728,189	Average of estimates based on number of generation units and capacity
Estimated Costs of all ERCOT MPs	$175,488,535	Extrapolated based on % of capacity owned by Top 20 MPs
Costs incurred so far as a % of total MP costs	59%	Based on sample data reported by the MPs
Estimated costs incurred so far by all ERCOT MPs	$103,500,814	
MP zonal refresh costs	$42,542,675	Based on estimate of 24% of total costs necessary for unwinding
Remaining costs to complete TNM implementation	$71,987,721	
Net cost to continue TNM implementation	$29,445,046	Total remaining costs less refresh and demobilization costs

While very difficult to quantify, many market participants emphasized that the ongoing delays in the nodal market implementation were imposing a cost on them that was greater than if the TNM had been implemented its original schedule. Many market participants, especially those without experience in other nodal markets, have relied upon consultants to provide much of their labor for implementation. While the TNM is delayed, these consultants must often be furloughed or idled while delays are addressed, imposing additional costs.

3.3.3. Glossary of ERCOT budget terminology

The nomenclature for terms associated with the TNM budget can be potentially confusing. The following glossary of terms has been taken from ERCOT, with only minor edits.

- **Internal Labor Costs**
  - Labor costs of ERCOT employees who are working on the Nodal program.
- **External Resource Costs**
  - Includes both contractor and vendor expenses. Examples of the two types of expenses would be contingent labor contracted to work on the Nodal program, and also software development expenses from the software vendors (ABB, AREVA, etc...). Contractor labor is for staff augmentation where ERCOT does not have the number of employees required to perform the additional Nodal project work or where ERCOT does not have employees with the skills to perform the work.
- **Administrative & Employee Expenses**
  - Equipment, tools, office materials & supplies. Also includes ERCOT employee expenses. For example, the expenses for trips by ERCOT employees to vendor sites to supervise software development would fall into this category.
- **Software**
  - Expenses for purchased 3rd party software not being developed solely for the Nodal program. For example, this would include a wide variety of software ranging from Oracle database licenses to Microsoft Windows Server licenses. This cost category also includes the maintenance expenses associated with software licenses.
- **Hardware**
  - Includes all computer hardware purchased to enable the Nodal market and the future maintenance on this equipment. Examples would be servers, data storage hardware and networking equipment.
- **Backfill**
  - This category represents the difference between ERCOT's labor expense for an internal employee and a contractor hired to perform that employee's duties while that employee is working on the Nodal program. For example, if the fully loaded cost to ERCOT for an employee was \$50/hr and that

employee was reassigned from ERCOT base operations to the Nodal program and a contractor was hired at $70/hr to perform the base operations duties while the employee is working on the Nodal program, the cost to the Nodal program is the difference between the two expenses, in this case $20/hr.

- **Indirect Support Costs**
    - Several ERCOT administrative departments charge the Nodal program an allocation for services provided to Nodal. For example, ERCOT Procurement, Finance, Legal, and some others provide their services to the Nodal program. The amount charged to the Nodal program is based on an allocation that has been audited and approved.
- **Facilities Allocation**
    - Similar to the Indirect Support Costs category, the Facilities Allocation is a reimbursement to ERCOT base operations from the Nodal program for the facilities space and services provided by ERCOT to the Nodal program.
- **Finance Charge**
    - Interest expenses related to debt incurred to finance the Nodal program.

4. OTHER IMPACT MARKET ASSESSMENT

This section presents the Other Market Impact Assessment (OMIA) update. The OMIA captures potential benefits and costs not otherwise captured in the EIA and IIA. This update reflects new impacts that were not recognized or identified at the time of the original CBA, and other impacts recognized in the 2004 OMIA, but for which the availability of updated information may offer new insights about the nature or degree of the impacts.[21]

A wide range of potential impact areas were examined, and a number were found to be relevant. For those areas deemed relevant, numerous sources of information were relied upon, including:

- Discussions with ERCOT staff;
- Information from Independent Market Monitors (IMMs), including written reports from ERCOT's IMM and the IMMs of other nodal markets;
- Protocol language issued since the 2006 CBA for market monitoring and co-optimization of energy and ancillary services;
- General knowledge about the ERCOT market and its operating environment, including recent significant market events.

The findings of the OMIA update are below. A summary is followed by a more detailed discussion of each area.

4.1. SUMMARY OF OMIA UPDATED FINDINGS

The OMIA update did not identify any substantially new types of impacts, nor did it reveal that the other impacts of a nodal market differ significantly from how they were characterized in the 2004 CBA OMIA. Several of the 2004 OMIA findings were substantiated through the review of updated information and events. At the same time, the updated information suggests that some of the other risks and costs appear to be less significant now than they were at the time of the 2004 OMIA. The 2004 OMIA suggested that were additional net benefits beyond those captured in the quantitative aspects of the CBA. The current OMIA update suggests to an even greater degree that these other impacts are net positive.

Specific insights are summarized below.

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21 The original OMIA applied a rather comprehensive methodology to identify potential other impacts of the nodal market design and operational changes. The scope of the update, however, was more limited. It was not intended to repeat that comprehensive process and instead examined possible drivers (such as the extended implementation schedule and recent market price excursion events) that could change the impacts identified in the original OMIA.

Events and ERCOT's changing environment have identified several Other Market Impact changes: (Discussed in Section 4.2, below.)

1. Given the experience market participants have gained since the 2004 OMIA was prepared, many of the potential risks associated with the nodal market have been largely resolved or mitigated. Although the market is perceived to be more complicated than originally envisioned, market participants have also acquired better understanding through their readiness activities and participation in various stakeholder groups.

2. The value of the nodal market is potentially higher because of the significant deployment of wind generation, given the nodal market's ability to alleviate limitations of ERCOT's current dispatch procedures and provide for rapid system responsiveness.

3. Analysis of ERCOT's summer price excursions by its IMM offers several observations, including that the zonal market may have difficulty in addressing some zonal congestion situations, resulting in high cost impacts, and that nodal markets offer customers more efficiency, choice and flexibility.

Market outcomes from other U.S. nodal markets substantiate the algorithmic and complexity risks identified in the 2004 OMIA. They also suggest that these risks and their impacts decrease over time as market participants and market operators become more aware and take appropriate corrective actions. Similarly, while nodal markets are still not able to capture all of the theoretical benefits of nodal price signals, ongoing refinements of market rules and algorithms are enhancing the benefits of better price signals to be recognized over time. (Discussed in Section 4.3, below.)

Resolution of market monitoring policies suggests that there are reduced nodal market risks associated with price anomalies and market manipulation. The addition of co-optimized ancillary services suggests there may be additional benefits that were not captured in the 2004 CBA. (Discussed in Section 4.4, below.)

4.2. UPDATED OTHER IMPACTS BASED ON CHANGES IN CIRCUMSTANCES AND EVENTS SINCE THE 2004 CBA

CRA/Resero considered the wide variety of circumstantial changes and events that have occurred since the 2004 CBA was conducted in the 2004 timeframe. These include the additional resource build-out that has occurred (especially with respect to wind development), implications of the extended implementation schedule and budget, and the 2008 summer price excursions. For each area reviewed in which potential benefits were suggested, CRA/Resero has updated the assessment of these other costs and benefits where they are distinct from impacts being captured in the updated EIA or IIA.

Complexity: Implications of the extended implementation schedule/budget not captured in the IIA or EIA

The fact that the implementation timeline is longer than initially anticipated influences the costs and benefits identified in the 2004 OMIA. For example, the 2004 OMIA identified the perception that a nodal market has a higher level of complexity that would adversely impact market participants during a limited transition period.

The extended implementation schedule reflects the nodal market's complexity, and based on their involvement in the design and development of the TNM thus far, market participants may judge the nodal market to be even more complex than they would have in 2004. In many respects, however, market participants have already addressed much of the complexity of the nodal market through their involvement in design, development, and training efforts at ERCOT, and through their own readiness efforts. In a sense, they have already progressed through part of that "transition period." As a result, many of the additional costs associated with addressing complexity could be viewed as sunk, and the going-forward incremental impacts on market participants will likely be lower than they were at the time the 2004 CBA was published.

Implications of Wind Expansion

The addition of wind resources in ERCOT increases the importance of the nodal market's telemetry-based 5-minute dispatch, which will replace the existing zonal market's scheduled-based dispatch. For example, the summer 2008 price excursions demonstrated the limitations of ERCOT's current dispatching procedures and the need for rapid system dispatch – a need that should be fulfilled by the ERCOT nodal design.[22]

Implications of Price Excursions:

The price excursions of 2008 offered a number of new insights with respect to limitations of the zonal market design and benefits of the nodal market design.

1. Scarcity pricing effects are much more costly under a zonal market

   While the EIA measures the impact of congestion under normal conditions, Commission and ERCOT policies provide for a form of "scarcity prices" when transmission constraints cannot be resolved. Transmission constraint resolution

22 See for example, "ERCOT Market Issues" presented to the Texas Industrial Energy Consumers Annual Meeting, by Dan Jones ERCOT IMM, Potomac Economics, July 23, 2008, refers to an event on July 8, 2008 where wind generation picked up and then dropped off by about 1,600 MW over approximately a 60-minute time period. The ramps up and down depleted the Regulation Down and Regulation Up products. With ERCOT's zonal scheduling process, where schedules may be established up to 30 minutes prior to the 15 minute dispatch window, it seems very challenging to manage such significant changes in balancing energy needs.

using shift factors averaged over a zone is much more difficult than constraint resolution using node-specific shift factors. The IMM's analysis of the summer events indicates that "inefficiency of the zonal model has recently produced an unusually high number of constraints that could not be resolved..." and that "...the pricing effects of such irresolvable constraints are much more geographically widespread than would be the case under nodal dispatch and pricing."[23] Under extreme pricing conditions, the application of the scarcity price when transmission constraints cannot be resolved would be much more limited under a nodal market.

2. Nodal markets provide for more customer choice and flexibility

Another implication of the 2008 price excursions was the observation that if prices closely reflect operating conditions and marginal costs, then market participants can be provided with more flexibility in the way they use the transmission system. However, if pricing does not conform to the operating conditions, then substantial operating restrictions must be imposed to preserve system reliability. In this sense, customer flexibility and choice are improved when the nodal market results in efficient and transparent pricing. Conversely, zonal market pricing that does not match the specific system conditions limits market flexibility.[24]

4.3. Updated Other Impacts Based on Review of Independent Market Monitoring Reports from Other Nodal Markets

CRA/Resero reviewed the most current IMM reports[25] and identifies within this section any updated implications with respect to "other" ERCOT nodal costs and benefits.

Generally, in many of the markets, the IMMs observe nodal market benefits, reporting, for example, that the nodal markets "... provide substantial benefits to the region by ensuring that the lowest cost supplies are used to meet demand in the short-term and by establishing transparent, efficient price signals that govern investment and retirement decisions in the long-term."[26]

The IMM reports do, however, generally support the findings of the 2004 OMIA that modeling complexities and algorithmic limitations prevent all of the theoretically possible, short-term

23 Presentation of Dan Jones, ERCOT's IMM, Potomac Economics, to the House Committee on Regulated Industries, June 23, 2008.

24 Id.

25 Updated reports were reviewed from ISO-NE, PJM, MISO, and NYISO.

26 2007 Assessment of the Electricity Markets in New England, page 1 Report available at http://www iso-ne com/pubs/spcl_rpts/2007/isone_2007_immu_rpt_fin_6-30-08.pdf.

efficiency gains from being realized and at times also diminish the clarity of the price signals that are intended to produce long-run benefits.

While these are not new findings, the current reports continue to suggest that as nodal markets become more established and as the market operator and market participants gain experience, incremental improvements to the markets lead to corresponding improvements in market efficiency and resultant benefits. Examples of such evidence in the IMM reports include the following:

- In ISO-NE, price signals from the nodal markets were diminished when ISO-NE made supplemental commitments in the Day-Ahead Market to compensate for deficiencies in the specificity of the market algorithms. While ISO-NE has put in place adjustments that are expected to remedy these deficiencies,[27] its experience does provide evidence that nodal market designs require some ongoing adjustments to recognize the theoretical benefits.

- Similarly, ISO-NE's experience with algorithms for setting LMPs offers some evidence that nodal algorithms can initially produce less-than-optimal results and require tuning of the configurations implemented at nodal start up.[28]

- In MISO, constraint relaxation methods that determine how LMPs are calculated when constraints bind (as with too many self-schedules) sometimes produce inefficient results.[29] Also, the practice of separately computing an ex-post price rather than using the ex-ante price derived from the dispatch algorithms leads to inconsistencies between LMPs and generators' dispatch signals.[30]

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27 ISO-NE has implemented solutions that include new transmission investment to reduce local reliability commitments; adding local reserve requirements for the forward reserve market and introducing real-time reserve markets that are co-optimized with the energy market; and a forward capacity market that procures capacity on a locational basis. ISO-NE, page 3.

28 For example, nodal market algorithms tend to prohibit certain resources from setting price unless they are dispatched in their flexible range (id. page 11). Additionally, ISO New England's ex post pricing model apparently a) creates a small upward bias in real-time prices in uncongested areas and b) occasionally distorts the value of congestion into constrained areas. (Id., page 12).

29 2007 State of the Market Report for the Midwest ISO, pages ix and 83. Report is available at http://www.midwestiso.org/publish/Document/24743f_11ad9f8f05b_-7b890a48324a/2007%20MISO%20SOM%20Report_Final%20Text.pdf?action=download&_property=Attachment.

30 Id, pages xvi and 55.

- In PJM, the lack of geographic specificity in the scarcity pricing design was found to not provide an effective price signal under scarcity conditions. PJM will be correcting this by adopting a more location-specific scarcity pricing mechanism.[31]

- In the NYISO, improvements to the real-time commitment process have been identified that will help resolve discrepancies that arise between the real-time pricing and the real-time dispatch due to ramping.[32]

- In the NYISO, several historical pricing deficiencies were resolved during this recent reporting period by the implementation of more specificity in the network model.[33]

In at least one instance, the IMM reports suggest that market participants are better able to use nodal transmission rights products to effectively hedge transmission risk as the markets mature, in this case resulting in prices for transmission rights that were more consistent with congestion costs.[34]

In at least one instance the IMM reports also suggest that outcomes of the nodal markets have resulted in transmission system investments and market rule changes that increase the efficiency of the network. For example, in ISO-NE some commitments for local reliability had the effect of diminishing energy and ancillary service prices and increasing uplifts in constrained areas. As a result, ISO-NE implemented solutions that included new transmission investment to reduce local reliability commitments; adding local reserve requirements for the forward reserve market and introducing real-time reserve markets that are co-optimized with the energy market; and a forward capacity market that procures capacity on a locational basis.[35]

In summary, the recent IMM reports substantiate many of the findings of the original OMIA: that because the nodal algorithms are complex and imperfect, at times their results do not

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31 2007 State of the Market Report, pages 6, 111 and 167. Complete report can be found at http://www2.pjm.com/markets/market-monitor/downloads/mmu-reports/2007-som-volume2.pdf.

32 "... particularly with respect to real-time scheduling system to better manage ramps at the top of the hour, especially during the morning and evening load changes ", 2007 State of the Market Report, New York ISO, page xi and pages 76-87. Report can be found at http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/NYISO_2007_SOM_Final.pdf.

33 Id. For example, the NYISO implemented a more disaggregated transmission network model for NYC where many lines used to be aggregated. (Pages 68 and 74). Also, better modeling of transmission constraints during periods of high re-dispatch costs to reduce the frequency of price corrections has already been implemented. Pages xiii and 11.

34 Midwest ISO, pages xvi and 88-93.

35 ISO-NE, page 2.

capture all of the potential efficiencies that could be realized from a nodal market. The IMM reports do indicate that, generally speaking, the nodal markets are producing substantial economic benefits through more efficient market outcomes. The reports also suggest that the nodal markets do mature over time and in the process they produce outcomes that more closely approach the theoretical optimum. Further, the IMM reports provide evidence that within the nodal structure market participants take advantage of nodal market information to make investment and operating decisions (e.g., risk management through hedging products) and that the market and system operators use nodal market results to make infrastructure improvements.

4.4. UPDATED OTHER IMPACTS BASED ON REVIEW OF DRAFTED MONITORING AND ANCILLARY SERVICE CO-OPTIMIZATION POLICIES

CRA/Resero reviewed two policies that were not in place at the time of the original CBA: the co-optimization of energy and ancillary services in the nodal market, and policies for market monitoring.

Co-optimization of energy and ancillary services would tend to result in more efficiencies with the nodal market than originally predicted. Although the EIA analysis does assume that spinning reserves are co-optimized with energy, ERCOT's policy to co-optimize the entire suite of ancillary services should result in a higher level of benefits from the nodal market than originally expected as well as benefits beyond those characterized in the OMIA.

With respect to monitoring, effective oversight of nodal markets requires timely access to large amounts of data that includes market results, load forecasts, bids and other inputs. It also requires a variety of sophisticated analytical tools and relevant analytical expertise to sift the data for anomalies and determine root causes. By developing an explicit protocol that places timely market data and appropriate analytical tools at the disposal of both the Independent Market Monitor (IMM) and the PUCT, ERCOT's framework for effective, independent oversight of the TNM should reduce the risks of nodal market price aberrations associated with pricing anomalies and inappropriate behavior.

5. ACKNOWLEDGEMENTS

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We would also like to thank the market participants with whom we spoke, who generously shared their time, insight, and information with us.

APPENDIX A: INPUT ASSUMPTIONS

This appendix summarizes salient inputs to the CRA nodal price forecasting model (GE MAPS) for ERCOT. The analyses simulate the years 2009 to 2012. Primary data sources for the CRA GE MAPS model include FERC submissions by generation and transmission owners (Forms 1, 714 and 715); the NERC Electricity Supply and Demand and Generation Availability databases; data from the US EPA; the Energy Velocity database; and CRA analysis of plant operations and market data. The study also uses data provided by the ERCOT Planning group. Major data components are listed below.

TRANSMISSION

The CRA model is based on load flow cases published by ERCOT in September 2008 for the study time horizon. Monitored constraints include:

- Commercially Significant Constraints (CSC) as defined by ERCOT for 2009. Since definitions of CSC are not available for future years, the 2009 definition is retained, or approximated as closely as possible in case of changes in topology;
- Closely Related Elements (CRE) monitored for their base rating, once again using the current list of elements;
- Contingency constraints that monitor each CRE for the loss of each other CRE related to a given CSC;
- All binding constraints from a UPLAN analysis by ERCOT planning staff for 2009-12;
- Constraints identified by CRA through contingency analysis, using a list of contingencies provided by ERCOT planning staff;
- Non-radial lines loaded above 50% of their base limit in the provided load flows.

LOAD INPUTS

GE MAPS is provided an hourly forecast load for each ERCOT weather zone, as published by ERCOT in November 2008. The weather zones are in turn mapped to the load flow cases, and the load for each weather zone is distributed among the load buses in that zone based on the ratio of loads in the snapshot provided in the load flow case.

ERCOT planning staff also provided a list of locations where load is not time-variant or weather-dependent. CRA modeled load at these buses as constant in each year. Additionally, the weather zone load forecast does not account for approximately 4,900 MW of behind-the-fence load – this was modeled based on levels indicated in the load flow cases.

THERMAL UNIT CHARACTERISTICS

GE MAPS includes a detailed model of thermal generation, in order to accurately simulate operational characteristics, and project realistic hourly dispatch and prices. Modeled characteristics include unit type, unit fuel type, heat rate values and shape (based on unit technology), summer and winter capacities, fixed and variable non-fuel operation and maintenance costs, startup fuel usage, forced and planned outage rates, minimum up and down times, and quick start and spinning reserve capabilities.

The CRA generation database reflects unit-specific data for each unit based on a wide variety of sources. In cases where unit-specific data is not available, representative values based on unit type, fuel, and size are used. Table 23: and Table 24: document these generic assumptions. Note that all costs and prices are shown in real 2007 dollars.

Table 23: Thermal Unit Characteristics

Unit Type & Size	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Minimum Downtime (Hrs)	Minimum Uptime (Hrs)	Heat Rate Blocks
Combined Cycle	$2.50	$21.00	8	6	2 – each 50% @ FLHR
Combustion Turbine <50 MW	$7.00	$15.00	1	1	One block
Combustion Turbine >50 MW	$7.00	$15.00	1	1	One block
Steam Turbine [coal] >200 MW	$3.00	$35.00	12	24	
Steam Turbine [coal] <100 MW	$3.00	$45.00	6	8	4. 50% @ 1.06% FLHR, 15% @ 90%, 30% @ 95%, 5% @ 100%
Steam Turbine [coal] <200 MW	$3.00	$35.00	8	8	
Steam Turbine [gas] >200 MW	$3.00	$30.00	8	16	
Steam Turbine [gas] <100 MW	$5.00	$34.00	6	10	
Steam Turbine [gas] <200 MW	$4.00	$30.00	6	10	4: 25% @ 118% FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [oil] >200 MW	$3.00	$30.00	8	16	
Steam Turbine [oil] <100 MW	$5.00	$34.00	6	10	
Steam Turbine [oil] <200 MW	$4.00	$30.00	6	10	

Table 24: Thermal Unit Characteristics

Unit Type & Size	Quick Start (%)	Spinning Reserve (%)	Forced Outage (%)	Planned Outage (%)	Typical Outage Length (Days)
Combined Cycle	-	20%	1.81	7.40	3
Combustion Turbine <50 MW	100%	0%	2.81	5.28	1
Combustion Turbine >50 MW	100%	0%	2.60	6.94	1
Steam Turbine [coal] >200 MW	-	20%	3.07	9.10	7
Steam Turbine [coal] <100 MW	-	20%	3.78	8.32	3
Steam Turbine [coal] <200 MW	-	20%	4.57	9.43	3
Steam Turbine [gas] >200 MW	-	20%	3.50	14.11	7
Steam Turbine [gas] <100 MW	-	20%	2.62	6.81	2
Steam Turbine [gas] <200 MW	-	20%	3.23	11.11	2
Steam Turbine [oil] >200 MW	-	20%	2.79	13.51	7
Steam Turbine [oil] <100 MW	-	20%	1.46	8.33	2
Steam Turbine [oil] <200 MW	-	20%	3.01	12.16	2

The list of generators, installation and retirement dates, and summer and winter capacities are drawn from the 2008 edition of the Capacity, Demand and Reserves (CDR) report published by ERCOT. The primary data sources for other unit characteristics are the NERC Electricity, Supply and Demand (ES&D) 2006 database, and the Energy Velocity database. Heat rate data is drawn from prior ES&D databases where available. For newer plants, heat rates are based on industry averages for the technology of the unit. The NERC Generation Availability Data System (GADS) 2003 database, released January 2005, is the source for forced and planned outage rates, based on plant type, size, and vintage. Fixed and variable operation and maintenance costs are estimates based on plant size, technology, and age. These estimates are supplemented by FERC Form 1 submissions where available.

Plants that are known to be cogeneration facilities are either modeled with a low heat rate (6000 Btu/kWh), or set as must-run units in the dispatch, to reflect the fact that steam demand requires operation of the plant even when uneconomical in the electricity market.

Nuclear Units

The study assumes that the South Texas and Comanche Peak plants run at full capacity when available, and that they have minimum up and down times of one week. Nuclear plants do not contribute to reserves. The model includes refueling and maintenance outages for each nuclear plant. In the near future, outages posted on the NRC website or announced in the trade press are included. For later years, refueling outages are projected on the basis of the refueling cycle, typical outage length, and last known outage dates of each plant. Since these facilities are treated as must run units, CRA does not specifically model their cost structure. The Comanche Peak 2 unit is up-rated by 37 MW in the course of the 2009 & 2010 refueling outages, as approved by the Nuclear Regulatory Commission.

Hydro Units

GE MAPS has special provisions for modeling hydro units, and requires specification of a monthly pattern of water flow, i.e. the minimum and maximum generating capability and the total energy for each plant. CRA assumes that the monthly maximum capacity is equal to the installed capacity, that the minimum capacity is zero (i.e. there are no stream flow regulations), and that the capacity factor is 17%. Plants are allowed to provide spinning reserves up to 50% of name plate capacity.

Renewable Resources

There is a substantial amount of wind generation online in ERCOT, as well as several farms in development or under construction. In consultation with ERCOT staff, CRA developed a list of new wind farms that were included in this study – these are summarized in Table 25. The Renewable Energy Credit (REC) market is not modeled, since it does not impact daily dispatch of the wind units.

ERCOT planning staff provided CRA with annual hourly wind profiles for each wind farm, originally developed in the Competitive Renewable Energy Zones (CREZ) process. These schedules were imposed for each year in this study.

Table 25: Wind Farms in Development

Farm	Zone	Capacity	Online
Post Oak Wind	W	200	11/2008
Goat Wind	W	70	1/2009
Penascal	S	202	1/2009
Gulf Wind 1	S	283	1/2009
Coyote Run	W	205	6/2009

Capacity Additions and Retirements

CRA includes new generation based on projects in development or in the permitting process, as indicated by trade press announcements, trade publications, environmental permit applications, and internal knowledge. In this study the list of thermal new entry was developed from the CDR report and in consultation with the ERCOT planning group. Table 26 lists new thermal units.

Since the study time horizon extends to 2012, CRA did not add any speculative new entry, or evaluate the economics of returning mothballed generation to service.

CRA tracks planned and announced retirements from power pool publications and trade press announcements. In this study, CRA retired the Leon Creek 3 unit, at the end of 2009.

Table 26: Thermal Unit Additions

Unit	Type	Size	Online
Bosque Expansion	CC	255	03/2009
Sandow 5	Coal	581	06/2009
Winchester Peaking	GT	178	06/2009
Laredo Peaking 4 & 5	GT	193	07/2009
Oak Grove 1	Coal	855	07/2009
Cedar Bayou 4	CC	544	08/2009
Barney M Davis	CC	538	11/2009
Nueces Bay	CC	538	11/2009
J K Spruce 2	Coal	750	07/2010
Oak Grove 2	Coal	855	07/2010
Jack County 2	CC	600	06/2011
Sandy Creek 1	Coal	800	06/2012

Environmental Regulations

CRA models NOx and SO_2 emission rates for all units where such data is available in either US Environmental Protection Agency (EPA) databases, or Energy Velocity. Variable operating and maintenance cost increases associated with the installation of scrubbers or selective catalytic reduction devices (SCRs) on existing plants are included in the marginal cost estimation where data is available. Data on retrofits is drawn from Energy Velocity.

In addition, CRA models compliance with various allowance trading programs. Per the EPA Acid Rain program, the cost of SO_2 allowances are included in the marginal cost of units – allowance prices are drawn from Cantor Fitzgerald and Evolution Markets environmental brokerage services.

CRA also includes allowance prices for the regional NOx programs in the Houston – Galveston area. In the Dallas – Fort Worth area, older units without NOx retrofits are retired, based on a list provided by ERCOT staff.

Given the regulatory uncertainty and the time frame of this analysis, CRA did not model either mercury or carbon emissions programs.

External Region Supply

ERCOT is connected to the Southwest Power Pool (SPP) via DC ties at Oklaunion and Monticello, and to the Mexican electric system via DC ties at Eagle Pass & McAllen, and a variable frequency transformer at Laredo. In this study, the North and East DC ties are modeled as importing power into ERCOT based on a schedule provided by ERCOT planning staff. The ties to Mexico are assumed not to run.

Market Model Assumptions

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.

B. Operating Reserves: Based on discussion with ERCOT staff, spinning reserves are modeled at 1,600 MW in all hours. This simulates both true spinning reserve, and an allowance for regulation reserves. Quick start reserves are not modeled. As described above, thermal units are allowed to provide spinning reserves up to a maximum of 20% of their capacity.

C. Marginal transmission Losses: GE MAPS has the capability of simulating marginal losses and their impact on nodal energy prices. However, CRA conducted this study by modeling transmission losses at average rates.

Fuel Prices

Natural gas and fuel oil price forecasts are based on the 2008 release of the Annual Energy Outlook (AEO), published by the Energy Information Administration. CRA forecasts spot gas prices at multiple points in the system, based on historical differentials between these points and associated hubs. The Henry Hub forecast is drawn from the AEO and presented graphically on Figure 1 which depicts historical prices, AEO forecast and NYMEX futures as traded on December 5, 2008. NYMEX prices are added for comparison purposes.

Similarly fuel oil prices are developed on a regional basis, starting with data in the AEO.

A number of generators can utilize a secondary fuel type. This possibility is simulated as follows:

- Natural Gas Primary: Units that primarily burn natural gas typically face stringent restrictions on the fraction of time that they may burn fuel oil. CRA makes the assumption that each unit is allowed to switch to fuel oil for the one month in each year in which the gas prices are highest.
- Fuel Oil Primary: Units that primarily burn oil may switch to gas whenever it is economically justified, with a heat rate degradation of 3%. Thus, the fuel type is switched between whenever the price of natural gas plus 3% is less than the price of the appropriate fuel oil (FO2 or FO6).

Coal prices are estimated per coal plant, based on 2008 actual coal purchase prices as published in Energy Velocity.

Nuclear plants are assumed to run whenever available, so nuclear fuel prices do not impact commitment and dispatch decisions in the market simulation model. CRA therefore does not do a detailed analysis of nuclear fuel prices.

Figure 12: Natural Gas Price Forecast and History. Henry Hub (real 2007 \$/MMbtu)