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ORIGINAL VOLUME III

Recommendations in PSC Staff Report on the Last IRP Filing

Load Forecasting

- **LG&E/KU should continue to examine and report on the potential impact of increasing competition and future environmental requirements and how these issues are incorporated into future load forecasts.**

  As stated in section 7.(7)(e), the Base IRP forecast does not explicitly incorporate potential impacts of increasing competition. Integrated resource planning is based on the assumption of an obligation to serve a specifically defined service territory.

  Future environmental requirements are explicitly incorporated in the Base IRP forecast and the High and Low forecast sensitivities. In addition, the company has developed an Aggressive Green scenario to understand the potential impact that the widespread, accelerated adoption of energy efficiency measures could have on electricity sales. Please see section 6 (Load Forecast, Reason for Forecast Changes) for a discussion of the expected impacts of the Energy Security and Independence Act of 2007 on energy consumption and peak demand. A summary of the "Aggressive Green" scenario is provided in the report titled *Aggressive Green Scenario* in Volume III, Technical Appendix.

- **LG&E/KU should continue its efforts to further integrate the load forecasting processes and report on these efforts in their next IRP filing.**

  As stated in section 6 (Load Forecast, Reason for Forecast Changes), several changes in forecasting methodology were incorporated in the 2008 IRP forecasts to streamline and further integrate the forecasting process while maintaining or enhancing the consistency of data inputs and the quality of the forecast. Please see section 6 for a complete discussion of those changes.

- **LG&E/KU should continue to refine their load forecasting models.**

  As stated in section 6 (Load Forecast, Reason for Forecast Changes), several changes in forecasting methodology were incorporated in the 2008 IRP forecasts to streamline and further integrate the forecasting process while maintaining or enhancing the consistency of data inputs and the quality of the forecast. Please see section 6.(1) for a complete discussion of those changes.

- **In light of the financial impacts related to the construction of TC2, LG&E/KU should consider reflecting potential future rate actions in future forecasts or explain why they should not be so reflected.**

LG&E/KU continue to provide present value of revenue requirements as required in Section 9 of the IRP. The Companies consistently seeks to provide reliable service in a least cost and reasonable manner. Increases in operating expenses and capital expenditures could cause the Companies to file a base rate case upon, or prior to, placing Trimble County Unit 2 in service, but such a determination will be based on the overall financial results of the Companies. The Companies have not reflected potential future rate actions in this IRP.

Demand Side Management (DSM)

- **LG&E/KU should use all five "California tests", the participant test, utility cost test, ratepayer impact measure test, total resource cost test, and societal cost test, to review DSM alternatives in the next IRP filing.**

  In the Phase I Economic Evaluation, where the costs of a single measure is evaluated using the participant tests and TRC absent any program or administrative costs.

  In the Phase II Economic Evaluation, where fully developed programs are evaluated results of all five of the California tests were calculated.

- **In their next IRP filing, consistent with the Commission's findings in Administrative Case No. 2005-000090, LG&E/KU should place a greater emphasis on DSM and attempt to expand the number of DSM technologies that receive a complete evaluation to determine if they would be cost effective.**

  The Companies initially evaluated 80 potential DSM initiatives. The qualitative analysis screened the number down to 28 initiatives for quantitative analysis. The Companies felt that increasing research and evaluation efforts on initiatives that passed the qualitative screening would yield greater opportunities than placing additional emphasis on initiatives that didn't pass the qualitative screening. A consultant was retained to assist the Companies in quantifying energy and demand savings potential. The additional research and evaluation resulted in a 240% increase in the indicatives passing the overall DSM screening process. Twelve of the twenty eight initiatives passing the qualitative screening also passed the overall evaluation process as opposed to five out of twenty seven from the last IRP.

- **In their next IRP filing, LG&E/KU should continue to consider and evaluate a variety of DSM technologies, including those applicable to low income customers that would be cost effective.**

  The Companies are unaware of any DSM technologies specifically geared to low income customers. The Companies have addressed low income needs through proposed enhancements to the existing low income weatherization program currently pending before the Commission in Case No. 2007-00319.

- **If any DSM technology applicable to commercial customers passes the qualitative and quantitative screening, LG&E/KU should approach those**

customers to determine if there is an interest in pursuing the programs. It may be beneficial for LG&E/KU to contact commercial customers engaged in new construction rather than those involved in renovations or retrofits of existing structures.

The Company receives input from customers regarding their interest in programs and technologies on an on-going basis as a result of feedback from energy audits, through contact with vendors, and through Company account representatives contact with customers. This information is considered closely in the consideration of new programs and in their design and implementation. The Company also regularly contacts a significant percentage of customers who have had energy audits to seek their input or need for further information and assistance. The proposed commercial programs are rebate/incentive in nature reflecting frequent requests from commercial customers.

Supply-Side Resource Assessment

- **LG&E/KU's December 22, 2005 letter regarding the termination of KU's purchase power contract with EEI stated that the loss of the 200 MW available under this contract would have no near term (2006-2007) impact on KU's capacity plans. As LG&E/KU's next IRP is not scheduled to be filed with the Commission until 2008, Staff recommends that KU provide a summary of its longer range capacity plans as part of the annual filings it makes pursuant to Commission Orders in Administrative Case No. 387, A Review of the Adequacy of Kentucky's Generation Capacity and Transmission System.**

  As stated in the Administrative Case No. 387 filed in March 2007, the Companies were still reviewing their resource options as to how to provide for the shortfall in 2008 and 2009. As identified in both the Administrative Case No. 387 filed in March 2008 and in this IRP, the shortfall for the summer peaks of 2008 and 2009 is being fulfilled by a firm contract with Dynegy's Bluegrass Unit 1 for 165 MW of power during the months of June through September. Then in 2010 when Trimble County unit 2 becomes commercial, there will no longer be a shortfall present.

Integration and Plan Optimization

- **Given the future implications of the CAIR, LG&E/KU should include a sensitivity analysis in the next IRP based on the possible retirement of a level of capacity much larger than the 180 MW included in the sensitivity analysis performed for this IRP.**

  One of the numerous sensitivities that the Companies performed in this IRP was a retirement of the Green River and Tyrone units. This is a total of 234 MW to be retired at one time. This sensitivity is covered in detail in the *2008 Optimal Expansion Plan Analysis* (March 2008) in Volume III, Technical Appendix.

- **Since the filing of this IRP, LG&E/KU have provided information in other proceedings concerning the status of KU's purchase power agreement with OMU. In the next IRP, LG&E/KU should include a detailed report on the status of this purchase power agreement.**

  The status report on the purchase power agreement with OMU is provided in Section 6 of this IRP under the subsection titled *OMU*.

- **In the next IRP filing, consistent with the Commission's findings in Administrative Case No. 2005-0090, LG&E/KU are encouraged to fully investigate the potential for incorporating renewable energy into their portfolio of supply-side resources.**

  The Companies have investigated the potential for incorporating renewable energy into the portfolio of supply-side resources reviewed. In addition, renewable energy units which passed the supply-side screening and were considered for the optimal plan included hydro units Ohio Falls 9-10 and a wind energy conversion of 50 MW. Among the numerous renewable energy technologies considered were options of wind, solar, biomass, geothermal, waste-to-energy, hydroelectric, and energy storage. Further details of the renewable energy options considered in the supply-side screening are provided in the report titled *Analysis of Supply-Side Technology Alternatives* (January 2008) contained in Volume III, Technical Appendix. Moreover, "Aggressive Green" scenario, a Renewable Portfolio Standard was considered. Further description of the "Aggressive Green" scenario is provided in the report titled *Aggressive Green Scenario* in Volume III, Technical Appendix.

- **In the next IRP, a decision to retire any generating unit(s) should be supported by a feasibility study regarding the decision to retire the unit(s).**

  LG&E/KU units which have retired since the last IRP are discussed in Section 6 of this IRP with references to the feasibility studies already supplied to the KPSC.

- **In the next IRP, LG&E/KU should ensure that their planning adequately reflects the impact of future CO_2 emission restrictions.**

  The IRP is subject to existing regulations, and as such, there are no existing CO_2 emission restriction regulations. Regardless, the Companies did perform sensitivity on the optimal plan for CO_2 and low emission allocations. This is covered in further detail in the *2008 Optimal Expansion Plan Analysis* (March 2008) in Volume III, Technical Appendix.

Aggressive Green Scenario

Overview

The topic of energy efficiency has received more attention in the media in recent years as concerns regarding global climate change have risen. In December 2007, President Bush signed into law the Energy Independence and Security Act of 2007 (ESA 2007). One set of provisions in the act tighten lighting and appliance efficiency standards as well as foster the development of new building and commercial equipment standards. Despite these measures, several environmental groups are calling for stricter standards, including the adoption of CO_2 regulations. The extent to which these standards will be adopted in the future is uncertain.

A controversial provision that was not included in the ESA 2007 was the proposed Renewable Energy Portfolio Standard (RPS). Under an RPS, retail electricity suppliers must provide a minimum amount of electricity from renewable energy resources or purchase tradable credits that represent an equivalent amount of renewable energy production. The extent to an RPS will be adopted moving forward is also uncertain.

To better understand the impact of these policies, the companies developed an "aggressive green" scenario as a sensitivity to the optimal plan. The aggressive green scenario illustrates the impact of "efficiency at all cost" and a national commitment toward eliminating coal generation in favor of renewables. The demand-side assumptions in the aggressive green scenario are consistent with the assumptions in the EIA's Best Available Technology case included in its Annual Energy Outlook 2007. The supply-side assumptions regarding an RPS are consistent with provisions in currently proposed legislation.

The following is a list of key assumptions and observations in the aggressive green scenario:

Key Assumptions

- Consumers purchase the most efficient appliances at normal replacement intervals regardless of cost.
- Kentucky adopts mandatory RPS of 15 percent by year 2020.
- Existing coal units must be retired after 50 year life beginning in 2015.

Key Observations

- Growth in companies' peak demand is reduced from 1.4 percent to 0.6 percent.
- Mandate to retire 50-year old coal plants would require the companies to retire nearly 1,800 MW of coal-fired capacity by 2022.
- Companies install in excess of 2,100 MW of renewables by 2020 to meet RPS.

Demand-Side Implications

The aggressive green scenario assumes that consumers purchase the most energy efficient equipment at regular replacement intervals regardless of cost. This is most likely to occur as a result of federal legislation mandating challenging minimum efficiency standards for electrical equipment and appliances. Incandescent light bulbs are phased out by 2012. New homes and buildings are built to the most energy efficient specifications available. In addition, new homes are equipped with solar panels beginning in 2012.

In the aggressive green energy forecast, large commercial and industrial customers are also assumed to increase their focus on energy efficiency. Large commercial customers consume 20 percent less energy by 2022. The growth in industrial sales by industry segment is taken from the EIA's low economic growth case in its Annual Energy Outlook 2007.

The base IRP, high, low, and aggressive green energy forecasts of LG&E and KU's energy sales are presented in Tables 1 and 2. The associated forecasts of annual peak load are shown in Tables 3 and 4 and Graphs 1 and 2. In the aggressive green scenario, total energy requirements decline through 2012 due to increased lighting efficiencies and increase thereafter due to customer growth. Because lighting consumption occurs primarily in the off-peak hours, peak demand continues to grow (albeit at a slower pace) throughout the forecast period.

Table 1
LG&E Energy Requirements Forecasts (GWh)

Year	Base IRP	High	Low	Aggressive Green
2008	13,321	13,559	13,081	13,090
2009	13,514	13,832	13,190	13,070
2010	13,682	14,049	13,305	13,031
2011	13,900	14,317	13,460	12,985
2012	14,099	14,578	13,612	12,962
2013	14,280	14,819	13,745	13,043
2014	14,430	15,018	13,846	13,128
2015	14,524	15,163	13,896	13,196
2016	14,640	15,309	13,980	13,275
2017	14,791	15,497	14,091	13,353
2018	14,975	15,722	14,241	13,451
2019	15,158	15,938	14,398	13,544
2020	15,362	16,180	14,568	13,648
2021	15,543	16,398	14,727	13,734
2022	15,737	16,628	14,892	13,829

Table 2
KU Energy Requirements Forecasts (GWh)

Year	Base IRP	High	Low	Aggressive Green
2008	23,514	24,065	22,956	23,156
2009	23,889	24,592	23,179	23,105
2010	24,239	25,070	23,414	22,997
2011	24,631	25,566	23,697	22,927
2012	24,981	26,040	23,904	22,898
2013	25,255	26,384	24,109	23,009
2014	25,497	26,714	24,260	23,134
2015	25,774	27,066	24,455	23,219
2016	26,055	27,430	24,675	23,335
2017	26,362	27,810	24,914	23,426
2018	26,749	28,281	25,223	23,553
2019	27,112	28,727	25,537	23,660
2020	27,552	29,271	25,872	23,791
2021	27,906	29,695	26,140	23,889
2022	28,300	30,150	26,446	24,000

Table 3
LGE Peak Demand Forecasts (MW)

Year	Base IRP	High	Low	Aggressive Green
2008	2,789	2,839	2,739	2,738
2009	2,817	2,883	2,749	2,770
2010	2,862	2,939	2,783	2,795
2011	2,908	2,996	2,816	2,804
2012	2,952	3,053	2,850	2,829
2013	2,995	3,109	2,883	2,840
2014	3,038	3,161	2,915	2,883
2015	3,075	3,209	2,944	2,905
2016	3,113	3,253	2,974	2,907
2017	3,152	3,300	3,005	2,944
2018	3,194	3,351	3,039	2,978
2019	3,236	3,400	3,076	2,982
2020	3,282	3,454	3,115	3,024
2021	3,324	3,503	3,152	3,062
2022	3,368	3,556	3,190	3,067

Graph 1
LG&E Peak Demand Forecasts

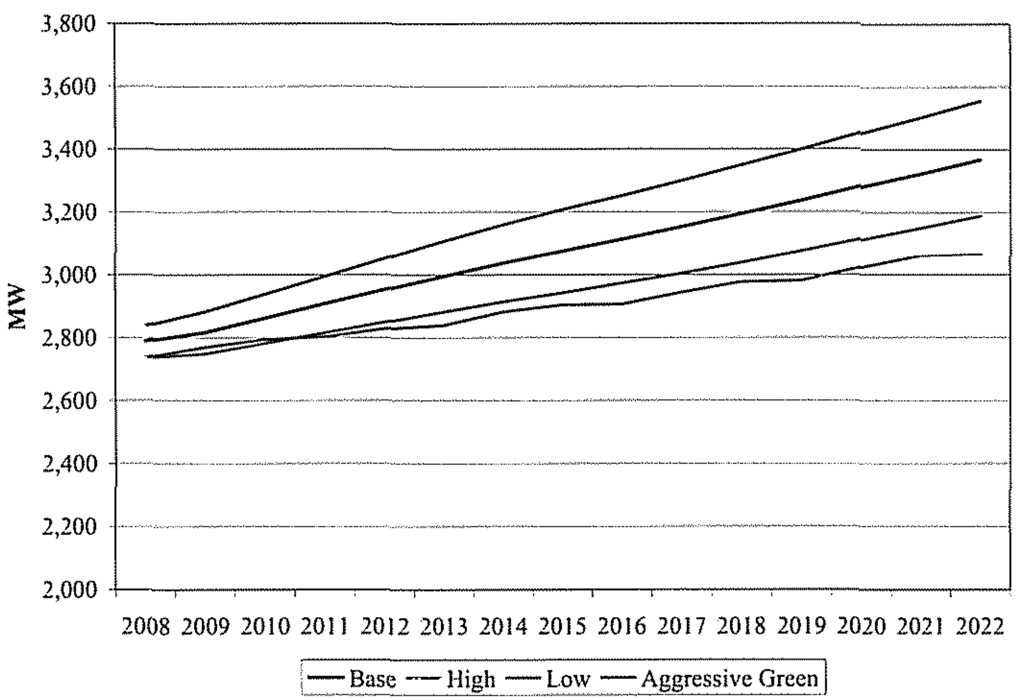
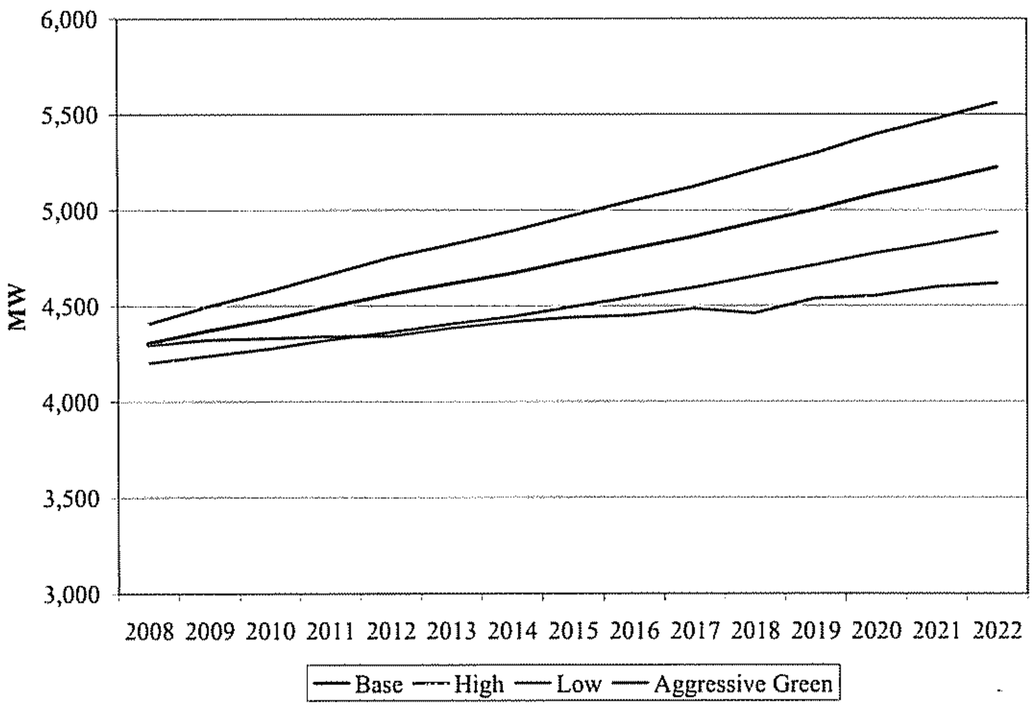


Table 4
KU Peak Demand Forecasts (MW)

Year	Base IRP	High	Low	Aggressive Green
2008	4,306	4,407	4,204	4,295
2009	4,371	4,500	4,241	4,325
2010	4,428	4,580	4,277	4,331
2011	4,496	4,667	4,325	4,342
2012	4,560	4,753	4,363	4,343
2013	4,615	4,821	4,405	4,386
2014	4,669	4,892	4,443	4,416
2015	4,736	4,972	4,495	4,440
2016	4,799	5,051	4,547	4,450
2017	4,861	5,125	4,596	4,487
2018	4,933	5,213	4,654	4,461
2019	5,001	5,296	4,713	4,538
2020	5,082	5,396	4,775	4,553
2021	5,149	5,476	4,826	4,599
2022	5,223	5,561	4,884	4,618

Graph 2
KU Peak Demand Forecasts



Supply-Side Implications

The aggressive green expansion plan analysis utilizes the same production model and methodology as the expansion plan analysis summarized in the report titled ***2008 Optimal Expansion Plan Analysis*** (March 2008) in Volume III, Technical Appendix. Production model inputs are the same with the exception of the load forecast, unit retirements, CO_2 emission allowance prices (Table 5), and available supply-side alternatives. Additional constraints placed in the model are: existing coal units must be retired after 50 year life beginning in 2015; renewable portfolio standard ("RPS") of 15% by 2020 (approximately 5,600 GWh in 2020). A provision that was passed by the House of Representatives but ultimately removed from the ESA 2007 had a national RPS target that aimed to reach 15 percent of total electricity sales by 2020.

The mandate to retire 50-year old coal plants would require the companies to retire nearly 1,800 MW of coal-fired capacity by 2022 (see Table 6). Supply-side technologies available in this analysis are summarized in Table 7. All new coal units must be constructed with carbon capture and sequestration ("CCS"). The Wind and Ohio Falls ("FALL") alternatives were the only renewable technologies included in the aggressive green analysis since they were identified as the most economical in the report titled ***Analysis of Supply-Side Technology Alternatives*** (March 2008) in Volume III, Technical Appendix, and to achieve reasonable model run time.

Table 5 - Aggressive Green
Emission Allowance Prices
($/Ton)

Year	SO_2	NOx	CO_2
2007	489	900	
2008	457	988	
2009	455	951	
2010	480	2,366	
2011	624	2,369	
2012	649	2,372	13.27
2013	673	2,274	14.89
2014	733	2,250	16.68
2015	794	3,098	18.44
2016	855	3,092	20.67
2017	916	3,086	23.36
2018	977	3,122	26.51
2019	1,038	3,149	30.06
2020	1,099	3,177	34.22
2021	1,160	3,250	39.04
2022	1,221	3,282	44.52

Table 6
Aggressive Green: Unit Retirements

Plant Name	Unit	50th Year Operation	Model Retire Year
Brown	1	2007	2015
Brown	2	2013	2015
Brown	3	2021	2021
Cane Run	4	2012	2015
Cane Run	5	2016	2016
Cane Run	6	2019	2019
Green River	3	2004	2015
Green River	4	2009	2015
Mill Creek	1	2022	2022
Tyrone	3	2003	2015

Units retired at the later of 50 years operation or May 2015.

Confidential Information

Table 7
Aggressive Green Supply-Side Alternatives Data
All Costs are in 2007 $

Unit Type[1]	Net Capability Summer[3] (MW)	Net Capability Winter (MW)	Overnight Installed Cost ($/kW)	Total Non-Fuel Variable O&M Non-Ozone Season ($/MWh)	Total Fixed O&M[4] ($M/yr)	Full Load HHV Heat Rate (mmbtu/MWh)	EFOR (%)	First Year Available	FGD Removal Efficiency (%)	NOx Emiss Rate (lb/mmbtu)	CO2 Emiss Rate (lb/mmbtu)
Supercritical Coal with CCS	739	771	[redacted]	4.61	32.1	12.35	8.60%	2015	98%	0.050	20.0
2x1 Combined Cycle	475	551	[redacted]	4.49	16.0	6.96	8.30%	2015	N/A	0.007	0.007
2x1 IGCC with CCS	522	552	[redacted]	3.31	28.2	10.08	8.60%	2015	99%	0.050	20.0
Wind Turbine	50	50	[redacted]	-	2.4	N/A	69.0%[5]	2015	N/A	N/A	N/A
Combustion Turbine	155	184	[redacted]	23.92	4.0	10.82	6.10%	2015	N/A	0.018	0.018
Ohio Falls Unit[2]	5	4	[redacted]	-	0.2	N/A	0.00%	2015	N/A	N/A	N/A

Notes to Table 7:

1 All units except Ohio Falls are "Greenfield" units "Greenfield" implies a location without an existing unit and infrastructure (fuel handling equipment etc)

2 The existing Ohio Falls layout has room for only two expansion units. Data represents a single generating unit Rating is average hourly production. Installed cost is based on unit rating of 16 8 MW

3 Summer Ratings are used for the months of April - September

4 Fixed O&M for Greenfield CT and Combined Cycle options include costs associated with reserving gas-line capacity

5 Wind turbine availability modeled at 31%

Table 8 displays the optimal expansion plans when optimization runs are made on Aggressive Green (Plan "M") forecast. For comparison purposes, the optimization of the base load forecast (Plan "A") is also shown. More information on Plan "A" can be found in the report titled ***2008 Optimal Expansion Plan Analysis*** (March 2008) in Volume III, Technical Appendix. The inclusion of the 30-year Present Value Revenue Requirements ("PVRR") for the scenarios are for informational purposes and is shown to indicate how much costs are affected by the sensitivities conducted.

Table 8
Aggressive Green Expansion Plan

Load Forecast:	Base	Aggressive Green
Retire Units:	No	Yes
Plan:	**"A"**	**"M"**
2008		
2009		
2010		
2011		
2012		
2013		
2014		
2015	1-CCCT	Wind (8) & FALL
2016		Wind (4)
2017		Wind
2018		Wind
2019	1-CCCT	Wind (6)
2020		Wind (22)
2021		
2022	1-SCCT	
	=========	=========
30 Yr PVRR ($B)	17.950	18.395
Cost Delta to Base	0	0.445
Plan Rank (Low to High)	1	2
Average $/MWh in 2015	29	37
Average $/MWh in 2020	35	46

Ohio Falls 9 and 10 installation was forced in 2015.
Average $/MWh based on new unit capital and system production costs only.

In order to meet the imposed RPS requirements, all added capacity throughout the 15-year plan must be renewables and is in excess of 2,100 MW due to retirements. Generally, lower load forecast cases will have lower PVRR, but the aggressive green scenario actually has higher PVRR due to the constraints imposed on it. Plan "M" costs are expected to be over 30% higher by 2020 in $/MWh considering capital and production costs only.

Kentucky Utilities Company
and
Louisville Gas and Electric Company

2008 Optimal Expansion Plan Analysis

Prepared by

Generation Planning

March 2008

2008 OPTIMAL INTEGRATED RESOURCE PLAN ANALYSIS

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EXECUTIVE SUMMARY

Kentucky Utilities Company and Louisville Gas and Electric Company (collectively, the Companies) continually evaluate their resource needs. The purpose of this study is to update this ongoing analysis. The base case strategy is determined based on a minimum expected Present Value of Revenue Requirements (PVRR) criterion and subject to certain constraints, including unit operating characteristics and maintaining a target reserve margin of 14%.

As precursors to the optimization process, two independent technology screening analyses were conducted, one for supply-side alternatives and the other for demand-side management (DSM) programs. The purpose of the supply-side screening analysis was to evaluate, compare and suggest the least-cost supply-side options to use in Strategist® optimizations. An independent screening analysis was conducted on numerous demand-side management options and ultimately recommended twelve new programs for consideration within Strategist®. The new DSM programs evaluated range from approximately 1 MW to 85 MW and include demand and energy reduction benefits. The DSM programs included in this analysis could reorder units selected to serve load. Therefore, an optimization was performed with the DSM programs in place and compared to an optimization without the DSM programs to determine cost effectiveness. The optimization with the DSM programs in place provided lower cost revenue requirements than the optimization without the DSM programs. Since inclusion of the DSM options was identified as economical in the production model, their benefits were incorporated into the base expansion plan and it is recommended that the DSM programs be implemented along with the base expansion plan.

In order to consider uncertainty in the process, a rigorous evaluation of several key assumptions was conducted. These sensitivity cases quantified the effects on the optimal plan of DSM performance, various load forecasts, unit retirements, carbon dioxide regulation, combined cycle operation, and breakeven analyses on natural gas prices and coal capital costs. Base case results conclude that the construction of gas-fired units through 2022 provide lowest cost revenue requirements. The first unit installed is a 2x1 combined cycle in 2015.

Introduction

The purpose of this study is to produce a multiple year Integrated Resource Plan for Kentucky Utilities Company and Louisville Gas and Electric Company (collectively, the Companies). The IRP is determined based on a minimum expected Present Value of Revenue Requirements (PVRR) criterion over a 30-year planning horizon and subject to certain constraints, including a target reserve margin of 14% and unit operating characteristics.

This report will first discuss the various modules of the Strategist® computer model used in the analysis. Next, the reserve margin used in this analysis will be briefly discussed followed by a discussion of the results of the supply-side screening analysis. A separate screening of Demand-Side Management (DSM) options has also been completed and will be discussed last. Based upon these supporting analyses, initial lists of technologies of various types and capacities will be suggested for further analysis within the optimization module of Strategist®. Sensitivities developed around five key areas (DSM performance, load forecast, unit retirements, carbon dioxide regulation, combined cycle operation), along with break even analyses on natural gas prices and coal construction costs, will be evaluated in computer optimizations and the least cost plan will be presented for consideration.

An Overview of the Strategist® Computer Model

The Load Forecast Adjustment (LFA), Generation and Fuel (GAF), Proview (PRV), and Capital Expenditure and Recovery (CER) modules of the Strategist® computer model were used in the study. The Strategist® computer software program can be used to either optimize a set of resource alternatives (determine a least-cost strategy under a prescribed set of constraints and assumptions) or evaluate a single pre-specified plan. Input parameters to the Strategist® model are described in Appendix A of this document.

The LFA module allows the user to create typical monthly load shapes for each company modeled to be transferred to the GAF module for production costing purposes. Inputs to the LFA are each modeled company's peak and energy load forecasts for multiple years and a load shape. Two companies are modeled in detail within the LFA. The Companies are modeled together and make up one of the two companies while Owensboro Municipal Utilities (OMU) is the second company. OMU is modeled due to the unique purchase power agreement it has with the Companies. The OMU contract is expected to terminate in May 2010. More details on the OMU contract termination can be found in Section 6. The demand and energy modeled for the Companies is after any peak and energy reductions associated with Interruptible or Curtailable customers. Existing DSM programs are then modeled separately within the LFA.

The GAF module simulates power system dispatch and operation using a load duration curve production costing technique. Production costs including fuel, incremental operation and maintenance (O&M), purchase power and emission costs are calculated in this module. Inputs to the GAF include generating unit and purchase power characteristics, fuel costs and unit or fuel specific emissions information.

PRV is an optimization module that evaluates all combinations of potential options to produce a list of resource plans, subject to user specified constraints, that satisfy the Companies' minimum target reserve margin criterion. PRV combines production cost analysis with an analysis of new construction expenditures (or DSM implementation costs) to suggest an optimal resource plan and sub-optimal resource plans based on minimizing utility cost. PRV receives revenue requirements information associated with capital expenditures from the CER. Inputs to PRV include generic generating unit characteristics from the GAF, DSM information from the LFA, and construction/implementation parameters such as each option's first year available.

The CER module calculates revenue requirements associated with capital expenditures for both the construction and in-service periods. PRV receives project-specific revenue requirement profiles for possible in-service dates from the CER for use in optimizations. The revenue requirement profiles are combined with the GAF production cost analysis to produce a total system revenue requirement for the study period. The CER contains capital information on resource projects associated with the optimal Integrated Resource Plan. Inputs to the CER include construction cost profiles, depreciation schedules and various economic assumptions.

Supporting Studies

Several supporting studies are utilized in this evaluation. These studies include the target minimum reserve margin, the supply-side technologies and the DSM programs used in this evaluation.

Minimum Reserve Margin Target Criterion

In January of 2008, a study was completed to determine an optimal reserve margin criterion to be used by the Companies. This study recommended that a target reserve margin of 14% be used in long range planning studies. Accordingly, in the evaluation and development of this optimal Integrated Resource Plan, the Companies have used a reserve margin target of 14%. The reserve margin study titled ***2008 Analysis of Reserve Margin Planning Criterion*** (March 2008) can be found in Volume III, Technical Appendix of the Companies 2008 Integrated Resource Plan.

Supply-Side Technology Screening Analysis

As a precursor to the optimization process, a technology screening analysis was conducted. The purpose of the screening analysis was to evaluate, compare and suggest the least-cost supply-side options to use in Strategist® optimizations. The number of supply-side options available necessitates that a screening analysis be conducted since modeling of all options in Strategist® is simply not feasible. The supply-side screening report ***Analysis of Supply-Side Technology Alternatives*** (April 2008), can be found in Volume III, Technical Appendix. The supply-side technologies suggested by the screening evaluation for detailed analysis within the Strategist® model are shown in Table 1.

Table 1
Supply-Side Technologies Suggested for Analysis with Strategist®

Supercritical Pulverized Coal – High Sulfur Fuel
3x1 Combined Cycle Combustion Turbine
2x1 Combined Cycle Combustion Turbine
Wind Energy Conversion
Simple Cycle Combustion Turbine
Run of River-Ohio Falls Station Expansion (Units 9 and 10)

The options listed in Table 1 are the options that passed the screening analysis and represent the complete list of supply-side alternatives available to Strategist®. The Companies will continue to pursue possible opportunities through the RFP process and through participation in the wholesale marketplace on a real time basis when evaluating future resources. Purchase opportunities are compared to construction alternatives in the CCN process to arrive at an optimal strategy. Peaking type purchase power opportunities in optimizations would serve only to evaluate the delay of CT construction for short periods of time, which is already being considered by the Companies in greater detail in the CCN process. Regardless of the method or the arena in which the evaluation is conducted, the Companies will continue to evaluate the benefits of purchase power, both short- and long-term, through participation in the wholesale marketplace on a real time basis as a method to delay generation construction. An Integrated Gasification Combined Cycle unit (IGCC) was also included in the Strategist® analysis due to its potential lower cost over pulverized coal if CO_2 emissions are regulated in the future.

Demand-Side Technology Screening Analysis

In addition to the supply-side screening discussed above, a demand-side screening was performed. More than eighty demand-side options underwent a qualitative screening evaluation, the results of which suggested that twenty-eight demand-side programs be evaluated further in a quantitative evaluation. The results of that evaluation indicate that twelve new demand-side programs be considered for implementation. Collectively, the new DSM programs are expected to reduce the Companies' system peak by approximately 109 MW by the summer of 2016. The existing DSM programs are assumed to continue into the future and have not been included in the optimization process. Because the sizes of the DSM programs are small when compared to competing supply-size options, it is intuitive that the program will not completely eliminate a new unit from the expansion plan. Instead, the program could serve to defer new construction in the event that smaller amounts of capacity are needed to maintain the target reserve margin. If the case that includes the DSM programs lowers the expected PVRR of the expansion plan, then the programs will be included in the Companies' plans to meet future needs. More details regarding all the Demand Side Management programs, including the cost of the new programs can be found in the report tiled ***Screening of Demand-Side Management (DSM) Options*** (March 2008) in Volume III of the Technical Appendix.

Base Case Development

Using the supply-side options identified in Table 1 along with the base assumptions for the demand and energy forecast, fuel forecast and new unit capital costs, an initial expansion plan can be developed. Appendix A of this report details all of the existing units' operating characteristics as well as documents all of the load forecasts (base, high and low), fuel prices and emission allowance cost information used in this evaluation. Table 2 below details relevant information pertaining to each of the supply-side options evaluated. There is a reserve margin shortfall in 2014 of approximately 20 MW. The reserve margin was allowed to drop for that year to approximately 13.7%. It is most likely that the projected deficit in 2014 will be met with a power purchase.

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Table 2
Supply-Side Alternatives Data
All Costs are in 2007 $

Unit Type[1]	Net Capability Summer[3] (MW)	Net Capability Winter (MW)	Overnight Installed Cost ($/kW)	Total Non-Fuel Variable O&M Non-Ozone Season ($/MWh)	Total Fixed O&M[4] ($M/yr)	Full Load HHV Heat Rate (mmbtu/MWh)	EFOR (%)	First Year Available	FGD Removal Efficiency (%)	NOx Emiss Rate (lb/mmbtu)
Supercritical Coal	739	771	[redacted]	2.56	26.2	8.86	8.60%	2015	98%	0.050
3x1 Combined Cycle	817	859	[redacted]	4.36	23.1	6.89	8.30%	2015	N/A	0.007
2x1 Combined Cycle	475	551	[redacted]	4.49	16.0	6.96	8.30%	2015	N/A	0.007
2x1 IGCC	584	618	[redacted]	2.64	24.9	8.39	8.60%	2015	99%	0.050
Wind Turbine	50	50	[redacted]	-	2.4	N/A	69.0%[5]	2015	N/A	N/A
Combustion Turbine	155	184	[redacted]	23.92	4.0	10.82	6.10%	2015	N/A	0.018
Ohio Falls Unit[2]	5	4	[redacted]	-	0.2	N/A	0.00%	2015	N/A	N/A

Notes to Table 2:

1 All units except Ohio Falls are "Greenfield" units. "Greenfield" implies a location without an existing unit and infrastructure (fuel handling equipment etc).
2 The existing Ohio Falls layout has room for only two expansion units. Data represents a single generating unit. Rating is average hourly production.
Installed cost is based on unit rating of 16.8 MW
3 Summer Ratings are used for the months of April - September
4 Fixed O&M for Greenfield CTs and Combined Cycle options include costs associated with reserving gas-line capacity
5 Wind turbine availability modeled at 31%

A few comments regarding the information contained in Table 2 are worth noting:

- Cost and performance data for all units except Ohio Falls Station are based on data provided by Cummins & Barnard (C&B) in December of 2007.
- Cost and performance data for the Ohio Falls Station option is based on an escalation (6% annually) of the cost evaluation supplied to the Companies by Devine Tarbell & Associates for a separate hydro project that was studied in 2006. Since this estimate was not site-specific to the Ohio Falls Station, it does not take into consideration environmental issues that may exist regarding the installation of Ohio Falls Station 9 and 10.
- As mentioned earlier and reiterated here, no purchase power alternatives are evaluated in this analysis but will be evaluated within the required CCN application process.

For a more complete description of the origins of the data associated with each of the supply-side options see the ***Analysis of Supply-Side Technology Alternatives*** (April 2008) in Volume III, Technical Appendix.

With the summary of the supply-side cost and performance data, the least cost base plan identified by Strategist® can be evaluated. For future reference, this plan will be referred to as Plan "A" and it represents the 30-year expansion strategy that minimizes the Present Value of Revenue Requirements criterion given the assumptions for each alternative's cost and performance (shown in the preceding Table 2) and the assumption of base load. The expansion plan for the fifteen year period (2008-2022) covered by the Integrated Resource Plan for Plan "A" and the PVRR associated with it are shown below in Table 3.

To facilitate the comparison of multiple plans, the names of the alternatives have been shortened. GFCU is the 750 MW supercritical coal unit, LCCT represents the 817 MW 3x1 combined cycle option, CCCT represents the 475 MW 2x1 combined cycle unit, IGCC represents the 584 MW 2x1 IGCC unit, Wind represents a 50 MW wind turbine, SCCT is the 155 MW simple cycle combustion turbine and the Ohio Falls Station options will be referred to as Falls.

Table 3
Initial Expansion Plan

Plan:	"A"
2008	
2009	
2010	
2011	
2012	
2013	
2014	
2015	1-CCCT
2016	
2017	
2018	
2019	1-CCCT
2020	
2021	
2022	1-SCCT
	=========
30 Yr PVRR ($B)	17.950

As can be observed in Table 3, optimization results using the base assumptions indicate that the installation of a Greenfield combined cycle unit in 2015 and 2019, followed by a Greenfield simple-cycle combustion turbine in 2022 is optimal. The thirty-year PVRR for this case, in 2007 year dollars, is estimated to be $17.95 billion.

Sensitivity Analyses

The supply-side alternatives identified in Table 2 were also evaluated in several other sensitivity cases. Sensitivities were performed in five areas: (1) DSM performance, (2) load forecast, (3) unit retirement (4) carbon emissions regulations and (5) combined cycle operation. Additionally, break even analyses were performed on (6) gas prices and (7) coal capital cost to determine the point at which the PVRR for an expansion plan with a coal unit installed in 2015 would be similar to Plan "A".

Sensitivity: DSM Performance

Several DSM programs have been studied and suggested for implementation in Case 2007-00319 and in this IRP as found in Volume III, Technical Appendix. Sensitivities were performed by removing DSM from Plan "A" and are summarized in Table 4. Table 5 summarizes the optimal expansion plans and costs for the DSM sensitivities. Plan "A" is shown for comparison.

Table 4
DSM Sensitivity Cases

Case	Description	MW Removed
"B"	2008 IRP DSM is Denied	109
"C"	Case 2007-00319 is Denied	195
"D"	Both Case "B" and Case "C" occur	304

Table 5
DSM Sensitivity

Plan:	"A"	"B"	"C"	"D"
2008				
2009				
2010				
2011				
2012				
2013				
2014				
2015	1-CCCT	1-CCCT	1-CCCT	1-CCCT
2016				1-SCCT
2017			1-SCCT	1-SCCT
2018		1-CCCT	1-SCCT	
2019	1-CCCT			1-CCCT
2020			1-CCCT	
2021				
2022	1-SCCT	1-SCCT		1-SCCT
	=========	=========	=========	=========
30 Yr PVRR ($B)	17.950	18.171	18.681	18.942
Cost Delta to Base	0	0.222	0.731	0.992
Plan Rank (Low to High)	1	2	3	4

The programs proposed in the 2008 IRP lower PVRR $222 Million for the 30-year period (Plan "B"). The programs proposed in Case No. 2007-00319 lower PVRR $731 Million (Plan "C"), while the combination (Plan "D") lowers PVRR $992 Million. Table 5 indicates that the inclusion of the DSM programs lower PVRR and should be implemented as proposed in Volume III, Technical Appendix. Therefore, all following sensitivities will include the full DSM benefits as included in Plan "A".

Sensitivity: Load

The load forecast is a significant factor influencing the Companies' Integrated Resource Plan. Each supply-side technology is designed for optimal unit performance at various levels of utilization. CTs, for instance, while relatively inexpensive to construct when compared to coal-fired units, are more costly to operate and maintain given the relative prices of gas and coal. Conversely, coal-fired units while expensive to construct, are relatively inexpensive to operate and maintain. The economics of adding a supply-side option to any generation system is based on the expected costs of operating (including any associated costs for environmental emission) and maintaining the unit over the full range of loads it is expected to serve. Significant economic penalties may be incurred if the unit is operated above or below the level it was planned to serve. For example, if a CT was added to a system in which load was greater than forecasted, the utilization of the CT may exceed the economical range for which it was planned. In other words, it may have been more economical to install intermediate load serving capacity (such as combined cycles) or baseload capacity (coal or hydro) instead. Thus, load growth scenarios that are different from that which is currently forecasted may have a significant impact on the selection of an optimal technology type.

Therefore, in order to evaluate the effect of various load forecasts, a load sensitivity analysis was incorporated into the process of determining an optimal resource plan.

In summary, the load sensitivity analysis consists of evaluating the effect of three load forecasts on the selection of resource alternatives. The three forecasts depict an expected system load growth case, a case where system load growth exceeds expected growth and a case in which system load growth is less than expected. For reference, the resulting forecasts are termed the base, high and low load forecasts. The details of and the basis for the various load forecasts are described in Volume II, Technical Appendices I-III. A tabulated summary of these respective forecasts can be found in Appendix A of this document.

Table 6 shows the optimal expansion plans when optimization runs are made on the low load (Plan "E") and high load (Plan "F") forecasts. For comparison purposes the optimization of the base load forecast (Plan "A") is also shown. The inclusion of the 30-year PVRR for the sensitivities are for informational purposes (i.e. the high load forecast is expected to have a higher cost than either the base or low load forecasts) and is shown to indicate how much costs are affected by the sensitivities conducted.

Table 6
Load Sensitivity

Load Forecast:	Base	Low	High
Plan:	**"A"**	**"E"**	**"F"**
2008			
2009			
2010			
2011			
2012			
2013			
2014			
2015	1-CCCT		1-CCCT & 1-SCCT
2016			1-SCCT
2017			
2018			1-CCCT
2019	1-CCCT	1-CCCT	
2020			
2021			1-SCCT
2022	1-SCCT		1-CCCT
	=========	=========	=============
30 Yr PVRR ($B)	17.950	15.665	20.371
Cost Delta to Base	0	(2.285)	2.421
Plan Rank (Low to High)	2	1	3

As with the base optimization, sensitivity optimizations around the forecasted load for the Companies continue to show that a combined cycle unit is installed in the first year of need. As should be anticipated, the occurrence of low load over the period as represented in Plan "E" results in the least cost PVRR, with Plan "A" (base load) and Plan "F" (high load) following respectively. It is noted that the first year available for all units is 2015. Allowing for an earlier install would result in the selection of units earlier than 2015 for the high load scenario.

Sensitivity: Unit Retirement

Waterside 7 and 8 were retired August 21, 2006 and Tyrone Units 1 and 2 were retired February 26, 2007 after determining it would be uneconomical to continue their operation. While no additional retirements are currently planned, the Companies have a number of units that are at least thirty-five years old [see the portion on *Aging Generating Units* in Section 8.(5)(b)]. Furthermore, the relatively high production costs of these units and the upcoming Clean Air Interstate Rule (CAIR) restrictions, as well as any future imposed environmental regulations, will only worsen their relative economics. It could become economic to retire many of these units even without a significant mechanical failure. Table 2 in Appendix A of this report displays the units affected by this sensitivity. Retirement sensitivities evaluated are summarized in Table 7.

Table 7
Retirement Sensitivity Cases

Case	Units Retired	Total MW
"G"	Green River 3 and 4	163
"H"	Tyrone 3	71
"I"	Green River 3 and 4, Tyrone 3	234
"J"	Haefling 1-3, Cane Run 11, Paddy's Run 11-12, Zorn 1	99

To simplify the retirement sensitivities, all units were assumed to retire simultaneously on December 31, 2014. The sensitivity utilizes the base load forecast. Table 8 summarizes the resulting optimal generation expansion plan and costs associated with the plan. As before, Plan "A" is shown for comparison.

Table 8
Retirement Sensitivity

Load Forecast:	Base	Base	Base	Base	Base
Retire Units:	**No**	**GR3-4**	**TY3**	**GR&TY**	**CTs**
Plan:	**"A"**	**"G"**	**"H"**	**"I"**	**"J"**
2008					
2009					
2010					
2011					
2012					
2013					
2014					
2015	1-CCCT	1-CCCT	1-CCCT	1-CCCT	1-CCCT
2016					
2017				1-SCCT	
2018		1-CCCT	1-SCCT	1-SCCT	1-SCCT
2019	1-CCCT				1-SCCT
2020			1-CCCT	1-CCCT	1-SCCT
2021		1-SCCT			
2022	1-SCCT	1-SCCT			1-CCCT
	=========	=========	=========	=========	=========
30 Yr PVRR ($B)	17.950	18.119	17.995	18.200	17.992
Cost Delta to Base	0	0.169	0.045	0.250	0.042
Plan Rank (Low to High)	1	4	3	5	2

The results of the retirement sensitivity reveal optimal generation expansion strategies very similar to what the DSM and load sensitivities suggested: a combination of combined cycle units and simple cycle combustion turbines through 2022.

Sensitivity: CO_2 Regulation

There has been much debate on the role that carbon dioxide (CO_2) contributes to global warming and the probability of regulating its emission is growing. Therefore, a sensitivity has been developed on CO_2 regulation. CO_2 emission allowance prices used in this evaluation can be found in Appendix A Table 8. The alternatives allowed in this scenario were expanded to allow the possible capture and sequestration (CCS) of CO_2. Along with the options described in Table 2, a

750 MW coal unit with CCS and a 550 MW IGCC with CCS have been included and their operation highlights are summarized in Table 9. Results for the CO_2 sensitivity can be found in Table 10.

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Table 9
Supply-Side Alternatives Data
All Costs are in 2007 $

Unit Type	Net Capability Summer (MW)	Net Capability Winter (MW)	Overnight Installed Cost ($/kW)	Total Non-Fuel Variable O&M Non-Ozone Season ($/MWh)	Total Fixed O&M ($M/yr)	Full Load HHV Heat Rate (mmbtu/MWh)	EFOR (%)	First Year Available	FGD Removal Efficiency (%)	NOx Emiss Rate (lb/mmbtu)	CO2 Emission Rate[1] (lb/mmbtu)
Supercritical Coal w/CCS	739	771	[redacted]	4.61	32.1	12.35	8.60%	2015	98%	0.050	20.0
2x1 IGCC w/CCS	522	552	[redacted]	3.31	28.2	10.08	8.60%	2015	99%	0.050	20.0

The CO_2 emission rate for coal and IGCC without CCS is 205.2 lb/mmbtu. Gas unit CO_2 emissions are 120.0 lb/mmbtu.

Table 10
CO_2 Sensitivity

Load Forecast:	Base	Base
Retire Units:	No	No
Plan:	**"A"**	**"K"**
2008		
2009		
2010		
2011		
2012		
2013		
2014		
2015	1-CCCT	1-CCCT
2016		
2017		
2018		
2019	1-CCCT	1-CCCT
2020		
2021		
2022	1-SCCT	1-SCCT
	=========	=========
30 Yr PVRR ($B)	17.950	18.310
Cost Delta to Base	0	0.361
Plan Rank (Low to High)	1	2

The optimal expansion plan resulting from the implementation of CO_2 regulation did not produce a different expansion plan. Instead, regulation at the CO_2 prices in this analysis simply acted as a "tax" added to existing production costs. As expected, Plan "K" has a higher PVRR ($361 Million) compared to Plan "A".

Sensitivity: Combined Cycle Operation

A combined cycle unit is considered "intermediate" generation and should have a capacity factor somewhere between a simple cycle combustion turbine and a baseload unit. The combined cycle units in Plan "A" operate at a capacity factor of approximately 24%, which is more like a super efficient peaking unit, considering that the efficiency of a combined cycle unit is 35% greater than that of a simple cycle combustion turbine, when contrasted with the capacity factor of approximately 90% for a new baseload unit. The data provided by C&B for the Screening Analysis projected a combined cycle capacity factor of approximately 60%. Requiring the combined cycle to operate at a higher capacity factor could make it economical to install another alternative in its place, either simple cycle combustion turbines if the load need is more peaking or a coal unit if the load need is more baseload. Table 11 displays the expansion plan results of the case that requires greater production from the combined cycle units.

Table 11
Combined Cycle Operation Sensitivity

Load Forecast:	Base	Base
Retire Units:	No	No
Plan:	**"A"**	**"L"**
2008		
2009		
2010		
2011		
2012		
2013		
2014		
2015	1-CCCT	1-SCCT
2016		1-SCCT
2017		
2018		1-SCCT
2019	1-CCCT	1-SCCT
2020		1-SCCT
2021		1-SCCT
2022	1-SCCT	1-SCCT
	=========	=========
30 Yr PVRR ($B)	17.950	18.045
Cost Delta to Base	0	0.095
Plan Rank (Low to High)	1	2

The optimal expansion plan changes when requiring greater production volumes from combined cycle units by making them "must run" units. Must run implies that the unit must be committed to operation prior to dispatching upper segments of other units. As Plan "L" indicates, the model opted to install simple cycle combustion turbines through 2022 instead of combined cycle units. This indicates that the Companies' system, given the inputs in the model, is in need of peaking generation more than baseload generation at this time.

Break Even Analysis: Gas Prices

The relative prices of natural gas and coal may have a significant impact on the selection of an optimal technology type. Therefore, in order to evaluate the effect of natural gas and coal prices, a fuel sensitivity analysis was incorporated into the Companies' process of determining an optimal Integrated Resource Plan. The natural gas prices were adjusted while holding the coal prices constant. This allows for a relatively simple method for evaluating the impact of the "gap," or difference in cost between that of coal and natural gas. All other inputs were held constant for this analysis. Results indicate that natural gas prices would need to increase by approximately 125% over those contained in Appendix A Table 4 before a coal unit becomes economical over a natural gas unit.

Break Even Analysis: Coal Capital Costs

Capital costs for generating units have increased dramatically in recent history. Baseload units generally have substantially higher $/kW capital requirements than peaking, but benefit from lower fuel costs during its lifetime of operation. Capital intense generating units will be impacted more by the recent cost increases since there is more cost to make up via lower fuel costs. This analysis simply adjusts coal capital costs while holding all other inputs constant in order to determine the point at which a coal unit becomes preferred over gas. Results indicate that coal capital costs would need to decrease by approximately 40% before being selected as the 2015 technology choice.

Summary and Recommendations

The results of the optimization performed with the base inputs identified Plan "A" as the least-cost expansion plan for meeting the Companies' load requirements. The plan calls for a combined cycle unit to be constructed at a Greenfield site in 2015 and 2019, and a Greenfield CT in 2022. This plan is supported by eleven sensitivities to key assumptions including DSM performance, load forecast, unit retirements, CO_2 regulation, combined cycle operation, natural gas prices, and coal construction costs. In nine of the eleven sensitivities, the optimal plan called for the construction of a Greenfield combined cycle unit in 2015, followed by a combination of Greenfield combined cycles and CTs through 2022. One of the sensitivities that did not have the previous ordering is the low load forecast, which recommended a combined cycle unit in 2019 as the only new unit requirement through 2022. The other sensitivity with different ordering, "Combined Cycle Operation", only called for the construction of Greenfield CTs through 2022.

Considering all options reviewed, this study recommends that the generation expansion strategy of the Companies be that shown in Plan "A", and that the Companies continue analyzing the economics of a combined cycle versus simple cycle combustion turbines to meet future load requirements.

Conclusion

By comparing the PVRR of Plan "A" with that of Plan "B", it can be seen that the twelve new DSM programs have lowered the 30-year PVRR by approximately $222 Million and therefore, based on the foregoing analysis, it is recommended that the Companies implement both the supply-side plan identified as Plan "A" as well as the new DSM programs. It is further recommended that purchase power continue to be reviewed as an option to delay generation construction.

2008 Expansion Plan

APPENDIX A

DATA ITEMS USED IN 2008 OPTIMAL INTEGRATED RESOURCE PLAN ANALYSIS

Existing System Data

The Strategist® computer program is used to simulate Kentucky Utilities Company's (KU) and Louisville Gas and Electric Company's (LG&E) generating systems. The model simulates the dispatch of both companies generating units and other purchases to serve load, and of Owensboro Municipal Utilities' (OMU) generating units and purchases to serve OMU's load while simultaneously maintaining the KU/LGE reserve margin requirements. The remaining generation available from OMU's units after meeting their requirements is economically dispatched by the Companies. The following sections outline the information and the sources of the information used to model the KU, LG&E and OMU generating systems.

A) General Data Items

1. Base Year: 2007

2. Study Period: 2007 to 2037 (with infinite end effects)

3. Economic Assumptions:

   Revenue requirements are determined on an annual basis and discounted to the base year giving a present worth of revenue requirements. Discounting is performed using a discount rate, which is assumed to remain constant for all years.

4. Financial Parameters:

a. Discount Rate:	7.85%
b. Capital/O&M costs Escalation Rates for Coal:	1.9%/1.6%
c. Capital/O&M costs Escalation Rates for Gas:	2.2%/1.6%
d. Combined Federal and State tax rate:	39.55%

5. Unserved Energy Cost:

   The cost placed on unserved energy is $15,000 per MWh (2007 dollars) and is based on study provided by Pace Global Energy Services.

6. Load Forecast:

   KU/LGE Base: See 2008 Expansion Plan Appendix A Table 1a.
   Based on LG&E and KU Energy and Demand Forecast for 2007-2037 contained in Section 7 of Volume I.

KU/LGE High: See 2008 Expansion Plan Appendix A Table 1b. LG&E and KU Energy and Demand Forecast for 2007-2037 contained in Section 7 of Volume I.

KU/LGE Low: See 2008 Expansion Plan Appendix A Table 1c. Based on LG&E and KU Energy and Demand Forecast for 2007-2037 contained in Section 7 of Volume I.

OMU: Developed April 24, 2007 by KU/LGE personnel based on historical data and information provided by OMU. See 2008 Expansion Plan Appendix A Table 1a.

7. Unit Retirements:

Base Assumption:

This evaluation reflects the recent retirements of Waterside 7 and 8, and Tyrone 1 and 2. The operating life of all other existing units is beyond the end of the study period.

Sensitivity:

Sensitivities were performed that considered the simultaneous retirement of aging units. The scenarios considered retirements of the units listed in Appendix A Table 2 on December 31, 2014.

8. Hourly Load Files:

Market Analysis provides the KU and LG&E typical hourly loads files with all load forecasts used. OMU typical hourly loads files are developed based on an OMU historical load shape.

9. KU/LG&E Unit Data:

a. Installed Capacity - See 2008 Expansion Plan Appendix A Table 3

b. Equivalent Forced Outage Rate - See 2008 Expansion Plan Appendix A Table 3

System FOR target developed based on benchmark averages for the top quartile. FORs have been increased by inclusion of maintenance outage hours (MOHs) to better reflect actual unit availability. Modeled EFOR = FOR + MOR.

c. Heat Rates: See 2008 Expansion Plan Appendix A Table 3

d. Fuel Costs:

Fuel Price Forecast Developed May 31, 2007

e. Maintenance Schedule:

Maintenance inputs were determined by reviewing the Companies' projected maintenance as of late spring 2007. Planned outages are scheduled to optimize reserves and reliability over all months of each year.

10. OMU Unit Data:

a. Installed Net Capacity:

OMU (Smith Unit 1): 136/143 (summer/winter)
OMU (Smith Unit 2): 259/265 (summer/winter)

b. Equivalent Forced Outage Rate:

OMU (Smith Unit 1): 15.27%
OMU (Smith Unit 2): 16.64%

c. Heat Rates (Full Load):

OMU (Smith Unit 1): 10,620 Btu/kWh
OMU (Smith Unit 2): 10,070 Btu/kWh

d. Heat Content of Fuel: 10,700 Btu/lb

e. Maintenance Schedules:

Planned outage inputs were developed with the assistance of OMU.

f. Contracted MW Demand Sale to KU: See 2008 Expansion Plan Appendix A Table 5.

g. Fuel Cost: See 2008 Expansion Plan Appendix A Table 6.

Fuel costs include associated costs for fuel handling and limestone.

h. OMU Scrubber O&M (Smith Units 1 & 2):

i. Variable O&M: Limestone charges included in fuel cost.
ii. Removal Efficiency: 93.5%

11. Other Purchases:

a. Contract Demand: See 2008 Expansion Plan Appendix A Table 5

OVEC (Firm): 174 MW

b. Forced Outage Rates:

OVEC: 0% FOR. Energy schedule incorporates outages.

c. Full Load Heat Rate (Btu/kWh):

OVEC: 10,000

For this transaction, which was modeled as a purchase power unit, the fuel price was input such that the fuel price times the heat rate would result in the expected energy cost of the purchase. A heat rate of 10,000 Btu/kWh is not meant to reflect the "real life" heat rate of the units associated with this transaction.

d. Heat Content of Fuel (Btu/lb):

OVEC: N/A

e. Fuel/Energy Cost:

See 2008 Expansion Plan Appendix A Table 6

f. Maintenance

OVEC: Maintenance requirements were provided by OVEC for calendar year 2007. The same profile is assumed for all other years.

Table 1a - 2008 Expansion Plan Appendix A
Base Forecast: Peak (MW) /Annual Energy (GWh)

Year	LGE Forecast Peak (MW)	LGE Forecast Energy (GWh)	KU Forecast Peak (MW)	KU Forecast Energy (GWh)	OMU Forecast Peak (MW)	OMU Forecast Energy (GWh)
2007	2,739	13,098	4,229	23,072	187	908
2008	2,789	13,321	4,306	23,514	187	909
2009	2,817	13,514	4,371	23,889	188	910
2010	2,862	13,682	4,428	24,239	188	913
2011	2,908	13,900	4,496	24,631	189	916
2012	2,952	14,099	4,560	24,981	189	919
2013	2,995	14,280	4,615	25,255	190	921
2014	3,038	14,430	4,669	25,497	190	924
2015	3,075	14,524	4,736	25,774	191	927
2016	3,113	14,640	4,799	26,055	192	930
2017	3,152	14,791	4,861	26,362	192	933
2018	3,194	14,975	4,933	26,749	193	935
2019	3,236	15,158	5,001	27,112	193	938
2020	3,282	15,362	5,082	27,552	194	941
2021	3,324	15,543	5,149	27,906	194	944
2022	3,368	15,737	5,223	28,300	195	947

Peaks and energy forecast reflect effects of interruptible/CSR but not DSM

Table 1b - 2008 Expansion Plan Appendix A
High Forecast: Peak (MW) /Annual Energy (GWh)

Year	LGE Forecast Peak (MW)	LGE Forecast Energy (GWh)	KU Forecast Peak (MW)	KU Forecast Energy (GWh)
2007	2,739	13,098	4,229	23,072
2008	2,839	13,559	4,407	24,065
2009	2,883	13,832	4,500	24,592
2010	2,939	14,049	4,580	25,070
2011	2,996	14,317	4,667	25,566
2012	3,053	14,578	4,753	26,040
2013	3,109	14,819	4,821	26,384
2014	3,161	15,018	4,892	26,714
2015	3,209	15,163	4,972	27,066
2016	3,253	15,309	5,051	27,430
2017	3,300	15,497	5,125	27,810
2018	3,351	15,722	5,213	28,281
2019	3,400	15,938	5,296	28,727
2020	3,454	16,180	5,396	29,271
2021	3,503	16,398	5,476	29,695
2022	3,556	16,628	5,561	30,150

Peaks and energy forecast reflect effects of interruptible/CSR but not DSM

Table 1c - 2008 Expansion Plan Appendix A
Low Forecast: Peak (MW) /Annual Energy (GWh)

	LGE Forecast		KU Forecast	
Year	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)
2007	2,739	13,098	4,229	23,072
2008	2,739	13,081	4,204	22,956
2009	2,749	13,190	4,241	23,179
2010	2,783	13,305	4,277	23,414
2011	2,816	13,460	4,325	23,697
2012	2,850	13,612	4,363	23,904
2013	2,883	13,745	4,405	24,109
2014	2,915	13,846	4,443	24,260
2015	2,944	13,896	4,495	24,455
2016	2,974	13,980	4,547	24,675
2017	3,005	14,091	4,596	24,914
2018	3,039	14,241	4,654	25,223
2019	3,076	14,398	4,713	25,537
2020	3,115	14,568	4,775	25,872
2021	3,152	14,727	4,826	26,140
2022	3,190	14,892	4,884	26,446

Peaks and energy forecast reflect effects of interruptible/CSR but not DSM

Table 2 - 2008 Expansion Plan Appendix A
Units Considered in the Retirement Sensitivity

Unit Type	Plant Name	Unit	Summer Capability (Net MW)	Current Age (Years)
Steam	Green River	3	68	54
Steam	Green River	4	95	49
Steam	Tyrone	3	71	55
CT	Cane Run	11	14	40
CT	Paddy's Run	11	12	40
CT	Paddy's Run	12	23	40
CT	Zorn	1	14	39
CT	Haefling	1,2,3	36	38

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Table 3 - 2008 Expansion Plan Appendix A
Louisville Gas and Electric/ Kentucky Utilities Generator Data

Unit	Installed Year	Summer Rating (MW)	EFOR %	Avg Heat Rate at Max Load (Mbtu/MWh)
Brown 1	1957	101	[redacted]	[redacted]
Brown 2	1963	167	[redacted]	[redacted]
Brown 3	1971	429	[redacted]	[redacted]
Brown 5	2001	117	[redacted]	[redacted]
Brown 6	1999	154	[redacted]	[redacted]
Brown 7	1999	154	[redacted]	[redacted]
Brown 8	1995	106	[redacted]	[redacted]
Brown 9	1994	106	[redacted]	[redacted]
Brown 10	1995	106	[redacted]	[redacted]
Brown 11	1996	106	[redacted]	[redacted]
Ghent 1	1974	475	[redacted]	[redacted]
Ghent 2	1977	484	[redacted]	[redacted]
Ghent 3	1981	493	[redacted]	[redacted]
Ghent 4	1984	493	[redacted]	[redacted]
Green River 3	1954	68	[redacted]	[redacted]
Green River 4	1959	95	[redacted]	[redacted]
Tyrone 3	1953	71	[redacted]	[redacted]
Dix 1-3	1925	24	[redacted]	[redacted]
Haefling 1-3	1970	36	[redacted]	[redacted]
Cane Run 4	1962	155	[redacted]	[redacted]
Cane Run 5	1966	168	[redacted]	[redacted]
Cane Run 6	1969	240	[redacted]	[redacted]
Mill Creek 1	1972	303	[redacted]	[redacted]
Mill Creek 2	1974	301	[redacted]	[redacted]
Mill Creek 3	1978	391	[redacted]	[redacted]
Mill Creek 4	1982	477	[redacted]	[redacted]
Trimble 1 (75%)	1990	383	[redacted]	[redacted]
Trimble 5	2002	160	[redacted]	[redacted]
Trimble 6	2002	160	[redacted]	[redacted]
Trimble 7	2004	160	[redacted]	[redacted]
Trimble 8	2004	160	[redacted]	[redacted]
Trimble 9	2004	160	[redacted]	[redacted]
Trimble 10	2004	160	[redacted]	[redacted]
Cane Run 11	1968	14	[redacted]	[redacted]
Paddys Run 11	1968	12	[redacted]	[redacted]
Paddys Run 12	1968	23	[redacted]	[redacted]
Paddys Run 13	2001	158	[redacted]	[redacted]
Zorn 1	1969	14	[redacted]	[redacted]
Ohio Falls 1-8	1928	45	[redacted]	[redacted]

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Table 4 - 2008 Expansion Plan Appendix A
Louisville Gas and Electric/ Kentucky Utilities Fuel Costs ($/Mbtu)

Year	Brown Units 1-3		Gr River Units 3-4	Tyrone Unit 3	Ghent		Cane Run Units 4-6	Mill Creek Units 1-4	Trimble High SO2	PRB	Oil	Gas *	Haefling Units 1-3 Gas*
2007	[redacted]												
2008	[redacted]												
2009	[redacted]												
2010	[redacted]												
2011	[redacted]												
2012	[redacted]												
2013	[redacted]												
2014	[redacted]												
2015	[redacted]												
2016	[redacted]												
2017	[redacted]												
2018	[redacted]												
2019	[redacted]												
2020	[redacted]												
2021	[redacted]												
2022	[redacted]												

* Indicates a seasonal profile applies. Price shown is annual average

Table 5 - 2008 Expansion Plan Appendix A
Kentucky Utilities/Louisville Gas and Electric
Purchases During Peak Month (MW)

Year	OMU (Firm)	OVEC (Firm)
2007	169	174
2008	168	174
2009	167	174
2010	0	174
2011	0	174
2012	0	174
2013	0	174
2014	0	174
2015	0	174
2016	0	174
2017	0	174
2018	0	174
2019	0	174
2020	0	174
2021	0	174
2022	0	174

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**Table 6 - 2008 Expansion Plan Appendix A
Modeled Energy Costs Associated with
Purchase Alternatives ($/Mbtu)**

Year	OMU (Firm)	OVEC (Firm)
2007	[redacted]	[redacted]
2008	[redacted]	[redacted]
2009	[redacted]	[redacted]
2010	[redacted]	[redacted]
2011	[redacted]	[redacted]
2012	[redacted]	[redacted]
2013	[redacted]	[redacted]
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]
2016	[redacted]	[redacted]
2017	[redacted]	[redacted]
2018	[redacted]	[redacted]
2019	[redacted]	[redacted]
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]

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**Table 7 - 2008 Expansion Plan Appendix A
Modeled Purchase Power Demand Costs
($/MW-Wk)**

Year	OMU (Firm)	OVEC (Firm)
2007	[redacted]	[redacted]
2008	[redacted]	[redacted]
2009	[redacted]	[redacted]
2010	[redacted]	[redacted]
2011	[redacted]	[redacted]
2012	[redacted]	[redacted]
2013	[redacted]	[redacted]
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]
2016	[redacted]	[redacted]
2017	[redacted]	[redacted]
2018	[redacted]	[redacted]
2019	[redacted]	[redacted]
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]

**Table 8 - 2008 Expansion Plan Appendix A
Emission Allowance Prices
($/Ton)**

Year	SO_2	NOx	CO_2
2007	489	900	
2008	457	988	
2009	455	951	
2010	480	2,366	
2011	624	2,369	
2012	649	2,372	4.61
2013	673	2,274	5.15
2014	733	2,250	5.73
2015	794	3,098	6.30
2016	855	3,092	7.04
2017	916	3,086	7.92
2018	977	3,122	8.96
2019	1,038	3,149	9.79
2020	1,099	3,177	10.42
2021	1,160	3,250	11.06
2022	1,221	3,282	11.70

Kentucky Utilities Company
and
Louisville Gas and Electric Company

Analysis of Supply-Side Technology Alternatives

Prepared by

Generation Planning & Analysis

April 2008

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS and ELECTRIC COMPANY
ANALYSIS OF
SUPPLY-SIDE TECHNOLOGY ALTERNATIVES

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KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS and ELECTRIC COMPANY
ANALYSIS OF
SUPPLY-SIDE TECHNOLOGY ALTERNATIVES

1. EXECUTIVE SUMMARY

Kentucky Utilities Company and Louisville Gas and Electric Company (the Companies) performed a detailed screening analysis of supply-side alternatives in order to evaluate, compare, and determine the least cost supply-side technology options to be used in further integrated resource optimization analysis.

Cummins & Barnard supplied the Companies with the bulk of data used in this evaluation, which includes the following: technology descriptions, detailed capital and operation and maintenance (O&M) cost estimates, and detailed performance and emission results at 57oF (average), 10oF (winter), and 88oF (summer) at base load for all technology alternatives and at expected operating load for peaking and intermediate load options. Other data used in the screening analysis was compiled via contracted studies from Devine Tarbell & Associates and Voith Siemens.

Fifty-five technology alternatives were screened through a levelized screening analysis in which total costs were calculated for each alternative, at various levels of utilization, over a 30-year period and levelized to reflect uniform payment streams in each year. This method tends to be more forward-looking than other methods since it evaluates the economics of owning and operating a unit over a multi-year period. Levelized costs of each alternative, at varying capacity factors, are then compared and the least-cost technologies for capacity factor increments throughout the planning period are determined. The screening analysis considers three sensitivity variables: capital cost, heat rate, and fuel cost. Environmental costs (emissions) pertaining to nitrogen oxides (NOx), sulfur dioxide (SO2), and carbon dioxide (CO2) are included in the analysis in two ways. The environmental cost implications regarding NOx and SO2 emissions are included in the base case analysis and accounted for as a variable cost similar to a fuel adder. Although there remains no current regulation for the emission of CO2, the impact of potential emission regulations is included as alternatives to the base analysis.

Based on the results of the levelized screening analysis, it is recommended that the technologies listed in Table 1 be retained for further evaluation in the integrated resource optimization analysis.

Table 1
Alternatives for Further Consideration

Supercritical Pulverized Coal Unit, High-Sulfur, 750 MW
3x1 GE 7FB Combined Cycle Combustion Turbine
2x1 GE 7FA Combined Cycle Combustion Turbine
Wind Energy Conversion
GE 7FA CT Simple Cycle Combustion Turbine
Ohio Falls 9-10 Hydro Units

2. INTRODUCTION

This study evaluated several supply-side technology costs and performance estimates for currently available and emerging technologies. As part of the Integrated Resource Plan process, Kentucky Utilities Company and Louisville Gas and Electric Company (the Companies) evaluate, at a high level, all of the currently available/emerging technologies. A detailed evaluation (using production costing computer models) of all currently available/emerging technologies is impractical due to the large number of possible alternatives and the significant amount of time required for computer simulation if each were modeled individually. The purpose of this study is to reduce the list of possible technology alternatives to a more manageable size. The study was conducted by first constructing optimal (least-cost) operation for each technology at various levels of utilization. To achieve this, a discussion of the sources for, and adjustments to, the data presented within this analysis and a brief description of each generating technology is presented. This is followed by a description of the levelized screening methodology and associated sensitivities. Finally, the basis for recommending one technology over another is presented and those technologies suggested for additional computer simulation are identified.

3. DATA SOURCES

Cummins & Barnard gathered information on several technology alternatives and submitted to the Companies a final study in December 2007. The document included technical descriptions for all technologies, detailed capital costs, performance expectations, emission rates, and O&M costs for conventional generation alternatives (pulverized coal, simple and combined cycle combustion turbines). The non-conventional technologies (renewable energy, waste-to-energy, advanced coal and combustion turbines, and energy storage systems) have the same data as the conventional alternatives but in less detail due to their lower level of maturity and frequency of use as generation options. The Companies' analysis and previously contracted studies from Devine Tarbell & Associates and Voith Siemens were used. All technologies analyzed in the screening process are found in Exhibit 1.

4. TECHNOLOGIES SCREENED

4.1 Coal-Fueled Technologies

4.1.1 Pulverized Coal

Conventional pulverized coal-fired units supply most of the Companies' present generation needs. This mature, well proven, and highly reliable technology is used throughout the utility industry. Typically, coal-fired units have high capital costs, long construction periods (up to 10 years) and are economical for baseload duty. Both subcritical and supercritical units were evaluated, with supercritical units typically being larger plants operating at higher temperatures and pressures and more efficiently. This evaluation contains seven "Greenfield" pulverized coal options, which include three subcritical units varying from 250 MW to 500 MW and four supercritical units ranging in size from 500 MW to 750 MW. Three of these options were evaluated as burning high-sulfur coal (4.5 percent or more sulfur content) and included both a subcritical and a supercritical unit of 500 MW size, and a 750 MW supercritical unit.

In order to meet state and federal air emissions regulations, all pulverized coal options utilize emissions controls as follows:

- NO_x: Combustion controls (low NO_x burners and overfire air) and selective catalytic reduction (SCR).
- Particulate Matter (PM_{10}): Fabric filter.
- Total Mercury (Hg°, Hg^{2+}, $Hg_{(p)}$): Powder Activated Carbon injection, fabric filter and wet limestone flue gas desulfurization (FGD).
- SO_2: Wet FGD
- Acid Mist [$PM_{2.5}$ (SO_3/H_2SO_4)]: Wet FGD followed by a wet ESP or Wet FGD with lime injection upstream of a baghouse.

4.1.2 Circulating Fluidized Bed

Circulating Fluidized Bed (CFB) boiler technology represents a mature and commercial technology for subcritical steam generation up to 340 MW and even higher with the installation of multiple CFB units supplying steam to a single steam turbine generator. CFB technology involves the injection into the boiler of crushed fuel and limestone and/or other inert bed materials which are suspended in a fluidized bed above the furnace floor by combustion air. This combustion air is injected into the furnace by primary air fans through numerous openings in the floor of the furnace. Secondary air is injected at a higher level in the furnace to promote fuel combustion and minimize NO_x formation. It is through the injection of limestone and the fluidized characteristics of the furnace materials that the CFB offers the inherent advantage of in situ SO_2 emissions control. The solid materials within the boiler are circulated through the furnace and cyclone systems to provide for in-bed sulfur removal and increased residence time in the system for burnout and reaction. The in-bed reaction of the calcium in the limestone can achieve boiler SO_2 removal efficiencies up to 95 percent, however, the addition of a polishing scrubber can increase SO_2 removal efficiencies to as high as 98 percent while reducing sorbent consumption. To date, CFB combustion technology exists primarily with subcritical steam cycles. For this analysis, both a 250 MW and a 500 MW subcritical CFB unit were considered.

In order to meet state and federal air emissions regulations, the CFB options utilize emissions controls as follows:

- NO_x: Combustion controls (inherently low combustion temperatures in CFB) and non-selective catalytic reduction (SNCR) w/ ammonia injection in the boiler.
- Particulate Matter (PM_{10}): Fabric filters.
- Total Mercury (Hg°, Hg^{2+}, $Hg_{(p)}$): CFB w/ a fabric filter.
- SO_2: In furnace limestone injection with a polishing scrubber.
- Acid Mist [$PM_{2.5}$ (SO_3/H_2SO_4)]: In furnace limestone injection with a polishing scrubber and baghouse.

4.1.3 Pressurized Fluidized Bed Combustion

Pressurized Fluidized Bed Combustion (PFBC) combined cycle units can be summarized as a standard combined cycle facility with an external combustor for the combustion turbine. The combustor is pressurized and supplied with coal and with combustion air from the combustion turbine compressor. Hot pressurized flue gas from the combustor is used to directly produce steam and is also sent through hot cyclones and supplied to a gas turbine for expansion and power production. Combustion turbine exhaust gas is then sent through a heat recovery steam generator (HRSG) for additional steam production for steam turbine power generation.

Due to the limited commercial deployment of this technology, the complexity of the system, the mixed performance results indicated, and the lack of significantly improved cycle efficiencies and emissions as compared to other technologies, PFBC technology is considered to still be a developmental technology.

In order to meet state and federal air emissions regulations, the 250 MW PFBC combined cycle option in this evaluation utilizes emissions controls as follows:

- NO_x: Ammonia injection in the furnace and a catalyst in the HRSG.
- Particulate Matter (PM_{10}) and Mercury: Hot Cyclones prior to the turbine and a baghouse after the HRSG.
- SO_2/Acid Mist: Limestone injection in the furnace.

4.1.4 Integrated Gasification Combined Cycle

Integrated Gasification Combined Cycle (IGCC) gasifies coal, producing a raw fuel gas that is cleaned of the majority of flue gas contaminants and sent to a combined cycle power island. The syngas is combusted in one or more gas turbines, which exhaust to multiple subcritical heat recovery steam generators (HRSGs) which produce steam for a conventional steam turbine. IGCC technology is considered to be in the second phase of implementation and commercialization with the next generation not likely to be operational until 2010 and beyond. The technology faces higher capital costs as compared to the pulverized coal and CFB technologies as well as historic low availability. Noted advantages to IGCC include the potential to provide a future carbon capture option and reduced water consumption rates as compared to other coal-fired designs.

This analysis considers three IGCC options: a 300 MW 1x1 unit (one combustion turbine with one steam turbine), a 600 MW 2x1 unit, and a 600 MW 2x1 unit using high-sulfur coal. These options utilize emissions controls as follows:

- NO_x: Combustion controls and nitrogen diluent injection.
- Particulate Matter (PM_{10}): Gas scrubber.
- H_2S: Carbonyl Sulfide (COS) hydrolysis / acid removal

4.1.5 Coal Technologies with CO_2 Capture and Sequestration

CO_2 capture technology has been evaluated for all of the coal-fired options in this evaluation with plant capacities greater than 250. All of the options have assumed post-combustion monoethanolamine CO_2 capture with the exception of IGCC, in which pre-combustion capture was analyzed. For sequestration, the captured CO_2 is assumed to be transported to an off-site, underground cavern via an underground pipeline with all capital and monitoring costs included. While cost estimates are provided for this work scope, it should be noted that sequestration technology is still under development and therefore, costs can vary greatly. As such, the values in this report should be considered indicative and subject to project specific applications.

4.2 Natural Gas-Fueled Technologies

4.2.1 Spark Ignition Engine

Spark ignition, also known as reciprocating, engines operate on fuels such as natural gas, propane, diesel or waste gases from industrial processes (engines using landfill gas and sewage-sludge digestion are referenced in Section 4.3.6). A 5 MW natural gas engine has been included in this analysis. While the technology is well proven as a means of backup power, it has not developed into a mature generation technology for base-load operation.

4.2.2 Simple Cycle Combustion Turbine

Simple Cycle Combustion Turbines (SCCTs) generate power by compressing ambient air and then heating the pressurized air by injecting and burning natural gas or oil, and forcing the heated gases to expand through a turbine. The turbine drives the air compressor and electrical generator.

SCCTs are commonly used to supply peaking capacity and are commercially proven with key features such as low capital cost, short design and installation schedules, and the availability of various unit sizes. Additionally, SCCTs have positive attributes of rapid startup and the modularity for ease of maintenance. These features, combined with operation over a low range of capacity factors, tend to offset the primary drawback of SCCTs, the high price relative to coal of oil or natural gas, making the SCCT an economical option for peaking duty but not for baseload or intermediate usage. The screening analysis includes three sizes of simple cycle combustion turbines (35, 76, and 155 MW at 88°F).

4.2.3 Combined Cycle Combustion Turbine

Combined Cycle Combustion Turbine (CCCT) plants consist of one or more combustion turbine unit(s), HRSGs, and a steam turbine generator. In addition to the SCCT generation process, the hot exhaust gases from combustion turbines are passed through the HRSG to produce high-pressure steam which is then expanded through a steam turbine that turns an electric generator. The exhaust gas heat recovery is cost effective for combustion turbines because the exhaust gas temperatures are very high.

CCCTs are generally chosen as baseload and intermediate generation providers due to their high efficiency, cost effective low emissions technology and relatively fast construction and startups beneficial to supplying base or intermediate load electric power. The key advantages of the CCCTs, when compared with reciprocating engines and SCCTs, are lower NO_x and carbon monoxide (CO) emissions, improved efficiency, and potentially greater operating flexibility if duct burners are used. Disadvantages are reduced plant reliability and increased maintenance, increased overall staffing requirements due to added plant complexity, and volatile natural gas prices. Five conventional CCCT configurations were evaluated in this study ranging in capacity from 114 MW to 817 MW at 88°F including both a double CT (2x1) and a triple CT (3x1) configuration.

4.2.4 Non-conventional Combustion Turbines

Three other advanced combustion turbine technologies (humid air turbine, Kalina Cycle, Cheng Cycle) are also included. These technologies are generally considered developmental, but offer significant potential for efficiency improvements over conventional technologies.

The Humid Air Turbine (HAT) utilizes moist air injected into the combustion chamber to generate electric power at a higher efficiency than a comparable combined cycle system. The Once-through Boiler with Partial Steam Generation design integrates a small HRSG into the simple cycle evaporating only a portion of the boiler feedwater. The steam is then separated in a steam/water separator where a mist eliminator provides steam with about 5 percent entrained droplets to moisturize high-pressure air from a compressor. The air-steam mixture is superheated within the HRSG before being injected into the combustor. A portion of the unevaporated boiler feedwater is blowndown to maintain water quality and the remainder is cycled back through the HRSG. The HAT reviewed herein is rated at 364 MW.

The Kalina Cycle combustion turbine involves injecting ammonia into the vapor side of the cycle resulting in higher efficiency compared to a conventional CCCT. The ammonia/water working fluid provides thermodynamic advantages based on non-isothermal boiling and condensing behavior of the dual component fluid, coupled with the ability to alter the ammonia concentration at various points in the cycle. This capability allows more effective heat acquisition, regenerative heat transfer, and heat rejection. The cycle is similar in nature to the combined cycle process except exhaust gas from the combustion turbine enters a heat recovery vapor generator (HRVG) and the ammonia/water mixture from the distillation condensation subsystem (DCSS) is heated in the HRVG. A portion of the mixture is removed at an intermediate point and is sent to a heat exchanger where it is heated with exhaust from the intermediate-pressure vapor turbine. The moisture returns to the HRVG where it is mixed with the balance of flow, superheated, and expanded in the vapor turbine generator. Additional vapor enters the HRVG from the high-pressure vapor turbine where it is reheated and supplied to the inlet of the intermediate-pressure vapor turbine. The vapor exhausts from the vapor turbine and condenses in the DCSS. The Kalina Cycle combustion turbine contained in this analysis is rated at 260 MW.

The Cheng cycle is characterized by the use of a gas turbine, which is capable of being injected with a large amount of superheated steam. A small HRSG which generates both saturated as well as superheated steam is typically added at the combustion turbine exhaust to supply this steam in a simple cycle application. Superheated steam from the HRSG is injected into the combustion chamber and expanded through the turbine section producing increased electrical power. The Cheng cycle is most beneficial in a cogeneration plant where varying process steam and electrical power demands are typically experienced. As studied here, the Cheng cycle's greatest advantage in an electric power generation only mode, is that it increases power output and decreases heat rate therefore driving efficiency up compared to a simple cycle unit. The downside of the Cheng cycle is increased plant staffing due to the small HRSG and increased combustion turbine maintenance and increased demineralized water usage due to the injection of steam. The Cheng Cycle combustion turbine contained in this analysis is rated at 127 MW.

4.2.5 *Microturbines*

Microturbines are similar in concept to the larger SCCTs used as conventional generation alternatives but typically offer output ranges from approximately 20 to 400 kW. Current commercial systems are air cooled and are capable of producing power at approximately 23-33 percent efficiency by employing a recuperator (air-to-air heat exchanger) that transfers exhaust heat to the air flowing into the combustor, thereby reducing the amount of fuel required. With a gaseous fuel source, microturbines can be placed anywhere with extreme ease and prompt installation due to their small size, similar to a refrigerator, and ability to burn various gaseous fuels, such as natural gas, propane and renewable gaseous fuels. Both baseload and peaking microturbines rated 30 kW are considered in this evaluation.

4.2.6 *Fuel Cell*

Fuel cells electrochemically convert hydrogen-rich fuel, typically natural gas, to direct current (DC) electricity. Inverters are required to convert the DC power to AC. Fuel cell construction is inherently modular making it easy to size power plants tailored to the utility's load growth and the constraints of the plant site.

Each cell consists of an anode, cathode, and an electrolyte. Fuel cells oxidize a fuel at the anode, which releases electrons into an electrical circuit. Simultaneously, water and heat are produced at either the anode or cathode depending on the electrolyte used. Fuel cells, unlike batteries, do not consume their electrodes with use, but only consume the fuel and oxygen (in the air) supplied to them. Efficiencies of fuel cells can reach up to 85 percent if the waste heat is recycled. In addition, fuel cells are also considered because of their environmental benefits as the only emissions from natural gas fuel cells are carbon dioxide and water.

There are six major fuel cell types in development: alkaline, polymer electrolyte (also known as proton exchange membrane), direct methanol, phosphoric acid, molten carbonate, and solid oxide. The most mature fuel cell type is the phosphoric acid fuel cell (PAFC) however significant reductions in generation cost can be realized with molten carbonate fuel cells (MCFC) due to their improved efficiency. A 300 kW MCFC with a 98 percent capacity factor was considered in this screening analysis.

4.3 Renewable Resource Technologies

4.3.1 Wind Energy

Wind is converted to power via a rotating turbine and generator. Utility-scale wind systems generally consist of multiple wind turbines with capacity factors dependent on the wind profile in the area. Wind power is rated on a scale of Class 1 to Class 7, with Class 7 representing an area with substantial wind speeds. A general rule to produce wind energy economically is to place wind turbines in a Class 3 or greater region. Most of Kentucky has a wind power class rating of 2 or less, meaning poor wind energy characteristics for wind power generation. Despite this limitation, a 50 MW wind unit was considered for this evaluation.

4.3.2 Solar

Solar energy conversion technologies capture the sun's energy and convert it to thermal energy (solar thermal) or electrical energy (solar photovoltaic), which drives the device (turbine, generator, or heat engine) for electrical generation. The advantages of solar technologies include no fuel requirements, no emissions produced, high reliability, and low O&M cost. The main disadvantages of solar photovoltaic technologies are high capital cost, low production capacity, and large amounts of required land.

Solar thermal power systems concentrate sunlight with mirrors or lenses to achieve the high temperatures needed to heat the thermal fluid. Solar thermal technologies currently in use include the following: parabolic trough, parabolic dish, solar chimney, and central receiver. Parabolic trough represents the vast majority of systems installed.

Solar photovoltaic power generation differs from solar thermal technology because it converts solar energy directly to DC electricity by the use of photovoltaic cells. These cells allow photons and electrons to interact with a semi-conductor material (usually silicon). Inverters are then required to convert the DC power to AC.

According to research reported by Cummins & Barnard, the relatively low solar intensity levels experienced in Kentucky result in relatively low capacity factors for solar technologies. Each of the five solar options was considered in the evaluation with ratings ranging from 50 kW to 100 MW and capacity factors between 18 and 65 percent.

4.3.3 Biomass

Biomass refers to using plant-based fuels for energy production typically in a configuration similar to pulverized coal units. Wood products are the primary biomass resource, however agricultural residues and yard wastes are also utilized. Efficiencies of biomass plants are lower when compared to modern coal units due to lower heating values and higher moisture contents in the fuel. The most efficient options for electrical generation from biomass resources include units co-fired with coal, offsetting a portion of the fossil fuel consumption. Biomass fuels present unique challenges when burned in any boiler as compared to coal due to higher moisture, chlorine, and volatile matter content, lower energy content, alkaline ash, and agglomeration of bed ash. The biomass alternative included in this evaluation is the 500 MW supercritical pulverized coal facility as previously mentioned, co-fired with ten percent biomass fuel by weight. Emissions controls are unchanged from the coal-only configuration.

4.3.4 Geothermal

Geothermal power plants use heat from the Earth's crust extracted through deep wells to generate steam and drive turbine generators for the production of electricity. Geothermal power is limited to locations where geothermal pressure reserves are found. Most geothermal reserves can be found in the western portion of the United States, but virtually no geothermal resources exist in Kentucky. There are three types of geothermal power conversion systems in common use including dry steam, flash steam, and binary cycle. Binary cycle plants, which utilize a turbine driven by fluid heated through a non-contact heat exchanger connected to the geothermal resource, could theoretically be implemented in Kentucky with very deep wells but this has not been proven. A 30 MW binary cycle unit is included in this study.

4.3.5 Hydroelectric

Hydroelectric power generation is a mature technology that is well understood. The costs and implementation schedules for these types of projects, however, can vary significantly based upon site specifics. The hydroelectric installation considered here is a run-of-river based design sized for 30 MW of generation capacity at a Greenfield location. Additionally, expansion at LG&E's existing Ohio Falls Station was screened, and is covered separately under the section titled "***Other Technologies***".

4.3.6 Waste to Energy

Waste-to-energy (WTE) technologies can utilize a variety of waste types to produce electricity. The economics associated with WTE facilities are difficult to determine, as costs are dependent upon waste transportation, processing, and tipping fees for the particular site. Values contained within this analysis are representative of technologies at generic sites.

<u>Municipal Solid Waste</u>

Converting Municipal Solid Waste (MSW) to energy was developed as a means of reducing the quantity of municipal and agricultural solid wastes with the avoidance of disposal costs being the primary component of determining economic feasibility. Unprocessed refuse is fed to the reciprocating grate in the boiler where it is combusted in a waterwall furnace (mass burning) only after limited processing of the refuse to remove non-combustible and large items. Other types of mass burning utilize refractory furnaces or rotary kiln furnaces. Smaller units utilize two-stage burning for higher efficiency via controlled-air furnaces. Large MSW facilities process up to 3,000 tons of waste per day. The driving force for MSW projects is the collection of a tipping fee to accept MSW, which must be competitive with the costs of hauling waste to the nearest landfill. Mass burning of MSW is widely believed to be a low cost alternative to other solid fuels, but it is difficult to justify due to environmental concerns over pollutants, high capital costs, poor load following characteristics, and low efficiency. A 7 MW unit with a 75 percent capacity factor requiring 300 to 350 tons per day of waste was considered in this evaluation.

<u>Refuse-Derived Fuel</u>

Refuse-Derived Fuel (RDF) is an evolution of MSW technology in which waste is sorted and processed into fluff or pellets that would be purchased as a fuel source by the generating facility. RDF is preferred in many refuse-to-energy applications due to its ability to be combusted with technologies traditionally used for coal. However, capital costs, unit size, capacity factors, and environmental concerns for RDF are similar to MSW characteristics. A 7 MW unit fueled by RDF with a capacity factor of 85 percent was also considered in the evaluation process.

Landfill Gas

Landfill Gas (LFG) is a valuable energy source that can be utilized in several applications, including power production, and is considered to be a commercial if not mature WTE technology. LFG is produced by the decomposition of wastes stored in landfills where it is collected and piped from wells, filtered, and then compressed. Although gas is produced when decomposition begins within a landfill, it may be several years before there is an adequate supply of gas to fuel an electric generator. Later, as the site ages, gas production (as well as the quality of the gas) declines to the point at which power generation is no longer economic. In the case of a typical well-engineered and well-operated landfill, gas may be produced for as many as 50 to 100 years, but electricity production may be economically feasible for only 10 to 15 years. Power can be generated via a combustion turbine, but internal combustion engines are most commonly used and, even then, such facilities are generally sized at less than 10 MWs. LFG projects are typically co-located at the landfill to minimize gas collection, interconnection, and transmission costs. This evaluation considers a 5 MW unit with a capacity factor of 90 percent.

Sewage Sludge & Anaerobic Digestion

Bio-methane fueled generators from the digestion of sewage sludge or livestock manure is very similar to landfill gas energy projects with respect to the quality of fuel fired and the generation equipment required. For these projects, the installation of an anaerobic digester is typically utilized in which sludge waste is digested by bacteria and the resultant methane gas produced from the process is collected, cleaned, and forwarded to a power generation system. This technology is generally viewed as a "green" technology due to the fact that it prevents the release of greenhouse gases (primarily methane) to the environment and, like other WTE projects, can offset the utilization of other fossil fuels for power generation. An 85 kW unit with a 90 percent capacity factor was considered in this analysis.

Tire-Derived Fuel

Tire-Derived Fuels (TDFs) consisting of chipped tires with the steel belts removed are attractive due to the high heating value, low ash and sulfur content, and low fuel cost. The co-firing of up to 10 percent by weight of TDF in a fluidized bed boiler can be considered a commercial technology as there is no significant change in the technology for a dedicated coal unit however there is very limited success with mass firing of TDF. While TDF offers a fuel heating value equivalent to or better than coal, the general lack of availability of TDF is a drawback. The TDF alternative included in this evaluation is a 10 percent TDF co-fired fluidized bed system and is rated at 50 MW with capacity factor of 92 percent.

4.4 Energy Storage Technologies

Energy storage systems are utilized for supplying energy during peak load periods. The energy storage devices must be charged or recharged by equipment utilizing electricity generated by another source. As such, charging is typically accomplished during periods of low demand by electricity with low generation costs. Alternatively, recharging energy can be sourced from renewable energy sources that are intermittent in nature, such as wind or solar. It is assumed that the energy storage options considered in this analysis are charged using power generated from the Companies' coal units. In return, the energy storage system can be dispatched at times of high demand and/or high generation cost. Energy storage technologies typically have very fast startup times, thus making them an ideal source for instant dispatchable power.

4.4.1 Pumped Hydro Energy Storage

Pumped Hydro Energy Storage (PHES) is the oldest and most prevalent of the central station energy storage options and requires a setup similar to conventional hydroelectric facilities. Conventional PHES plants typically use an upper and lower reservoir. Off-peak electrical energy is used to pump water from the lower reservoir to upper reservoir. When the energy is required during peak hours, the water in the upper reservoir is converted to electricity as the water flows through a turbine to the lower reservoir. Increasingly restrictive environmental regulations and established uses of the river systems in proximity to the Companies may further hamper consideration of this alternative. Finally, high capital costs and extended lead times are significant disadvantages that must be accounted for when considering this alternative.

A 500 MW PHES unit assumed to recover 80 percent of the energy input is considered in this screening analysis. Pumped hydro is considered a viable option to serve intermediate load levels but the low capacity factor (20 percent in this evaluation) makes it difficult for this technology to compete with other peaking technologies.

4.4.2 Lead-Acid Battery Storage

With a Lead-Acid Battery Storage (LABS) unit, off-peak energy is used to charge a battery for use during peak periods. A battery energy storage system consists of the battery, DC switchgear, AC/DC converter/charger, transformer, AC switchgear, and a building to house the components. During peak power demand periods, the battery system can discharge power to the utility system for approximately 4 to 5 hours and then recharge during non-peak hours. The overall efficiency of a LABS system is approximately 71 percent from charge to discharge. In addition to high initial cost, a battery system will require replacement every 4 to 10 years, depending upon duty cycle. The LABS unit included in this analysis is rated at 5 MW and has a capacity factor of 20 percent and is assumed to recover 87 percent of the energy input.

4.4.3 Compressed Air Energy Storage

Compressed Air Energy Storage (CAES) uses an electric motor-driven compressor to pressurize an underground cavern or reservoir with air during off-peak periods typically with power supplied by low cost base-loaded units. During peak periods, the compressed air is heated and passed through a gas turbine expander to produce electrical power at an attractive heat rate ranging from 4,000 to 5,000 Btu/kWh. CAES facilities provide more electrical power to the grid than is utilized during cavern charging mode because of fuel that is supplied to the system during the energy generation mode. The necessary geology occurs across nearly 75 percent of the United States however the technology lacks the maturity of the other energy storage options due to the limited number of installations in operation. A 500 MW CAES unit with a 25 percent capacity factor was used in this evaluation.

4.5 Other Technologies

4.5.1 Ohio Falls Expansion

Expansion of the Ohio Falls Station by the addition of Units 9 and 10 into existing empty bays was included as an option in the screening analysis. This expansion included two 209.2" diameter propeller units housed in an extension of the existing powerhouse. These units would rotate at 149 rpm and have a maximum turbine output of 16.8 MW (summer rating of 5 MW and dependent on river flow) each. Based upon historical river flow, expected energy from the expansion units would be approximately 74 GWH annually. Therefore, the maximum capacity factor would be 25 percent. The estimated capital cost for Units 9 and 10 is $95 million combined. The Ohio Falls Station is considered a run-of-the-river facility where nature and the

Army Corps of Engineers control the river flow. Therefore, the energy production of the facility can vary significantly and may not be available at the time of the Companies' peak needs.

Cost/performance data for the Ohio Falls Units 9 and 10 option are based on an escalation (6 percent annually) of the cost evaluation supplied to the Companies by Devine Tarbell & Associates for a separate hydro project that was studied in 2006. Since this estimate was not site-specific to the Ohio Falls station, it does not consider environmental or other issues that may exist regarding the installation of Ohio Falls 9 and 10.

5. ANALYSIS OVERVIEW

The Companies screening analysis consists of 56 generation alternatives developed primarily by Cummins & Barnard. The screening process involves utilizing specific unit operating data such as unit ratings, heat rate, operation and maintenance expenses, and capacity factors to estimate lifetime costs associated with owning and operating each technology type and size.

The base analysis includes the relevant fuel costs as well as the costs of SO_2 and NO_x emissions. The specific fuels utilized by each technology evaluated in this analysis are identified in Exhibit 1. Coal units are evaluated as utilizing either 100 percent Eastern bituminous high-sulfur coal or a blend of 78 percent Eastern Bituminous coal with 22 percent Powder River Basin coal. The costs for natural gas units include a firm gas charge of $0.363 per mmBtu of gas to guarantee the availability of the fuel supply for these units. This charge is applied either as a peak or baseload charge, depending on the type of unit.

In addition, emissions cost adders are included to account for regulations limiting the emission of SO_2 and NO_x from certain generating facilities. The emissions adders are calculated by year by multiplying the forecasted market emissions allowance price by the emissions rate. Cummins & Barnard provided the expected SO_2 and NO_x emissions rates, as shown in Exhibit 2(a), for all applicable technologies assuming the appropriate emissions controls. The emissions allowance price forecasts used in this analysis are based on the April 2007 forward price curves through 2009 for NO_x and through 2010 for SO_2. For the years thereafter, the prices are based on forecasts from Hill & Associates. The emissions allowance price forecasts are shown in Exhibit 2(b).

Also included in the analysis are tax credits for specific types of generation projects. For renewable energy projects, a federal production tax credit is included in the amount of two cents per kWh for wind, geothermal, and biomass projects and one cent per kWh for MSW, RDF, TDF, LFG, sewage sludge, and hydropower projects. A state income tax credit was also included for these options as well as the solar options. In addition, the Kentucky Clean Coal Tax Credit of $2 per ton is included for all technologies utilizing Eastern Bituminous coal.

Sensitivities are utilized to provide valuable information on how each technology will perform under various operating conditions. Some of the sensitivities contained in this analysis are based on variations in capital cost, technology operating efficiency (measured by heat rate), and fuel cost. Each of the previously mentioned sensitivities has three possible scenarios: base, low, and high, which results in 27 sensitivity combinations. The base case analysis excludes costs associated with CO_2 emissions. Since CO_2 emissions regulations are a possibility in the future, scenarios which considers CO_2 emissions costs are included in this analysis as alternatives to the base case.

An analysis comparing total levelized costs for all technologies as a function of capacity factor was also performed. This additional level of analytical scrutiny results in 891 (i.e., 27 cases x 11 capacity factor ranges x 3 least cost options = 891) "opportunities" for each technology to be identified as one of the three least cost options. Total costs are evaluated over a 30-year planning period in all possible case combinations.

Descriptions of the sensitivity analysis, resulting scenarios evaluated, screening analysis, and the levelized analysis are included in the following sections. The final portion of this evaluation includes a presentation of the lowest cost, most workable technologies to be considered further in the detailed analysis.

6. SENSITIVITY ANALYSIS

Variances between original cost estimates and actual cost estimates are possible. These differences result from technology ratings (conventional or non-conventional). Conventional technology estimates are expected to be more "on target" as compared with non-conventional alternatives where costs are more dynamic due to the immature nature of their technology and uncertainties associated with less frequent utilization and installation. A sensitivity analysis that addresses several variables with potential to change the perceived benefits of each technology has been incorporated into the screening process. Sensitivities present within the analysis do not include all possible relevant variables; however, the included permutations do provide pertinent information about how a technology performs under several combinations of economic and operating conditions. The variables identified for sensitivity analysis in the screening study are capital cost, technology operating efficiency (measured by heat rate), fuel cost, and the addition of costs associated with controlling CO_2 emissions. Two cases in addition to the base case were analyzed in the screening analysis to evaluate the impact of CO_2 emissions legislation. These cases, as discussed below, demonstrate the impact of assumed intermediate and high CO_2 emissions allowance costs.

The sensitivity cases evaluate potential additional cost of CO_2 emissions in addition to costs associated with SO_2 and NO_x emissions. Rising concentrations of greenhouse gases may be responsible for undesirable climate changes, and several bills to restrict CO_2 emissions have been proposed however, the magnitude of the proposed legislation varies significantly. The estimated cost of CO_2 emission allowances beginning in 2012 is expected to be in the range of $5 to $40 per ton of CO_2 emitted. As with SO_2 and NO_x, Cummins & Barnard provided the expected CO_2 emissions rates for all applicable technologies. The annual CO_2 emissions costs are calculated as the product the annual CO_2 emissions volumes and the forecasted emissions allowance prices at both the intermediate and high price levels, resulting in two separate CO_2 sensitivity cases.

6.1 Capital Cost

Based on research and experience by Cummins & Barnard, high and low boundaries for capital costs were provided for each technology, expressed as a percentage to be added or subtracted from the base capital cost to account for cost uncertainty. Generally, the more conventional or commercially mature technologies have a narrower capital cost range compared to more developmental or site-dependent technologies which generally have a wider range. These capital cost ranges were used to assign high and low capital cost scenarios for each technology.

6.2 Technology Operating Efficiency

The second sensitivity performed in the screening analysis involved the heat rate associated with each technology, referred to by Cummins & Barnard as the base heat rate. Decreasing (or increasing) the base heat rate represents a better (or worse) than expected efficiency of the operating facility over that expected during the design phase. A ± 5 percent adjustment to the heat rate, specified for all technologies included within this analysis, was utilized where applicable.

6.3 Fuel Cost

The third sensitivity conducted in the screening analysis considers the cost of fuel consumed by each technology. The Companies develop 30-year base fuel forecasts for all fuels that are to be used at existing plants. Sensitivity fuel forecasts are then developed depicting high and low fuel cost scenarios. These fuel forecasts are used for the technologies that utilize coal and natural gas. For the other technologies, the fuel costs are estimated based on research or data provided by Cummins and Barnard. The fuel costs utilized for each technology screened for the base and sensitivity fuel forecasts and are shown in Exhibit 3.

6.4 CO_2 Emissions

Two alternatives to the base case were evaluated regarding the impact of CO_2 emissions. Starting in 2012, both intermediate and high CO_2 emissions allowance costs were added to the fuel costs of each technology affected by potential CO_2 legislation in a similar manner to that for SO_2 and NO_x. The CO_2 allowance prices utilized in these scenarios are based on proposed legislation and are shown in Exhibit 2(b).

7. RESULTING SCENARIOS

The sensitivity analysis would not be as inclusive if all combinations of sensitivity variables were not analyzed. In other words, because there are three variables for which a sensitivity analysis is being performed (capital cost, heat rate, fuel cost) and each variable has three possible values (base, low or high), 27 total combinations of sensitivity cases must be evaluated. Two additional analyses were performed utilizing the intermediate and high CO_2 cost adders as discussed above. These analyses each produced an additional 27 combination of cases to be evaluated.

Exhibit 2(a) shows the cost (capital, fixed O&M, and variable O&M) and base heat rate information associated with each of the previously described technologies operating at 88°F. All technologies evaluated in this analysis are shown in this exhibit.

8. SCREENING ANALYSIS

The least-cost operation of the technologies presented in this study occurs over significantly different capacity factors. Therefore, an analysis that compares the total cost for each technology as a function of capacity factor is required. As previously discussed, the cost data for all technologies in this analysis originate from Cummins & Barnard or were derived based on information and/or cost estimates received by the Companies. All technologies listed in Exhibit 2(a), regardless of viability or technical maturity, were evaluated over a 30-year planning period in all 27 cases for both the base case analysis and the alternative analyses with CO_2 impact.

Several technologies were limited to maximum capacity factors based on design characteristics of the option and their application to the Companies' service territory. The pumped hydro energy storage, battery energy storage, and compressed air energy storage options were limited to 20 to 25 percent capacity factors based on design characteristics of the technologies supplied by Cummins & Barnard.

In general, conditions in Kentucky are not conducive to use solar power generation. This is reflected in the low capacity factors associated with these technologies which ranged from 18 to

65 percent. The five solar technologies (thermal) are expected to perform from 20 percent capacity factor for photovoltaic up to 70 percent capacity factor for a solar chimney. For solar power, most of the installations have been in the western part of the United States where solar radiation levels enable economic installation. For the Midwest, solar radiation levels are not ideal for solar technology. Wind energy was limited to a 30 percent capacity factor due to the generally low wind speeds that are prevalent in Kentucky, with the exception of a small area in eastern Kentucky.

The two hydro options, one supplied by Cummins & Barnard as part of the supply side screening alternatives, and expansion of the Ohio Falls Station were limited to 40 percent and 30 percent capacity factors, respectively. These limitations were based on the projected energy received from these run-of-the river projects.

Due to limitations in fuel supply, the MSD, RDF, LFG, and sewage sludge options were limited to capacity factors between 75 and 90 percent. The IGCC units were limited to 85 percent due to expected outage issues. The peaking microturbine is limited to a 15 percent capacity factor as it would run only during peak periods.

9. LEVELIZED SCREENING METHODOLOGY AND RESULTS

9.1 Base Analysis

A 30-year levelized cost methodology was utilized in the base analysis. An annual total cost comprised of capital, fixed O&M, variable O&M, fuel and other costs, is determined for each technology over a range of capacity factors from 0-100 percent in 10 percent increments. For each technology, levelized costs in $/kW at varying capacity factors were compared and least-cost technologies at each capacity factor increment were determined. Levelization allows for the cost of each technology to be compared over the 30-year life of each project with different escalation rates and forecasts for the various cost components. A non-levelized analysis considers costs of owning and operating generating units for only a single year. Exhibits 4 and 5 include relevant information, which when utilized in conjunction with Exhibits 2 and 3, allow replication of the results presented here. Exhibit 4 provides a complete source of equations used in the levelization process. Exhibit 5 provides miscellaneous information referred to within the equations of Exhibit 4 in addition to the Adjusted 30-year Levelization Factor (Adj. L_N) for the cost components that are escalated at constant rates such as O&M, capital, and energy storage charging costs. Adjusted L_Ns for the sum of fuel costs and emissions allowance costs can be determined in a similar manner.

Using the equations of Exhibit 4 and data contained within Exhibits 2(a)-2(b), Exhibit 3, and Exhibit 5, the total 30-year levelized cost ($/kW-yr in 2007 dollars) of each technology was calculated for each capacity factor increment. The results of this process are shown in pages 1 through 27 of Exhibit 6. Least-cost technologies over all ranges of capacity factors have been identified at the bottom of each case exhibit and are shaded in the tables. Technology capacity factors shown in pages 1 through 27 of Exhibit 6 were limited to the maximum allowed by the technology and/or environment in which they operate as previously discussed. For easy reference, technologies that have been identified as least cost over any range of capacity factors in at least one of the 27 cases have been summarized in Table 2.

Table 2
Least-Costly Technologies
In At-Least One Sensitivity Case

Supercritical Pulverized Coal Unit, High Sulfur – 750 MW
3x1 GE 7FB Combined Cycle Combustion Turbine
Geothermal
Kalina Cycle Combined Cycle Combustion Turbine
Wind Energy Conversion
GE 7FA CT Simple Cycle Combustion Turbine

Exhibit 7 is a graphical representation of the technologies of these six options with base emissions, which appear as a least-cost generation alternative. The intersection of the lines with the vertical axis represents the fixed costs (carrying charges and fixed O&M) associated with the technology. The slope of the line is a function of the variable costs (fuel and variable O&M).

Identifying not only the least cost technologies, but also the second least cost and even the third least cost further enhances the results of this analysis. First, second, and third least-cost technology identification is justified by the fact that the $/kW-yr difference between them may be minimal over any increment of capacity factors. The second and third least-cost technologies for at least one capacity factor increment in any of the 27 cases are summarized in Table 3.

Table 3
Second and Third Least-Costly Technologies
In At-Least One Sensitivity Case

Supercritical Pulverized Coal Unit, High Sulfur – 750 MW
Supercritical Pulverized Coal Unit – 750 MW
3x1 GE 7FB Combined Cycle Combustion Turbine
2x1 GE 7FA Combined Cycle Combustion Turbine
Geothermal
Subcritical Pulverized Coal Unit, High Sulfur – 500 MW
Kalina Cycle Combined Cycle Combustion Turbine
Wind Energy Conversion
Ohio Falls 9 & 10
Siemens 5000F Combined Cycle Combustion Turbine
Pumped Hydro Energy Storage
Subcritical Pulverized Coal Unit – 500 MW

The 12 different technology types and sizes specified between Tables 3 and 4 are those, at first glance, that appear to deserve consideration in detailed computer models. However, this list must be examined further before selecting technologies to pass onto the detailed analysis. As previously stated, there are 891 "opportunities" for each technology to be identified as one of the first three least cost options. Table 4, identifies how many occurrences a technology appeared as either first, second, or third least cost options over any capacity factor range. All technologies not identified within Table 4 failed to appear as one of the top three least-cost options in any of the cases identified.

Table 4
The Frequency of Occurrence of Each Technology as First, Second or Third Least Cost

# Occurrences				
1st	**2nd**	**3rd**	**Total**	**Technology Name**
111	51	14	176	Supercritical Pulverized Coal, High Sulfur - 750 MW
0	102	58	160	Supercritical Pulverized Coal - 750 MW
68	49	11	128	Combined Cycle 3x1 GE 7FB CT - Intermediate Load
0	34	66	100	Combined Cycle 2x1 GE 7FA CT - Intermediate Load
50	7	18	75	Geothermal - 30 MW
0	0	65	65	Subcritical Pulverized Coal, High Sulfur - 500 MW
1	26	24	51	Kalina Cycle CC CT - 282 MW
40	5	2	47	Wind Energy Conversion - 50 MW
27	0	0	27	Simple Cycle GE 7FA CT - Peaking Capacity
0	14	6	20	Ohio Falls 9-10
0	0	16	16	Siemens 5000F CC CT - Intermediate Load
0	9	6	15	Pumped Hydro Energy Storage - 500 MW
0	0	11	11	Subcritical Pulverized Coal - 500 MW

Table 4 shows that the 750 MW Supercritical Pulverized Coal, High Sulfur unit was selected 176 times as the first, second, or third least-cost technology while the Pumped Hydro Energy Storage was selected only fifteen times. Table 4 provides a good starting point for further reducing the list of technologies identified in Tables 2 and 3.

A review of Table 4 reveals that four different coal-fired technologies have been identified among the 11 least cost technologies. They are a 750 MW supercritical high-sulfur pulverized coal unit, a 750 MW supercritical pulverized coal unit, a 500 MW subcritical high-sulfur pulverized coal unit, and a 500 MW subcritical pulverized coal unit. Of these, only the 750 MW high sulfur unit ranks first among least cost generation alternatives in any of the sensitivity scenarios and therefore, it is the only coal unit recommended for further analysis.

The GE 7FA simple cycle combustion turbines will be considered for further optimization analysis as it is the only simply cycle configuration among the least cost alternatives. In addition, both the 3x1 and 2x1 GE 7F combined cycle combustion turbine configurations are considered for further optimization analysis. However, the Siemens 5000F option is eliminated as a redundant and lower ranking option as it only ranks third a total of 16 times. As stated previously in this report, the Kalina Cycle CCCT is only in developmental stages and is not commercially available. Therefore, even though it shows up among the least cost generation alternatives, this option is not evaluated further.

Although it was not the least-cost technology in any of the sensitivity cases, the expansion of the Ohio Falls hydroelectric station is included for further evaluation. And, while the wind profile for most of Kentucky is not suitable for power generation, the wind energy conversion option is included for further evaluation for potential opportunities as another "green" alternative. However, both the geothermal and the pumped hydro energy storage options are eliminated as there are no suitable resources in Kentucky for these options to be developed into a power generation project.

9.2 Alternative Analyses with CO_2 Impact

As previously described, two separate analyses were performed to evaluate the impact of CO_2 legislation on the outcome of the screening analysis. The same sensitivities (variability of capital cost, heat rate, and fuel cost) were performed in these analyses as were performed in the base case analysis which excluded any costs for CO_2 emissions. After implementing CO_2 allowance prices at intermediate and high levels as shown in Exhibit 2(b), the least-cost technologies in at least one sensitivity case over any capacity factor range were determined just as in the analysis previously presented.

As mentioned for the base analysis with only NO_x and SO_2 emissions, by using the equations of Exhibit 4 and data contained within Exhibits 2(a)-2(b), Exhibit 3, and Exhibit 5 [with the addition of CO_2 adders applied similarly to that of NO_x and SO_2], the total 30-year levelized cost ($/kW-yr in 2007 dollars) of each technology was calculated for each capacity factor increment with both the intermediate and high CO_2 price forecasts. The results of this process are similar to that of the base case using the high price forecast and the results using the high CO_2 price forecast are shown in pages 1 through 27 of Exhibit 8. Least-cost technologies over all ranges of capacity factors have been identified at the bottom of each case exhibit and are shaded in the tables. Technology capacity factors shown in pages 1 through 27 of Exhibit 8 were limited to the maximum allowed by the technology and/or environment in which they operate as specified by the data sources. For reference, these technologies are listed in Table 5.

Table 5
Least-Costly Technologies
In At-Least One Sensitivity Case

Base Case	CO_2 EA Prices		
No CO_2	*Intermediate*	*High*	Technology
√	√	√	Supercritical Pulverized Coal, High Sulfur - 750 MW
√	√	√	Combined Cycle 3x1 GE 7FB CT - Intermediate Load
√	√	√	Geothermal - 30 MW
√	√	√	Kalina Cycle CC CT - 282 MW
√	√	√	Wind Energy Conversion - 50 MW
√	√	√	Simple Cycle GE 7FA CT - Peaking Capacity
		√	Pumped Hydro Energy Storage - 500 MW
		√	Hydroelectric - New

Table 5 shows that the least cost technologies remain the same with the intermediate CO_2 emissions prices as compared to the base case. With high CO_2 emissions prices, pumped hydro energy storage and new hydroelectric are included among the lowest cost technology options.

Table 6 identifies those technologies that were either identified as a second or third least-costly technology in the scenarios including CO_2 emissions costs as compared to the base case. This shows that the technologies remain the same, with the exception of adding the new hydroelectric option, when the high CO_2 allowance price forecast is considered.

Table 6
Second and Third Least-Costly Technologies
In At-Least One Sensitivity Case

Base Case	CO_2 EA Prices		
No CO_2	*Intermediate*	*High*	Technology
√	√	√	Supercritical Pulverized Coal, High Sulfur - 750 MW
√	√	√	Supercritical Pulverized Coal - 750 MW
√	√	√	Combined Cycle 3x1 GE 7FB CT - Intermediate Load
√	√	√	Combined Cycle 2x1 GE 7FA CT - Intermediate Load
√	√	√	Geothermal - 30 MW
√	√	√	Subcritical Pulverized Coal, High Sulfur - 500 MW
√	√	√	Kalina Cycle CC CT - 282 MW
√	√	√	Wind Energy Conversion - 50 MW
√	√	√	Ohio Falls 9-10
√	√	√	Siemens 5000F CC CT - Intermediate Load
√	√	√	Pumped Hydro Energy Storage - 500 MW
√	√	√	Subcritical Pulverized Coal - 500 MW
		√	Hydroelectric - New

Table 7 identifies how many times a technology appeared as either the first, second or third least-cost option over any capacity factor range and with intermediate CO_2 emissions allowance prices. Including the intermediate CO_2 allowance price forecast has virtually no impact as compared to the base case, with the exception of slight changes to the order and number of occurrences.

Table 7
The Frequency of Occurrence of Each Technology as First, Second or Third Least Cost With Intermediate CO_2 Prices

# Occurrences				
1st	**2nd**	**3rd**	**Total**	**Technology Name**
80	79	15	174	Supercritical Pulverized Coal, High Sulfur - 750 MW
0	71	85	156	Supercritical Pulverized Coal - 750 MW
66	51	15	132	Combined Cycle 3x1 GE 7FB CT - Intermediate Load
0	32	66	98	Combined Cycle 2x1 GE 7FA CT - Intermediate Load
76	7	11	94	Geothermal - 30 MW
7	27	17	51	Kalina Cycle CC CT - 282 MW
0	0	48	48	Subcritical Pulverized Coal, High Sulfur - 500 MW
41	4	2	47	Wind Energy Conversion - 50 MW
27	0	0	27	Simple Cycle GE 7FA CT - Peaking Capacity
0	15	9	24	Ohio Falls 9-10
0	11	7	18	Pumped Hydro Energy Storage - 500 MW
0	0	15	15	Siemens 5000F CC CT - Intermediate Load
0	0	7	7	Subcritical Pulverized Coal - 500 MW

Table 8 below identifies how many times a technology appeared as either the first, second or third least-cost option over any capacity factor range and with high CO_2 emissions allowance prices. Including the high CO_2 allowance price forecast has only a minor impact as compared to the base case. In addition to further inconsequential changes to the order and number of occurrences, the geothermal option ranks as least cost significantly more and new hydroelectric is included, as previously mentioned. Given the scarcity of available resources for these options, they remain excluded from further analysis.

Table 8
The Frequency of Occurrence of Each Technology as First, Second or Third Least Cost With High CO_2 Prices

# Occurrences				
1st	**2nd**	**3rd**	**Total**	**Technology Name**
39	108	13	160	Supercritical Pulverized Coal, High Sulfur - 750 MW
0	35	109	144	Supercritical Pulverized Coal - 750 MW
58	53	24	135	Combined Cycle 3x1 GE 7FB CT - Intermediate Load
116	6	10	132	Geothermal - 30 MW
0	25	71	96	Combined Cycle 2x1 GE 7FA CT - Intermediate Load
11	31	11	53	Kalina Cycle CC CT - 282 MW
43	6	1	50	Wind Energy Conversion - 50 MW
0	19	10	29	Ohio Falls 9-10
27	0	0	27	Simple Cycle GE 7FA CT - Peaking Capacity
1	13	11	25	Pumped Hydro Energy Storage - 500 MW
0	0	17	17	Subcritical Pulverized Coal, High Sulfur - 500 MW
0	0	14	14	Siemens 5000F CC CT - Intermediate Load
2	1	3	6	Hydroelectric - New - 30 MW
0	0	3	3	Subcritical Pulverized Coal - 500 MW

In general, the least cost technologies are consistent regardless of whether CO_2 emissions are not limited (as with the base case) or whether CO_2 emissions allowances prices are forecast at the intermediate or high level. The 750 MW Supercritical Pulverized Coal, High Sulfur is the lowest cost technology alternative with the highest ranking in all cases, confirming its selection as the coal option to be further analyzed. The only additional technology ranking third or better in any scenario as compared to the base case is the inclusion of new hydroelectric with the high CO_2 allowance price case. As previously mentioned, there is a scarcity of available hydro resources in Kentucky so this technology is excluded from further analysis.

10. RECOMMENDATIONS

Based on the various analyses discussed above, the technologies listed in Table 9 are recommended for further analysis in the optimization studies using Strategist®, a detailed modeling program. The technologies identified will provide a diverse set of alternatives to be evaluated in production and capital costing computer models. Exhibit 9 is a graphical representation of the least-cost technologies, which will be further evaluated in the Strategist® optimization software modeling.

Table 9
Technologies Suggested for Analysis
Within Strategist®

Supercritical Pulverized Coal Unit, High-Sulfur, 750 MW
3x1 GE 7FB Combined Cycle Combustion Turbine
2x1 GE 7FA Combined Cycle Combustion Turbine
Wind Energy Conversion
GE 7FA CT Simple Cycle Combustion Turbine
Ohio Falls 9-10 Hydro Units

Appendix A

Technologies Screened

Tech. ID	Technology Description	Category	Sub-Category	Fuel Type
1	Pumped Hydro Energy Storage - 500 MW	Storage	Pumped Hydro	Charging Only
2	Lead-Acid Battery Energy Storage - 5 MW	Storage	Battery	Charging Only
3	Compressed Air Energy Storage - 500 MW	Storage	Compressed Air	Gas and Charging
4	Simple Cycle GE LM6000 CT - Peaking Capacity	Natural Gas	SCCT	Gas
5	Simple Cycle GE 7EA CT - Peaking Capacity	Natural Gas	SCCT	Gas
6	Simple Cycle GE 7FA CT - Peaking Capacity	Natural Gas	SCCT	Gas
7	Combined Cycle GE 7EA CT - Intermediate Load	Natural Gas	CCCT	Gas
8	Combined Cycle GE 7FA CT - Intermediate Load	Natural Gas	CCCT	Gas
9	Combined Cycle 2x1 GE 7FA CT - Intermediate Load	Natural Gas	CCCT	Gas
10	Combined Cycle 3x1 GE 7FB CT - Intermediate Load	Natural Gas	CCCT	Gas
11	Siemens 5000F CC CT - Intermediate Load	Natural Gas	CCCT	Gas
12	Humid Air Turbine Cycle CT - 366 MW	Natural Gas	CCCT	Gas
13	Kalina Cycle CC CT - 282 MW	Natural Gas	CCCT	Gas
14	Cheng Cycle CT - 140 MW	Natural Gas	CCCT	Gas
15	Peaking Microturbine - 0.03 MW	Natural Gas	CT	Gas
16	Baseload Microturbine - 0 03 MW	Natural Gas	CT	Gas
17	Subcritical Pulverized Coal - 250 MW	Coal	Pulverized Coal	Coal
18	Subcritical Pulverized Coal - 500 MW	Coal	Pulverized Coal	Coal
19	Subcritical Pulverized Coal, High Sulfur - 500 MW	Coal	Pulverized Coal	Coal
20	Circulating Fluidized Bed - 250 MW	Coal	Fluidized Bed Combustion	Coal
21	Circulating Fluidized Bed - 500 MW	Coal	Fluidized Bed Combustion	Coal
22	Supercritical Pulverized Coal - 500 MW	Coal	Pulverized Coal	Coal
23	Supercritical Pulverized Coal. High Sulfur - 500 MW	Coal	Pulverized Coal	Coal
24	Supercritical Pulverized Coal - 750 MW	Coal	Pulverized Coal	Coal
25	Supercritical Pulverized Coal High Sulfur - 750 MW	Coal	Pulverized Coal	Coal
26	Pressurized Fluidized Bed Combustion	Coal	Fluidized Bed Combustion	Coal
27	1x1 IGCC	Coal	IGCC	Coal Gasification
28	2x1 IGCC	Coal	IGCC	Coal Gasification
29	2x1 IGCC, High Sulfur	Coal	IGCC	Coal Gasification
30	Subcritical Pulverized Coal - 500 MW - CCS	Coal	Pulverized Coal	Coal
31	Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	Coal	Pulverized Coal	Coal
32	Circulating Fluidized Bed - 500 MW - CCS	Coal	Fluidized Bed Combustion	Coal
33	Supercritical Pulverized Coal - 500 MW - CCS	Coal	Pulverized Coal	Coal
34	Supercritical Pulverized Coal. High Sulfur - 500 MW - CCS	Coal	Pulverized Coal	Coal
35	Supercritical Pulverized Coal - 750 MW - CCS	Coal	Pulverized Coal	Coal
36	Supercritical Pulverized Coal. High Sulfur - 750 MW - CCS	Coal	Pulverized Coal	Coal
37	1x1 IGCC - CCS	Coal	IGCC	Coal Gasification
38	2x1 IGCC - CCS	Coal	IGCC	Coal Gasification
39	2x1 IGCC. High Sulfur - CCS	Coal	IGCC	Coal Gasification
40	Wind Energy Conversion - 50 MW	Renewable	Wind	No Fuel
41	Geothermal - 30 MW	Renewable	Geothermal	Renew
42	Solar Photovoltaic - 50 kW	Renewable	Solar	No Fuel
43	Solar Thermal Parabolic Trough - 100 MW	Renewable	Solar	No Fuel
44	Solar Thermal. Parabolic Dish - 1 2 MW	Renewable	Solar	No Fuel
45	Solar Thermal. Central Receiver - 50 MW	Renewable	Solar	No Fuel
46	Solar Thermal Solar Chimney - 50 MW	Renewable	Solar	No Fuel
47	MSW Mass Burn - 7 MW	Waste To Energy	MSW	MSW
48	RDF Stoker-Fired - 7 MW	Waste To Energy	RDF	RDF
49	Landfill Gas IC Engine - 5 MW	Waste To Energy	LFG	Landfill Gas
50	TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	Waste To Energy	TDF	10% TDF / 90% Coal
51	Sewage Sludge & Anaerobic Digestion - 085 MW	Waste To Energy	SS	No Fuel
52	Bio Mass (Co-Fire)	Waste To Energy	Bio Mass	10% Renew / 90% Coal
53	Molten Carbonate Fuel Cell - 300 kW	Natural Gas	Fuel Cell	Gas
54	Spark Ignition Engine - 5 MW	Natural Gas	Reciprocating Engine	Gas
55	Hydroelectric - New - 30 MW	Renewable	Hydro	No Fuel
200	Ohio Falls 9-10	Renewable	Hydro	No Fuel

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Exhibit 2(a)

Heat Rate and Capital Cost Sensitivity Data

Technology	Rating, MW (88°F)	Heat Rate Data, Btu/kWh Base	High	Low	Technology Installed Cost, $/kW Base	High	Low	Fixed O&M $/kW	Variable O&M $/MWh	AVG LD In/Out	Emissions Rates (lb/mmBtu) SO_2	NO_x	CO_2
Pumped Hydro Energy Storage - 500 MW	500	-	-	-	[redacted]			$11.69	$34.54	1.25	-	-	-
Lead-Acid Battery Energy Storage - 5 MW	5	-	-	-				$19.15	$31.66	1.15			
Compressed Air Energy Storage - 500 MW	500	4,600	4,830	4,370				$18.66	$23.60	1.12	0.0014	0.05	118.0
Simple Cycle GE LM6000 CT - Peaking Capacity	35	9,624	10,105	9,143				$22.66	$27.94		0.0014	0.05	118.0
Simple Cycle GE 7EA CT - Peaking Capacity	76	12,041	12,643	11,439				$15.69	$26.36		0.0014	0.03	118.0
Simple Cycle GE 7FA CT - Peaking Capacity	155	10,815	11,356	10,274				$11.92	$23.92		0.0014	0.0180	118.0
Combined Cycle GE 7EA CT - Intermediate Load	114	8,264	8,677	7,851				$32.48	$5.35		0.0014	0.007	118.0
Combined Cycle GE 7FA CT - Intermediate Load	238	7,222	7,583	6,861				$20.49	$4.57		0.0014	0.007	118.0
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	475	7,214	7,575	6,853				$17.98	$4.49		0.0014	0.007	118.0
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	817	7,161	7,519	6,803				$13.85	$4.36		0.0014	0.007	118.0
Siemens 5000F CC CT - Intermediate Load	267	7,257	7,620	6,894				$14.99	$4.59		0.0014	0.007	118.0
Humid Air Turbine Cycle CT - 366 MW	364	10,382	10,901	9,863				$8.48	$4.66		0.0014	0.018	118.0
Kalina Cycle CC CT - 282 MW	260	6,373	6,692	6,054				$16.49	$2.40		0.0014	0.007	118.0
Cheng Cycle CT - 140 MW	127	7,437	7,809	7,065				$15.09	$5.11		0.0014	0.024	118.0
Peaking Microturbine - 0.03 MW	0.03	14,561	15,289	13,833				$147.81	$32.43		0.0014	0.018	118.0
Baseload Microturbine - 0.03 MW	0.03	14,561	15,289	13,833				$148.36	$6.44		0.0014	0.018	118.0
Subcritical Pulverized Coal - 250 MW	250	9,260	9,723	8,797				$55.06	$2.69		0.09	0.05	197.0
Subcritical Pulverized Coal - 500 MW	500	9,218	9,679	8,757				$42.19	$2.64		0.09	0.05	197.0
Subcritical Pulverized Coal, High Sulfur - 500 MW	500	9,145	9,602	8,688				$46.02	$2.71		0.09	0.05	200.3
Circulating Fluidized Bed - 250 MW	250	9,384	9,853	8,915				$48.92	$2.30		0.095	0.09	197.0
Circulating Fluidized Bed - 500 MW	500	9,348	9,815	8,881				$39.89	$2.25		0.095	0.09	197.0
Supercritical Pulverized Coal - 500 MW	500	8,920	9,366	8,474				$45.74	$2.07		0.09	0.05	197.0
Supercritical Pulverized Coal, High Sulfur - 500 MW	500	8,852	9,295	8,409				$46.41	$2.62		0.09	0.05	200.3
Supercritical Pulverized Coal - 750 MW	739	8,928	9,374	8,482				$34.93	$2.49		0.09	0.05	197.0
Supercritical Pulverized Coal, High Sulfur - 750 MW	739	8,858	9,301	8,415				$35.39	$2.56		0.09	0.05	200.3
Pressurized Fluidized Bed Combustion	248	10,396	10,916	9,876				$80.37	$3.06		0.12	0.09	197.0
1x1 IGCC	269	8,448	8,870	8,026				$54.88	$2.66		0.05	0.05	197.0
2x1 IGCC	580	8,412	8,833	7,991				$43.54	$2.63		0.05	0.05	197.0
2x1 IGCC, High Sulfur	584	8,391	8,811	7,971				$42.67	$2.64		0.01	0.02	200.3
Subcritical Pulverized Coal - 500 MW - CCS	501	12,808	13,448	12,168				$50.88	$4.75		0.09	0.05	19.7
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	500	12,570	13,199	11,942				$54.80	$5.10		0.11	0.05	20.0
Circulating Fluidized Bed - 500 MW - CCS	500	12,940	13,587	12,293				$48.59	$4.32		0.1	0.09	19.7
Supercritical Pulverized Coal - 500 MW - CCS	500	12,258	12,871	11,645				$54.54	$4.02		0.09	0.05	19.7
Supercritical Pulverized Coal, High Sulfur - 500 MW - CCS	500	12,080	12,684	11,476				$55.25	$4.75		0.11	0.05	20.0
Supercritical Pulverized Coal - 750 MW - CCS	739	12,198	12,808	11,588				$42.89	$4.41		0.09	0.05	19.7
Supercritical Pulverized Coal, High Sulfur - 750 MW - CCS	739	12,018	12,619	11,417				$43.44	$4.61		0.11	0.05	20.0
1x1 IGCC - CCS	261	10,110	10,616	9,605				$67.11	$3.26		0.05	0.05	19.7
2x1 IGCC - CCS	516	10,099	10,604	9,594				$53.85	$3.26		0.05	0.05	19.7
2x1 IGCC, High Sulfur - CCS	522	10,076	10,580	9,572				$54.00	$3.31		0.05	0.05	20.0
Wind Energy Conversion - 50 MW	50	-	-	-				$48.36	$0.00		-	-	
Geothermal - 30 MW	30	-	-	-				$65.04	$6.35		-	-	
Solar Photovoltaic - 50 kW	0.1	-	-	-				$39.58	$0.01		-	-	-
Solar Thermal, Parabolic Trough - 100 MW	100	-	-	-				$66.60	$1.27		-	-	-
Solar Thermal, Parabolic Dish - 1.2 MW	1.2	-	-	-				$60.34	$0.01			-	-
Solar Thermal, Central Receiver - 50 MW	50			-				$119.63	$0.75			-	-
Solar Thermal, Solar Chimney - 50 MW	50		-	-				$69.41	$0.01			-	
MSW Mass Burn - 7 MW	7	19,568	20,546	18,590				$568.11	$37.83		0.06	0.15	214.5
RDF Stoker-Fired - 7 MW	7	16,936	17,783	16,089				$471.48	$11.86		0.06	0.15	219.0
Landfill Gas IC Engine - 5 MW	5	9,898	10,393	9,403				$201.52	$0.00		0.26	0.21	170.0
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	50	10,726	11,262	10,190				$97.43	$2.94		0.09	0.05	195.8
Sewage Sludge & Anaerobic Digestion - .085 MW	0.085	9,900	10,395	9,405				$214.84	$0.00		0	0.21	181.0
Bio Mass (Co-Fire)	500	8,980	9,429	8,531				$47.09	$1.69		0.09	0.05	197.8
Molten Carbonate Fuel Cell - 300 kW	0.3	8,059	8,462	7,656				$65.64	$4.70		0.00012	0.0025	118.0
Spark Ignition Engine - 5 MW	5	9,492	9,967	9,017				$170.12	$0.00		0.002	0.21	118.0
Hydroelectric - New - 30 MW	30	-	-	-				$39.37	$0.00			-	-
Ohio Falls 9-10	34	-	-	-				$10.38	$0.00			-	-

Emissions Allowance Prices

	SO_2 \$/ton	NO_x \$/ton	CO_2 \$/ton	
			Intermediate	High
2007	457	988	0.00	0.00
2008	457	988	0.00	0.00
2009	455	951	0.00	0.00
2010	480	2,366	0.00	0.00
2011	624	2,369	0.00	0.00
2012	649	2,372	4.61	40.71
2013	673	2,274	5.15	43.50
2014	733	2,250	5.73	45.07
2015	794	3,098	6.30	51.32
2016	855	3,092	7.04	53.08
2017	916	3,086	7.92	54.36
2018	977	3,122	8.96	55.91
2019	1,038	3,149	9.79	57.35
2020	1,099	3,177	10.42	59.20
2021	1,160	3,250	11.06	60.81
2022	1,221	3,282	11.70	62.30
2023	1,282	3,281	12.46	63.94
2024	1,343	3,123	13.24	66.03
2025	1,404	2,970	14.06	67.71
2026	1,431	3,026	14.92	69.40
2027	1,458	3,084	15.83	71.71
2028	1,486	3,143	16.77	73.59
2029	1,514	3,202	17.72	75.49
2030	1,543	3,263	18.85	77.89
2031	1,572	3,325	19.21	79.37
2032	1,602	3,388	19.57	80.88
2033	1,632	3,453	19.94	82.42
2034	1,663	3,518	20.32	83.98
2035	1,695	3,585	20.71	85.58
2036	1,727	3,653	21.10	87.20

Example calculation of SO_2 adder:

(NO_x and CO_2 adders are caculated similarly)

Using Supercritical Pulverized Coal Unit - High Sulfur, 750 MW

SO_2 Emission Rate = 0.09 lb SO_2 / mmBTU

2007 SO_2 \$/Ton = \$457

2007 SCPC-HS
SO_2 Cost Adder =

$$\frac{0.09\#SO_2}{\text{mmBtu}} * \frac{457\ \$}{\text{Ton } SO_2} * \frac{100\ \text{Cents}}{\$} * \frac{1\ \text{ton } SO_2}{2000\ \#}$$

2007 High Sulfur
SO_2 Cost Adder = 2.1 cents/mmBtu

Fuel Forecast for Screening Analysis

(Cents/MBtu)

	Base Fuel Costs								Low Fuel Costs								High Fuel Costs							
	High SO_2	PRB Coal	Gas	LFG	TDF	Bio-Mass	MSW Tip Fee	RDF	High SO_2	PRB Coal	Gas	LFG	TDF	Bio-Mass	MSW Tip Fee	RDF	High SO_2	PRB Coal	Gas	LFG	TDF	Bio-Mass	MSW Tip Fee	RDF
2007	[redacted]																							
2008																								
2009																								
2010																								
2011																								
2012																								
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LEVELIZATION EQUATIONS USED IN TECHNOLOGY SCREENING

The total levelized cost of a particular technology in a specific year at a specific capacity factor is comprised of (at most) five separate components. The five possible components are levelized capital cost, levelized fixed cost, levelized variable cost, levelized fuel cost and levelized charging cost. The actual components utilized in calculating total levelized cost vary from technology to technology. For example, some technologies may exclude the charging component while others exclude the fuel component. Basically, technologies fall into four categories: Those that...

I. Burn fuel only (i.e. Pulverized Coal, Gas Turbine)
II. Burn no fuel and utilize no "grid" energy (i.e. Solar, Wind)
III. Burn no fuel but utilize "grid" energy for charging (i.e. Battery, Pumped Hydro)
IV. Burn fuel during generation <u>and</u> utilize "grid" energy for charging (i.e. CAES)

A levelization factor (L_n) converts a series of payments that are made over "n" periods and subject to a constant apparent escalation rate into an equivalent levelized payment stream and is calculated as follows:

$$L_n = \frac{k\,(1-k^n)}{a_n\,(1-k)}$$ n = number of years = 30

$$k = \frac{1+e_a}{1+i}$$ e_a = apparent esc rate including inflation and real escalation (i.e., VO&M = 2.0%). See Exhibit 5.

$$a_n = \frac{(1+i)^n - 1}{i\,(1+i)^n}$$ i = Discount Rate = Present Value Rate = 7.14%

$$\text{Adj } L_n = L_n/(1+e_a)$$

The screening analysis utilizes the Adj. L_n. The Adj. L_n makes adjustments for beginning/ending year dollars to be consistent with the Companies' economic analysis methods. An Adj. L_n is calculated for the fixed, variable, fuel and charging costs only. The capital cost component does not utilize an Adj. L_n for levelization because it is levelized through a Fixed Charge Rate (FCR).

Definition of Variables:

Variable		Definition (Units)	Source
Year	=	Levelized Year - Base Year	Exhibit 5
Inst Cost	=	Installed Cost or Total Generic Unit Cost ($/kW)	Exhibit 3
FCR%	=	Fixed Charge Rate (%)	Exhibit 5
Cap Esc%	=	Capital Escalation Rate (%)	Exhibit 5
FO&M	=	Fixed O&M ($/kW)	Exhibit 3
VO&M	=	Variable O&M ($/MWh)	Exhibit 3
Fix Esc	=	Fixed O&M Escalation Rate (%)	Exhibit 5
Var Esc	=	Variable O&M Escalation Rate (%)	Exhibit 5
Fix Adj L_n	=	Fixed O&M Levelization Factor	Exhibit 5
Var Adj L_n	=	Variable O&M Levelization Factor	Exhibit 5
Fuel Adj L_n	=	Fuel Cost Levelization Factor	Base Fuel Only; Exhibit 5
Charge Adj L_n	=	Charging Cost Levelization Factor	Exhibit 5
CF%	=	Capacity Factor (%)	0-100 %
MW	=	Size of Technology (MW)	Exhibit 2 (a)
HR	=	Heat Rate (Btu/KWh)	Exhibit 2 (a)
FC	=	Fuel Cost ($/MBtu)	Exhibit 3
Avg Ld IO	=	Average Load (kWh In/kWh Out)	Exhibit 2 (a)
Charge	=	Charging Cost ($/MWh)	Exhibit 5
SO_2	=	SO_2 Adder (Cents/MBtu)	Exhibit 2(b)
NO_x	=	NO_x Adder (Cents/MBtu)	Exhibit 2(b)
CO_2	=	CO_2 Adder (Cents/MBtu)	Exhibit 2(b)

Exhibit 4 (cont.)

Cost Components of Technologies that:

1. **Burn Fuel Only**

$$Capital = Inst\ Cost \times FCR\,\% \times (1 + Cap\ Esc\,\%)^{\wedge Year}$$

$$Fixed = FO\,\&\,M \times (1 + Fix\ Esc\%)^{\wedge Year} \times Fix\ Adj\ L_n$$

$$Variable = \frac{(VO\,\&\,M) \times (1 + Var\ Esc\%)^{\wedge Year} \times CF\% \times 8760\ {}^{Hrs}\!/_{Year} \times MW}{MW \times 1000\ {}^{KW}\!/_{MW}} \times Var\ Adj\ L_n$$

$$Fuel = \frac{MW \times 1000\ {}^{KW}\!/_{MW} \times 8760\ {}^{Hrs}\!/_{Year} \times CF\% \times HR \times (FC + SO_2 + NO_x + CO_2)}{MW \times 1000\ {}^{KW}\!/_{MW} \times (10)^6\ {}^{BTU}\!/_{MBTU}} \times Fuel\ Adj\ L_n$$

2. **Burn No Fuel and No Charging Energy**

Use Capital, Fixed and Variable Equations from above.

3. **Burn No Fuel but Utilize Charging Energy**

Use Capital, Fixed and Variable Equations from above and Charging.

$$Charging = \frac{Avg\ Ld\ IO \times Charge \times MW \times 8760\ {}^{Hrs}\!/_{Year} \times CF\%}{MW \times 1000\ {}^{KW}\!/_{MW}} \times Charge\ Adj\ L_n$$

4. **Burn Fuel and Utilize Charging Energy**

Use Capital, Fixed, Variable, Fuel and Charging equations from above.

Adjusted L_n and Other Miscellaneous Data

(All Fuel prices are in Cents/MBtu)

Year	Cumulative F O&M Esc	Cumulative V O&M Esc	Cumulative Capital Esc	Cost Charging	
	1.72%	1.72%	2.10%	21.18	Base Yr ($/MWh) charging cost
				1.72%	Charging Esc.
2007	1 000	1 000	1 000	[redacted]	
2008	1 017	1 017	1 021	[redacted]	
2009	1 035	1 035	1 042	[redacted]	
2010	1 052	1 052	1 064	[redacted]	
2011	1 070	1 070	1 087	[redacted]	
2012	1 089	1 089	1 110	[redacted]	
2013	1 107	1 107	1 133	[redacted]	
2014	1 126	1 126	1 157	[redacted]	
2015	1 146	1 146	1 181	[redacted]	
2016	1 165	1 165	1 206	[redacted]	
2017	1 185	1 185	1 231	[redacted]	
2018	1 206	1 206	1 257	[redacted]	
2019	1 226	1 226	1 283	[redacted]	
2020	1 247	1 247	1 310	[redacted]	
2021	1 269	1 269	1 338	[redacted]	
2022	1 291	1 291	1 366	[redacted]	
2023	1 313	1 313	1 394	[redacted]	
2024	1 335	1 335	1 424	[redacted]	
2025	1 358	1 358	1 454	[redacted]	
2026	1 381	1 381	1 484	[redacted]	
2027	1 405	1 405	1 515	[redacted]	
2028	1 429	1 429	1 547	[redacted]	
2029	1 454	1 454	1 580	[redacted]	
2030	1 479	1 479	1 613	[redacted]	
2031	1 504	1 504	1 647	[redacted]	
2032	1 530	1 530	1 681	[redacted]	
2033	1 556	1 556	1 717	[redacted]	
2034	1 583	1 583	1 753	[redacted]	
2035	1 610	1 610	1 789	[redacted]	
2036	1 637	1 637	1 827	[redacted]	

Fuel Notes:

6/1/07 Fuel Forecast Used All fuel prices in cents per million Btu with the exception of charging which is in $/MWh

Charging cost base upon average cost of off-peak generation

		Fixed	*Variable*	*Capital*	Charging
Base Year =	2007				
Levelized Year =	2007				
Ea =		1 72%	1.72%	2 10%	[redacted]
PV Rate (i) =	7.65%				
k =		0 9431	0 9431	0 9467	[redacted]
n =	30				
An =	11 4190				
L_n =		1 201	1 201	1.254	[redacted]
Adj L_n =		1.181	1.181	1.229	[redacted]

Input

Not an Input

Calculated

Change "Levelized Year" to year desired for "Snapshot" year analysis

Change "n" to 1 for "Snapshot" year analysis and 30 for levelized analyis

Fixed Charge Rates by Technology

Coal	9 51%
Simple Cycle CT	10 59%
Combined Cycle CT	9 39%
Other	9 97%

Exhibit 6

30-Year Levelized Cost for All Technologies over All Capacity Factors

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- Base 2007 ($/kW yr)
Heat Rate- Base
Fuel Forecast- Base

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	147	210	273	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	221	279	337	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	140	231	323	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	172	290	408	526	644	762	880	998	1116	1234	1352
Simple Cycle GE 7EA CT - Peaking Capacity	128	267	405	544	683	821	960	1099	1237	1376	1515
Simple Cycle GE 7FA CT - Peaking Capacity	102	227	351	476	601	725	850	975	1099	1224	1349
Combined Cycle GE 7EA CT - Intermediate Load	191	273	354	436	518	599	681	763	844	926	1008
Combined Cycle GE 7FA CT - Intermediate Loac	144	215	287	358	430	501	572	644	715	786	858
Combined Cycle 2x1 GE 7FA CT - Intermediate Loac	122	193	264	336	407	478	549	620	692	763	834
Combined Cycle 3x1 GE 7FB CT - Intermediate Loac	104	175	245	316	386	457	528	598	669	739	810
Siemens 5000F CC CT - Intermediate Load	134	206	277	349	421	492	564	635	707	779	850
Humid Air Turbine Cycle CT - 366 MW	132	233	333	434	535	635	736	837	937	1038	----
Kalina Cycle CC CT - 282 MW	145	206	268	329	390	452	513	574	636	697	----
Cheng Cycle CT - 140 MW	151	225	299	373	447	521	595	669	742	816	----
Peaking Microturbine - 0.03 MW	422	590	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	456	597	738	879	1021	1162	1303	1444	1585	1726	1867
Subcritical Pulverized Coal - 250 MW	331	352	374	395	416	437	459	480	501	523	544
Subcritical Pulverized Coal - 500 MW	291	312	334	355	376	397	419	440	461	483	504
Subcritical Pulverized Coal, High Sulfur - 500 MW	297	317	337	357	377	397	417	437	457	477	497
Circulating Fluidized Bed - 250 MW	330	352	373	395	416	438	459	481	502	524	545
Circulating Fluidized Bed - 500 MW	293	314	336	357	379	400	421	443	464	486	507
Supercritical Pulverized Coal - 500 MW	299	319	339	359	379	399	419	439	459	479	499
Supercritical Pulverized Coal High Sulfur - 500 MW	303	322	342	361	380	400	419	438	458	477	496
Supercritical Pulverized Coal - 750 MW	277	298	318	339	359	380	400	421	441	462	482
Supercritical Pulverized Coal High Sulfur - 750 MW	280	299	319	338	357	377	396	416	435	454	474
Pressurized Fluidized Bed Combustior	412	436	461	485	510	534	559	583	608	----	----
1x1 IGCC	368	388	407	427	446	466	486	505	525	----	----
2x1 IGCC	327	347	366	386	405	425	444	464	483	----	----
2x1 IGCC, High Sulfur	327	345	363	382	400	418	436	454	473	----	----
Subcritical Pulverized Coal - 500 MW - CCS	524	555	585	616	646	677	708	738	769	799	830
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	532	561	590	619	648	677	706	735	764	793	823
Circulating Fluidized Bed - 500 MW - CCS	532	563	594	624	655	686	717	748	779	809	840
Supercritical Pulverized Coal - 500 MW - CCS	531	560	589	618	646	675	704	733	762	791	819
Supercritical Pulverized Coal. High Sulfur - 500 MW - CCS	538	566	593	621	649	677	704	732	760	788	815
Supercritical Pulverized Coal - 750 MW - CCS	501	530	559	588	617	646	675	704	733	762	791
Supercritical Pulverized Coal High Sulfur - 750 MW - CCS	505	533	560	588	615	643	670	698	725	753	780
1x1 IGCC - CCS	510	533	557	580	604	627	651	674	697	----	----
2x1 IGCC - CCS	462	485	509	532	556	579	603	626	649	----	----
2x1 IGCC High Sulfur - CCS	464	486	509	531	553	576	598	620	643	----	----
Wind Energy Conversion - 50 MW	259	248	237	225	----	----	----	----	----	----	----
Geothermal - 30 MW	484	480	476	472	467	462	456	449	442	435	428
Solar Photovoltaic - 50 kW	766	766	----	----	----	----	----	----	----	----	----
Solar Thermal Parabolic Trough - 100 MW	506	507	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	734	734	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	771	772	773	773	773	774	774	----	----	----	----
Solar Thermal Solar Chimney - 50 MW	646	646	646	645	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1741	1712	1683	1653	1624	1595	1566	1537	----	----	----
RDF Stoker-Fired - 7 MW	1665	1747	1829	1912	1994	2076	2158	2241	2323	----	----
Landfill Gas IC Engine - 5 MW	455	494	533	572	611	651	690	729	768	807	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	489	512	536	559	582	605	629	652	675	698	721
Sewage Sludge & Anaerobic Digestion - 085 MW	693	689	685	681	676	672	668	663	656	649	----
Bio Mass (Co-Fire)	324	344	363	383	402	422	441	461	480	500	519
Molten Carbonate Fuel Cell - 300 kW	463	542	621	701	780	859	938	1017	1096	1176	----
Spark Ignition Engine - 5 MW	402	491	580	669	758	847	936	1025	1114	1203	----
Hydroelectric - New - 30 MW	473	467	462	456	449	----	----	----	----	----	----
Ohio Falls 9-10	293	287	281	273	----	----	----	----	----	----	----
Minimum Levelized $/kW	102	175	237	225	357	377	396	416	435	435	428

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost-Low 2007 ($/kW yr)
Heat Rate-Low
Fuel Forecast-Low

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	134	197	260	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	201	259	317	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	128	204	280	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	158	243	329	414	499	585	670	755	841	926	1011
Simple Cycle GE 7EA CT - Peaking Capacity	118	216	314	412	510	608	706	804	902	1000	1098
Simple Cycle GE 7FA CT - Peaking Capacity	94	182	270	358	446	534	622	710	798	886	974
Combined Cycle GE 7EA CT - Intermediate Load	177	231	284	338	392	445	499	553	606	660	714
Combined Cycle GE 7FA CT - Intermediate Load	132	179	226	272	319	366	413	460	507	553	600
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	112	159	206	252	299	346	393	440	487	533	580
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	96	142	189	235	281	328	374	421	467	513	560
Siemens 5000F CC CT - Intermediate Load	124	171	218	265	312	359	406	453	500	547	594
Humid Air Turbine Cycle CT - 366 MW	123	188	254	319	385	450	516	581	646	712	----
Kalina Cycle CC CT - 282 MW	133	173	212	252	292	332	371	411	451	491	----
Cheng Cycle CT - 140 MW	139	188	236	285	334	383	431	480	529	578	----
Peaking Microturbine - 0 03 MW	398	517	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	430	522	614	705	797	889	981	1072	1164	1256	1348
Subcritical Pulverized Coal - 250 MW	305	325	345	365	385	405	426	446	466	486	506
Subcritical Pulverized Coal - 500 MW	267	287	307	327	347	367	387	407	427	447	467
Subcritical Pulverized Coal, High Sulfur - 500 MW	272	291	310	329	348	366	385	404	423	442	461
Circulating Fluidized Bed - 250 MW	303	323	343	364	384	404	424	444	465	485	505
Circulating Fluidized Bed - 500 MW	269	289	309	329	349	369	389	409	430	450	470
Supercritical Pulverized Coal - 500 MW	275	294	312	331	350	369	387	406	425	444	462
Supercritical Pulverized Coal High Sulfur - 500 MW	278	296	314	333	351	369	387	406	424	442	460
Supercritical Pulverized Coal - 750 MW	254	273	293	312	331	351	370	389	408	428	447
Supercritical Pulverized Coal. High Sulfur - 750 MW	256	274	292	310	329	347	365	383	401	419	438
Pressurized Fluidized Bed Combustion	364	387	410	433	456	479	502	525	549	----	----
1x1 IGCC	337	355	374	392	411	429	448	466	484	----	----
2x1 IGCC	300	318	337	355	373	392	410	428	446	----	----
2x1 IGCC, High Sulfur	299	316	333	350	367	385	402	419	436	----	----
Subcritical Pulverized Coal - 500 MW - CCS	478	507	536	564	593	622	651	680	709	737	766
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	486	513	541	568	596	623	650	678	705	732	760
Circulating Fluidized Bed - 500 MW - CCS	509	538	567	596	625	654	683	712	742	771	800
Supercritical Pulverized Coal - 500 MW - CCS	507	534	561	588	615	642	669	697	724	751	778
Supercritical Pulverized Coal. High Sulfur - 500 MW - CCS	514	540	566	593	619	645	671	697	724	750	776
Supercritical Pulverized Coal - 750 MW - CCS	479	506	534	561	588	615	643	670	697	725	752
Supercritical Pulverized Coal. High Sulfur - 750 MW - CCS	482	508	534	560	586	612	638	664	690	716	742
1x1 IGCC - CCS	488	510	532	554	576	599	621	643	665	----	----
2x1 IGCC - CCS	442	464	486	508	530	553	575	597	619	----	----
2x1 IGCC. High Sulfur - CCS	444	465	486	507	528	549	570	591	612	----	----
Wind Energy Conversion - 50 MW	238	227	216	203	----	----	----	----	----	----	----
Geothermal - 30 MW	443	439	435	431	426	421	414	407	400	393	386
Solar Photovoltaic - 50 kW	622	622	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	421	422	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	601	601	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	645	646	647	647	647	648	647	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	533	533	533	532	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1634	1610	1587	1563	1539	1515	1492	1468	----	----	----
RDF Stoker-Fired - 7 MW	1499	1576	1653	1730	1807	1884	1961	2038	2115	----	----
Landfill Gas IC Engine - 5 MW	422	445	469	492	516	539	563	586	610	633	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	451	473	495	517	538	560	582	604	625	647	669
Sewage Sludge & Anaerobic Digestion - 085 MW	627	623	619	614	610	605	601	595	588	581	----
Bio Mass (Co-Fire)	298	316	335	353	371	390	408	426	444	463	481
Molten Carbonate Fuel Cell - 300 kW	388	440	492	544	595	647	699	751	803	855	----
Spark Ignition Engine - 5 MW	383	440	496	553	610	667	723	780	837	893	----
Hydroelectric - New - 30 MW	409	403	398	392	384	----	----	----	----	----	----
Ohio Falls 9-10	279	273	267	259	----	----	----	----	----	----	----
Minimum Levelized $/kW	94	142	189	203	281	328	365	383	400	393	386

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost-Low 2007 ($/kW yr)
Heat Rate-Low
Fuel Forecast- Base

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	134	197	260	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	201	259	317	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	128	217	307	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	158	271	385	498	611	725	838	951	1065	1178	1291
Simple Cycle GE 7EA CT - Peaking Capacity	118	251	385	518	651	785	918	1051	1185	1318	1451
Simple Cycle GE 7FA CT - Peaking Capacity	94	213	333	452	571	691	810	929	1049	1168	1287
Combined Cycle GE 7EA CT - Intermediate Load	177	255	333	411	489	567	645	723	801	879	957
Combined Cycle GE 7FA CT - Intermediate Load	132	200	268	336	404	472	540	608	676	744	812
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	112	180	248	316	384	452	520	588	656	724	792
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	96	163	231	298	365	433	500	567	635	702	769
Siemens 5000F CC CT - Intermediate Load	124	192	261	329	397	466	534	603	671	739	808
Humid Air Turbine Cycle CT - 366 MW	123	219	315	411	506	602	698	794	890	986	----
Kalina Cycle CC CT - 282 MW	133	191	250	308	367	425	483	542	600	659	----
Cheng Cycle CT - 140 MW	139	209	280	350	421	491	562	632	703	773	----
Peaking Microturbine - 0.03 MW	398	559	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	430	564	699	833	968	1102	1237	1371	1505	1640	1774
Subcritical Pulverized Coal - 250 MW	305	325	346	366	387	407	428	448	468	489	509
Subcritical Pulverized Coal - 500 MW	267	287	308	328	348	368	389	409	429	450	470
Subcritical Pulverized Coal, High Sulfur - 500 MW	272	291	310	330	349	368	387	407	426	445	464
Circulating Fluidized Bed - 250 MW	303	324	344	365	385	406	426	447	467	488	508
Circulating Fluidized Bed - 500 MW	269	289	310	330	351	371	391	412	432	453	473
Supercritical Pulverized Coal - 500 MW	275	294	313	332	351	370	389	409	428	447	466
Supercritical Pulverized Coal. High Sulfur - 500 MW	278	297	315	334	352	371	389	408	426	445	463
Supercritical Pulverized Coal - 750 MW	*254*	*274*	*293*	*313*	*333*	*352*	*372*	*391*	*411*	*431*	*450*
Supercritical Pulverized Coal. High Sulfur - 750 MW	256	274	293	311	330	348	367	385	404	422	441
Pressurized Fluidized Bed Combustion	364	387	411	434	458	481	505	528	551	----	----
1x1 IGCC	337	356	375	393	412	431	450	469	487	----	----
2x1 IGCC	300	319	337	356	375	393	412	431	449	----	----
2x1 IGCC, High Sulfur	299	316	334	351	368	386	403	421	438	----	----
Subcritical Pulverized Coal - 500 MW - CCS	478	507	537	566	595	624	654	683	712	741	771
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	486	514	542	569	597	625	653	681	709	736	764
Circulating Fluidized Bed - 500 MW - CCS	509	539	568	598	627	657	686	716	745	775	804
Supercritical Pulverized Coal - 500 MW - CCS	507	535	562	590	617	645	672	700	727	755	782
Supercritical Pulverized Coal. High Sulfur - 500 MW - CCS	514	541	567	594	621	647	674	700	727	754	780
Supercritical Pulverized Coal - 750 MW - CCS	*479*	*507*	*534*	*562*	*590*	*618*	*645*	*673*	*701*	*729*	*756*
Supercritical Pulverized Coal. High Sulfur - 750 MW - CCS	482	508	535	561	588	614	640	667	693	720	746
1x1 IGCC - CCS	488	510	533	555	578	600	623	645	668	----	----
2x1 IGCC - CCS	442	464	487	509	532	554	577	599	622	----	----
2x1 IGCC. High Sulfur - CCS	444	465	487	508	530	551	572	594	615	----	----
Wind Energy Conversion - 50 MW	238	227	216	203	----	----	----	----	----	----	----
Geothermal - 30 MW	443	439	435	431	426	421	414	407	400	393	386
Solar Photovoltaic - 50 kW	622	622	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	421	422	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	601	601	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	645	646	647	647	647	648	647	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	*533*	*533*	*533*	*532*	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1634	1608	1582	1556	1530	1504	1478	1452	----	----	----
RDF Stoker-Fired - 7 MW	1499	1577	1656	1734	1813	1891	1970	2048	2127	----	----
Landfill Gas IC Engine - 5 MW	422	459	496	533	570	606	643	680	717	754	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	451	473	496	518	540	562	585	607	629	651	673
Sewage Sludge & Anaerobic Digestion - 085 MW	627	623	619	614	610	605	601	595	588	581	----
Bio Mass (Co-Fire)	298	317	335	354	373	391	410	428	447	466	484
Molten Carbonate Fuel Cell - 300 kW	388	463	539	614	690	765	841	916	992	1067	----
Spark Ignition Engine - 5 MW	383	468	552	637	721	806	890	975	1060	1144	----
Hydroelectric - New - 30 MW	409	403	398	392	384	----	----	----	----	----	----
Ohio Falls 9-10	279	273	267	259	----	----	----	----	----	----	----
Minimum Levelized $/kW	*94*	*163*	*216*	*203*	*330*	*348*	*367*	*385*	*400*	*393*	*386*

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost-Low **2007 ($/kW yr)**
Heat Rate-Low
Fuel Forecast- High

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	134	197	260	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	201	259	317	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	128	228	328	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	158	293	429	564	699	835	970	1105	1241	1376	1511
Simple Cycle GE 7EA CT - Peaking Capacity	118	279	439	600	761	921	1082	1243	1403	1564	1725
Simple Cycle GE 7FA CT - Peaking Capacity	94	238	382	526	670	814	958	1102	1246	1390	1534
Combined Cycle GE 7EA CT - Intermediate Load	177	274	371	468	564	661	758	855	952	1049	1145
Combined Cycle GE 7FA CT - Intermediate Load	132	217	301	386	470	555	639	724	808	893	978
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	112	196	281	365	450	534	618	703	787	871	956
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	96	180	263	347	430	514	598	681	765	849	932
Siemens 5000F CC CT - Intermediate Load	124	209	294	379	463	548	633	718	803	888	973
Humid Air Turbine Cycle CT - 366 MW	123	243	362	482	602	721	841	960	1080	1200	----
Kalina Cycle CC CT - 282 MW	133	206	279	352	425	498	571	643	716	789	----
Cheng Cycle CT - 140 MW	139	226	314	401	489	576	664	751	839	926	----
Peaking Microturbine - 0 03 MW	398	592	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	430	598	765	933	1101	1269	1436	1604	1772	1940	2107
Subcritical Pulverized Coal - 250 MW	305	326	348	369	391	412	433	455	476	498	519
Subcritical Pulverized Coal - 500 MW	267	288	310	331	352	373	395	416	437	459	480
Subcritical Pulverized Coal, High Sulfur - 500 MW	272	292	312	332	352	373	393	413	433	453	473
Circulating Fluidized Bed - 250 MW	303	325	346	368	389	411	432	454	475	497	518
Circulating Fluidized Bed - 500 MW	269	290	312	333	355	376	397	419	440	462	483
Supercritical Pulverized Coal - 500 MW	275	295	315	335	355	375	395	415	436	456	476
Supercritical Pulverized Coal. High Sulfur - 500 MW	278	297	317	336	356	375	395	414	434	453	472
Supercritical Pulverized Coal - 750 MW	254	275	295	316	336	357	378	398	419	440	460
Supercritical Pulverized Coal. High Sulfur - 750 MW	256	275	295	314	333	353	372	392	411	430	450
Pressurized Fluidized Bed Combustion	364	388	413	437	462	486	511	535	560	----	----
1x1 IGCC	337	357	376	396	415	435	455	474	494	----	----
2x1 IGCC	300	320	339	359	378	398	417	437	456	----	----
2x1 IGCC, High Sulfur	299	317	335	354	372	390	408	426	445	----	----
Subcritical Pulverized Coal - 500 MW - CCS	478	509	539	570	600	631	662	692	723	753	784
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	486	515	544	573	602	631	660	689	718	747	777
Circulating Fluidized Bed - 500 MW - CCS	509	540	571	601	632	663	694	725	756	786	817
Supercritical Pulverized Coal - 500 MW - CCS	507	536	565	594	622	651	680	709	738	767	795
Supercritical Pulverized Coal. High Sulfur - 500 MW - CCS	514	542	569	597	625	653	680	708	736	764	791
Supercritical Pulverized Coal - 750 MW - CCS	479	508	537	566	595	624	653	682	712	741	770
Supercritical Pulverized Coal. High Sulfur - 750 MW - CCS	482	510	537	565	592	620	647	675	702	730	757
1x1 IGCC - CCS	488	512	535	559	582	606	629	653	676	----	----
2x1 IGCC - CCS	442	466	489	513	536	560	583	607	630	----	----
2x1 IGCC. High Sulfur - CCS	444	466	489	511	533	556	578	600	623	----	----
Wind Energy Conversion - 50 MW	238	227	216	203	----	----	----	----	----	----	----
Geothermal - 30 MW	443	439	435	431	426	421	414	407	400	393	386
Solar Photovoltaic - 50 kW	622	622	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	421	422	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	601	601	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	645	646	647	647	647	648	647	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	533	533	533	532	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1634	1606	1577	1549	1521	1493	1464	1436	----	----	----
RDF Stoker-Fired - 7 MW	1499	1581	1664	1746	1829	1911	1994	2076	2159	----	----
Landfill Gas IC Engine - 5 MW	422	469	517	564	611	659	706	753	801	848	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	451	474	498	521	545	568	591	614	638	661	684
Sewage Sludge & Anaerobic Digestion - 085 MW	627	623	619	614	610	605	601	595	588	581	----
Bio Mass (Co-Fire)	298	318	337	357	376	396	415	435	454	473	493
Molten Carbonate Fuel Cell - 300 kW	388	482	576	669	763	857	951	1045	1139	1232	----
Spark Ignition Engine - 5 MW	383	489	596	702	808	914	1021	1127	1233	1339	----
Hydroelectric - New - 30 MW	409	403	398	392	384	----	----	----	----	----	----
Ohio Falls 9-10	279	273	267	259	----	----	----	----	----	----	----
Minimum Levelized $/kW	94	180	216	203	333	353	372	392	400	393	386

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost-Low 2007 ($/kW yr)
Heat Rate- Base
Fuel Forecast-Low

	Capacity Factors										
Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	134	197	260	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	201	259	317	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	128	205	283	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	159	247	335	423	511	599	687	775	863	951	1039
Simple Cycle GE 7EA CT - Peaking Capacity	119	220	322	423	524	626	727	828	930	1031	1132
Simple Cycle GE 7FA CT - Peaking Capacity	95	186	278	369	460	552	643	734	826	917	1008
Combined Cycle GE 7EA CT - Intermediate Load	178	234	290	347	403	459	515	571	627	684	740
Combined Cycle GE 7FA CT - Intermediate Load	133	182	231	280	329	379	428	477	526	575	624
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	113	162	211	260	309	358	407	456	504	553	602
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	97	145	194	242	291	339	388	436	485	533	582
Siemens 5000F CC CT - Intermediate Load	125	174	224	273	322	371	421	470	519	569	618
Humid Air Turbine Cycle CT - 366 MW	124	193	261	330	398	467	536	604	673	741	----
Kalina Cycle CC CT - 282 MW	134	176	217	259	300	342	384	425	467	508	----
Cheng Cycle CT - 140 MW	139	190	241	292	343	394	445	496	547	598	----
Peaking Microturbine - 0.03 MW	399	522	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0.03 MW	433	529	625	722	818	914	1010	1106	1202	1299	1395
Subcritical Pulverized Coal - 250 MW	305	326	347	368	389	410	431	452	473	494	515
Subcritical Pulverized Coal - 500 MW	*267*	*288*	*309*	*330*	*351*	*372*	*393*	*414*	*435*	*456*	*477*
Subcritical Pulverized Coal, High Sulfur - 500 MW	272	292	311	331	351	370	390	410	429	449	469
Circulating Fluidized Bed - 250 MW	303	324	345	367	388	409	430	451	472	494	515
Circulating Fluidized Bed - 500 MW	269	290	311	332	353	374	395	416	437	458	479
Supercritical Pulverized Coal - 500 MW	275	295	314	334	354	373	393	412	432	452	471
Supercritical Pulverized Coal, High Sulfur - 500 MW	278	297	316	335	354	374	393	412	431	450	469
Supercritical Pulverized Coal - 750 MW	254	274	294	315	335	355	375	395	415	436	456
Supercritical Pulverized Coal, High Sulfur - 750 MW	256	275	294	313	332	351	370	389	408	427	446
Pressurized Fluidized Bed Combustion	364	388	412	436	460	484	508	532	556	----	----
1x1 IGCC	337	356	376	395	414	433	453	472	491	----	----
2x1 IGCC	300	319	338	357	377	396	415	434	453	----	----
2x1 IGCC, High Sulfur	299	317	335	353	370	388	406	424	442	----	----
Subcritical Pulverized Coal - 500 MW - CCS	478	508	538	568	598	628	658	688	718	748	779
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	486	515	543	572	600	629	658	686	715	743	772
Circulating Fluidized Bed - 500 MW - CCS	509	539	570	600	630	660	691	721	751	782	812
Supercritical Pulverized Coal - 500 MW - CCS	507	535	564	592	620	648	677	705	733	762	790
Supercritical Pulverized Coal, High Sulfur - 500 MW - CCS	514	541	569	596	623	650	678	705	732	760	787
Supercritical Pulverized Coal - 750 MW - CCS	479	508	536	565	593	622	650	679	707	736	764
Supercritical Pulverized Coal, High Sulfur - 750 MW - CCS	482	509	536	563	590	617	644	672	699	726	753
1x1 IGCC - CCS	488	511	534	557	580	603	626	649	673	----	----
2x1 IGCC - CCS	442	465	488	511	534	557	580	603	627	----	----
2x1 IGCC, High Sulfur - CCS	444	466	488	510	532	554	576	598	620	----	----
Wind Energy Conversion - 50 MW	238	227	216	203	----	----	----	----	----	----	----
Geothermal - 30 MW	*443*	*439*	*435*	*431*	*426*	*421*	*414*	*407*	*400*	*393*	*386*
Solar Photovoltaic - 50 kW	622	622	----	----	----	----	----	----	----	----	----
Solar Thermal, Parabolic Trough - 100 MW	421	422	----	----	----	----	----	----	----	----	----
Solar Thermal, Parabolic Dish - 1.2 MW	601	601	----	----	----	----	----	----	----	----	----
Solar Thermal, Central Receiver - 50 MW	645	646	647	647	647	648	647	----	----	----	----
Solar Thermal, Solar Chimney - 50 MW	533	533	533	532	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1634	1607	1580	1554	1527	1500	1473	1446	----	----	----
RDF Stoker-Fired - 7 MW	1499	1580	1661	1741	1822	1903	1984	2065	2146	----	----
Landfill Gas IC Engine - 5 MW	422	447	472	497	522	547	572	597	622	647	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	451	474	497	520	543	566	589	611	634	657	680
Sewage Sludge & Anaerobic Digestion - .085 MW	627	623	619	615	610	606	602	596	589	582	----
Bio Mass (Co-Fire)	298	317	336	356	375	394	413	432	451	471	490
Molten Carbonate Fuel Cell - 300 kW	389	443	498	552	606	661	715	769	824	878	----
Spark Ignition Engine - 5 MW	385	445	504	564	624	683	743	803	862	922	----
Hydroelectric - New - 30 MW	409	403	398	392	384	----	----	----	----	----	----
Ohio Falls 9-10	*279*	*273*	*267*	*259*	----	----	----	----	----	----	----
Minimum Levelized $/kW	95	145	194	203	291	339	370	389	400	393	386

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost-Low **2007 ($/kW yr)**
Heat Rate- Base
Fuel Forecast- Base

					Capacity Factors						
Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	134	197	260	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	201	259	317	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	128	219	311	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	159	277	395	513	631	749	867	985	1103	1221	1339
Simple Cycle GE 7EA CT - Peaking Capacity	119	258	396	535	674	812	951	1090	1228	1367	1506
Simple Cycle GE 7FA CT - Peaking Capacity	95	220	344	469	594	718	843	968	1092	1217	1342
Combined Cycle GE 7EA CT - Intermediate Load	178	260	341	423	505	586	668	750	831	913	995
Combined Cycle GE 7FA CT - Intermediate Load	133	204	276	347	419	490	561	633	704	775	847
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	113	184	255	327	398	469	540	611	683	754	825
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	97	168	238	309	379	450	521	591	662	732	803
Siemens 5000F CC CT - Intermediate Load	125	197	268	340	412	483	555	626	698	770	*841*
Humid Air Turbine Cycle CT - 366 MW	124	225	325	426	527	627	728	829	929	1030	----
Kalina Cycle CC CT - 282 MW	134	195	257	318	379	441	502	563	625	686	----
Cheng Cycle CT - 140 MW	139	213	287	361	435	509	583	657	730	804	----
Peaking Microturbine - 0.03 MW	399	567	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	433	574	715	856	998	1139	1280	1421	1562	1703	1844
Subcritical Pulverized Coal - 250 MW	305	326	348	369	390	411	433	454	475	497	518
Subcritical Pulverized Coal - 500 MW	267	288	310	331	352	373	395	416	437	459	480
Subcritical Pulverized Coal, High Sulfur - 500 MW	272	292	312	332	352	372	392	412	432	452	472
Circulating Fluidized Bed - 250 MW	303	325	346	368	389	411	432	454	475	497	518
Circulating Fluidized Bed - 500 MW	269	290	312	333	355	376	397	419	440	462	483
Supercritical Pulverized Coal - 500 MW	275	295	315	335	355	375	395	415	435	455	475
Supercritical Pulverized Coal. High Sulfur - 500 MW	278	297	317	336	355	375	394	413	433	452	471
Supercritical Pulverized Coal - 750 MW	254	275	295	316	336	357	377	398	418	439	459
Supercritical Pulverized Coal. High Sulfur - 750 MW	256	275	295	314	333	353	372	392	411	430	450
Pressurized Fluidized Bed Combustion	364	388	413	437	*462*	*486*	*511*	*535*	*560*	----	----
1x1 IGCC	337	357	376	396	415	435	455	474	494	----	----
2x1 IGCC	300	320	339	359	378	398	417	437	456	----	----
2x1 IGCC, High Sulfur	299	317	335	354	372	390	408	426	445	----	----
Subcritical Pulverized Coal - 500 MW - CCS	478	509	539	570	600	631	662	692	723	753	784
Subcritical Pulverized Coal. High Sulfur - 500 MW - CCS	486	515	544	573	602	631	660	689	718	747	777
Circulating Fluidized Bed - 500 MW - CCS	509	540	571	601	632	663	694	725	756	786	817
Supercritical Pulverized Coal - 500 MW - CCS	507	536	565	594	622	651	680	709	738	767	795
Supercritical Pulverized Coal. High Sulfur - 500 MW - CCS	514	542	569	597	625	653	680	708	736	764	791
Supercritical Pulverized Coal - 750 MW - CCS	479	508	537	566	595	624	653	682	711	740	769
Supercritical Pulverized Coal. High Sulfur - 750 MW - CCS	482	510	537	565	592	620	647	675	702	730	757
1x1 IGCC - CCS	488	511	535	558	582	605	629	652	675	----	----
2x1 IGCC - CCS	442	465	489	512	536	559	583	606	629	----	----
2x1 IGCC. High Sulfur - CCS	444	466	489	511	533	556	578	600	623	----	----
Wind Energy Conversion - 50 MW	238	227	216	203	----	----	----	----	----	----	----
Geothermal - 30 MW	*443*	*439*	*435*	*431*	*426*	*421*	*414*	*407*	*400*	*393*	*386*
Solar Photovoltaic - 50 kW	622	622	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	421	422	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	601	601	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	645	646	647	647	647	648	647	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	533	533	533	532	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1634	1605	1576	1546	1517	1488	1459	1430	----	----	----
RDF Stoker-Fired - 7 MW	1499	1581	1663	1746	1828	1910	1992	2075	2157	----	----
Landfill Gas IC Engine - 5 MW	422	461	500	539	578	618	657	696	735	774	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	451	474	498	521	544	567	591	614	637	660	683
Sewage Sludge & Anaerobic Digestion - 085 MW	627	623	619	615	610	606	602	596	589	582	----
Bio Mass (Co-Fire)	298	318	337	357	376	396	415	435	454	474	493
Molten Carbonate Fuel Cell - 300 kW	389	468	547	627	706	785	864	943	1022	1102	----
Spark Ignition Engine - 5 MW	385	474	563	652	741	830	919	1008	1097	1186	----
Hydroelectric - New - 30 MW	409	403	398	392	384	----	----	----	----	----	----
Ohio Falls 9-10	*279*	*273*	*267*	*259*	----	----	----	----	----	----	----
Minimum Levelized $/kW	95	168	216	203	333	353	372	392	400	393	386

Exhibit 6

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost-Low **2007 ($/kW yr)**
Heat Rate- Base
Fuel Forecast- High

					Capacity Factors						
Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	134	197	260	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	201	259	317	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	128	231	333	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	159	300	440	581	722	862	1003	1144	1284	1425	1566
Simple Cycle GE 7EA CT - Peaking Capacity	119	286	454	621	788	956	1123	1290	1458	1625	1792
Simple Cycle GE 7FA CT - Peaking Capacity	95	246	396	547	698	848	999	1150	1300	1451	1602
Combined Cycle GE 7EA CT - Intermediate Load	178	280	381	483	585	686	788	890	991	1093	1195
Combined Cycle GE 7FA CT - Intermediate Load	133	222	311	399	488	577	666	754	843	932	1021
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	113	202	290	379	467	556	645	733	822	910	999
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	97	185	273	361	448	536	624	712	800	888	975
Siemens 5000F CC CT - Intermediate Load	125	214	303	392	481	570	660	749	838	927	1016
Humid Air Turbine Cycle CT - 366 MW	124	250	375	501	627	752	878	1003	1129	1255	----
Kalina Cycle CC CT - 282 MW	134	211	287	364	441	517	594	670	747	824	----
Cheng Cycle CT - 140 MW	139	231	323	414	506	598	690	782	874	965	----
Peaking Microturbine - 0.03 MW	399	602	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0.03 MW	433	609	785	962	1138	1314	1490	1666	1842	2019	2195
Subcritical Pulverized Coal - 250 MW	305	327	350	372	395	417	439	462	484	507	529
Subcritical Pulverized Coal - 500 MW	267	289	312	334	356	378	401	423	445	468	490
Subcritical Pulverized Coal, High Sulfur - 500 MW	272	293	314	335	356	377	398	419	440	461	482
Circulating Fluidized Bed - 250 MW	303	326	348	371	393	416	439	461	484	507	529
Circulating Fluidized Bed - 500 MW	269	291	314	336	359	381	403	426	448	471	493
Supercritical Pulverized Coal - 500 MW	275	296	317	338	359	380	401	422	443	464	485
Supercritical Pulverized Coal. High Sulfur - 500 MW	278	298	319	339	359	380	400	420	441	461	481
Supercritical Pulverized Coal - 750 MW	254	275	297	318	340	361	383	404	426	447	469
Supercritical Pulverized Coal. High Sulfur - 750 MW	256	276	296	317	337	357	377	398	418	438	458
Pressurized Fluidized Bed Combustion	364	390	415	441	466	492	517	543	569	----	----
1x1 IGCC	337	357	378	398	419	439	460	480	501	----	----
2x1 IGCC	300	320	341	361	382	402	423	443	464	----	----
2x1 IGCC, High Sulfur	299	318	337	356	375	394	413	432	451	----	----
Subcritical Pulverized Coal - 500 MW - CCS	478	510	542	574	606	638	670	702	734	766	798
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	486	516	547	577	608	638	668	699	729	760	790
Circulating Fluidized Bed - 500 MW - CCS	509	541	574	606	638	670	703	735	767	799	832
Supercritical Pulverized Coal - 500 MW - CCS	507	537	567	598	628	658	688	718	748	779	809
Supercritical Pulverized Coal. High Sulfur - 500 MW - CCS	514	543	572	601	630	659	688	717	746	775	804
Supercritical Pulverized Coal - 750 MW - CCS	479	509	540	570	601	631	661	692	722	752	783
Supercritical Pulverized Coal High Sulfur - 750 MW - CCS	482	511	539	568	597	626	654	683	712	741	769
1x1 IGCC - CCS	488	513	537	562	586	611	636	660	685	----	----
2x1 IGCC - CCS	442	467	491	516	540	565	590	614	639	----	----
2x1 IGCC. High Sulfur - CCS	444	467	491	514	538	561	585	608	631	----	----
Wind Energy Conversion - 50 MW	238	227	216	203	----	----	----	----	----	----	----
Geothermal - 30 MW	443	439	435	431	426	421	414	407	400	393	386
Solar Photovoltaic - 50 kW	622	622	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	421	422	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	601	601	----	----	----	----	----	----	----	----	----
Solar Thermal Central Receiver - 50 MW	645	646	647	647	647	648	647	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	533	533	533	532	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1634	1603	1571	1540	1508	1477	1445	1414	----	----	----
RDF Stoker-Fired - 7 MW	1499	1585	1672	1758	1845	1931	2018	2104	2191	----	----
Landfill Gas IC Engine - 5 MW	422	472	522	572	622	673	723	773	823	873	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	451	475	500	524	549	573	598	622	646	671	695
Sewage Sludge & Anaerobic Digestion - 085 MW	627	623	619	615	610	606	602	596	589	582	----
Bio Mass (Co-Fire)	298	319	339	360	380	401	421	442	462	482	503
Molten Carbonate Fuel Cell - 300 kW	389	488	586	685	783	882	980	1079	1177	1276	----
Spark Ignition Engine - 5 MW	385	497	609	720	832	944	1056	1168	1279	1391	----
Hydroelectric - New - 30 MW	409	403	398	392	384	----	----	----	----	----	----
Ohio Falls 9-10	279	273	267	259	----	----	----	----	----	----	----
Minimum Levelized $/kW	95	185	216	203	337	357	377	398	400	393	386

Exhibit 6

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost-Low **2007 ($/kW yr)**
Heat Rate- High
Fuel Forecast-Low

	Capacity Factors										
Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	134	197	260	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	201	259	317	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	128	207	286	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	160	251	343	434	525	617	708	799	891	982	1073
Simple Cycle GE 7EA CT - Peaking Capacity	120	225	331	436	541	647	752	857	963	1068	1173
Simple Cycle GE 7FA CT - Peaking Capacity	96	191	285	380	475	569	664	759	853	948	1043
Combined Cycle GE 7EA CT - Intermediate Load	179	238	297	356	414	473	532	591	650	709	767
Combined Cycle GE 7FA CT - Intermediate Load	134	185	236	288	339	390	441	493	544	595	646
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	114	165	216	268	319	370	421	472	524	575	626
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	97	148	199	249	300	351	402	452	503	554	605
Siemens 5000F CC CT - Intermediate Load	126	178	229	281	332	384	435	487	539	590	642
Humid Air Turbine Cycle CT - 366 MW	126	198	270	342	413	485	557	629	701	773	----
Kalina Cycle CC CT - 282 MW	134	178	221	265	308	352	395	439	482	526	----
Cheng Cycle CT - 140 MW	140	193	247	300	353	407	460	513	567	620	----
Peaking Microturbine - 0 03 MW	400	527	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	436	537	637	738	839	940	1040	1141	1242	1342	1443
Subcritical Pulverized Coal - 250 MW	305	327	349	371	392	414	436	458	480	502	523
Subcritical Pulverized Coal - 500 MW	*267*	*289*	*311*	*333*	*354*	*376*	*398*	*420*	*442*	*464*	*485*
Subcritical Pulverized Coal, High Sulfur - 500 MW	272	293	313	334	354	375	395	416	436	457	478
Circulating Fluidized Bed - 250 MW	303	325	347	369	391	413	435	457	480	502	524
Circulating Fluidized Bed - 500 MW	269	291	313	335	357	379	401	423	445	467	489
Supercritical Pulverized Coal - 500 MW	275	296	316	337	357	378	398	419	439	460	480
Supercritical Pulverized Coal. High Sulfur - 500 MW	278	298	318	338	358	377	397	417	437	457	477
Supercritical Pulverized Coal - 750 MW	254	275	296	317	338	359	380	401	422	444	465
Supercritical Pulverized Coal. High Sulfur - 750 MW	256	276	296	315	335	355	375	395	414	434	454
Pressurized Fluidized Bed Combustion	364	389	414	439	*464*	*489*	*515*	*540*	*565*	----	----
1x1 IGCC	337	357	377	397	417	437	458	478	498	----	----
2x1 IGCC	300	320	340	360	380	400	420	440	460	----	----
2x1 IGCC, High Sulfur	299	318	336	355	373	392	410	429	447	----	----
Subcritical Pulverized Coal - 500 MW - CCS	478	509	541	572	604	635	666	698	729	760	792
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	486	516	545	575	605	635	664	694	724	754	783
Circulating Fluidized Bed - 500 MW - CCS	509	541	572	604	635	667	699	730	762	793	825
Supercritical Pulverized Coal - 500 MW - CCS	507	537	566	596	625	655	684	714	743	773	802
Supercritical Pulverized Coal. High Sulfur - 500 MW - CCS	514	542	571	599	628	656	684	713	741	770	798
Supercritical Pulverized Coal - 750 MW - CCS	479	509	538	568	598	628	657	687	717	747	776
Supercritical Pulverized Coal High Sulfur - 750 MW - CCS	482	510	538	567	595	623	651	679	707	736	764
1x1 IGCC - CCS	488	512	536	560	585	609	633	657	681	----	----
2x1 IGCC - CCS	442	466	490	514	538	562	586	610	634	----	----
2x1 IGCC. High Sulfur - CCS	444	467	490	512	535	558	581	604	627	----	----
Wind Energy Conversion - 50 MW	238	227	216	203	----	----	----	----	----	----	----
Geothermal - 30 MW	*443*	*439*	*435*	*431*	*426*	*421*	*414*	*407*	*400*	*393*	*386*
Solar Photovoltaic - 50 kW	622	622	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	421	422	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	601	601	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	645	646	647	647	647	648	647	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	533	533	533	532	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1634	1604	1575	1545	1515	1485	1456	1426	----	----	----
RDF Stoker-Fired - 7 MW	1499	1583	1668	1752	1837	1921	2006	2090	2175	----	----
Landfill Gas IC Engine - 5 MW	422	449	475	502	528	555	581	608	634	661	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	451	475	499	523	547	571	595	618	642	666	690
Sewage Sludge & Anaerobic Digestion - 085 MW	627	623	619	615	611	607	602	597	590	583	----
Bio Mass (Co-Fire)	298	318	338	358	378	398	418	438	458	479	499
Molten Carbonate Fuel Cell - 300 kW	390	447	504	560	617	674	731	788	844	901	----
Spark Ignition Engine - 5 MW	386	449	512	574	637	700	763	825	888	951	----
Hydroelectric - New - 30 MW	409	403	398	392	384	----	----	----	----	----	----
Ohio Falls 9-10	*279*	*273*	*267*	*259*	----	----	----	----	----	----	----
Minimum Levelized $/kW	96	148	199	203	300	351	375	395	400	393	386

Exhibit 6

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost-Low **2007 ($/kW yr)**
Heat Rate- High
Fuel Forecast- Base

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	134	197	260	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	201	259	317	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	*128*	*222*	*316*	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	160	282	404	526	648	770	892	1014	1136	1258	1380
Simple Cycle GE 7EA CT - Peaking Capacity	120	264	408	552	696	840	984	1128	1272	1416	1560
Simple Cycle GE 7FA CT - Peaking Capacity	96	225	355	484	613	743	872	1001	1131	1260	1389
Combined Cycle GE 7EA CT - Intermediate Load	179	265	350	436	521	607	692	778	863	949	1034
Combined Cycle GE 7FA CT - Intermediate Load	134	209	283	358	433	507	582	656	731	806	880
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	114	189	263	338	412	487	562	636	711	786	860
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	97	171	245	319	392	466	540	614	688	762	836
Siemens 5000F CC CT - Intermediate Load	126	201	276	351	426	501	576	651	727	802	877
Humid Air Turbine Cycle CT - 366 MW	126	231	337	442	548	653	759	864	970	1075	----
Kalina Cycle CC CT - 282 MW	134	198	262	327	391	455	519	583	648	712	----
Cheng Cycle CT - 140 MW	140	217	295	372	449	527	604	681	759	836	----
Peaking Microturbine - 0.03 MW	400	575	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0.03 MW	436	584	732	880	1027	1175	1323	1471	1619	1767	1914
Subcritical Pulverized Coal - 250 MW	*305*	*327*	*350*	*372*	*394*	*416*	*439*	*461*	*483*	*506*	*528*
Subcritical Pulverized Coal - 500 MW	267	289	311	334	356	378	400	422	444	467	489
Subcritical Pulverized Coal, High Sulfur - 500 MW	272	293	314	335	356	376	397	418	439	460	481
Circulating Fluidized Bed - 250 MW	303	326	348	371	393	416	438	461	483	506	528
Circulating Fluidized Bed - 500 MW	269	291	314	336	358	380	403	425	447	470	492
Supercritical Pulverized Coal - 500 MW	275	296	317	338	358	379	400	421	442	463	483
Supercritical Pulverized Coal, High Sulfur - 500 MW	278	298	318	339	359	379	399	420	440	460	480
Supercritical Pulverized Coal - 750 MW	254	275	297	318	340	361	382	404	425	446	468
Supercritical Pulverized Coal, High Sulfur - 750 MW	256	276	296	316	337	357	377	397	417	437	457
Pressurized Fluidized Bed Combustion	364	390	415	441	466	492	517	543	569	----	----
1x1 IGCC	337	357	378	398	419	439	460	480	501	----	----
2x1 IGCC	300	320	341	361	381	402	422	442	463	----	----
2x1 IGCC, High Sulfur	299	318	337	356	375	394	412	431	450	----	----
Subcritical Pulverized Coal - 500 MW - CCS	478	510	542	573	605	637	669	701	733	764	796
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	486	516	547	577	607	637	668	698	728	759	789
Circulating Fluidized Bed - 500 MW - CCS	509	541	573	605	638	670	702	734	766	798	831
Supercritical Pulverized Coal - 500 MW - CCS	507	537	567	597	627	657	687	717	747	778	808
Supercritical Pulverized Coal, High Sulfur - 500 MW - CCS	514	543	572	601	629	658	687	716	745	774	802
Supercritical Pulverized Coal - 750 MW - CCS	479	509	540	570	600	630	661	691	721	752	782
Supercritical Pulverized Coal, High Sulfur - 750 MW - CCS	482	511	539	568	596	625	654	682	711	740	768
1x1 IGCC - CCS	488	512	537	561	586	610	635	659	684	----	----
2x1 IGCC - CCS	442	466	491	515	540	564	589	613	638	----	----
2x1 IGCC, High Sulfur - CCS	444	467	491	514	537	561	584	607	630	----	----
Wind Energy Conversion - 50 MW	*238*	*227*	*216*	*203*	----	----	----	----	----	----	----
Geothermal - 30 MW	443	439	435	431	426	421	414	407	400	393	386
Solar Photovoltaic - 50 kW	622	622	----	----	----	----	----	----	----	----	----
Solar Thermal, Parabolic Trough - 100 MW	421	422	----	----	----	----	----	----	----	----	----
Solar Thermal, Parabolic Dish - 1.2 MW	601	601	----	----	----	----	----	----	----	----	----
Solar Thermal, Central Receiver - 50 MW	645	646	647	647	647	648	647	----	----	----	----
Solar Thermal, Solar Chimney - 50 MW	533	533	533	532	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1634	1602	1569	1537	1504	1472	1440	1407	----	----	----
RDF Stoker-Fired - 7 MW	1499	1585	1671	1757	1843	1929	2015	2101	2187	----	----
Landfill Gas IC Engine - 5 MW	422	463	505	546	587	629	670	711	753	794	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	451	475	500	524	548	573	597	621	646	670	694
Sewage Sludge & Anaerobic Digestion - .085 MW	627	623	619	615	611	607	602	597	590	583	----
Bio Mass (Co-Fire)	298	318	339	359	380	400	420	441	461	481	502
Molten Carbonate Fuel Cell - 300 kW	390	473	556	639	722	804	887	970	1053	1136	----
Spark Ignition Engine - 5 MW	386	479	573	666	760	853	946	1040	1133	1227	----
Hydroelectric - New - 30 MW	*409*	*403*	*398*	*392*	*384*	----	----	----	----	----	----
Ohio Falls 9-10	279	273	267	259	----	----	----	----	----	----	----
Minimum Levelized $/kW	96	171	216	203	337	357	377	397	400	393	386

Exhibit 6

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost-Low — **2007 ($/kW yr)**
Heat Rate- High
Fuel Forecast- High

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	134	197	260	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	201	259	317	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	128	233	339	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	160	307	453	600	747	893	1040	1187	1333	1480	1627
Simple Cycle GE 7EA CT - Peaking Capacity	120	295	469	644	819	993	1168	1343	1517	1692	1867
Simple Cycle GE 7FA CT - Peaking Capacity	96	253	409	566	723	879	1036	1193	1349	1506	1663
Combined Cycle GE 7EA CT - Intermediate Load	179	285	392	498	604	711	817	923	1030	1136	1242
Combined Cycle GE 7FA CT - Intermediate Load	134	227	320	413	505	598	691	784	877	970	1062
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	114	207	300	392	485	578	671	764	857	949	1042
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	97	189	281	373	465	557	649	742	834	926	1018
Siemens 5000F CC CT - Intermediate Load	126	219	313	406	499	593	686	779	873	966	1059
Humid Air Turbine Cycle CT - 366 MW	126	258	389	521	652	784	916	1047	1179	1311	----
Kalina Cycle CC CT - 282 MW	134	214	295	375	455	536	616	696	777	857	----
Cheng Cycle CT - 140 MW	140	236	332	429	525	621	717	813	909	1006	----
Peaking Microturbine - 0 03 MW	400	611	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	436	621	805	990	1175	1359	1544	1728	1913	2098	2282
Subcritical Pulverized Coal - 250 MW	305	328	352	375	399	422	445	469	492	515	539
Subcritical Pulverized Coal - 500 MW	267	290	314	337	360	383	407	430	453	477	500
Subcritical Pulverized Coal, High Sulfur - 500 MW	272	294	316	338	360	382	403	425	447	469	491
Circulating Fluidized Bed - 250 MW	303	327	350	374	397	421	445	468	492	515	539
Circulating Fluidized Bed - 500 MW	269	292	316	339	363	386	409	433	456	480	503
Supercritical Pulverized Coal - 500 MW	275	297	319	341	363	385	407	429	451	473	495
Supercritical Pulverized Coal High Sulfur - 500 MW	278	299	320	342	363	384	405	427	448	469	490
Supercritical Pulverized Coal - 750 MW	254	276	299	321	344	366	389	411	434	456	479
Supercritical Pulverized Coal. High Sulfur - 750 MW	256	277	298	319	340	362	383	404	425	446	467
Pressurized Fluidized Bed Combustion	364	391	418	444	471	498	525	551	578	----	----
1x1 IGCC	337	358	380	401	423	444	465	487	508	----	----
2x1 IGCC	300	321	343	364	385	406	428	449	470	----	----
2x1 IGCC, High Sulfur	299	319	339	359	378	398	418	438	458	----	----
Subcritical Pulverized Coal - 500 MW - CCS	478	511	545	578	612	645	678	712	745	778	812
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	486	518	549	581	612	644	676	707	739	771	802
Circulating Fluidized Bed - 500 MW - CCS	509	543	576	610	643	677	711	744	778	811	845
Supercritical Pulverized Coal - 500 MW - CCS	507	538	570	601	633	664	696	727	759	790	822
Supercritical Pulverized Coal. High Sulfur - 500 MW - CCS	*514*	*544*	*574*	*605*	*635*	*665*	*695*	*725*	*755*	*786*	*816*
Supercritical Pulverized Coal - 750 MW - CCS	479	511	542	574	605	637	669	700	732	763	795
Supercritical Pulverized Coal. High Sulfur - 750 MW - CCS	482	512	542	572	602	632	662	692	722	752	781
1x1 IGCC - CCS	488	514	539	565	591	616	642	668	693	----	----
2x1 IGCC - CCS	442	468	493	519	545	570	596	622	647	----	----
2x1 IGCC. High Sulfur - CCS	444	468	493	517	542	566	590	615	639	----	----
Wind Energy Conversion - 50 MW	238	227	216	203	----	----	----	----	----	----	----
Geothermal - 30 MW	443	439	435	431	426	421	414	407	400	393	386
Solar Photovoltaic - 50 kW	622	622	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - *100 MW*	*421*	*422*	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	601	601	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	645	646	647	647	647	648	647	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	533	533	533	532	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1634	1599	1564	1530	1495	1460	1425	1390	----	----	----
RDF Stoker-Fired - 7 MW	1499	1589	1680	1770	1861	1951	2042	2132	2223	----	----
Landfill Gas IC Engine - 5 MW	422	475	528	581	634	686	739	792	845	898	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	451	477	502	528	553	579	604	630	655	681	706
Sewage Sludge & Anaerobic Digestion - 085 MW	627	623	619	615	611	607	602	597	590	583	----
Bio Mass (Co-Fire)	*298*	*320*	*341*	*363*	*384*	*406*	*427*	449	*470*	491	513
Molten Carbonate Fuel Cell - 300 kW	390	493	596	700	803	906	1009	1112	1216	1319	----
Spark Ignition Engine - 5 MW	386	503	621	738	856	973	1091	1208	1326	1443	----
Hydroelectric - New - 30 MW	409	403	398	392	384	----	----	----	----	----	----
Ohio Falls 9-10	279	273	267	259	----	----	----	----	----	----	----
Minimum Levelized $/kW	96	189	216	203	340	362	383	404	400	393	386

Exhibit 6

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- Base 2007 ($/kW yr)
Heat Rate-Low
Fuel Forecast-Low

	Capacity Factors										
Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	147	210	273	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	221	279	337	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	140	216	292	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	171	256	342	427	512	598	683	768	854	939	1024
Simple Cycle GE 7EA CT - Peaking Capacity	127	225	323	421	519	617	715	813	911	1009	1107
Simple Cycle GE 7FA CT - Peaking Capacity	101	189	277	365	453	541	629	717	805	893	981
Combined Cycle GE 7EA CT - Intermediate Load	190	244	297	351	405	458	512	566	619	673	727
Combined Cycle GE 7FA CT - Intermediate Load	143	190	237	283	330	377	424	471	518	564	611
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	121	168	215	261	308	355	402	449	496	542	589
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	103	149	196	242	288	335	381	428	474	520	567
Siemens 5000F CC CT - Intermediate Load	133	180	227	274	321	368	415	462	509	556	603
Humid Air Turbine Cycle CT - 366 MW	131	196	262	327	393	458	524	589	654	720	----
Kalina Cycle CC CT - 282 MW	144	184	223	263	303	343	382	422	462	502	----
Cheng Cycle CT - 140 MW	151	200	248	297	346	395	443	492	541	590	----
Peaking Microturbine - 0 03 MW	421	540	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	453	545	637	728	820	912	1004	1095	1187	1279	1371
Subcritical Pulverized Coal - 250 MW	331	351	371	391	411	431	452	472	492	512	532
Subcritical Pulverized Coal - 500 MW	291	311	331	351	371	391	411	431	451	471	491
Subcritical Pulverized Coal, High Sulfur - 500 MW	297	316	335	354	373	391	410	429	448	467	486
Circulating Fluidized Bed - 250 MW	330	350	370	391	411	431	451	471	492	512	532
Circulating Fluidized Bed - 500 MW	293	313	333	353	373	393	413	433	454	474	494
Supercritical Pulverized Coal - 500 MW	299	318	336	355	374	393	411	430	449	468	486
Supercritical Pulverized Coal. High Sulfur - 500 MW	303	321	339	358	376	394	412	431	449	467	485
Supercritical Pulverized Coal - 750 MW	277	296	316	335	354	374	393	412	431	451	470
Supercritical Pulverized Coal. High Sulfur - 750 MW	280	298	316	334	353	371	389	407	425	443	462
Pressurized Fluidized Bed Combustion	412	435	458	481	504	527	550	573	597	----	----
1x1 IGCC	368	386	405	423	442	460	479	497	515	----	----
2x1 IGCC	327	345	364	382	400	419	437	455	473	----	----
2x1 IGCC, High Sulfur	327	344	361	378	395	413	430	447	464	----	----
Subcritical Pulverized Coal - 500 MW - CCS	524	553	582	610	639	668	697	726	755	783	812
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	532	559	587	614	642	669	696	724	751	778	806
Circulating Fluidized Bed - 500 MW - CCS	532	561	590	619	648	677	706	735	765	794	823
Supercritical Pulverized Coal - 500 MW - CCS	531	558	585	612	639	666	693	721	748	775	802
Supercritical Pulverized Coal. High Sulfur - 500 MW - CCS	538	564	590	617	643	669	695	721	748	774	800
Supercritical Pulverized Coal - 750 MW - CCS	501	528	556	583	610	637	665	692	719	747	774
Supercritical Pulverized Coal High Sulfur - 750 MW - CCS	505	531	557	583	609	635	661	687	713	739	765
1x1 IGCC - CCS	510	532	554	576	598	621	643	665	687	----	----
2x1 IGCC - CCS	462	484	506	528	550	573	595	617	639	----	----
2x1 IGCC. High Sulfur - CCS	464	485	506	527	548	569	590	611	632	----	----
Wind Energy Conversion - 50 MW	259	248	237	225	----	----	----	----	----	----	----
Geothermal - 30 MW	484	480	476	472	467	462	456	449	442	435	428
Solar Photovoltaic - 50 kW	766	766	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	506	507	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	734	734	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	771	772	773	773	773	774	774	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	646	646	646	645	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1741	1717	1694	1670	1646	1622	1599	1575	----	----	----
RDF Stoker-Fired - 7 MW	1665	1742	1819	1896	1973	2050	2127	2204	2281	----	----
Landfill Gas IC Engine - 5 MW	455	478	502	525	549	572	596	619	643	666	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	489	511	533	555	576	598	620	642	664	685	707
Sewage Sludge & Anaerobic Digestion - 085 MW	693	689	685	680	676	672	667	662	655	648	----
Bio Mass (Co-Fire)	324	342	361	379	397	416	434	452	470	489	507
Molten Carbonate Fuel Cell - 300 kW	462	514	566	618	669	721	773	825	877	929	----
Spark Ignition Engine - 5 MW	400	457	513	570	627	684	740	797	854	910	----
Hydroelectric - New - 30 MW	473	467	462	456	449	----	----	----	----	----	----
Ohio Falls 9-10	293	287	281	273	----	----	----	----	----	----	----
Minimum Levelized $/kW	101	149	196	225	288	335	381	407	425	435	428

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- Base 2007 ($/kW yr)
Heat Rate-Low
Fuel Forecast- Base

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	147	210	273	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	221	279	337	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	140	229	319	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	171	284	398	511	624	738	851	964	1078	1191	1304
Simple Cycle GE 7EA CT - Peaking Capacity	127	260	394	527	660	794	927	1060	1194	1327	1460
Simple Cycle GE 7FA CT - Peaking Capacity	101	220	340	459	578	698	817	936	1056	1175	1294
Combined Cycle GE 7EA CT - Intermediate Load	190	268	346	424	502	580	658	736	814	892	970
Combined Cycle GE 7FA CT - Intermediate Load	143	211	279	347	415	483	551	619	687	755	823
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	121	189	257	325	393	461	529	597	665	733	801
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	103	170	238	305	372	440	507	574	642	709	776
Siemens 5000F CC CT - Intermediate Load	133	201	270	338	406	475	543	612	680	748	817
Humid Air Turbine Cycle CT - 366 MW	131	227	323	419	514	610	706	802	898	994	----
Kalina Cycle CC CT - 282 MW	144	202	261	319	378	436	494	553	611	670	----
Cheng Cycle CT - 140 MW	151	221	292	362	433	503	574	644	715	785	----
Peaking Microturbine - 0 03 MW	421	582	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	453	587	722	856	991	1125	1260	1394	1528	1663	1797
Subcritical Pulverized Coal - 250 MW	331	351	372	392	413	433	454	474	494	515	535
Subcritical Pulverized Coal - 500 MW	291	311	332	352	372	392	413	433	453	474	494
Subcritical Pulverized Coal, High Sulfur - 500 MW	297	316	335	355	374	393	412	432	451	470	489
Circulating Fluidized Bed - 250 MW	330	351	371	392	412	433	453	474	494	515	535
Circulating Fluidized Bed - 500 MW	293	313	334	354	375	395	415	436	456	477	497
Supercritical Pulverized Coal - 500 MW	299	318	337	356	375	394	413	433	452	471	490
Supercritical Pulverized Coal. High Sulfur - 500 MW	303	322	340	359	377	396	414	433	451	470	488
Supercritical Pulverized Coal - 750 MW	277	297	316	336	356	375	395	414	434	454	473
Supercritical Pulverized Coal. High Sulfur - 750 MW	280	298	317	335	354	372	391	409	428	446	465
Pressurized Fluidized Bed Combustion	412	435	459	482	506	529	553	576	599	----	----
1x1 IGCC	368	387	406	424	443	462	481	500	518	----	----
2x1 IGCC	327	346	364	383	402	420	439	458	476	----	----
2x1 IGCC, High Sulfur	327	344	362	379	396	414	431	449	466	----	----
Subcritical Pulverized Coal - 500 MW - CCS	524	553	583	612	641	670	700	729	758	787	817
Subcritical Pulverized Coal. High Sulfur - 500 MW - CCS	532	560	588	615	643	671	699	727	755	782	810
Circulating Fluidized Bed - 500 MW - CCS	532	562	591	621	650	680	709	739	768	798	827
Supercritical Pulverized Coal - 500 MW - CCS	531	559	586	614	641	669	696	724	751	779	806
Supercritical Pulverized Coal. High Sulfur - 500 MW - CCS	538	565	591	618	645	671	698	724	751	778	804
Supercritical Pulverized Coal - 750 MW - CCS	501	529	556	584	612	640	667	695	723	751	778
Supercritical Pulverized Coal. High Sulfur - 750 MW - CCS	505	531	558	584	611	637	663	690	716	743	769
1x1 IGCC - CCS	510	532	555	577	600	622	645	667	690	----	----
2x1 IGCC - CCS	462	484	507	529	552	574	597	619	642	----	----
2x1 IGCC. High Sulfur - CCS	464	485	507	528	550	571	592	614	635	----	----
Wind Energy Conversion - 50 MW	259	248	237	225	----	----	----	----	----	----	----
Geothermal - 30 MW	*484*	*480*	*476*	*472*	*467*	*462*	*456*	*449*	*442*	*435*	*428*
Solar Photovoltaic - 50 kW	766	766	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	506	507	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	734	734	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	771	772	773	773	773	774	774	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	646	646	646	645	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1741	1715	1689	1663	1637	1611	1585	1559	----	----	----
RDF Stoker-Fired - 7 MW	1665	1743	1822	1900	1979	2057	2136	2214	2293	----	----
Landfill Gas IC Engine - 5 MW	455	492	529	566	603	639	676	713	750	787	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	489	511	534	556	578	600	623	645	667	689	711
Sewage Sludge & Anaerobic Digestion - 085 MW	693	689	685	680	676	672	667	662	655	648	----
Bio Mass (Co-Fire)	324	343	361	380	399	417	436	454	473	492	510
Molten Carbonate Fuel Cell - 300 kW	462	537	613	688	764	839	915	990	1066	1141	----
Spark Ignition Engine - 5 MW	400	485	569	654	738	823	907	992	1077	1161	----
Hydroelectric - New - 30 MW	473	467	462	456	449	----	----	----	----	----	----
Ohio Falls 9-10	*293*	*287*	*281*	*273*	----	----	----	----	----	----	----
Minimum Levelized $/kW	101	170	237	225	354	372	391	409	428	435	428

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- Base 2007 ($/kW yr)
Heat Rate-Low
Fuel Forecast- High

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	147	210	273	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	221	279	337	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	140	240	340	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	171	306	442	577	712	848	983	1118	1254	1389	1524
Simple Cycle GE 7EA CT - Peaking Capacity	127	288	448	609	770	930	1091	1252	1412	1573	1734
Simple Cycle GE 7FA CT - Peaking Capacity	101	245	389	533	677	821	965	1109	1253	1397	1541
Combined Cycle GE 7EA CT - Intermediate Load	190	287	384	481	577	674	771	868	965	1062	1158
Combined Cycle GE 7FA CT - Intermediate Load	143	228	312	397	481	566	650	735	819	904	989
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	121	205	290	374	459	543	627	712	796	880	965
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	103	187	270	354	437	521	605	688	772	856	939
Siemens 5000F CC CT - Intermediate Load	133	218	303	388	472	557	642	727	812	897	982
Humid Air Turbine Cycle CT - 366 MW	131	251	370	490	610	729	849	968	1088	1208	----
Kalina Cycle CC CT - 282 MW	144	217	290	363	436	509	582	654	727	800	----
Cheng Cycle CT - 140 MW	151	238	326	413	501	588	676	763	851	938	----
Peaking Microturbine - 0.03 MW	421	615	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	453	621	788	956	1124	1292	1459	1627	1795	1963	2130
Subcritical Pulverized Coal - 250 MW	331	352	374	395	417	438	459	481	502	524	545
Subcritical Pulverized Coal - 500 MW	291	312	334	355	376	397	419	440	461	483	504
Subcritical Pulverized Coal, High Sulfur - 500 MW	297	317	337	357	377	398	418	438	458	478	498
Circulating Fluidized Bed - 250 MW	330	352	373	395	416	438	459	481	502	524	545
Circulating Fluidized Bed - 500 MW	293	314	336	357	379	400	421	443	464	486	507
Supercritical Pulverized Coal - 500 MW	299	319	339	359	379	399	419	439	460	480	500
Supercritical Pulverized Coal. High Sulfur - 500 MW	303	322	342	361	381	400	420	439	459	478	497
Supercritical Pulverized Coal - 750 MW	277	298	318	339	359	380	401	421	442	463	483
Supercritical Pulverized Coal. High Sulfur - 750 MW	280	299	319	338	357	377	396	416	435	454	474
Pressurized Fluidized Bed Combustion	412	436	461	485	510	534	559	583	608	----	----
1x1 IGCC	368	388	407	427	446	466	486	505	525	----	----
2x1 IGCC	327	347	366	386	405	425	444	464	483	----	----
2x1 IGCC, High Sulfur	327	345	363	382	400	418	436	454	473	----	----
Subcritical Pulverized Coal - 500 MW - CCS	524	555	585	616	646	677	708	738	769	799	830
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	532	561	590	619	648	677	706	735	764	793	823
Circulating Fluidized Bed - 500 MW - CCS	532	563	594	624	655	686	717	748	779	809	840
Supercritical Pulverized Coal - 500 MW - CCS	531	560	589	618	646	675	704	733	762	791	819
Supercritical Pulverized Coal. High Sulfur - 500 MW - CCS	538	566	593	621	649	677	704	732	760	788	815
Supercritical Pulverized Coal - 750 MW - CCS	*501*	*530*	*559*	*588*	*617*	*646*	*675*	*704*	*734*	*763*	*792*
Supercritical Pulverized Coal. High Sulfur - 750 MW - CCS	505	533	560	588	615	643	670	698	725	753	780
1x1 IGCC - CCS	510	534	557	581	604	628	651	675	698	----	----
2x1 IGCC - CCS	462	486	509	533	556	580	603	627	650	----	----
2x1 IGCC. High Sulfur - CCS	464	486	509	531	553	576	598	620	643	----	----
Wind Energy Conversion - 50 MW	259	248	237	225	----	----	----	----	----	----	----
Geothermal - 30 MW	484	480	476	472	467	462	456	449	442	435	428
Solar Photovoltaic - 50 kW	766	766	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	506	507	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	734	734	----	----	----	----	----	----	----	----	----
Solar Thermal Central Receiver - 50 MW	771	772	773	773	773	774	774	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	*646*	*646*	*646*	*645*	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1741	1713	1684	1656	1628	1600	1571	1543	----	----	----
RDF Stoker-Fired - 7 MW	1665	1747	1830	1912	1995	2077	2160	2242	2325	----	----
Landfill Gas IC Engine - 5 MW	455	502	550	597	644	692	739	786	834	881	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	489	512	536	559	583	606	629	653	676	699	722
Sewage Sludge & Anaerobic Digestion - 085 MW	693	689	685	680	676	672	667	662	655	648	----
Bio Mass (Co-Fire)	324	344	363	383	402	422	441	461	480	500	519
Molten Carbonate Fuel Cell - 300 kW	462	556	650	743	837	931	1025	1119	1213	1306	----
Spark Ignition Engine - 5 MW	400	506	613	719	825	931	1038	1144	1250	1356	----
Hydroelectric - New - 30 MW	473	467	462	456	449	----	----	----	----	----	----
Ohio Falls 9-10	293	287	281	273	----	----	----	----	----	----	----
Minimum Levelized $/kW	*101*	*187*	*237*	*225*	*357*	*377*	*396*	*416*	*435*	*435*	*428*

Exhibit 6

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- Base 2007 ($/kW yr)
Heat Rate- Base
Fuel Forecast-Low

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	147	210	273	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	221	279	337	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	140	217	295	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	172	260	348	436	524	612	700	788	876	964	1052
Simple Cycle GE 7EA CT - Peaking Capacity	128	229	331	432	533	635	736	837	939	1040	1141
Simple Cycle GE 7FA CT - Peaking Capacity	102	193	285	376	467	559	650	741	833	924	1015
Combined Cycle GE 7EA CT - Intermediate Load	191	247	303	360	416	472	528	584	640	697	753
Combined Cycle GE 7FA CT - Intermediate Load	144	193	242	291	340	390	439	488	537	586	635
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	122	171	220	269	318	367	416	465	513	562	611
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	104	152	201	249	298	346	395	443	492	540	589
Siemens 5000F CC CT - Intermediate Load	134	183	233	282	331	380	430	479	528	578	627
Humid Air Turbine Cycle CT - 366 MW	132	201	269	338	406	475	544	612	681	749	----
Kalina Cycle CC CT - 282 MW	145	187	228	270	311	353	395	436	478	519	----
Cheng Cycle CT - 140 MW	151	202	253	304	355	406	457	508	559	610	----
Peaking Microturbine - 0 03 MW	422	545	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	456	552	648	745	841	937	1033	1129	1225	1322	1418
Subcritical Pulverized Coal - 250 MW	331	352	373	394	415	436	457	478	499	520	541
Subcritical Pulverized Coal - 500 MW	291	312	333	354	375	396	417	438	459	480	501
Subcritical Pulverized Coal, High Sulfur - 500 MW	297	317	336	356	376	395	415	435	454	474	494
Circulating Fluidized Bed - 250 MW	330	351	372	394	415	436	457	478	499	521	542
Circulating Fluidized Bed - 500 MW	293	314	335	356	377	398	419	440	461	482	503
Supercritical Pulverized Coal - 500 MW	299	319	338	358	378	397	417	436	456	476	495
Supercritical Pulverized Coal. High Sulfur - 500 MW	303	322	341	360	379	399	418	437	456	475	494
Supercritical Pulverized Coal - 750 MW	277	297	317	338	358	378	398	418	438	459	479
Supercritical Pulverized Coal High Sulfur - 750 MW	280	299	318	337	356	375	394	413	432	451	470
Pressurized Fluidized Bed Combustion	412	436	460	484	508	532	556	580	604	----	----
1x1 IGCC	368	387	407	426	445	464	484	503	522	----	----
2x1 IGCC	327	346	365	384	404	423	442	461	480	----	----
2x1 IGCC, High Sulfur	327	345	363	381	398	416	434	452	470	----	----
Subcritical Pulverized Coal - 500 MW - CCS	524	554	584	614	644	674	704	734	764	794	825
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	532	561	589	618	646	675	704	732	761	789	818
Circulating Fluidized Bed - 500 MW - CCS	532	562	593	623	653	683	714	744	774	805	835
Supercritical Pulverized Coal - 500 MW - CCS	531	559	588	616	644	672	701	729	757	786	814
Supercritical Pulverized Coal. High Sulfur - 500 MW - CCS	538	565	593	620	647	674	702	729	756	784	811
Supercritical Pulverized Coal - 750 MW - CCS	501	530	558	587	615	644	672	701	729	758	786
Supercritical Pulverized Coal High Sulfur - 750 MW - CCS	505	532	559	586	613	640	667	695	722	749	776
1x1 IGCC - CCS	510	533	556	579	602	625	648	671	695	----	----
2x1 IGCC - CCS	462	485	508	531	554	577	600	623	647	----	----
2x1 IGCC. High Sulfur - CCS	464	486	508	530	552	574	596	618	640	----	----
Wind Energy Conversion - 50 MW	259	248	237	225	----	----	----	----	----	----	----
Geothermal - 30 MW	484	480	476	472	467	462	456	449	442	435	428
Solar Photovoltaic - 50 kW	766	766	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	506	507	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	734	734	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	771	772	773	773	773	774	774	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	646	646	646	645	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1741	1714	1687	1661	1634	1607	1580	1553	----	----	----
RDF Stoker-Fired - 7 MW	1665	1746	1827	1907	1988	2069	2150	2231	2312	----	----
Landfill Gas IC Engine - 5 MW	455	480	505	530	555	580	605	630	655	680	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	489	512	535	558	581	604	627	650	672	695	718
Sewage Sludge & Anaerobic Digestion - 085 MW	693	689	685	681	676	672	668	663	656	649	----
Bio Mass (Co-Fire)	324	343	362	382	401	420	439	458	477	497	516
Molten Carbonate Fuel Cell - 300 kW	463	517	572	626	680	735	789	843	898	952	----
Spark Ignition Engine - 5 MW	402	462	521	581	641	700	760	820	879	939	----
Hydroelectric - New - 30 MW	473	467	462	456	449	----	----	----	----	----	----
Ohio Falls 9-10	293	287	281	273	----	----	----	----	----	----	----
Minimum Levelized $/kW	102	152	201	225	298	346	394	413	432	435	428

Exhibit 6

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- Base **2007 ($/kW yr)**
Heat Rate- Base
Fuel Forecast- High

	Capacity Factors										
Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	147	210	273	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	221	279	337	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	140	243	345	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	172	313	453	594	735	875	1016	1157	1297	1438	1579
Simple Cycle GE 7EA CT - Peaking Capacity	128	295	463	630	797	965	1132	1299	1467	1634	1801
Simple Cycle GE 7FA CT - Peaking Capacity	102	253	403	554	705	855	1006	1157	1307	1458	1609
Combined Cycle GE 7EA CT - Intermediate Load	191	293	394	496	598	699	801	903	1004	1106	1208
Combined Cycle GE 7FA CT - Intermediate Load	144	233	322	410	499	588	677	765	854	943	1032
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	122	211	299	388	476	565	654	742	831	919	1008
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	104	192	280	368	455	543	631	719	807	895	982
Siemens 5000F CC CT - Intermediate Load	134	223	312	401	490	579	669	758	847	936	1025
Humid Air Turbine Cycle CT - 366 MW	132	258	383	509	635	760	886	1011	1137	1263	----
Kalina Cycle CC CT - 282 MW	145	222	298	375	452	528	605	681	758	835	----
Cheng Cycle CT - 140 MW	151	243	335	426	518	610	702	794	886	977	----
Peaking Microturbine - 0 03 MW	422	625	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	456	632	808	985	1161	1337	1513	1689	1865	2042	2218
Subcritical Pulverized Coal - 250 MW	331	353	376	398	421	443	465	488	510	533	555
Subcritical Pulverized Coal - 500 MW	291	313	336	358	380	402	425	447	469	492	514
Subcritical Pulverized Coal, High Sulfur - 500 MW	297	318	339	360	381	402	423	444	465	486	507
Circulating Fluidized Bed - 250 MW	330	353	375	398	420	443	466	488	511	534	556
Circulating Fluidized Bed - 500 MW	293	315	338	360	383	405	427	450	472	495	517
Supercritical Pulverized Coal - 500 MW	299	320	341	362	383	404	425	446	467	488	509
Supercritical Pulverized Coal, High Sulfur - 500 MW	303	323	344	364	384	405	425	445	466	486	506
Supercritical Pulverized Coal - 750 MW	277	298	320	341	363	384	406	427	449	470	492
Supercritical Pulverized Coal High Sulfur - 750 MW	280	300	320	341	361	381	401	422	442	462	482
Pressurized Fluidized Bed Combustion	412	438	463	489	514	540	565	591	617	----	----
1x1 IGCC	368	388	409	429	450	470	491	511	532	----	----
2x1 IGCC	327	347	368	388	409	429	450	470	491	----	----
2x1 IGCC, High Sulfur	327	346	365	384	403	422	441	460	479	----	----
Subcritical Pulverized Coal - 500 MW - CCS	524	556	588	620	652	684	716	748	780	812	844
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	532	562	593	623	654	684	714	745	775	806	836
Circulating Fluidized Bed - 500 MW - CCS	532	564	597	629	661	693	726	758	790	822	855
Supercritical Pulverized Coal - 500 MW - CCS	531	561	591	622	652	682	712	742	772	803	833
Supercritical Pulverized Coal High Sulfur - 500 MW - CCS	538	567	596	625	654	683	712	741	770	799	828
Supercritical Pulverized Coal - 750 MW - CCS	501	531	562	592	623	653	683	714	744	774	805
Supercritical Pulverized Coal High Sulfur - 750 MW - CCS	505	534	562	591	620	649	677	706	735	764	792
1x1 IGCC - CCS	510	535	559	584	608	633	658	682	707	----	----
2x1 IGCC - CCS	462	487	511	536	560	585	610	634	659	----	----
2x1 IGCC High Sulfur - CCS	464	487	511	534	558	581	605	628	651	----	----
Wind Energy Conversion - 50 MW	259	248	237	225	----	----	----	----	----	----	----
Geothermal - 30 MW	*484*	*480*	*476*	*472*	467	*462*	456	449	442	435	428
Solar Photovoltaic - 50 kW	766	766	----	----	----	----	----	----	----	----	----
Solar Thermal Parabolic Trough - 100 MW	506	507	----	----	----	----	----	----	----	----	----
Solar Thermal, Parabolic Dish - 1 2 MW	734	734	----	----	----	----	----	----	----	----	----
Solar Thermal, Central Receiver - 50 MW	771	772	773	773	773	774	774	----	----	----	----
Solar Thermal Solar Chimney - 50 MW	646	646	646	645	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1741	1710	1678	1647	1615	1584	1552	1521	----	----	----
RDF Stoker-Fired - 7 MW	1665	1751	1838	1924	2011	2097	2184	2270	2357	----	----
Landfill Gas IC Engine - 5 MW	455	505	555	605	655	706	756	806	856	906	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	489	513	538	562	587	611	636	660	685	709	733
Sewage Sludge & Anaerobic Digestion - 085 MW	693	689	685	681	676	672	668	663	656	649	----
Bio Mass (Co-Fire)	324	345	365	386	406	427	447	468	488	508	529
Molten Carbonate Fuel Cell - 300 kW	463	562	660	759	857	956	1054	1153	1251	1350	----
Spark Ignition Engine - 5 MW	402	514	626	737	849	961	1073	1185	1296	1408	----
Hydroelectric - New - 30 MW	473	467	462	456	449	----	----	----	----	----	----
Ohio Falls 9-10	293	287	281	273	----	----	----	----	----	----	----
Minimum Levelized $/kW	102	192	237	225	361	381	401	422	442	435	428

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- Base 2007 ($/kW yr)
Heat Rate- High
Fuel Forecast-Low

	Capacity Factors										
Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	147	210	273	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	221	279	337	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	140	219	298	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	173	264	356	447	538	630	721	812	904	995	1086
Simple Cycle GE 7EA CT - Peaking Capacity	129	234	340	445	550	656	761	866	972	1077	1182
Simple Cycle GE 7FA CT - Peaking Capacity	103	198	292	387	482	576	671	766	860	955	1050
Combined Cycle GE 7EA CT - Intermediate Load	192	251	310	369	427	486	545	604	663	722	780
Combined Cycle GE 7FA CT - Intermediate Load	145	196	247	299	350	401	452	504	555	606	657
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	123	174	225	277	328	379	430	481	533	584	635
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	104	155	206	256	307	358	409	459	510	561	612
Siemens 5000F CC CT - Intermediate Load	135	187	238	290	341	393	444	496	548	599	651
Humid Air Turbine Cycle CT - 366 MW	134	206	278	350	421	493	565	637	709	781	----
Kalina Cycle CC CT - 282 MW	145	189	232	276	319	363	406	450	493	537	----
Cheng Cycle CT - 140 MW	152	205	259	312	365	419	472	525	579	632	----
Peaking Microturbine - 0.03 MW	423	550	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0.03 MW	459	560	660	761	862	963	1063	1164	1265	1365	1466
Subcritical Pulverized Coal - 250 MW	331	353	375	397	418	440	462	484	506	528	549
Subcritical Pulverized Coal - 500 MW	291	313	335	357	378	400	422	444	466	488	509
Subcritical Pulverized Coal, High Sulfur - 500 MW	297	318	338	359	379	400	420	441	461	482	503
Circulating Fluidized Bed - 250 MW	330	352	374	396	418	440	462	484	507	529	551
Circulating Fluidized Bed - 500 MW	293	315	337	359	381	403	425	447	469	491	513
Supercritical Pulverized Coal - 500 MW	299	320	340	361	381	402	422	443	463	484	504
Supercritical Pulverized Coal, High Sulfur - 500 MW	303	323	343	363	383	402	422	442	462	482	502
Supercritical Pulverized Coal - 750 MW	277	298	319	340	361	382	403	424	445	467	488
Supercritical Pulverized Coal, High Sulfur - 750 MW	280	300	320	339	359	379	399	419	438	458	478
Pressurized Fluidized Bed Combustion	412	437	462	487	512	537	563	588	613	----	----
1x1 IGCC	368	388	408	428	448	468	489	509	529	----	----
2x1 IGCC	327	347	367	387	407	427	447	467	487	----	----
2x1 IGCC, High Sulfur	327	346	364	383	401	420	438	457	475	----	----
Subcritical Pulverized Coal - 500 MW - CCS	524	555	587	618	650	681	712	744	775	806	838
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	532	562	591	621	651	681	710	740	770	800	829
Circulating Fluidized Bed - 500 MW - CCS	532	564	595	627	658	690	722	753	785	816	848
Supercritical Pulverized Coal - 500 MW - CCS	531	561	590	620	649	679	708	738	767	797	826
Supercritical Pulverized Coal, High Sulfur - 500 MW - CCS	538	566	595	623	652	680	708	737	765	794	822
Supercritical Pulverized Coal - 750 MW - CCS	501	531	560	590	620	650	679	709	739	769	798
Supercritical Pulverized Coal, High Sulfur - 750 MW - CCS	505	533	561	590	618	646	674	702	730	759	787
1x1 IGCC - CCS	510	534	558	582	607	631	655	679	703	----	----
2x1 IGCC - CCS	462	486	510	534	558	582	606	630	654	----	----
2x1 IGCC, High Sulfur - CCS	464	487	510	532	555	578	601	624	647	----	----
Wind Energy Conversion - 50 MW	259	248	237	225	----	----	----	----	----	----	----
Geothermal - 30 MW	484	480	476	472	467	462	456	449	442	435	428
Solar Photovoltaic - 50 kW	766	766	----	----	----	----	----	----	----	----	----
Solar Thermal, Parabolic Trough - 100 MW	506	507	----	----	----	----	----	----	----	----	----
Solar Thermal, Parabolic Dish - 1.2 MW	734	734	----	----	----	----	----	----	----	----	----
Solar Thermal, Central Receiver - 50 MW	771	772	773	773	773	774	774	----	----	----	----
Solar Thermal, Solar Chimney - 50 MW	646	646	646	645	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1741	1711	1682	1652	1622	1592	1563	1533	----	----	----
RDF Stoker-Fired - 7 MW	1665	1749	1834	1918	2003	2087	2172	2256	2341	----	----
Landfill Gas IC Engine - 5 MW	455	482	508	535	561	588	614	641	667	694	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	489	513	537	561	585	609	633	656	680	704	728
Sewage Sludge & Anaerobic Digestion - .085 MW	693	689	685	681	677	673	668	663	657	650	----
Bio Mass (Co-Fire)	324	344	364	384	404	424	444	465	485	505	525
Molten Carbonate Fuel Cell - 300 kW	464	521	578	634	691	748	805	862	918	975	----
Spark Ignition Engine - 5 MW	403	466	529	591	654	717	780	842	905	968	----
Hydroelectric - New - 30 MW	473	467	462	456	449	----	----	----	----	----	----
Ohio Falls 9-10	293	287	281	273	----	----	----	----	----	----	----
Minimum Levelized $/kW	103	155	206	225	307	358	399	419	438	435	428

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- Base **2007 ($/kW yr)**
Heat Rate- High
Fuel Forecast- Base

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	147	210	273	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	221	279	337	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	140	234	328	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	173	295	417	539	661	783	905	1027	1149	1271	1393
Simple Cycle GE 7EA CT - Peaking Capacity	129	273	417	561	705	849	993	1137	1281	1425	1569
Simple Cycle GE 7FA CT - Peaking Capacity	103	232	362	491	620	750	879	1008	1138	1267	1396
Combined Cycle GE 7EA CT - Intermediate Load	192	278	363	449	534	620	705	791	876	962	1047
Combined Cycle GE 7FA CT - Intermediate Load	145	220	294	369	444	518	593	667	742	817	891
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	123	198	272	347	421	496	571	645	720	795	869
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	104	178	252	326	399	473	547	621	695	769	843
Siemens 5000F CC CT - Intermediate Load	135	210	285	360	435	510	585	660	736	811	886
Humid Air Turbine Cycle CT - 366 MW	134	239	345	450	556	661	767	872	978	1083	----
Kalina Cycle CC CT - 282 MW	145	209	273	338	402	466	530	594	659	723	----
Cheng Cycle CT - 140 MW	152	229	307	384	461	539	616	693	771	848	----
Peaking Microturbine - 0.03 MW	423	598	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	459	607	755	903	1050	1198	1346	1494	1642	1790	1937
Subcritical Pulverized Coal - 250 MW	331	353	376	398	420	442	465	487	509	532	554
Subcritical Pulverized Coal - 500 MW	291	313	335	358	380	402	424	446	468	491	513
Subcritical Pulverized Coal, High Sulfur - 500 MW	297	318	339	360	381	401	422	443	464	485	506
Circulating Fluidized Bed - 250 MW	330	353	375	398	420	443	465	488	510	533	555
Circulating Fluidized Bed - 500 MW	293	315	338	360	382	404	427	449	471	494	516
Supercritical Pulverized Coal - 500 MW	299	320	341	362	382	403	424	445	466	487	507
Supercritical Pulverized Coal. High Sulfur - 500 MW	303	323	343	364	384	404	424	445	465	485	505
Supercritical Pulverized Coal - 750 MW	277	298	320	341	363	384	405	427	448	469	491
Supercritical Pulverized Coal. High Sulfur - 750 MW	280	300	320	340	361	381	401	421	441	461	481
Pressurized Fluidized Bed Combustion	412	438	463	489	514	540	565	591	617	----	----
1x1 IGCC	368	388	409	429	450	470	491	511	532	----	----
2x1 IGCC	327	347	368	388	408	429	449	469	490	----	----
2x1 IGCC, High Sulfur	327	346	365	384	403	422	440	459	478	----	----
Subcritical Pulverized Coal - 500 MW - CCS	524	556	588	619	651	683	715	747	779	810	842
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	532	562	593	623	653	683	714	744	774	805	835
Circulating Fluidized Bed - 500 MW - CCS	532	564	596	628	661	693	725	757	789	821	854
Supercritical Pulverized Coal - 500 MW - CCS	531	561	591	621	651	681	711	741	771	802	832
Supercritical Pulverized Coal, High Sulfur - 500 MW - CCS	538	567	596	625	653	682	711	740	769	798	826
Supercritical Pulverized Coal - 750 MW - CCS	501	531	562	592	622	652	683	713	743	774	804
Supercritical Pulverized Coal. High Sulfur - 750 MW - CCS	505	534	562	591	619	648	677	705	734	763	791
1x1 IGCC - CCS	510	534	559	583	608	632	657	681	706	----	----
2x1 IGCC - CCS	462	486	511	535	560	584	609	633	658	----	----
2x1 IGCC. High Sulfur - CCS	464	487	511	534	557	581	604	627	650	----	----
Wind Energy Conversion - 50 MW	259	248	237	225	----	----	----	----	----	----	----
Geothermal - 30 MW	484	480	476	472	467	462	456	449	442	435	428
Solar Photovoltaic - 50 kW	766	766	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	506	507	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	734	734	----	----	----	----	----	----	----	----	----
Solar Thermal Central Receiver - 50 MW	771	772	773	773	773	774	774	----	----	----	----
Solar Thermal Solar Chimney - 50 MW	646	646	646	645	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1741	1709	1676	1644	1611	1579	1547	1514	----	----	----
RDF Stoker-Fired - 7 MW	1665	1751	1837	1923	2009	2095	2181	2267	2353	----	----
Landfill Gas IC Engine - 5 MW	455	496	538	579	620	662	703	744	786	827	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	489	513	538	562	586	611	635	659	684	708	732
Sewage Sludge & Anaerobic Digestion - 085 MW	693	689	685	681	677	673	668	663	657	650	----
Bio Mass (Co-Fire)	324	344	365	385	406	426	446	467	487	508	528
Molten Carbonate Fuel Cell - 300 kW	464	547	630	713	796	878	961	1044	1127	1210	----
Spark Ignition Engine - 5 MW	403	496	590	683	777	870	963	1057	1150	1244	----
Hydroelectric - New - 30 MW	473	467	462	456	449	----	----	----	----	----	----
Ohio Falls 9-10	293	287	281	273	----	----	----	----	----	----	----
Minimum Levelized $/kW	103	178	237	225	361	381	401	421	441	435	428

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- Base **2007 ($/kW yr)**
Heat Rate- High
Fuel Forecast- High

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	147	210	273	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	221	279	337	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	140	245	351	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	173	320	466	613	760	906	1053	1200	1346	1493	1640
Simple Cycle GE 7EA CT - Peaking Capacity	129	304	478	653	828	1002	1177	1352	1526	1701	1876
Simple Cycle GE 7FA CT - Peaking Capacity	103	260	416	573	730	886	1043	1200	1356	1513	1670
Combined Cycle GE 7EA CT - Intermediate Load	192	298	405	511	617	724	830	936	1043	1149	1255
Combined Cycle GE 7FA CT - Intermediate Load	145	238	331	424	516	609	702	795	888	981	1073
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	123	216	309	401	494	587	680	773	866	958	1051
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	104	196	288	380	472	564	656	749	841	933	1025
Siemens 5000F CC CT - Intermediate Load	135	228	322	415	508	602	695	788	882	975	1068
Humid Air Turbine Cycle CT - 366 MW	134	266	397	529	660	792	924	1055	1187	1319	----
Kalina Cycle CC CT - 282 MW	145	225	306	386	466	547	627	707	788	868	----
Cheng Cycle CT - 140 MW	152	248	344	441	537	633	729	825	921	1018	----
Peaking Microturbine - 0 03 MW	423	634	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	459	644	828	1013	1198	1382	1567	1751	1936	2121	2305
Subcritical Pulverized Coal - 250 MW	331	354	378	401	425	448	471	495	518	541	565
Subcritical Pulverized Coal - 500 MW	291	314	338	361	384	407	431	454	477	501	524
Subcritical Pulverized Coal, High Sulfur - 500 MW	297	319	341	363	385	407	428	450	472	494	516
Circulating Fluidized Bed - 250 MW	330	354	377	401	424	448	472	495	519	542	566
Circulating Fluidized Bed - 500 MW	293	316	340	363	387	410	433	457	480	504	527
Supercritical Pulverized Coal - 500 MW	299	321	343	365	387	409	431	453	475	497	519
Supercritical Pulverized Coal High Sulfur - 500 MW	303	324	345	367	388	409	430	452	473	494	515
Supercritical Pulverized Coal - 750 MW	277	299	322	344	367	389	412	434	457	479	502
Supercritical Pulverized Coal. High Sulfur - 750 MW	280	301	322	343	364	386	407	428	449	470	491
Pressurized Fluidized Bed Combustion	412	439	466	492	519	546	573	599	626	----	----
1x1 IGCC	368	389	411	432	454	475	496	518	539	----	----
2x1 IGCC	327	348	370	391	412	433	455	476	497	----	----
2x1 IGCC, High Sulfur	327	347	367	387	406	426	446	466	486	----	----
Subcritical Pulverized Coal - 500 MW - CCS	524	557	591	624	658	691	724	758	791	824	858
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	532	564	595	627	658	690	722	753	785	817	848
Circulating Fluidized Bed - 500 MW - CCS	532	566	599	633	666	700	734	767	801	834	868
Supercritical Pulverized Coal - 500 MW - CCS	531	562	594	625	657	688	720	751	783	814	846
Supercritical Pulverized Coal High Sulfur - 500 MW - CCS	538	568	598	629	659	689	719	749	779	810	840
Supercritical Pulverized Coal - 750 MW - CCS	501	533	564	596	627	659	691	722	754	785	817
Supercritical Pulverized Coal. High Sulfur - 750 MW - CCS	505	535	565	595	625	655	685	715	745	775	804
1x1 IGCC - CCS	510	536	561	587	613	638	664	690	715	----	----
2x1 IGCC - CCS	462	488	513	539	565	590	616	642	667	----	----
2x1 IGCC High Sulfur - CCS	464	488	513	537	562	586	610	635	659	----	----
Wind Energy Conversion - 50 MW	259	248	237	225	----	----	----	----	----	----	----
Geothermal - 30 MW	484	480	476	472	467	462	456	449	442	435	428
Solar Photovoltaic - 50 kW	766	766	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	506	507	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	734	734	----	----	----	----	----	----	----	----	----
Solar Thermal Central Receiver - 50 MW	771	772	773	773	773	774	774	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	646	646	646	645	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1741	1706	1671	1637	1602	1567	1532	1497	----	----	----
RDF Stoker-Fired - 7 MW	1665	1755	1846	1936	2027	2117	2208	2298	2389	----	----
Landfill Gas IC Engine - 5 MW	455	508	561	614	667	719	772	825	878	931	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	489	515	540	566	591	617	642	668	693	719	744
Sewage Sludge & Anaerobic Digestion - 085 MW	693	689	685	681	677	673	668	663	657	650	----
Bio Mass (Co-Fire)	324	346	367	389	410	432	453	475	496	517	539
Molten Carbonate Fuel Cell - 300 kW	464	567	670	774	877	980	1083	1186	1290	1393	----
Spark Ignition Engine - 5 MW	403	520	638	755	873	990	1108	1225	1343	1460	----
Hydroelectric - New - 30 MW	473	467	462	456	449	----	----	----	----	----	----
Ohio Falls 9-10	293	287	281	273	----	----	----	----	----	----	----
Minimum Levelized $/kW	103	196	237	225	364	386	407	428	442	435	428

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- High 2007 ($/kW yr)
Heat Rate-Low
Fuel Forecast-Low

	Capacity Factors										
Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	194	257	320	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	271	329	387	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	181	257	333	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	197	282	368	453	538	624	709	794	880	965	1050
Simple Cycle GE 7EA CT - Peaking Capacity	145	243	341	439	537	635	733	831	929	1027	1125
Simple Cycle GE 7FA CT - Peaking Capacity	115	203	291	379	467	555	643	731	819	907	995
Combined Cycle GE 7EA CT - Intermediate Load	216	270	323	377	431	484	538	592	645	699	753
Combined Cycle GE 7FA CT - Intermediate Load	163	210	257	303	350	397	444	491	538	584	631
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	137	184	231	277	324	371	418	465	512	558	605
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	117	163	210	256	302	349	395	442	488	534	581
Siemens 5000F CC CT - Intermediate Load	153	200	247	294	341	388	435	482	529	576	623
Humid Air Turbine Cycle CT - 366 MW	149	214	280	345	411	476	542	607	672	738	----
Kalina Cycle CC CT - 282 MW	167	207	246	286	326	366	405	445	485	525	----
Cheng Cycle CT - 140 MW	174	223	271	320	369	418	466	515	564	613	----
Peaking Microturbine - 0 03 MW	466	585	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	498	590	682	773	865	957	1049	1140	1232	1324	1416
Subcritical Pulverized Coal - 250 MW	398	418	438	458	478	498	519	539	559	579	599
Subcritical Pulverized Coal - 500 MW	352	372	392	412	432	452	472	492	512	532	552
Subcritical Pulverized Coal, High Sulfur - 500 MW	357	376	395	414	433	451	470	489	508	527	546
Circulating Fluidized Bed - 250 MW	398	418	438	459	479	499	519	539	560	580	600
Circulating Fluidized Bed - 500 MW	355	375	395	415	435	455	475	495	516	536	556
Supercritical Pulverized Coal - 500 MW	361	380	398	417	436	455	473	492	511	530	548
Supercritical Pulverized Coal. High Sulfur - 500 MW	365	383	401	420	438	456	474	493	511	529	547
Supercritical Pulverized Coal - 750 MW	336	355	375	394	413	433	452	471	490	510	529
Supercritical Pulverized Coal. High Sulfur - 750 MW	339	357	375	393	412	430	448	466	484	502	521
Pressurized Fluidized Bed Combustion	523	546	569	592	615	638	661	684	708	----	----
1x1 IGCC	458	476	495	513	532	550	569	587	605	----	----
2x1 IGCC	410	428	447	465	483	502	520	538	556	----	----
2x1 IGCC, High Sulfur	410	427	444	461	478	496	513	530	547	----	----
Subcritical Pulverized Coal - 500 MW - CCS	687	716	745	773	802	831	860	889	918	946	975
Subcritical Pulverized Coal. High Sulfur - 500 MW - CCS	696	723	751	778	806	833	860	888	915	942	970
Circulating Fluidized Bed - 500 MW - CCS	699	728	757	786	815	844	873	902	932	961	990
Supercritical Pulverized Coal - 500 MW - CCS	694	721	748	775	802	829	856	884	911	938	965
Supercritical Pulverized Coal. High Sulfur - 500 MW - CCS	703	729	755	782	808	834	860	886	913	939	965
Supercritical Pulverized Coal - 750 MW - CCS	659	686	714	741	768	795	823	850	877	905	932
Supercritical Pulverized Coal. High Sulfur - 750 MW - CCS	664	690	716	742	768	794	820	846	872	898	924
1x1 IGCC - CCS	660	682	704	726	748	771	793	815	837	----	----
2x1 IGCC - CCS	601	623	645	667	689	712	734	756	778	----	----
2x1 IGCC. High Sulfur - CCS	603	624	645	666	687	708	729	750	771	----	----
Wind Energy Conversion - 50 MW	299	288	277	265	----	----	----	----	----	----	----
Geothermal - 30 MW	586	582	578	574	570	565	559	553	547	540	533
Solar Photovoltaic - 50 kW	909	909	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	592	593	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	867	867	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	897	898	899	899	900	900	900	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	758	758	758	757	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1848	1824	1801	1777	1753	1729	1706	1682	----	----	----
RDF Stoker-Fired - 7 MW	1831	1908	1985	2062	2139	2216	2293	2370	2447	----	----
Landfill Gas IC Engine - 5 MW	487	510	534	557	581	604	628	651	675	698	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	582	604	626	648	669	691	713	735	757	778	800
Sewage Sludge & Anaerobic Digestion - 085 MW	759	755	751	746	742	738	733	728	722	716	----
Bio Mass (Co-Fire)	391	409	428	446	464	483	501	519	537	556	574
Molten Carbonate Fuel Cell - 300 kW	537	589	641	693	744	796	848	900	952	1004	----
Spark Ignition Engine - 5 MW	416	473	529	586	643	700	756	813	870	926	----
Hydroelectric - New - 30 MW	622	616	611	605	599	----	----	----	----	----	----
Ohio Falls 9-10	391	385	379	372	----	----	----	----	----	----	----
Minimum Levelized $/kW	115	163	210	256	302	349	395	442	484	502	521

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- High — **2007 ($/kW yr)**
Heat Rate-Low
Fuel Forecast- Base

	Capacity Factors										
Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	194	257	320	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	271	329	387	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	181	270	360	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	197	310	424	537	650	764	877	990	1104	1217	1330
Simple Cycle GE 7EA CT - Peaking Capacity	145	278	412	545	678	812	945	1078	1212	1345	1478
Simple Cycle GE 7FA CT - Peaking Capacity	115	234	354	473	592	712	831	950	1070	1189	1308
Combined Cycle GE 7EA CT - Intermediate Load	216	294	372	450	528	606	684	762	840	918	996
Combined Cycle GE 7FA CT - Intermediate Load	163	231	299	367	435	503	571	639	707	775	843
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	137	205	273	341	409	477	545	613	681	749	817
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	117	184	252	319	386	454	521	588	656	723	790
Siemens 5000F CC CT - Intermediate Load	153	221	290	358	426	495	563	632	700	768	837
Humid Air Turbine Cycle CT - 366 MW	149	245	341	437	532	628	724	820	916	1012	----
Kalina Cycle CC CT - 282 MW	167	225	284	342	401	459	517	576	634	693	----
Cheng Cycle CT - 140 MW	174	244	315	385	456	526	597	667	738	808	----
Peaking Microturbine - 0.03 MW	466	627	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0.03 MW	498	632	767	901	1036	1170	1305	1439	1573	1708	1842
Subcritical Pulverized Coal - 250 MW	398	418	439	459	480	500	521	541	561	582	602
Subcritical Pulverized Coal - 500 MW	352	372	393	413	433	453	474	494	514	535	555
Subcritical Pulverized Coal, High Sulfur - 500 MW	357	376	395	415	434	453	472	492	511	530	549
Circulating Fluidized Bed - 250 MW	398	419	439	460	480	501	521	542	562	583	603
Circulating Fluidized Bed - 500 MW	355	375	396	416	437	457	477	498	518	539	559
Supercritical Pulverized Coal - 500 MW	361	380	399	418	437	456	475	495	514	533	552
Supercritical Pulverized Coal. High Sulfur - 500 MW	365	384	402	421	439	458	476	495	513	532	550
Supercritical Pulverized Coal - 750 MW	336	356	375	395	415	434	454	473	493	513	532
Supercritical Pulverized Coal. High Sulfur - 750 MW	339	357	376	394	413	431	450	468	487	505	524
Pressurized Fluidized Bed Combustion	523	546	570	593	617	640	664	687	710	----	----
1x1 IGCC	458	477	496	514	533	552	571	590	608	----	----
2x1 IGCC	410	429	447	466	485	503	522	541	559	----	----
2x1 IGCC, High Sulfur	410	427	445	462	479	497	514	532	549	----	----
Subcritical Pulverized Coal - 500 MW - CCS	687	716	746	775	804	833	863	892	921	950	980
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	696	724	752	779	807	835	863	891	919	946	974
Circulating Fluidized Bed - 500 MW - CCS	699	729	758	788	817	847	876	906	935	965	994
Supercritical Pulverized Coal - 500 MW - CCS	694	722	749	777	804	832	859	887	914	942	969
Supercritical Pulverized Coal. High Sulfur - 500 MW - CCS	703	730	756	783	810	836	863	889	916	943	969
Supercritical Pulverized Coal - 750 MW - CCS	659	687	714	742	770	798	825	853	881	909	936
Supercritical Pulverized Coal. High Sulfur - 750 MW - CCS	664	690	717	743	770	796	822	849	875	902	928
1x1 IGCC - CCS	660	682	705	727	750	772	795	817	840	----	----
2x1 IGCC - CCS	601	623	646	668	691	713	736	758	781	----	----
2x1 IGCC. High Sulfur - CCS	603	624	646	667	689	710	731	753	774	----	----
Wind Energy Conversion - 50 MW	299	288	277	265	----	----	----	----	----	----	----
Geothermal - 30 MW	586	582	578	574	570	565	559	553	547	540	533
Solar Photovoltaic - 50 kW	909	909	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	592	593	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1.2 MW	867	867	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	897	898	899	899	900	900	900	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	758	758	758	757	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1848	1822	1796	1770	1744	1718	1692	1666	----	----	----
RDF Stoker-Fired - 7 MW	1831	1909	1988	2066	2145	2223	2302	2380	2459	----	----
Landfill Gas IC Engine - 5 MW	487	524	561	598	635	671	708	745	782	819	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	582	604	627	649	671	693	716	738	760	782	804
Sewage Sludge & Anaerobic Digestion - .085 MW	759	755	751	746	742	738	733	728	722	716	----
Bio Mass (Co-Fire)	391	410	428	447	466	484	503	521	540	559	577
Molten Carbonate Fuel Cell - 300 kW	537	612	688	763	839	914	990	1065	1141	1216	----
Spark Ignition Engine - 5 MW	416	501	585	670	754	839	923	1008	1093	1177	----
Hydroelectric - New - 30 MW	622	616	611	605	599	----	----	----	----	----	----
Ohio Falls 9-10	391	385	379	372	----	----	----	----	----	----	----
Minimum Levelized $/kW	115	184	252	265	386	431	450	468	487	505	524

Exhibit 6

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- High 2007 ($/kW yr)
Heat Rate-Low
Fuel Forecast- High

Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
	Capacity Factors										
Pumped Hydro Energy Storage - 500 MW	194	257	320	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	271	329	387	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	181	281	381	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	197	332	468	603	738	874	1009	1144	1280	1415	1550
Simple Cycle GE 7EA CT - Peaking Capacity	145	306	466	627	788	948	1109	1270	1430	1591	1752
Simple Cycle GE 7FA CT - Peaking Capacity	115	259	403	547	691	835	979	1123	1267	1411	1555
Combined Cycle GE 7EA CT - Intermediate Load	216	313	410	507	603	700	797	894	991	1088	1184
Combined Cycle GE 7FA CT - Intermediate Load	163	248	332	417	501	586	670	755	839	924	1009
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	137	221	306	390	475	559	643	728	812	896	981
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	117	201	284	368	451	535	619	702	786	870	953
Siemens 5000F CC CT - Intermediate Load	153	238	323	408	492	577	662	747	832	917	1002
Humid Air Turbine Cycle CT - 366 MW	149	269	388	508	628	747	867	986	1106	1226	----
Kalina Cycle CC CT - 282 MW	167	240	313	386	459	532	605	677	750	823	----
Cheng Cycle CT - 140 MW	174	261	349	436	524	611	699	786	874	961	----
Peaking Microturbine - 0.03 MW	466	660	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0.03 MW	498	666	833	1001	1169	1337	1504	1672	1840	2008	2175
Subcritical Pulverized Coal - 250 MW	398	419	441	462	484	505	526	548	569	591	612
Subcritical Pulverized Coal - 500 MW	352	373	395	416	437	458	480	501	522	544	565
Subcritical Pulverized Coal, High Sulfur - 500 MW	357	377	397	417	437	458	478	498	518	538	558
Circulating Fluidized Bed - 250 MW	398	420	441	463	484	506	527	549	570	592	613
Circulating Fluidized Bed - 500 MW	355	376	398	419	441	462	483	505	526	548	569
Supercritical Pulverized Coal - 500 MW	361	381	401	421	441	461	481	501	522	542	562
Supercritical Pulverized Coal. High Sulfur - 500 MW	365	384	404	423	443	462	482	501	521	540	559
Supercritical Pulverized Coal - 750 MW	336	357	377	398	418	439	460	480	501	522	542
Supercritical Pulverized Coal. High Sulfur - 750 MW	339	358	378	397	416	436	455	475	494	513	533
Pressurized Fluidized Bed Combustion	523	547	572	596	621	645	670	694	719	----	----
1x1 IGCC	458	478	497	517	536	556	576	595	615	----	----
2x1 IGCC	410	430	449	469	488	508	527	547	566	----	----
2x1 IGCC, High Sulfur	410	428	446	465	483	501	519	537	556	----	----
Subcritical Pulverized Coal - 500 MW - CCS	687	718	748	779	809	840	871	901	932	962	993
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	696	725	754	783	812	841	870	899	928	957	987
Circulating Fluidized Bed - 500 MW - CCS	699	730	761	791	822	853	884	915	946	976	1007
Supercritical Pulverized Coal - 500 MW - CCS	694	723	752	781	809	838	867	896	925	954	982
Supercritical Pulverized Coal. High Sulfur - 500 MW - CCS	703	731	758	786	814	842	869	897	925	953	980
Supercritical Pulverized Coal - 750 MW - CCS	659	688	717	746	775	804	833	862	892	921	950
Supercritical Pulverized Coal. High Sulfur - 750 MW - CCS	664	692	719	747	774	802	829	857	884	912	939
1x1 IGCC - CCS	660	684	707	731	754	778	801	825	848	----	----
2x1 IGCC - CCS	601	625	648	672	695	719	742	766	789	----	----
2x1 IGCC. High Sulfur - CCS	603	625	648	670	692	715	737	759	782	----	----
Wind Energy Conversion - 50 MW	299	288	277	265	----	----	----	----	----	----	----
Geothermal - 30 MW	586	582	578	574	570	565	559	553	547	540	533
Solar Photovoltaic - 50 kW	909	909	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	592	593	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1.2 MW	867	867	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	897	898	899	899	900	900	900	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	758	758	758	757	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1848	1820	1791	1763	1735	1707	1678	1650	----	----	----
RDF Stoker-Fired - 7 MW	1831	1913	1996	2078	2161	2243	2326	2408	2491	----	----
Landfill Gas IC Engine - 5 MW	487	534	582	629	676	724	771	818	866	913	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	582	605	629	652	676	699	722	746	769	792	815
Sewage Sludge & Anaerobic Digestion - .085 MW	759	755	751	746	742	738	733	728	722	716	----
Bio Mass (Co-Fire)	391	411	430	450	469	489	508	528	547	567	586
Molten Carbonate Fuel Cell - 300 kW	537	631	725	818	912	1006	1100	1194	1288	1381	----
Spark Ignition Engine - 5 MW	416	522	629	735	841	947	1054	1160	1266	1372	----
Hydroelectric - New - 30 MW	622	616	611	605	599	----	----	----	----	----	----
Ohio Falls 9-10	391	385	379	372	----	----	----	----	----	----	----
Minimum Levelized $/kW	115	201	277	265	416	436	455	475	494	513	533

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- High 2007 ($/kW yr)
Heat Rate- Base
Fuel Forecast-Low

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	194	257	320	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	271	329	387	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	181	258	336	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	198	286	374	462	550	638	726	814	902	990	1078
Simple Cycle GE 7EA CT - Peaking Capacity	146	247	349	450	551	653	754	855	957	1058	1159
Simple Cycle GE 7FA CT - Peaking Capacity	116	207	299	390	481	573	664	755	847	938	1029
Combined Cycle GE 7EA CT - Intermediate Load	217	273	329	386	442	498	554	610	666	723	779
Combined Cycle GE 7FA CT - Intermediate Load	164	213	262	311	360	410	459	508	557	606	655
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	138	187	236	285	334	383	432	481	529	578	627
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	118	166	215	263	312	360	409	457	506	554	603
Siemens 5000F CC CT - Intermediate Load	154	203	253	302	351	400	450	499	548	598	647
Humid Air Turbine Cycle CT - 366 MW	150	219	287	356	424	493	562	630	699	767	----
Kalina Cycle CC CT - 282 MW	168	210	251	293	334	376	418	459	501	542	----
Cheng Cycle CT - 140 MW	174	225	276	327	378	429	480	531	582	633	----
Peaking Microturbine - 0.03 MW	467	590	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0.03 MW	501	597	693	790	886	982	1078	1174	1270	1367	1463
Subcritical Pulverized Coal - 250 MW	398	419	440	461	482	503	524	545	566	587	608
Subcritical Pulverized Coal - 500 MW	352	373	394	415	436	457	478	499	520	541	562
Subcritical Pulverized Coal, High Sulfur - 500 MW	357	377	396	416	436	455	475	495	514	534	554
Circulating Fluidized Bed - 250 MW	398	419	440	462	483	504	525	546	567	589	610
Circulating Fluidized Bed - 500 MW	355	376	397	418	439	460	481	502	523	544	565
Supercritical Pulverized Coal - 500 MW	361	381	400	420	440	459	479	498	518	538	557
Supercritical Pulverized Coal High Sulfur - 500 MW	365	384	403	422	441	461	480	499	518	537	556
Supercritical Pulverized Coal - 750 MW	336	356	376	397	417	437	457	477	497	518	538
Supercritical Pulverized Coal. High Sulfur - 750 MW	339	358	377	396	415	434	453	472	491	510	529
Pressurized Fluidized Bed Combustion	523	547	571	595	619	643	667	691	715	----	----
1x1 IGCC	458	477	497	516	535	554	574	593	612	----	----
2x1 IGCC	410	429	448	467	487	506	525	544	563	----	----
2x1 IGCC, High Sulfur	410	428	446	464	481	499	517	535	553	----	----
Subcritical Pulverized Coal - 500 MW - CCS	687	717	747	777	807	837	867	897	927	957	988
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	696	725	753	782	810	839	868	896	925	953	982
Circulating Fluidized Bed - 500 MW - CCS	699	729	760	790	820	850	881	911	941	972	1002
Supercritical Pulverized Coal - 500 MW - CCS	694	722	751	779	807	835	864	892	920	949	977
Supercritical Pulverized Coal High Sulfur - 500 MW - CCS	703	730	758	785	812	839	867	894	921	949	976
Supercritical Pulverized Coal - 750 MW - CCS	659	688	716	745	773	802	830	859	887	916	944
Supercritical Pulverized Coal. High Sulfur - 750 MW - CCS	664	691	718	745	772	799	826	854	881	908	935
1x1 IGCC - CCS	660	683	706	729	752	775	798	821	845	----	----
2x1 IGCC - CCS	601	624	647	670	693	716	739	762	786	----	----
2x1 IGCC. High Sulfur - CCS	603	625	647	669	691	713	735	757	779	----	----
Wind Energy Conversion - 50 MW	299	288	277	265	----	----	----	----	----	----	----
Geothermal - 30 MW	586	582	578	574	570	565	559	553	547	540	533
Solar Photovoltaic - 50 kW	909	909	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	592	593	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1.2 MW	867	867	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	897	898	899	899	900	900	900	----	----	----	----
Solar Thermal Solar Chimney - 50 MW	758	758	758	757	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1848	1821	1794	1768	1741	1714	1687	1660	----	----	----
RDF Stoker-Fired - 7 MW	1831	1912	1993	2073	2154	2235	2316	2397	2478	----	----
Landfill Gas IC Engine - 5 MW	487	512	537	562	587	612	637	662	687	712	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	582	605	628	651	674	697	720	743	765	788	811
Sewage Sludge & Anaerobic Digestion - .085 MW	759	755	751	747	742	738	734	729	723	717	----
Bio Mass (Co-Fire)	391	410	429	449	468	487	506	525	545	564	583
Molten Carbonate Fuel Cell - 300 kW	538	592	647	701	755	810	864	918	973	1027	----
Spark Ignition Engine - 5 MW	418	478	537	597	657	716	776	836	895	955	----
Hydroelectric - New - 30 MW	622	616	611	605	599	----	----	----	----	----	----
Ohio Falls 9-10	391	385	379	372	----	----	----	----	----	----	----
Minimum Levelized $/kW	116	166	215	263	312	360	409	457	491	510	529

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- High **2007 ($/kW yr)**
Heat Rate- Base
Fuel Forecast- Base

	Capacity Factors										
Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	194	257	320	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	271	329	387	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	181	272	364	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	198	316	434	552	670	788	906	1024	1142	1260	1378
Simple Cycle GE 7EA CT - Peaking Capacity	146	285	423	562	701	839	978	1117	1255	1394	1533
Simple Cycle GE 7FA CT - Peaking Capacity	116	241	365	490	615	739	864	989	1113	1238	1363
Combined Cycle GE 7EA CT - Intermediate Load	217	299	380	462	544	625	707	789	870	952	1034
Combined Cycle GE 7FA CT - Intermediate Load	164	235	307	378	450	521	592	664	735	806	878
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	138	209	280	352	423	494	565	636	708	779	850
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	118	189	259	330	400	471	542	612	683	753	824
Siemens 5000F CC CT - Intermediate Load	154	226	297	369	441	512	584	655	727	799	870
Humid Air Turbine Cycle CT - 366 MW	150	251	351	452	553	653	754	855	955	1056	----
Kalina Cycle CC CT - 282 MW	168	229	291	352	413	475	536	597	659	720	----
Cheng Cycle CT - 140 MW	174	248	322	396	470	544	618	692	765	839	----
Peaking Microturbine - 0 03 MW	467	635	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	501	642	783	924	1066	1207	1348	1489	1630	1771	1912
Subcritical Pulverized Coal - 250 MW	398	419	441	462	483	504	526	547	568	590	611
Subcritical Pulverized Coal - 500 MW	352	373	395	416	437	458	480	501	522	544	565
Subcritical Pulverized Coal, High Sulfur - 500 MW	357	377	397	417	437	457	477	497	517	537	557
Circulating Fluidized Bed - 250 MW	398	420	441	463	484	506	527	549	570	592	613
Circulating Fluidized Bed - 500 MW	355	376	398	419	441	462	483	505	526	548	569
Supercritical Pulverized Coal - 500 MW	361	381	401	421	441	461	481	501	521	541	561
Supercritical Pulverized Coal. High Sulfur - 500 MW	365	384	404	423	442	462	481	500	520	539	558
Supercritical Pulverized Coal - 750 MW	336	357	377	398	418	439	459	480	500	521	541
Supercritical Pulverized Coal High Sulfur - 750 MW	339	358	378	397	416	436	455	475	494	513	533
Pressurized Fluidized Bed Combustion	523	547	572	596	621	645	670	694	719	----	----
1x1 IGCC	458	478	497	517	536	556	576	595	615	----	----
2x1 IGCC	410	430	449	469	488	508	527	547	566	----	----
2x1 IGCC, High Sulfur	410	428	446	465	483	501	519	537	556	----	----
Subcritical Pulverized Coal - 500 MW - CCS	687	718	748	779	809	840	871	901	932	962	993
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	696	725	754	783	812	841	870	899	928	957	987
Circulating Fluidized Bed - 500 MW - CCS	699	730	761	791	822	853	884	915	946	976	1007
Supercritical Pulverized Coal - 500 MW - CCS	694	723	752	781	809	838	867	896	925	954	982
Supercritical Pulverized Coal High Sulfur - 500 MW - CCS	703	731	758	786	814	842	869	897	925	953	980
Supercritical Pulverized Coal - 750 MW - CCS	659	688	717	746	775	804	833	862	891	920	949
Supercritical Pulverized Coal High Sulfur - 750 MW - CCS	664	692	719	747	774	802	829	857	884	912	939
1x1 IGCC - CCS	660	683	707	730	754	777	801	824	847	----	----
2x1 IGCC - CCS	601	624	648	671	695	718	742	765	788	----	----
2x1 IGCC. High Sulfur - CCS	603	625	648	670	692	715	737	759	782	----	----
Wind Energy Conversion - 50 MW	299	288	277	265	----	----	----	----	----	----	----
Geothermal - 30 MW	586	582	578	574	570	565	559	553	547	540	533
Solar Photovoltaic - 50 kW	909	909	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	592	593	----	----	----	----	----	----	----	----	----
Solar Thermal Parabolic Dish - 1 2 MW	867	867	----	----	----	----	----	----	----	----	----
Solar Thermal Central Receiver - 50 MW	897	898	899	899	900	900	900	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	758	758	758	757	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1848	1819	1790	1760	1731	1702	1673	1644	----	----	----
RDF Stoker-Fired - 7 MW	1831	1913	1995	2078	2160	2242	2324	2407	2489	----	----
Landfill Gas IC Engine - 5 MW	487	526	565	604	643	683	722	761	800	839	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	582	605	629	652	675	698	722	745	768	791	814
Sewage Sludge & Anaerobic Digestion - 085 MW	759	755	751	747	742	738	734	729	723	717	----
Bio Mass (Co-Fire)	391	411	430	450	469	489	508	528	547	567	586
Molten Carbonate Fuel Cell - 300 kW	538	617	696	776	855	934	1013	1092	1171	1251	----
Spark Ignition Engine - 5 MW	418	507	596	685	774	863	952	1041	1130	1219	----
Hydroelectric - New - 30 MW	622	616	611	605	599	----	----	----	----	----	----
Ohio Falls 9-10	391	385	379	372	----	----	----	----	----	----	----
Minimum Levelized $/kW	116	189	259	265	400	436	455	475	494	513	533

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- High 2007 ($/kW yr)
Heat Rate- Base
Fuel Forecast- High

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	194	257	320	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	271	329	387	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	181	284	386	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	198	339	479	620	761	901	1042	1183	1323	1464	1605
Simple Cycle GE 7EA CT - Peaking Capacity	146	313	481	648	815	983	1150	1317	1485	1652	1819
Simple Cycle GE 7FA CT - Peaking Capacity	116	267	417	568	719	869	1020	1171	1321	1472	1623
Combined Cycle GE 7EA CT - Intermediate Load	217	319	420	522	624	725	827	929	1030	1132	1234
Combined Cycle GE 7FA CT - Intermediate Load	164	253	342	430	519	608	697	785	874	963	1052
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	138	227	315	404	492	581	670	758	847	935	1024
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	118	206	294	382	469	557	645	733	821	909	996
Siemens 5000F CC CT - Intermediate Load	154	243	332	421	510	599	689	778	867	956	1045
Humid Air Turbine Cycle CT - 366 MW	150	276	401	527	653	778	904	1029	1155	1281	----
Kalina Cycle CC CT - 282 MW	168	245	321	398	475	551	628	704	781	858	----
Cheng Cycle CT - 140 MW	174	266	358	449	541	633	725	817	909	1000	----
Peaking Microturbine - 0.03 MW	467	670	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0.03 MW	501	677	853	1030	1206	1382	1558	1734	1910	2087	2263
Subcritical Pulverized Coal - 250 MW	398	420	443	465	488	510	532	555	577	600	622
Subcritical Pulverized Coal - 500 MW	352	374	397	419	441	463	486	508	530	553	575
Subcritical Pulverized Coal, High Sulfur - 500 MW	357	378	399	420	441	462	483	504	525	546	567
Circulating Fluidized Bed - 250 MW	398	421	443	466	488	511	534	556	579	602	624
Circulating Fluidized Bed - 500 MW	355	377	400	422	445	467	489	512	534	557	579
Supercritical Pulverized Coal - 500 MW	361	382	403	424	445	466	487	508	529	550	571
Supercritical Pulverized Coal. High Sulfur - 500 MW	365	385	406	426	446	467	487	507	528	548	568
Supercritical Pulverized Coal - 750 MW	336	357	379	400	422	443	465	486	508	529	551
Supercritical Pulverized Coal. High Sulfur - 750 MW	339	359	379	400	420	440	460	481	501	521	541
Pressurized Fluidized Bed Combustion	523	549	574	600	625	651	676	702	728	----	----
1x1 IGCC	458	478	499	519	540	560	581	601	622	----	----
2x1 IGCC	410	430	451	471	492	512	533	553	574	----	----
2x1 IGCC, High Sulfur	410	429	448	467	486	505	524	543	562	----	----
Subcritical Pulverized Coal - 500 MW - CCS	687	719	751	783	815	847	879	911	943	975	1007
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	696	726	757	787	818	848	878	909	939	970	1000
Circulating Fluidized Bed - 500 MW - CCS	699	731	764	796	828	860	893	925	957	989	1022
Supercritical Pulverized Coal - 500 MW - CCS	694	724	754	785	815	845	875	905	935	966	996
Supercritical Pulverized Coal. High Sulfur - 500 MW - CCS	703	732	761	790	819	848	877	906	935	964	993
Supercritical Pulverized Coal - 750 MW - CCS	659	689	720	750	781	811	841	872	902	932	963
Supercritical Pulverized Coal. High Sulfur - 750 MW - CCS	664	693	721	750	779	808	836	865	894	923	951
1x1 IGCC - CCS	660	685	709	734	758	783	808	832	857	----	----
2x1 IGCC - CCS	601	626	650	675	699	724	749	773	798	----	----
2x1 IGCC. High Sulfur - CCS	603	626	650	673	697	720	744	767	790	----	----
Wind Energy Conversion - 50 MW	299	288	277	265	----	----	----	----	----	----	----
Geothermal - 30 MW	586	582	578	574	570	565	559	553	547	540	533
Solar Photovoltaic - 50 kW	909	909	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	592	593	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1.2 MW	867	867	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	897	898	899	899	900	900	900	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	758	758	758	757	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1848	1817	1785	1754	1722	1691	1659	1628	----	----	----
RDF Stoker-Fired - 7 MW	1831	1917	2004	2090	2177	2263	2350	2436	2523	----	----
Landfill Gas IC Engine - 5 MW	487	537	587	637	687	738	788	838	888	938	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	582	606	631	655	680	704	729	753	778	802	826
Sewage Sludge & Anaerobic Digestion - .085 MW	759	755	751	747	742	738	734	729	723	717	----
Bio Mass (Co-Fire)	391	412	432	453	473	494	514	535	555	576	596
Molten Carbonate Fuel Cell - 300 kW	538	637	735	834	932	1031	1129	1228	1326	1425	----
Spark Ignition Engine - 5 MW	418	530	642	753	865	977	1089	1201	1312	1424	----
Hydroelectric - New - 30 MW	622	616	611	605	599	----	----	----	----	----	----
Ohio Falls 9-10	391	385	379	372	----	----	----	----	----	----	----
Minimum Levelized $/kW	116	206	277	265	420	440	460	481	501	521	533

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- High **2007 ($/kW yr)**
Heat Rate- High
Fuel Forecast-Low

					Capacity Factors						
Technology	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Pumped Hydro Energy Storage - 500 MW	194	257	320	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	271	329	387	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	181	260	339	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	199	290	382	473	564	656	747	838	930	1021	1112
Simple Cycle GE 7EA CT - Peaking Capacity	147	252	358	463	568	674	779	884	990	1095	1200
Simple Cycle GE 7FA CT - Peaking Capacity	117	212	306	401	496	590	685	780	874	969	1064
Combined Cycle GE 7EA CT - Intermediate Load	218	277	336	395	453	512	571	630	689	748	806
Combined Cycle GE 7FA CT - Intermediate Load	165	216	267	319	370	421	472	524	575	626	677
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	139	190	241	293	344	395	446	497	549	600	651
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	118	169	220	270	321	372	423	473	524	575	626
Siemens 5000F CC CT - Intermediate Load	155	207	258	310	361	413	464	516	568	619	671
Humid Air Turbine Cycle CT - 366 MW	152	224	296	368	439	511	583	655	727	799	----
Kalina Cycle CC CT - 282 MW	168	212	255	299	342	386	429	473	516	560	----
Cheng Cycle CT - 140 MW	175	228	282	335	388	442	495	548	602	655	----
Peaking Microturbine - 0 03 MW	468	595	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	504	605	705	806	907	1008	1108	1209	1310	1410	1511
Subcritical Pulverized Coal - 250 MW	398	420	442	464	485	507	529	551	573	595	616
Subcritical Pulverized Coal - 500 MW	352	374	396	418	439	461	483	505	527	549	570
Subcritical Pulverized Coal, High Sulfur - 500 MW	357	378	398	419	439	460	480	501	521	542	563
Circulating Fluidized Bed - 250 MW	398	420	442	464	486	508	530	552	575	597	619
Circulating Fluidized Bed - 500 MW	355	377	399	421	443	465	487	509	531	553	575
Supercritical Pulverized Coal - 500 MW	361	382	402	423	443	464	484	505	525	546	566
Supercritical Pulverized Coal High Sulfur - 500 MW	365	385	405	425	445	464	484	504	524	544	564
Supercritical Pulverized Coal - 750 MW	336	357	378	399	420	441	462	483	504	526	547
Supercritical Pulverized Coal, High Sulfur - 750 MW	339	359	379	398	418	438	458	478	497	517	537
Pressurized Fluidized Bed Combustion	523	548	573	598	623	648	674	699	724	----	----
1x1 IGCC	458	478	498	518	538	558	579	599	619	----	----
2x1 IGCC	410	430	450	470	490	510	530	550	570	----	----
2x1 IGCC, High Sulfur	410	429	447	466	484	503	521	540	558	----	----
Subcritical Pulverized Coal - 500 MW - CCS	687	718	750	781	813	844	875	907	938	969	1001
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	696	726	755	785	815	845	874	904	934	964	993
Circulating Fluidized Bed - 500 MW - CCS	699	731	762	794	825	857	889	920	952	983	1015
Supercritical Pulverized Coal - 500 MW - CCS	694	724	753	783	812	842	871	901	930	960	989
Supercritical Pulverized Coal High Sulfur - 500 MW - CCS	703	731	760	788	817	845	873	902	930	959	987
Supercritical Pulverized Coal - 750 MW - CCS	659	689	718	748	778	808	837	867	897	927	956
Supercritical Pulverized Coal High Sulfur - 750 MW - CCS	664	692	720	749	777	805	833	861	889	918	946
1x1 IGCC - CCS	660	684	708	732	757	781	805	829	853	----	----
2x1 IGCC - CCS	601	625	649	673	697	721	745	769	793	----	----
2x1 IGCC High Sulfur - CCS	603	626	649	671	694	717	740	763	786	----	----
Wind Energy Conversion - 50 MW	299	288	277	265	----	----	----	----	----	----	----
Geothermal - 30 MW	586	582	578	574	570	565	559	553	547	540	533
Solar Photovoltaic - 50 kW	909	909	----	----	----	----	----	----	----	----	----
Solar Thermal Parabolic Trough - 100 MW	592	593	----	----	----	----	----	----	----	----	----
Solar Thermal Parabolic Dish - 1 2 MW	867	867	----	----	----	----	----	----	----	----	----
Solar Thermal Central Receiver - 50 MW	897	898	899	899	900	900	900	----	----	----	----
Solar Thermal Solar Chimney - 50 MW	758	758	758	757	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1848	1818	1789	1759	1729	1699	1670	1640	----	----	----
RDF Stoker-Fired - 7 MW	1831	1915	2000	2084	2169	2253	2338	2422	2507	----	----
Landfill Gas IC Engine - 5 MW	487	514	540	567	593	620	646	673	699	726	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	582	606	630	654	678	702	726	749	773	797	821
Sewage Sludge & Anaerobic Digestion - 085 MW	759	755	751	747	743	739	734	730	724	718	----
Bio Mass (Co-Fire)	391	411	431	451	471	491	512	532	552	572	592
Molten Carbonate Fuel Cell - 300 kW	539	596	653	709	766	823	880	937	993	1050	----
Spark Ignition Engine - 5 MW	419	482	545	607	670	733	796	858	921	984	----
Hydroelectric - New - 30 MW	622	616	611	605	599	----	----	----	----	----	----
Ohio Falls 9-10	391	385	379	372	----	----	----	----	----	----	----
Minimum Levelized $/kW	117	169	220	265	321	372	423	473	497	517	533

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- High 2007 ($/kW yr)
Heat Rate- High
Fuel Forecast- Base

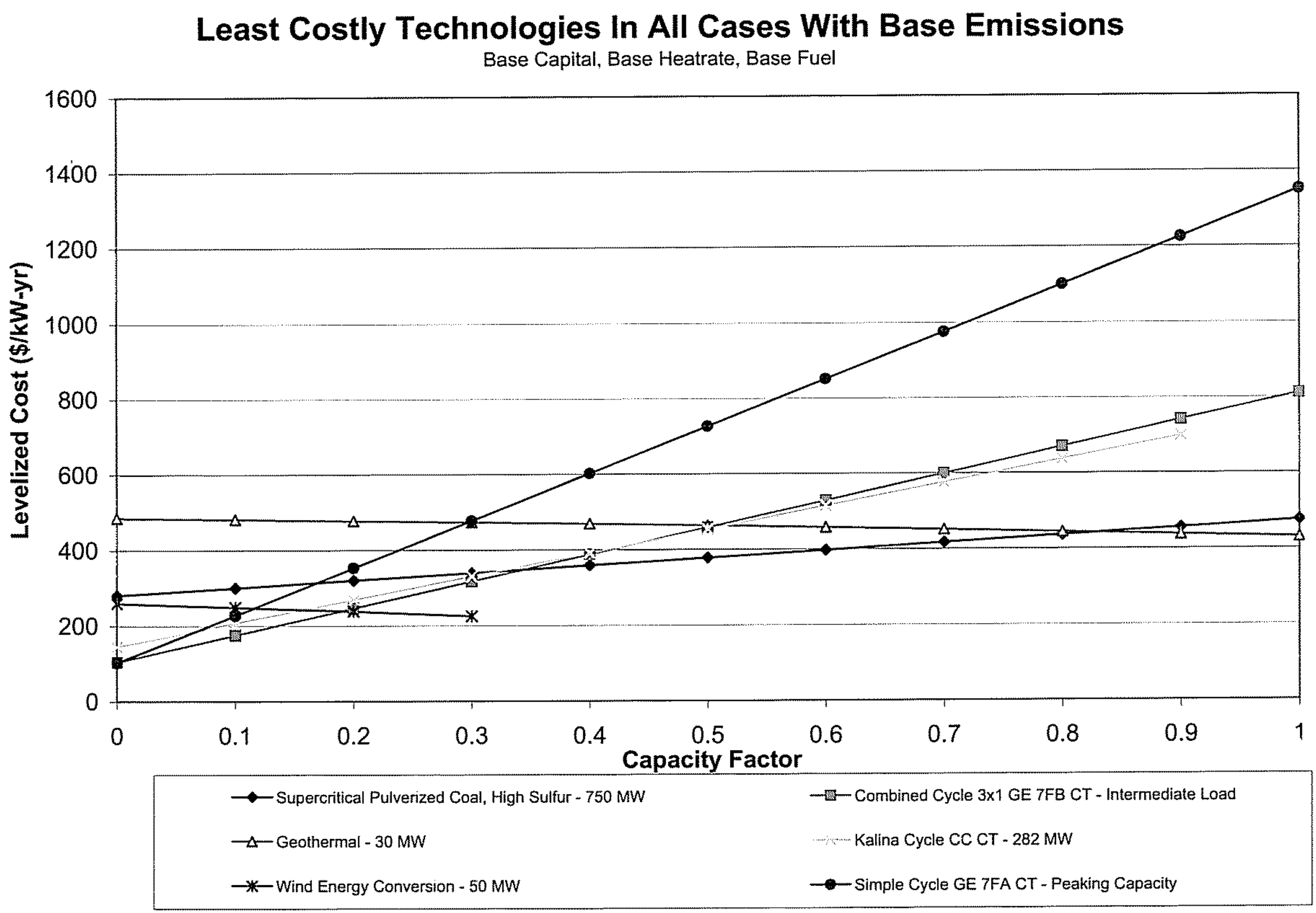
	Capacity Factors										
Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	194	257	320	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	271	329	387	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	181	275	369	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	199	321	443	565	687	809	931	1053	1175	1297	1419
Simple Cycle GE 7EA CT - Peaking Capacity	147	291	435	579	723	867	1011	1155	1299	1443	1587
Simple Cycle GE 7FA CT - Peaking Capacity	117	246	376	505	634	764	893	1022	1152	1281	1410
Combined Cycle GE 7EA CT - Intermediate Load	218	304	389	475	560	646	731	817	902	988	1073
Combined Cycle GE 7FA CT - Intermediate Load	165	240	314	389	464	538	613	687	762	837	911
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	139	214	288	363	437	512	587	661	736	811	885
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	118	192	266	340	413	487	561	635	709	783	857
Siemens 5000F CC CT - Intermediate Load	155	230	305	380	455	530	605	680	756	831	906
Humid Air Turbine Cycle CT - 366 MW	152	257	363	468	574	679	785	890	996	1101	----
Kalina Cycle CC CT - 282 MW	168	232	296	361	425	489	553	617	682	746	----
Cheng Cycle CT - 140 MW	175	252	330	407	484	562	639	716	794	871	----
Peaking Microturbine - 0 03 MW	468	643	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	504	652	800	948	1095	1243	1391	1539	1687	1835	1982
Subcritical Pulverized Coal - 250 MW	398	420	443	465	487	509	532	554	576	599	621
Subcritical Pulverized Coal - 500 MW	352	374	396	419	441	463	485	507	529	552	574
Subcritical Pulverized Coal, High Sulfur - 500 MW	357	378	399	420	441	461	482	503	524	545	566
Circulating Fluidized Bed - 250 MW	398	421	443	466	488	511	533	556	578	601	623
Circulating Fluidized Bed - 500 MW	355	377	400	422	444	466	489	511	533	556	578
Supercritical Pulverized Coal - 500 MW	361	382	403	424	444	465	486	507	528	549	569
Supercritical Pulverized Coal, High Sulfur - 500 MW	365	385	405	426	446	466	486	507	527	547	567
Supercritical Pulverized Coal - 750 MW	336	357	379	400	422	443	464	486	507	528	550
Supercritical Pulverized Coal, High Sulfur - 750 MW	339	359	379	399	420	440	460	480	500	520	540
Pressurized Fluidized Bed Combustion	523	549	574	600	625	651	676	702	728	----	----
1x1 IGCC	458	478	499	519	540	560	581	601	622	----	----
2x1 IGCC	410	430	451	471	491	512	532	552	573	----	----
2x1 IGCC, High Sulfur	410	429	448	467	486	505	523	542	561	----	----
Subcritical Pulverized Coal - 500 MW - CCS	687	719	751	782	814	846	878	910	942	973	1005
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	696	726	757	787	817	847	878	908	938	969	999
Circulating Fluidized Bed - 500 MW - CCS	699	731	763	795	828	860	892	924	956	988	1021
Supercritical Pulverized Coal - 500 MW - CCS	694	724	754	784	814	844	874	904	934	965	995
Supercritical Pulverized Coal, High Sulfur - 500 MW - CCS	703	732	761	790	818	847	876	905	934	963	991
Supercritical Pulverized Coal - 750 MW - CCS	659	689	720	750	780	810	841	871	901	932	962
Supercritical Pulverized Coal, High Sulfur - 750 MW - CCS	664	693	721	750	778	807	836	864	893	922	950
1x1 IGCC - CCS	660	684	709	733	758	782	807	831	856	----	----
2x1 IGCC - CCS	601	625	650	674	699	723	748	772	797	----	----
2x1 IGCC, High Sulfur - CCS	603	626	650	673	696	720	743	766	789	----	----
Wind Energy Conversion - 50 MW	299	288	277	265	----	----	----	----	----	----	----
Geothermal - 30 MW	586	582	578	574	570	565	559	553	547	540	533
Solar Photovoltaic - 50 kW	909	909	----	----	----	----	----	----	----	----	----
Solar Thermal, Parabolic Trough - 100 MW	592	593	----	----	----	----	----	----	----	----	----
Solar Thermal, Parabolic Dish - 1 2 MW	867	867	----	----	----	----	----	----	----	----	----
Solar Thermal, Central Receiver - 50 MW	897	898	899	899	900	900	900	----	----	----	----
Solar Thermal, Solar Chimney - 50 MW	758	758	758	757	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1848	1816	1783	1751	1718	1686	1654	1621	----	----	----
RDF Stoker-Fired - 7 MW	1831	1917	2003	2089	2175	2261	2347	2433	2519	----	----
Landfill Gas IC Engine - 5 MW	487	528	570	611	652	694	735	776	818	859	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	582	606	631	655	679	704	728	752	777	801	825
Sewage Sludge & Anaerobic Digestion - 085 MW	759	755	751	747	743	739	734	730	724	718	----
Bio Mass (Co-Fire)	391	411	432	452	473	493	514	534	554	575	595
Molten Carbonate Fuel Cell - 300 kW	539	622	705	788	871	953	1036	1119	1202	1285	----
Spark Ignition Engine - 5 MW	419	512	606	699	793	886	979	1073	1166	1260	----
Hydroelectric - New - 30 MW	622	616	611	605	599	----	----	----	----	----	----
Ohio Falls 9-10	391	385	379	372	----	----	----	----	----	----	----
Minimum Levelized $/kW	117	192	266	265	413	440	460	480	500	520	533

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- High **2007 ($/kW yr)**
Heat Rate- High
Fuel Forecast- High

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	194	257	320	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	271	329	387	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	181	286	392	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	199	346	492	639	786	932	1079	1226	1372	1519	1666
Simple Cycle GE 7EA CT - Peaking Capacity	147	322	496	671	846	1020	1195	1370	1544	1719	1894
Simple Cycle GE 7FA CT - Peaking Capacity	117	274	430	587	744	900	1057	1214	1370	1527	1684
Combined Cycle GE 7EA CT - Intermediate Load	218	324	431	537	643	750	856	962	1069	1175	1281
Combined Cycle GE 7FA CT - Intermediate Load	165	258	351	444	536	629	722	815	908	1001	1093
Combined Cycle 2x1 GE 7FA CT - Intermediate Load	139	232	325	417	510	603	696	789	882	974	1067
Combined Cycle 3x1 GE 7FB CT - Intermediate Load	118	210	302	394	486	578	670	763	855	947	1039
Siemens 5000F CC CT - Intermediate Load	155	248	342	435	528	622	715	808	902	995	1088
Humid Air Turbine Cycle CT - 366 MW	152	284	415	547	678	810	942	1073	1205	1337	----
Kalina Cycle CC CT - 282 MW	168	248	329	409	489	570	650	730	811	891	----
Cheng Cycle CT - 140 MW	175	271	367	464	560	656	752	848	944	1041	----
Peaking Microturbine - 0.03 MW	468	679	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	504	689	873	1058	1243	1427	1612	1796	1981	2166	2350
Subcritical Pulverized Coal - 250 MW	398	421	445	468	492	515	538	562	585	608	632
Subcritical Pulverized Coal - 500 MW	352	375	399	422	445	468	492	515	538	562	585
Subcritical Pulverized Coal, High Sulfur - 500 MW	357	379	401	423	445	467	488	510	532	554	576
Circulating Fluidized Bed - 250 MW	398	422	445	469	492	516	540	563	587	610	634
Circulating Fluidized Bed - 500 MW	355	378	402	425	449	472	495	519	542	566	589
Supercritical Pulverized Coal - 500 MW	361	383	405	427	449	471	493	515	537	559	581
Supercritical Pulverized Coal High Sulfur - 500 MW	365	386	407	429	450	471	492	514	535	556	577
Supercritical Pulverized Coal - 750 MW	336	358	381	403	426	448	471	493	516	538	561
Supercritical Pulverized Coal High Sulfur - 750 MW	339	360	381	402	423	445	466	487	508	529	550
Pressurized Fluidized Bed Combustion	523	550	577	603	630	657	684	710	737	----	----
1x1 IGCC	458	479	501	522	544	565	586	608	629	----	----
2x1 IGCC	410	431	453	474	495	516	538	559	580	----	----
2x1 IGCC, High Sulfur	410	430	450	470	489	509	529	549	569	----	----
Subcritical Pulverized Coal - 500 MW - CCS	687	720	754	787	821	854	887	921	954	987	1021
Subcritical Pulverized Coal, High Sulfur - 500 MW - CCS	696	728	759	791	822	854	886	917	949	981	1012
Circulating Fluidized Bed - 500 MW - CCS	699	733	766	800	833	867	901	934	968	1001	1035
Supercritical Pulverized Coal - 500 MW - CCS	694	725	757	788	820	851	883	914	946	977	1009
Supercritical Pulverized Coal High Sulfur - 500 MW - CCS	703	733	763	794	824	854	884	914	944	975	1005
Supercritical Pulverized Coal - 750 MW - CCS	659	691	722	754	785	817	849	880	912	943	975
Supercritical Pulverized Coal High Sulfur - 750 MW - CCS	664	694	724	754	784	814	844	874	904	934	963
1x1 IGCC - CCS	660	686	711	737	763	788	814	840	865	----	----
2x1 IGCC - CCS	601	627	652	678	704	729	755	781	806	----	----
2x1 IGCC. High Sulfur - CCS	603	627	652	676	701	725	749	774	798	----	----
Wind Energy Conversion - 50 MW	299	288	277	265	----	----	----	----	----	----	----
Geothermal - 30 MW	586	582	578	574	570	565	559	553	547	540	533
Solar Photovoltaic - 50 kW	909	909	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	592	593	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	867	867	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	897	898	899	899	900	900	900	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	758	758	758	757	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1848	1813	1778	1744	1709	1674	1639	1604	----	----	----
RDF Stoker-Fired - 7 MW	1831	1921	2012	2102	2193	2283	2374	2464	2555	----	----
Landfill Gas IC Engine - 5 MW	487	540	593	646	699	751	804	857	910	963	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	582	608	633	659	684	710	735	761	786	812	837
Sewage Sludge & Anaerobic Digestion - 085 MW	759	755	751	747	743	739	734	730	724	718	----
Bio Mass (Co-Fire)	391	413	434	456	477	499	520	542	563	585	606
Molten Carbonate Fuel Cell - 300 kW	539	642	745	849	952	1055	1158	1261	1365	1468	----
Spark Ignition Engine - 5 MW	419	536	654	771	889	1006	1124	1241	1359	1476	----
Hydroelectric - New - 30 MW	622	616	611	605	599	----	----	----	----	----	----
Ohio Falls 9-10	391	385	379	372	----	----	----	----	----	----	----
Minimum Levelized $/kW	117	210	277	265	423	445	466	487	508	529	533

Exhibit 7



Least Costly Technologies In All Cases With Base Emissions
Base Capital, Base Heatrate, Base Fuel
Levelized Cost ($/kW-yr)
1600
1400
1200
1000
800
600
400
200
0
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Capacity Factor
Supercritical Pulverized Coal, High Sulfur - 750 MW
Combined Cycle 3x1 GE 7FB CT - Intermediate Load
Geothermal - 30 MW
Kalina Cycle CC CT - 282 MW
Wind Energy Conversion - 50 MW
Simple Cycle GE 7FA CT - Peaking Capacity

Exhibit 8

30-Year Levelized Cost for
All Technologies over All Capacity
Factors with CO_2 Emissions
(High Price Forecast)

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost- Base 2007 ($/kW yr)
Heat Rate- Base
Fuel Forecast- Base

Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
						Capacity Factors					
Pumped Hydro Energy Storage - 500 MW	147	210	273	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	221	279	337	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	140	237	333	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	172	301	429	558	687	815	944	1073	1201	1330	1459
Simple Cycle GE 7EA CT - Peaking Capacity	128	280	432	584	736	888	1040	1192	1344	1496	1648
Simple Cycle GE 7FA CT - Peaking Capacity	102	239	375	512	649	785	922	1059	1195	1332	1469
Combined Cycle GE 7EA CT - Intermediate Load	191	282	373	464	555	646	737	828	919	1010	1101
Combined Cycle GE 7FA CT - Intermediate Load	144	224	303	383	462	542	621	701	780	860	939
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	122	201	281	360	439	519	598	677	757	836	915
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	104	183	261	340	418	497	575	654	733	811	890
Siemens 5000F CC CT - Intermediate Load	134	214	294	373	453	533	613	693	772	852	932
Humid Air Turbine Cycle CT - 366 MW	132	244	357	469	581	694	806	918	1031	1143	----
Kalina Cycle CC CT - 282 MW	145	213	282	350	419	487	556	624	693	761	----
Cheng Cycle CT - 140 MW	151	233	315	398	480	562	644	727	809	891	----
Peaking Microturbine - 0.03 MW	422	606	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0.03 MW	456	613	771	928	1086	1243	1401	1558	1715	1873	2030
Subcritical Pulverized Coal - 250 MW	331	364	398	431	464	497	531	564	597	630	664
Subcritical Pulverized Coal - 500 MW	291	324	357	390	424	457	490	523	556	589	623
Subcritical Pulverized Coal, High Sulfur - 500 MW	297	329	360	392	424	456	487	519	551	583	614
Circulating Fluidized Bed - 250 MW	330	364	397	431	464	498	532	565	599	632	666
Circulating Fluidized Bed - 500 MW	293	326	360	393	427	460	493	527	560	593	627
Supercritical Pulverized Coal - 500 MW	299	330	362	393	425	456	488	519	551	582	614
Supercritical Pulverized Coal, High Sulfur - 500 MW	303	334	364	395	426	457	487	518	549	580	610
Supercritical Pulverized Coal - 750 MW	277	309	341	373	405	437	469	501	533	565	597
Supercritical Pulverized Coal High Sulfur - 750 MW	280	311	341	372	403	433	464	494	525	556	586
Pressurized Fluidized Bed Combustion	412	450	488	525	563	601	639	677	715	----	----
1x1 IGCC	368	398	429	459	490	520	551	581	612	----	----
2x1 IGCC	327	357	388	418	448	479	509	539	570	----	----
2x1 IGCC, High Sulfur	327	356	385	414	443	471	500	529	558	----	----
Subcritical Pulverized Coal - 500 MW - CCS	524	557	589	622	654	687	720	*752*	*785*	*817*	*850*
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	532	563	594	625	656	687	718	749	781	812	843
Circulating Fluidized Bed - 500 MW - CCS	532	565	598	630	663	696	729	762	795	827	860
Supercritical Pulverized Coal - 500 MW - CCS	531	562	592	623	654	685	715	746	777	807	838
Supercritical Pulverized Coal, High Sulfur - 500 MW	538	568	597	627	656	686	716	745	775	805	834
Supercritical Pulverized Coal - 750 MW - CCS	501	532	563	594	625	656	687	718	749	779	810
Supercritical Pulverized Coal High Sulfur - 750 MW	505	534	564	593	623	652	681	711	740	770	799
1x1 IGCC - CCS	510	535	560	585	610	635	661	686	711	----	----
2x1 IGCC - CCS	*462*	*487*	*512*	*537*	*562*	*587*	*613*	*638*	*663*	----	----
2x1 IGCC High Sulfur - CCS	464	488	512	536	560	584	607	631	655	----	----
Wind Energy Conversion - 50 MW	259	248	237	225	----	----	----	----	----	----	----
Geothermal - 30 MW	484	480	476	472	467	462	456	449	442	435	428
Solar Photovoltaic - 50 kW	766	766	----	----	----	----	----	----	----	----	----
Solar Thermal Parabolic Trough - 100 MW	506	507	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1.2 MW	734	734	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	771	772	773	773	773	774	774	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	646	646	646	645	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1741	1773	1804	1836	1868	1900	1931	1963	----	----	----
RDF Stoker-Fired - 7 MW	1665	1774	1882	1991	2099	2208	2317	2425	2534	----	----
Landfill Gas IC Engine - 5 MW	455	508	562	615	668	722	775	828	882	935	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	489	526	563	600	637	674	711	748	785	821	858
Sewage Sludge & Anaerobic Digestion - .085 MW	693	695	698	700	703	705	707	708	709	708	----
Bio Mass (Co-Fire)	324	355	387	418	449	480	511	543	574	605	636
Molten Carbonate Fuel Cell - 300 kW	463	551	639	727	816	904	992	1080	1168	1256	----
Spark Ignition Engine - 5 MW	402	502	601	701	800	900	999	1099	1199	1298	----
Hydroelectric - New - 30 MW	473	467	462	456	449	----	----	----	----	----	----
Ohio Falls 9-10	293	287	281	273	----	----	----	----	----	----	----
Minimum Levelized $/kW	102	183	237	225	403	433	456	449	442	435	428

Exhibit 8

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost-Low 2007 ($/kW yr)
Heat Rate-Low
Fuel Forecast-Low

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	134	197	260	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	201	259	317	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	128	209	290	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	158	253	349	444	539	635	730	825	921	1016	1111
Simple Cycle GE 7EA CT - Peaking Capacity	118	229	339	450	561	671	782	893	1003	1114	1225
Simple Cycle GE 7FA CT - Peaking Capacity	94	193	293	392	491	591	690	789	889	988	1087
Combined Cycle GE 7EA CT - Intermediate Load	177	239	302	364	426	489	551	613	676	738	800
Combined Cycle GE 7FA CT - Intermediate Load	132	186	241	295	350	404	459	513	568	622	677
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	112	166	221	275	330	384	439	493	548	602	657
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	96	150	204	258	311	365	419	473	527	581	634
Siemens 5000F CC CT - Intermediate Load	124	179	233	288	343	397	452	507	561	616	671
Humid Air Turbine Cycle CT - 366 MW	123	199	276	352	428	505	581	657	734	810	----
Kalina Cycle CC CT - 282 MW	133	179	226	272	319	365	411	458	504	551	----
Cheng Cycle CT - 140 MW	139	195	252	308	365	421	478	534	591	647	----
Peaking Microturbine - 0 03 MW	398	532	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	430	537	644	751	858	966	1073	1180	1287	1394	1501
Subcritical Pulverized Coal - 250 MW	305	337	368	400	431	463	494	526	557	589	620
Subcritical Pulverized Coal - 500 MW	267	298	330	361	393	424	455	487	518	549	581
Subcritical Pulverized Coal, High Sulfur - 500 MW	272	302	332	362	392	422	452	482	512	543	573
Circulating Fluidized Bed - 250 MW	303	335	367	398	430	462	494	526	558	589	621
Circulating Fluidized Bed - 500 MW	269	301	332	364	395	427	459	490	522	553	585
Supercritical Pulverized Coal - 500 MW	275	305	335	364	394	424	454	484	514	543	573
Supercritical Pulverized Coal High Sulfur - 500 MW	278	307	336	365	395	424	453	482	511	540	570
Supercritical Pulverized Coal - 750 MW	254	284	315	345	375	406	436	466	497	527	557
Supercritical Pulverized Coal. High Sulfur - 750 MW	256	285	314	343	372	402	431	460	489	518	547
Pressurized Fluidized Bed Combustion	364	400	436	472	508	544	579	615	651	----	----
1x1 IGCC	337	366	395	424	453	481	510	539	568	----	----
2x1 IGCC	300	329	358	386	415	444	473	501	530	----	----
2x1 IGCC, High Sulfur	299	326	354	381	408	436	463	490	518	----	----
Subcritical Pulverized Coal - 500 MW - CCS	*478*	*509*	*540*	*570*	*601*	*632*	*663*	*694*	*725*	*755*	*786*
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	486	515	545	574	604	633	662	692	721	751	780
Circulating Fluidized Bed - 500 MW - CCS	509	540	571	602	633	664	695	726	757	787	818
Supercritical Pulverized Coal - 500 MW - CCS	507	536	565	594	623	652	681	710	739	768	797
Supercritical Pulverized Coal High Sulfur - 500 MW	514	542	570	598	626	654	682	710	739	767	795
Supercritical Pulverized Coal - 750 MW - CCS	479	508	537	567	596	625	654	683	712	742	771
Supercritical Pulverized Coal. High Sulfur - 750 MW	482	510	537	565	593	621	648	676	704	732	759
1x1 IGCC - CCS	488	512	535	559	583	606	630	654	677	----	----
2x1 IGCC - CCS	442	466	489	513	537	560	584	608	631	----	----
2x1 IGCC. High Sulfur - CCS	444	467	489	512	534	557	580	602	625	----	----
Wind Energy Conversion - 50 MW	238	227	216	203	----	----	----	----	----	----	----
Geothermal - 30 MW	443	439	435	431	426	421	414	407	400	393	386
Solar Photovoltaic - 50 kW	*622*	*622*	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	421	422	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	601	601	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	645	646	647	647	647	648	647	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	533	533	533	532	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1634	1666	1698	1730	1761	1793	1825	1857	----	----	----
RDF Stoker-Fired - 7 MW	1499	1601	1704	1806	1909	2011	2114	2216	2319	----	----
Landfill Gas IC Engine - 5 MW	422	458	495	531	568	604	641	677	714	750	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	451	486	521	556	591	626	661	696	731	766	800
Sewage Sludge & Anaerobic Digestion - 085 MW	627	629	631	633	635	637	639	639	639	638	----
Bio Mass (Co-Fire)	298	328	357	386	416	445	475	504	534	563	592
Molten Carbonate Fuel Cell - 300 kW	388	448	509	569	629	690	750	810	870	931	----
Spark Ignition Engine - 5 MW	383	450	516	583	650	717	783	850	917	983	----
Hydroelectric - New - 30 MW	409	403	398	392	384	----	----	----	----	----	----
Ohio Falls 9-10	279	273	267	259	----	----	----	----	----	----	----
Minimum Levelized $/kW	94	150	204	203	311	365	411	407	400	393	386

Exhibit 8

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost-Low 2007 ($/kW yr)
Heat Rate-Low
Fuel Forecast- Base

Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
					Capacity Factors						
Pumped Hydro Energy Storage - 500 MW	134	197	260	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	201	259	317	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	128	222	316	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	158	281	405	528	651	775	898	1021	1145	1268	1391
Simple Cycle GE 7EA CT - Peaking Capacity	118	264	410	556	702	848	994	1140	1286	1432	1578
Simple Cycle GE 7FA CT - Peaking Capacity	94	225	357	488	619	751	882	1013	1145	1276	1407
Combined Cycle GE 7EA CT - Intermediate Load	177	264	350	437	524	610	697	784	870	957	1044
Combined Cycle GE 7FA CT - Intermediate Load	132	208	284	359	435	511	587	662	738	814	890
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	112	188	263	339	414	490	566	641	717	792	868
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	96	171	246	321	396	471	546	621	696	771	846
Siemens 5000F CC CT - Intermediate Load	124	200	276	352	428	504	580	656	732	808	884
Humid Air Turbine Cycle CT - 366 MW	123	230	337	444	550	657	764	871	978	1085	----
Kalina Cycle CC CT - 282 MW	133	198	263	329	394	459	524	589	654	720	----
Cheng Cycle CT - 140 MW	139	217	296	374	453	531	609	688	766	845	----
Peaking Microturbine - 0.03 MW	398	575	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	430	580	730	880	1030	1179	1329	1479	1629	1779	1929
Subcritical Pulverized Coal - 250 MW	305	337	368	400	432	464	495	527	559	591	622
Subcritical Pulverized Coal - 500 MW	267	299	330	362	393	425	457	488	520	551	583
Subcritical Pulverized Coal, High Sulfur - 500 MW	272	302	333	363	393	423	454	484	514	545	575
Circulating Fluidized Bed - 250 MW	303	335	367	399	431	463	495	527	559	591	624
Circulating Fluidized Bed - 500 MW	269	301	333	364	396	428	460	492	524	555	587
Supercritical Pulverized Coal - 500 MW	275	305	335	365	395	425	455	485	515	545	576
Supercritical Pulverized Coal. High Sulfur - 500 MW	278	307	337	366	395	424	454	483	512	541	571
Supercritical Pulverized Coal - 750 MW	254	285	315	346	376	407	437	468	498	529	559
Supercritical Pulverized Coal. High Sulfur - 750 MW	256	285	315	344	373	403	432	461	491	520	549
Pressurized Fluidized Bed Combustion	364	400	436	472	509	545	581	617	653	----	----
1x1 IGCC	337	366	395	424	453	482	511	540	569	----	----
2x1 IGCC	300	329	358	387	416	444	473	502	531	----	----
2x1 IGCC, High Sulfur	299	327	354	382	409	437	465	492	520	----	----
Subcritical Pulverized Coal - 500 MW - CCS	478	509	541	572	603	634	666	697	728	759	791
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	486	516	545	575	605	635	664	694	724	754	783
Circulating Fluidized Bed - 500 MW - CCS	509	540	572	603	635	666	697	729	760	791	823
Supercritical Pulverized Coal - 500 MW - CCS	507	536	566	595	625	654	683	713	742	772	801
Supercritical Pulverized Coal. High Sulfur - 500 MW	514	542	571	599	628	656	684	713	741	770	798
Supercritical Pulverized Coal - 750 MW - CCS	479	509	538	568	597	627	657	686	716	746	775
Supercritical Pulverized Coal. High Sulfur - 750 MW	482	510	538	567	595	623	651	679	707	736	764
1x1 IGCC - CCS	488	512	536	560	584	608	632	656	680	----	----
2x1 IGCC - CCS	442	466	490	514	538	562	586	610	634	----	----
2x1 IGCC. High Sulfur - CCS	444	467	490	513	536	559	582	605	628	----	----
Wind Energy Conversion - 50 MW	238	227	216	203	----	----	----	----	----	----	----
Geothermal - 30 MW	443	439	435	431	426	421	414	407	400	393	386
Solar Photovoltaic - 50 kW	622	622	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	421	422	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	601	601	----	----	----	----	----	----	----	----	----
Solar Thermal Central Receiver - 50 MW	645	646	647	647	647	648	647	----	----	----	----
Solar Thermal Solar Chimney - 50 MW	533	533	533	532	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1634	1666	1697	1729	1761	1793	1824	1856	----	----	----
RDF Stoker-Fired - 7 MW	1499	1603	1706	1810	1913	2017	2120	2224	2327	----	----
Landfill Gas IC Engine - 5 MW	422	472	523	573	623	674	724	774	825	875	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	451	486	522	557	592	627	662	698	733	768	803
Sewage Sludge & Anaerobic Digestion - 085 MW	627	629	631	633	635	637	639	639	639	638	----
Bio Mass (Co-Fire)	298	328	357	387	417	446	476	506	535	565	595
Molten Carbonate Fuel Cell - 300 kW	388	472	556	640	724	808	892	976	1060	1144	----
Spark Ignition Engine - 5 MW	383	478	572	667	761	856	950	1045	1140	1234	----
Hydroelectric - New - 30 MW	409	403	398	392	384	----	----	----	----	----	----
Ohio Falls 9-10	279	273	267	259	----	----	----	----	----	----	----
Minimum Levelized $/kW	94	171	216	203	373	403	414	407	400	393	386

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost-Low 2007 ($/kW yr)
Heat Rate-Low
Fuel Forecast- High

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	134	197	260	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	201	259	317	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	128	233	338	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	158	303	449	594	739	885	1030	1175	1321	1466	1611
Simple Cycle GE 7EA CT - Peaking Capacity	118	291	465	638	811	985	1158	1331	1505	1678	1851
Simple Cycle GE 7FA CT - Peaking Capacity	94	250	406	562	718	874	1030	1186	1342	1498	1654
Combined Cycle GE 7EA CT - Intermediate Load	177	283	388	494	600	705	811	917	1022	1128	1234
Combined Cycle GE 7FA CT - Intermediate Load	132	224	316	409	501	593	685	777	870	962	1054
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	*112*	*204*	*296*	*389*	*481*	*573*	*665*	*757*	*849*	*942*	*1034*
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	96	187	279	370	462	553	645	736	827	919	1010
Siemens 5000F CC CT - Intermediate Load	124	217	309	402	495	587	680	773	866	958	1051
Humid Air Turbine Cycle CT - 366 MW	123	254	385	515	646	777	908	1038	1169	1300	----
Kalina Cycle CC CT - 282 MW	133	213	293	372	452	532	612	692	771	851	----
Cheng Cycle CT - 140 MW	139	234	330	425	521	616	712	807	902	998	----
Peaking Microturbine - 0 03 MW	398	608	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	430	613	797	980	1163	1346	1530	1713	1896	2080	2263
Subcritical Pulverized Coal - 250 MW	305	337	370	402	435	467	499	532	564	596	629
Subcritical Pulverized Coal - 500 MW	267	299	332	364	396	428	461	493	525	557	590
Subcritical Pulverized Coal, High Sulfur - 500 MW	272	303	334	365	396	427	458	489	520	551	582
Circulating Fluidized Bed - 250 MW	303	336	368	401	434	467	499	532	565	597	630
Circulating Fluidized Bed - 500 MW	269	301	334	366	399	431	464	496	529	561	594
Supercritical Pulverized Coal - 500 MW	275	306	336	367	397	428	459	489	520	550	581
Supercritical Pulverized Coal, High Sulfur - 500 MW	*278*	*308*	*338*	*368*	*398*	*428*	*458*	*488*	*518*	*548*	*577*
Supercritical Pulverized Coal - 750 MW	254	285	316	348	379	410	441	472	504	535	566
Supercritical Pulverized Coal High Sulfur - 750 MW	256	286	316	346	375	405	435	465	495	525	555
Pressurized Fluidized Bed Combustion	364	401	438	475	511	548	585	622	659	----	----
1x1 IGCC	337	367	396	426	455	485	515	544	574	----	----
2x1 IGCC	300	329	359	388	418	447	477	506	536	----	----
2x1 IGCC, High Sulfur	299	327	355	384	412	440	468	496	524	----	----
Subcritical Pulverized Coal - 500 MW - CCS	478	510	543	575	608	640	673	705	738	770	803
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	486	517	548	579	610	641	672	703	734	765	796
Circulating Fluidized Bed - 500 MW - CCS	509	542	574	607	640	673	705	738	771	803	836
Supercritical Pulverized Coal - 500 MW - CCS	507	538	568	599	629	660	691	721	752	782	813
Supercritical Pulverized Coal, High Sulfur - 500 MW	514	544	573	603	632	662	691	721	750	780	809
Supercritical Pulverized Coal - 750 MW - CCS	479	510	541	571	602	633	664	695	726	756	787
Supercritical Pulverized Coal High Sulfur - 750 MW	482	511	541	570	599	628	658	687	716	746	775
1x1 IGCC - CCS	*488*	*513*	*538*	*563*	*588*	*613*	*638*	*663*	*688*	----	----
2x1 IGCC - CCS	442	467	492	517	542	567	592	617	642	----	----
2x1 IGCC. High Sulfur - CCS	444	468	492	515	539	563	587	610	634	----	----
Wind Energy Conversion - 50 MW	238	227	216	203	----	----	----	----	----	----	----
Geothermal - 30 MW	443	439	435	431	426	421	414	407	400	393	386
Solar Photovoltaic - 50 kW	622	622	----	----	----	----	----	----	----	----	----
Solar Thermal, Parabolic Trough - 100 MW	421	422	----	----	----	----	----	----	----	----	----
Solar Thermal, Parabolic Dish - 1 2 MW	601	601	----	----	----	----	----	----	----	----	----
Solar Thermal, Central Receiver - 50 MW	645	646	647	647	647	648	647	----	----	----	----
Solar Thermal, Solar Chimney - 50 MW	533	533	533	532	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1634	1666	1697	1729	1761	1793	1824	1856	----	----	----
RDF Stoker-Fired - 7 MW	1499	1606	1712	1819	1925	2032	2139	2245	2352	----	----
Landfill Gas IC Engine - 5 MW	422	483	544	606	667	728	789	851	912	973	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	451	487	523	559	595	631	667	703	739	774	810
Sewage Sludge & Anaerobic Digestion - 085 MW	*627*	*629*	*631*	*633*	*635*	*637*	*639*	*639*	*639*	*638*	----
Bio Mass (Co-Fire)	298	328	359	389	419	450	480	510	541	571	601
Molten Carbonate Fuel Cell - 300 kW	388	490	593	695	798	900	1003	1105	1208	1310	----
Spark Ignition Engine - 5 MW	383	499	616	732	849	965	1081	1198	1314	1430	----
Hydroelectric - New - 30 MW	409	403	398	392	384	----	----	----	----	----	----
Ohio Falls 9-10	279	273	267	259	----	----	----	----	----	----	----
Minimum Levelized $/kW	94	187	216	203	375	405	414	407	400	393	386

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost-Low **2007 ($/kW yr)**
Heat Rate- Base
Fuel Forecast-Low

Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
						Capacity Factors					
Pumped Hydro Energy Storage - 500 MW	134	197	260	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	201	259	317	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	128	211	293	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	159	258	356	455	554	652	751	850	948	1047	1146
Simple Cycle GE 7EA CT - Peaking Capacity	119	234	348	463	578	692	807	922	1036	1151	1266
Simple Cycle GE 7FA CT - Peaking Capacity	95	198	302	405	508	612	715	818	922	1025	1128
Combined Cycle GE 7EA CT - Intermediate Load	178	243	309	374	439	505	570	635	701	766	831
Combined Cycle GE 7FA CT - Intermediate Load	133	190	247	304	361	418	475	533	590	647	704
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	*113*	*170*	*227*	*284*	*341*	*398*	*455*	*512*	*570*	*627*	*684*
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	97	153	210	266	323	379	436	492	549	605	662
Siemens 5000F CC CT - Intermediate Load	125	182	240	297	354	411	469	526	583	641	698
Humid Air Turbine Cycle CT - 366 MW	124	204	284	364	445	525	605	685	765	845	----
Kalina Cycle CC CT - 282 MW	134	183	231	280	329	377	426	475	524	572	----
Cheng Cycle CT - 140 MW	139	198	257	317	376	435	494	554	613	672	----
Peaking Microturbine - 0 03 MW	399	538	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	433	545	658	770	882	995	1107	1220	1332	1444	1557
Subcritical Pulverized Coal - 250 MW	305	338	371	404	437	470	503	536	569	602	635
Subcritical Pulverized Coal - 500 MW	267	300	333	366	399	432	465	498	530	563	596
Subcritical Pulverized Coal, High Sulfur - 500 MW	272	304	335	367	398	430	461	493	524	556	587
Circulating Fluidized Bed - 250 MW	303	336	370	403	436	470	503	537	570	603	637
Circulating Fluidized Bed - 500 MW	269	302	335	368	402	435	468	501	534	567	601
Supercritical Pulverized Coal - 500 MW	275	306	338	369	400	431	463	494	525	556	588
Supercritical Pulverized Coal High Sulfur - 500 MW	*278*	*309*	*339*	*370*	*400*	*431*	*461*	*492*	*522*	*553*	*583*
Supercritical Pulverized Coal - 750 MW	254	286	317	349	381	413	444	476	508	540	571
Supercritical Pulverized Coal High Sulfur - 750 MW	256	286	317	347	378	408	439	469	499	530	560
Pressurized Fluidized Bed Combustion	364	402	439	477	514	552	589	627	665	----	----
1x1 IGCC	337	367	397	428	458	488	518	548	579	----	----
2x1 IGCC	300	330	360	390	420	450	481	511	541	----	----
2x1 IGCC, High Sulfur	299	328	356	385	414	442	471	500	528	----	----
Subcritical Pulverized Coal - 500 MW - CCS	478	510	542	574	607	639	671	703	735	767	800
Subcritical Pulverized Coal High Sulfur - 500 MW - (	486	517	547	578	608	639	670	700	731	762	792
Circulating Fluidized Bed - 500 MW - CCS	509	541	574	606	639	671	703	736	768	800	833
Supercritical Pulverized Coal - 500 MW - CCS	507	537	568	598	628	658	689	719	749	780	810
Supercritical Pulverized Coal High Sulfur - 500 MW	514	543	573	602	631	660	690	719	748	778	807
Supercritical Pulverized Coal - 750 MW - CCS	479	509	540	570	601	631	662	692	723	753	784
Supercritical Pulverized Coal High Sulfur - 750 MW	482	511	540	569	598	627	656	685	714	743	772
1x1 IGCC - CCS	*488*	*513*	*537*	*562*	*587*	*612*	*636*	*661*	*686*	----	----
2x1 IGCC - CCS	442	467	491	516	541	566	590	615	640	----	----
2x1 IGCC, High Sulfur - CCS	444	468	491	515	538	562	585	609	632	----	----
Wind Energy Conversion - 50 MW	238	227	216	203	----	----	----	----	----	----	----
Geothermal - 30 MW	443	439	435	431	426	421	414	407	400	393	386
Solar Photovoltaic - 50 kW	622	622	----	----	----	----	----	----	----	----	----
Solar Thermal, Parabolic Trough - 100 MW	421	422	----	----	----	----	----	----	----	----	----
Solar Thermal Parabolic Dish - 1 2 MW	601	601	----	----	----	----	----	----	----	----	----
Solar Thermal, Central Receiver - 50 MW	645	646	647	647	647	648	647	----	----	----	----
Solar Thermal, Solar Chimney - 50 MW	533	533	533	532	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1634	1666	1697	1729	1761	1793	1824	1856	----	----	----
RDF Stoker-Fired - 7 MW	1499	1607	1714	1822	1929	2037	2144	2252	2359	----	----
Landfill Gas IC Engine - 5 MW	422	461	499	538	576	615	653	692	730	769	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	451	488	525	561	598	635	672	708	745	781	818
Sewage Sludge & Anaerobic Digestion - 085 MW	*627*	*629*	*632*	*634*	*637*	*639*	*641*	*642*	*642*	*641*	----
Bio Mass (Co-Fire)	298	329	360	391	422	453	483	514	545	576	607
Molten Carbonate Fuel Cell - 300 kW	389	452	515	579	642	705	768	831	895	958	----
Spark Ignition Engine - 5 MW	385	455	525	596	666	736	806	876	947	1017	----
Hydroelectric - New - 30 MW	409	403	398	392	384	----	----	----	----	----	----
Ohio Falls 9-10	279	273	267	259	----	----	----	----	----	----	----
Minimum Levelized $/kW	95	153	210	203	323	377	414	407	400	393	386

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost-Low **2007 ($/kW yr)**
Heat Rate- Base
Fuel Forecast- Base

					Capacity Factors						
Technology	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Pumped Hydro Energy Storage - 500 MW	134	197	260	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	201	259	317	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	128	225	321	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	159	288	416	545	674	802	931	1060	1188	1317	1446
Simple Cycle GE 7EA CT - Peaking Capacity	119	271	423	575	727	879	1031	1183	1335	1487	1639
Simple Cycle GE 7FA CT - Peaking Capacity	95	232	368	505	642	778	915	1052	1188	1325	1462
Combined Cycle GE 7EA CT - Intermediate Load	178	269	360	451	542	633	724	815	906	997	1088
Combined Cycle GE 7FA CT - Intermediate Load	133	213	292	372	451	531	610	690	769	849	928
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	*113*	*192*	*272*	*351*	*430*	*510*	*589*	*668*	*748*	*827*	*906*
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	97	176	254	333	411	490	568	647	726	804	883
Siemens 5000F CC CT - Intermediate Load	125	205	285	364	444	524	604	684	763	843	923
Humid Air Turbine Cycle CT - 366 MW	124	236	349	461	573	686	798	910	1023	1135	----
Kalina Cycle CC CT - 282 MW	134	202	271	339	408	476	545	613	682	750	----
Cheng Cycle CT - 140 MW	139	221	303	386	468	550	632	715	797	879	----
Peaking Microturbine - 0 03 MW	399	583	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	433	590	748	905	1063	1220	1378	1535	1692	1850	2007
Subcritical Pulverized Coal - 250 MW	305	338	372	405	438	471	505	538	571	604	638
Subcritical Pulverized Coal - 500 MW	267	300	333	366	400	433	466	499	532	565	599
Subcritical Pulverized Coal, High Sulfur - 500 MW	272	304	335	367	399	431	462	494	526	558	589
Circulating Fluidized Bed - 250 MW	303	337	370	404	437	471	505	538	572	605	639
Circulating Fluidized Bed - 500 MW	269	302	336	369	403	436	469	503	536	569	603
Supercritical Pulverized Coal - 500 MW	275	306	338	369	401	432	464	495	527	558	590
Supercritical Pulverized Coal High Sulfur - 500 MW	*278*	*309*	*339*	*370*	*401*	*432*	*462*	*493*	*524*	*555*	*585*
Supercritical Pulverized Coal - 750 MW	254	286	318	350	382	414	446	478	510	542	574
Supercritical Pulverized Coal, High Sulfur - 750 MW	256	287	317	348	379	409	440	470	501	532	562
Pressurized Fluidized Bed Combustion	364	402	440	477	515	553	591	629	667	----	----
1x1 IGCC	337	367	398	428	459	489	520	550	581	----	----
2x1 IGCC	300	330	361	391	421	452	482	512	543	----	----
2x1 IGCC, High Sulfur	299	328	357	386	415	443	472	501	530	----	----
Subcritical Pulverized Coal - 500 MW - CCS	478	511	543	576	608	641	674	706	739	771	804
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	486	517	548	579	610	641	672	703	735	766	797
Circulating Fluidized Bed - 500 MW - CCS	509	542	575	607	640	673	706	739	772	804	837
Supercritical Pulverized Coal - 500 MW - CCS	507	538	568	599	630	661	691	722	753	783	814
Supercritical Pulverized Coal, High Sulfur - 500 MW	514	544	573	603	632	662	692	721	751	781	810
Supercritical Pulverized Coal - 750 MW - CCS	479	510	541	572	603	634	665	696	727	757	788
Supercritical Pulverized Coal High Sulfur - 750 MW	482	511	541	570	600	629	658	688	717	747	776
1x1 IGCC - CCS	*488*	*513*	*538*	*563*	*588*	*613*	*639*	*664*	*689*	----	----
2x1 IGCC - CCS	442	467	492	517	542	567	593	618	643	----	----
2x1 IGCC, High Sulfur - CCS	444	468	492	516	540	564	587	611	635	----	----
Wind Energy Conversion - 50 MW	238	227	216	203	----	----	----	----	----	----	----
Geothermal - 30 MW	443	439	435	431	426	421	414	407	400	393	386
Solar Photovoltaic - 50 kW	622	622	----	----	----	----	----	----	----	----	----
Solar Thermal Parabolic Trough - 100 MW	421	422	----	----	----	----	----	----	----	----	----
Solar Thermal Parabolic Dish - 1 2 MW	601	601	----	----	----	----	----	----	----	----	----
Solar Thermal, Central Receiver - 50 MW	645	646	647	647	647	648	647	----	----	----	----
Solar Thermal, Solar Chimney - 50 MW	533	533	533	532	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1634	1666	1697	1729	1761	1793	1824	1856	----	----	----
RDF Stoker-Fired - 7 MW	1499	1608	1716	1825	1933	2042	2151	2259	2368	----	----
Landfill Gas IC Engine - 5 MW	422	475	529	582	635	689	742	795	849	902	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	451	488	525	562	599	636	673	710	747	783	820
Sewage Sludge & Anaerobic Digestion - 085 MW	*627*	*629*	*632*	*634*	*637*	*639*	*641*	*642*	*642*	*641*	----
Bio Mass (Co-Fire)	298	329	361	392	423	454	485	517	548	579	610
Molten Carbonate Fuel Cell - 300 kW	389	477	565	653	742	830	918	1006	1094	1182	----
Spark Ignition Engine - 5 MW	385	485	584	684	783	883	982	1082	1182	1281	----
Hydroelectric - New - 30 MW	409	403	398	392	384	----	----	----	----	----	----
Ohio Falls 9-10	279	273	267	259	----	----	----	----	----	----	----
Minimum Levelized $/kW	95	176	216	203	379	409	414	407	400	393	386

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost-Low **2007 ($/kW yr)**
Heat Rate- Base
Fuel Forecast- High

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	134	197	260	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	201	259	317	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	128	236	344	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	159	311	463	615	767	919	1071	1223	1375	1527	1679
Simple Cycle GE 7EA CT - Peaking Capacity	119	300	482	663	844	1026	1207	1388	1570	1751	1932
Simple Cycle GE 7FA CT - Peaking Capacity	95	258	420	583	746	908	1071	1234	1396	1559	1722
Combined Cycle GE 7EA CT - Intermediate Load	178	289	400	511	622	733	844	955	1066	1177	1288
Combined Cycle GE 7FA CT - Intermediate Load	133	230	327	424	521	618	714	811	908	1005	1102
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	113	210	306	403	500	597	693	790	887	984	1080
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	97	193	289	385	481	577	673	769	865	961	1057
Siemens 5000F CC CT - Intermediate Load	125	222	320	417	514	611	709	806	903	1000	1098
Humid Air Turbine Cycle CT - 366 MW	124	261	399	536	673	810	948	1085	1222	1360	----
Kalina Cycle CC CT - 282 MW	134	218	302	386	469	553	637	721	805	889	----
Cheng Cycle CT - 140 MW	139	239	339	440	540	640	740	841	941	1041	----
Peaking Microturbine - 0 03 MW	399	618	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	433	626	818	1011	1203	1396	1588	1781	1974	2166	2359
Subcritical Pulverized Coal - 250 MW	305	339	373	407	441	475	509	542	576	610	644
Subcritical Pulverized Coal - 500 MW	267	301	335	368	402	436	470	504	538	571	605
Subcritical Pulverized Coal, High Sulfur - 500 MW	272	304	337	369	402	434	466	499	531	564	596
Circulating Fluidized Bed - 250 MW	303	337	371	406	440	474	508	543	577	611	645
Circulating Fluidized Bed - 500 MW	269	303	337	371	405	439	473	507	541	575	609
Supercritical Pulverized Coal - 500 MW	275	307	339	371	404	436	468	500	532	564	597
Supercritical Pulverized Coal, High Sulfur - 500 MW	278	309	341	372	403	434	466	497	528	560	591
Supercritical Pulverized Coal - 750 MW	254	287	319	352	384	417	450	482	515	548	580
Supercritical Pulverized Coal, High Sulfur - 750 MW	256	287	319	350	381	412	444	475	506	538	569
Pressurized Fluidized Bed Combustion	364	403	441	480	519	557	596	635	673	----	----
1x1 IGCC	337	368	399	430	461	492	523	554	585	----	----
2x1 IGCC	300	331	362	393	424	455	485	516	547	----	----
2x1 IGCC, High Sulfur	299	328	358	387	417	446	476	505	535	----	----
Subcritical Pulverized Coal - 500 MW - CCS	478	512	546	580	614	648	682	716	749	783	817
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	486	518	551	583	615	647	680	712	744	777	809
Circulating Fluidized Bed - 500 MW - CCS	509	543	577	611	646	680	714	748	782	816	850
Supercritical Pulverized Coal - 500 MW - CCS	507	539	571	603	635	667	699	731	763	795	827
Supercritical Pulverized Coal, High Sulfur - 500 MW	514	545	576	606	637	668	699	730	761	791	822
Supercritical Pulverized Coal - 750 MW - CCS	479	511	543	575	608	640	672	704	736	768	801
Supercritical Pulverized Coal High Sulfur - 750 MW	482	513	543	574	604	635	666	696	727	757	788
1x1 IGCC - CCS	488	514	540	566	593	619	645	671	697	----	----
2x1 IGCC - CCS	442	468	494	520	546	572	598	624	650	----	----
2x1 IGCC, High Sulfur - CCS	444	469	494	519	543	568	593	618	643	----	----
Wind Energy Conversion - 50 MW	238	227	216	203	----	----	----	----	----	----	----
Geothermal - 30 MW	443	439	435	431	426	421	414	407	400	393	386
Solar Photovoltaic - 50 kW	622	622	----	----	----	----	----	----	----	----	----
Solar Thermal, Parabolic Trough - 100 MW	421	422	----	----	----	----	----	----	----	----	----
Solar Thermal Parabolic Dish - 1 2 MW	601	601	----	----	----	----	----	----	----	----	----
Solar Thermal, Central Receiver - 50 MW	645	646	647	647	647	648	647	----	----	----	----
Solar Thermal Solar Chimney - 50 MW	533	533	533	532	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1634	1666	1697	1729	1760	1792	1824	1855	----	----	----
RDF Stoker-Fired - 7 MW	1499	1611	1723	1835	1947	2058	2170	2282	2394	----	----
Landfill Gas IC Engine - 5 MW	422	487	551	616	681	745	810	875	939	1004	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	451	489	527	564	602	640	677	715	753	790	828
Sewage Sludge & Anaerobic Digestion - 085 MW	627	629	632	634	637	639	641	642	642	641	----
Bio Mass (Co-Fire)	298	330	362	394	426	458	489	521	553	585	617
Molten Carbonate Fuel Cell - 300 kW	389	497	604	712	820	927	1035	1142	1250	1358	----
Spark Ignition Engine - 5 MW	385	508	630	753	875	998	1120	1243	1365	1488	----
Hydroelectric - New - 30 MW	409	403	398	392	384	----	----	----	----	----	----
Ohio Falls 9-10	279	273	267	259	----	----	----	----	----	----	----
Minimum Levelized $/kW	95	193	216	203	381	412	414	407	400	393	386

Exhibit 8

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost-Low **2007 ($/kW yr)**
Heat Rate- High
Fuel Forecast-Low

	Capacity Factors										
Technology	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Pumped Hydro Energy Storage - 500 MW	134	197	260	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	201	259	317	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	128	212	296	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	160	262	364	466	568	670	772	874	976	1078	1180
Simple Cycle GE 7EA CT - Peaking Capacity	120	239	359	478	597	717	836	955	1075	1194	1313
Simple Cycle GE 7FA CT - Peaking Capacity	96	203	311	418	525	633	740	847	955	1062	1169
Combined Cycle GE 7EA CT - Intermediate Load	179	247	316	384	452	521	589	657	726	794	862
Combined Cycle GE 7FA CT - Intermediate Load	134	194	253	313	373	432	492	552	611	671	731
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	114	174	233	293	353	412	472	532	591	651	711
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	97	156	215	274	333	392	451	510	569	628	688
Siemens 5000F CC CT - Intermediate Load	126	186	246	306	366	426	486	546	606	666	727
Humid Air Turbine Cycle CT - 366 MW	126	210	294	378	461	545	629	713	797	881	----
Kalina Cycle CC CT - 282 MW	134	185	236	287	338	389	440	491	542	593	----
Cheng Cycle CT - 140 MW	140	202	264	326	388	450	512	574	636	697	----
Peaking Microturbine - 0.03 MW	400	544	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	436	554	671	789	907	1024	1142	1259	1377	1495	1612
Subcritical Pulverized Coal - 250 MW	305	339	374	408	443	477	512	546	581	615	650
Subcritical Pulverized Coal - 500 MW	267	301	336	370	405	439	473	508	542	576	611
Subcritical Pulverized Coal, High Sulfur - 500 MW	272	305	338	371	404	437	470	503	536	569	602
Circulating Fluidized Bed - 250 MW	303	338	373	408	443	478	512	547	582	617	652
Circulating Fluidized Bed - 500 MW	269	304	338	373	408	443	477	512	547	581	616
Supercritical Pulverized Coal - 500 MW	275	308	340	373	406	439	471	504	537	569	602
Supercritical Pulverized Coal. High Sulfur - 500 MW	278	310	342	374	405	437	469	501	533	565	596
Supercritical Pulverized Coal - 750 MW	254	287	321	354	387	420	454	487	520	553	587
Supercritical Pulverized Coal High Sulfur - 750 MW	256	288	320	352	383	415	447	479	511	543	574
Pressurized Fluidized Bed Combustion	364	403	443	482	521	561	600	640	679	----	----
1x1 IGCC	337	369	400	432	464	495	527	558	590	----	----
2x1 IGCC	300	332	363	395	426	458	489	521	552	----	----
2x1 IGCC, High Sulfur	299	329	359	389	419	449	479	509	539	----	----
Subcritical Pulverized Coal - 500 MW - CCS	478	511	545	578	612	645	679	712	746	779	813
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	486	518	550	582	613	645	677	709	741	773	804
Circulating Fluidized Bed - 500 MW - CCS	509	543	577	610	644	678	712	746	780	813	847
Supercritical Pulverized Coal - 500 MW - CCS	507	539	570	602	633	665	697	728	760	791	823
Supercritical Pulverized Coal. High Sulfur - 500 MW	514	544	575	605	636	666	697	727	758	788	819
Supercritical Pulverized Coal - 750 MW - CCS	479	511	543	574	606	638	670	702	734	765	797
Supercritical Pulverized Coal High Sulfur - 750 MW	482	512	542	573	603	633	663	693	723	754	784
1x1 IGCC - CCS	488	514	540	565	591	617	643	669	694	----	----
2x1 IGCC - CCS	442	468	494	519	545	571	597	623	648	----	----
2x1 IGCC. High Sulfur - CCS	444	469	493	518	542	567	592	616	641	----	----
Wind Energy Conversion - 50 MW	238	227	216	203	----	----	----	----	----	----	----
Geothermal - 30 MW	443	439	435	431	426	421	414	407	400	393	386
Solar Photovoltaic - 50 kW	622	622	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	421	422	----	----	----	----	----	----	----	----	----
Solar Thermal Parabolic Dish - 1 2 MW	601	601	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	645	646	647	647	647	648	647	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	533	533	533	532	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1634	1666	1697	1729	1760	1792	1824	1855	----	----	----
RDF Stoker-Fired - 7 MW	1499	1612	1724	1837	1949	2062	2175	2287	2400	----	----
Landfill Gas IC Engine - 5 MW	422	463	504	544	585	626	667	707	748	789	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	451	490	528	567	605	644	682	720	759	797	835
Sewage Sludge & Anaerobic Digestion - 085 MW	627	630	633	636	638	641	644	645	645	645	----
Bio Mass (Co-Fire)	298	330	363	395	428	460	493	525	558	590	622
Molten Carbonate Fuel Cell - 300 kW	390	456	522	589	655	721	787	853	919	986	----
Spark Ignition Engine - 5 MW	386	460	533	607	681	755	828	902	976	1050	----
Hydroelectric - New - 30 MW	409	403	398	392	384	----	----	----	----	----	----
Ohio Falls 9-10	279	273	267	259	----	----	----	----	----	----	----
Minimum Levelized $/kW	96	156	215	203	333	389	414	407	400	393	386

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost-Low **2007 ($/kW yr)**
Heat Rate- High
Fuel Forecast- Base

Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
					Capacity Factors						
Pumped Hydro Energy Storage - 500 MW	134	197	260	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	201	259	317	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	128	227	326	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	160	293	427	560	693	827	960	1093	1227	1360	1493
Simple Cycle GE 7EA CT - Peaking Capacity	120	279	437	596	755	913	1072	1231	1389	1548	1707
Simple Cycle GE 7FA CT - Peaking Capacity	96	238	380	522	664	806	948	1090	1232	1374	1516
Combined Cycle GE 7EA CT - Intermediate Load	179	274	370	465	560	656	751	846	942	1037	1132
Combined Cycle GE 7FA CT - Intermediate Load	134	217	301	384	467	550	634	717	800	883	967
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	114	197	280	363	446	529	612	696	779	862	945
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	97	179	262	344	426	509	591	673	756	838	920
Siemens 5000F CC CT - Intermediate Load	126	210	293	377	460	544	627	711	794	878	962
Humid Air Turbine Cycle CT - 366 MW	126	244	361	479	597	714	832	950	1067	1185	----
Kalina Cycle CC CT - 282 MW	134	206	277	349	421	493	564	636	708	780	----
Cheng Cycle CT - 140 MW	140	226	312	398	485	571	657	743	829	915	----
Peaking Microturbine - 0.03 MW	400	591	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	436	601	766	931	1096	1261	1426	1591	1756	1921	2087
Subcritical Pulverized Coal - 250 MW	305	340	375	409	444	479	514	549	583	618	653
Subcritical Pulverized Coal - 500 MW	267	302	336	371	405	440	475	509	544	578	613
Subcritical Pulverized Coal, High Sulfur - 500 MW	272	305	338	372	405	438	471	504	538	571	604
Circulating Fluidized Bed - 250 MW	303	338	373	408	444	479	514	549	584	619	654
Circulating Fluidized Bed - 500 MW	269	304	339	374	409	444	479	514	548	583	618
Supercritical Pulverized Coal - 500 MW	275	308	341	374	407	440	473	506	538	571	604
Supercritical Pulverized Coal, High Sulfur - 500 MW	278	310	342	374	406	438	470	502	535	567	599
Supercritical Pulverized Coal - 750 MW	254	287	321	354	388	421	455	488	522	555	589
Supercritical Pulverized Coal. High Sulfur - 750 MW	256	288	320	352	384	416	448	480	512	545	577
Pressurized Fluidized Bed Combustion	364	404	443	483	522	562	602	641	681	----	----
1x1 IGCC	337	369	401	433	464	496	528	560	592	----	----
2x1 IGCC	300	332	363	395	427	459	490	522	554	----	----
2x1 IGCC, High Sulfur	299	329	359	390	420	450	480	510	541	----	----
Subcritical Pulverized Coal - 500 MW - CCS	478	512	546	580	614	648	682	716	750	784	818
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	486	518	551	583	615	647	680	712	744	777	809
Circulating Fluidized Bed - 500 MW - CCS	509	543	578	612	646	680	715	749	783	817	852
Supercritical Pulverized Coal - 500 MW - CCS	507	539	571	603	635	667	699	731	763	795	827
Supercritical Pulverized Coal High Sulfur - 500 MW	514	545	576	606	637	668	699	730	761	791	822
Supercritical Pulverized Coal - 750 MW - CCS	479	511	544	576	608	640	673	705	737	769	802
Supercritical Pulverized Coal High Sulfur - 750 MW	482	513	543	574	604	635	666	696	727	757	788
1x1 IGCC - CCS	488	514	540	566	593	619	645	671	697	----	----
2x1 IGCC - CCS	442	468	494	520	547	573	599	625	651	----	----
2x1 IGCC High Sulfur - CCS	444	469	494	519	544	569	594	619	644	----	----
Wind Energy Conversion - 50 MW	238	227	216	203	----	----	----	----	----	----	----
Geothermal - 30 MW	443	439	435	431	426	421	414	407	400	393	386
Solar Photovoltaic - 50 kW	622	622	----	----	----	----	----	----	----	----	----
Solar Thermal, Parabolic Trough - 100 MW	421	422	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	601	601	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	645	646	647	647	647	648	647	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	533	533	533	532	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1634	1666	1697	1729	1760	1792	1824	1855	----	----	----
RDF Stoker-Fired - 7 MW	1499	1613	1727	1840	1954	2068	2182	2295	2409	----	----
Landfill Gas IC Engine - 5 MW	422	478	534	591	647	703	759	816	872	928	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	451	490	528	567	606	645	683	722	761	799	838
Sewage Sludge & Anaerobic Digestion - 085 MW	627	630	633	636	638	641	644	645	645	645	----
Bio Mass (Co-Fire)	298	331	363	396	429	461	494	527	559	592	624
Molten Carbonate Fuel Cell - 300 kW	390	482	575	667	759	852	944	1037	1129	1221	----
Spark Ignition Engine - 5 MW	386	491	595	700	804	909	1013	1118	1223	1327	----
Hydroelectric - New - 30 MW	409	403	398	392	384	----	----	----	----	----	----
Ohio Falls 9-10	279	273	267	259	----	----	----	----	----	----	----
Minimum Levelized $/kW	96	179	216	203	384	416	414	407	400	393	386

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost-Low 2007 ($/kW yr)
Heat Rate- High
Fuel Forecast- High

Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
					Capacity Factors						
Pumped Hydro Energy Storage - 500 MW	134	197	260	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	201	259	317	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	128	239	349	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	160	318	476	634	792	950	1108	1266	1424	1582	1740
Simple Cycle GE 7EA CT - Peaking Capacity	120	309	497	686	875	1063	1252	1441	1629	1818	2007
Simple Cycle GE 7FA CT - Peaking Capacity	96	265	435	604	773	943	1112	1281	1451	1620	1789
Combined Cycle GE 7EA CT - Intermediate Load	179	295	411	528	644	760	876	992	1108	1225	1341
Combined Cycle GE 7FA CT - Intermediate Load	134	235	337	438	540	641	743	844	946	1047	1149
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	114	215	317	418	519	620	722	823	924	1026	1127
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	97	198	298	399	499	600	700	801	901	1002	1102
Siemens 5000F CC CT - Intermediate Load	126	228	330	432	534	636	738	840	942	1044	1146
Humid Air Turbine Cycle CT - 366 MW	126	270	414	558	702	846	990	1134	1278	1422	----
Kalina Cycle CC CT - 282 MW	134	222	310	398	486	573	661	749	837	925	----
Cheng Cycle CT - 140 MW	140	245	350	455	560	665	770	875	980	1085	----
Peaking Microturbine - 0 03 MW	400	629	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	436	638	840	1042	1243	1445	1647	1849	2051	2253	2455
Subcritical Pulverized Coal - 250 MW	305	340	376	411	447	482	518	553	589	624	660
Subcritical Pulverized Coal - 500 MW	267	302	338	373	408	444	479	515	550	585	621
Subcritical Pulverized Coal, High Sulfur - 500 MW	272	306	340	374	407	441	475	509	543	577	611
Circulating Fluidized Bed - 250 MW	303	339	375	411	447	482	518	554	590	626	662
Circulating Fluidized Bed - 500 MW	269	305	340	376	412	448	483	519	555	590	626
Supercritical Pulverized Coal - 500 MW	275	309	342	376	409	443	477	510	544	577	611
Supercritical Pulverized Coal. High Sulfur - 500 MW	278	311	343	376	409	442	474	507	540	573	605
Supercritical Pulverized Coal - 750 MW	254	288	322	356	391	425	459	493	527	561	595
Supercritical Pulverized Coal. High Sulfur - 750 MW	256	289	321	354	387	420	452	485	518	550	583
Pressurized Fluidized Bed Combustion	364	404	445	485	526	566	607	647	687	----	----
1x1 IGCC	337	369	402	434	467	499	532	564	597	----	----
2x1 IGCC	300	332	365	397	429	462	494	526	559	----	----
2x1 IGCC, High Sulfur	299	330	361	391	422	453	484	515	545	----	----
Subcritical Pulverized Coal - 500 MW - CCS	478	513	549	584	619	655	690	726	761	796	832
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	486	520	553	587	621	654	688	721	755	789	822
Circulating Fluidized Bed - 500 MW - CCS	509	545	580	616	652	687	723	759	795	830	866
Supercritical Pulverized Coal - 500 MW - CCS	507	540	574	607	640	674	707	741	774	807	841
Supercritical Pulverized Coal. High Sulfur - 500 MW	514	546	578	610	643	675	707	739	771	803	836
Supercritical Pulverized Coal - 750 MW - CCS	479	513	546	580	613	647	681	714	748	781	815
Supercritical Pulverized Coal. High Sulfur - 750 MW	482	514	546	577	609	641	673	705	737	768	800
1x1 IGCC - CCS	488	515	542	570	597	624	651	679	706	----	----
2x1 IGCC - CCS	442	469	496	524	551	578	605	633	660	----	----
2x1 IGCC. High Sulfur - CCS	444	470	496	522	548	574	600	625	651	----	----
Wind Energy Conversion - 50 MW	238	227	216	203	----	----	----	----	----	----	----
Geothermal - 30 MW	443	439	435	431	426	421	414	407	400	393	386
Solar Photovoltaic - 50 kW	622	622	----	----	----	----	----	----	----	----	----
Solar Thermal Parabolic Trough - 100 MW	421	422	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	601	601	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	645	646	647	647	647	648	647	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	533	533	533	532	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1634	1665	1697	1728	1760	1791	1823	1854	----	----	----
RDF Stoker-Fired - 7 MW	1499	1616	1733	1851	1968	2085	2202	2319	2436	----	----
Landfill Gas IC Engine - 5 MW	422	490	558	627	695	763	831	900	968	1036	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	451	491	530	570	609	649	689	728	767	807	846
Sewage Sludge & Anaerobic Digestion - 085 MW	627	630	633	636	638	641	644	645	645	645	----
Bio Mass (Co-Fire)	298	331	365	398	431	465	498	531	565	598	631
Molten Carbonate Fuel Cell - 300 kW	390	503	616	728	841	954	1067	1179	1292	1405	----
Spark Ignition Engine - 5 MW	386	515	643	772	900	1029	1158	1286	1415	1544	----
Hydroelectric - New - 30 MW	409	403	398	392	384	----	----	----	----	----	----
Ohio Falls 9-10	279	273	267	259	----	----	----	----	----	----	----
Minimum Levelized $/kW	96	197	216	203	384	420	414	407	400	393	386

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost- Base 2007 ($/kW yr)
Heat Rate-Low
Fuel Forecast-Low

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	147	210	273	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	221	279	337	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	140	221	302	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	171	266	362	457	552	648	743	838	934	1029	1124
Simple Cycle GE 7EA CT - Peaking Capacity	127	238	348	459	570	680	791	902	1012	1123	1234
Simple Cycle GE 7FA CT - Peaking Capacity	101	200	300	399	498	598	697	796	896	995	1094
Combined Cycle GE 7EA CT - Intermediate Load	190	252	315	377	439	502	564	626	689	751	813
Combined Cycle GE 7FA CT - Intermediate Load	143	197	252	306	361	415	470	524	579	633	688
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	121	175	230	284	339	393	448	502	557	611	666
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	103	157	211	265	318	372	426	480	534	588	641
Siemens 5000F CC CT - Intermediate Load	133	188	242	297	352	406	461	516	570	625	680
Humid Air Turbine Cycle CT - 366 MW	131	207	284	360	436	513	589	665	742	818	----
Kalina Cycle CC CT - 282 MW	144	190	237	283	330	376	422	469	515	562	----
Cheng Cycle CT - 140 MW	151	207	264	320	377	433	490	546	603	659	----
Peaking Microturbine - 0 03 MW	421	555	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	453	560	667	774	881	989	1096	1203	1310	1417	1524
Subcritical Pulverized Coal - 250 MW	331	363	394	426	457	489	520	552	583	615	646
Subcritical Pulverized Coal - 500 MW	291	322	354	385	417	448	479	511	542	573	605
Subcritical Pulverized Coal, High Sulfur - 500 MW	297	327	357	387	417	447	477	507	537	568	598
Circulating Fluidized Bed - 250 MW	330	362	394	425	457	489	521	553	585	616	648
Circulating Fluidized Bed - 500 MW	293	325	356	388	419	451	483	514	546	577	609
Supercritical Pulverized Coal - 500 MW	299	329	359	388	418	448	478	508	538	567	597
Supercritical Pulverized Coal. High Sulfur - 500 MW	303	332	361	390	420	449	478	507	536	565	595
Supercritical Pulverized Coal - 750 MW	277	307	338	368	398	429	459	489	520	550	580
Supercritical Pulverized Coal High Sulfur - 750 MW	280	309	338	367	396	426	455	484	513	542	571
Pressurized Fluidized Bed Combustion	412	448	484	520	556	592	627	663	699	----	----
1x1 IGCC	368	397	426	455	484	512	541	570	599	----	----
2x1 IGCC	327	356	385	413	442	471	500	528	557	----	----
2x1 IGCC, High Sulfur	327	354	382	409	436	464	491	518	546	----	----
Subcritical Pulverized Coal - 500 MW - CCS	524	555	586	616	647	678	709	740	771	801	832
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	532	561	591	620	650	679	708	738	767	797	826
Circulating Fluidized Bed - 500 MW - CCS	532	563	594	625	656	687	718	749	780	810	841
Supercritical Pulverized Coal - 500 MW - CCS	531	560	589	618	647	676	705	734	763	792	821
Supercritical Pulverized Coal. High Sulfur - 500 MW	538	566	594	622	650	678	706	734	763	791	819
Supercritical Pulverized Coal - 750 MW - CCS	501	530	559	589	618	647	676	705	734	764	793
Supercritical Pulverized Coal High Sulfur - 750 MW	505	533	560	588	616	644	671	699	727	755	782
1x1 IGCC - CCS	510	534	557	581	605	628	652	676	699	----	----
2x1 IGCC - CCS	462	486	509	533	557	580	604	628	651	----	----
2x1 IGCC. High Sulfur - CCS	464	487	509	532	554	577	600	622	645	----	----
Wind Energy Conversion - 50 MW	259	248	237	225	----	----	----	----	----	----	----
Geothermal - 30 MW	484	480	476	472	467	462	456	449	442	435	428
Solar Photovoltaic - 50 kW	766	766	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	506	507	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	734	734	----	----	----	----	----	----	----	----	----
Solar Thermal Central Receiver - 50 MW	771	772	773	773	773	774	774	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	646	646	646	645	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1741	1773	1805	1837	1868	1900	1932	1964	----	----	----
RDF Stoker-Fired - 7 MW	1665	1767	1870	1972	2075	2177	2280	2382	2485	----	----
Landfill Gas IC Engine - 5 MW	455	491	528	564	601	637	674	710	747	783	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	489	524	559	594	629	664	699	734	769	804	838
Sewage Sludge & Anaerobic Digestion - 085 MW	693	695	697	699	701	703	705	706	706	705	----
Bio Mass (Co-Fire)	324	354	383	412	442	471	501	530	560	589	618
Molten Carbonate Fuel Cell - 300 kW	462	522	583	643	703	764	824	884	944	1005	----
Spark Ignition Engine - 5 MW	400	467	533	600	667	734	800	867	934	1000	----
Hydroelectric - New - 30 MW	473	467	462	456	449	----	----	----	----	----	----
Ohio Falls 9-10	293	287	281	273	----	----	----	----	----	----	----
Minimum Levelized $/kW	101	157	211	225	318	372	422	449	442	435	428

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost- Base **2007 ($/kW yr)**
Heat Rate-Low
Fuel Forecast- Base

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	147	210	273	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	221	279	337	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	140	234	328	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	171	294	418	541	664	788	911	1034	1158	1281	1404
Simple Cycle GE 7EA CT - Peaking Capacity	127	273	419	565	711	857	1003	1149	1295	1441	1587
Simple Cycle GE 7FA CT - Peaking Capacity	101	232	364	495	626	758	889	1020	1152	1283	1414
Combined Cycle GE 7EA CT - Intermediate Load	190	277	363	450	537	623	710	797	883	970	1057
Combined Cycle GE 7FA CT - Intermediate Load	143	219	295	370	446	522	598	673	749	825	901
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	121	197	272	348	423	499	575	650	726	801	877
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	103	178	253	328	403	478	553	628	703	778	853
Siemens 5000F CC CT - Intermediate Load	133	209	285	361	437	513	589	665	741	817	893
Humid Air Turbine Cycle CT - 366 MW	131	238	345	452	558	665	772	879	986	1093	----
Kalina Cycle CC CT - 282 MW	144	209	274	340	405	470	535	600	665	731	----
Cheng Cycle CT - 140 MW	151	229	308	386	465	543	621	700	778	857	----
Peaking Microturbine - 0 03 MW	421	598	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	453	603	753	903	1053	1202	1352	1502	1652	1802	1952
Subcritical Pulverized Coal - 250 MW	331	363	394	426	458	490	521	553	585	617	648
Subcritical Pulverized Coal - 500 MW	291	323	354	386	417	449	481	512	544	575	607
Subcritical Pulverized Coal, High Sulfur - 500 MW	297	327	358	388	418	448	479	509	539	570	600
Circulating Fluidized Bed - 250 MW	330	362	394	426	458	490	522	554	586	618	651
Circulating Fluidized Bed - 500 MW	293	325	357	388	420	452	484	516	548	579	611
Supercritical Pulverized Coal - 500 MW	299	329	359	389	419	449	479	509	539	569	600
Supercritical Pulverized Coal, High Sulfur - 500 MW	303	332	362	391	420	449	479	508	537	566	596
Supercritical Pulverized Coal - 750 MW	277	308	338	369	399	430	460	491	521	552	582
Supercritical Pulverized Coal High Sulfur - 750 MW	280	309	339	368	397	427	456	485	515	544	573
Pressurized Fluidized Bed Combustion	412	448	484	520	557	593	629	665	701	----	----
1x1 IGCC	368	397	426	455	484	513	542	571	600	----	----
2x1 IGCC	327	356	385	414	443	471	500	529	558	----	----
2x1 IGCC, High Sulfur	327	355	382	410	437	465	493	520	548	----	----
Subcritical Pulverized Coal - 500 MW - CCS	524	555	587	618	649	680	712	743	774	805	837
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	532	562	591	621	651	681	710	740	770	800	829
Circulating Fluidized Bed - 500 MW - CCS	532	563	595	626	658	689	720	752	783	814	846
Supercritical Pulverized Coal - 500 MW - CCS	531	560	590	619	649	678	707	737	766	796	825
Supercritical Pulverized Coal High Sulfur - 500 MW	538	566	595	623	652	680	708	737	765	794	822
Supercritical Pulverized Coal - 750 MW - CCS	501	531	560	590	619	649	679	708	738	768	797
Supercritical Pulverized Coal High Sulfur - 750 MW	505	533	561	590	618	646	674	702	730	759	787
1x1 IGCC - CCS	510	534	558	582	606	630	654	678	702	----	----
2x1 IGCC - CCS	462	486	510	534	558	582	606	630	654	----	----
2x1 IGCC High Sulfur - CCS	464	487	510	533	556	579	602	625	648	----	----
Wind Energy Conversion - 50 MW	259	248	237	225	----	----	----	----	----	----	----
Geothermal - 30 MW	484	480	476	472	467	462	456	449	442	435	428
Solar Photovoltaic - 50 kW	766	766	----	----	----	----	----	----	----	----	----
Solar Thermal, Parabolic Trough - 100 MW	506	507	----	----	----	----	----	----	----	----	----
Solar Thermal Parabolic Dish - 1 2 MW	734	734	----	----	----	----	----	----	----	----	----
Solar Thermal Central Receiver - 50 MW	771	772	773	773	773	774	774	----	----	----	----
Solar Thermal, Solar Chimney - 50 MW	646	646	646	645	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1741	1773	1804	1836	1868	1900	1931	1963	----	----	----
RDF Stoker-Fired - 7 MW	1665	1769	1872	1976	2079	2183	2286	2390	2493	----	----
Landfill Gas IC Engine - 5 MW	455	505	556	606	656	707	757	807	858	908	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	489	524	560	595	630	665	700	736	771	806	841
Sewage Sludge & Anaerobic Digestion - 085 MW	693	695	697	699	701	703	705	706	706	705	----
Bio Mass (Co-Fire)	324	354	383	413	443	473	502	532	561	591	621
Molten Carbonate Fuel Cell - 300 kW	462	546	630	714	798	882	966	1050	1134	1218	----
Spark Ignition Engine - 5 MW	400	495	589	684	778	873	967	1062	1157	1251	----
Hydroelectric - New - 30 MW	473	467	462	456	449	----	----	----	----	----	----
Ohio Falls 9-10	293	287	281	273	----	----	----	----	----	----	----
Minimum Levelized $/kW	101	178	237	225	397	427	456	449	442	435	428

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost- Base 2007 ($/kW yr)
Heat Rate-Low
Fuel Forecast- High

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	147	210	273	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	221	279	337	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	140	245	350	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	171	316	462	607	752	898	1043	1188	1334	1479	1624
Simple Cycle GE 7EA CT - Peaking Capacity	127	300	474	647	820	994	1167	1340	1514	1687	1860
Simple Cycle GE 7FA CT - Peaking Capacity	101	257	413	569	725	881	1037	1193	1349	1505	1661
Combined Cycle GE 7EA CT - Intermediate Load	190	296	401	507	613	718	824	930	1035	1141	1247
Combined Cycle GE 7FA CT - Intermediate Load	143	235	327	420	512	604	696	788	881	973	1065
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	121	213	305	398	490	582	674	766	858	951	1043
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	103	194	286	377	469	560	652	743	834	926	1017
Siemens 5000F CC CT - Intermediate Load	133	226	318	411	504	596	689	782	875	967	1060
Humid Air Turbine Cycle CT - 366 MW	131	262	393	523	654	785	916	1046	1177	1308	----
Kalina Cycle CC CT - 282 MW	144	224	304	383	463	543	623	703	782	862	----
Cheng Cycle CT - 140 MW	151	246	342	437	533	628	724	819	914	1010	----
Peaking Microturbine - 0 03 MW	421	631	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	453	636	820	1003	1186	1369	1553	1736	1919	2103	2286
Subcritical Pulverized Coal - 250 MW	331	363	396	428	461	493	525	558	590	622	655
Subcritical Pulverized Coal - 500 MW	291	323	356	388	420	452	485	517	549	581	614
Subcritical Pulverized Coal, High Sulfur - 500 MW	297	328	359	390	421	452	483	514	545	576	607
Circulating Fluidized Bed - 250 MW	330	363	395	428	461	494	526	559	592	624	657
Circulating Fluidized Bed - 500 MW	293	325	358	390	423	455	488	520	553	585	618
Supercritical Pulverized Coal - 500 MW	299	330	360	391	421	452	483	513	544	574	605
Supercritical Pulverized Coal. High Sulfur - 500 MW	303	333	363	393	423	453	483	513	543	573	602
Supercritical Pulverized Coal - 750 MW	277	308	339	371	402	433	464	495	527	558	589
Supercritical Pulverized Coal High Sulfur - 750 MW	280	310	340	370	399	429	459	489	519	549	579
Pressurized Fluidized Bed Combustion	412	449	486	523	559	596	633	670	707	----	----
1x1 IGCC	368	398	427	457	486	516	546	575	605	----	----
2x1 IGCC	327	356	386	415	445	474	504	533	563	----	----
2x1 IGCC, High Sulfur	327	355	383	412	440	468	496	524	552	----	----
Subcritical Pulverized Coal - 500 MW - CCS	524	556	589	621	654	686	719	751	784	816	849
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	532	563	594	625	656	687	718	749	780	811	842
Circulating Fluidized Bed - 500 MW - CCS	532	565	597	630	663	696	728	761	794	826	859
Supercritical Pulverized Coal - 500 MW - CCS	531	562	592	623	653	684	715	745	776	806	837
Supercritical Pulverized Coal. High Sulfur - 500 MW	538	568	597	627	656	686	715	745	774	804	833
Supercritical Pulverized Coal - 750 MW - CCS	501	532	563	593	624	655	686	717	748	778	809
Supercritical Pulverized Coal High Sulfur - 750 MW	505	534	564	593	622	651	681	710	739	769	798
1x1 IGCC - CCS	510	535	560	585	610	635	660	685	710	----	----
2x1 IGCC - CCS	462	487	512	537	562	587	612	637	662	----	----
2x1 IGCC High Sulfur - CCS	464	488	512	535	559	583	607	630	654	----	----
Wind Energy Conversion - 50 MW	259	248	237	225	----	----	----	----	----	----	----
Geothermal - 30 MW	484	480	476	472	467	462	456	449	442	435	428
Solar Photovoltaic - 50 kW	766	766	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	506	507	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	734	734	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	771	772	773	773	773	774	774	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	646	646	646	645	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1741	1773	1804	1836	1868	1900	1931	1963	----	----	----
RDF Stoker-Fired - 7 MW	1665	1772	1878	1985	2091	2198	2305	2411	2518	----	----
Landfill Gas IC Engine - 5 MW	455	516	577	639	700	761	822	884	945	1006	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	489	525	561	597	633	669	705	741	777	813	848
Sewage Sludge & Anaerobic Digestion - 085 MW	693	695	697	699	701	703	705	706	706	705	----
Bio Mass (Co-Fire)	324	354	385	415	446	476	506	536	567	597	627
Molten Carbonate Fuel Cell - 300 kW	462	564	667	769	872	974	1077	1179	1282	1384	----
Spark Ignition Engine - 5 MW	400	516	633	749	866	982	1098	1215	1331	1447	----
Hydroelectric - New - 30 MW	473	467	462	456	449	----	----	----	----	----	----
Ohio Falls 9-10	293	287	281	273	----	----	----	----	----	----	----
Minimum Levelized $/kW	101	194	237	225	399	429	456	449	442	435	428

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost- Base 2007 ($/kW yr)
Heat Rate- Base
Fuel Forecast-Low

	Capacity Factors										
Technology	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Pumped Hydro Energy Storage - 500 MW	147	210	273	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	221	279	337	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	140	223	305	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	172	271	369	468	567	665	764	863	961	1060	1159
Simple Cycle GE 7EA CT - Peaking Capacity	128	243	357	472	587	701	816	931	1045	1160	1275
Simple Cycle GE 7FA CT - Peaking Capacity	102	205	309	412	515	619	722	825	929	1032	1135
Combined Cycle GE 7EA CT - Intermediate Load	191	256	322	387	452	518	583	648	714	779	844
Combined Cycle GE 7FA CT - Intermediate Load	144	201	258	315	372	429	486	544	601	658	715
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	122	179	236	293	350	407	464	521	579	636	693
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	104	160	217	273	330	386	443	499	556	612	669
Siemens 5000F CC CT - Intermediate Load	134	191	249	306	363	420	478	535	592	650	707
Humid Air Turbine Cycle CT - 366 MW	132	212	292	372	453	533	613	693	773	853	----
Kalina Cycle CC CT - 282 MW	145	194	242	291	340	388	437	486	535	583	----
Cheng Cycle CT - 140 MW	151	210	269	329	388	447	506	566	625	684	----
Peaking Microturbine - 0 03 MW	422	561	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	456	568	681	793	905	1018	1130	1243	1355	1467	1580
Subcritical Pulverized Coal - 250 MW	331	364	397	430	463	496	529	562	595	628	661
Subcritical Pulverized Coal - 500 MW	291	324	357	390	423	456	489	522	554	587	620
Subcritical Pulverized Coal, High Sulfur - 500 MW	297	329	360	392	423	455	486	518	549	581	612
Circulating Fluidized Bed - 250 MW	330	363	397	430	463	497	530	564	597	630	664
Circulating Fluidized Bed - 500 MW	293	326	359	392	426	459	492	525	558	591	625
Supercritical Pulverized Coal - 500 MW	299	330	362	393	424	455	487	518	549	580	612
Supercritical Pulverized Coal. High Sulfur - 500 MW	303	334	364	395	425	456	486	517	547	578	608
Supercritical Pulverized Coal - 750 MW	277	309	340	372	404	436	467	499	531	563	594
Supercritical Pulverized Coal. High Sulfur - 750 MW	280	310	341	371	402	432	463	493	523	554	584
Pressurized Fluidized Bed Combustion	412	450	487	525	562	600	637	675	713	----	----
1x1 IGCC	368	398	428	459	489	519	549	579	610	----	----
2x1 IGCC	327	357	387	417	447	477	508	538	568	----	----
2x1 IGCC, High Sulfur	327	356	384	413	442	470	499	528	556	----	----
Subcritical Pulverized Coal - 500 MW - CCS	524	556	588	620	653	685	717	749	781	813	846
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	532	563	593	624	654	685	716	746	777	808	838
Circulating Fluidized Bed - 500 MW - CCS	532	564	597	629	662	694	726	759	791	823	856
Supercritical Pulverized Coal - 500 MW - CCS	531	561	592	622	652	682	713	743	773	804	834
Supercritical Pulverized Coal. High Sulfur - 500 MW	538	567	597	626	655	684	714	743	772	802	831
Supercritical Pulverized Coal - 750 MW - CCS	501	531	562	592	623	653	684	714	745	775	806
Supercritical Pulverized Coal. High Sulfur - 750 MW	505	534	563	592	621	650	679	708	737	766	795
1x1 IGCC - CCS	510	535	559	584	609	634	658	683	708	----	----
2x1 IGCC - CCS	462	487	511	536	561	586	610	635	660	----	----
2x1 IGCC. High Sulfur - CCS	464	488	511	535	558	582	605	629	652	----	----
Wind Energy Conversion - 50 MW	259	248	237	225	----	----	----	----	----	----	----
Geothermal - 30 MW	484	480	476	472	467	462	456	449	442	435	428
Solar Photovoltaic - 50 kW	766	766	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	506	507	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	734	734	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	771	772	773	773	773	774	774	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	646	646	646	645	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1741	1773	1804	1836	1868	1900	1931	1963	----	----	----
RDF Stoker-Fired - 7 MW	1665	1773	1880	1988	2095	2203	2310	2418	2525	----	----
Landfill Gas IC Engine - 5 MW	455	494	532	571	609	648	686	725	763	802	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	489	526	563	599	636	673	710	746	783	819	856
Sewage Sludge & Anaerobic Digestion - 085 MW	693	695	698	700	703	705	707	708	709	708	----
Bio Mass (Co-Fire)	324	355	386	417	448	479	509	540	571	602	633
Molten Carbonate Fuel Cell - 300 kW	463	526	589	653	716	779	842	905	969	1032	----
Spark Ignition Engine - 5 MW	402	472	542	613	683	753	823	893	964	1034	----
Hydroelectric - New - 30 MW	473	467	462	456	449	----	----	----	----	----	----
Ohio Falls 9-10	293	287	281	273	----	----	----	----	----	----	----
Minimum Levelized $/kW	102	160	217	225	330	386	437	449	442	435	428

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost- Base 2007 ($/kW yr)
Heat Rate- Base
Fuel Forecast- High

	Capacity Factors										
Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	147	210	273	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	221	279	337	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	140	248	356	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	172	324	476	628	780	932	1084	1236	1388	1540	1692
Simple Cycle GE 7EA CT - Peaking Capacity	128	309	491	672	853	1035	1216	1397	1579	1760	1941
Simple Cycle GE 7FA CT - Peaking Capacity	102	265	427	590	753	915	1078	1241	1403	1566	1729
Combined Cycle GE 7EA CT - Intermediate Load	191	302	413	524	635	746	857	968	1079	1190	1301
Combined Cycle GE 7FA CT - Intermediate Load	144	241	338	435	532	629	725	822	919	1016	1113
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	122	219	315	412	509	606	702	799	896	993	1089
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	104	200	296	392	488	584	680	776	872	968	1064
Siemens 5000F CC CT - Intermediate Load	134	231	329	426	523	620	718	815	912	1009	1107
Humid Air Turbine Cycle CT - 366 MW	132	269	407	544	681	818	956	1093	1230	1368	----
Kalina Cycle CC CT - 282 MW	145	229	313	397	480	564	648	732	816	900	----
Cheng Cycle CT - 140 MW	151	251	351	452	552	652	752	853	953	1053	----
Peaking Microturbine - 0.03 MW	422	641	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	456	649	841	1034	1226	1419	1611	1804	1997	2189	2382
Subcritical Pulverized Coal - 250 MW	331	365	399	433	467	501	535	568	602	636	670
Subcritical Pulverized Coal - 500 MW	291	325	359	392	426	460	494	528	562	595	629
Subcritical Pulverized Coal, High Sulfur - 500 MW	297	329	362	394	427	459	491	524	556	589	621
Circulating Fluidized Bed - 250 MW	330	364	398	433	467	501	535	570	604	638	672
Circulating Fluidized Bed - 500 MW	293	327	361	395	429	463	497	531	565	599	633
Supercritical Pulverized Coal - 500 MW	299	331	363	395	428	460	492	524	556	588	621
Supercritical Pulverized Coal. High Sulfur - 500 MW	303	334	366	397	428	459	491	522	553	585	616
Supercritical Pulverized Coal - 750 MW	277	310	342	375	407	440	473	505	538	571	603
Supercritical Pulverized Coal. High Sulfur - 750 MW	280	311	343	374	405	436	468	499	530	562	593
Pressurized Fluidized Bed Combustion	412	451	489	528	567	605	644	683	721	----	----
1x1 IGCC	368	399	430	461	492	523	554	585	616	----	----
2x1 IGCC	327	358	389	420	451	482	512	543	574	----	----
2x1 IGCC, High Sulfur	327	356	386	415	445	474	504	533	563	----	----
Subcritical Pulverized Coal - 500 MW - CCS	524	558	592	626	660	694	728	762	795	829	863
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	532	564	597	629	661	693	726	758	790	823	855
Circulating Fluidized Bed - 500 MW - CCS	532	566	600	634	669	703	737	771	805	839	873
Supercritical Pulverized Coal - 500 MW - CCS	531	563	595	627	659	691	723	755	787	819	851
Supercritical Pulverized Coal. High Sulfur - 500 MW	538	569	600	630	661	692	723	754	785	815	846
Supercritical Pulverized Coal - 750 MW - CCS	501	533	565	597	630	662	694	726	758	790	823
Supercritical Pulverized Coal. High Sulfur - 750 MW	505	536	566	597	627	658	689	719	750	780	811
1x1 IGCC - CCS	510	536	562	588	615	641	667	693	719	----	----
2x1 IGCC - CCS	462	488	514	540	566	592	618	644	670	----	----
2x1 IGCC High Sulfur - CCS	464	489	514	539	563	588	613	638	663	----	----
Wind Energy Conversion - 50 MW	259	248	237	225	----	----	----	----	----	----	----
Geothermal - 30 MW	484	480	476	472	467	462	456	449	442	435	428
Solar Photovoltaic - 50 kW	766	766	----	----	----	----	----	----	----	----	----
Solar Thermal Parabolic Trough - 100 MW	506	507	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	734	734	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	771	772	773	773	773	774	774	----	----	----	----
Solar Thermal Solar Chimney - 50 MW	646	646	646	645	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1741	1773	1804	1836	1867	1899	1931	1962	----	----	----
RDF Stoker-Fired - 7 MW	1665	1777	1889	2001	2113	2224	2336	2448	2560	----	----
Landfill Gas IC Engine - 5 MW	455	520	584	649	714	778	843	908	972	1037	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	489	527	565	602	640	678	715	753	791	828	866
Sewage Sludge & Anaerobic Digestion - 085 MW	693	695	698	700	703	705	707	708	709	708	----
Bio Mass (Co-Fire)	324	356	388	420	452	484	515	547	579	611	643
Molten Carbonate Fuel Cell - 300 kW	463	571	678	786	894	1001	1109	1216	1324	1432	----
Spark Ignition Engine - 5 MW	402	525	647	770	892	1015	1137	1260	1382	1505	----
Hydroelectric - New - 30 MW	473	467	462	456	449	----	----	----	----	----	----
Ohio Falls 9-10	293	287	281	273	----	----	----	----	----	----	----
Minimum Levelized $/kW	102	200	237	225	405	436	456	449	442	435	428

Exhibit 8

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost- Base **2007 ($/kW yr)**
Heat Rate- High
Fuel Forecast-Low

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	147	210	273	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	221	279	337	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	140	224	308	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	173	275	377	479	581	683	785	887	989	1091	1193
Simple Cycle GE 7EA CT - Peaking Capacity	129	248	368	487	606	726	845	964	1084	1203	1322
Simple Cycle GE 7FA CT - Peaking Capacity	103	210	318	425	532	640	747	854	962	1069	1176
Combined Cycle GE 7EA CT - Intermediate Load	192	260	329	397	465	534	602	670	739	807	875
Combined Cycle GE 7FA CT - Intermediate Load	145	205	264	324	384	443	503	563	622	682	742
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	123	183	242	302	362	421	481	541	600	660	720
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	104	163	222	281	340	399	458	517	576	635	695
Siemens 5000F CC CT - Intermediate Load	135	195	255	315	375	435	495	555	615	675	736
Humid Air Turbine Cycle CT - 366 MW	134	218	302	386	469	553	637	721	805	889	----
Kalina Cycle CC CT - 282 MW	145	196	247	298	349	400	451	502	553	604	----
Cheng Cycle CT - 140 MW	152	214	276	338	400	462	524	586	648	709	----
Peaking Microturbine - 0 03 MW	423	567	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	459	577	694	812	930	1047	1165	1282	1400	1518	1635
Subcritical Pulverized Coal - 250 MW	331	365	400	434	469	503	538	572	607	641	676
Subcritical Pulverized Coal - 500 MW	291	325	360	394	429	463	497	532	566	600	635
Subcritical Pulverized Coal, High Sulfur - 500 MW	297	330	363	396	429	462	495	528	561	594	627
Circulating Fluidized Bed - 250 MW	330	365	400	435	470	505	539	574	609	644	679
Circulating Fluidized Bed - 500 MW	293	328	362	397	432	467	501	536	571	605	640
Supercritical Pulverized Coal - 500 MW	299	332	364	397	430	463	495	528	561	593	626
Supercritical Pulverized Coal. High Sulfur - 500 MW	303	335	367	399	430	462	494	526	558	590	621
Supercritical Pulverized Coal - 750 MW	277	310	344	377	410	443	477	510	543	576	610
Supercritical Pulverized Coal. High Sulfur - 750 MW	280	312	344	376	407	439	471	503	535	567	598
Pressurized Fluidized Bed Combustion	412	451	491	530	569	609	648	688	727	----	----
1x1 IGCC	368	400	431	463	495	526	558	589	621	----	----
2x1 IGCC	327	359	390	422	453	485	516	548	579	----	----
2x1 IGCC, High Sulfur	327	357	387	417	447	477	507	537	567	----	----
Subcritical Pulverized Coal - 500 MW - CCS	524	557	591	624	658	691	725	758	792	825	859
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	532	564	596	628	659	691	723	755	787	819	850
Circulating Fluidized Bed - 500 MW - CCS	532	566	600	633	667	701	735	769	803	836	870
Supercritical Pulverized Coal - 500 MW - CCS	531	563	594	626	657	689	721	752	784	815	847
Supercritical Pulverized Coal. High Sulfur - 500 MW	538	568	599	629	660	690	721	751	782	812	843
Supercritical Pulverized Coal - 750 MW - CCS	501	533	565	596	628	660	692	724	756	787	819
Supercritical Pulverized Coal. High Sulfur - 750 MW	505	535	565	596	626	656	686	716	746	777	807
1x1 IGCC - CCS	510	536	562	587	613	639	665	691	716	----	----
2x1 IGCC - CCS	462	488	514	539	565	591	617	643	668	----	----
2x1 IGCC. High Sulfur - CCS	464	489	513	538	562	587	612	636	661	----	----
Wind Energy Conversion - 50 MW	259	248	237	225	----	----	----	----	----	----	----
Geothermal - 30 MW	484	480	476	472	467	462	456	449	442	435	428
Solar Photovoltaic - 50 kW	766	766	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	506	507	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	734	734	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	771	772	773	773	773	774	774	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	646	646	646	645	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1741	1773	1804	1836	1867	1899	1931	1962	----	----	----
RDF Stoker-Fired - 7 MW	1665	1778	1890	2003	2115	2228	2341	2453	2566	----	----
Landfill Gas IC Engine - 5 MW	455	496	537	577	618	659	700	740	781	822	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	489	528	566	605	643	682	720	758	797	835	873
Sewage Sludge & Anaerobic Digestion - 085 MW	693	696	699	702	704	707	710	712	712	712	----
Bio Mass (Co-Fire)	324	356	389	421	454	486	519	551	584	616	648
Molten Carbonate Fuel Cell - 300 kW	464	530	596	663	729	795	861	927	993	1060	----
Spark Ignition Engine - 5 MW	403	477	550	624	698	772	845	919	993	1067	----
Hydroelectric - New - 30 MW	473	467	462	456	449	----	----	----	----	----	----
Ohio Falls 9-10	293	287	281	273	----	----	----	----	----	----	----
Minimum Levelized $/kW	103	163	222	225	340	399	451	449	442	435	428

Exhibit 8

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost- Base **2007 ($/kW yr)**
Heat Rate- High
Fuel Forecast- Base

	Capacity Factors										
Technology	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Pumped Hydro Energy Storage - 500 MW	147	210	273	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	221	279	337	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	140	239	338	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	173	306	440	573	706	840	973	1106	1240	1373	1506
Simple Cycle GE 7EA CT - Peaking Capacity	129	288	446	605	764	922	1081	1240	1398	1557	1716
Simple Cycle GE 7FA CT - Peaking Capacity	103	245	387	529	671	813	955	1097	1239	1381	1523
Combined Cycle GE 7EA CT - Intermediate Load,	192	287	383	478	573	669	764	859	955	1050	1145
Combined Cycle GE 7FA CT - Intermediate Load	145	228	312	395	478	561	645	728	811	894	978
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	123	206	289	372	455	538	621	705	788	871	954
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	104	186	269	351	433	516	598	680	763	845	927
Siemens 5000F CC CT - Intermediate Load	135	219	302	386	469	553	636	720	803	887	971
Humid Air Turbine Cycle CT - 366 MW	134	252	369	487	605	722	840	958	1075	1193	----
Kalina Cycle CC CT - 282 MW	145	217	288	360	432	504	575	647	719	791	----
Cheng Cycle CT - 140 MW	152	238	324	410	497	583	669	755	841	927	----
Peaking Microturbine - 0 03 MW	423	614	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	459	624	789	954	1119	1284	1449	1614	1779	1944	2110
Subcritical Pulverized Coal - 250 MW	331	366	401	435	470	505	540	575	609	644	679
Subcritical Pulverized Coal - 500 MW	291	326	360	395	429	464	499	533	568	602	637
Subcritical Pulverized Coal, High Sulfur - 500 MW	297	330	363	397	430	463	496	529	563	596	629
Circulating Fluidized Bed - 250 MW	330	365	400	435	471	506	541	576	611	646	681
Circulating Fluidized Bed - 500 MW	293	328	363	398	433	468	503	538	572	607	642
Supercritical Pulverized Coal - 500 MW	299	332	365	398	431	464	497	530	562	595	628
Supercritical Pulverized Coal High Sulfur - 500 MW	303	335	367	399	431	463	495	527	560	592	624
Supercritical Pulverized Coal - 750 MW	277	310	344	377	411	444	478	511	545	578	612
Supercritical Pulverized Coal. High Sulfur - 750 MW	280	312	344	376	408	440	472	504	536	569	601
Pressurized Fluidized Bed Combustion	412	452	491	531	570	610	650	689	729	----	----
1x1 IGCC	368	400	432	464	495	527	559	591	623	----	----
2x1 IGCC	327	359	390	422	454	486	517	549	581	----	----
2x1 IGCC, High Sulfur	327	357	387	418	448	478	508	538	569	----	----
Subcritical Pulverized Coal - 500 MW - CCS	524	558	592	626	660	694	728	762	796	830	864
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	532	564	597	629	661	693	726	758	790	823	855
Circulating Fluidized Bed - 500 MW - CCS	532	566	601	635	669	703	738	772	806	840	875
Supercritical Pulverized Coal - 500 MW - CCS	531	563	595	627	659	691	723	755	787	819	851
Supercritical Pulverized Coal. High Sulfur - 500 MW	538	569	600	630	661	692	723	754	785	815	846
Supercritical Pulverized Coal - 750 MW - CCS	501	533	566	598	630	662	695	727	759	791	824
Supercritical Pulverized Coal High Sulfur - 750 MW	505	536	566	597	627	658	689	719	750	780	811
1x1 IGCC - CCS	510	536	562	588	615	641	667	693	719	----	----
2x1 IGCC - CCS	462	488	514	540	567	593	619	645	671	----	----
2x1 IGCC. High Sulfur - CCS	464	489	514	539	564	589	614	639	664	----	----
Wind Energy Conversion - 50 MW	259	248	237	225	----	----	----	----	----	----	----
Geothermal - 30 MW	484	480	476	472	467	462	456	449	442	435	428
Solar Photovoltaic - 50 kW	766	766	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	506	507	----	----	----	----	----	----	----	----	----
Solar Thermal Parabolic Dish - 1 2 MW	734	734	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	771	772	773	773	773	774	774	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	646	646	646	645	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1741	1773	1804	1836	1867	1899	1931	1962	----	----	----
RDF Stoker-Fired - 7 MW	1665	1779	1893	2006	2120	2234	2348	2461	2575	----	----
Landfill Gas IC Engine - 5 MW	455	511	567	624	680	736	792	849	905	961	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	489	528	566	605	644	683	721	760	799	837	876
Sewage Sludge & Anaerobic Digestion - 085 MW	693	696	699	702	704	707	710	712	712	712	----
Bio Mass (Co-Fire)	324	357	389	422	455	487	520	553	585	618	651
Molten Carbonate Fuel Cell - 300 kW	464	556	649	741	833	926	1018	1111	1203	1295	----
Spark Ignition Engine - 5 MW	403	508	612	717	821	926	1030	1135	1240	1344	----
Hydroelectric - New - 30 MW	473	467	462	456	449	----	----	----	----	----	----
Ohio Falls 9-10	293	287	281	273	----	----	----	----	----	----	----
Minimum Levelized $/kW	103	186	237	225	408	440	456	449	442	435	428

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost- Base 2007 ($/kW yr)
Heat Rate- High
Fuel Forecast- High

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	147	210	273	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	221	279	337	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	140	251	361	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	173	331	489	647	805	963	1121	1279	1437	1595	1753
Simple Cycle GE 7EA CT - Peaking Capacity	129	318	506	695	884	1072	1261	1450	1638	1827	2016
Simple Cycle GE 7FA CT - Peaking Capacity	103	272	442	611	780	950	1119	1288	1458	1627	1796
Combined Cycle GE 7EA CT - Intermediate Load	192	308	424	541	657	773	889	1005	1121	1238	1354
Combined Cycle GE 7FA CT - Intermediate Load	145	246	348	449	551	652	754	855	957	1058	1160
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	123	224	326	427	528	629	731	832	933	1035	1136
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	104	205	305	406	506	607	707	808	908	1009	1109
Siemens 5000F CC CT - Intermediate Load	135	237	339	441	543	645	747	849	951	1053	1155
Humid Air Turbine Cycle CT - 366 MW	134	278	422	566	710	854	998	1142	1286	1430	----
Kalina Cycle CC CT - 282 MW	145	233	321	409	497	584	672	760	848	936	----
Cheng Cycle CT - 140 MW	152	257	362	467	572	677	782	887	992	1097	----
Peaking Microturbine - 0 03 MW	423	652	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	459	661	863	1065	1266	1468	1670	1872	2074	2276	2478
Subcritical Pulverized Coal - 250 MW	331	366	402	437	473	508	544	579	615	650	686
Subcritical Pulverized Coal - 500 MW	291	326	362	397	432	468	503	539	574	609	645
Subcritical Pulverized Coal, High Sulfur - 500 MW	297	331	365	399	432	466	500	534	568	602	636
Circulating Fluidized Bed - 250 MW	330	366	402	438	474	509	545	581	617	653	689
Circulating Fluidized Bed - 500 MW	293	329	364	400	436	472	507	543	579	614	650
Supercritical Pulverized Coal - 500 MW	299	333	366	400	433	467	501	534	568	601	635
Supercritical Pulverized Coal. High Sulfur - 500 MW	303	336	368	401	434	467	499	532	565	598	630
Supercritical Pulverized Coal - 750 MW	277	311	345	379	414	448	482	516	550	584	618
Supercritical Pulverized Coal High Sulfur - 750 MW	280	313	345	378	411	444	476	509	542	574	607
Pressurized Fluidized Bed Combustion	412	452	493	533	574	614	655	695	735	----	----
1x1 IGCC	368	400	433	465	498	530	563	595	628	----	----
2x1 IGCC	327	359	392	424	456	489	521	553	586	----	----
2x1 IGCC, High Sulfur	327	358	389	419	450	481	512	543	573	----	----
Subcritical Pulverized Coal - 500 MW - CCS	524	559	595	630	665	701	736	772	807	842	878
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	532	566	599	633	667	700	734	767	801	835	868
Circulating Fluidized Bed - 500 MW - CCS	532	568	603	639	675	710	746	782	818	853	889
Supercritical Pulverized Coal - 500 MW - CCS	531	564	598	631	664	698	731	765	798	831	865
Supercritical Pulverized Coal. High Sulfur - 500 MW	538	570	602	634	667	699	731	763	795	827	860
Supercritical Pulverized Coal - 750 MW - CCS	501	535	568	602	635	669	703	736	770	803	837
Supercritical Pulverized Coal. High Sulfur - 750 MW	505	537	569	600	632	664	696	728	760	791	823
1x1 IGCC - CCS	510	537	564	592	619	646	673	701	728	----	----
2x1 IGCC - CCS	462	489	516	544	571	598	625	653	680	----	----
2x1 IGCC. High Sulfur - CCS	464	490	516	542	568	594	620	645	671	----	----
Wind Energy Conversion - 50 MW	259	248	237	225	----	----	----	----	----	----	----
Geothermal - 30 MW	484	480	476	472	467	462	456	449	442	435	428
Solar Photovoltaic - 50 kW	766	766	----	----	----	----	----	----	----	----	----
Solar Thermal Parabolic Trough - 100 MW	506	507	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	734	734	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	771	772	773	773	773	774	774	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	646	646	646	645	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1741	1772	1804	1835	1867	1898	1930	1961	----	----	----
RDF Stoker-Fired - 7 MW	1665	1782	1899	2017	2134	2251	2368	2485	2602	----	----
Landfill Gas IC Engine - 5 MW	455	523	591	660	728	796	864	933	1001	1069	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	489	529	568	608	647	687	727	766	806	845	884
Sewage Sludge & Anaerobic Digestion - 085 MW	693	696	699	702	704	707	710	712	712	712	----
Bio Mass (Co-Fire)	324	357	391	424	457	491	524	557	591	624	657
Molten Carbonate Fuel Cell - 300 kW	464	577	690	802	915	1028	1141	1253	1366	1479	----
Spark Ignition Engine - 5 MW	403	532	660	789	917	1046	1175	1303	1432	1561	----
Hydroelectric - New - 30 MW	473	467	462	456	449	----	----	----	----	----	----
Ohio Falls 9-10	293	287	281	273	----	----	----	----	----	----	----
Minimum Levelized $/kW	103	205	237	225	411	444	456	449	442	435	428

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost- High **2007 ($/kW yr)**
Heat Rate-Low
Fuel Forecast-Low

	Capacity Factors										
Technology	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Pumped Hydro Energy Storage - 500 MW	194	257	320	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	271	329	387	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	181	262	343	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	197	292	388	483	578	674	769	864	960	1055	1150
Simple Cycle GE 7EA CT - Peaking Capacity	145	256	366	477	588	698	809	920	1030	1141	1252
Simple Cycle GE 7FA CT - Peaking Capacity	115	214	314	413	512	612	711	810	910	1009	1108
Combined Cycle GE 7EA CT - Intermediate Load	216	278	341	403	465	528	590	652	715	777	839
Combined Cycle GE 7FA CT - Intermediate Load	163	217	272	326	381	435	490	544	599	653	708
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	137	191	246	300	355	409	464	518	573	627	682
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	117	171	225	279	332	386	440	494	548	602	655
Siemens 5000F CC CT - Intermediate Load	153	208	262	317	372	426	481	536	590	645	700
Humid Air Turbine Cycle CT - 366 MW	149	225	302	378	454	531	607	683	760	836	----
Kalina Cycle CC CT - 282 MW	167	213	260	306	353	399	445	492	538	585	----
Cheng Cycle CT - 140 MW	174	230	287	343	400	456	513	569	626	682	----
Peaking Microturbine - 0.03 MW	466	600	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	498	605	712	819	926	1034	1141	1248	1355	1462	1569
Subcritical Pulverized Coal - 250 MW	398	430	461	493	524	556	587	619	650	682	713
Subcritical Pulverized Coal - 500 MW	352	383	415	446	478	509	540	572	603	634	666
Subcritical Pulverized Coal, High Sulfur - 500 MW	357	387	417	447	477	507	537	567	597	628	658
Circulating Fluidized Bed - 250 MW	398	430	462	493	525	557	589	621	653	684	716
Circulating Fluidized Bed - 500 MW	355	387	418	450	481	513	545	576	608	639	671
Supercritical Pulverized Coal - 500 MW	361	391	421	450	480	510	540	570	600	629	659
Supercritical Pulverized Coal. High Sulfur - 500 MW	365	394	423	452	482	511	540	569	598	627	657
Supercritical Pulverized Coal - 750 MW	336	366	397	427	457	488	518	548	579	609	639
Supercritical Pulverized Coal. High Sulfur - 750 MW	339	368	397	426	455	485	514	543	572	601	630
Pressurized Fluidized Bed Combustion	523	559	595	631	667	703	738	774	810	----	----
1x1 IGCC	458	487	516	545	574	602	631	660	689	----	----
2x1 IGCC	410	439	468	496	525	554	583	611	640	----	----
2x1 IGCC, High Sulfur	410	437	465	492	519	547	574	601	629	----	----
Subcritical Pulverized Coal - 500 MW - CCS	687	718	749	779	810	841	872	903	934	964	995
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	696	725	755	784	814	843	872	902	931	961	990
Circulating Fluidized Bed - 500 MW - CCS	699	730	761	792	823	854	885	916	947	977	1008
Supercritical Pulverized Coal - 500 MW - CCS	694	723	752	781	810	839	868	897	926	955	984
Supercritical Pulverized Coal. High Sulfur - 500 MW	703	731	759	787	815	843	871	899	928	956	984
Supercritical Pulverized Coal - 750 MW - CCS	659	688	717	747	776	805	834	863	892	922	951
Supercritical Pulverized Coal. High Sulfur - 750 MW	664	692	719	747	775	803	830	858	886	914	941
1x1 IGCC - CCS	660	684	707	731	755	778	802	826	849	----	----
2x1 IGCC - CCS	601	625	648	672	696	719	743	767	790	----	----
2x1 IGCC. High Sulfur - CCS	603	626	648	671	693	716	739	761	784	----	----
Wind Energy Conversion - 50 MW	299	288	277	265	----	----	----	----	----	----	----
Geothermal - 30 MW	586	582	578	574	570	565	559	553	547	540	533
Solar Photovoltaic - 50 kW	909	909	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	592	593	----	----	----	----	----	----	----	----	----
Solar Thermal Parabolic Dish - 1 2 MW	867	867	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	897	898	899	899	900	900	900	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	758	758	758	757	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1848	1880	1912	1944	1975	2007	2039	2071	----	----	----
RDF Stoker-Fired - 7 MW	1831	1933	2036	2138	2241	2343	2446	2548	2651	----	----
Landfill Gas IC Engine - 5 MW	487	523	560	596	633	669	706	742	779	815	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	582	617	652	687	722	757	792	827	862	897	932
Sewage Sludge & Anaerobic Digestion - 085 MW	759	761	763	765	767	769	771	773	773	773	----
Bio Mass (Co-Fire)	391	421	450	479	509	538	568	597	627	656	686
Molten Carbonate Fuel Cell - 300 kW	537	597	658	718	778	839	899	959	1019	1080	----
Spark Ignition Engine - 5 MW	416	483	549	616	683	750	816	883	950	1016	----
Hydroelectric - New - 30 MW	622	616	611	605	599	----	----	----	----	----	----
Ohio Falls 9-10	391	385	379	372	----	----	----	----	----	----	----
Minimum Levelized $/kW	115	171	225	265	332	386	440	492	538	540	533

Exhibit 8

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost- High 2007 ($/kW yr)
Heat Rate-Low
Fuel Forecast- Base

	Capacity Factors										
Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	194	257	320	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	271	329	387	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	181	275	369	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	197	320	444	567	690	814	937	1060	1184	1307	1430
Simple Cycle GE 7EA CT - Peaking Capacity	145	291	437	583	729	875	1021	1167	1313	1459	1605
Simple Cycle GE 7FA CT - Peaking Capacity	115	246	378	509	640	772	903	1034	1166	1297	1428
Combined Cycle GE 7EA CT - Intermediate Load	216	303	389	476	563	649	736	823	909	996	1083
Combined Cycle GE 7FA CT - Intermediate Load	163	239	315	390	466	542	618	693	769	845	921
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	137	213	288	364	439	515	591	666	742	817	893
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	117	192	267	342	417	492	567	642	717	792	867
Siemens 5000F CC CT - Intermediate Load	153	229	305	381	457	533	609	685	761	837	913
Humid Air Turbine Cycle CT - 366 MW	149	256	363	470	576	683	790	897	1004	1111	----
Kalina Cycle CC CT - 282 MW	167	232	297	363	428	493	558	623	688	754	----
Cheng Cycle CT - 140 MW	174	252	331	409	488	566	644	723	801	880	----
Peaking Microturbine - 0 03 MW	466	643	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	498	648	798	948	1098	1247	1397	1547	1697	1847	1997
Subcritical Pulverized Coal - 250 MW	398	430	461	493	525	557	588	620	652	684	715
Subcritical Pulverized Coal - 500 MW	352	384	415	447	478	510	542	573	605	636	668
Subcritical Pulverized Coal, High Sulfur - 500 MW	357	387	418	448	478	508	539	569	599	630	660
Circulating Fluidized Bed - 250 MW	398	430	462	494	526	558	590	622	654	686	719
Circulating Fluidized Bed - 500 MW	355	387	419	450	482	514	546	578	610	641	673
Supercritical Pulverized Coal - 500 MW	361	391	421	451	481	511	541	571	601	631	662
Supercritical Pulverized Coal. High Sulfur - 500 MW	365	394	424	453	482	511	541	570	599	628	658
Supercritical Pulverized Coal - 750 MW	336	367	397	428	458	489	519	550	580	611	641
Supercritical Pulverized Coal. High Sulfur - 750 MW	339	368	398	427	456	486	515	544	574	603	632
Pressurized Fluidized Bed Combustion	523	559	595	631	668	704	740	776	812	----	----
1x1 IGCC	458	487	516	545	574	603	632	661	690	----	----
2x1 IGCC	410	439	468	497	526	554	583	612	641	----	----
2x1 IGCC, High Sulfur	410	438	465	493	520	548	576	603	631	----	----
Subcritical Pulverized Coal - 500 MW - CCS	687	718	750	781	812	843	875	906	937	968	1000
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	696	726	755	785	815	845	874	904	934	964	993
Circulating Fluidized Bed - 500 MW - CCS	699	730	762	793	825	856	887	919	950	981	1013
Supercritical Pulverized Coal - 500 MW - CCS	694	723	753	782	812	841	870	900	929	959	988
Supercritical Pulverized Coal. High Sulfur - 500 MW	703	731	760	788	817	845	873	902	930	959	987
Supercritical Pulverized Coal - 750 MW - CCS	659	689	718	748	777	807	837	866	896	926	955
Supercritical Pulverized Coal High Sulfur - 750 MW	664	692	720	749	777	805	833	861	889	918	946
1x1 IGCC - CCS	660	684	708	732	756	780	804	828	852	----	----
2x1 IGCC - CCS	601	625	649	673	697	721	745	769	793	----	----
2x1 IGCC. High Sulfur - CCS	603	626	649	672	695	718	741	764	787	----	----
Wind Energy Conversion - 50 MW	299	288	277	265	----	----	----	----	----	----	----
Geothermal - 30 MW	586	582	578	574	570	565	559	553	547	540	533
Solar Photovoltaic - 50 kW	909	909	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	592	593	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Dish - 1 2 MW	867	867	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	897	898	899	899	900	900	900	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	758	758	758	757	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1848	1880	1911	1943	1975	2007	2038	2070	----	----	----
RDF Stoker-Fired - 7 MW	1831	1935	2038	2142	2245	2349	2452	2556	2659	----	----
Landfill Gas IC Engine - 5 MW	487	537	588	638	688	739	789	839	890	940	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	582	617	653	688	723	758	793	829	864	899	934
Sewage Sludge & Anaerobic Digestion - 085 MW	759	761	763	765	767	769	771	773	773	773	----
Bio Mass (Co-Fire)	391	421	450	480	510	540	569	599	628	658	688
Molten Carbonate Fuel Cell - 300 kW	537	621	705	789	873	957	1041	1125	1209	1293	----
Spark Ignition Engine - 5 MW	416	511	605	700	794	889	983	1078	1173	1267	----
Hydroelectric - New - 30 MW	622	616	611	605	599	----	----	----	----	----	----
Ohio Falls 9-10	391	385	379	372	----	----	----	----	----	----	----
Minimum Levelized $/kW	115	192	267	265	417	486	515	544	547	540	533

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost- High **2007 ($/kW yr)**
Heat Rate-Low
Fuel Forecast- High

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	194	257	320	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	271	329	387	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	181	286	391	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	197	342	488	633	778	924	1069	1214	1360	1505	1650
Simple Cycle GE 7EA CT - Peaking Capacity	145	318	492	665	838	1012	1185	1358	1532	1705	1878
Simple Cycle GE 7FA CT - Peaking Capacity	115	271	427	583	739	895	1051	1207	1363	1519	1675
Combined Cycle GE 7EA CT - Intermediate Load	216	322	427	533	639	744	850	956	1061	1167	1273
Combined Cycle GE 7FA CT - Intermediate Load	163	255	347	440	532	624	716	808	901	993	1085
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	137	229	321	414	506	598	690	782	874	967	1059
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	117	208	300	391	483	574	666	757	848	940	1031
Siemens 5000F CC CT - Intermediate Load	153	246	338	431	524	616	709	802	895	987	1080
Humid Air Turbine Cycle CT - 366 MW	149	280	411	541	672	803	934	1064	1195	1326	----
Kalina Cycle CC CT - 282 MW	167	247	327	406	486	566	646	726	805	885	----
Cheng Cycle CT - 140 MW	174	269	365	460	556	651	747	842	937	1033	----
Peaking Microturbine - 0 03 MW	466	676	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	498	681	865	1048	1231	1414	1598	1781	1964	2148	2331
Subcritical Pulverized Coal - 250 MW	398	430	463	495	528	560	592	625	657	689	722
Subcritical Pulverized Coal - 500 MW	352	384	417	449	481	513	546	578	610	642	675
Subcritical Pulverized Coal, High Sulfur - 500 MW	357	388	419	450	481	512	543	574	605	636	667
Circulating Fluidized Bed - 250 MW	398	431	463	496	529	562	594	627	660	692	725
Circulating Fluidized Bed - 500 MW	355	387	420	452	485	517	550	582	615	647	680
Supercritical Pulverized Coal - 500 MW	361	392	422	453	483	514	545	575	606	636	667
Supercritical Pulverized Coal High Sulfur - 500 MW	365	395	425	455	485	515	545	575	605	635	664
Supercritical Pulverized Coal - 750 MW	336	367	398	430	461	492	523	554	586	617	648
Supercritical Pulverized Coal, High Sulfur - 750 MW	339	369	399	429	458	488	518	548	578	608	638
Pressurized Fluidized Bed Combustion	523	560	597	634	670	707	744	781	818	----	----
1x1 IGCC	458	488	517	547	576	606	636	665	695	----	----
2x1 IGCC	410	439	469	498	528	557	587	616	646	----	----
2x1 IGCC, High Sulfur	410	438	466	495	523	551	579	607	635	----	----
Subcritical Pulverized Coal - 500 MW - CCS	687	719	752	784	817	849	882	914	947	979	1012
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	696	727	758	789	820	851	882	913	944	975	1006
Circulating Fluidized Bed - 500 MW - CCS	699	732	764	797	830	863	895	928	961	993	1026
Supercritical Pulverized Coal - 500 MW - CCS	694	725	755	786	816	847	878	908	939	969	1000
Supercritical Pulverized Coal, High Sulfur - 500 MW	703	733	762	792	821	851	880	910	939	969	998
Supercritical Pulverized Coal - 750 MW - CCS	659	690	721	751	782	813	844	875	906	936	967
Supercritical Pulverized Coal High Sulfur - 750 MW	664	693	723	752	781	810	840	869	898	928	957
1x1 IGCC - CCS	660	685	710	735	760	785	810	835	860	----	----
2x1 IGCC - CCS	601	626	651	676	701	726	751	776	801	----	----
2x1 IGCC, High Sulfur - CCS	603	627	651	674	698	722	746	769	793	----	----
Wind Energy Conversion - 50 MW	299	288	277	265	----	----	----	----	----	----	----
Geothermal - 30 MW	586	582	578	574	570	565	559	553	547	540	533
Solar Photovoltaic - 50 kW	909	909	----	----	----	----	----	----	----	----	----
Solar Thermal, Parabolic Trough - 100 MW	592	593	----	----	----	----	----	----	----	----	----
Solar Thermal, Parabolic Dish - 1 2 MW	867	867	----	----	----	----	----	----	----	----	----
Solar Thermal Central Receiver - 50 MW	897	898	899	899	900	900	900	----	----	----	----
Solar Thermal Solar Chimney - 50 MW	758	758	758	757	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1848	1880	1911	1943	1975	2007	2038	2070	----	----	----
RDF Stoker-Fired - 7 MW	1831	1938	2044	2151	2257	2364	2471	2577	2684	----	----
Landfill Gas IC Engine - 5 MW	487	548	609	671	732	793	854	916	977	1038	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	582	618	654	690	726	762	798	834	870	906	942
Sewage Sludge & Anaerobic Digestion - 085 MW	759	761	763	765	767	769	771	773	773	773	----
Bio Mass (Co-Fire)	391	421	452	482	513	543	573	603	634	664	694
Molten Carbonate Fuel Cell - 300 kW	537	639	742	844	947	1049	1152	1254	1357	1459	----
Spark Ignition Engine - 5 MW	416	532	649	765	882	998	1114	1231	1347	1463	----
Hydroelectric - New - 30 MW	622	616	611	605	599	----	----	----	----	----	----
Ohio Falls 9-10	391	385	379	372	----	----	----	----	----	----	----
Minimum Levelized $/kW	115	208	277	265	458	488	518	548	547	540	533

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost- High **2007 ($/kW yr)**
Heat Rate- Base
Fuel Forecast-Low

	Capacity Factors										
Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	194	257	320	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	271	329	387	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	181	264	346	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	198	297	395	494	593	691	790	889	987	1086	1185
Simple Cycle GE 7EA CT - Peaking Capacity	146	261	375	490	605	719	834	949	1063	1178	1293
Simple Cycle GE 7FA CT - Peaking Capacity	116	219	323	426	529	633	736	839	943	1046	1149
Combined Cycle GE 7EA CT - Intermediate Load	217	282	348	413	478	544	609	674	740	805	870
Combined Cycle GE 7FA CT - Intermediate Load	164	221	278	335	392	449	506	564	621	678	735
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	138	195	252	309	366	423	480	537	595	652	709
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	118	174	231	287	344	400	457	513	570	626	683
Siemens 5000F CC CT - Intermediate Load	154	211	269	326	383	440	498	555	612	670	727
Humid Air Turbine Cycle CT - 366 MW	150	230	310	390	471	551	631	711	791	871	----
Kalina Cycle CC CT - 282 MW	168	217	265	314	363	411	460	509	558	606	----
Cheng Cycle CT - 140 MW	174	233	292	352	411	470	529	589	648	707	----
Peaking Microturbine - 0 03 MW	467	606	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	501	613	726	838	950	1063	1175	1288	1400	1512	1625
Subcritical Pulverized Coal - 250 MW	398	431	464	497	530	563	596	629	662	695	728
Subcritical Pulverized Coal - 500 MW	352	385	418	451	484	517	550	583	615	648	681
Subcritical Pulverized Coal, High Sulfur - 500 MW	357	389	420	452	483	515	546	578	609	641	672
Circulating Fluidized Bed - 250 MW	398	431	465	498	531	565	598	632	665	698	732
Circulating Fluidized Bed - 500 MW	355	388	421	454	488	521	554	587	620	653	687
Supercritical Pulverized Coal - 500 MW	361	392	424	455	486	517	549	580	611	642	674
Supercritical Pulverized Coal. High Sulfur - 500 MW	365	396	426	457	487	518	548	579	609	640	670
Supercritical Pulverized Coal - 750 MW	336	368	399	431	463	495	526	558	590	622	653
Supercritical Pulverized Coal High Sulfur - 750 MW	339	369	400	430	461	491	522	552	582	613	643
Pressurized Fluidized Bed Combustion	523	561	598	636	673	711	748	786	824	----	----
1x1 IGCC	458	488	518	549	579	609	639	669	700	----	----
2x1 IGCC	410	440	470	500	530	560	591	621	651	----	----
2x1 IGCC, High Sulfur	410	439	467	496	525	553	582	611	639	----	----
Subcritical Pulverized Coal - 500 MW - CCS	687	719	751	783	816	848	880	912	944	976	1009
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	696	727	757	788	818	849	880	910	941	972	1002
Circulating Fluidized Bed - 500 MW - CCS	699	731	764	796	829	861	893	926	958	990	1023
Supercritical Pulverized Coal - 500 MW - CCS	694	724	755	785	815	845	876	906	936	967	997
Supercritical Pulverized Coal. High Sulfur - 500 MW	703	732	762	791	820	849	879	908	937	967	996
Supercritical Pulverized Coal - 750 MW - CCS	659	689	720	750	781	811	842	872	903	933	964
Supercritical Pulverized Coal High Sulfur - 750 MW	664	693	722	751	780	809	838	867	896	925	954
1x1 IGCC - CCS	660	685	709	734	759	784	808	833	858	----	----
2x1 IGCC - CCS	601	626	650	675	700	725	749	774	799	----	----
2x1 IGCC High Sulfur - CCS	603	627	650	674	697	721	744	768	791	----	----
Wind Energy Conversion - 50 MW	299	288	277	265	----	----	----	----	----	----	----
Geothermal - 30 MW	586	582	578	574	570	565	559	553	547	540	533
Solar Photovoltaic - 50 kW	909	909	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	592	593	----	----	----	----	----	----	----	----	----
Solar Thermal Parabolic Dish - 1 2 MW	867	867	----	----	----	----	----	----	----	----	----
Solar Thermal, Central Receiver - 50 MW	897	898	899	899	900	900	900	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	758	758	758	757	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1848	1880	1911	1943	1975	2007	2038	2070	----	----	----
RDF Stoker-Fired - 7 MW	1831	1939	2046	2154	2261	2369	2476	2584	2691	----	----
Landfill Gas IC Engine - 5 MW	487	526	564	603	641	680	718	757	795	834	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	582	619	656	692	729	766	803	839	876	913	949
Sewage Sludge & Anaerobic Digestion - 085 MW	759	761	764	766	769	771	773	775	776	776	----
Bio Mass (Co-Fire)	391	422	453	484	515	546	577	607	638	669	700
Molten Carbonate Fuel Cell - 300 kW	538	601	664	728	791	854	917	980	1044	1107	----
Spark Ignition Engine - 5 MW	418	488	558	629	699	769	839	909	980	1050	----
Hydroelectric - New - 30 MW	622	616	611	605	599	----	----	----	----	----	----
Ohio Falls 9-10	391	385	379	372	----	----	----	----	----	----	----
Minimum Levelized $/kW	116	174	231	265	344	400	457	509	547	540	533

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost- High 2007 ($/kW yr)
Heat Rate- Base
Fuel Forecast- Base

					Capacity Factors						
Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	194	257	320	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	271	329	387	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	181	278	374	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	198	327	455	584	713	841	970	1099	1227	1356	1485
Simple Cycle GE 7EA CT - Peaking Capacity	146	298	450	602	754	906	1058	1210	1362	1514	1666
Simple Cycle GE 7FA CT - Peaking Capacity	116	253	389	526	663	799	936	1073	1209	1346	1483
Combined Cycle GE 7EA CT - Intermediate Load	217	308	399	490	581	672	763	854	945	1036	1127
Combined Cycle GE 7FA CT - Intermediate Load	164	244	323	403	482	562	641	721	800	880	959
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	138	217	297	376	455	535	614	693	773	852	931
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	118	197	275	354	432	511	589	668	747	825	904
Siemens 5000F CC CT - Intermediate Load	154	234	314	393	473	553	633	713	792	872	952
Humid Air Turbine Cycle CT - 366 MW	150	262	375	487	599	712	824	936	1049	1161	----
Kalina Cycle CC CT - 282 MW	168	236	305	373	442	510	579	647	716	784	----
Cheng Cycle CT - 140 MW	174	256	338	421	503	585	667	750	832	914	----
Peaking Microturbine - 0.03 MW	467	651	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	501	658	816	973	1131	1288	1446	1603	1760	1918	2075
Subcritical Pulverized Coal - 250 MW	398	431	465	498	531	564	598	631	664	697	731
Subcritical Pulverized Coal - 500 MW	352	385	418	451	485	518	551	584	617	650	684
Subcritical Pulverized Coal, High Sulfur - 500 MW	357	389	420	452	484	516	547	579	611	643	674
Circulating Fluidized Bed - 250 MW	398	432	465	499	532	566	600	633	667	700	734
Circulating Fluidized Bed - 500 MW	355	388	422	455	489	522	555	589	622	655	689
Supercritical Pulverized Coal - 500 MW	361	392	424	455	487	518	550	581	613	644	676
Supercritical Pulverized Coal, High Sulfur - 500 MW	365	396	426	457	488	519	549	580	611	642	672
Supercritical Pulverized Coal - 750 MW	336	368	400	432	464	496	528	560	592	624	656
Supercritical Pulverized Coal High Sulfur - 750 MW	339	370	400	431	462	492	523	553	584	615	645
Pressurized Fluidized Bed Combustion	523	561	599	636	674	712	750	788	826	----	----
1x1 IGCC	458	488	519	549	580	610	641	671	702	----	----
2x1 IGCC	410	440	471	501	531	562	592	622	653	----	----
2x1 IGCC, High Sulfur	410	439	468	497	526	554	583	612	641	----	----
Subcritical Pulverized Coal - 500 MW - CCS	687	720	752	785	817	850	883	915	948	980	1013
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	696	727	758	789	820	851	882	913	945	976	1007
Circulating Fluidized Bed - 500 MW - CCS	699	732	765	797	830	863	896	929	962	994	1027
Supercritical Pulverized Coal - 500 MW - CCS	694	725	755	786	817	848	878	909	940	970	1001
Supercritical Pulverized Coal High Sulfur - 500 MW	703	733	762	792	821	851	881	910	940	970	999
Supercritical Pulverized Coal - 750 MW - CCS	659	690	721	752	783	814	845	876	907	937	968
Supercritical Pulverized Coal High Sulfur - 750 MW	664	693	723	752	782	811	840	870	899	929	958
1x1 IGCC - CCS	660	685	710	735	760	785	811	836	861	----	----
2x1 IGCC - CCS	601	626	651	676	701	726	752	777	802	----	----
2x1 IGCC High Sulfur - CCS	603	627	651	675	699	723	746	770	794	----	----
Wind Energy Conversion - 50 MW	299	288	277	265	----	----	----	----	----	----	----
Geothermal - 30 MW	586	582	578	574	570	565	559	553	547	540	533
Solar Photovoltaic - 50 kW	909	909	----	----	----	----	----	----	----	----	----
Solar Thermal, Parabolic Trough - 100 MW	592	593	----	----	----	----	----	----	----	----	----
Solar Thermal, Parabolic Dish - 1 2 MW	867	867	----	----	----	----	----	----	----	----	----
Solar Thermal Central Receiver - 50 MW	897	898	899	899	900	900	900	----	----	----	----
Solar Thermal Solar Chimney - 50 MW	758	758	758	757	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1848	1880	1911	1943	1975	2007	2038	2070	----	----	----
RDF Stoker-Fired - 7 MW	1831	1940	2048	2157	2265	2374	2483	2591	2700	----	----
Landfill Gas IC Engine - 5 MW	487	540	594	647	700	754	807	860	914	967	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	582	619	656	693	730	767	804	841	878	915	951
Sewage Sludge & Anaerobic Digestion - 085 MW	759	761	764	766	769	771	773	775	776	776	----
Bio Mass (Co-Fire)	391	422	454	485	516	547	578	610	641	672	703
Molten Carbonate Fuel Cell - 300 kW	538	626	714	802	891	979	1067	1155	1243	1331	----
Spark Ignition Engine - 5 MW	418	518	617	717	816	916	1015	1115	1215	1314	----
Hydroelectric - New - 30 MW	622	616	611	605	599	----	----	----	----	----	----
Ohio Falls 9-10	391	385	379	372	----	----	----	----	----	----	----
Minimum Levelized $/kW	116	197	275	265	432	492	523	553	547	540	533

Exhibit 8

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost- High 2007 ($/kW yr)
Heat Rate- Base
Fuel Forecast- High

	Capacity Factors										
Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	194	257	320	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	271	329	387	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	181	289	397	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	198	350	502	654	806	958	1110	1262	1414	1566	1718
Simple Cycle GE 7EA CT - Peaking Capacity	146	327	509	690	871	1053	1234	1415	1597	1778	1959
Simple Cycle GE 7FA CT - Peaking Capacity	116	279	441	604	767	929	1092	1255	1417	1580	1743
Combined Cycle GE 7EA CT - Intermediate Load	217	328	439	550	661	772	883	994	1105	1216	1327
Combined Cycle GE 7FA CT - Intermediate Load	164	261	358	455	552	649	745	842	939	1036	1133
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	138	235	331	428	525	622	718	815	912	1009	1105
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	118	214	310	406	502	598	694	790	886	982	1078
Siemens 5000F CC CT - Intermediate Load	154	251	349	446	543	640	738	835	932	1029	1127
Humid Air Turbine Cycle CT - 366 MW	150	287	425	562	699	836	974	1111	1248	1386	----
Kalina Cycle CC CT - 282 MW	168	252	336	420	503	587	671	755	839	923	----
Cheng Cycle CT - 140 MW	174	274	374	475	575	675	775	876	976	1076	----
Peaking Microturbine - 0.03 MW	467	686	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0.03 MW	501	694	886	1079	1271	1464	1656	1849	2042	2234	2427
Subcritical Pulverized Coal - 250 MW	398	432	466	500	534	568	602	635	669	703	737
Subcritical Pulverized Coal - 500 MW	352	386	420	453	487	521	555	589	623	656	690
Subcritical Pulverized Coal, High Sulfur - 500 MW	357	389	422	454	487	519	551	584	616	649	681
Circulating Fluidized Bed - 250 MW	398	432	466	501	535	569	603	638	672	706	740
Circulating Fluidized Bed - 500 MW	355	389	423	457	491	525	559	593	627	661	695
Supercritical Pulverized Coal - 500 MW	361	393	425	457	490	522	554	586	618	650	683
Supercritical Pulverized Coal, High Sulfur - 500 MW	365	396	428	459	490	521	553	584	615	647	678
Supercritical Pulverized Coal - 750 MW	336	369	401	434	466	499	532	564	597	630	662
Supercritical Pulverized Coal, High Sulfur - 750 MW	339	370	402	433	464	495	527	558	589	621	652
Pressurized Fluidized Bed Combustion	523	562	600	639	678	716	755	794	832	----	----
1x1 IGCC	458	489	520	551	582	613	644	675	706	----	----
2x1 IGCC	410	441	472	503	534	565	595	626	657	----	----
2x1 IGCC, High Sulfur	410	439	469	498	528	557	587	616	646	----	----
Subcritical Pulverized Coal - 500 MW - CCS	687	721	755	789	823	857	891	925	958	992	1026
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	696	728	761	793	825	857	890	922	954	987	1019
Circulating Fluidized Bed - 500 MW - CCS	699	733	767	801	836	870	904	938	972	1006	1040
Supercritical Pulverized Coal - 500 MW - CCS	694	726	758	790	822	854	886	918	950	982	1014
Supercritical Pulverized Coal, High Sulfur - 500 MW	703	734	765	795	826	857	888	919	950	980	1011
Supercritical Pulverized Coal - 750 MW - CCS	659	691	723	755	788	820	852	884	916	948	981
Supercritical Pulverized Coal, High Sulfur - 750 MW	664	695	725	756	786	817	848	878	909	939	970
1x1 IGCC - CCS	660	686	712	738	765	791	817	843	869	----	----
2x1 IGCC - CCS	601	627	653	679	705	731	757	783	809	----	----
2x1 IGCC, High Sulfur - CCS	603	628	653	678	702	727	752	777	802	----	----
Wind Energy Conversion - 50 MW	299	288	277	265	----	----	----	----	----	----	----
Geothermal - 30 MW	586	582	578	574	570	565	559	553	547	540	533
Solar Photovoltaic - 50 kW	909	909	----	----	----	----	----	----	----	----	----
Solar Thermal, Parabolic Trough - 100 MW	592	593	----	----	----	----	----	----	----	----	----
Solar Thermal, Parabolic Dish - 1.2 MW	867	867	----	----	----	----	----	----	----	----	----
Solar Thermal, Central Receiver - 50 MW	897	898	899	899	900	900	900	----	----	----	----
Solar Thermal, Solar Chimney - 50 MW	758	758	758	757	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1848	1880	1911	1943	1974	2006	2038	2069	----	----	----
RDF Stoker-Fired - 7 MW	1831	1943	2055	2167	2279	2390	2502	2614	2726	----	----
Landfill Gas IC Engine - 5 MW	487	552	616	681	746	810	875	940	1004	1069	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	582	620	658	695	733	771	808	846	884	921	959
Sewage Sludge & Anaerobic Digestion - .085 MW	759	761	764	766	769	771	773	775	776	776	----
Bio Mass (Co-Fire)	391	423	455	487	519	551	582	614	646	678	710
Molten Carbonate Fuel Cell - 300 kW	538	646	753	861	969	1076	1184	1291	1399	1507	----
Spark Ignition Engine - 5 MW	418	541	663	786	908	1031	1153	1276	1398	1521	----
Hydroelectric - New - 30 MW	622	616	611	605	599	----	----	----	----	----	----
Ohio Falls 9-10	391	385	379	372	----	----	----	----	----	----	----
Minimum Levelized $/kW	116	214	277	265	464	495	527	553	547	540	533

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost- High **2007 ($/kW yr)**
Heat Rate- High
Fuel Forecast-Low

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	194	257	320	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	271	329	387	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	181	265	349	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	199	301	403	505	607	709	811	913	1015	1117	1219
Simple Cycle GE 7EA CT - Peaking Capacity	147	266	386	505	624	744	863	982	1102	1221	1340
Simple Cycle GE 7FA CT - Peaking Capacity	117	224	332	439	546	654	761	868	976	1083	1190
Combined Cycle GE 7EA CT - Intermediate Load	218	286	355	423	491	560	628	696	765	833	901
Combined Cycle GE 7FA CT - Intermediate Load	165	225	284	344	404	463	523	583	642	702	762
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	139	199	258	318	378	437	497	557	616	676	736
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	118	177	236	295	354	413	472	531	590	649	709
Siemens 5000F CC CT - Intermediate Load	155	215	275	335	395	455	515	575	635	695	756
Humid Air Turbine Cycle CT - 366 MW	152	236	320	404	487	571	655	739	823	907	----
Kalina Cycle CC CT - 282 MW	168	219	270	321	372	423	474	525	576	627	----
Cheng Cycle CT - 140 MW	175	237	299	361	423	485	547	609	671	732	----
Peaking Microturbine - 0.03 MW	468	612	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	504	622	739	857	975	1092	1210	1327	1445	1563	1680
Subcritical Pulverized Coal - 250 MW	398	432	467	501	536	570	605	639	674	708	743
Subcritical Pulverized Coal - 500 MW	352	386	421	455	490	524	558	593	627	661	696
Subcritical Pulverized Coal, High Sulfur - 500 MW	357	390	423	456	489	522	555	588	621	654	687
Circulating Fluidized Bed - 250 MW	398	433	468	503	538	573	607	642	677	712	747
Circulating Fluidized Bed - 500 MW	355	390	424	459	494	529	563	598	633	667	702
Supercritical Pulverized Coal - 500 MW	361	394	426	459	492	525	557	590	623	655	688
Supercritical Pulverized Coal High Sulfur - 500 MW	365	397	429	461	492	524	556	588	620	652	683
Supercritical Pulverized Coal - 750 MW	336	369	403	436	469	502	536	569	602	635	669
Supercritical Pulverized Coal. High Sulfur - 750 MW	339	371	403	435	466	498	530	562	594	626	657
Pressurized Fluidized Bed Combustion	523	562	602	641	680	720	759	799	838	----	----
1x1 IGCC	458	490	521	553	585	616	648	679	711	----	----
2x1 IGCC	410	442	473	505	536	568	599	631	662	----	----
2x1 IGCC, High Sulfur	410	440	470	500	530	560	590	620	650	----	----
Subcritical Pulverized Coal - 500 MW - CCS	687	720	754	787	821	854	888	921	955	988	1022
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	696	728	760	792	823	855	887	919	951	983	1014
Circulating Fluidized Bed - 500 MW - CCS	699	733	767	800	834	868	902	936	970	1003	1037
Supercritical Pulverized Coal - 500 MW - CCS	694	726	757	789	820	852	884	915	947	978	1010
Supercritical Pulverized Coal High Sulfur - 500 MW	703	733	764	794	825	855	886	916	947	977	1008
Supercritical Pulverized Coal - 750 MW - CCS	659	691	723	754	786	818	850	882	914	945	977
Supercritical Pulverized Coal. High Sulfur - 750 MW	664	694	724	755	785	815	845	875	905	936	966
1x1 IGCC - CCS	660	686	712	737	763	789	815	841	866	----	----
2x1 IGCC - CCS	601	627	653	678	704	730	756	782	807	----	----
2x1 IGCC. High Sulfur - CCS	603	628	652	677	701	726	751	775	800	----	----
Wind Energy Conversion - 50 MW	299	288	277	265	----	----	----	----	----	----	----
Geothermal - 30 MW	586	582	578	574	570	565	559	553	547	540	533
Solar Photovoltaic - 50 kW	909	909	----	----	----	----	----	----	----	----	----
Solar Thermal Parabolic Trough - 100 MW	592	593	----	----	----	----	----	----	----	----	----
Solar Thermal Parabolic Dish - 1 2 MW	867	867	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	897	898	899	899	900	900	900	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	758	758	758	757	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1848	1880	1911	1943	1974	2006	2038	2069	----	----	----
RDF Stoker-Fired - 7 MW	1831	1944	2056	2169	2281	2394	2507	2619	2732	----	----
Landfill Gas IC Engine - 5 MW	487	528	569	609	650	691	732	772	813	854	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	582	621	659	698	736	775	813	852	890	928	967
Sewage Sludge & Anaerobic Digestion - 085 MW	759	762	765	768	770	773	776	778	779	780	----
Bio Mass (Co-Fire)	391	423	456	488	521	553	586	618	651	683	715
Molten Carbonate Fuel Cell - 300 kW	539	605	671	738	804	870	936	1002	1068	1135	----
Spark Ignition Engine - 5 MW	419	493	566	640	714	788	861	935	1009	1083	----
Hydroelectric - New - 30 MW	622	616	611	605	599	----	----	----	----	----	----
Ohio Falls 9-10	391	385	379	372	----	----	----	----	----	----	----
Minimum Levelized $/kW	117	177	236	265	354	413	472	525	547	540	533

Exhibit 8

Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost- High **2007 ($/kW yr)**
Heat Rate- High
Fuel Forecast- Base

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	194	257	320	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	271	329	387	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	181	280	379	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	199	332	466	599	732	866	999	1132	1266	1399	1532
Simple Cycle GE 7EA CT - Peaking Capacity	147	306	464	623	782	940	1099	1258	1416	1575	1734
Simple Cycle GE 7FA CT - Peaking Capacity	117	259	401	543	685	827	969	1111	1253	1395	1537
Combined Cycle GE 7EA CT - Intermediate Load	218	313	409	504	599	695	790	885	981	1076	1171
Combined Cycle GE 7FA CT - Intermediate Load	165	248	332	415	498	581	665	748	831	914	998
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	139	222	305	388	471	554	637	721	804	887	970
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	118	200	283	365	447	530	612	694	777	859	941
Siemens 5000F CC CT - Intermediate Load	155	239	322	406	489	573	656	740	823	907	991
Humid Air Turbine Cycle CT - 366 MW	152	270	387	505	623	740	858	976	1093	1211	----
Kalina Cycle CC CT - 282 MW	168	240	311	383	455	527	598	670	742	814	----
Cheng Cycle CT - 140 MW	175	261	347	433	520	606	692	778	864	950	----
Peaking Microturbine - 0.03 MW	468	659	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0.03 MW	504	669	834	999	1164	1329	1494	1659	1824	1989	2155
Subcritical Pulverized Coal - 250 MW	398	433	468	502	537	572	607	642	676	711	746
Subcritical Pulverized Coal - 500 MW	352	387	421	456	490	525	560	594	629	663	698
Subcritical Pulverized Coal, High Sulfur - 500 MW	357	390	423	457	490	523	556	589	623	656	689
Circulating Fluidized Bed - 250 MW	398	433	468	503	539	574	609	644	679	714	749
Circulating Fluidized Bed - 500 MW	355	390	425	460	495	530	565	600	634	669	704
Supercritical Pulverized Coal - 500 MW	361	394	427	460	493	526	559	592	624	657	690
Supercritical Pulverized Coal. High Sulfur - 500 MW	365	397	429	461	493	525	557	589	622	654	686
Supercritical Pulverized Coal - 750 MW	336	369	403	436	470	503	537	570	604	637	671
Supercritical Pulverized Coal. High Sulfur - 750 MW	339	371	403	435	467	499	531	563	595	628	660
Pressurized Fluidized Bed Combustion	523	563	602	642	681	721	761	800	840	----	----
1x1 IGCC	458	490	522	554	585	617	649	681	713	----	----
2x1 IGCC	410	442	473	505	537	569	600	632	664	----	----
2x1 IGCC, High Sulfur	410	440	470	501	531	561	591	621	652	----	----
Subcritical Pulverized Coal - 500 MW - CCS	687	721	755	789	823	857	891	925	959	993	1027
Subcritical Pulverized Coal, High Sulfur - 500 MW - (	696	728	761	793	825	857	890	922	954	987	1019
Circulating Fluidized Bed - 500 MW - CCS	699	733	768	802	836	870	905	939	973	1007	1042
Supercritical Pulverized Coal - 500 MW - CCS	694	726	758	790	822	854	886	918	950	982	1014
Supercritical Pulverized Coal. High Sulfur - 500 MW	703	734	765	795	826	857	888	919	950	980	1011
Supercritical Pulverized Coal - 750 MW - CCS	659	691	724	756	788	820	853	885	917	949	982
Supercritical Pulverized Coal. High Sulfur - 750 MW	664	695	725	756	786	817	848	878	909	939	970
1x1 IGCC - CCS	660	686	712	738	765	791	817	843	869	----	----
2x1 IGCC - CCS	601	627	653	679	706	732	758	784	810	----	----
2x1 IGCC. High Sulfur - CCS	603	628	653	678	703	728	753	778	803	----	----
Wind Energy Conversion - 50 MW	299	288	277	265	----	----	----	----	----	----	----
Geothermal - 30 MW	586	582	578	574	570	565	559	553	547	540	533
Solar Photovoltaic - 50 kW	909	909	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	592	593	----	----	----	----	----	----	----	----	----
Solar Thermal Parabolic Dish - 1 2 MW	867	867	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	897	898	899	899	900	900	900	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	758	758	758	757	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1848	1880	1911	1943	1974	2006	2038	2069	----	----	----
RDF Stoker-Fired - 7 MW	1831	1945	2059	2172	2286	2400	2514	2627	2741	----	----
Landfill Gas IC Engine - 5 MW	487	543	599	656	712	768	824	881	937	993	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	582	621	659	698	737	776	814	853	892	930	969
Sewage Sludge & Anaerobic Digestion - 085 MW	759	762	765	768	770	773	776	778	779	780	----
Bio Mass (Co-Fire)	391	424	456	489	522	554	587	620	652	685	718
Molten Carbonate Fuel Cell - 300 kW	539	631	724	816	908	1001	1093	1186	1278	1370	----
Spark Ignition Engine - 5 MW	419	524	628	733	837	942	1046	1151	1256	1360	----
Hydroelectric - New - 30 MW	622	616	611	605	599	----	----	----	----	----	----
Ohio Falls 9-10	391	385	379	372	----	----	----	----	----	----	----
Minimum Levelized $/kW	117	200	277	265	447	499	531	553	547	540	533

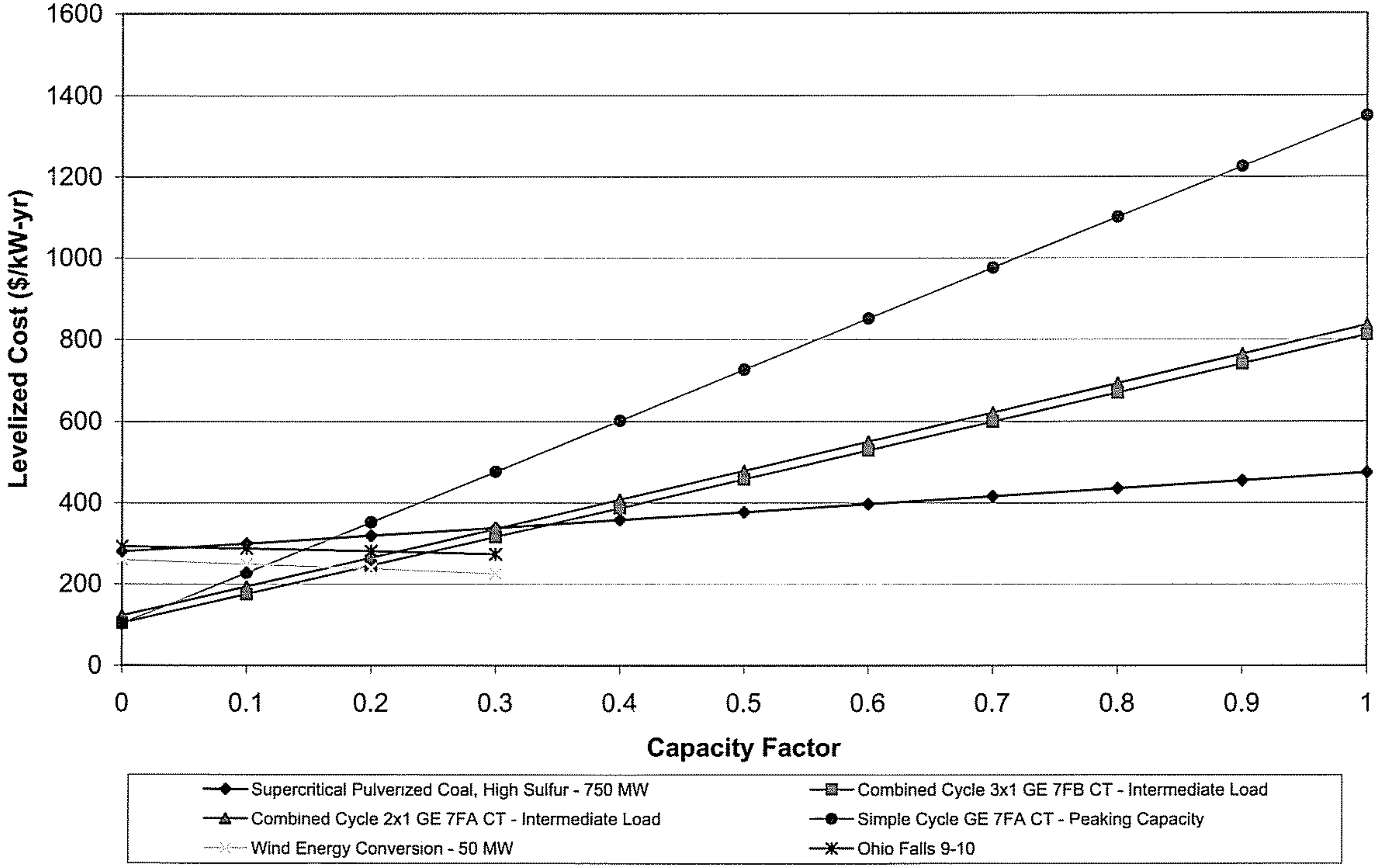
Levelized Dollars at Various Capacity Factors With SO2 Adders, with High CO2 Adders, and with NOx Adders

Capital Cost- High 2007 ($/kW yr)
Heat Rate- High
Fuel Forecast- High

	Capacity Factors										
Technology	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Pumped Hydro Energy Storage - 500 MW	194	257	320	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	271	329	387	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	181	292	402	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - Peaking Capacity	199	357	515	673	831	989	1147	1305	1463	1621	1779
Simple Cycle GE 7EA CT - Peaking Capacity	147	336	524	713	902	1090	1279	1468	1656	1845	2034
Simple Cycle GE 7FA CT - Peaking Capacity	117	286	456	625	794	964	1133	1302	1472	1641	1810
Combined Cycle GE 7EA CT - Intermediate Load	218	334	450	567	683	799	915	1031	1147	1264	1380
Combined Cycle GE 7FA CT - Intermediate Load	165	266	368	469	571	672	774	875	977	1078	1180
Combined Cycle 2x1 GE 7FA CT - Intermediate Loa	139	240	342	443	544	645	747	848	949	1051	1152
Combined Cycle 3x1 GE 7FB CT - Intermediate Loa	118	219	319	420	520	621	721	822	922	1023	1123
Siemens 5000F CC CT - Intermediate Load	155	257	359	461	563	665	767	869	971	1073	1175
Humid Air Turbine Cycle CT - 366 MW	152	296	440	584	728	872	1016	1160	1304	1448	----
Kalina Cycle CC CT - 282 MW	168	256	344	432	520	607	695	783	871	959	----
Cheng Cycle CT - 140 MW	175	280	385	490	595	700	805	910	1015	1120	----
Peaking Microturbine - 0 03 MW	468	697	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0 03 MW	504	706	908	1110	1311	1513	1715	1917	2119	2321	2523
Subcritical Pulverized Coal - 250 MW	398	433	469	504	540	575	611	646	682	717	753
Subcritical Pulverized Coal - 500 MW	352	387	423	458	493	529	564	600	635	670	706
Subcritical Pulverized Coal, High Sulfur - 500 MW	357	391	425	459	492	526	560	594	628	662	696
Circulating Fluidized Bed - 250 MW	398	434	470	506	542	577	613	649	685	721	757
Circulating Fluidized Bed - 500 MW	355	391	426	462	498	534	569	605	641	676	712
Supercritical Pulverized Coal - 500 MW	361	395	428	462	495	529	563	596	630	663	697
Supercritical Pulverized Coal. High Sulfur - 500 MW	365	398	430	463	496	529	561	594	627	660	692
Supercritical Pulverized Coal - 750 MW	336	370	404	438	473	507	541	575	609	643	677
Supercritical Pulverized Coal. High Sulfur - 750 MW	339	372	404	437	470	503	535	568	601	633	666
Pressurized Fluidized Bed Combustion	523	563	604	644	685	725	766	806	846	----	----
1x1 IGCC	458	490	523	555	588	620	653	685	718	----	----
2x1 IGCC	410	442	475	507	539	572	604	636	669	----	----
2x1 IGCC, High Sulfur	410	441	472	502	533	564	595	626	656	----	----
Subcritical Pulverized Coal - 500 MW - CCS	687	722	758	793	828	864	899	935	970	1005	1041
Subcritical Pulverized Coal. High Sulfur - 500 MW - (	696	730	763	797	831	864	898	931	965	999	1032
Circulating Fluidized Bed - 500 MW - CCS	699	735	770	806	842	877	913	949	985	1020	1056
Supercritical Pulverized Coal - 500 MW - CCS	694	727	761	794	827	861	894	928	961	994	1028
Supercritical Pulverized Coal. High Sulfur - 500 MW	703	735	767	799	832	864	896	928	960	992	1025
Supercritical Pulverized Coal - 750 MW - CCS	659	693	726	760	793	827	861	894	928	961	995
Supercritical Pulverized Coal. High Sulfur - 750 MW	664	696	728	759	791	823	855	887	919	950	982
1x1 IGCC - CCS	660	687	714	742	769	796	823	851	878	----	----
2x1 IGCC - CCS	601	628	655	683	710	737	764	792	819	----	----
2x1 IGCC. High Sulfur - CCS	603	629	655	681	707	733	759	784	810	----	----
Wind Energy Conversion - 50 MW	299	288	277	265	----	----	----	----	----	----	----
Geothermal - 30 MW	586	582	578	574	570	565	559	553	547	540	533
Solar Photovoltaic - 50 kW	909	909	----	----	----	----	----	----	----	----	----
Solar Thermal. Parabolic Trough - 100 MW	592	593	----	----	----	----	----	----	----	----	----
Solar Thermal Parabolic Dish - 1 2 MW	867	867	----	----	----	----	----	----	----	----	----
Solar Thermal. Central Receiver - 50 MW	897	898	899	899	900	900	900	----	----	----	----
Solar Thermal. Solar Chimney - 50 MW	758	758	758	757	----	----	----	----	----	----	----
MSW Mass Burn - 7 MW	1848	1879	1911	1942	1974	2005	2037	2068	----	----	----
RDF Stoker-Fired - 7 MW	1831	1948	2065	2183	2300	2417	2534	2651	2768	----	----
Landfill Gas IC Engine - 5 MW	487	555	623	692	760	828	896	965	1033	1101	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	582	622	661	701	740	780	820	859	899	938	978
Sewage Sludge & Anaerobic Digestion - 085 MW	759	762	765	768	770	773	776	778	779	780	----
Bio Mass (Co-Fire)	391	424	458	491	524	558	591	624	658	691	724
Molten Carbonate Fuel Cell - 300 kW	539	652	765	877	990	1103	1216	1328	1441	1554	----
Spark Ignition Engine - 5 MW	419	548	676	805	933	1062	1191	1319	1448	1577	----
Hydroelectric - New - 30 MW	622	616	611	605	599	----	----	----	----	----	----
Ohio Falls 9-10	391	385	379	372	----	----	----	----	----	----	----
Minimum Levelized $/kW	117	219	277	265	470	503	535	553	547	540	533

Least Cost Technologies Considered For Further Analysis

Base Capital, Base Heatrate, Base Fuel



Kentucky Utilities Company
and
Louisville Gas and Electric Company

Screening of Demand-Side Management Options

Prepared by

Energy Efficiency Operations

March 2008

Table of Contents

Introduction

Kentucky Utilities Company (KU) and Louisville Gas and Electric Company (LG&E) (collectively, the Companies) evaluate future electric service requirements of customers with balanced consideration of demand-side and supply-side resource options. The purpose of this study is to evaluate and screen available demand-side management (DSM) alternatives to be included in the integrated analysis portion of the 2008 Integrated Resource Plan (IRP). Each alternative was investigated and evaluated using a two-step screening process. The first step was qualitative in nature, where each alternative was evaluated based on four criteria. The alternatives that passed the first step underwent a second step of screening that was quantitative in nature. The quantitative screening process was broken down into two separate phases and is discussed in the Quantitative Screening Process section of this report. The DSM programs that passed the quantitative screening process were evaluated with supply-side alternatives in the integrated analysis.

Qualitative Screening Process

A list of 80 alternatives was identified which needed to be evaluated (see EXHIBIT DSM-1). Next, criteria were defined to facilitate an objective evaluation of the alternatives. Based upon the Companies' objectives to provide low cost, reliable energy to our customers, and the comments from the PSC Staff Report on KU and LG&E's most recently filed IRP(Case No. 2005-00162), four criteria were selected. The next task was to assign weights or values to each of the criteria. The highest weights were assigned to the criteria judged to be the most important to develop a successful DSM program. The most important criterion was the cost effectiveness of peak demand reduction. Each potential DSM option was evaluated, based on a scale of 1 to 4, using the four criteria. The four criteria, their weights, and an explanation of each are shown on EXHIBIT DSM-2.

Qualitative Screening Results

The results of the qualitative screening process are shown on EXHIBIT DSM-3. EXHIBIT DSM-4 depicts a graphical representation of the results of the qualitative screening process. Each bar in the graph represents the weighted average of the evaluations. The weighted averages are ranked from the highest to the lowest. The horizontal dark line on EXHIBIT DSM-3 and EXHIBIT DSM-4 delineates desirable programs produced by the qualitative screening analysis which resulted in 28 DSM options for further analysis. The cut off of 2.5 was selected by the Companies Energy Efficiency Operations Department. Of the 28 programs, 15 programs target residential customers and 13 target commercial customers. These 28 options were then evaluated in the quantitative screening process.

Quantitative Screening Process

The 28 options that passed the qualitative screening process were modeled in more detail using DSM Portfolio Pro software. DSM Portfolio Pro is a PC-based software package developed by Quantec, LLC. It is a screening tool that determines the cost effectiveness of DSM options by modeling their costs and benefits over a period of time. The program uses hourly load shapes for the DSM options as well as the Companies' aggregate hourly system load shape. Portfolio Pro utilizes marginal energy costs to estimate the change in production costs resulting from the implementation of each DSM option. A detailed production-costing model, PROSYM, was used to determine the marginal energy costs used.

Portfolio Pro calculates the net present value of the quantifiable costs and benefits assignable to both the Companies and the customers participating in a DSM program. For each DSM initiative, Portfolio Pro requires the administrative costs, participant's costs, life span of the technology, expected level of participation, expected level of free-riders, and rate schedules. Portfolio Pro calculates changes to the participant's bill, changes in the Companies' revenue, changes in production costs, and changes in the peak demand. The present value for each DSM alternative is calculated and reported as the costs and benefits using the five "California Tests." These five tests include the participant, utility cost, ratepayer impact measure (RIM), total resource cost (TRC), and societal cost tests. The participant test includes changes in all costs and benefits to the customer participating in the DSM program. The TRC test combines the RIM and participant tests and indicates overall benefits of the DSM option to the average customer, whereas the RIM test considers all impacts to the non-participants.

The quantitative screening was set up in two phases. In Phase I, the cost to administer the program was not considered and it was assumed that the program had only one participant per company (KU and LG&E). This phase was created to remove non-cost effective programs. If the benefits of a program do not exceed the cost of the program without the administration cost, then it will not pass with a higher penetration of customers and the added burden of the administrative costs. The only cost included in this phase was the incremental cost of the DSM alternative. Of the 28 programs evaluated in the Phase I portion of the qualitative screening process, 15 passed the Participant Test and Total Resource Cost Test screening in this phase and were further evaluated in greater detail in Phase II of the quantitative analysis. EXHIBIT DSM-5 is a list of the assumptions used in Phase I of the quantitative analysis and the resulting benefit cost ratio.

Each program that passed Phase I of the quantitative screening process was put through a program design phase (Phase II). The costs to administer the programs and the expected levels of penetration for each Company (KU and LG&E) were added to the programs that passed Phase I. Additionally, all five of the California tests were calculated as part of the Phase II analysis. See EXHIBIT DSM-2 for a complete description of the quantitative screening process. A breakdown of the cost to deliver each program to the targeted customers, the number of customers expected to participate in each program, and other pertinent assumptions can be found on EXHIBIT DSM-6.

Quantitative Screening Results

Portfolio Pro calculates the net present value of the costs and benefits of a given DSM program and calculates the benefit to cost ratios for each of the perspectives of the California Tests. Results of the programs evaluated in Phase II of the quantitative screening process are shown on EXHIBIT DSM-7. The programs are ranked by the benefit to cost ratios for the TRC test.

DSM Resources that failed the Quantitative Screening Process

Below are descriptions of the programs that failed the quantitative screening and the reasons they failed. For each program, (C) represents commercial and (R) represents residential programs.

High Efficiency Heat Pump (Replace Existing Unit) (R)

This program encourages residential customers to replace existing, less efficient heat pumps with high efficiency heat pump units. Peak and energy savings are insufficient to overcome the costs of this program.

Refrigerator Replacement Incentive (R)

Many residential customers have aging, poorly insulated refrigerators featuring less efficient fan and refrigeration systems. The peak and energy efficiency savings are insufficient to overcome the cost to administer this program.

Room Air Conditioner Replacement (R)

This program would promote the change out of older room air conditioner units to new, more energy efficient units. The peak and energy efficiency savings are insufficient to overcome the cost to administer this program.

DSM Resources That Passed Quantitative Screening

Below are descriptions of the 12 programs that passed the quantitative screening. For each program, (C) represents commercial and (R) represents residential programs.

Duct Evaluation & Sealing (R)

Many residential air conditioners have duct systems that are poorly constructed and insulated, resulting in high rates of leakage. This program will perform diagnostic testing of residential duct systems and where potential savings are identified, will assist and provide incentives to customers for corrective action. Based upon energy and demand savings this program is cost effective with a TRC of 1.14 and a Participant test of 2.5.

Duct Evaluation & Sealing (C)

Many commercial air conditioners and heat pumps have duct systems that are poorly insulated and have high rates of leakage. This program will perform diagnostic testing of commercial duct systems and where potential savings are identified, will assist and provide incentives to customers for corrective action. Based upon energy and demand savings this program is cost effective with a TRC of 2.31 and a Participant test of 7.62.

Geothermal Heat Pump (new construction) (C)

Geothermal heat pumps are highly efficient heating and cooling systems, but have high first costs. This program would provide incentives for commercial customers building new facilities to install geothermal systems. Analysis is inclusive of heating and cooling benefits only. The peak and energy savings offer marginally effective return with a TRC of 1.00 and a Participant test of 1.99.

Window Shading & Films (R)

Solar gain through windows is generally the largest contributor to residential cooling loads. This program would provide incentives for residential customers to install high performance film to existing windows to reduce solar heat gain, reducing cooling costs. The peak and energy savings are cost effective with a TRC of 1.55 and a Participant test of 1.71.

High Efficiency Motors (C)

This program encourages commercial customers that are considering replacing worn out motors to purchase energy efficient motors. The peak and energy savings are cost effective with a TRC of 1.71 and a Participant test of 5.32.

Responsive Pricing/Smart Metering/Energy Use Display (R)

This is a Time of Use (TOU) rate program with a real time component. The TOU rate will be a 3 tier TOU rate, but with a fourth "real time" component. Customers would receive smart thermostats, energy use display devices, and water heater/pool pump controllers to automate energy use based on the price of electricity. This program is an expansion and offering to all residential customers, of our Responsive Pricing/Smart Metering Program. Based upon the energy and demand savings, this program is cost effective with a TRC of 2.42. With a participant cost of zero, the result of the Participant Test is infinity.

Refrigeration Optimization (C)

This program will help commercial customers with refrigerators and freezers improve the operational performance with improved controls, defrost cycles, and high efficiency fan motors. Based upon the energy and demand savings this program is cost effective with a TRC of 1.52 and a Participant test of 3.34.

Removal of Second Refrigerator (R)

This program would provide incentives for residential customers to remove old, inefficient second refrigerators in the home. Multiple refrigerators are in place in 22 – 29% of our customer's homes. Participant costs of "zero" results in an "infinite" Participant Test. Peak and energy savings are cost effective with a TRC of 4.38.

Energy Management System (C)

Commercial customers would be provided an incentive to install a system to monitor and control HVAC, lighting and equipment energy consumption, in order to reduce peak demand and usage. Based upon the energy and demand savings this program is cost effective with a TRC of 1.37 and a Participant Test of 2.21.

High Efficiency Heat Pump (replacing resistive heat) (C)

This program would provide incentives for commercial customers currently serviced by electric resistive heating to convert and install a high efficiency heat pump system(s). The peak and energy savings offer marginally effective return with a TRC of 1.1 and a Participant test of 2.36.

Heat Pump Water Heater – Restaurant & Laundries (C)

Commercial restaurant and laundry customers, who have significant hot water usage, would be eligible to receive incentives to convert from electric resistance water heating to the more energy efficient heat pump water heater technology. The peak and energy savings offer marginally effective return with a TRC of 1.72 and a Participant test of 4.07.

Refrigeration Case Cover (C)

This program would provide incentives for commercial customers' to retrofit their refrigerator and freezer units with doors and case covers. The peak and energy savings offer marginally effective return with a TRC of 1.1 and a Participant test of 4.33.

Recommendations

All of the programs that passed the quantitative screening process were considered in the integrated analysis portion of the IRP where the DSM programs are evaluated with the supply-side alternatives. The integrated analysis is used to determine the direction the Companies should take in meeting the future needs of our customers.

DSM program design is a complex, dynamic, and time-consuming activity. Alternatives that are ultimately selected through this evaluation process may not be implemented as they have been described in this document. DSM alternatives that are ultimately proposed will be subjected to a much more rigorous program design cycle, which could result in program concepts and program details being changed significantly, or programs not being implemented.

Residential

High Efficiency Heat Pump (replacing resistive heat)
Insulation
Window Shading and Films
Duct Evaluation & Sealing
Removal of 2nd Refrigerator
High Efficiency Outdoor Lighting
High Efficiency Heat Pump (replace existing unit)
Occupancy Sensors
High Efficiency Air Conditioning (replace existing)
Energy Star Certification for Existing Homes
Refrigerator Replacement Incentive
Room Air Conditioner Replacement
Water Heater Replacement (elect. to gas)
High Efficiency Heat Pump (replacing gas heat)
Responsive Pricing/Smart Metering/Energy Use Display
Geothermal Heat Pump
Solar Water Heating
Electric Thermal Storage - Cooling (special rate)
Attic Ventilation
Dual Fuel Heating System
Ceiling Fans
Energy Star or Equivalent For Existing Multi Family Homes
Instantaneous Water Heating - Gas
Strategic tree-planting
Window Replacement
Removal of 2nd Freezer
Replace Electric With Gas Clothes Drier Purchase Incentive
Dehumidifier
Passive Solar Heating (new construction)
Air-to-Air Heat Exchangers (new construction)
Energy Star Clothes Washer Replacement Incentive
Freezer Replacement Incentive
Water Heater Replacement (elect. to elect.)
Gas Air Conditioning
Electric Thermal Storage - Heating (special rate)
Daylighting
Door Replacement
Replace Electric With Gas Oven/Range Purchase Incentive
Hydronic Distribution of Cooling and Heating
Instantaneous Water Heating - Electric
Photovoltaic
Solar Greenhouses and Sunspaces
Windmills
Fuel Cells

Exhibit DSM-1
Page 2 of 2

Commercial

High Efficiency Heat Pump (replacing resistive heat)
Window Shading and Films
Duct Evaluation & Sealing
High Efficiency Motors/ASD Motors
Electric Thermal Storage - Cooling (special rate)
Geothermal Heat Pump (new construction)
Energy Management System
Refrigeration Optimization
High Efficiency Heat Pump (replace existing unit)
Building Commissioning
Heat Pump Water Heaters - Restaurants & Laundrys
Refrigeration Case Covers
High Efficiency Air Conditioning (replace existing)
High Efficiency Cooking
Clean CHP/CHRP
Desiccant Cooling
Polarized Refrigerant Oxidant Agent
Chilled Water System Optimization
Daylighting
Instantaneous Water Heating - Electric
Instantaneous Water Heating - Gas
Strategic Tree Planting
Cool Roofs (coatings, membranes)
Water Heater Replacement (elect. to elect.)
Solar Water Heating
Water Heater Replacement (elect. to gas)
Air-to-Air Heat Exchangers
Passive Solar Heating
Hydronic Distribution of Cooling and Heating (small comm.)
Door Replacement
Green Roofs (plants)
Window Replacement
Photovoltaic
Windmills
Fuel Cells
Solar Greenhouses and Sunspaces

DSM Screening Process for 2008 IRP

Qualitative Screening Criteria

Criteria	Description	Weighting
Customer Acceptance	The degree to which an acceptable number of customers is willing to participate to create a successful program. The highest scores would be reserved for measures that have beneficial side effects, e.g., enhanced worker productivity or improvements in the quality of a product or service.	25%
Technical Reliability	The degree to which the technology is commercially available and the necessary data are available to evaluate this measure.	15%
Cost Effectiveness of Energy Conservation	The cost of this measure to reduce a kwh relative to the cost of generation in $/kwh.	25%
Cost Effectiveness of Peak Demand Reduction	The cost of this measure to reduce a kw relative to the cost of generation in $/kw.	35%

Each DSM measure will be given a grade for each criterion based on a zero to four scale with four being an excellent rating. The weighted averages of the ratings will be calculated. Measures that are below the selected cutoff will be eliminated from further evaluation except when they might complement other measures in the context of a larger DSM program. For example, low-E windows for homes might score poorly individually but improve the cost-effectiveness of a residential new construction program in which the cost of the windows is partially offset by lower costs of HVAC equipment. The selected cutoff will be determined from any obvious breakpoints between the sorted weighted average scores of the measures.

Quantitative Screening Criteria

The quantitative screening analysis will be performed in DSM Portfolio Pro and will consist of the following phases.

Phase I:

Phase I will not include the cost to administer the program and will include only one participant per company. All programs that pass the Participant Test and Total Resource Cost Test (TRC) will be analyzed in Phase II.

Phase II:

Each program passing Phase I will be evaluated again, using all costs including the cost of administration and the best estimate of penetration. All five California Test results were calculated as part of the Phase II analysis with primary emphasis placed upon the Participants Test and the TRC.

Each of the DSM programs that pass Phase II of the quantitative screening may be aggregated to create a larger program. The aggregate program(s) will then compete with supply-side options in the integrated planning model.

Preliminary DSM Screening Sorted

	Customer Acceptance	Technical Reliability	Cost Effectiveness of Energy Conservation	Cost Effectiveness of Peak Demand Reduction	Weighted Average	Market Segment
	25%	15%	25%	35%		
High Efficiency Heat Pump (replacing resistive heat)	4	4	3.75	2	3.24	R
High Efficiency Heat Pump (replacing resistive heat)	4	4	3.75	2	3.24	C
Window Shading and Films	3	4	3	3	3.15	C
Insulation	3.6	4	3	2.4	3.09	R
Window Shading and Films	3.2	3.5	3	2.8	3.06	R
Duct Evaluation & Sealing	3.4	3.4	3	2.5	2.99	R
Duct Evaluation & Sealing	3.4	3.4	3	2.5	2.99	C
Removal of 2nd Refrigerator	2.4	4	3.4	2.4	2.89	R
High Efficiency Outdoor Lighting	4	4	3.75	1	2.89	R
High Efficiency Heat Pump (replace existing unit)	3.8	4	2.5	2	2.88	R
High Efficiency Air Conditioning (replace existing)	3.8	4	2.25	2	2.81	R
Energy Star Certification for Existing Homes	3.6	3.6	2.4	2.2	2.81	R
Refrigerator Replacement Incentive	4	4	2	2	2.80	R
High Efficiency Motors	3	4	3	2	2.80	C
Heat Pump Water Heaters - Restaurants & Laundrys	3	4	3	2	2.80	C
Refrigeration Case Covers	2	4	4	2	2.80	C
Room Air Conditioner Replacement	3.6	4	2.25	2	2.76	R
Electric Thermal Storage - Cooling (special rate)	2	3	3	3	2.75	C
Water Heater Replacement (elect. to gas)	2.8	4	2.8	2	2.70	R
High Efficiency Heat Pump (replacing gas heat)	3.2	4	2.25	2	2.66	R
Geothermal Heat Pump (new construction)	3	4	2.3	2.1	2.66	C
Responsive Pricing/Smart Metering/Energy Use Display	3	3	3	2	2.65	R
Energy Management System	3	3	3	2	2.65	C
Refrigeration Optimization	3	3	3	2	2.65	C
Geothermal Heat Pump	3	4	2.3	2	2.63	R
High Efficiency Heat Pump (replace existing unit)	2.5	4	2.5	2	2.55	C
High Efficiency Air Conditioning (replace existing)	2.5	4	2.5	2	2.55	C
Building Commissioning	3	2	3	2	2.50	C
Energy Star or Equivalent For Existing Multi Family Homes	2.6	3.4	2.3	2	2.44	R
Dual Fuel Heating System	2.8	4	2	1.8	2.43	R
Attic Ventilation	3.5	3.5	2	1.5	2.43	R
Occupancy Sensors	2.5	2.6	2.8	2	2.42	R
Ceiling Fans	3.5	4	2	1.25	2.41	R
Instantaneous Water Heating - Gas	3	3	2.3	1.75	2.39	R
Electric Thermal Storage - Cooling (special rate)	1	2	3	3	2.35	R
Strategic tree-planting	3	2	2.4	2	2.35	R
Window Replacement	3.4	3.4	1.6	1.6	2.32	R
Removal of 2nd Freezer	2	4	2	2	2.30	R
Replace Electric With Gas Clothes Drier Purchase Incentive	2.6	4	2	1.5	2.28	R
Dehumidifier	3.5	3.75	1.5	1.25	2.25	R
Passive Solar Heating (new construction)	2.8	3	3	1	2.25	R
Solar Water Heating	2.4	3.2	2.5	1.5	2.23	R
Air-to-Air Heat Exchangers (new construction)	2	3.25	2.5	1.75	2.23	R
Energy Star Clothes Washer Replacement Incentive	3.2	3.8	2	1	2.22	R

Preliminary DSM Screening Sorted

	Customer Acceptance	Technical Reliability	Cost Effectiveness of Energy Conservation	Cost Effectiveness of Peak Demand Reduction	Weighted Average	Market Segment
	25%	15%	25%	35%		
Freezer Replacement Incentive	3	4	2	1	2.20	R
Water Heater Replacement (elect. to elect.)	4	4	1	1	2.20	R
High Efficiency Cooking	3	4	2	1	2.20	C
Gas Air Conditioning	1.6	3	1	3	2.15	R
Clean CHP/CHRP	2	3	2	2	2.15	C
Desiccant Cooling	2	2	1	3	2.10	C
Polarized Refrigerant Oxidant Agent	2	1	3	2	2.10	C
Electric Thermal Storage - Heating (special rate)	2	3	3	1	2.05	R
Chilled Water System Optimization	3	3	2	1	2.05	C
Daylighting	3	.3	2	1	2.05	C
Instantaneous Water Heating - Electric	3	3	2	1	2.05	C
Instantaneous Water Heating - Gas	3	3	2	1	2.05	C
Strategic Tree Planting	3	3	2	1	2.05	C
Cool Roofs (coatings, membranes)	2	3	3	1	2.05	C
Daylighting	2.4	3	2	1.3	2.01	R
Door Replacement	3	3.4	1.5	1	1.99	R
Water Heater Replacement (elect. to elect.)	3	4	1	1	1.95	C
Water Heater Replacement (elect. to gas)	2	4	2	1	1.95	C
Replace Electric With Gas Oven/Range Purchase Incentive	2.8	4	1	1	1.90	R
Hydronic Distribution of Cooling and Heating	1.75	3.25	1.5	1.5	1.83	R
Solar Water Heating	2	3	2	1	1.80	C
Air-to-Air Heat Exchangers	2	3	2	1	1.80	C
Passive Solar Heating	2	3	2	1	1.80	C
Hydronic Distribution of Cooling and Heating (small comm.)	2	3	2	1	1.80	C
Door Replacement	2	3	2	1	1.80	C
Green Roofs (plants)	1	2	2	2	1.75	C
Instantaneous Water Heating - Electric	2.2	2.75	1.5	1	1.69	R
Photovoltaic	2	3	1	1	1.55	R
Window Replacement	2	3	1	1	1.55	C
Photovoltaic	2	3	1	1	1.55	C
Windmills	2	3	1	1	1.55	C
Fuel Cells	2	2	1	1	1.40	C
Solar Greenhouses and Sunspaces	1.5	2.5	1	1	1.35	R
Solar Greenhouses and Sunspaces	1	3	1	1	1.30	C
Windmills	1	2	1	1	1.15	R
Fuel Cells	1	1.5	1	1	1.08	R

Results of Qualitative Screening

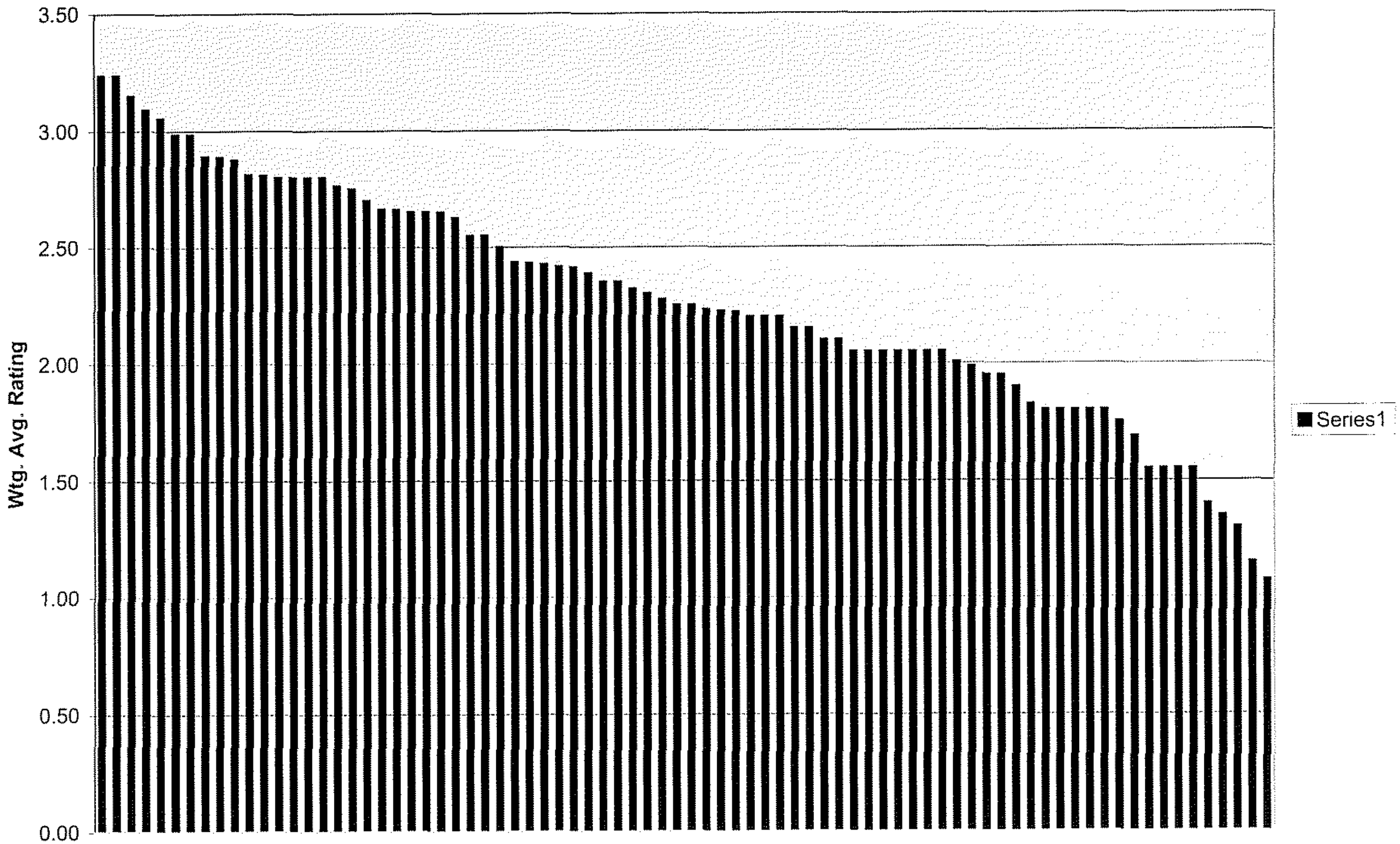


Exhibit DSM-4

Assumptions and Results of Phase I Quantitative Screening Process

Customer Class	Program Description	Per Participant Cost	Peak kw Reduction	Annual kWh Reduction	% Free Riders	Measure Lifetime	TRC B/C	Participant Test	RIM Test	Utility Test	Societal Test
R	Responsive Pricing/Smart Metering/Energy Use Display	$0.00	1.21	1100	0	15	6.52	infinity			
R	Room Air Conditioner Replacement	$40.00	0.36	167	0	10	5.07	2.45			
C	Duct Evaluation & Sealing	$508.00	0.77	3398	0	15	4.62	5.49			
C	High Efficiency Motors	$441.00	3.49	2700	0	15	3.42	3.44			
R	Removal of 2nd Refrigerator	$0.00	0.19	1310	0	10	2.5	infinity			
C	Refrigeration Case Covers	$668.00	2.47	9060	0	4	2.41	3.61			
R	Window Shading and Films	$450.00	0.61	444	0	15	1.97	1.08			
C	Heat Pump Water Heaters - Restaurants & Laundrys	$15,300.00	6.96	66430	0	15	1.9	3.69			
C	Refrigeration Optimization	$8,355.00	7.83	28991	0	15	1.8	2.96			
R	Duct Evaluation & Sealing	$700.00	0.4	1123	0	15	1.7	1.51			
C	Energy Management System	$2,700.00	2.07	4400	0	15	1.62	2.05			
R	Refrigerator Replacement Incentive	$31.50	0.04	85	0	18	1.56	2.31			
C	High Efficiency Heat Pump (replacing resistive heat)	$5,452.00	0.46	21901	0	15	1.36	2.21			
C	Geothermal Heat Pump (new construction)	$12,046.00	10.6	22457	0	15	1.19	1.59			
R	High Efficiency Heat Pump (replace existing unit)	$700.00	0.6	970	0	15	1.01	1.05			
C	High Efficiency Air Conditioning (replace existing)	$673.50	0.7	710	0	15	1.64	0.92			
R	High Efficiency Air Conditioning (replace existing)	$400.00	0.33	375	0	15	1.44	0.65			
C	Electric Thermal Storage - Cooling (special rate)	$33.00	1	0	0	20	1.25	0.87			
R	Energy Star Certification for Existing Homes	$1,200.00	0.55	1363	0	15	1.01	0.89			
C	High Efficiency Heat Pump (replace existing unit)	$134.70	0.14	142.00	0	15	0.84				
R	High Efficiency Outdoor Lighting	$40.00	0.00	139.50	0	10	0.8				
R	Insulation	$672.00	0.11	271.00	0	25	0.75				
R	High Efficiency Heat Pump (replacing gas heat)	$4,150.00	(0.76)	(4791.00)	0	15	0.73				
R	Geothermal Heat Pump	$6,000.00	1.38	5753.00	0	15	0.67				
C	Building Commissioning	$20,000.00	1.39	6212.00	0	7	0.67				
C	Window Shading and Films	$4,820.00	0.81	10081.00	0	15	0.37				
R	High Efficiency Heat Pump (replacing resistive heat)	$6,050.00	(1.10)	4977.00	0	15	0.09				
R	Water Heater Replacement (elect. to gas)	$900.00	0.32	4254.00	0	13	0.08				

Responsive Pricing/Smart Metering/Energy Use Display

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total	Assumption
Program Management	150,000	154,500	159,135	163,909	168,826	173,891	179,108	1,149,369	
Program Clerical	65,000	66,950	68,959	71,027	73,158	75,353	77,613	498,060	
Total Program Labor	215,000	221,450	228,094	234,936	241,984	249,244	256,721	1,647,429	
Advertising	310,000	306,000	312,120	424,483	432,973	441,632	450,465	2,677,673	$30 per participant 1st 3 years, $40 last 4 ye
Data Processing	50,000	51,000	52,020	53,060	54,122	55,204	56,308	371,714	$50,000 per year (extensive network)
Office Supplies & Expenses	12,000	12,240	12,485	12,734	12,989	13,249	13,514	89,211	$1000 per month
Outside Services - Purchase/Install Control & Display Devices	3,775,000	3,850,500	3,927,510	4,006,060	4,086,181	4,167,905	4,251,263	28,064,420	$450 per customer with electric hot water, $
Outside Services - Administration	120,000	122,400	124,848	127,345	129,892	132,490	135,139	892,114	$10,000 Monthly Administration Fee
Program Ongoing Operating Costs	600,000	1,224,000	1,872,720	2,546,899	3,247,296	3,974,691	4,729,882	18,195,489	10% cumulative devices at $60 per device
Evaluation	355,740	405,131	457,086	518,386	574,381	632,409	692,531	3,635,664	Assume 7% program costs
Total Program Costs	5,437,740	6,192,721	6,986,882	7,923,905	8,779,818	9,666,824	10,585,824	55,573,714	
Total Customers	10,000	10,000	10,000	10,000	10,000	10,000	10,000	70,000	Baseline
LG&E Heat Pump and Electric Water Heat	1,700	1,700	1,700	1,700	1,700	1,700	1,700	11,900	
LG&E Gas Heat/Central AC	3,300	3,300	3,300	3,300	3,300	3,300	3,300	23,100	
KU Heat Pump and Electric Water Heat	2,500	2,500	2,500	2,500	2,500	2,500	2,500	17,500	
KU Gas Heat/Central AC	2,500	2,500	2,500	2,500	2,500	2,500	2,500	17,500	
Cumulative Customers	10,000	20,000	30,000	40,000	50,000	60,000	70,000		

Assumptions:

Meters and communication cards are rate based and installed where possible throughout service territory

100,000 residential meters installed each year for a total of 700,000 meters (85% residential customers)

10% of customers elect to utilize responsive pricing (10,000 customers per year)

LG&E Customers with electric water heater	30%
KU Customers with electric water heater	50%

Energy control and display devices are funded through DSM

No adverse impact on load control program

Reduction in overall annual kWh usage (5%)

Cost of device	100
Cost of device installation	50

Room A/C Replacement Incentive

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total	Assumption
Program Management	37,500	38,625	39,784	40,977	42,207	43,473	44,777	287,342	
Program Clerical	16,250	16,738	17,240	17,757	18,290	18,838	19,403	124,515	
Total Program Labor	53,750	55,363	57,023	58,734	60,496	62,311	64,180	411,857	
Advertising	15,000	15,300	20,808	21,224	21,649	22,082	22,523	138,586	$20 per participant ($5000 broucheres)
Data Processing	6,250	1,275	1,301	1,327	1,353	1,380	1,408	14,293	$1250 per year ($5000 initial setup)
Office Supplies & Expenses	600	612	624	637	649	662	676	4,461	$50 per month
Outside Services - Rebate Processing	12,500	19,125	26,010	26,530	27,061	27,602	28,154	166,982	$25 participant (includes QC testing)
Outside Services - Administration	22,000	12,240	12,485	12,734	12,989	13,249	13,514	99,211	$1000 Monthly Administration Fee ($10,000 1st Year setup)
Outside Services - Old A/C Disposal	25,000	38,250	52,020	53,060	54,122	55,204	56,308	333,964	$50 per unit
Evaluation	10,332	11,290	13,740	14,054	14,377	14,706	15,044	93,544	Assume 7% program costs
Total Program Costs Excluding Rebates	145,432	153,455	184,011	188,301	192,695	197,197	201,807	1,262,898	
Customer Costs	20,000	30,600	41,616	42,448	43,297	44,163	45,046	267,171	$40 per A/C
Rebates	12,500	19,125	26,010	26,530	27,061	27,602	28,154	166,982	Assume $25
Net Customer Cost	7,500	11,475	15,606	15,918	16,236	16,561	16,892	100,189	
Total Room A/C's Replaced	500	750	1,000	1,000	1,000	1,000	1,000	6,250	

Assumptions:

Incremental Cost	$40.00
Old Unit EER	9.7
New Unit EER	11.9
Customer is replacing regardless	
Company disposes of old unit as proof of replacement	

Commercial Duct Sealing

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total	Assumption
Program Management	37,500	38,625	39,784	40,977	42,207	43,473	44,777	287,342	
Program Clerical	16,250	16,738	17,240	17,757	18,290	18,838	19,403	124,515	
Total Program Labor	53,750	55,363	57,023	58,734	60,496	62,311	64,180	411,857	
Advertising	9,400	6,732	11,444	11,673	11,907	12,145	12,388	75,689	$40 per participant ($5000 broucheres)
Data Processing	6,250	1,275	1,301	1,327	1,353	1,380	1,408	14,293	$1250 per year ($5000 initial setup)
Office Supplies & Expenses	600	612	624	637	649	662	676	4,461	$50 per month
Outside Services - Rebate Processing	2,500	3,825	6,503	6,633	6,765	6,901	7,039	40,164	$25 participant (includes QC testing)
Outside Services - Administration	22,000	12,240	12,485	12,734	12,989	13,249	13,514	99,211	$1000 Monthly Administration Fee ($10,000 1st Year setup)
Outside Services - Testing Only	2,000	3,060	5,202	5,306	5,412	5,520	5,631	32,131	$200 per evaluation not needing additional work
Evaluation	7,805	7,424	9,352	9,579	9,811	10,050	10,295	64,315	Assume 7% program costs
Total Program Costs Excluding Rebates	104,305	90,530	103,934	106,622	109,383	112,218	115,129	742,122	
Customer Costs	50,800	77,724	132,131	134,773	137,469	140,218	143,023	816,138	$508 Each For Testing & Sealing
Rebates	15,000	22,950	39,015	39,795	40,591	41,403	42,231	240,986	Assume $150
Net Customer Cost	35,800	54,774	93,116	94,978	96,878	98,815	100,792	575,152	
Evaluation Only Participants	10	15	25	25	25	25	25	150	
Evaluation & Sealing Participants	100	150	250	250	250	250	250	1,500	
Total Participants	110	165	275	275	275	275	275	1,650	
LG&E HP Sealing Participants	18	26	44	44	44	44	44	263	
LG&E Gas w/AC Sealing Participants	33	49	81	81	81	81	81	488	
KU HP Sealing Participants	25	38	63	63	63	63	63	375	
KU Gas w/AC Sealing Participants	25	38	63	63	63	63	63	375	

High Efficiency Motors

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total	Assumption
Program Management	37,500	38,625	39,784	40,977	42,207	43,473	44,777	287,342	
Program Clerical	16,250	16,738	17,240	17,757	18,290	18,838	19,403	124,515	
Total Program Labor	53,750	55,363	57,023	58,734	60,496	62,311	64,180	411,857	
Advertising	8,200	4,896	6,659	6,792	6,928	7,066	7,207	47,747	$40 per participant ($5000 broucheres)
Data Processing	6,250	1,275	1,301	1,327	1,353	1,380	1,408	14,293	$1250 per year ($5000 initial setup)
Office Supplies & Expenses	600	612	624	637	649	662	676	4,461	$50 per month
Outside Services - Rebate Processing	2,000	3,060	4,162	4,245	4,330	4,416	4,505	26,717	$25 participant (includes QC testing)
Outside Services - Administration	22,000	12,240	12,485	12,734	12,989	13,249	13,514	99,211	*$1000 Monthly Administration Fee ($10,000 1st Year setup)*
Evaluation	7,616	7,135	8,088	8,290	8,497	8,709	8,927	57,262	Assume 7% program costs
Total Program Costs Excluding Rebates	100,416	84,580	90,341	92,758	95,242	97,794	100,417	661,548	
Customer Costs	47,550	74,837	103,197	105,261	107,366	109,514	111,704	659,430	$441 for ODP, $850 for TEFC
Rebates	16,000	24,480	33,293	33,959	34,638	35,331	36,037	213,737	Assume $200
Net Customer Cost	*31,550*	*50,357*	*69,904*	*71,303*	*72,729*	*74,183*	*75,667*	445,693	
ODP Motors	50	70	90	90	90	90	90	570	
TEFC Motors	30	50	70	70	70	70	70	430	
Total Participants	80	120	160	160	160	160	160	1,000	

Remove 2nd Refrigerator

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total	Assumption
Program Management	37,500	38,625	39,784	40,977	42,207	43,473	44,777	287,342	
Program Clencal	16,250	16,738	17,240	17,757	18,290	18,838	19,403	124,515	
Total Program Labor	53,750	55,363	57,023	58,734	60,496	62,311	64,180	411,857	
Advertising	55,000	102,000	104,040	106,121	108,243	110,408	112,616	698,428	$20 per participant ($5000 broucheres)
Data Processing	6,250	1,275	1,301	1,327	1,353	1,380	1,408	14,293	$1250 per year ($5000 initial setup)
Office Supplies & Expenses	600	612	624	637	649	662	676	4,461	$50 per month
Outside Services - Refrigerator Removal/Disposal	125,000	255,000	260,100	265,302	270,608	276,020	281,541	1,733,571	$200 per refrigerator
Outside Services - Administration	22,000	12,240	12,485	12,734	12,989	13,249	13,514	99,211	$1000 Monthly Administration Fee ($10,000 1st Year setup)
Outside Services - Incentive Processing	37,500	76,500	78,030	79,591	81,182	82,806	84,462	520,071	$15 per refrigerator
Evaluation	27,132	47,459	48,202	48,961	49,737	50,529	51,338	323,357	Assume 7% program costs
Total Program Costs Excluding Rebates	327,232	550,449	561,805	573,406	585,258	597,365	609,734	3,805,250	
Customer Costs	0	0	0	0	0	0	0	0	
Rebates	87,500	175,000	175,000	175,000	175,000	175,000	175,000	1,137,500	$35 per refrigerator
Net Customer Cost	(87,500)	(175,000)	(175,000)	(175,000)	(175,000)	(175,000)	(175,000)	(1,137,500)	
Total Refrigerators Removed	2,500	5,000	5,000	5,000	5,000	5,000	5,000	32,500	

Refrigeration Case Covers

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total	Assumption
Program Management	37,500	38,625	39,784	40,977	42,207	43,473	44,777	287,342	
Program Clerical	16,250	16,738	17,240	17,757	18,290	18,838	19,403	124,515	
Total Program Labor	53,750	55,363	57,023	58,734	60,496	62,311	64,180	411,857	
Advertising	8,000	5,100	6,242	6,367	6,495	6,624	6,757	45,586	$40 per participant ($5000 broucheres)
Data Processing	6,250	1,275	1,301	1,327	1,353	1,380	1,408	14,293	$1250 per year ($5000 initial setup)
Office Supplies & Expenses	600	612	624	637	649	662	676	4,461	$50 per month
Outside Services - Rebate Processing	1,875	3,188	3,902	3,980	4,059	4,140	4,223	25,366	$25 participant (includes QC testing)
Outside Services - Administration	22,000	12,240	12,485	12,734	12,989	13,249	13,514	99,211	$1000 Monthly Administration Fee ($10,000 1st Year setup)
Evaluation	6,998	6,337	6,803	6,979	7,159	7,345	7,536	49,157	Assume 7% program costs
Total Program Costs Excluding Rebates	99,473	84,114	88,380	90,757	93,201	95,712	98,293	649,931	
Customer Costs	501,000	851,700	1,042,481	1,063,330	1,084,597	1,106,289	1,128,415	6,777,812	$668 per store (20 linear feet)
Rebates	7,500	12,750	15,606	15,918	16,236	16,561	16,892	101,464	Assume $100 per store (20 linear feet)
Net Customer Cost	493,500	838,950	1,026,875	1,047,412	1,068,361	1,089,728	1,111,522	6,676,348	
Total Stores	75	125	150	150	150	150	150	950	

Assumptions:

Linear Feet Per Store	20
Cost Per Linear Foot	$33.40
Total Cost Per Store	$668

Window Films - Residential

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total	Assumption
Program Management	37,500	38,625	39,784	40,977	42,207	43,473	44,777	287,342	
Program Clerical	16,250	16,738	17,240	17,757	18,290	18,838	19,403	124,515	
Total Program Labor	53,750	55,363	57,023	58,734	60,496	62,311	64,180	411,857	
Advertising	15,000	15,300	20,808	21,224	21,649	22,082	22,523	138,586	$20 per participant ($5000 broucheres)
Data Processing	6,250	1,275	1,301	1,327	1,353	1,380	1,408	14,293	$1250 per year ($5000 initial setup)
Office Supplies & Expenses	600	612	624	637	649	662	676	4,461	$50 per month
Outside Services - Rebate Processing	12,500	19,125	26,010	26,530	27,061	27,602	28,154	166,982	$25 participant (includes QC testing)
Outside Services - Administration	22,000	12,240	12,485	12,734	12,989	13,249	13,514	99,211	$1000 Monthly Administration Fee ($10,000 1st Year setup)
Evaluation	12,957	15,307	19,202	19,626	20,059	20,503	20,957	128,610	Assume 7% program costs
Total Program Costs Excluding Rebates	123,057	119,221	137,453	140,812	144,257	147,789	151,412	964,000	
Customer Costs	225,000	344,250	468,180	477,544	487,094	496,836	506,773	3,005,678	$3 per square foot
Rebates	75,000	114,750	156,060	159,181	162,365	165,612	168,924	1,001,893	$1 per square foot
Net Customer Cost	150,000	229,500	312,120	318,362	324,730	331,224	337,849	2,003,785	
Total Customers Participating	500	750	1,000	1,000	1,000	1,000	1,000	6,250	
Average Square Footage Per Customer	150	150	150	150	150	150	150	150	
Total Square Footage Installed	75,000	112,500	150,000	150,000	150,000	150,000	150,000	937,500	
LG&E Heat Pump	85	128	170	170	170	170	170	1063	
LG&E Gas Heat with central AC	165	247	330	330	330	330	330	2062	
KU Heat Pump	125	188	250	250	250	250	250	1563	
KU Gas Heat with central AC	125	187	250	250	250	250	250	1562	

Heat Pump Water Heater

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total	Assumption
Program Management	37,500	38,625	39,784	40,977	42,207	43,473	44,777	287,342	
Program Clerical	16,250	16,738	17,240	17,757	18,290	18,838	19,403	124,515	
Total Program Labor	53,750	55,363	57,023	58,734	60,496	62,311	64,180	411,857	
Advertising	7,000	3,060	3,121	3,184	3,247	3,312	3,378	26,303	$40 per participant ($5000 broucheres)
Data Processing	6,250	1,275	1,301	1,327	1,353	1,380	1,408	14,293	$1250 per year ($5000 initial setup)
Office Supplies & Expenses	600	612	624	637	649	662	676	4,461	$50 per month
Outside Services - Rebate Processing	1,250	1,913	1,951	1,990	2,030	2,070	2,112	13,314	$25 participant (includes QC testing)
Outside Services - Administration	22,000	12,240	12,485	12,734	12,989	13,249	13,514	99,211	$1000 Monthly Administration Fee ($10,000 1st Year setup)
Evaluation	11,610	13,245	13,548	13,859	14,178	14,504	14,837	95,781	Assume 7% program costs
Total Program Costs Excluding Rebates	102,460	87,707	90,053	92,465	94,942	97,488	100,105	665,220	
Customer Costs	765,000	1,170,450	1,193,859	1,217,736	1,242,091	1,266,933	1,292,271	8,148,340	$15,300 per unit
Rebates	75,000	114,750	117,045	119,386	121,774	124,209	126,693	798,857	Assume $1,500
Net Customer Cost	690,000	1,055,700	1,076,814	1,098,350	1,120,317	1,142,724	1,165,578	7,349,483	
Total Units	50	75	75	75	75	75	75	500	

Assumptions:
Restaurants & Laundries
240 Gallons Storage
209 Gallons Peak Hour

2 - 120 gallon tanks @ $650	$1,300
120 GPH Heat Pump Water Heater	$14,000
TotaL Cost	$15,300

Refrigeration Optimization

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total	Assumption
Program Management	37,500	38,625	39,784	40,977	42,207	43,473	44,777	287,342	
Program Clerical	16,250	16,738	17,240	17,757	18,290	18,838	19,403	124,515	
Total Program Labor	53,750	55,363	57,023	58,734	60,496	62,311	64,180	411,857	
Advertising	6,400	2,040	3,121	3,608	3,680	3,754	3,829	26,432	$40 per participant ($5000 broucheres)
Data Processing	6,250	1,275	1,301	1,327	1,353	1,380	1,408	14,293	$1250 per year ($5000 initial setup)
Office Supplies & Expenses	600	612	624	637	649	662	676	4,461	$50 per month
Outside Services - Rebate Processing	875	1,275	1,951	2,255	2,300	2,346	2,393	13,395	$25 participant (includes QC testing)
Outside Services - Administration	22,000	12,240	12,485	12,734	12,989	13,249	13,514	99,211	$1000 Monthly Administration Fee ($10,000 1st Year setup)
Evaluation	8,741	8,666	10,817	11,865	12,143	12,428	12,721	77,382	Assume 7% program costs
Total Program Costs Excluding Rebates	*98,616*	*81,471*	*87,322*	*91,160*	*93,611*	*96,131*	*98,720*	*647,032*	
Customer Costs	292,425	426,105	651,941	753,643	768,716	784,091	799,772	4,476,693	$8,355 per unit
Rebates	35,000	51,000	78,030	90,203	92,007	93,847	95,724	535,810	Assume $1,000
Net Customer Cost	257,425	375,105	573,911	663,441	676,710	690,244	704,049	3,940,883	
Total Units	35	50	75	85	85	85	85	500	

Assumptions:

Average cost per SBC $ 8,355

Residential Duct Sealing

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total	Assumption
Program Management	37,500	38,625	39,784	40,977	42,207	43,473	44,777	287,342	
Program Clerical	16,250	16,738	17,240	17,757	18,290	18,838	19,403	124,515	
Total Program Labor	53,750	55,363	57,023	58,734	60,496	62,311	64,180	411,857	
Advertising	12,000	16,320	20,808	25,469	25,978	26,498	27,028	154,101	$20 per participant ($5000 broucheres)
Data Processing	6,200	1,275	1,301	1,327	1,353	1,380	1,408	14,243	$1250 per year ($5000 initial setup)
Office Supplies & Expenses	600	612	624	637	649	662	676	4,461	$50 per month
Outside Services - Rebate Processing	8,750	20,400	26,010	31,836	32,473	33,122	33,785	186,377	$25 participant (includes QC testing)
Outside Services - Administration	22,000	12,240	12,485	12,734	12,989	13,249	13,514	99,211	$1000 Monthly Administration Fee ($10,000 1st Year setup)
Outside Services - Testing Only	7,000	16,320	20,808	25,469	25,978	26,498	27,028	149,101	$200 per evaluation not needing additional work
Evaluation	15,439	26,570	32,675	39,014	39,835	40,674	41,532	235,739	Assume 7% program costs
Total Program Costs Excluding Rebates	125,739	149,099	171,734	195,220	199,753	204,395	209,150	1,255,090	
Customer Costs	220,500	514,080	655,452	802,273	818,319	834,685	851,379	4,696,688	$700 Each For Testing & Sealing
Rebates	110,250	257,040	327,726	401,137	409,159	417,343	425,689	2,348,344	Assume $350
Net Customer Cost	110,250	257,040	327,726	401,137	409,159	417,343	425,689	2,348,344	
Evaluation Only Participants	35	80	100	120	120	120	120	695	
Evaluation & Sealing Participants	315	720	900	1,080	1,080	1,080	1,080	6,255	
Total Participants	350	800	1,000	1,200	1,200	1,200	1,200	6,950	
LG&E HP Sealing Participants	55	126	158	189	189	189	189	1095	
LG&E Gas w/AC Sealing Participants	102	234	293	351	351	351	351	2033	
KU HP Sealing Participants	79	180	225	270	270	270	270	1564	
KU Gas w/AC Sealing Participants	79	180	225	270	270	270	270	1564	

Energy Management System

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total	Assumption
Program Management	37,500	38,625	39,784	40,977	42,207	43,473	44,777	287,342	
Program Clerical	16,250	16,738	17,240	17,757	18,290	18,838	19,403	124,515	
Total Program Labor	53,750	55,363	57,023	58,734	60,496	62,311	64,180	411,857	
Advertising	13,000	12,240	12,485	12,734	12,989	13,249	13,514	90,211	$40 per participant ($5000 broucheres)
Data Processing	6,250	1,275	1,301	1,327	1,353	1,380	1,408	14,293	$1250 per year ($5000 initial setup)
Office Supplies & Expenses	600	612	624	637	649	662	676	4,461	$50 per month
Outside Services - Rebate Processing	5,000	7,650	7,803	7,959	8,118	8,281	8,446	53,257	$25 participant (includes QC testing)
Outside Services - Administration	22,000	12,240	12,485	12,734	12,989	13,249	13,514	99,211	$1000 Monthly Administration Fee ($10,000 1st Year setup)
Evaluation	10,542	11,612	11,883	12,160	12,444	12,736	13,034	84,410	Assume 7% program costs
Total Program Costs Excluding Rebates	111,142	100,991	103,603	106,285	109,040	111,868	114,772	757,701	
Customer Costs	540,000	826,200	842,724	859,578	876,770	894,305	912,192	5,751,770	$2,700 per 10,000 square foot building
Rebates	50,000	76,500	78,030	79,591	81,182	82,806	84,462	532,571	Assume $250
Net Customer Cost	490,000	749,700	764,694	779,988	795,588	811,499	827,729	5,219,198	
Total Participants	200	300	300	300	300	300	300	2,000	

Assumptions:

Building Square Footage	10,000
Cost Per Square Foot	$0.27
	$2,700

Refrigerator Replacement Incentive

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total	Assumption
Program Management	37,500	38,625	39,784	40,977	42,207	43,473	44,777	287,342	
Program Clerical	16,250	16,738	17,240	17,757	18,290	18,838	19,403	124,515	
Total Program Labor	53,750	55,363	57,023	58,734	60,496	62,311	64,180	411,857	
Advertising	15,000	15,300	20,808	21,224	21,649	22,082	22,523	138,586	$20 per participant ($5000 broucheres)
Data Processing	6,250	1,275	1,301	1,327	1,353	1,380	1,408	14,293	$1250 per year ($5000 initial setup)
Office Supplies & Expenses	600	612	624	637	649	662	676	4,461	$50 per month
Outside Services - Rebate Processing	12,500	19,125	26,010	26,530	27,061	27,602	28,154	166,982	$25 participant (includes QC testing)
Outside Services - Administration	22,000	12,240	12,485	12,734	12,989	13,249	13,514	99,211	$1000 Monthly Administration Fee ($10,000 1st Year setup)
Evaluation	8,582	8,613	10,098	10,340	10,588	10,842	11,103	70,166	Assume 7% program costs
Total Program Costs Excluding Rebates	118,682	112,527	128,349	131,526	134,785	138,128	141,558	905,556	
Customer Costs	15,750	24,098	32,773	33,428	34,097	34,779	35,474	210,397	$31.50 per refrigerator
Rebates	12,500	19,125	26,010	26,530	27,061	27,602	28,154	166,982	Assume $25
Net Customer Cost	3,250	4,973	6,763	6,898	7,036	7,177	7,320	43,415	
Total Refrigerators Replaced	500	750	1,000	1,000	1,000	1,000	1,000	6,250	

Assumptions:

Cubic Feet	18
Incremental Cost	$31.50
Energy Star versus non Energy Star	
Customer is replacing regardless	
Customer shows proof of removal on invoice	
Per SBC	

Replace Resistive Heat With High Efficiency Heat Pump

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total	Assumption
Program Management	37,500	38,625	39,784	40,977	42,207	43,473	44,777	287,342	
Program Clerical	16,250	16,738	17,240	17,757	18,290	18,838	19,403	124,515	
Total Program Labor	53,750	55,363	57,023	58,734	60,496	62,311	64,180	411,857	
Advertising	7,400	3,672	4,994	5,094	5,196	5,300	5,406	37,061	*$40 per participant* ($5000 broucheres)
Data Processing	6,250	1,275	1,301	1,327	1,353	1,380	1,408	14,293	$1250 per year ($5000 initial setup)
Office Supplies & Expenses	600	612	624	637	649	662	676	4,461	$50 per month
Outside Services - Rebate Processing	1,500	2,295	3,121	3,184	3,247	3,312	3,378	20,038	$25 participant (includes QC testing)
Outside Services - Administration	22,000	12,240	12,485	12,734	12,989	13,249	13,514	99,211	$1000 Monthly Administration Fee ($10,000 1st Year setup)
Evaluation	8,505	8,495	9,938	10,177	10,421	10,672	10,929	69,137	Assume 7% program costs
Total Program Costs Excluding Rebates	100,005	83,951	89,486	91,886	94,352	96,886	99,491	656,058	
Customer Costs	327,120	500,494	680,671	694,285	708,170	722,334	736,781	4,369,854	*$5,452 Per Unit*
Rebates	30,000	45,900	62,424	63,672	64,946	66,245	67,570	400,757	Assume $500
Net Customer Cost	297,120	454,594	618,247	630,612	643,224	656,089	669,211	3,969,097	
LG&E Participants	20	30	40	40	40	40	40	250	
KU Participants	40	60	80	80	80	80	80	500	
Total Participants	60	90	120	120	120	120	120	750	

Assumptions:

All customers already have existing central A/C

Incremental Cost (1909.40 per ton) $5,452

Geothermal HP (new construction)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total	Assumption
Program Management	37,500	38,625	39,784	40,977	42,207	43,473	44,777	287,342	
Program Clerical	16,250	16,738	17,240	17,757	18,290	18,838	19,403	124,515	
Total Program Labor	53,750	55,363	57,023	58,734	60,496	62,311	64,180	411,857	
Advertising	6,200	2,040	2,081	2,122	2,165	2,208	2,252	19,069	$40 per participant ($5000 broucheres)
Data Processing	6,250	1,275	1,301	1,327	1,353	1,380	1,408	14,293	$1250 per year ($5000 initial setup)
Office Supplies & Expenses	600	612	624	637	649	662	676	4,461	$50 per month
Outside Services - Rebate Processing	750	1,275	1,301	1,327	1,353	1,380	1,408	8,793	$25 participant (includes QC testing)
Outside Services - Administration	22,000	12,240	12,485	12,734	12,989	13,249	13,514	99,211	$1000 Monthly Administration Fee ($10,000 1st Year setup)
Evaluation	11,519	14,021	14,340	14,667	15,002	15,344	15,695	100,588	Assume 7% program costs
Total Program Costs Excluding Rebates	101,069	86,826	89,155	91,548	94,007	96,535	99,132	658,271	
Customer Costs	361,380	614,346	626,633	639,166	651,949	664,988	678,288	4,236,749	$12,046 per 5 ton unit
Rebates	75,000	127,500	130,050	132,651	135,304	138,010	140,770	879,285	*Assume $2500*
Net Customer Cost	286,380	486,846	496,583	506,515	516,645	526,978	537,517	3,357,463	
Total Participants	30	50	50	50	50	50	50	330	

Assumptions:	Increment Cost
5 Ton Geothermaal Heat Pump	$12,046
Per Ton	$2,409

Replace Heat Pump With High Efficiency Model

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total	Assumption
Program Management	37,500	38,625	39,784	40,977	42,207	43,473	44,777	287,342	
Program Clerical	16,250	16,738	17,240	17,757	18,290	18,838	19,403	124,515	
Total Program Labor	53,750	55,363	57,023	58,734	60,496	62,311	64,180	411,857	
Advertising	7,000	4,080	6,242	6,367	6,495	6,624	6,757	43,566	$20 per participant ($5000 broucheres)
Data Processing	6,250	1,275	1,301	1,327	1,353	1,380	1,408	14,293	$1250 per year ($5000 initial setup)
Office Supplies & Expenses	*600*	*612*	624	637	649	662	676	4,461	$50 per month
Outside Services - Rebate Processing	2,500	5,100	7,803	7,959	8,118	8,281	8,446	48,207	$25 participant (includes QC testing)
Outside Services - Administration	22,000	12,240	12,485	12,734	12,989	13,249	13,514	99,211	$1000 Monthly Administration Fee ($10,000 1st Year setup)
Evaluation	8,897	10,505	13,630	13,943	14,263	14,591	14,926	90,755	Assume 7% program costs
Total Program Costs Excluding Rebates	100,997	89,174	99,109	101,701	104,364	107,098	109,907	712,350	
Customer Costs	70,000	142,800	218,484	222,854	227,311	231,857	236,494	1,349,800	$700 per heat pump
Rebates	*35,000*	*71,400*	*109,242*	111,427	113,655	115,928	118,247	674,900	Assume $350
Net Customer Cost	35,000	71,400	109,242	111,427	113,655	115,928	118,247	674,900	
Total Heat Pumps Replaced	100	200	300	300	300	300	300	1,800	

Assumptions:

Old heat pump no longer functional	
Old Seer	10
New Seer	13
Tons	4
Incremental Cost vs. Standard Efficiency	*$700*

Assumptions and Results of Phase II Quantitative Screening Process

Customer Class	Program Description	Per Participant Peak kw Reduction	Per Participant Annual kWh Reduction	% Free Riders	Measure Lifetime	Participant Test	TRC Test	RIM Test	Utility Test	Societal Test
R	Responsive Pricing/Smart Metering/Energy Use Display	1.21	1100	0	15	infinity	**2.42**	0.97	2.22	2.42
R	Room Air Conditioner Replacement	0.36	167	0	10	6.10	0.83	0.62	0.89	0.83
C	Duct Evaluation & Sealing	0.77	3398	0	15	7.62	**2.31**	0.58	3.15	2.31
C	High Efficiency Motors	3.49	2700	0	15	5.32	**1.71**	0.70	2.57	1.71
R	Removal of 2nd Refrigerator	0.19	1310	0	10	infinity	**4.38**	0.56	3.37	4.38
C	Refrigeration Case Covers	2.47	9060	0	4	4.33	**1.11**	0.46	1.94	1.11
R	Window Shading and Films	0.61	444	0	15	1.71	**1.55**	1.16	3.17	1.55
C	Heat Pump Water Heaters - Restaurants & Laundrys	6.96	66430	0	15	4.07	**1.72**	0.48	10.30	1.72
C	Refrigeration Optimization	7.83	28991	0	15	3.34	**1.52**	0.54	6.49	1.52
R	Duct Evaluation & Sealing	0.4	1123	0	15	2.50	**1.14**	0.51	1.32	1.14
C	Energy Management System	2.07	4400	0	15	2.21	**1.37**	0.45	4.47	1.37
R	*Refrigerator Replacement Incentive*	0.04	85	0	18	11.13	0.28	0.20	0.29	0.28
C	High Efficiency Heat Pump (replacing resistive heat)	0.46	21901	0	15	2.36	**1.10**	0.53	5.18	1.10
C	Geothermal Heat Pump (new construction)	10.6	22457	0	15	1.99	**1.00**	0.59	3.16	1.00
R	High Efficiency Heat Pump (replace existing unit)	0.6	970	0	15	2.08	0.63	0.47	0.93	0.63

Kentucky Utilities Company/Louisville Gas and Electric Company
Transmission Construction Projects

Project No.	Description	Expected Completion Date

CONFIDENTIAL INFORMATION REDACTED

Transmission System Map

CONFIDENTIAL INFORMATION REDACTED

Kentucky Utilities Company
and
Louisville Gas and Electric Company

2008 Analysis of Reserve Margin Planning Criterion

Prepared by

Generation Planning

March 2008

2008 ANALYSIS OF
RESERVE MARGIN PLANNING CRITERION

TABLE OF CONTENTS

2008 ANALYSIS OF RESERVE MARGIN PLANNING CRITERION
EXECUTIVE SUMMARY

The Companies 2005 Integrated Resource Plan (Case No. 2005-00162) stated that maintaining a 12 percent to 14 percent reserve margin was the optimal range, and a 14 percent target was recommended for planning purposes. The need to maintain a level of capacity in reserve is well established in the utility industry. Additional generation capacity must be available should there be an unexpected loss of generation, reduced generation capacity due to equipment problems, unanticipated load growth, variances in load due to extreme weather conditions, and/or disruptions in contracted purchased power.

The key variables for studies of this type are: (1) the number and length of planned generating unit outages and maintenance outages, (2) generating unit forced/equivalent forced outage rates, (3) the availability of purchase power capacity for import, (4) the customers perceived cost of unserved/emergency energy and (5) the expected system load. The availability of the Companies' existing units is based on historical data and expected performance. The availability of proposed generating units is such that it falls within the accepted availability for units of a given type, size and class. Since there is no industry standard for the cost of unserved energy, the Companies' relied on a third party report for guidance. Pace Global Energy Services prepared for the Companies the report titled "Cost of Unserved Energy" and is included as Appendix A. Sensitivity values around the base customer perceived value of unserved energy cost were evaluated, as were market purchases, a high annual load forecast, and unit availability sensitivities. The Strategist® computer model was utilized in the evaluation and the least cost present value of revenue requirements (PVRR) was used as the primary decision factor.

Optimizations were utilized to create a least cost ordering of supply-side options for various reserve margin levels given each set of key variables. This methodology was repeated for all possible combinations of the key variables over a range of reserve margins. Reserve margins with PVRR within 0.5 percent of the minimum PVRR were considered as economically equivalent.

Given the base case assumptions used in this study, together with the detailed sensitivity analysis performed on the purchase power market, unit availability, customer perceived unserved energy cost, annual load forecast, a target reserve margin in the range of 13 percent to 15 percent is considered optimal. It is recommended that the Companies maintain a target reserve margin of 14 percent for planning purposes.

INTRODUCTION

The Companies 2005 Integrated Resource Plan (Case No. 2005-00162) stated that maintaining a 12 percent to 14 percent reserve margin[1] was the optimal range, and a 14 percent target was recommended for planning purposes. The need to maintain a level of capacity in reserve is well established in the utility industry. Additional capacity must be available (either physical generators or purchase power) should there be an unexpected loss of generation, reduced generation capacity due to equipment problems, unanticipated load growth, variances in load due to extreme weather conditions, and/or disruptions in contracted purchase power.

This study was conducted to evaluate and document the economics of maintaining various target reserve margin levels given the aforementioned challenges. As a result of this study, a recommendation of a target reserve margin for planning purposes is made.

The study was conducted using the Strategist® computer model. Strategist® is a capital and production costing computer model with the capability to compute total fuel, fixed and variable operating costs and emission related expenses for existing and future units, as well as the capability to develop a least-cost resource plan for future years. Strategist® can also evaluate the reliability of electricity power supply and model power transactions. Finally, Strategist® calculates an annual and study period PVRR for all computer simulations. A minimum present value criterion over the study period (30 years) will be used in this study as the principal economic decision parameter.

This report will: (1) provide a summary of the study methodology and assumptions; (2) detail assumptions that most strongly influence margin analysis; (3) describe scenarios and sensitivities developed; and finally, (4) recommend the least-cost target reserve margin level for the combined KU/LG&E system.

1 Reserve Margin %= (Total Supply Capability – Peak Load) / Peak Load

STUDY METHODOLOGY

The methodology used in the analysis consisted of using Strategist® to create an optimized (or least cost) supply strategy for a specified reserve margin level and a given set of assumptions and key variables. This least-cost resource plan is commonly referred to as the "optimal" expansion plan. Strategist® optimizations were made for both a base set of assumptions and sensitivities (discussed later) at target reserve margin levels ranging from 7 percent to 18 percent in 1 percent increments. The 7 percent and 18 percent levels are selected as reasonable minimum and maximum reserve margins based on results in the 2005 IRP. The optimization process determines the least-cost resources from those available to satisfy the user input target reserve margin level. The objective of the optimizations is to balance costs associated with maintaining a reliable supply system with the customers' perceived cost of unserved energy. The result of the optimization is a least-cost supply-side plan for a given set of assumptions (i.e. reserve margin, load forecast, unit availability, etc.). The reserve margin level, which yields the minimum PVRR for each set of assumptions and key variables, can then be determined. The reserve margin levels suggested by the individual optimizations can then be reviewed to determine the least-cost reserve margin planning level for the Companies.

STUDY ASSUMPTIONS

Appendix B of this report provides detailed information describing inputs utilized in the modeling of KU, LG&E and Owensboro Municipal Utilities (OMU) generating systems. Utilizing the multi-area production costing capability of Strategist®, OMU is modeled separately. This allows for more accurate simulation of contractual arrangements between KU and OMU.

Several inputs strongly influence resource expansion studies of this nature. These inputs include: (1) the number and length of planned generating unit outages and maintenance outages, (2) generating unit forced and equivalent forced outage rates, (3) the availability of purchase power capacity for import, (4) the customers perceived cost of unserved or emergency energy, and (5) load forecast and load factor.

Key Input 1: Unit Planned Outages

A planned outage (PO) is defined as the removal of a generating unit from service to perform work on specific components scheduled well in advance with a predetermined start date and duration. The guidelines for the scheduling of major and minor planned outages on baseload units in the KU/LG&E system at the time this analysis was conducted are shown in Table 1. A major maintenance typically refers to work on both the steam turbine and generator while minor maintenance typically refers to boiler inspection and smaller balance of plant equipment maintenance.

Table 1
KU/LG&E Planned Outage Practices on Baseload Units

	Minor Maintenance		Major Maintenance	
	Duration	Time Between	Duration	Time Between
Mill Creek	5 weeks*	~ 2 years	8 weeks	~ 8 years
Trimble Co. 1	4 weeks	~ 2 years	8 weeks	~ 8 years
All Other Units	3 weeks	~ 1 year	8 weeks	~ 7 years

* - 4 weeks every other year and 1 week in years between

As shown in Table 1, the Companies anticipate that on average, most units will be out three weeks for minor planned maintenance work every year and out eight weeks for major maintenance every seven years. Trimble County and Mill Creek minor planned maintenance events are expected to last approximately four and five weeks, respectively every two years, while major maintenance events are scheduled every eight years with durations of eight weeks.

In this analysis, maintenance was not re-optimized for any sensitivity run. The planned maintenance schedule that exists in each series is identical for the existing units regardless of what target reserve margin is being evaluated or what sensitivity evaluation is being performed. Optimization of unit maintenance is a highly computer intensive task which would not significantly affect studies of this type. This analysis assumes that the Companies' current major and minor maintenance needs (weeks) will not change over time.

Key Input 2: Unit Forced Outages/Equivalent Forced Outages

Forced outages are events that require the full unit be removed from service unexpectedly and immediately. Forced outage rates (FORs) are defined as the total number of forced outage hours divided by the sum of (total number of forced outage hours + total number of service hours). Equivalent forced outage rates (EFORs) are similar to FORs but include hours in which the unit is derated (capable of operating but unable to operate at full load). FORs and EFORs provide information on how frequently particular events cause unit outages or derates. The system rate is an internally developed target with the intention of top quartile performance.

A maintenance outage (MO) is defined as the removal of a generating unit from service to perform work on specific components which could have been delayed beyond the end of the next weekend, but requires that the unit be removed from service before the next major or minor planned outage. Maintenance outages, like forced outages and forced derates, may occur at any time during the year, may have flexible start dates, and may or may not have a predetermined duration. To capture the random nature of events that trigger a MO and to maximize the effect of the MO event on system capacity (i.e. reduce the generating system capability during the weekday when load is greatest instead of on the weekend), maintenance outage hours have been included in the modeled forced outage rates of the units.

Table 2 shows modeled base forced outage rates and modeled base equivalent forced outage rates for baseload units.

CONFIDENTIAL INFORMATION

Table 2
Modeled FOR and EFOR

Unit	FOR %	EFOR %
Brown 1	[redacted]	
Brown 2		
Brown 3		
Cane Run 4		
Cane Run 5		
Cane Run 6		
Ghent 1		
Ghent 2		
Ghent 3		
Ghent 4		
Green River 3		
Green River 4		
Mill Creek 1		
Mill Creek 2		
Mill Creek 3		
Mill Creek 4		
Trimble 1 (75%)		
Tyrone 3		

As part of this evaluation, two unit availability sensitivities were performed. One decreased the availability of the coal units by increasing each coal unit's EFOR by 5 percent annually, and the second decreased the availability of the peaking units by increasing each CT's EFOR by 10 percent annually. Modeled EFOR for CTs can be found in Appendix B's Table 2.

Key Input 3: Availability of Firm/Non-Firm Purchase Capability

Currently, the Companies have contracted for the purchase of firm capacity from Ohio Valley Electric Corporation (OVEC) and OMU (expected termination May 2010). The dispatch of purchase power units in Strategist® approximates the actual dispatch of the purchase capacity. These were the only existing purchase power alternatives available in the base series of runs.

The OVEC purchase is modeled in Strategist® as a purchase power unit. KU's future purchases from OMU are modeled using Strategist®'s multi-area modeling feature, which parallels the actual dispatching of all units. However, in order to model a least-cost dispatch of the combined KU/LG&E and OMU generating systems, a detailed model of the OMU generation system is required. The details of the OMU generation system model and the amount of on-peak capacity available from OMU by year during the study period can be found in Appendix B.

Like unit availability, a sensitivity was also performed on purchase power. While the base assumption limited purchase power only to the above two purchase power contracts, this sensitivity allowed purchase power from the wholesale power market to be evaluated. Two weekday on-peak (5x16) spot purchase volumes were evaluated, 204 MW and 304 MW at maximum. Spot purchases are short-term market purchases that can have a large energy cost and very little or no demand cost associated with them. This cost profile is utilized because spot purchases generally have a short turnaround between notification and physical delivery. This evaluation assumes that spot purchases are considered to be non-firm capacity. This study assumes that spot purchases are 5 times the monthly firm forward price for the 5x16 period. The spot/hourly market may not have power available on occasion; therefore, the spot market was assumed to have 95 percent availability. Table 3 and Appendix B convey information associated with the purchases modeled in Strategist®.

Table 3
Modeled Purchase Information

Supplier	MW	EFOR	Term
OMU	*	Smith 1 – 15.27% Smith 2 – 16.64%	Through May 2010
OVEC	174 MW	NA	Throughout Study Period
Spot**	204 & 304	5.00%	Weekday On Peak Periods Only Throughout Study Period

* Changes annually to reflect OMU's load growth
** Two Spot MW purchases evaluated

Aside from the contractual and spot purchases discussed above, one additional purchase type is automatically modeled in Strategist®: emergency (unserved) energy.

Key Input 4: Customer Perceived Cost of Emergency/Unserved Energy

Emergency energy is automatically determined by the Strategist® model and is a direct measure of the system's inability to meet its load demands; therefore, emergency energy purchases are a key factor in determining the optimal target reserve margin level for use in resource planning studies. The cost of emergency/unserved energy is defined as the cost (whether real or perceived) to a customer during an outage on the transmission or distribution system, or for capacity shortages, which result in a power outage. The perceived and realized cost of this type of energy is highly dependent on customer type (i.e., residential, commercial, industrial), the duration of the outage, and the frequency at which outages occur. A residential customer who might only be inconvenienced by an outage would likely place a lower value on this type of energy than an industrial customer who may incur a substantial economic loss due to an outage. Likewise, within customer classes, the value of unserved energy can vary greatly due to individual customer needs. In addition to variations customers place on unserved energy, the following attributes of the outage or curtailment may affect the overall perceived value by the customer: timing (hour, season), duration, magnitude (partial or total), advance notice given, frequency, and coverage (area affected).

A report was prepared for the Companies by Pace Global Energy Services. The report is titled "Cost of Unserved Energy" and is included in this report as Appendix A. The forecasted percentage of the Companies' energy sales by class is applied to the survey results and a weighted average unserved energy cost estimate is calculated.

Table 4
Customer Perceived Outage Cost Estimates

Class	Average ($/kWh Unserved)[1]	LG&E/KU Customer Sales (%)[1]	Weighted Cost ($/kWh Unserved)
Residential	2.04	34	0.69
Commercial	31.90	30	9.57
Industrial	13.04	36	4.69
		Weighted Sum	14.96
		Est. Base Cost of Unserved Energy	*~15.0*

1 As identified in the Pace Global report "Cost of Unserved Energy"

Therefore, based on the results as shown in Table 4, a base cost of $15 per kWh for unserved energy is used in this study. An estimate of customer load (kWh) not served during power outages or capacity shortages is determined by the Strategist® model and labeled as "Unserved Energy". The unserved energy (kWh) is then multiplied by the unserved energy cost ($/kWh) to determine the cost associated with the power outage or capacity shortfall from the customer's perspective. To consider the sensitivity of results to the base assumption of $15/kWh value for unserved energy, values of $13/kWh and $19/kWh were identified by Pace Global Energy Services as the likely range of unserved energy costs and were also evaluated in this study.

Key Input 5: Higher than Expected Load Forecast

A system load factor that is higher than forecast could also change the optimal mix of supply-side technologies. This change could force units such as peakers, normally considered alternatives with low capital cost but high operating expense, to operate at capacity factors that would have made baseload units (such as combined cycles or coal-fired units) the better choice. The change in supply-side technologies could affect the optimal system reserve margin target due to the inherent difference in the capacity and availability of combustion turbines, combined cycles and coal-fired units. Therefore, in recognition of the fact that precise load forecasting is unlikely, an annual load forecast sensitivity was performed. This sensitivity allows for a more thorough strategy and possibly less exposure to the higher prices that can be experienced during the summer period. Anytime load sensitivities are used in this evaluation, the resulting reserve margins shown in the tables and the figures are calculated based on the installed capacity and the base load forecast and not the new forecast. This is done to more fully represent the situation where the Companies are anticipating the load reflected by the base load forecast but the observed peak loads are higher than expected.

The high load forecast developed by the Sales Analysis & Forecasting department has higher peaks and energies than the base forecast in each and every month and is developed using the same methodology that went into developing the base load forecast. Appendix B contains additional detail on the Base and High Load Forecasts.

STRATEGIST® ANALYSIS

Combinations of the above variables (unit availability, load forecast, load factor, unserved energy cost and purchase power) were used to develop a series of cases that enabled the determination of a least cost reserve margin under various conditions. (Note: A series is defined as an optimization for a fixed set of variables over the range of 7 percent to 18 percent minimum reserve margin.) Table 5, summarizes the key variables for each of the 36 series of cases evaluated. For each series, twelve optimizations were performed with a minimum target reserve margin ranging from 7 percent to 18 percent (in 1 percent increments). Each optimization produced the least-cost supply-side strategy for that given set of assumptions (including minimum target reserve margin) for the key variables. Series 1 through 12 are series where no spot market purchases are available. These series are weighted to represent 50 percent of the analysis. Series 13a through 24a have a 204 MW spot purchase available, and series 13b through 24b have a 304 MW spot purchase available. The two spot purchase levels are weighted to each represent 25 percent of the analysis.

Table 5
Identification of Key Variables Evaluated

Series #	Coal Unit Availability	Combustion Turbine Availability	Load Forecast	Unserved Energy Cost ($/kWh)	5x16 Purchase Modeled	
1	Base	Base	Base	13	No	
2	Base	Base	Base	15	No	
3	Base	Base	Base	19	No	
4	Low	Base	Base	13	No	
5	Low	Base	Base	15	No	
6	Low	Base	Base	19	No	50%
7	Base	Base	High	13	No	
8	Base	Base	High	15	No	
9	Base	Base	High	19	No	
10	Base	Low	Base	13	No	
11	Base	Low	Base	15	No	
12	Base	Low	Base	19	No	
13a	Base	Base	Base	13	Yes (204 MW)	
14a	Base	Base	Base	15	Yes (204 MW)	
15a	Base	Base	Base	19	Yes (204 MW)	
16a	Low	Base	Base	13	Yes (204 MW)	
17a	Low	Base	Base	15	Yes (204 MW)	
18a	Low	Base	Base	19	Yes (204 MW)	25%
19a	Base	Base	High	13	Yes (204 MW)	
20a	Base	Base	High	15	Yes (204 MW)	
21a	Base	Base	High	19	Yes (204 MW)	
22a	Base	Low	Base	13	Yes (204 MW)	
23a	Base	Low	Base	15	Yes (204 MW)	
24a	Base	Low	Base	19	Yes (204 MW)	
13b	Base	Base	Base	13	Yes (304 MW)	
14b	Base	Base	Base	15	Yes (304 MW)	
15b	Base	Base	Base	19	Yes (304 MW)	
16b	Low	Base	Base	13	Yes (304 MW)	
17b	Low	Base	Base	15	Yes (304 MW)	
18b	Low	Base	Base	19	Yes (304 MW)	25%
19b	Base	Base	High	13	Yes (304 MW)	
20b	Base	Base	High	15	Yes (304 MW)	
21b	Base	Base	High	19	Yes (304 MW)	
22b	Base	Low	Base	13	Yes (304 MW)	
23b	Base	Low	Base	15	Yes (304 MW)	
24b	Base	Low	Base	19	Yes (304 MW)	

Optimizations were conducted to determine the reserve margin level that yields the minimum PVRR under all scenarios. At each target reserve margin level from 7 percent to 18 percent, all other key variables were held constant. The optimization quantifies the cost and reliability effects of all combinations of potential generating technologies and results in expansion plans, all of which meet both the pre-specified constraints and the specific target reserve margin criterion. The capital and production costs (including the cost of unserved energy) of each plan is determined by the Strategist® model, and the expansion plan with the lowest PVRR is selected as the least-cost plan for that case. The first case is developed with a reserve margin of 7 percent and optimized in Strategist®. The next case is developed by increasing the target reserve margin by 1 percent and performing another optimization. This methodology is repeated until the target reserve margin being evaluated would exceed 18 percent, at which time a key variable is changed and the process begins anew at a 7 percent reserve margin. Performing optimization simulations at each reserve margin level assures that the optimal (least costly) ordering of units is maintained. The results of the optimizations determine the reserve margin level at which the minimum PVRR occurs for each series.

As an example, consider the results of the optimization process for Series 1, 2 and 3 shown in Figure 1. The larger values of PVRR at the high or low end of the reserve margin curve shown in Figure 1 reflect the increase in costs due to capital expenditures or unserved energy respectively. The increase in PVRR on the upper ends of the curves (i.e. occurring at the higher reserve margin levels) is a function of increased capital/operating expenditures for generation construction associated with maintaining the higher reserve margin. Conversely, the increase in PVRR values at the lower target reserve margin levels is a function of both the amount of unserved energy and the value placed on unserved energy. The minimum PVRR (indicated by the arrows in Figure 1), which for Series 1 through 3 occurs at a 10 percent reserve margin, strikes a balance between capital/operating expenditures associated with maintaining a target reserve margin and the value placed on unserved energy. Notice also in Figure 1 that the PVRR values are relatively the same near and around the minimum PVRR. For example, using the $15/kWh (Series 2) curve in Figure 1, there is less than 0.5 percent difference between the PVRR associated with maintaining a 10 percent reserve margin and maintaining a 7 percent to 13 percent reserve margin level. The overall flatness of the curves around the minimum PVRR value suggests reserve margin levels with a PVRR within a small variance of the minimum PVRR could be considered economically identical or nearly identical to the lowest PVRR. This indicates a greater level of system reliability, as measured by reserve margin, can be attained with minimal increase in cost and for this reason, it is difficult to recommend a single target reserve margin point based solely on the minimum PVRR for each series. Figure 2 graphically displays all reserve margins for Series 1-3 that are within 0.5 percent of each respective Series' minimum PVRR. It suggests that, based solely on Series 1-3, that a reserve margin range of 8 percent to 12 percent is optimal. The reserve margin range is determined by observing the reserve margin levels that are common to each case. Maintaining a reserve margin within this range guarantees that given the base assumptions for load, unit availability and purchase power, the least-cost case possible is maintained under all assumptions for unserved energy.

If we now add Series 4-12 to Figure 2, a better overall picture of how the sensitivities affect both the reserve margin ranges and cost can be observed (see Figure 3). Figure 3 stops at Series 12 because it is a convenient break point for graphing purposes in that it is the last case without the purchase option. (Note that for convenience the legend associated with Figure 3 lists each Series in the order that it appears in the chart, i.e.: the least cost case is at the bottom of the legend box and the most costly case is at the top). As one would expect, the least costly case without market purchases is Series 1 where unserved energy cost is $13/kWh. Increasing the Companies' load forecast when unserved energy is assumed to cost $19/kWh (Series 9) is the most expensive sensitivity evaluated. All others sensitivities without the market purchase alternative fall between Series 1 and Series 9. Figures 4a and 4b complete the process for the remaining Series with market purchases available.

Again, the base Series with unserved energy at $13/kWh is the least costly series while increasing the Companies load forecast when unserved energy is assumed to be $19/kWh is the most expensive.

To re-emphasize, Figures 3 and 4 are graphical representations of economically equivalent reserve margins for each evaluated where a Series is defined by a fixed set of key variable assumptions evaluated over a span of minimum reserve margin values. The reserve margin ranges shown in Figures 3 and 4 are considered economically equivalent because they exceed the series minimum by less than 0.5 percent. Considering costs within a range of 0.5 percent allows for a more narrow analysis of possible reserve margin planning levels while insuring that proper consideration is given to the other possible values of the key variables. Table 6, below, shows the range of reserve margin levels for all Series 1-24b and is a tabular form of the data contained in Figures 3 and 4. Essentially, Table 6 summarizes the ranges of reserve margins for each set of case assumptions (or Series) where the cost of maintaining the reserve margin range is equivalent.

Table 6
Economically Equivalent Reserve Margin Levels

Series #	Coal Unit Availability	Combustion Turbine Availability	Load Forecast	Unserved Energy Cost ($/kWh)	5x16 Purchase Modeled	Economically Equivalent Reserve Margin
1	Base	Base	Base	13	No	7% - 12%
2	Base	Base	Base	15	No	7% - 13%
3	Base	Base	Base	19	No	8% - 13%
4	Low	Base	Base	13	No	13% - 18%
5	Low	Base	Base	15	No	13% - 18%
6	Low	Base	Base	19	No	13% - 18%
7	Base	Base	High	13	No	13% - 15%
8	Base	Base	High	15	No	13% - 15%
9	Base	Base	High	19	No	13% - 15%
10	Base	Low	Base	13	No	12% - 16%
11	Base	Low	Base	15	No	13% - 18%
12	Base	Low	Base	19	No	14% - 18%
13a	Base	Base	Base	13	Yes (204 MW)	7% - 12%
14a	Base	Base	Base	15	Yes (204 MW)	8% - 12%
15a	Base	Base	Base	19	Yes (204 MW)	8% - 12%
16a	Low	Base	Base	13	Yes (204 MW)	13% - 16%
17a	Low	Base	Base	15	Yes (204 MW)	13% - 18%
18a	Low	Base	Base	19	Yes (204 MW)	13% - 18%
19a	Base	Base	High	13	Yes (204 MW)	13% - 14%
20a	Base	Base	High	15	Yes (204 MW)	13% - 14%
21a	Base	Base	High	19	Yes (204 MW)	13% - 14%
22a	Base	Low	Base	13	Yes (204 MW)	14% - 16%
23a	Base	Low	Base	15	Yes (204 MW)	14% - 16%
24a	Base	Low	Base	19	Yes (204 MW)	15% - 18%
13b	Base	Base	Base	13	Yes (304 MW)	7% - 12%
14b	Base	Base	Base	15	Yes (304 MW)	7% - 12%
15b	Base	Base	Base	19	Yes (304 MW)	7% - 12%
16b	Low	Base	Base	13	Yes (304 MW)	13% - 16%
17b	Low	Base	Base	15	Yes (304 MW)	13% - 18%
18b	Low	Base	Base	19	Yes (304 MW)	13% - 18%
19b	Base	Base	High	13	Yes (304 MW)	13% - 14%
20b	Base	Base	High	15	Yes (304 MW)	13% - 14%
21b	Base	Base	High	19	Yes (304 MW)	13% - 14%
22b	Base	Low	Base	13	Yes (304 MW)	14% - 16%
23b	Base	Low	Base	15	Yes (304 MW)	14% - 16%
24b	Base	Low	Base	19	Yes (304 MW)	14% - 17%

Based on the information in Table 6 and Figures 3, 4a and 4b, the most appropriate reserve margin range that would best balance the costs of maintaining a high reserve margin with the cost of unserved energy can be determined. Again, Figures 3, 4a and 4b can greatly assist in this process. Just as was done for Series 1-3 (in Figure 2), the reserve margin range can be determined by first counting the number of times that each Series identifies a specific reserve margin as being included as that series' economically equivalent PVRR. This process is repeated for all Series and the number of times that a particular reserve margin level is included as that series' economically equivalent PVRR is accumulated. For example if Figure 3 is examined, it can be seen that a 13 percent reserve margin was identified in ten Series, that 14 percent was identified in nine Series, 15 percent was identified in nine separate Series, and so on. Tables 7 and 8a-c (below) summarize the frequency of occurrence of each reserve margin level in the suggested reserve margin range of each Series in Figures 3, 4a and 4b respectively. If a specific reserve margin was within the economically equivalent reserve margin range, a "1" would be placed in the table at the appropriate location. Tables 8a and 8b represent the two purchase volumes evaluated, and Table 8c is the combination of Tables 8a and8b.

Table 7
Number of Times Reserve Margin is
Identified in Economically Equivalent Range
(No Market Purchase Alternative)

	Minimum Reserve Margin											
Series #	7%	8%	9%	10%	11%	12%	13%	14%	15%	16%	17%	18%
1	1	1	1	1	1	1						
2	1	1	1	1	1	1	1					
3		1	1	1	1	1	1					
4							1	1	1	1	1	1
5							1	1	1	1	1	1
6							1	1	1	1	1	1
7							1	1	1			
8							1	1	1			
9							1	1	1			
10						1	1	1	1	1		
11							1	1	1	1	1	1
12								1	1	1	1	1
Sub-Total	**2**	**3**	**3**	**3**	**3**	**4**	**10**	**9**	**9**	**6**	**5**	**5**

Table 8a
Number of Times Reserve Margin is Identified in Economically Equivalent Range

(With 204 MW Market Purchase Alternative)

	Minimum Reserve Margin											
Series #	7%	8%	9%	10%	11%	12%	13%	14%	15%	16%	17%	18%
13a	1	1	1	1	1	1						
14a		1	1	1	1	1						
15a		1	1	1	1	1						
16a							1	1	1	1		
17a							1	1	1	1	1	1
18a							1	1	1	1	1	1
19a							1	1				
20a							1	1				
21a							1	1				
22a								1	1	1		
23a								1	1	1		
24a									1	1	1	1
Sub-Total	**1**	**3**	**3**	**3**	**3**	**3**	**6**	**8**	**6**	**6**	**3**	**3**

Table 8b
Number of Times Reserve Margin is Identified in Economically Equivalent Range

(With 304 MW Market Purchase Alternative)

	Minimum Reserve Margin											
Series #	7%	8%	9%	10%	11%	12%	13%	14%	15%	16%	17%	18%
13b	1	1	1	1	1	1						
14b	1	1	1	1	1	1						
15b	1	1	1	1	1	1						
16b							1	1	1	1		
17b							1	1	1	1		
18b							1	1	1	1	1	1
19b							1	1				
20b							1	1				
21b							1	1				
22b								1	1	1		
23b								1	1	1		
24b								1	1	1	1	
Sub-Total	**3**	**3**	**3**	**3**	**3**	**3**	**6**	**9**	**6**	**6**	**2**	**1**

Table 8c
Number of Times Reserve Margin is Identified in Economically Equivalent Range
(Average for Purchase Alternative Cases)

	Minimum Reserve Margin											
Series #	7%	8%	9%	10%	11%	12%	13%	14%	15%	16%	17%	18%
13	1	1	1	1	1	1						
14	1	1	1	1	1	1						
15	1	1	1	1	1	1						
16							1	1	1	1		
17							1	1	1	1	1	1
18							1	1	1	1	1	1
19							1	1				
20							1	1				
21							1	1				
22								1	1	1		
23								1	1	1		
24								1	1	1	1	1
Sub-Total	**2**	**3**	**3**	**3**	**3**	**3**	**6**	**9**	**6**	**6**	**3**	**2**

Figures 5, 6a and 6b incorporate Tables 7, 8a and 8b respectively with the addition of the dashed line. Table 9 (graphically presented in Figure 7) summarizes the data in Tables 7, 8a and 8b revealing that a reserve margin range of 13 percent to 15 percent would be ideal, and 14 percent is economical in eighteen (or 3/4) of the cases evaluated.

Table 9
Total Number of Times Reserve Margin is Identified in Economically Equivalent Range
(All Series)

	Minimum Reserve Margin											
	7%	8%	9%	10%	11%	12%	13%	14%	15%	16%	17%	18%
No Market	2	3	3	3	3	4	10	9	9	6	5	5
With Market (Avg)	2	3	3	3	3	3	6	9	6	6	3	2
Total (All)	4	6	6	6	6	7	16	18	15	12	8	7

LOSS OF LOAD PROBABILITY

After determining the optimal reserve margin range bases solely on NPVRR, loss of load hours (LOLH) were evaluated for series 1-3 (base EFOR, load, and without spot purchase) to assure that the typical standard metric of one day in ten years criteria was satisfied. As can be seen in table 10, varying the emergency energy cost does not materially impact LOLH for the three series. The one day in ten years criteria is satisfied at a reserve margin of 14 percent or greater. Loss of load must be less than 2.4 on average (24 hours/10 years) for the metric to be satisfied.

Table 10
Loss of Load Hours (2010-2037)

Series	Reserve Margin %	Average LOLH/yr
1	7	15.93
1	8	13.65
1	9	10.61
1	10	7.94
1	11	5.80
1	12	4.42
1	13	2.98
1	14	2.07
1	15	1.57
1	16	1.16
1	17	0.83
1	18	0.64
2	7	15.93
2	8	12.94
2	9	10.07
2	10	7.70
2	11	5.80
2	12	4.42
2	13	2.98
2	14	2.06
2	15	1.57
2	16	1.16
2	17	0.83
2	18	0.63
3	7	15.93
3	8	13.65
3	9	10.61
3	10	7.94
3	11	5.80
3	12	4.42
3	13	2.98
3	14	2.07
3	15	1.57
3	16	1.16
3	17	0.83
3	18	0.64

SUMMARY AND RECOMMENDATION

Key variables representing a base case series of simulations and sensitivities were analyzed in optimization studies. The key variables were evaluated over a range of target reserve margin levels. For each series, the minimum reserve margin level was determined. This minimum value strikes the best balance between the perceived cost to the customer of unserved energy and capital/operational expenditures for generation construction or purchased power options. The balance between unserved energy cost and capital expenditures/purchase power is apparent through graphical analysis as the relatively flat region near and around the minimum PVRR value for each case. This suggests that reserve margins in this region of values can be maintained at or near the same cost. Therefore, the value for reserve margin at the high end of the range of reserve margins can be recommended as the planning reserve margin because it represents the maximum system reliability at the lowest cost. The analysis summarized in Tables 6-9 suggest a 13 percent to 15 percent reserve margin range would provide the most flexibility to minimize the cost impacts associated with decreasing unit availabilities, variances in seasonal or annual load projections and the wholesale power market. Therefore, given the assumptions and sensitivities analyzed in this study this analysis suggests an optimal target reserve margin in the range of 13 percent to 15 percent and that 14 percent be the Companies target reserve margin for planning purposes.

2008 Reserve Margin

APPENDIX A

PACE | Global Energy Services

4401 Fair Lakes Court
Fairfax, Virginia 22033-3848 USA
Phone: 703-818-9100
Fax: 703-818-9108

FINAL REPORT

Cost of Unserved Energy

Prepared for:

E.ON US

October 12, 2007

TABLE OF CONTENTS

EXHIBITS

INTRODUCTION AND EXECUTIVE SUMMARY

Pace Global Energy Services (Pace Global) was engaged by Cummins and Barnard to develop an estimate of the value of unserved energy for electric utility customers to be incorporated in a reserve margin analysis for the E.ON electric utility companies in Kentucky.[1] Proper valuation of outages is an important element of resource planning because it helps to clarify the value of tradeoffs between building too much generation and not having enough generation available to serve the utilities' entire loads under all or increasingly broad conditions. This balance, or at least the ability to address it and plan for it, has become increasingly important during the past decade as power quality and system reliability issues have become more prominent.

Estimates of the cost of unserved energy, or value of lost load, can vary widely – especially depending on the duration of the assumed outage and on the customer class. As the duration of a power outage gets longer, the costs borne by customers increase across all customer classes but the marginal impact for longer outages differs by customer class. Pace Global's findings in this area show that lengthier outages become disproportionately more costly for residential customers and less costly for industrial customers. These results are summarized below in Exhibit 1. Furthermore, the estimated costs exhibit a wide range of values across customer classes, with costs to residential customers being significantly lower than costs to either commercial or industrial customers. These results are summarized in Exhibit 2.

The focus of the reserve margin analysis is on reserves needed to serve peak load, so the primary results presented herein are estimates of the cost of lost load during on-peak periods. These estimates range from about $13-$19 per peak kWh, on an economy-wide basis, depending on the selection of studies to include, and are summarized below in Exhibit 3. Based on a careful assessment of the studies available for review, Pace Global recommends that a value of $14.96/kWh be adopted as a proxy for the value of unserved energy.

BACKGROUND

Utility customers – commercial, industrial, and residential – are becoming more reliant on improved power quality at their sites. As manufacturers have become increasingly dependent on computer controls, commercial sector businesses more dependent on data processing, and health facilities more dependent on environmental controls, voltage fluctuations and other power quality problems impose production and commercial costs that would have been less likely two decades ago. Similarly, the economy has in general become more dependent on electric power and the economic cost of regional blackouts has steadily increased over the past few decades.

Pace Global has conducted a survey of available planning and academic literature on the value of lost load ("VOLL") and customer valuation of the cost of power outages, and has synthesized

[1] This Report and the information and statements herein are based in whole or in part on information obtained from various sources as of September 9, 2007.

cost estimates that are suitable for the primary task of assessing E.ON's reserve margin. This report provides a summary of Pace Global's literature survey and assessment of the available studies. In the course of developing an estimate of costs of unserved energy, three issues were repeatedly encountered:

- the range or scope of the studies,
- the impact on costs of the duration of outages,
- and the differences in costs across customer types.

In addition, there is evidence from one study that the costs of outages may vary widely by the type of outage, i.e. whether it is caused by generation problems or transmission and distribution problems.

PRIMARY ANALYSIS ISSUES

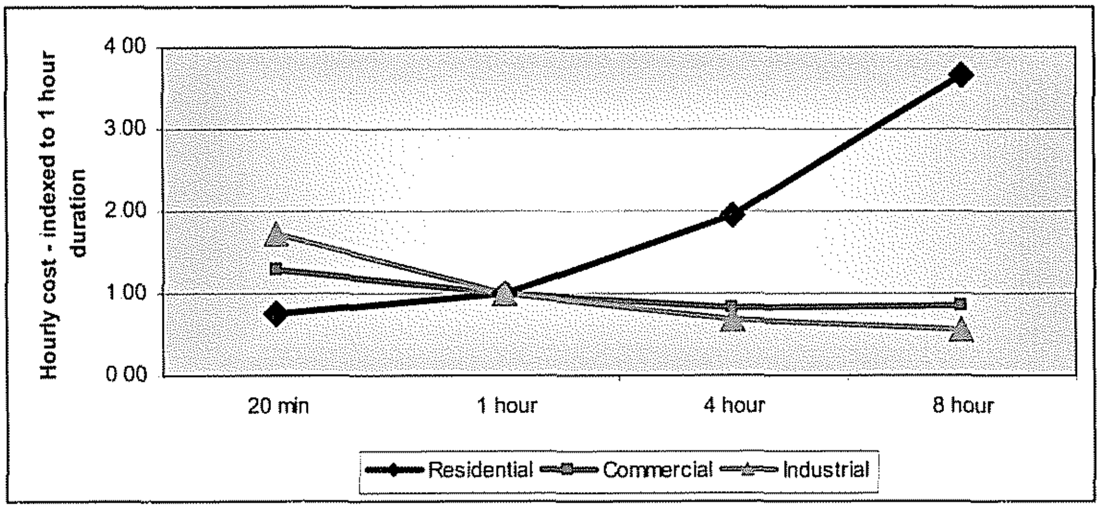
SCOPE OF PUBLIC ANALYSES

Most customer cost surveys that are publicly available were conducted during the 1980s or early 1990s, using data from electric utilities in the East and West coast regions of the U.S. and from Canada and Europe. Studies that were used for this project are shown in Attachment 2, and comprise 12 different data sets. Cost estimates for all studies have been converted from their original currencies and base period values to 2007$. Two of the more recent studies provide regional data that is more applicable to the Midwest study area: an econometric review prepared by Lawton et al for the Lawrence Berkeley National Laboratory ("LBNL") that includes data from the late 1990s from Southern Company, Duke, and Cinergy (as well as several other Eastern and Western utilities), and a 2002 study by Chowdhury for the Mid-American utility service area. Pace Global also reviewed other studies by Beenstock and Goldin (on priority pricing in Israel); Caves et al (on the cost of power interruptions in the industrial sector); Kariuki and Allan (on cost of outages in the residential sector); Carson et al (on contingent valuation); Matsukawa and Fujii (on customer preferences for backup power equipment); Serra and Fierro (on outage costs in Chile); and Dalton et al (on value based transmission planning). These latter studies were excluded from the sample of studies due to their lack of usable cost estimate data. Pace Global also discarded, as too outdated, data from Cramton and Lien that related to a 1977 Finnish study.

DURATION OF OUTAGE

The costs of outages are correlated with the duration of the outage – the longer the outage, the higher the cost. With no exceptions, all studies show a steady uninterrupted increase in costs as outage durations increase from 20 minutes to 8 hours. By itself, this is unremarkable – it simply reflects survey participants' responses that longer outages are more costly. However, when the average cost estimates by customer class and outage duration are normalized to a single one-hour period, it is evident that the marginal cost of outages over time is most severe for residential customers and least severe for industrial customers. As an outage endures, residential customers are most likely to continue to incur – or believe they are incurring - increasing costs, while business customers' incremental hourly losses decline over time. These results are illustrated below in Exhibit 1.

Exhibit 1: Marginal Changes in Costs by Duration of Outage



Source: Pace Global

CUSTOMER CLASS COST VARIATIONS

In addition to large cost variations between customer classes, the several studies reviewed by Pace Global demonstrated wide variations within customer classes. Exhibit 2 shows minimum, median, and maximum cost estimates for each customer class. The values labeled as "normalized to peak hours" were presented in each of the studies as either the customer class average cost per kWh when the outage occurs in the peak period, or as the average of costs for a one-hour outage normalized by dividing each survey respondent's estimate by the respondent's annual peak load. The values labeled as "normalized to annual kWh" were presented in each of the studies as the average of costs for that customer class for a one-hour outage normalized by dividing each survey respondent's estimate by the respondent's annual kWh consumption. That is, these values are not a measure of the cost of energy not served. Rather, they are used solely to normalize outage costs across customer classes.

Despite the wide range of estimates within classes, there was no evident pattern of individual studies' cost estimates being systematically lower or higher across all customer classes. In other words, system-wide cost estimates derived from the different studies would be expected to display a narrower range of results. Efforts to test this are hindered by the lack of consistency across the studies with regard to the customer classes covered by the studies. Of 12 data sets accessible for this project, none had costs normalized by annual consumption for all three customer classes and only five had costs normalized by peak load for all three customer classes.

Comparison of the system-wide cost estimates for the five studies that had peak-normalized costs for all customer classes shows that maximum value is less than three times as large as the minimum value, significantly less than the max/min ratios displayed for customer class in Exhibit 2. (*see worksheet for Exhibit 2 in Attachment 1*)

Exhibit 2: Costs per kWh – Annual Costs vs Peak Period Costs ($2007)

	Normalized to Peak Hour ($/kWh)				Normalized to Annual kWh ($/kWh)			
	Minimum	Median	Maximum	Max/Min	Minimum	Median	Maximum	Max/Min
Residential	$0.61	$1.96	$2.86	5	n/a	n/a	n/a	n/a
Commercial	$8.11	$24.48	$63.39	8	$0.0039	$0.0098	$0.0178	5
Industrial	$3.15	$10.36	$61.72	20	$0.0008	$0.0042	$0.0292	36

Source: Pace Global

DIFFERENTIATION BY TYPE OF OUTAGE

Generation outages and transmission & distribution outages can have different impacts on customers. Outages caused by insufficient generation availability are expected to impose a lower cost because customers can be given advance warning of maximum generation conditions and take steps to shut down and/or protect critical facilities. Outages caused by transmission or distribution failures, however, are typically more sudden and can occur with little advance warning. Only one study that Pace Global reviewed (Sullivan et al) delineates between these types of outages, showing that peak-period outages caused by failure of the T&D system are expected to be about twice as costly as generation outages.

ESTIMATED COST OF UNSERVED ENERGY

As mentioned above, Pace Global has reviewed and incorporated survey and analysis results from 12 different studies. Cost estimates for all studies have been converted to 2007$. The cost variations across studies by customer class are shown to be large, but the variation, or range, of system-wide cost estimates is considerably narrower. Estimates of the cost of unserved energy are provided below for average system-wide costs, calculated from the entire data set as a simple average of the peak period $/kWh costs, and for some modified selections of data, as described. E.ON's forecasted customer class weighting (residential-34%, commercial-30%, industrial-36% were used to develop the system-wide averages. These results are presented in Exhibit 3.

Exhibit 3: Cost of Unserved Energy – Alternative Groupings (2007$/kWh)

	Residential	Commercial	Industrial	System-wide
Equal weighting for all data sets				
All	$1.90	$28.57	$19.74	$16.33
North American	$2.21	$29.31	$10.83	$13.44
Grouped by study sets				
All	$1.74	$30.24	$24.75	$18.57
North American	$2.04	$31.90	$13.04	$14.96
E.ON customer class weights	34%	30%	36%	

Source: Pace Global

The first block of estimates give equal weighting to all separate data sets. The studies by Sullivan et al and Subramiam et al each included more than one set of results. Sullivan presented results for generation outages and for transmission and distribution outages, and Subramiam presented three sets of results for customers with varying levels of back-up generation. In the first block of estimates, each of those separate studies are given equal weight with all other studies. In the second block of estimates, the averages of the Sullivan alternatives and of the Subramiam alternatives are each included as one cost estimate. Adopting an estimate that is based on grouped sets of data rather than all individual sets of data could avoid an implicit bias that would be introduced by employing multiple data points from individual surveys.

The second row of each block of estimates includes only studies done for utility areas in the U.S. and Canada, and excludes British data from Cramton and Lien and from Kiriuki. Excluding the British studies from the analysis removes any implicit biases that may be introduced by incorrectly assuming that the economy, business structure, or reliance on electric power, of British customers is the same as North American customers.

SUMMARY AND RECOMMENDATIONS

As indicated herein, estimates of the cost of unserved energy can vary widely across and within customer segments. Pace Global has assessed the analyses of several surveys of residential, commercial, and industrial customers in the U.S., Canada, and Britain that were conducted over the past twenty years, including studies that were done within the past decade that address customer costs in Midwestern and southeastern utility markets. Careful analysis of those reports, and synthesis of their results into a common set of estimates, leads to the conclusion that overall costs of service interruptions during peak hours is likely in a range of about $13/kWh to $19/kWh. Based on that synthesis, Pace Global recommends that a value of $14.96/kWh be adopted as a proxy for the value of unserved energy.

ATTACHMENTS

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Attachment 1 – Worksheets for Exhibits

Outage Costs (2007$)

Row		momentary	1 min	20 min	1 hour	2 hour	4 hour	8 hour	24 hour
	Residential - Normalized to Annual kWh Basis								
1	Allan (Residential subdivision)		$0.00000	$0.00006	$0.00033		$0.00322	$0.00963	
2	Kariuki			$0.00015	$0.00051		$0.00352		
	Commercial - Normalized to Annual kWh Basis								
3	LBNL - Small C&I (2003)		$0.00321	$0.00585	$0.01778		$0.04222	$0.04944	
4	Chowdhury		$0.00236	$0.00809	$0.00983		$0.03081	$0.05732	
5	Subramiam (no standby system)		*$0.00048*	*$0.00335*	*$0.00770*		*$0.03046*	*$0.09078*	
6	Subramiam (battery system backup)		$0.00017	$0.00256	$0.00387		$0.01215	$0.02698	
7	Subramiam (engine system backup)		$0.00001	$0.00068	$0.00436		$0.01234	$0.02238	
8	Kariuki	$0.00112	$0.00117	$0.00401	$0.01200		$0.04430	$0.09055	$0.11625
9	Tollefson	$0.00150	$0.00141	$0.00335	$0.00999	$0.01753	$0.03967	$0.06808	$0.14091
	Industrial - Normalized to Annual kWh Basis								
10	LBNL - Large C&I (2003)		$0.00126	$0.00184	$0.00424		$0.00769	$0.01147	
11	Chowdhury		$0.00229	$0.00393	$0.00736		$0.01418	$0.02445	
12	Subramiam (no standby system)		*$0.00040*	*$0.00170*	*$0.00362*		*$0.01079*	*$0.02075*	
13	Subramiam (battery system backup)		$0.00009	$0.00050	$0.00082		$0.00263	$0.00390	
14	Subramiam (engine system backup)		$0.00046	$0.00105	$0.00152		$0.00719	$0.00964	
15	Kariuki	$0.00738	$0.00765	$0.01544	$0.02917		$0.07962	$0.13037	$0.16394
16	Tollefson	$0.01128	$0.01172	$0.01239	$0.01560	$0.01822	$0.02780	$0.05194	$0.06924
	System Wide - Normalized to Annual kWh Basis								
17	Allan (towns, surround farms)		$0.00006	$0.00056	$0.00140		$0.00618	$0.01652	
18	Allan (small-to-medium sized city)		$0.00009	$0.00082	$0.00200		$0.00837	$0.02210	
19	*Allan (large city)*		*$0.00020*	*$0.00107*	*$0.00243*		*$0.00868*	*$0.02071*	
20	Allan (larger city)		$0.00039	$0.00119	$0.00261		$0.00802	$0.01821	
21	Allan (large city and surround farms)		$0.00031	$0.00096	$0.00213		$0.00678	$0.01564	
22	Chowdhury		$0.00321	$0.00570	$0.00863		$0.02181	$0.03552	
	Residential - Peak Hour Basis								
23	Cramton and Lien (British)			$0.35	$1.24		$8.52		
24	Chowdhury				$0.61				
25	Christensen				$2.78				
26	Sullivan (generation outage)				*$2.60*				
27	Sullivan (T&D outage)				$2.86				
	Commercial - Peak Hour Basis								
28	LBNL - Small C&I (2003)				$50.48				
29	Cramton and Lien (British)		$2.30	$8.92	$24.48		$89.79	$180.80	$229.89
30	Chowdhury				$43.04				
31	Christensen				$19.98				
32	Sullivan (generation outage)				$29.08				
33	Sullivan (T&D outage)				$63.39				
	Industrial - Peak Hour Basis								
34	LBNL - Large C&I (2003)				$19.50				
35	Cramton and Lien (British)		$14.87	$32.86	$58.01		$166.06	$276.13	$345.64
36	Chowdhury				$26.86				
37	Christensen				$10.36				
38	Sullivan (generation outage)				$4.98				
39	Sullivan (T&D outage)				$10.53				
	System Wide - Peak Hour Basis								
40	Chowdhury				$22.58				
41	Sullivan (generation outage)				$10.78				
42	Sullivan (T&D outage)				$22.34				
	Residential - Normalized to Peak kW Basis								
43	Kariuki				$1.32				
	Commericial - Normalized to Peak kW Basis								
44	Subramiam (no standby system)				$21.65		$14.46		
45	Subramiam (battery system backup)				$8.11				
46	Subramiam (engine system backup)				$9.48				
47	Kariuki				$26.02				
48	Tollefson				$18.61				
	Industrial - Normalized to Peak kW Basis								
49	Subramiam (no standby system)				$8.04		$6.31		
50	Subramiam (battery system backup)				$3.15				
51	Subramiam (engine system backup)				$5.99				
52	Kariuki				$61.72				
53	Tollefson				$8.06				

Duration of outages - relative cost analysis - indexed to one hour

Residential	20 min	1 hour	4 hour	8 hour
Cramton and Lien (British)	0.85	1.00	1.71	
Allan-residential subdivision	0.56	1.00	2.44	3.66
Kariuki	0.86	1.00	1.71	
Average	0.75	1.00	1.96	3.66
Commercial				
LBNL-Small C&I (2003)	0.99	1.00	0.59	0.35
Cramton and Lien (British)	1.09	1.00	0.92	0.92
Chowdhury	2.47	1.00	0.80	0.75
Subramiam-No Standby	1.30	1.00	0.99	1.47
Subramiam-Battery Backup	1.98	1.00	0.78	0.87
Subramiam-Engine Backup	0.47	1.00	0.71	0.64
Kariuki	1.00	1.00	0.92	0.94
Tollefson	1.01	1.00	0.99	0.85
Average	1.29	1.00	0.84	0.85
Industrial				
LBNL-Large C&I (2003)	1.30	1.00	0.45	0.34
Cramton and Lien (British)	1.70	1.00	0.72	0.59
Chowdhury	1.60	1.00	0.48	0.41
Subramiam-No Standby	1.41	1.00	0.74	0.72
Subramiam-Battery	1.82	1.00	0.81	0.60
Subramiam-Engine Backup	2.08	1.00	1.18	0.79
Kariuki	1.59	1.00	0.68	0.56
Tollefson	2.38	1.00	0.45	0.42
Average	1.73	1.00	0.69	0.55
System-Wide				
Chowdhury	1.98	1.00	0.63	0.51
Allan-towns/surrounding farms	1.20	1.00	1.10	1.48
Allan-small/med city	1.23	1.00	1.05	1.38
Allan-large city	1.32	1.00	0.89	1.07
Allan-larger city	1.37	1.00	0.77	0.87
Allan-large city/surrounding farms	1.36	1.00	0.80	0.92
Avg of System-Wide estimates	1.41	1.00	0.87	1.04

Summaries	20 min	1 hour	4 hour	8 hour
indexed to one hour				
Residential	0.75	1.00	1.96	3.66
Commercial	1.29	1.00	0.84	0.85
Industrial	1.73	1.00	0.69	0.55

Exhibit 2

	Normalized to Peak Hour ($/kWh)				Normalized to Annual kWh ($/kWh)				
	Minimum	Median	Maximum	Max/Min	Minimum	Median	Maximum	Max/Min	
Residential	$0.61	$1.96	$2.86	5	n/a	n/a	n/a	n/a	*Rows 23-27, 43*
Commercial	$8.11	$24.48	$63.39	8	$0.0039	$0.0098	$0.0178	5	*Rows 28-33, 44-48 (peak); 3-9 (annual)*
Industrial	$3.15	$10.36	$61.72	20	$0.0008	$0.0042	$0.0292	36	*Rows 34-39, 49-53 (peak); 10-16 (annual)*

	Residential	Comercial	Industrial	System-Wide	*source:*
Cramton and Lien	$1.24	$24.48	$58.01	$28.65	*Rows 23, 29, 35*
Chowdhury	$0.61	$43.04	$26.86	$22.79	*Rows 24, 30, 36*
Christensen	$2.78	$19.98	$10.36	$10.67	*Rows 25, 31, 37*
Sullivan (gen outage)	$2.60	$29.08	$4.98	$11.40	*Rows 26, 32, 38*
Sullivan (T&D outage)	$2.86	$63.39	$10.53	$23.78	*Rows 27, 33, 39*
weights	0.34	0.3	0.36	$19.46	

Exhibit 3

	Residential	Commercial	Industrial	System-wide	
Equal weighting for all data sets					
All	$1.90	$28.57	$19.74	$16.33	*Rows: 23-27, 43 (res); 28-33, 44-48 (com); 34-39, 49-53 (ind)*
North American	$2.21	$29.31	$10.83	$13.44	*Rows: 24-27 (res); 28, 30-33, 44-48 (com); 34, 36-39, 49-53 (ind)*
Grouped by study sets					
All	$1.74	$30.24	$24.75	$18.57	*see above, but row groups 26-27, 32-33, 38-39, 44-46, 49-51 are averaged*
North American	$2.04	$31.90	$13.04	$14.96	*see above, but row groups 26-27, 32-33, 38-39, 44-46, 49-51 are averaged*
E.ON class weights	34%	30%	36%		

Attachment 2 – References

R. Allan and R. Billinton, 1993. "Power System Reliability and Its Assessment, Part 3 Distribution Systems and Economic Considerations," *Power Engineering Journal*, pp. 185-192.

A.A. Chowdhury, T.C. Mielnik, L.E. Lawton, M.J. Sullivan, and A. Katz, June 2004 "Reliability Worth Assessment in Electric Power Delivery Systems," *IEEE Power Engineering Society General Meeting*, Vol. 1: 654 – 660.

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L. Lawton, M. Sullivan, K. Van Liere, A. Katz, and J. Eto, 2003. A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys," *Prepared for Lawrence Berkeley National Laboratory*, LBNL-54365

R.K. Subramaniam, G. Wacker, and R. Billinton, 1993. "Understanding Commercial Losses Resulting from Electric Service Interruptions," *IEEE Transactions on Industry Applications*, 29(1): 233-237.

R.K. Subramaniam, R. Billinton, and G. Wacker, 1993. "Understanding Industrial Losses Resulting from Electric Service Interruptions," *IEEE Transactions on Industry Applications*, 29(1): 238-244.

M.J. Sullivan, B. N. Suddeth, T. Vardell, and A. Vojdani., 1996, "Interruption Costs, Customer Satisfaction and Expectations for Service Reliability," *IEEE Transactions on Power Systems*, 11(2): 989-995.

G. Tollefson, 1993. "A Canadian Customer Survey to Assess Power System Reliability Worth," *IEEE Transactions on Power Systems*, 9(1): 443-450.

P. Cramton and J, Lien, 2000. "Value of Lost Load", University of Maryland.

Attachment 3 – Source Data

Report Title:	Power System Reliability and Its Assessment Part 3		
Author(s):	Allan, R and Billinton, R		
Abstract:	Addresses reliability in electric power systems. Part 3 specifically considers		
Published:	August 1993		
Data Vintage:	1985		
conversion from $C to $ U.S.		0.73278	source: www.oanda.com
Inflation multiplier to $2007		1.7143	

Table 4 Composite Customer Damage Functions for Example Service Areas (consumption-normalized costs in 1985 Canadian dollar/kWh)

example service area	Interruption Duration				
	1 min	20 min	1 hour	4 hour	8 hour
Apartment Buildings	0.00000	0.00007	0.00039	0.00355	0.01066
Residential subdivision	0.00000	0.00005	0.00026	0.00256	0.00767
small-to medium-size city	0.00008	0.00065	0.00159	0.00666	0.01759
towns and surround farms	0.00005	0.00044	0.00111	0.00492	0.01315
large city	0.00016	0.00085	0.00193	0.00691	0.01649
larger city	0.00031	0.00095	0.00208	0.00638	0.01450
large city and surrounding farms	0.00025	0.00077	0.00169	0.00540	0.01245

Converted to 2007$ by Pace Global

Table 4 Composite Customer Damage Functions for Example Service Areas

example service area	Interruption Duration				
	1 min	20 min	1 hour	4 hour	8 hour
Apartment Buildings	0.00000	0.00008	0.00050	0.00446	0.01339
Residential subdivision	0.00000	0.00006	0.00033	0.00322	0.00963
small-to medium-size city	0.00009	0.00082	0.00200	0.00837	0.02210
towns and surround farms	0.00006	0.00056	0.00140	0.00618	0.01652
large city	0.00020	0.00107	0.00243	0.00868	0.02071
larger city	0.00039	0.00119	0.00261	0.00802	0.01821
large city and surrounding farms	0.00031	0.00096	0.00213	0.00678	0.01564

Attachment 3 – Source Data

Report Title: Reliability Worth Assessment in Electric Power Delivery Systems
Author(s): Chowdhury, A; Mielnik, T; Lawton, L; Sullivan, M and Katz, A
Abstract: Discussed the results of a 2002 customer survey conducted by MidAmerican Energy Company to determine the value of lost load. This is the first customer survey study conducted for the Midwest region of the United States.
Published: October 2004
Data Vintage: 2002
Inflation multiplier to $2007 1.1472

Table II: Per Event Outage Costs

Scenario	Total Weighted Avg	Commercial (Business)	Industrial	Institutional
2 seconds	na	na	na	28,565
1 minute	10,899	379	14,055	na
20 minute	8,866	744	20,551	15,373
1 hour	14,154	1,002	33,436	21,878
4 hour	27,152	2,299	61,710	53,455
8 hour	35,169	4,188	92,210	na

Table III Per Annual kWh Costs

Scenario	Total Weighted Avg	Commercial (Business)	Industrial	Institutional
2 seconds	-	-	-	0.00877
1 minute	0.00280	0.00206	0.00200	-
20 minute	0.00497	0.00705	0.00343	0.00430
1 hour	0.00752	0.00857	0.00642	0.00749
4 hour	0.01901	0.02766	0.01236	0.01777
8 hour	0.03096	0.05146	0.02131	-

Table IV Per kW Demand Costs

Scenario	Total Weighted Avg	Commercial (Business)	Industrial	Institutional
2 seconds	na	na	na	31.54
1 minute	11.64	9.03	8.98	na
20 minute	20.15	30.87	13.08	13.48
1 hour	29.13	37.52	23.41	21.1
4 hour	72.97	121.15	40.19	53.32
8 hour	121.14	225.41	67.15	na

Table VIII: Outage Cost per Peak kWh

Customer Group	Outage Cost Per Peak kWh
Residential	0.53
Commercial	37.52
Industrial	23.41
Organization	21.10
Total System	19.68

Attachment 3 – Source Data

Chowdhury (2004) continued

Converted to 2007$ by Pace Global

Table II: Per Event Outage Costs

Scenario	Total Weighted Avg	Commercial (Business)	Industrial	Institutional
2 seconds	na	na	na	32,769
1 minute	12,503	435	16,123	na
20 minute	10,171	853	23,575	17,635
1 hour	16,237	1,149	38,357	25,098
4 hour	31,148	2,637	70,792	61,322
8 hour	40,345	4,804	105,780	na

Table III Per Annual kWh Costs

Scenario	Total Weighted Avg	Commercial (Business)	Industrial	Institutional
2 seconds	-	-	-	0.01006
1 minute	0.00321	0.00236	0.00229	-
20 minute	0.00570	0.00809	0.00393	0.00493
1 hour	0.00863	0.00983	0.00736	0.00859
4 hour	0.02181	0.03173	0.01418	0.02039
8 hour	0.03552	0.05903	0.02445	-

Table IV Per kW Demand Costs

Scenario	Total Weighted Avg	Commercial (Business)	Industrial	Institutional
2 seconds	na	na	na	36.18
1 minute	13.35	10.36	10.30	na
20 minute	23.12	35.41	15.00	15.46
1 hour	33.42	43.04	26.86	24.21
4 hour	83.71	138.98	46.10	61.17
8 hour	138.97	258.58	77.03	na

Table VIII: Outage Cost per Peak kWh

Customer Group	Outage Cost Per Peak kWh
Residential	0.61
Commercial	43.04
Industrial	26.86
Organization	24.21
Total System	22.58

Report Title: Assessment of Other Factors: Benefit-Cost Analysis of Transmission Expansion Plans
Author(s): Christensen Associates Energy Consulting, LLC
Abstract: *Evaluated the costs and benefits from transmission expansion for the* American Transmission Company. Included an extensive literature review of the cost of unserved energy.
Published: August 2005
Data Vintage: 1999
Inflation multiplier to $2007 1.2213

Table 5: Distribution of per-kWh Outage Costs (1999 $)

Class	# of Observations	17th Percentile	50th Percentile	83rd Percentile
Residential	97	0.3	2.28	7.67
Commercial	43	0.12	16.36	24.44
Industrial	49	0.39	8.48	24.67

Converted to 2007$ by Pace Global

Table 5: Distribution of per-kWh Outage Costs

Class	# of Observations	17th Percentile	50th Percentile	83rd Percentile
Residential	97	0.37	2.78	9.37
Commercial	43	0.15	19.98	29.85
Industrial	49	0.48	10.36	30.13

Report Title: Value of Lost Load
Author(s): Cramton, P and Lien, J
Abstract: Discusses the parameters that effect an estimate of the Value of Lost Load. Addresses the use of VOLL studies to value reliability.
Published: February 2000
Data Vintage: 1993
Inflation multiplier to $2007 1.3523

Table 2: 1993 British study - Sector Customer Damage Functions per peak kWh (1999 $)

	Outage Duration						
Customer Category	< 1 sec	1 min	20 min	1 hour	4 hours	8 hours	24 hours
Industrial	10.5	11	24.3	42.9	122.8	204.2	255.6
Commercial	1.7	1.7	6.6	18.1	66.4	133.7	170
Residential	-	-	0.26	0.92	6.3	-	-
Large Users	11.5	11.5	11.7	12.2	15.1	16.5	22.7

Converted to 2007$ by Pace Global

Table 2: 1993 British study - Sector Customer Damage Functions per peak kWh

	Outage Duration						
Customer Category	< 1 sec	1 min	20 min	1 hour	4 hours	8 hours	24 hours
Industrial	14.20	14.87	32.86	58.01	166.06	276.13	345.64
Commercial	2.30	2.30	8.92	24.48	89.79	180.80	229.89
Residential			0.35	1.24	8.52		
Large Users	15.55	15.55	15.82	16.50	20.42	22.31	30.70

Attachment 3 – Source Data

Report Title: Evaluation of Reliability Worth and Value of Lost Load
Author(s): Kariuki, K and Allan, R
Abstract: Discusses customers perceptions of reliability worth in electric supply in the United Kingdom. Utilized customer surveys to determine customer outage costs and the benefits from reliability.
Published: March 1996
Data Vintage: 1992
conversion from £ to $ U S 1 76613 source: www oanda com
Inflation multiplier to $2007 1 3834

Table 1: Customer Interruption Costs (CIC) (£) values

sector	No. of Responses	Response Rate	CIC (£) for an interruption duration of: mom.	1 min	20 min	1 h	4 h	8 h	24 h
Residential	4014	19.10	-	-	0.19	0.70	4.78	-	-
Commercial	203	4.00	11.47	11.74	49.12	106	345	719	1,000
Industrial	119	5.70	1,200	1,500	2,900	4,300	7,600	12,000	16,300
Large User	19	29.20	216,000	216,000	219,000	233,000	329,000	413,000	581,000

Table 2: Sector Customer Damage Function for sectors investigated

	SCDFs (£/MWh)				SCDFs (£/kW)			
	Res.	Comm	Ind	L. user	Res.	Comm	Ind	L. user
mom	-	0.46	3.02	1.07	-	0.99	6.15	6.74
1 min	-	0.48	3.13	1.07	-	1.02	6.47	6.74
20 min	0.06	1.64	6.32	1.09	0.15	3.89	14.27	6.86
1 h	0.21	4.91	11.94	1.36	0.54	10.65	25.26	7.18
4 h	1.44	18.13	32.59	1.52	3.72	39.04	72.22	8.86
8 h	-	37.06	53.36	1.71	-	78.65	120.11	9.71
24 h	-	47.58	67.1	2.39	-	99.98	150.38	13.35

Converted to 2007$ and to kWh by Pace Global

Table 1: Customer Interruption Costs (CIC)

sector	No. of Responses	Response Rate	CIC ($) for an interruption duration of: mom.	1 min	20 min	1 h	4 h	8 h	24 h
Residential	4014	19.10	-	-	0.46	1.71	11.68	-	-
Commercial	203	4.00	28.02	28.68	120.01	259	843	1,757	2,443
Industrial	119	5.70	2,932	3,665	7,085	10,506	18,569	29,319	39,825
Large User	19	29.20	527,738	527,738	535,068	569,273	803,824	1,009,055	1,419,518

Table 2: Sector Customer Damage Function for sectors investigated

	SCDFs ($/kWh)				SCDFs ($/kW)			
	Res.	Comm	Ind	L. user	Res.	Comm	Ind	L. user
mom		0.00112	0.00738	0.00261		2.42	15.03	16.47
1 min		0.00117	0.00765	0.00261		2.49	15.81	16.47
20 min	0.00015	0.00401	0.01544	0.00266	0.37	9.50	34.86	16.76
1 h	0.00051	0.01200	0.02917	0.00332	1.32	26.02	61.72	17.54
4 h	0.00352	0.04430	0.07962	0.00371	9.09	95.38	176.45	21.65
8 h		0.09055	0.13037	0.00418		192.16	293.46	23.72
24 h		0.11625	0.16394	0.00584		244.27	367.41	32.62

Attachment 3 – Source Data

Report Title: A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys

Author(s): Eto, J and Population Research Systems, LLC. (Lawrence Berkeley National Laboratory)

Abstract: Average outage costs and Tobit models that estimate customer damage functions are presented. based on studies of eight U S. utilities in the southeast. west, and Midwest The customer damage functions express customer outage costs for a given outage scenario and customer class as a function of location, time of day. consumption. and business type

Published: November 2003

Data Vintage: 2002

Inflation multiplier to $2007 1.1472

Source data:

Table 3-2: Outage Costs by Duration - Large C&I

Duration	Average Cost per Annual kWh	Average Cost Per Peak kW
All	0.0041	20
Voltage Sag	0.0006	3
1-2 sec	0.0010	5
1 min	0.0011	5
15 min	0.0083	29
20 min	0.0016	7
30 min	0.0024	14
1 hr	0.0037	15
4 hr	0.0067	35
8 hr	0.0100	45
12 hr	0.0187	-

Table 4-2: Outage Costs by Duration - Small-Medium C&I

Duration	Average Cost per Annual kWh	Average Cost Per Peak kW
All	0.0218	55
Voltage Sag	0.0015	1
1-2 sec	0.0132	34
1 min	0.0028	2
15 min	0.004	9
20 min	0.0051	3
30 min	0.0211	49
1 hr	0.0155	40
4 hr	0.0368	91
8 hr	0.0431	99
12 hr	0.0408	-

Table 3-3: Outage Costs for a 1-hr Outage - Large C&I

Season	Average Cost Per Peak kW
All	17
Winter	25
Summer	16
Day	
All	15
Weekday	17
Weekend	NA
Region	
All Regions	15
Northwest	18
Southwest	22
Southeast	15
West	33
Midwest	11
SIC	
All SIC	20
Agriculture	1
Mining	11
Construction	0
Manufacturing	21
Telco & Utilities	18
Trade & Retail	13
Finance, Ins, R.E.	168
Service	9
Public Admin	19

Table 4-3: Outage Costs for a 1-hr Outage - Small-Medium C&I

Season	Average Cost Per Peak kW
All	44
Winter	47
Summer	46
Day	
All	40
Weekday	44
Weekend	25
Region	
All Regions	40
Northwest	18
Southwest	66
Southeast	26
West	102
Midwest	4
SIC	
All SIC	29
Agriculture	66
Mining	4
Construction	47
Manufacturing	52
Telco & Utilities	23
Trade & Retail	35
Finance, Ins, R.E.	53
Service	15
Public Admin	20

Attachment 3 – Source Data

Eto (2003) continued

Converted to 2007$ by Pace Global

Table 3-2: Outage Costs by Duration - Large C&I

Duration	Average Cost per Annual kWh	Average Cost Per Peak kW
All	0.0047	22.94
Voltage Sag	0.0007	3.44
1-2 sec	0.0011	5.74
1 min	0.0013	5.74
15 min	0.0095	33.27
20 min	0.0018	8.03
30 min	0.0028	16.06
1 hr	0.0042	17.21
4 hr	0.0077	40.15
8 hr	0.0115	51.62
12 hr	0.0215	-

Table 4-2: Outage Costs by Duration - Small-Medium C&I

Duration	Average Cost per Annual kWh	Average Cost Per Peak kW
All	0.0250	63.09
Voltage Sag	0.0017	1.15
1-2 sec	0.0151	39.00
1 min	0.0032	2.29
15 min	0.0046	10.32
20 min	0.0059	3.44
30 min	0.0242	56.21
1 hr	0.0178	45.89
4 hr	0.0422	104.39
8 hr	0.0494	113.57
12 hr	0.0468	-

Table 3-3: Outage Costs for a 1-hr Outage - Large C&I

Season	Average Cost Per Peak kW
All	19.50
Winter	28.68
Summer	18.35
Day	
All	17.21
Weekday	19.50
Weekend	NA
Region	
All Regions	17.21
Northwest	20.65
Southwest	25.24
Southeast	17.21
West	37.86
Midwest	12.62
SIC	
All SIC	22.94
Agriculture	1.15
Mining	12.62
Construction	0.00
Manufacturing	24.09
Telco & Utilities	20.65
Trade & Retail	14.91
Finance, Ins, R.E.	192.72
Service	10.32
Public Admin	21.80

Table 4-3: Outage Costs for a 1-hr Outage - Small-Medium

Season	Average Cost Per Peak kW
All	50.48
Winter	53.92
Summer	52.77
Day	
All	45.89
Weekday	50.48
Weekend	28.68
Region	
All Regions	45.89
Northwest	20.65
Southwest	75.71
Southeast	29.83
West	117.01
Midwest	4.59
SIC	
All SIC	33.27
Agriculture	75.71
Mining	4.59
Construction	53.92
Manufacturing	59.65
Telco & Utilities	26.38
Trade & Retail	40.15
Finance, Ins, R.E.	60.80
Service	17.21
Public Admin	22.94

Report Title: Understanding Commercial Losses Resulting from Electric Service Interruptions
Author(s): Subramaniam, R; Wacker, G; and Billinton, R
Abstract: Analyzed the costs to commercial customers based on an unplanned interruption in electricity supply. An extensive customer survey was conducted to collect data from commercial users with different types of electricity backup systems.
Published: January 1993
Data Vintage: 1992
Inflation multiplier to $2007 1.3834

Table III: Commercial Outage Costs for Winter (Outage at 10am, Friday, end of January)

	Respondents with		
	No Standby System	Battery System	Engine System
1 min ($)	63.44	14.13	1.64
20 min ($)	269.91	176.06	688.77
1 hr ($)	668.96	561.76	1761.28
4 hr ($)	2451.35	2375.57	4734.15
8 hr ($)	6589.78	6483.64	11554.40
1 min ($/kWh)	0.000345	0.000120	0.000008
20 min ($/kWh)	0.002421	0.001850	0.000491
1 hr ($kWh)	0.005566	0.002800	0.003153
4 hr ($/kWh)	0.022017	0.008785	0.008920
8 hr ($/kWh)	0.065625	0.019500	0.016180
1 min ($/kW)	1.04	0.30	0.01
20 min ($/kW)	5.91	1.49	1.48
1 hr ($/kW)	15.65	5.86	6.85
4 hr ($kW)	57.69	19.87	20.24
8 hr ($/kW)	148.93	49.19	44.02

Converted to 2007$ by Pace Global

Table III: Commercial Outage Costs for Winter (Outage at 10am, Friday, end of January)

	Respondents with		
	No Standby System	Battery System	Engine System
1 min ($)	87.76	19.55	2.27
20 min ($)	373.39	243.56	952.83
1 hr ($)	925.43	777.13	2436.52
4 hr ($)	3391.15	3286.32	6549.14
8 hr ($)	9116.19	8969.35	15984.15
1 min ($/kWh)	0.000478	0.000166	0.000011
20 min ($/kWh)	0.003349	0.002559	0.000679
1 hr ($kWh)	0.007700	0.003873	0.004362
4 hr ($/kWh)	0.030458	0.012153	0.012340
8 hr ($/kWh)	0.090784	0.026976	0.022383
1 min ($/kW)	1.44	0.42	0.02
20 min ($/kW)	8.18	2.06	2.05
1 hr ($/kW)	21.65	8.11	9.48
4 hr ($kW)	79.81	27.49	28.00
8 hr ($/kW)	206.03	68.05	60.90

Attachment 3 – Source Data

Report Title: Understanding Industrial Losses Resulting from Electric Service Interruptions
Author(s): Subramaniam, R; Wacker, G; and Billinton, R
Abstract: Analyzed the costs to industrial customers based on an unplanned interruption in electricity supply. An extensive customer survey was conducted to collect data from industrial users with different types of electricity backup systems.
Published: January 1993
Data Vintage: 1992
Inflation multiplier to $2007 1.3834

Table III: Industrial Outage Costs for Winter (Outage at 10am, Friday, end of January)

	Respondents with		
	No Standby System	Battery System	Engine System
1 min ($)	262.00	4247.00	8781.00
20 min ($)	1644.00	9234.00	11317.00
1 hr ($)	3355.00	14457.00	18428.00
4 hr ($)	8047.00	31272.00	31540.00
8 hr ($)	20266.00	46180.00	45827.00
1 min ($/kWh)	0.000292	0.000068	0.000330
20 min ($/kWh)	0.001230	0.000358	0.000761
1 hr ($kWh)	0.002620	0.000590	0.001100
4 hr ($/kWh)	0.007800	0.001900	0.005200
8 hr ($/kWh)	0.015000	0.002820	0.006970
1 min ($/kW)	0.66	0.27	0.60
20 min ($/kW)	3.08	1.45	3.01
1 hr ($/kW)	5.81	2.28	4.33
4 hr ($kW)	17.07	6.66	19.51
8 hr ($/kW)	33.35	9.90	26.40

Converted to 2007$ by Pace Global

Table III: Industrial Outage Costs for Winter (Outage at 10am, Friday, end of January)

	Respondents with		
	No Standby System	Battery System	Engine System
1 min ($)	362.45	5875.22	12147.48
20 min ($)	2274.28	12774.15	15655.74
1 hr ($)	4641.25	19999.56	25492.97
4 hr ($)	11132.08	43261.13	43631.88
8 hr ($)	28035.63	63884.60	63396.26
1 min ($/kWh)	0.000404	0.000094	0.000457
20 min ($/kWh)	0.001702	0.000495	0.001053
1 hr ($kWh)	0.003624	0.000816	0.001522
4 hr ($/kWh)	0.010790	0.002628	0.007194
8 hr ($/kWh)	0.020751	0.003901	0.009642
1 min ($/kW)	0.91	0.37	0.83
20 min ($/kW)	4.26	2.01	4.16
1 hr ($/kW)	8.04	3.15	5.99
4 hr ($kW)	23.61	9.21	26.99
8 hr ($/kW)	46.14	13.70	36.52

Report Title:	Interruption Costs, Customer Satisfaction and Expectations for Service Reliability
Author(s):	Sullivan, M; Vardell, T; Suddeth, N; and Vojdani, A
Abstract:	*Summarizes the results of a comprehensive customer survey* carried out by Duke Power Company. Details the difference in outage costs between generation and transmission outages.
Published:	May 1996
Data Vintage:	1992
Inflation multiplier to $2007	1.3834

Table 2: Customer Outage Cost Summary

Market Segment	Generation Outage Mean Outage Cost	Transmission or Distribution Outage Mean Outage Cost
Residential Customers		
Cost Per Event	4.91	5.39
Cost Per Peak kWh	1.88	2.07
Commercial Customers		
Cost Per Event	604.19	1317.21
Cost Per Peak kWh	21.02	45.82
Industrial Customers		
Cost Per Event	4443	9403.55
Cost Per Peak kWh	3.6	7.61
System Wide		
Cost Per Event	-	-
Cost Per Peak kWh	7.79	16.15

Converted to 2007$ by Pace Global

Table 2: Customer Outage Cost Summary

Market Segment	Generation Outage Mean Outage Cost	Transmission or Distribution Outage Mean Outage Cost
Residential Customers		
Cost Per Event	6.79	7.46
Cost Per Peak kWh	2.60	2.86
Commercial Customers		
Cost Per Event	835.83	1822.21
Cost Per Peak kWh	29.08	63.39
Industrial Customers		
Cost Per Event	6146.37	13008.70
Cost Per Peak kWh	4.98	10.53
System Wide		
Cost Per Event	-	-
Cost Per Peak kWh	10.78	22.34

Attachment 3 – Source Data

Report Title: A Canadian Customer Survey to Assess Power System Reliability Worth
Author(s): Tollefson, G; Billinton. R; Wacker. G; Chan. E; and Aweya J
Abstract: Presents the results of a Canadian electric utility customer survey Analyzes the costs associated with outages for different types of commercial and industrial users
Published: February 1994
Data Vintage: 1991
conversion from $C to $ U S 0 87288 source: www oanda com
Inflation multiplier for report data to $2007 1 4152

Table 4: Interruption Costs in 1991 Canadian Dollars

Interruption Duration	Commercial			Industrial		
	$/int	$/kWh	$/kW	$/int	$/kWh	$/kW
2 second	141	0.0012	0.27	1048	0.0091	0.90
1 minute	171	0.0011	1.88	1193	0.0095	2.16
20 minutes	400	0.0027	5.58	1721	0.0100	3.09
1 hour	1183	0.0081	15.07	3323	0.0126	6.53
2 hours	2087	0.0142	31.60	4809	0.0148	11.58
4 hours	4353	0.0321	75.90	8496	0.0225	23.81
8 hours	7807	0.0551	121.97	14821	0.0420	44.06
1 day	17139	0.1141	146.90	24708	0.0560	70.13

Table 5: One Hour Interruption Costs for Commercial and Small Industrial SIC's

SIC Code	Business Description	Responses	$/ interr	$/kWh	$/kW
60	Food and Drug	116	1034	0.0059	14.39
61	Clothing Stores	42	272	0.0099	14.71
62	Household Furniture	41	496	0.0112	31.00
63	Automotive	119	1116	0.0094	32.94
64	General Merchandise	25	1517	0.0098	23.39
65	Other Retail	83	549	0.0055	4.62
69	Vending and Direct	9	1588	0.0030	0.00
91	Accommodations	45	879	0.0022	1.03
92	Food Service	37	1118	0.0104	15.47
96	Entertainment	45	5354	0.0145	18.51
97	Personal Services	44	54	0.0012	0.31
99	Other Services	49	477	0.0079	2.73
Total Commercial		657	1183	0.0081	15.07
4	Logging	5	400	0.0071	16.06
5	Forestry	1	0	0.0000	0.00
6	Mining	13	2253	0.0011	2.33
7	Crude Petroleum	80	9835	0.0706	214.54
8	Quarry and Sand	10	908	0.0290	4.14
9	Services to Mining	10	26389	0.0004	1.65
10	Food Industries	70	3612	0.0054	15.90
11	Beverage Industries	14	647	0.0006	1.21
15	Rubber Products	10	585	0.0032	1.39
16	Plastic Products	42	2087	0.0021	2.26
17	Leather Products	8	4090	0.0006	1.06
18	Primary Textiles	2	925	0.0060	13.44
19	Textile Products	20	403	0.0028	6.94
24	Clothing	14	1619	0.0041	6.75
25	Wood Industries	47	1611	0.0011	2.28
26	Furniture	22	1291	0.0106	18.03
27	Paper Products	10	25296	0.0374	5.85
28	Printing & Publishing	79	964	0.0023	4.67
29	Primary Metal	25	1427	0.0008	2.75
30	Fabricated Metal	119	1289	0.0053	6.60
31	Machinery	38	1250	0.0071	5.98
32	Transportation	25	7114	0.0068	33.39
33	Electrical Products	28	3207	0.0019	6.82
35	Non-metal minerals	32	3341	0.0041	7.46
36	Refined Petroleum	5	1355	0.0426	0.00
37	Chemical Products	38	879	0.0017	3.61
39	Other Manufacturing	50	1377	0.0111	11.90
-	Undefined	2	18000	0.0000	- 0.00
Total Industrial		819	3323	0.0126	6.53

Attachment 3 – Source Data

Tollefson (1991) continued

Converted to 2007$ by Pace Global

Table 4: Interruption Costs in U.S. $

Interruption Duration	Commercial			Industrial		
	$/int	$/kWh	$/kW	$/int	$/kWh	$/kW
2 second	174	0.0015	0.33	1295	0.0113	1.12
1 minute	211	0.0014	2.33	1474	0.0117	2.67
20 minutes	495	0.0034	6.89	2126	0.0124	3.82
1 hour	1461	0.0100	18.61	4105	0.0156	8.06
2 hours	2579	0.0175	39.04	5940	0.0182	14.30
4 hours	5377	0.0397	93.77	10496	0.0278	29.41
8 hours	9644	0.0681	150.67	18309	0.0519	54.43
1 day	21172	0.1409	181.47	30522	0.0692	86.64

Table 5: One Hour Interruption Costs for Commercial and Small Industrial SIC's

SIC Code	Business Description	Responses	$/ interr	$/kWh	$/kW
60	Food and Drug	116	1277	0.0073	17.78
61	Clothing Stores	42	336	0.0122	18.17
62	Household Furniture	41	613	0.0138	38.30
63	Automotive	119	1378	0.0116	40.70
64	General Merchandise	25	1875	0.0121	28.90
65	Other Retail	83	678	0.0068	5.71
69	Vending and Direct	9	1962	0.0037	0.00
91	Accommodations	45	1085	0.0027	1.27
92	Food Service	37	1381	0.0128	19.11
96	Entertainment	45	6614	0.0179	22.86
97	*Personal Services*	44	67	0.0015	0.38
99	Other Services	49	589	0.0098	3.38
Total Commercial		657	1461	0.0100	18.61
4	Logging	5	494	0.0088	19.84
5	Forestry	1	0	0.0000	0.00
6	Mining	13	2783	0.0014	2.87
7	Crude Petroleum	80	12150	0.0872	265.03
8	Quarry and Sand	10	1122	0.0358	5.12
9	Services to Mining	10	32599	0.0005	2.04
10	Food Industries	70	4461	0.0067	19.64
11	Beverage Industries	14	799	0.0007	1.49
15	Rubber Products	10	723	0.0040	1.72
16	Plastic Products	42	2578	0.0026	2.79
17	Leather Products	8	5053	0.0007	1.31
18	Primary Textiles	2	1143	0.0074	16.60
19	Textile Products	20	498	0.0035	8.57
24	Clothing	14	2000	0.0051	8.34
25	Wood Industries	47	1991	0.0014	2.81
26	Furniture	22	1595	0.0131	22.28
27	Paper Products	10	31250	0.0462	7.23
28	Printing & Publishing	79	1191	0.0028	5.77
29	*Primary Metal*	25	1763	0.0010	3.40
30	Fabricated Metal	119	1592	0.0065	8.15
31	Machinery	38	1544	0.0088	7.39
32	Transportation	25	8788	0.0084	41.25
33	Electrical Products	28	3962	0.0023	8.43
35	Non-metal minerals	32	4128	0.0051	9.21
36	Refined Petroleum	5	1673	0.0526	0.00
37	Chemical Products	38	1086	0.0021	4.47
39	Other Manufacturing	50	1701	0.0137	14.71
-	Undefined	2	22236	0.0000	0.00
Total Industrial		819	4105	0.0156	8.06

Attachment 4 – Inflation Rates **Page 1 of 1**

Table 1.1.4. Price Indexes for Gross Domestic Product
[Index numbers, 2000=100]
LaLast Revised on September 27, 2007 Next Release Date October 31, 2007

BEA Data		Adjustment to 2007$	
1980	54.062	2.2109	
1981	59.128	2.0215	
1982	62.738	1.9052	
1983	65.214	1.8328	
1984	67.664	1.7665	
1985	69.724	1.7143	
1986	71.269	1.6771	
1987	73.204	1.6328	
1988	75.706	1.5788	
1989	78.569	1.5213	
1990	81.614	1.4645	
1991	84.457	1.4152	
1992	86.402	1.3834	
1993	88.39	1.3523	
1994	90.265	1.3242	
1995	92.115	1.2976	
1996	93.859	1.2735	
1997	95.415	1.2527	
1998	96.475	1.2389	
1999	97.868	1.2213	
2000	100	1.1953	
2001	102.402	1.1672	
2002	104.193	1.1472	
2003	106.409	1.1233	
2004	109.462	1.0919	
2005	113.005	1.0577	
2006	116.568	1.0254	
2007	119.527	1.0000	*note: 2007 is Q II value*

source: U.S. Bureau of Economic Analysis

2008 Reserve Margin

APPENDIX B

DATA ITEMS USED IN OPTIMAL MARGIN ANALYSIS

Existing System Data

The Strategist® computer program is used to model Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company's (KU) generating systems. The model simulates the dispatch of both companies generating units and other purchases to serve load, and of Owensboro Municipal Utilities' (OMU) generating units and purchases to serve OMU's load while simultaneously maintaining the KU/LG&E reserve margin requirements. The remaining generation available from OMU's units after meeting their requirements is economically dispatched by the Companies. The following sections outline the information and the sources of the information used in the programs to model the KU, LG&E and OMU generating systems.

A) General Data Items

1. Base Year - 2007

2. Study Period - 2007 to 2037 (with no end effects)

3. Economic Assumptions

   Revenue requirements are determined on an annual basis and discounted to the base year giving a present worth of revenue requirements. Discounting is performed using a discount rate, which is assumed to remain constant for all years.

4. Financial Parameters:

a. Discount Rate:	7.85%
b. Capital/O&M costs Escalation Rates for Coal:	1.9%/1.6%
c. Capital/O&M costs Escalation Rates for Gas:	2.2%/1.6%
d. Combined Federal and State tax rate:	39.55%

5. Retirements

   This evaluation reflects the recent retirements of Waterside 7 & 8 (August 2006) and Tyrone 1 & 2 (February 2007). The operating life of all other existing units is beyond the end of the study period.

6. Unserved Energy Cost

   The cost placed on unserved energy is varied from the base value of $15/kWh (2004 dollars) to $13 and $19/kWh (no escalation is applied in the model).

7. Load Forecast - See Appendix B, Table 1a

Base LG&E and KU: May 11, 2007 Energy and Demand Forecast 2007-2037 (Load Forecasting)

OMU: Developed April 24, 2007. OMU forecast: 2007 through May 2010.

High Load Forecast: See Appendix B, Table 1b.
Forecasting and Marketing developed a High Demand and Energy forecast for KU/LGE in association with the May 11, 2007 Demand and Energy Forecast.

8. Hourly Load File Used

Market Forecasting provides LG&E and KU typical hourly load files with each forecast they develop. OMU typical hourly loads files are developed based on an OMU historical load shape.

9. KU/LG&E Unit Data

a. Installed/Existing Capacity - See Appendix B, Table 2

b. Equivalent Forced Outage Rate - See Appendix B, Table 2

System FOR target developed based on benchmark averages for the top quartile. FORs have been increased by inclusion of maintenance outage hours (MOHs) to better reflect actual unit availability. Modeled EFOR = FOR + MOR.

c. Heat Rates - See Appendix B, Table 2

d. Fuel Cost - See Appendix B, Table 3

e. Maintenance Schedules -

Maintenance inputs were determined by reviewing the Companies' projected maintenance as of Spring 2007. Planned outages are scheduled to optimize reserves and reliability over all months of each year.

10. OMU Unit Data

a. Installed Net Capacity

OMU (Smith Unit 1): 136/143 (summer/winter)

OMU (Smith Unit 2): 259/265 (summer/winter)

b. Equivalent Forced Outage Rate

OMU (Smith Unit 1): 15.27%
OMU (Smith Unit 2): 16.64%

c. Heat Rates (Full Load)-

OMU (Smith Unit 1): 10,620 Btu/kWh
OMU (Smith Unit 2): 10,070 Btu/kWh

d. Heat Content of Fuel: 10,700 Btu/lb

e. Maintenance Schedules -

Planned outage inputs were developed with the assistance of OMU.

f. Contracted MW Demand Sale to KU - See Appendix B, Table 4.

g. Fuel Cost - See Appendix B, Table 5.

Fuel costs include associated costs for fuel handling and limestone.

h. OMU Scrubber O&M (Smith Units 1 & 2)
   i. Variable O&M: Limestone charges included in fuel cost.
   ii. Removal Efficiency: 93.5%

11. Other Purchases
   a. Contract Demand - See Appendix B, Table 4
      OVEC (Firm): 174 MW
      5x16 On-Peak Market Purchase; Weekday On-Peak Hrs, All Months
      (Non-Firm): 204 MW and 304 MW

   b. Forced Outage Rates

      OVEC: 0% partial FOR. Energy schedule incorporates outages.

      5x16 On-Peak Market Purchase: 5.0%

   c. Full Load Heat Rate (Btu/kWh)

      OVEC: 10,000

5x16 On-Peak Market Purchase: 10,000

For these transactions, which were modeled as purchase power units, the fuel price was input such that the fuel price times the heat rate would result in the expected energy cost of the purchase. A heat rate of 10,000 Btu/kWh is not meant to reflect the "real life" heat rate of the units associated with these transactions.

d. Heat Content of Fuel (Btu/lb)

OVEC: N/A
5x16 On-Peak Market Purchase: N/A

e. Fuel/Energy Cost

See Appendix B, Table 5

Table 1a - 2008 Reserve Margin Appendix B
Base Forecast: Peak (MW) /Annual Energy (GWh)

	LGE Forecast		KU Forecast		OMU Forecast	
Year	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)
2007	2,739	13,098	4,229	23,073	187	908
2008	2,789	13,321	4,306	23,513	187	909
2009	2,821	13,523	4,375	23,897	188	910
2010	2,869	13,695	4,435	24,254		
2011	2,918	13,919	4,506	24,651		
2012	2,966	14,140	4,573	25,025		
2013	3,011	14,356	4,631	25,340		
2014	3,057	14,572	4,690	25,663		
2015	3,099	14,763	4,762	26,057		
2016	3,138	14,943	4,827	26,415		
2017	3,179	15,125	4,891	26,761		
2018	3,221	15,319	4,963	27,159		
2019	3,263	15,509	5,031	27,528		
2020	3,308	15,715	5,112	27,972		
2021	3,348	15,899	5,177	28,326		
2022	3,391	16,090	5,249	28,721		
2023	3,435	16,292	5,307	29,041		
2024	3,483	16,511	5,374	29,405		
2025	3,527	16,712	5,444	29,787		
2026	3,572	16,913	5,509	30,147		
2027	3,613	17,100	5,587	30,572		
2028	3,658	17,303	5,662	30,981		
2029	3,702	17,507	5,740	31,407		
2030	3,747	17,712	5,813	31,807		
2031	3,792	17,914	5,893	32,245		
2032	3,836	18,112	5,970	32,670		
2033	3,882	18,324	6,054	33,125		
2034	3,928	18,531	6,138	33,587		
2035	3,976	18,750	6,224	34,057		
2036	4,023	18,967	6,310	34,530		
2037	4,072	19,186	6,398	35,007		

Peaks and energy forecast reflect effects of interruptible/CSR but not DSM.

Table 1b - 2008 Reserve Margin Appendix B
High Forecast: Peak (MW) /Annual Energy (GWh)

	LGE Forecast		KU Forecast	
Year	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)
2007	2,739	13,098	4,229	23,072
2008	2,839	13,559	4,407	24,065
2009	2,887	13,839	4,504	24,599
2010	2,946	14,063	4,587	25,084
2011	3,005	14,337	4,677	25,586
2012	3,066	14,618	4,767	26,084
2013	3,124	14,895	4,837	26,470
2014	3,180	15,159	4,912	26,880
2015	3,233	15,402	4,998	27,350
2016	3,279	15,611	5,079	27,791
2017	3,327	15,832	5,155	28,209
2018	3,378	16,066	5,243	28,691
2019	3,427	16,289	5,326	29,144
2020	3,481	16,533	5,426	29,691
2021	3,528	16,751	5,504	30,115
2022	3,579	16,982	5,587	30,571
2023	3,629	17,210	5,658	30,962
2024	3,684	17,462	5,734	31,375
2025	3,733	17,684	5,819	31,840
2026	3,783	17,914	5,897	32,270
2027	3,828	18,118	5,984	32,743
2028	3,882	18,364	6,071	33,222
2029	3,933	18,599	6,163	33,724
2030	3,981	18,816	6,245	34,174
2031	4,032	19,049	6,337	34,678
2032	4,083	19,282	6,430	35,186
2033	4,136	19,522	6,524	35,701
2034	4,188	19,758	6,624	36,247
2035	4,243	20,009	6,728	36,814
2036	4,296	20,252	6,832	37,382
2037	4,352	20,507	6,942	37,984
Peaks and energy forecast reflect effects of interruptible/CSR but not DSM.				

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Table 2 - 2008 Reserve Margin Appendix B
Louisville Gas and Electric/ Kentucky Utilities Generator Data

Unit	Installed Year	Summer Rating (MW)	EFOR %	Avg Heat Rate at Max Load (Mbtu/MWh)
Brown 1	1957	101	[redacted]	
Brown 2	1963	167		
Brown 3	1971	429		
Brown 5	2001	117		
Brown 6	1999	154		
Brown 7	1999	154		
Brown 8	1995	106		
Brown 9	1994	106		
Brown 10	1995	106		
Brown 11	1996	106		
Ghent 1	1974	475		
Ghent 2	1977	484		
Ghent 3	1981	493		
Ghent 4	1984	493		
Green River 3	1954	68		
Green River 4	1959	95		
Tyrone 3	1953	71		
Dix 1-3	1925	24		
Haefling 1-3	1970	36		
Cane Run 4	1962	155		
Cane Run 5	1966	168		
Cane Run 6	1969	240		
Mill Creek 1	1972	303		
Mill Creek 2	1974	301		
Mill Creek 3	1978	391		
Mill Creek 4	1982	477		
Trimble 1 (75%)	1990	383		
Trimble 5	2002	160		
Trimble 6	2002	160		
Trimble 7	2004	160		
Trimble 8	2004	160		
Trimble 9	2004	160		
Trimble 10	2004	160		
Cane Run 11	1968	14		
Paddys Run 11	1968	12		
Paddys Run 12	1968	23		
Paddys Run 13	2001	158		
Zorn 1	1969	14		
Ohio Falls 1-8	1928	45		

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Table 3 - 2008 Reserve Margin Appendix B

Louisville Gas and Electric/ Kentucky Utilities Fuel Costs ($/Mbtu)

Year	Brown Units 1-3	Gr River Units 3-4	Tyrone Unit 3	Ghent	Cane Run Units 4-6	Mill Creek Units 1-4	Trimble High SO2	Trimble PRB	Oil	Gas *	Haefling Units 1-3 Gas*
2007	[redacted]										
2008											
2009											
2010											
2011											
2012											
2013											
2014											
2015											
2016											
2017											
2018											
2019											
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2021											
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2026											
2027											
2028											
2029											
2030											
2031											
2032											
2033											
2034											
2035											
2036											
2037											

* Indicates a seasonal profile applies. Price shown is annual average.

Table 4 - 2008 Reserve Margin Appendix B

Kentucky Utilities/Louisville Gas and Electric

Purchases During Peak Month (MW)

Year	OMU (Firm)	OVEC (Firm)	5x16 Purch (Non-Firm)
2007	169	174	204 & 304
2008	168	174	204 & 304
2009	167	174	204 & 304
2010	0	174	204 & 304
2011	0	174	204 & 304
2012	0	174	204 & 304
2013	0	174	204 & 304
2014	0	174	204 & 304
2015	0	174	204 & 304
2016	0	174	204 & 304
2017	0	174	204 & 304
2018	0	174	204 & 304
2019	0	174	204 & 304
2020	0	174	204 & 304
2021	0	174	204 & 304
2022	0	174	204 & 304
2023	0	174	204 & 304
2024	0	174	204 & 304
2025	0	174	204 & 304
2026	0	174	204 & 304
2027	0	174	204 & 304
2028	0	174	204 & 304
2029	0	174	204 & 304
2030	0	174	204 & 304
2031	0	174	204 & 304
2032	0	174	204 & 304
2033	0	174	204 & 304
2034	0	174	204 & 304
2035	0	174	204 & 304
2036	0	174	204 & 304
2037	0	174	204 & 304

5x16 Purchase is a sensitivity

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Table 5 - 2008 Reserve Margin Appendix B

Modeled Energy Costs Associated with Purchase Alternatives ($/Mbtu)

Year	OMU (Firm)	OVEC (Firm)	5x16 Purchase (Non-Firm)
2007	[redacted]	[redacted]	Market Based
2008	[redacted]	[redacted]	Market Based
2009	[redacted]	[redacted]	Market Based
2010	[redacted]	[redacted]	Market Based
2011	[redacted]	[redacted]	Market Based
2012	[redacted]	[redacted]	Market Based
2013	[redacted]	[redacted]	Market Based
2014	[redacted]	[redacted]	Market Based
2015	[redacted]	[redacted]	Market Based
2016	[redacted]	[redacted]	Market Based
2017	[redacted]	[redacted]	Market Based
2018	[redacted]	[redacted]	Market Based
2019	[redacted]	[redacted]	Market Based
2020	[redacted]	[redacted]	Market Based
2021	[redacted]	[redacted]	Market Based
2022	[redacted]	[redacted]	Market Based
2023	[redacted]	[redacted]	Market Based
2024	[redacted]	[redacted]	Market Based
2025	[redacted]	[redacted]	Market Based
2026	[redacted]	[redacted]	Market Based
2027	[redacted]	[redacted]	Market Based
2028	[redacted]	[redacted]	Market Based
2029	[redacted]	[redacted]	Market Based
2030	[redacted]	[redacted]	Market Based
2031	[redacted]	[redacted]	Market Based
2032	[redacted]	[redacted]	Market Based
2033	[redacted]	[redacted]	Market Based
2034	[redacted]	[redacted]	Market Based
2035	[redacted]	[redacted]	Market Based
2036	[redacted]	[redacted]	Market Based
2037	[redacted]	[redacted]	Market Based

Figure 1

Base Availability; Base Load; No Market Purchase Available

Present Value Revenue Requirement vs Margin

Base Case with Unserved Energy at 13, 15 & 19 $/kWh

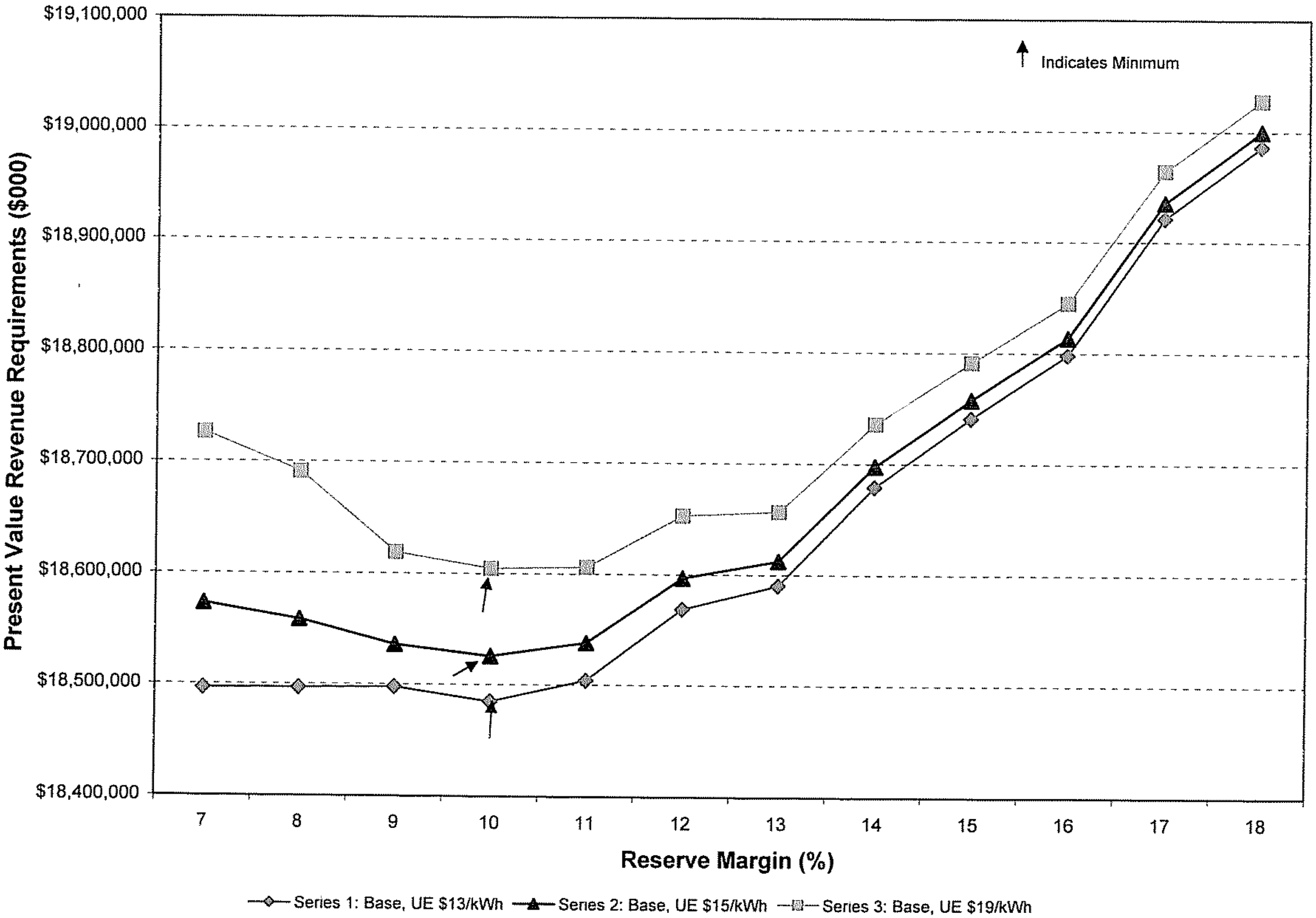


Figure 2

Base Availability; Base Load; No Market Purchase Available

Economically Equivalent PVRR vs Reserve Margin

Margins within 0.50% of Minimum Cost

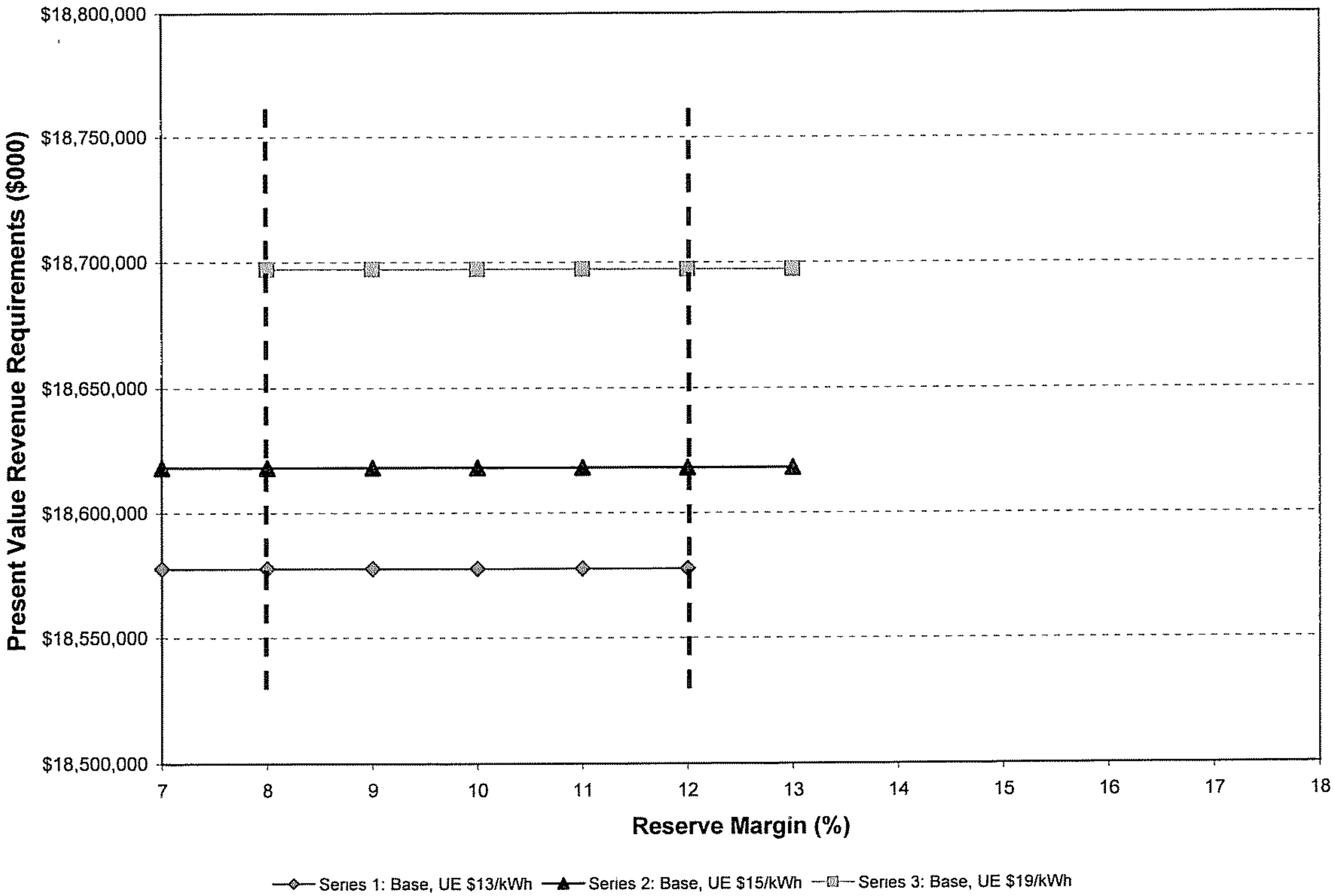


Figure 3

Series 1-12: No Market Purchase Available

Economically Equivalent PVRR vs Reserve Margin

Margins within 0.50% of Minimum Cost

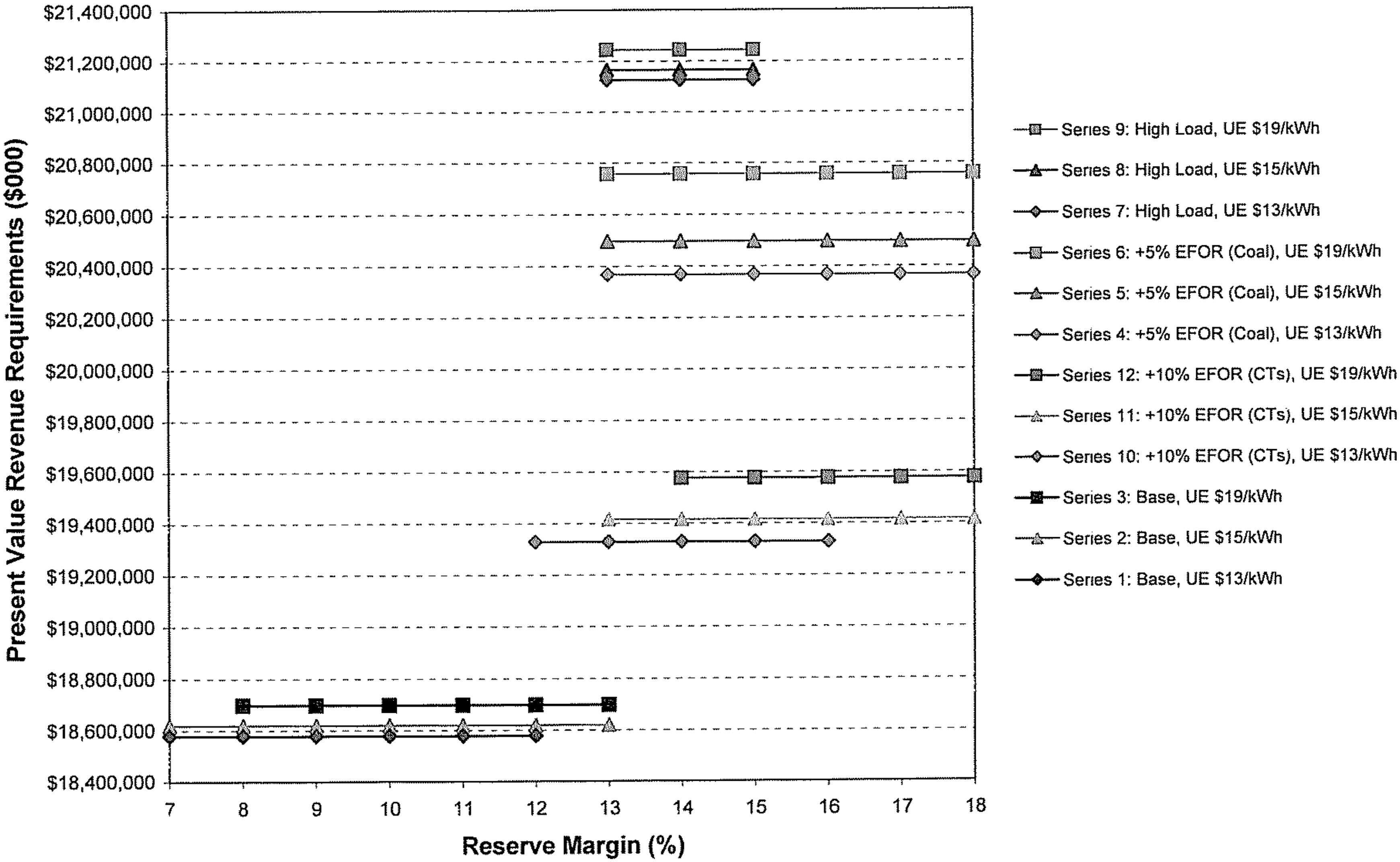


Figure 4a

Series 13a-24a: 204 MW Market Purchase Available

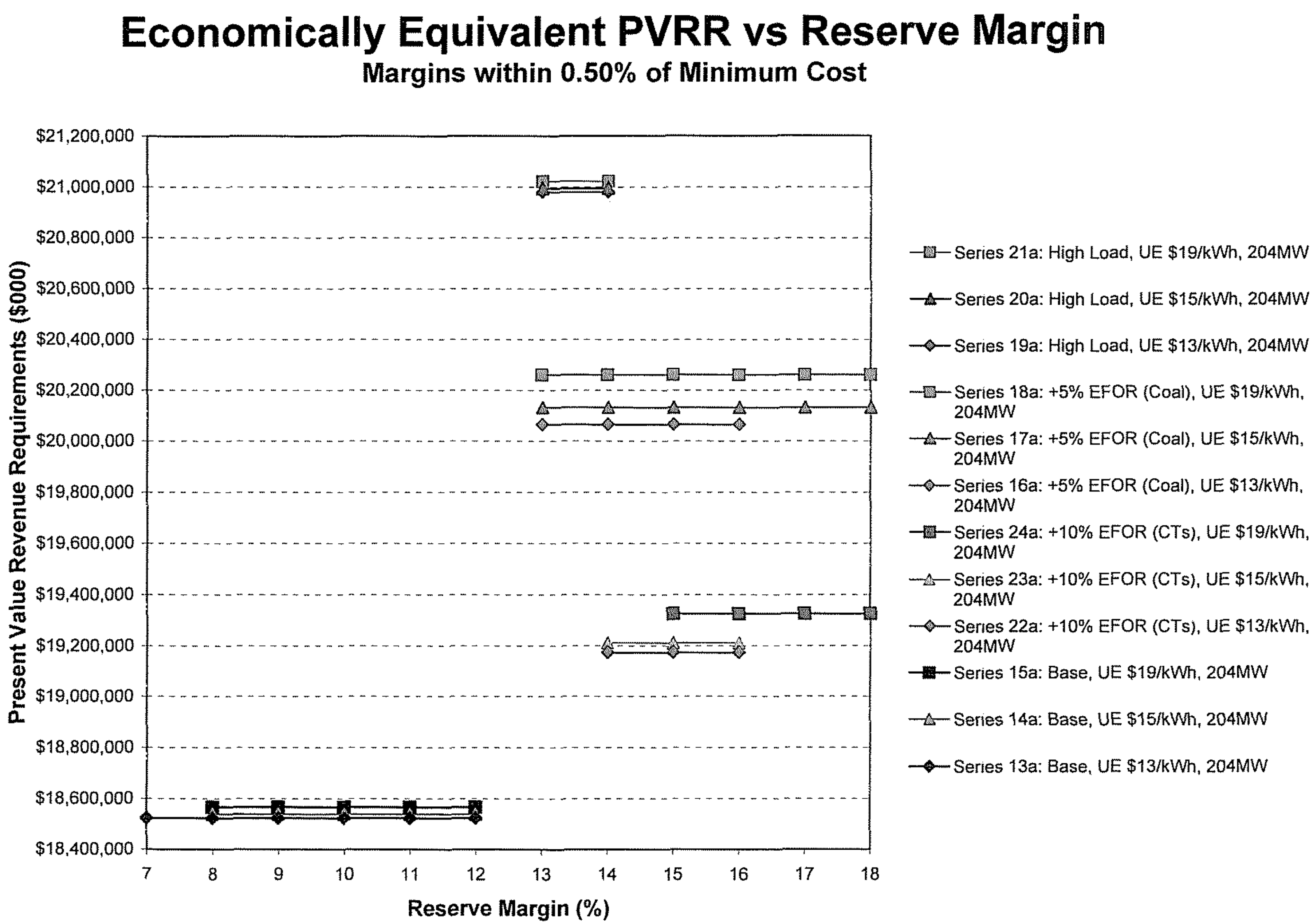


Figure 4b

Series 13b-24b: 304 MW Market Purchase Available

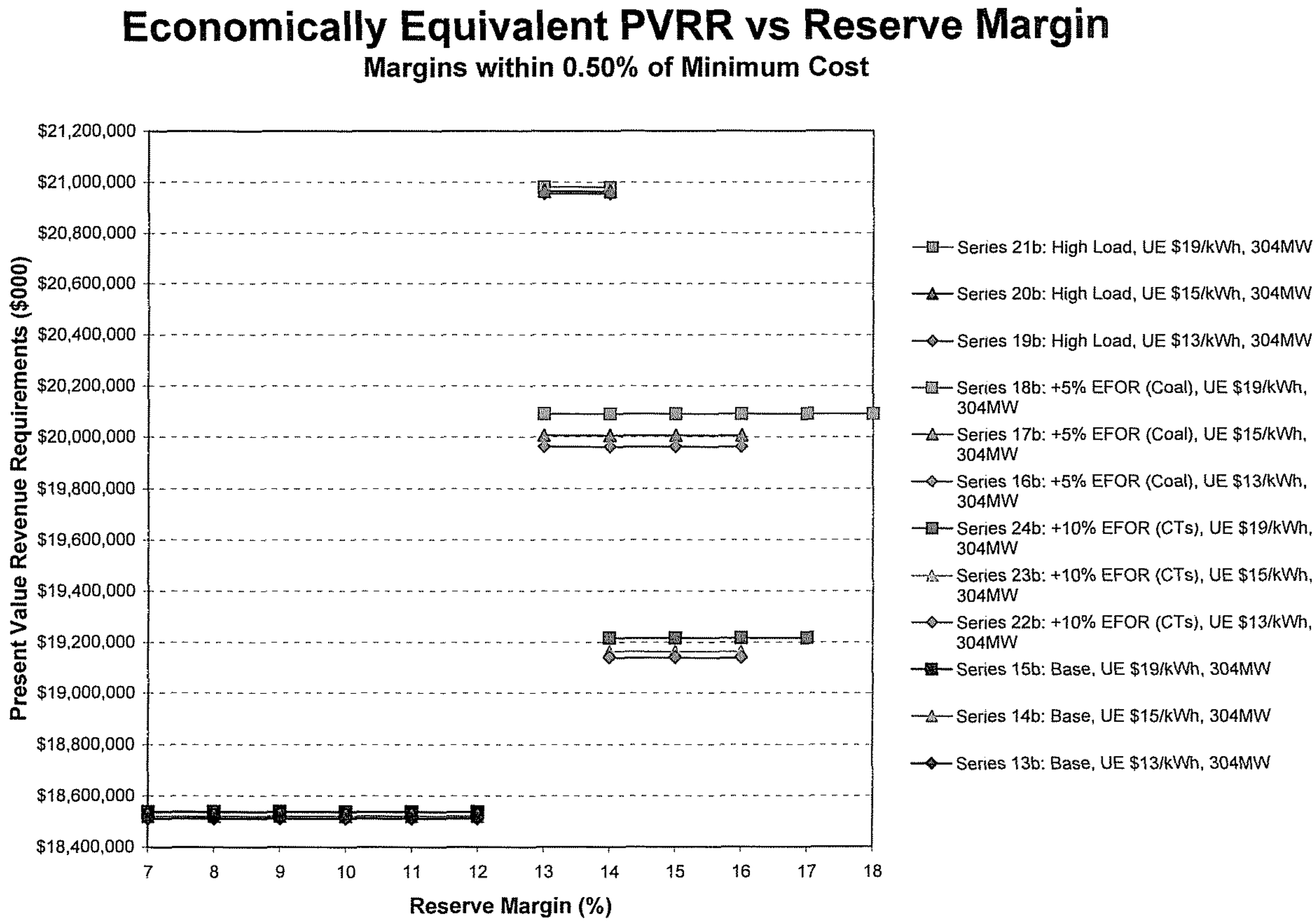


Figure 5

Series 1-12: No Market Purchase Available

Economically Equivalent PVRR vs Reserve Margin

Margins within 0.50% of Minimum Cost

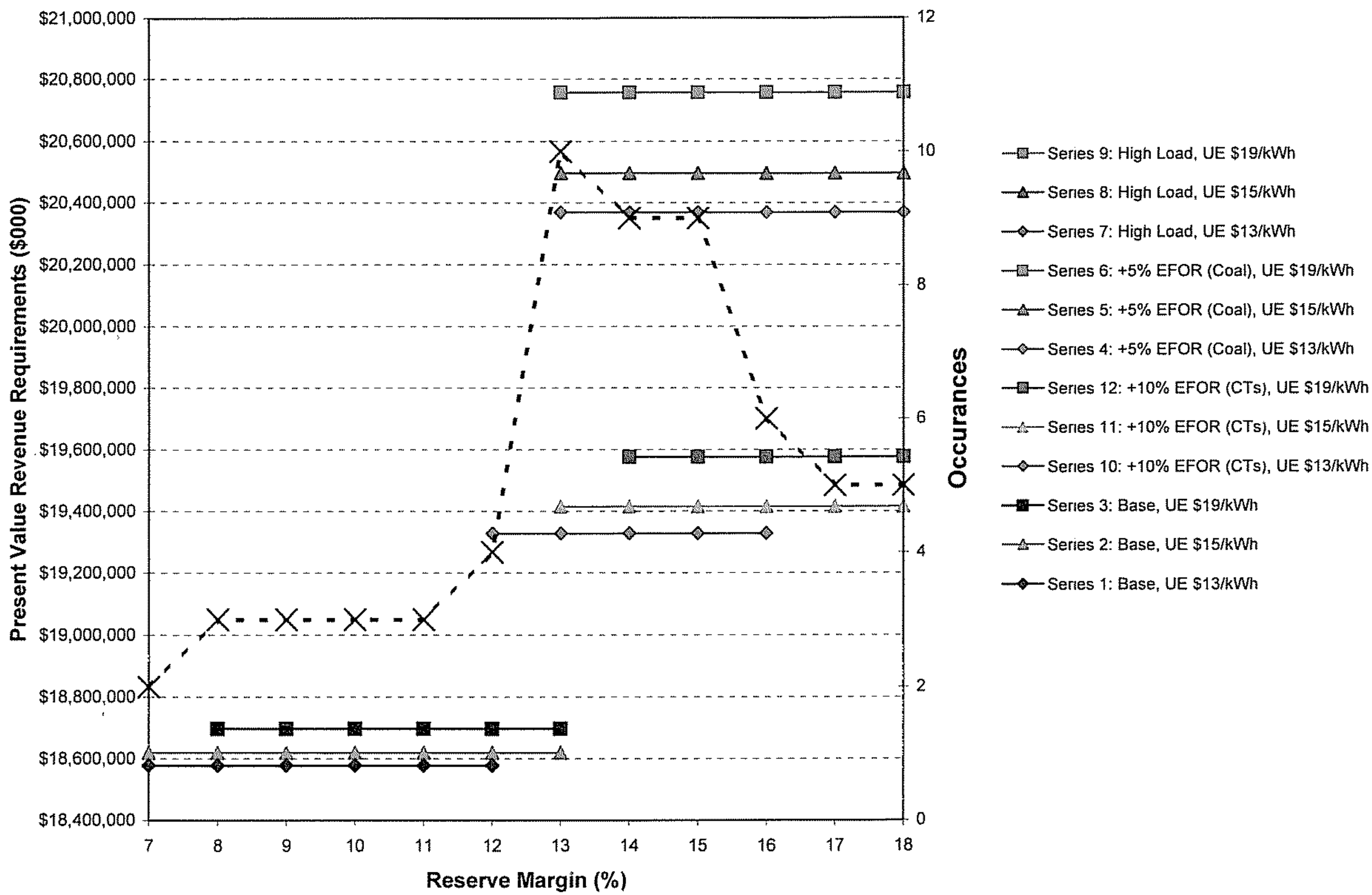


Figure 6a

Series 13a-24a: 204 MW Market Purchase Available

Economically Equivalent PVRR vs Reserve Margin

Margins within 0.50% of Minimum Cost

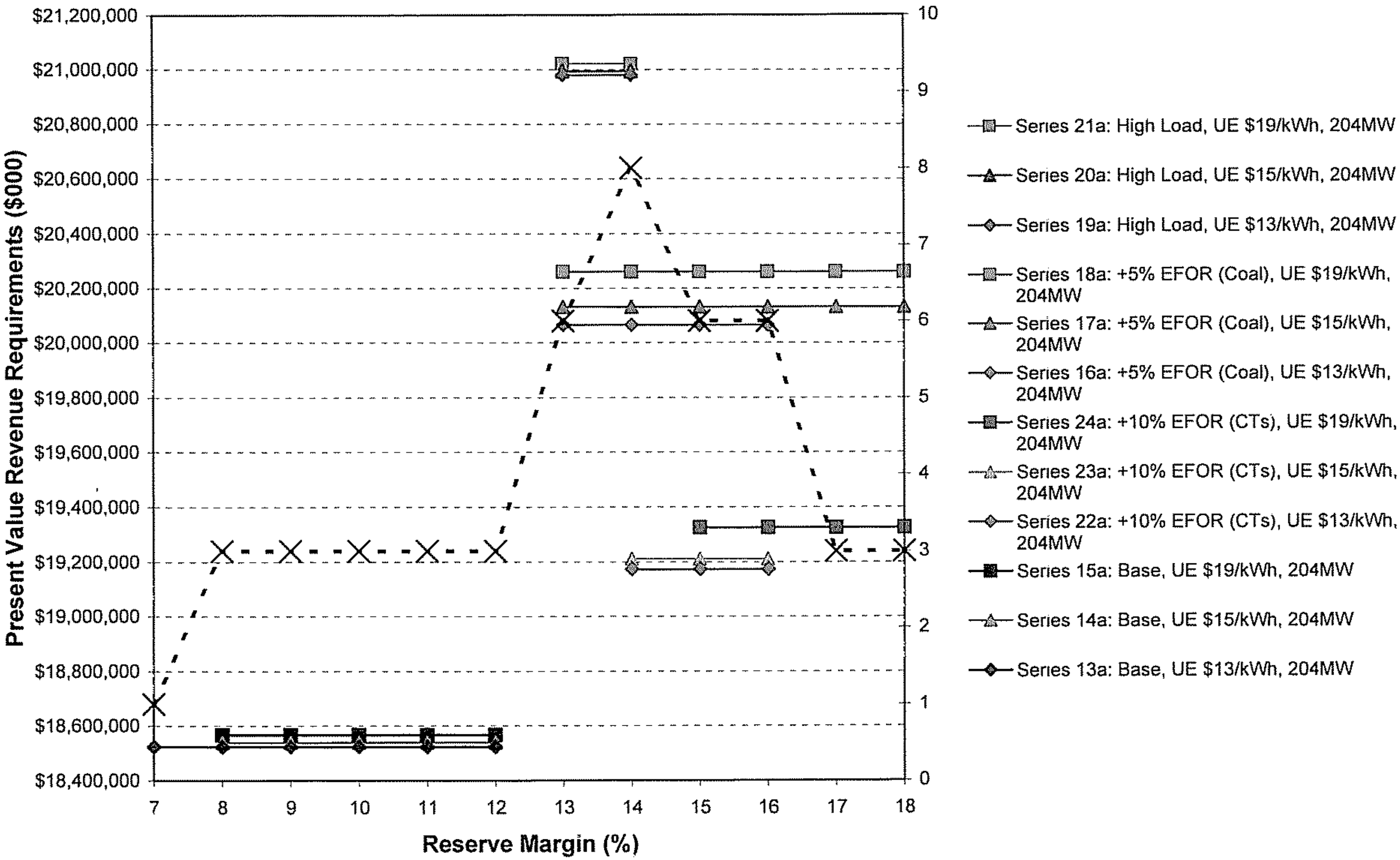


Figure 6b

Series 13b-24b: 304 MW Market Purchase Available

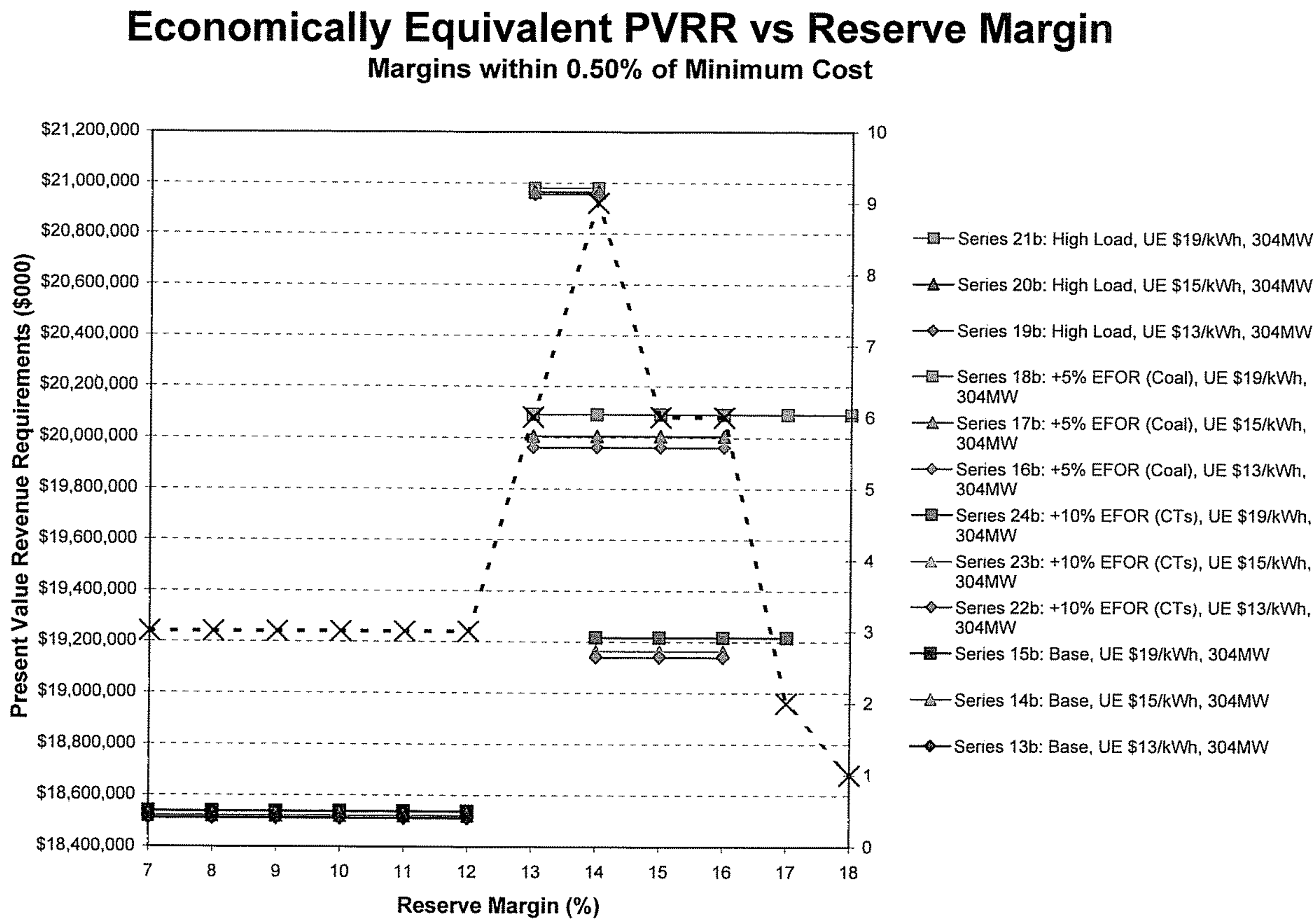
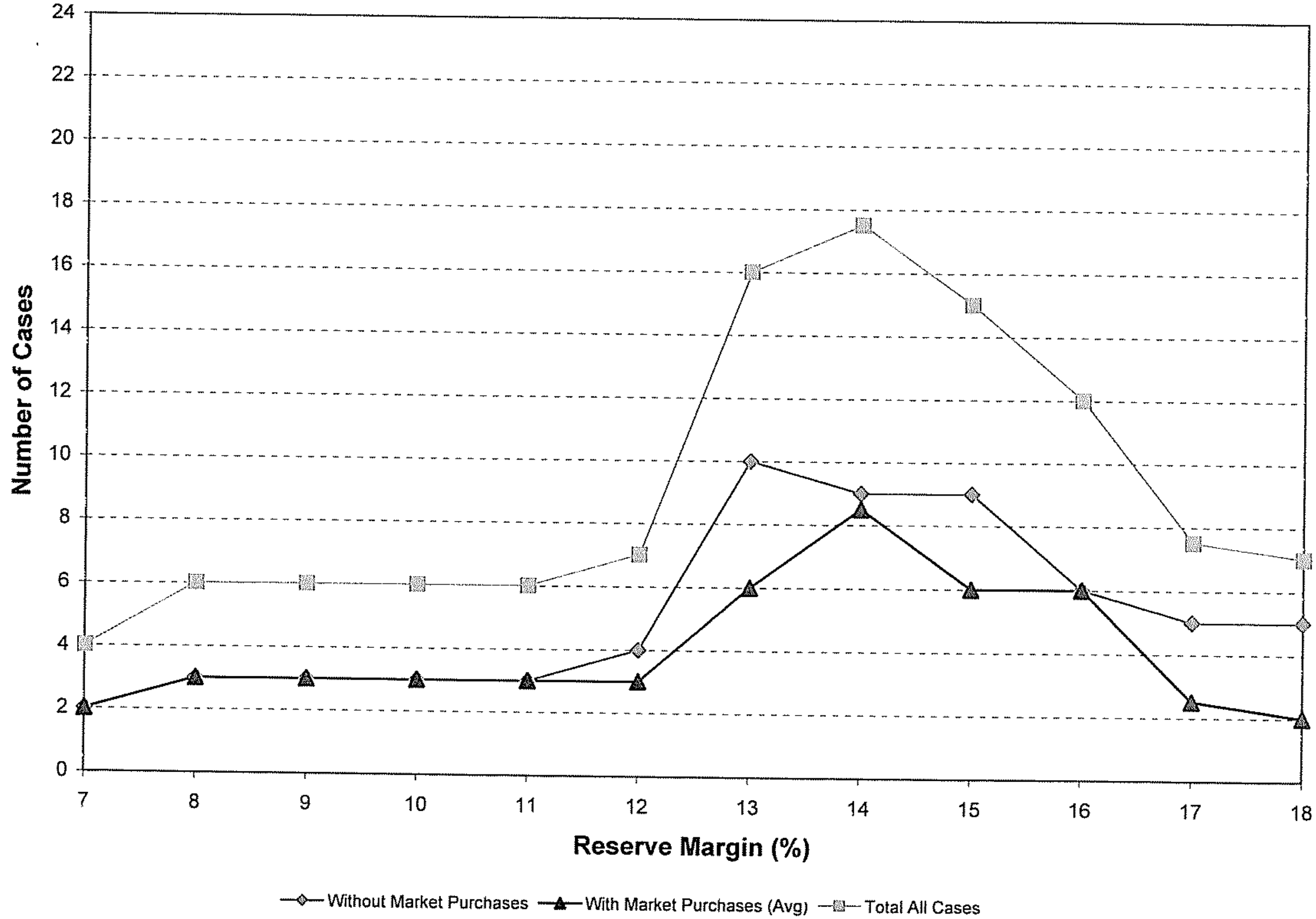


Figure 7
All Series

Economically Equivalent PVRR vs Reserve Margin
Margins within 0.50% of Minimum Cost



Update to the 2004 SO_2
Compliance Strategy
For

U.S.

Subsidiaries
Kentucky Utilities and
Louisville Gas and Electric

March 2008

Sulfur Dioxide Compliance Strategy

TABLE OF CONTENTS

Executive Summary

The purpose of this document is to update the 2004 SO_2 Compliance strategy including the cost estimates of the flue gas desulfurization ("FGD" or "scrubber") systems being built at Kentucky Utilities Company's ("KU's") Ghent and E.W. Brown stations, along with both quantitative and qualitative explanations that support the changes in cost. A Certificate of Public Convenience and Necessity ("CPCN") was granted and environmental cost recovery ("ECR") treatment approved by the Kentucky Public Service Commission ("Commission") on June 20, 2005 as Project KU-21 in Case No. 2004-00426. However, since Commission approval, and despite the efforts of KU to control capital costs, the cost estimate of the KU FGD program at the Ghent and E.W. Brown ("Brown") stations has increased from $658.9 million to $1,182.4 million, primarily driven by market prices for materials, equipment and labor, a significant scope increase for the ductwork routing of Brown units 1 and 2, and problems with the ID fans purchased for Ghent 3, Ghent 4 and Brown 3. In addition, it has been determined that the optimal construction schedule at Brown is one year longer than originally planned, with an in-service date in 2010.

The changes in capital cost, combined with the changes in the forecasted prices of SO_2 allowances and fuel necessitate a re-evaluation of the Companies' 2004 least-cost SO_2 compliance plan. On December 22, 2006, the Commission approved in Case No. 2006-00493 an application for changes to the Ghent FGD CPCNs that also included an update to the Ghent FGD project[1] in general and demonstrated that the addition of FGDs at Ghent continues to be the least-cost next step in environmental compliance. In April 2007, the Commission was presented with a further program update that demonstrated that the plan to construct an FGD on Brown Units 1, 2 and 3 continued to be economical. The purpose of this review is to evaluate whether the continued construction of wet FGD systems on Ghent Units 1, 3 and 4 and Brown Units 1, 2 and 3 and the simultaneous switching of these units to high sulfur coal is the least-cost plan for continued environmental compliance.

The scrubbing and fuel switching of the remaining units at Ghent and the construction of an FGD system at Brown in conjunction with purchasing SO_2 allowances on an as-needed basis, remains the least-cost SO_2 compliance plan. Though the addition of the FGD systems does not eliminate the need to purchase SO_2 allowances, the installation of environmental controls significantly reduces the need to purchase SO_2 allowances and is required for continued economical compliance with the SO_2 emission reduction requirements of the Clean Air Act Amendments of 1990. Over the 20-year analysis period, completing KU's FGD program should:

[1] *In the Matter of: Application of Kentucky Utilities Company to modify certain Certificates of Public Convenience and Necessity to construct ductwork for two flue gas desulfurization units at the Ghent power station*, Order dated December 22, 2006, finding 4 at Page 4 - "KU's updated PVRR analysis demonstrates that constructing three new FGDs at the Ghent Station continues to be the most cost-effective means for KU to comply with the relevant emission limits imposed by the CAIR."

1. Decrease the cost of SO_2 compliance by approximately $224 million in PVRR compared to not scrubbing Ghent 1 and by $99 million compared to not scrubbing the Brown units;
2. Delay exhausting the Companies' SO_2 allowance bank until 2021 and reduce the allowance shortfall to approximately 173,000 tons through 2028;
3. Increase fuel procurement flexibility;
4. Position the Companies for the SO_2 reduction requirements associated with the CAIR and future regulations targeting fine particulates and mercury; and
5. Increase typical residential customers' bills (1000 kWh/month) by $2.17/month, which equates to a 3.5% increase in ECR billing factor above KU's original estimate in Case No. 2004-00426.

The Companies will continue to construct an FGD for Ghent 4 in 2008, for Ghent 1 in 2009, and for Brown 1, 2 and 3 in 2010, while purchasing allowances on an as-needed basis and continuing the practice of environmental dispatching. The Companies will also evaluate additional environmental technologies for existing generating assets.

Background

The Clean Air Act Amendments of 1990 ("CAAA") sought to reduce the effects of acid deposition through a phased reduction in SO_2 and NO_x emissions from 1980 levels in the 48 contiguous states. Subsequently, the Clean Air Interstate Rule ("CAIR") was finalized by the Environmental Protection Agency in March 2005. CAIR requires significant additional reductions/limits in phases for NO_x and SO_2. With regard to SO_2, CAIR will reduce the allowable SO_2 emissions of Kentucky Utilities Company ("KU") and Louisville Gas & Electric Company ("LG&E"), (collectively "the Companies") by approximately 50% in 2010 and 65% in 2015.

In order to comply with these regulations, the Companies have constructed flue gas desulfurization ("FGD") systems on many of the fleet's coal-fired units (Ghent 1, Trimble County 1, Mill Creek 1-4 and Cane Run 4-6). By increasing the FGDs' SO_2 removal efficiency where economically feasible, LG&E is expected to meet CAAA Phase II requirements and provide a bank of SO_2 allowances. The Companies' joint planning process assumes that allowances banked by either utility can be utilized by either Company, thereby mitigating the combined Companies' exposure to the volatile SO_2 allowance market.

On December 20, 2004, the Companies filed with the Commission an application for a Certificate of Public Convenience and Necessity ("CPCN") and environmental cost recovery ("ECR") treatment for additional wet FGD systems on E.W. Brown ("Brown") units 1, 2 and 3 and the remaining un-scrubbed units at Ghent. On June 20, 2005, the Commission approved these projects under Project KU-21 in Case No. 2004-00426. Since that time, the Companies have proceeded with the construction of these projects. On November 16, 2006, the Companies filed an application for changes to the Ghent FGD CPCNs. That application, which also included an update on the Ghent FGD project in general, was approved as Case No. 2006-00493 on December 22, 2006. On April 26, 2007, the Commission was presented with a further program update of market impacts on the program total projected cost that demonstrated that the plan to construct an FGD on Brown Units 1, 2 and 3 continued to be economical. The purpose of this document is to provide a further update on KU's FGD program.

KU's total program expenditures and commitments to date at the Ghent station are $522 million of the total $682 million in capital, where commitments means KU has approved major purchase orders. The Ghent 3 FGD was placed into service in 2007 as planned and the Ghent limestone preparation facility is currently being commissioned as planned. The Ghent 4 FGD is nearing completion and will be commissioned in late spring 2008 as planned, and the Ghent 1 FGD is on schedule for the spring 2009 commissioning. The Ghent 1 FGD is the only construction activity that remains at risk of increasing costs due to market influences (i.e., labor and consumable materials prices). Although all major equipment and large purchase orders have been awarded on Ghent 1, a significant amount of field construction remains to complete the FGD.

KU's total program expenditures and commitments to date at the Brown station are $182 million of the total $500 million in capital, where commitments means KU has approved major purchase orders. Recent photographs of this construction can be found in **Appendix 1**. Since 2004, several factors impacting the cost of the Brown FGD project have changed, as discussed in the following section. The goal of this revised evaluation is to identify the current least-cost plan, given the impact of these new factors.

Significant Changes since 2004 Filing

Since the ***2004 SO_2 Compliance Strategy for Kentucky Utilities Company and Louisville Gas and Electric Company*** was finalized and submitted to the Commission in Case No. 2004-00426, significant changes have occurred that have impacted the following key drivers of least-cost environmental evaluations.

- SO_2 allowance market
- Fuel price forecasts
- FGD capital costs and the construction schedule for the FGD at Brown.

SO_2 Allowance Prices

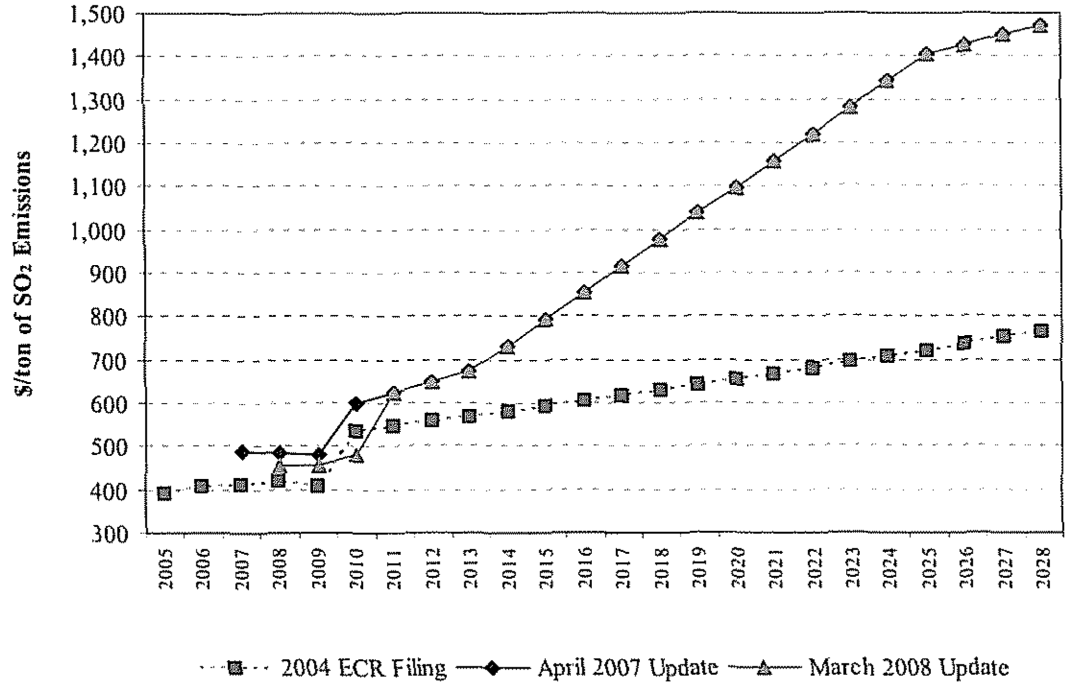
Previous testimony documented the change in expectations since the 2004 ECR Application regarding the higher cost of SO_2-related CAIR compliance over the longer term. [2] This expectation of higher SO_2 emissions allowance costs supports a strategy of FGD construction rather than purchasing allowances from the allowance market.

The following graph highlights the change in SO_2 allowance cost projections since the original ECR filing, as previously noted in the April 2007 update. Though the near-term price forecast has weakened slightly, the long-term forecast remains high. This robust projection of longer-term SO_2 allowance costs stems from a fuller understanding of the long-run marginal cost of complying – through retrofitting existing generation capacity – with a tightening constraint on physical emissions. The following recent developments in construction and commodity markets have intensified the challenge of meeting reduction targets for emissions:

- Construction costs for building FGDs have increased, due in part to materials, labor, and contractor availability issues;
- Higher natural gas prices encourage continuing reliance on coal-fired generation, slowing the trend in physical reduction of emissions and thereby adding upward pressure to the SO_2 allowance market;
- Similarly, plans for coal-fired generation capacity additions in excess of the level underlying the 2004 forecast add further upward pressure to the SO_2 allowance market; and
- Recent increases in the price-spread between low-sulfur and high-sulfur coals have created incentives to switch fuels, where operationally feasible, contributing to the challenge of reducing emissions and supporting higher prices for SO_2 allowances.

[2] See Case No. 2006-00493, Testimony of John P. Malloy (page 11, beginning line 6)

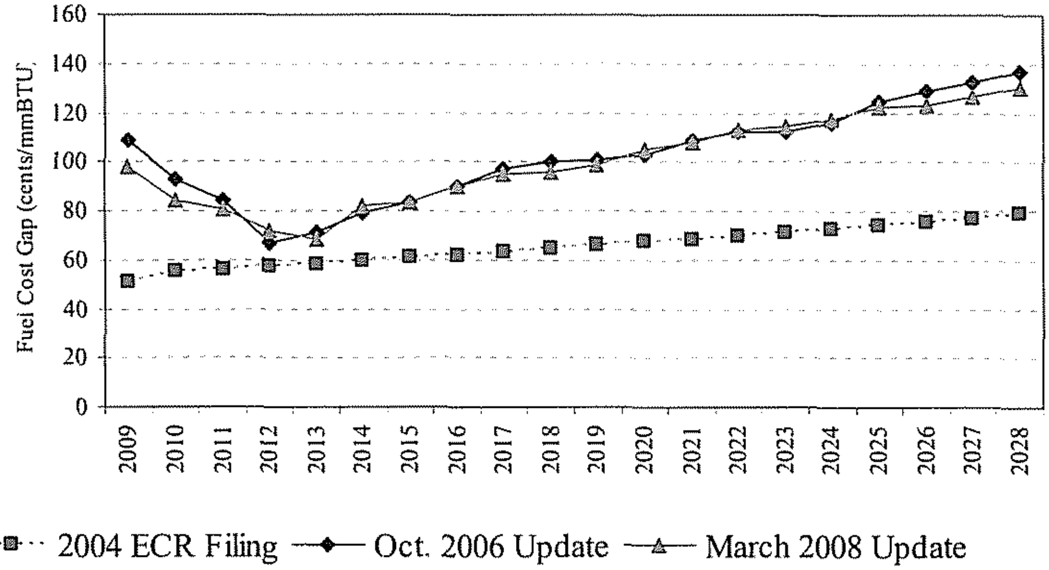
Forecasted SO_2 Emissions Allowance Prices



High and Low Sulfur Coal Prices

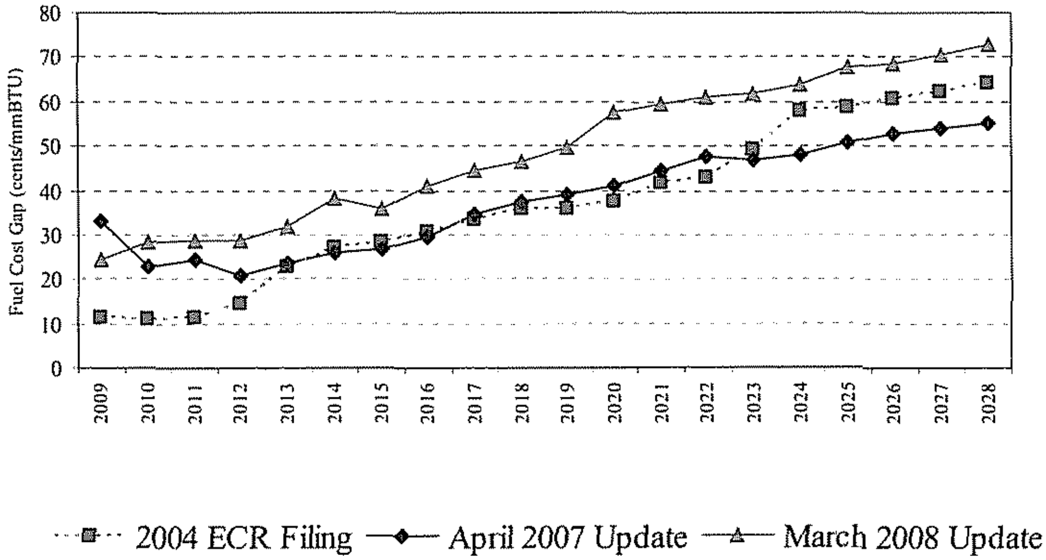
The most recent coal forecast for deliveries to the Ghent Station continues to show that high sulfur coal will be delivered at a significant discount to low sulfur coal. As shown in the figure below, a comparison of the current forecast to the forecast used in the October 2006 Update shows that the low/high sulfur fuel price gap has remained generally unchanged. When compared to the fuel price gap used in the 2004 ECR Filing (Case No. 2004-00426), the price gap has increased in the near term as a function of current market conditions and in the long term as a result of an expected depletion of low sulfur eastern compliance coal in Central Appalachia. This comparison also reflects a belief that this gap will decrease through 2013 as more FGDs are installed and some low sulfur coal demand shifts to high sulfur.

Fuel Price Gap Between Low and High Sulfur Coal at Ghent



In the April 2007 update, the near-term forecasted price for Eastern Kentucky low sulfur coal, which is currently burned at Brown, was shown to have increased relative to the forecast that was used in the 2004 ECR Filing (Case No. 2004-00426). This increase resulted in a significant increase in savings for 2009-2012 of 10-20 cents/mmBtu, when switching from low sulfur fuel to high sulfur coal. Due to recent transportation cost increases for low sulfur coal and decreases for high sulfur coal, the forecasted low/high sulfur fuel price gap and the resulting increase in savings is currently forecasted to continue through the study period as demonstrated in the following graph.

Fuel Price Gap Between Low and High Sulfur Coal at Brown



At both the Ghent and Brown stations, the increases in the forecasted low/high sulfur fuel price gaps continue to make physical compliance with CAAA and CAIR a more economic alternative than financial compliance through reliance on the allowance market. As the fuel price spread increases, fuel savings associated with scrubbing increase, which reduces the overall cost of compliance. As a result the Companies' customers receive the benefit of relatively lower fuel prices through the calculation of the monthly Fuel Adjustment Clause.

Capital Costs

Since Commission approval, and despite the efforts of KU to control capital costs during an unprecedented construction market, the cost estimate of the KU FGD program at the Ghent and Brown stations has increased from $658.9 million to $1,182.4 million. This increase is primarily driven by the extraordinary escalation of market prices during 2006 and 2007 for materials, equipment and labor. In addition to market influences, scope refinements have been required to account for geological conditions and vendor equipment issues unforeseen in the original project planning. The subsections below describe the significant market and scope drivers for Ghent and Brown.

Ghent

The original estimate performed in early 2004 to construct three wet FGDs on Ghent Units 1, 3 and 4 was $425 million. By October 2006, market impacts from unprecedented escalation of labor, equipment and material costs in the construction industry worldwide, as well as furthering of engineering on scope finalization had increased the projected costs to $525 million.

In April of 2007, the estimated cost to complete the Ghent project had increased to $569 million to capture the cost impacts of revised forecasts from project contractors. The contractor forecasts had been adjusted to reflect actual expenditures to date, change orders received, and revised forecasted trend to final costs that incorporated then-current market prices and labor retention incentives.

In addition to the increases in labor, equipment and material costs described above, the estimated completion cost for the Ghent project is being impacted by issues associated with the installation of the Flakt Woods' Induced Draft ("ID") Fans on Ghent 3. Ghent 3's ID fans have experienced substantial failures since being placed into service in 2007. Identical fans have been purchased for Ghent 4 and Brown 3 from Flakt Woods. Resolution of these fan issues is described in detail later in this paper; however, current projections of impacts to the Ghent budget are estimated at $30 million.

In summary, the cost impacts from market impacts, ID fan problems and final scope determinations are:

• **Market Impacts (Labor, Material, Equipment)**	**$109m**
• **ID Fans**	**$ 30m**
• **Scope Refinements (Limestone System/Balance of Plant)**	**$ 82m**
	$221m

The current estimate for the Ghent FGD program is $682 million.

Approximately 68% of the Ghent Program dollars have been spent to date. Unit 3's FGD was placed into service in 2007, while the Ghent Limestone Preparation Facility will be completed by April 2008 and Unit 4's FGD commissioned in June 2008. The Unit 1 foundation is complete, absorber tower and chimney erection is in progress, and all major equipment contracts and subcontracts have been awarded. Therefore, the remaining risks lie in the potentially greater escalation in the costs of construction labor, materials used during construction (excluding major purchase orders), consumables and rental equipment as compared to the escalation rates used in the estimate.

Ghent ID Fan Issues – In October 2006, the purchase order for the ID fans to be used at Ghent 3, Ghent 4 and Brown 3 was issued to a Swedish vendor, Flakt Woods. The fans were installed on Ghent 3 in May 2007. Problems such as motor oil leaks and motor bearing issues were experienced in June 2007. These issues were quickly followed by blades sticking, ID fan bearing failure, and galling of the main blade drive shaft. To date, the fans on Ghent 3 have caused numerous outages and de-rate incidents. The fans continue to be unreliable and continuing problems are anticipated going forward. Though the Company's preference for long-term resolution is to resolve the bearing failures, a realistic forecast includes the need to replace the Flakt Woods fans with new fans. Implementation of either option will impact project costs.

As a result of lessons learned on Ghent Unit 3's ID fans, KU re-bid replacement fans for Ghent 3, Ghent 4 and Brown 3. The short-term resolution for Ghent 4 to avoid the unreliability of the Flakt Woods fans is to use the existing ID Fans for the FGD start-up in 2008. Unit 4 will experience a 5-10% de-rate at maximum capacity as a result of using the existing lower capacity fans; however, unit reliability will be maintained and fuel savings and allowance bank preservation will approach planning levels as the FGD goes in service. The derate will only occur when the unit is required to generate within 5%-10% of its maximum capacity.

Long-term options for the Ghent 3 ID fans include resolving the bearing failure issues and implementing those solutions on the Unit 4 fans, or replacing the Ghent 3 fans with new fans. The current forecasted cost to completely resolve the ID fan issues includes $30 million to replace the existing Flakt Woods fans with fans from other vendors.

Brown

The original November 2004 estimated cost for the Brown FGD Program was $235 million. This estimate was increased to $359 million in April 2007 primarily due to increases on ductwork, market impact for materials and labor and changes to the limestone system.

Current estimates for the Brown FGD total $500 million. Primary drivers in the cost increases remain material, equipment and labor cost escalations, as well as finalization of scope and resolution to the ID fan issues on Brown 3.

In summary, the cost impacts from market impacts, ID fan problems and final scope determinations are:

• **Market Impacts (Labor, Material, Equipment)**	**$116m**
• **Ductwork and ID Fans**	**$ 74m**
• **Scope Refinements (Limestone System/Balance of Plant)**	**$ 54m**
	$244m

Currently the Brown FGD Program has $182 million committed or 36% of the estimated total cost of $500 million. The FGD portion of the project is 37% committed with the FGD foundations, technology and module under construction and awarded through lump sum contracts. The balance of plant scope is 95% committed and nearly completed, including the completion of the warehouse, training building and fire suppression system. The limestone system is 24% committed and includes use of the original Ghent limestone equipment to control overall impacts to the Brown cost. The majority of major equipment has been committed for all scopes listed above. The most significant risks continue to be escalation of construction labor, materials used during construction (excluding major purchase orders), consumables and rental equipment beyond those estimated. The contractor has included in the current estimate $33 million in contingency to account for potential escalations.

Brown's Schedule Change - The Brown FGD was originally expected to be placed in service in 2009, with a tie-in to Unit 3 in the spring of 2009 and to Units 1 and 2 during the fall of 2009. The Brown FGD is now expected to be in service in 2010, with a Unit 3 tie-in during the spring of 2010 and a tie-in to Units 1 and 2 during the fall of 2010. Contributing factors to this altered schedule are the contractor's revised labor estimate and the receipt of ID fan delivery lead times quoted in the ID fan replacement bids. Lead times in the Brown ID fan bids indicated 60 weeks from the date of order, making the original in-service date impossible. This one-year extension will allow the Company greater flexibility to optimize the construction plans, as well as to implement alternative contracting plans where feasible.

Brown Station's Unique Characteristics - A significant driver in Brown's overall cost is the unique features at Brown that are significantly different from the Ghent FGD projects as well as most other FGD projects throughout the United States.

> Absorber - Having multiple boiler units at the Brown Station served by a single FGD absorber module necessitates having a larger absorber vessel and equipment for associated systems, as compared to those for the single Ghent units. The increased cross-sectional area of the larger absorber drives an increase in the quantities of mist eliminator panels, mist eliminator wash nozzles and piping, recycle nozzles and piping and in heavier support structure for those components. The Brown FGD also has an additional recycle spray header level and associated equipment to scrub the additional units.
>
> Duct - The Brown Units are confined on three sides by existing roads, railroads, fuel yard, cooling towers and associated piping, and overhead electrical lines. Due to the lack of available space, the FGD was located on the open side, next to Unit 3. This location was the only viable location; however, it required a long duct run from Brown 1 and 2. The additional ducting results in additional costs for expansion joints, support structure, foundations, and insulation and lagging. This additional cost is magnified by the fact that Brown 1 and 2 are arranged inverted to Unit 3, thus requiring longer duct length. Additional cost beyond a single FGD unit is caused by additional dampers and controls, which are necessary to isolate each unit to optimize Station operations.
>
> Site Topography and Geology - In order to make room for the FGD, the existing training building and warehouses in the area had to be demolished and replaced. Then, the area available for the FGD and limestone systems required extensive blasting and excavation to level the limestone hillside. Upon completion of the blasting and excavation, Karst features that were known to exist were investigated and final scoping of the excavation, geology remediation and foundation designs were finalized. This final scoping was not possible until final FGD sizing, location and excavation were completed.
>
> Terrain - The Brown terrain results in more difficult excavation and increased excavation quantities. The shallow limestone rock requires blasting for deep foundation excavations, as well as frequent hoe-ramming or rock trenching for shallow excavations. The terrain and rocky soil conditions result in high unit

rates for underground utilities, foundations, as well as the electrical grounding grid when compared to similar scopes at Ghent.

Balance of Plant (BOP) - The lack of existing capacity for utilities such as service water, fire protection systems, compressed air and quench water cause the project to have to upgrade existing systems or install new utility systems. Final impacts to the balance of plant systems are now known. In addition to these balance of plant scopes, the handling and dewatering of the gypsum, produced as an FGD process byproduct, will be a new system at Brown where Ghent's existing system required only modifications.

Economic Analysis

The June 2005 Order[3] issued by the Commission approving both the CCN and ECR cost recovery of the proposed FGD projects at the Companies' Ghent and Brown stations was based on supporting analytics that the FGDs represented the most reasonable least-cost plan for continued environmental compliance. A revised present value revenue requirements ("PVRR") evaluation of the economics of constructing FGDs at Ghent and Brown has been completed with the previously mentioned changes regarding fuel prices, project timing, and capital costs. The purpose of this updated evaluation is to identify the current least-cost plan, given the revised forecasts. To do so, individual alternatives were compared to the Base Case which represents the Companies' current plan to complete two FGDs at Ghent and build one FGD for all three Brown units (in-service in 2010). In all cases, only a wet FGD with a 98% SO_2 removal efficiency is considered.

The Cases were evaluated using the PROSYM™ detailed hourly production costing computer model and the Strategist Capital Expenditure and Recovery module. Used together, these tools have the capability to simulate the hourly production costs (e.g., fuel, fixed and variable operation and maintenance, and emissions costs) and to quantify the revenue requirements impact associated with each capital project. **Appendix 2** contains economic and forward-looking assumptions used in this analysis. Each alternative was independently evaluated within PROSYM™ using the Companies' base price forecasts for fuel and SO_2 and NO_x allowances and the estimates for capital construction costs as previously discussed.

The total PVRR for each Case has been categorized into four areas:

1. Production Costs represent the revenue requirements associated with fuel, fixed and variable operation and maintenance expenses and purchased power expenses.
2. NO_x Allowances represents the revenue requirements associated with the use of any NO_x allowances less the sale of excess NO_x allowances. Note that NO_x

[3] In the Matter Of: ***The Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity to Construct Flue Gas Desulfurization Systems and Approval of its 2004 Compliance Plan for Recovery by Environmental Surcharge, Case No. 2004-00426***, Final Order dated June 20, 2005.

emission levels are quantified because the retrofitting of an SO_2 control technology impacts how that unit is dispatched, which in turn, affects NO_x tonnage emissions.

3. SO2 Allowances represents the revenue requirements associated with the use of any SO_2 allowances less the sale of excess SO_2 allowances.
4. Incremental Capital Costs represents the revenue requirements associated with any capital expenditures for the Case less the revenue requirements associated with any sunk capital costs.

The value of SO_2 and NO_x allowances used are calculated as the net annual difference between the Companies' allocated and used allowances at the respective market prices, thereby including the economic value of using banked allowances. It is assumed that unlimited allowances are available from the market at the forecasted allowance price.

Ghent Evaluation

In order to identify the least-cost compliance strategy at Ghent, the Base Case was compared to a "Without Ghent 1 FGD Case" in which the FGD at Ghent 4 is completed as scheduled in May 2008 and the FGD at Ghent 1 is not completed. No further construction is assumed to take place and current contractual commitments are fully satisfied, resulting in a nominal capital expenditure savings of $52.2 million. The Brown FGD is assumed to be completed in both cases.

SO_2 Compliance Strategies Evaluated for Ghent

Case	Construct FGDs at	Ghent FGD Capital Cost[1] ($M)
Base Case	Ghent 1,3,4	$682.5
Without Ghent 1 FGD	Ghent 3,4 only	$630.3

[1] *Total FGD Capital Costs are the sum of annual (nominal dollars) construction expenditures.*

The Ghent Case Summary table below summarizes the four main cost categories and compares the resulting PVRR of the "Without Ghent 1 FGD Case" to that of the Base Case. The table is a summary of the annual data contained in **Appendices 3 and 4.** **Appendix 3** presents the annual results of each Case compared to the Base Case while **Appendix 4** details the SO_2 emissions associated with each Case.

Ghent Case Summary

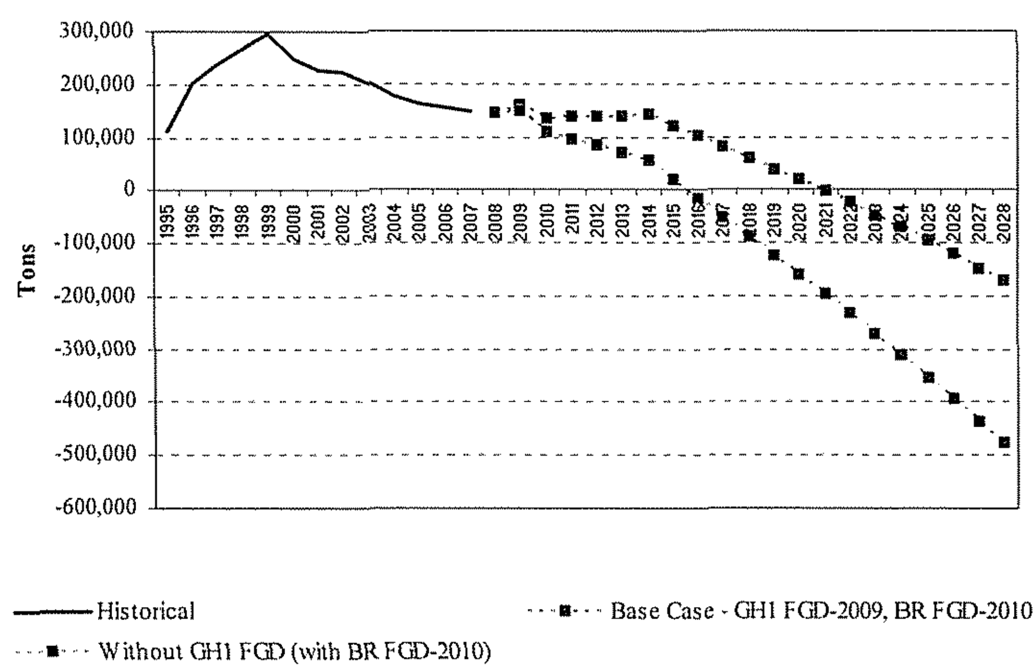
Case	Production Cost	NO_x Allowances	SO_2 Allowances	Incremental Capital Cost	Total PVRR	Incremental Cost over Base
Base Case-Ghent 1 FGD in 2009	13,810	-1	129	64	14,001	Base
Without Ghent 1 FGD	13,965	3	258	0	14,225	224

2008 PVRR $ millions: Production & allowance costs estimated 2008-2028: Both cases include Brown FGD in 2010: 8.02% discount rate

As can be observed in the table above, the approved current plan (Base Case) to build an FGD on Ghent 1 with an in-service date of 2009 (in addition to completing the FGD on Ghent 4 in May 2008) remains the least-cost option at Ghent by a sizeable margin. This plan results in a PVRR that is $224 million lower than the "Without Ghent 1 FGD" option. Though the "Without Ghent 1 FGD Case" requires less capital, the savings are not sufficient to offset the resulting increased production and SO_2 allowance costs.

Beginning in 2000, it became necessary for the Companies to begin using banked SO_2 allowances for compliance. As the figure below shows, the Companies' combined banked SO_2 allowances, once in excess of 297,000 tons (during 1999) had declined to just over 147,000 tons by year-end 2007. The number of banked credits for the Base Case is projected to be fully depleted before the end of 2021. The Base Case delays the need to purchase SO_2 allowances by five years compared to cancelling the Ghent 1 FGD, which requires an additional 304,000 tons over the study period.

SO_2 Allowance Bank
(Combined Company)



Brown Evaluation

In order to identify the least-cost compliance strategy at Brown, the Base Case which includes building one FGD for all three Brown units with an in-service date in 2010, was compared to a one-year delay scenario (in-service in 2011). In addition, a "Without Brown FGD" Case was included in which the FGD would not be completed at the Brown station and no further construction would take place, although the Company would satisfy current contractual commitments at an estimated capital expenditure of $174 million, plus $120.2 million for the ash pond. The Ghent FGDs are assumed to be completed in all cases. The table below summarizes the three SO_2 compliance strategies at Brown that were evaluated in this update.

SO_2 Compliance Strategies Evaluated for Brown

Case	Construct FGD at	In-Service Date	Brown FGD Capital Cost[1] ($M)	Ash Pond Cost[1] ($M)
Base Case	Brown Units 1,2,3	2010	$499.9	$153.0
Delay Case	Brown Units 1,2,3	2011	$533.5	$156.2
Without Brown FGD	None (Purch. Allowances)	n/a	$174.0	$120.2

[1] *Total FGD Capital Costs and Ash Pond Costs are the sum of annual (nominal dollars) construction expenditures*

The Brown Case Summary table below summarizes the primary cost categories and compares the resulting PVRR of each Case to that of the Base Case. The table is a summary of the annual data contained in **Appendices 3 and 4**. **Appendix 3** presents the annual results of each Case compared to the Base Case while **Appendix 4** details the SO_2 emissions associated with each Case.

Brown Case Summary

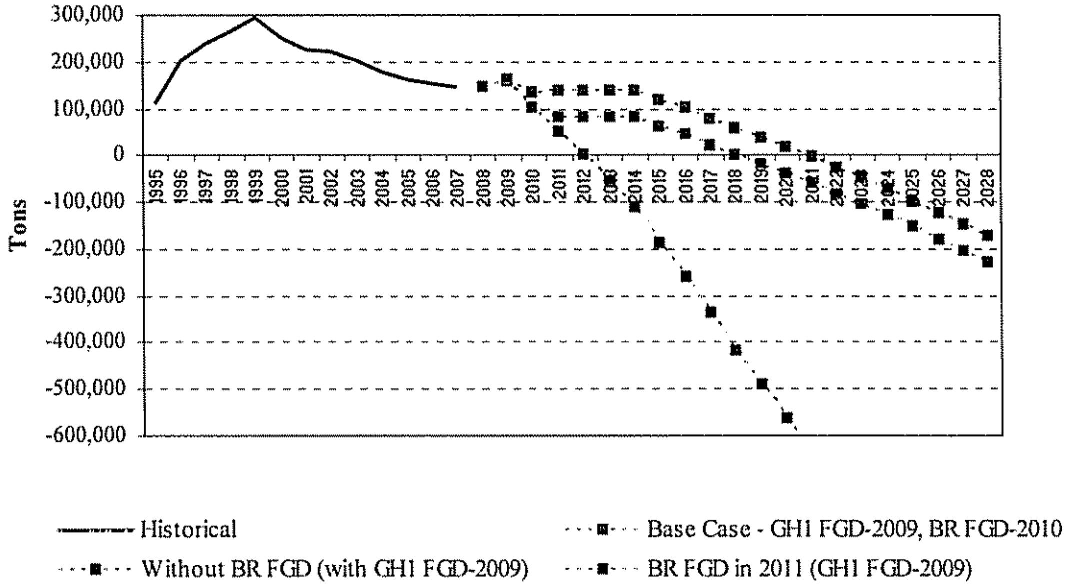
Case	Production Cost	NO_x Allowances	SO_2 Allowances	Incremental Capital Cost	Total PVRR	Incremental Cost over Base
Base Case - BR123 FGD in 2010	**13,810**	**-1**	**129**	**552**	**14,490**	**Base**
Delay Case - BR123 FGD in 2011	13.805	-1	155	589	14,547	58
Without Brown FGD	13,885	-3	567	140	14,588	99

2008 PVRR $ millions: Production & allowance costs estimated 2008-2028; All cases include Ghent 1 FGD in 2009; 8.02% discount rate
Incremental capital cost includes the Brown ash pond

As can be observed in the table above, the current plan (Base Case) to build an FGD on Brown Units 1, 2 and 3 for an in-service date of 2010 is the least-cost option and results in a PVRR that is $58 million lower than the second least-cost option of completing the FGD in 2011. Though the "Without Brown FGD" Case requires less capital, the savings are not sufficient to offset the resulting increased production and SO_2 allowance costs, resulting in a PVRR that is $99 million higher than the Base Case.

As shown in the figure below, the Base Case delays the need to purchase SO_2 allowances by two years compared to the second least-cost Case (Delay Case – Brown FGD in 2011) which requires an additional 56,000 tons over the study period. The "Without Brown FGD" Case necessitates purchasing SO_2 allowances starting in 2012 and significantly increases SO_2 allowance market exposure by requiring 1.2 million total tons to be purchased over the next twenty years.

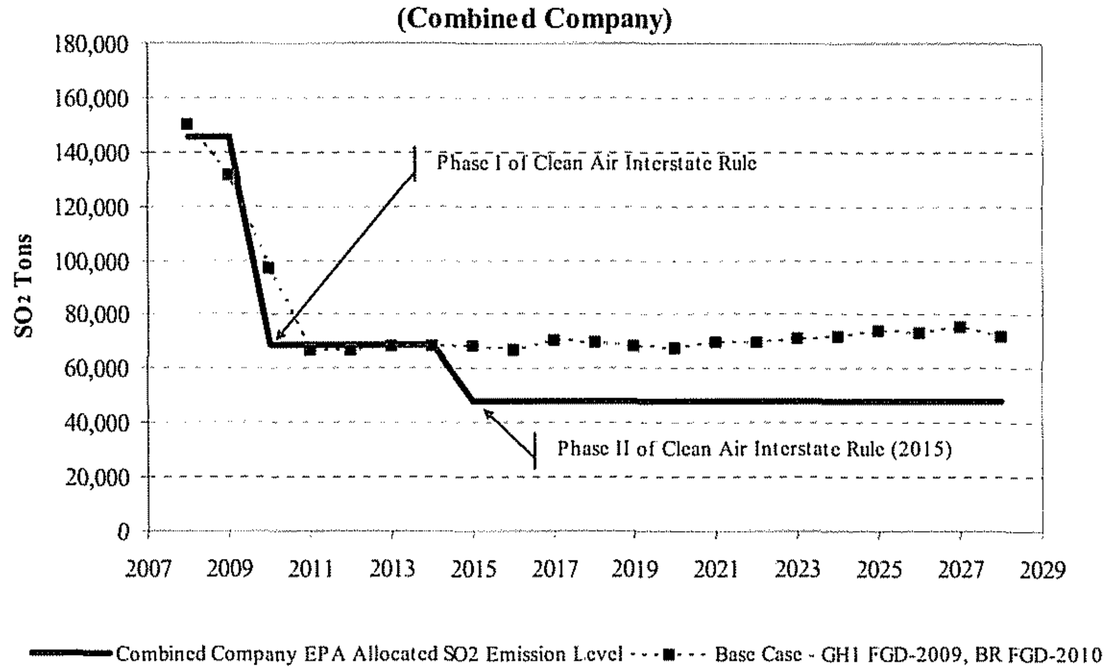
SO_2 Allowance Bank
(Combined Company)



Discussion of Base Results

Each of the FGD build alternatives allows the postponement of the Companies' initial SO_2 allowance purchases. However, no alternatives allow for all of the SO_2 allowances required to comply over the twenty-year study period to be provided without purchasing allowances from the SO_2 allowance market. With the Base Case, exposure to the volatile SO_2 market is mitigated, but the market is still relied on for approximately 173,000 tons to supply the allowance shortfall over the period. The figure below illustrates the difference between the Companies' projected annual Base Case SO_2 emissions and the Companies' anticipated annual allowable emission level. The difference between SO_2 emissions and allowance allocations is currently being covered by banked allowances. The implementation of Phase II of CAIR significantly widens the gap between the allowable emission level and forecast emissions. Though the annual allocation of SO_2 allowances does not change with the implementation of Phase I and Phase II of CAIR, allowed emission levels in tons are reduced dramatically. This is because the CAIR requires, beginning in 2010 (Phase I), that each ton of emitted SO_2 be matched with two allocated or purchased SO_2 allowances. The implementation of Phase II of the CAIR further limits allowed emissions by requiring that each ton of emitted SO_2 be matched with three allocated or purchased SO_2 allowances.

Annual SO_2 Emissions and Allocated Emissions Level



Least-Cost Plan and SO_2 Compliance Strategy

Completing wet FGDs on Ghent 4 in 2008 and on Ghent 1 in 2009 in addition to a wet FGD system for Brown 1, 2, and 3 for service starting in 2010 is the current least-cost Case. Since the original filing, significant increases in the project's capital costs and a one-year long construction schedule at Brown have been partially offset by increases in SO_2 allowance price forecasts and the near-term price gap between high and low sulfur coal.

Without scrubbing at Brown, the Companies face a significant SO_2 allowance shortfall of over 1.2 million tons through 2028. Not scrubbing at Ghent 1 exposes the Companies to a shortfall of 475,000 SO_2 tons. Though the Base Case allows the shortfall of allowances to be economically mitigated, future allowance purchases of 173,000 tons are still expected.

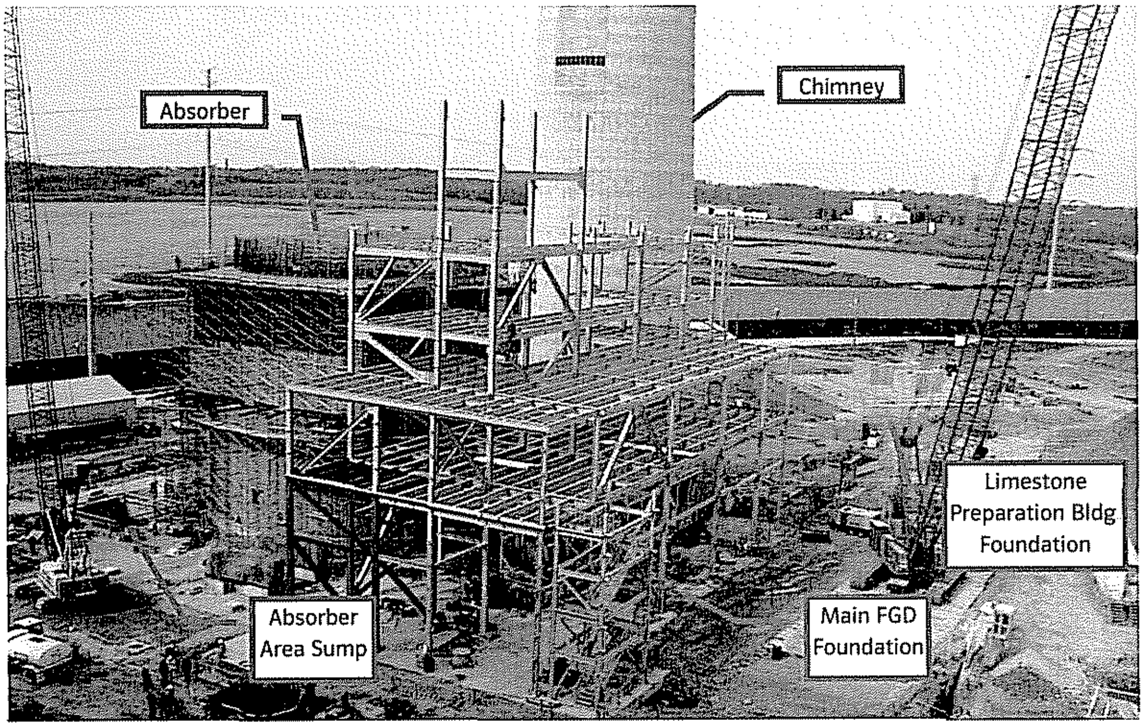
Scrubbing and fuel switching of the remaining units at Ghent and the units at Brown, in conjunction with purchasing SO_2 allowances on an as-needed basis, is the least-cost SO_2 compliance plan with the following impacts projected over the 20 year analysis period:

1. Decreases the cost of SO_2 compliance by approximately $224 million in PVRR compared to not scrubbing Ghent 1 and by $99 million compared to not scrubbing the Brown units;
2. Delays the depletion of the Companies' SO_2 allowance bank until 2021 and reduces the allowance shortfall to approximately 173,000 tons through 2028
3. Increases fuel procurement flexibility;

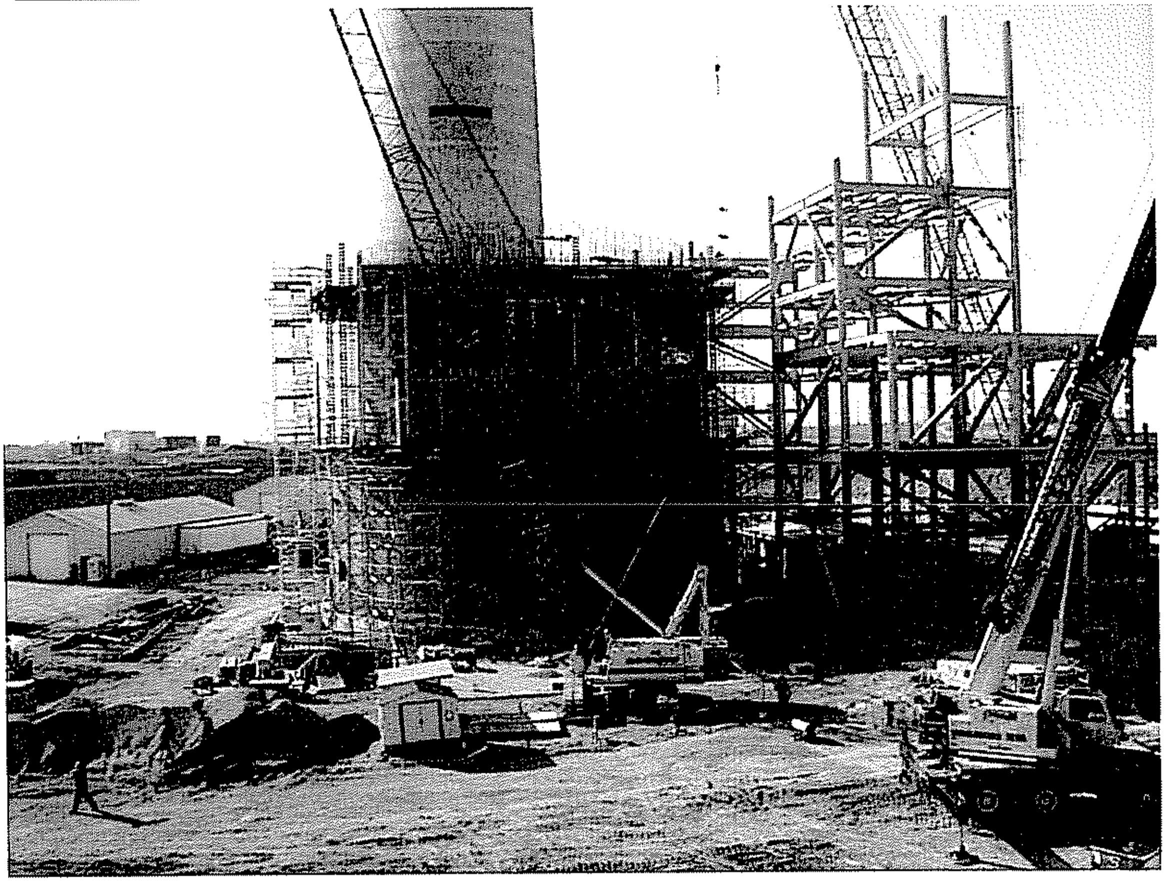
4. Positions the Companies for the SO_2 reduction requirements associated with the CAIR and future regulations targeting fine particulates and mercury; and
5. Increases typical residential customers' bills (1000 kwh/month) by $2.17/month, which equates to a 3.5% increase in ECR billing factor above KU's original estimate in Case No. 2004-00426.

Overall, nothing has occurred that has changed the Companies' strategic decision to build FGDs in order to comply with SO_2 regulations. Therefore, the Companies plan to move forward with the implementation of the Base Case: (1) to construct an FGD for Ghent 4 in 2008, for Ghent 1 in 2009, and for Brown 1, 2, and 3 in 2010; (2) to purchase allowances on an as-needed basis; and (3) to continue the practice of environmental dispatching. Additionally, the Companies will evaluate additional environmental technologies for existing generating assets.

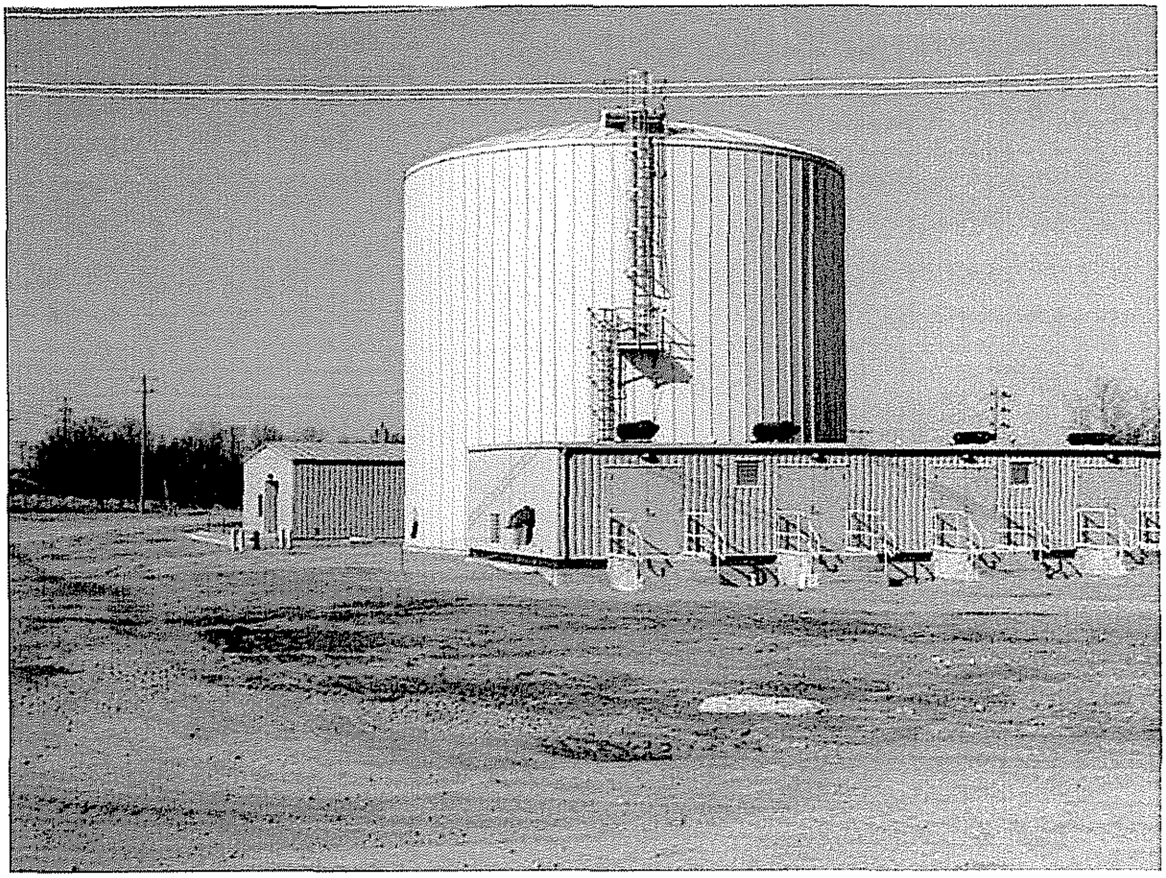
Appendix 1



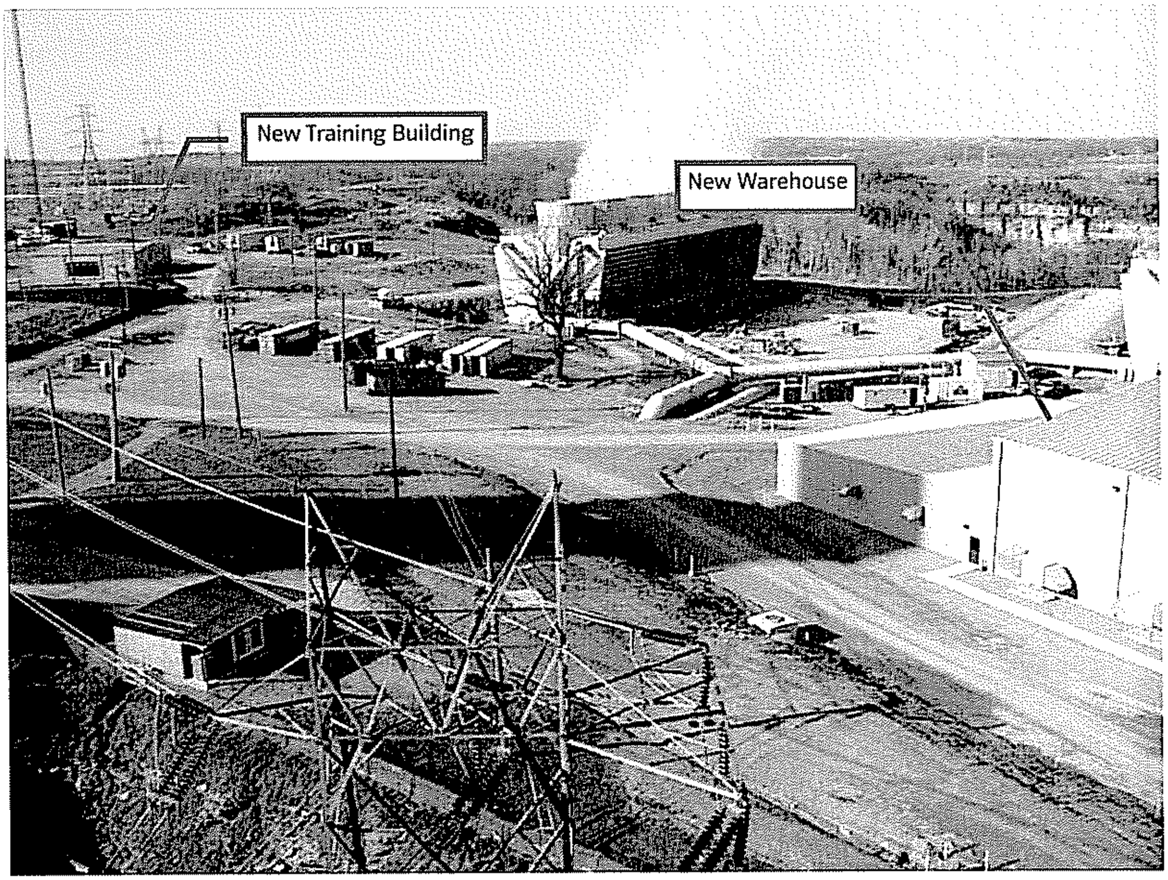
The picture above, of the Brown construction, (dated 3/14/2008) shows the main FGD foundation with the recycle pumps sitting under the partially erected steel structure next to the absorber. The absorber area sump is located in the photo immediately to the left of the absorber. The partially erected steel structure will provide support and access for the piping that will be installed in the area above the recycle pumps. The chimney can be seen in the upper center of the photo and the limestone preparation building will be built on the rectangular foundation that can seen in the middle right of the photo.



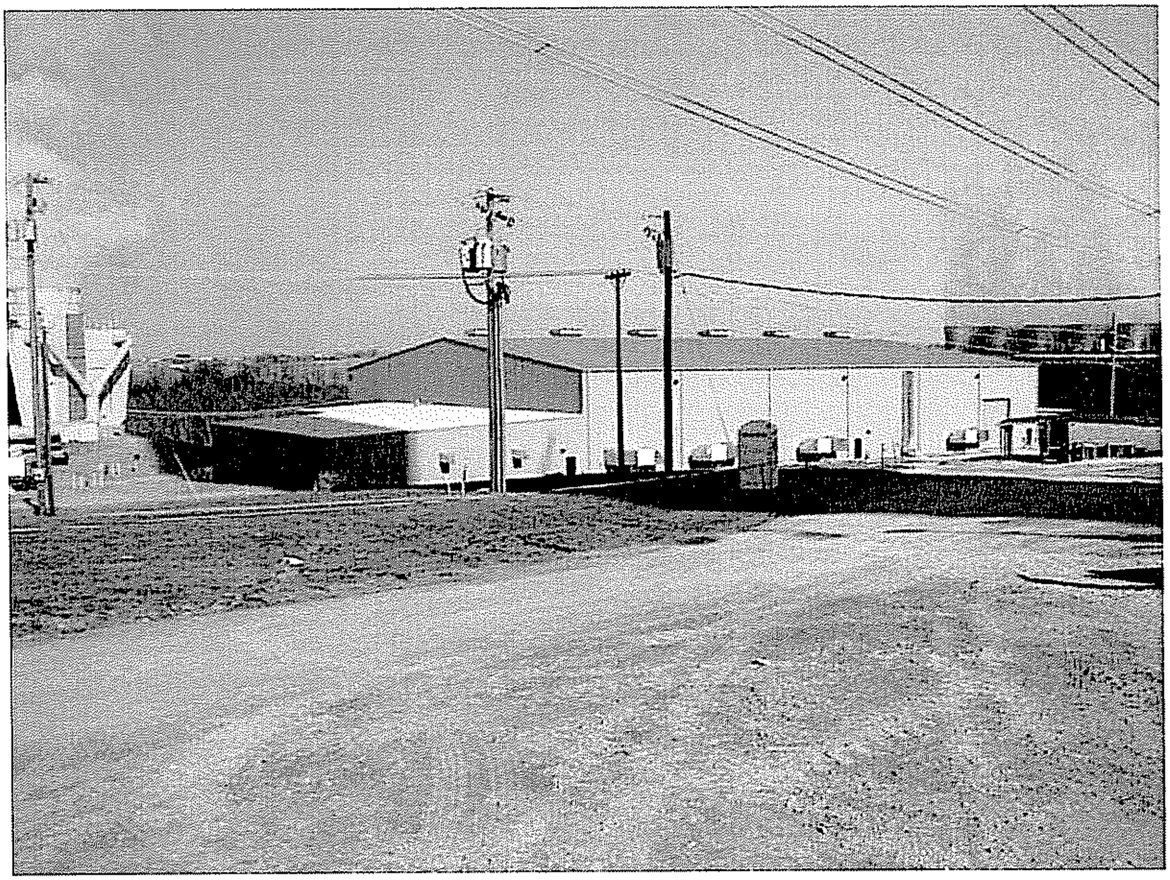
The picture above (dated 3/12/2008) shows a closer view of the FGD area from a different angle. In the background behind the steel structure, the edge of the excavated area indicates the amount of soil that was removed and the amount of rock that was blasted and excavated to prepare the site for the FGD construction.



The picture above (dated 3/12/2008) shows the fire protection/quench water tank and pump enclosure. The tank will be a dual purpose tank that will hold and supply water for the fire protection system for the new items being installed as part of the FGD Project and will supply water for the quench water system that will quench the flue gas in case of a process upset where recycle pump flow is lost. Without quenching of the flue gas, the FRP mist eliminator panels would be overheated and damaged.



The above photo (dated 3/12/2008) shows the balance-of-plant work that has been done to install new electrical manholes and underground ductbanks for the conduits to contain power, controls and communications cables between the existing plant and the new FGD items in addition to new fire hydrants and new underground fire protection piping that have been installed.



The above photo (dated 3/12/2008) shows the new warehouse.

Appendix 2

- Base Case: Scrub Ghent consistent with the Commission's Order in Case No. 2004-00426. Scrub Brown with an in-service date in 2010.

- Study Period: 20-year period for Production Cost impacts (2008-2028) 30-year period for Capital Costs impacts (2008 through book life of project).

  The production costs include items such as fuel, O&M and purchase power and are estimated using the PROSYM production model. This model was run for the 2008-2028 time period.

  The revenue requirements associated with capital costs are determined via the Capital Expenditure and Recovery module of the Strategist production and capital costing software. Capital projects with a 20 year book/tax life and an in-service date after 2008 would have the last years of their life excluded from the revenue requirement calculation if capital costs impacts were halted at 2028. Doing so would have the effect of underestimating the capital cost of alternatives and would favor construction of new projects. Therefore, to completely account for capital projects costs over their lifetime, the revenue requirements associated with new capital projects were extended through the end of their book life.

- KU/LGE continues as a regulated entity subject to the oversight of the Kentucky Public Service Commission and the Commission continues to require the Companies to implement the least reasonable-cost strategy to the benefit of the native load customers.

- Capital costs, O&M costs, and the costs of increased emissions (both NO_x and SO_2) associated with the addition of new environmental projects will be subject to recovery through the Environmental Cost Recovery mechanism.

- Financial Data

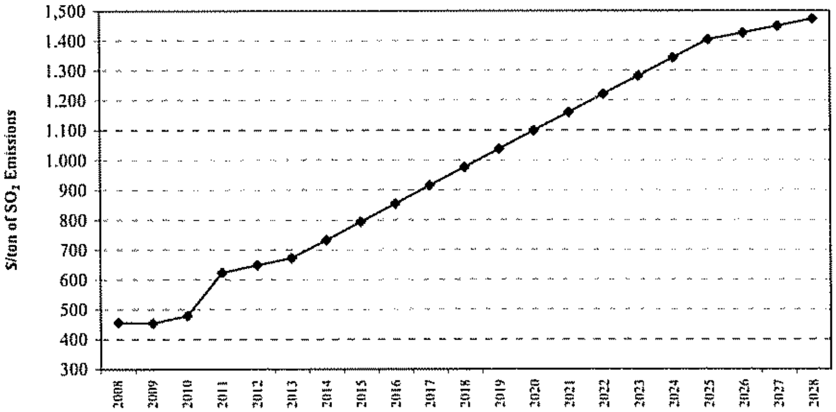
➢ Discount Rate (%):	8.02 %
➢ Federal Income Tax Rate (%)	38.9 %
➢ AFUDC Rate (%):	8.02 %
➢ Insurance Rate (%):	0.07 %
➢ Property Tax Rate (%):	0.15 %
➢ Percentage of Debt in Capital Structure (%):	44.05 %
➢ Debt Interest Rate/Weighted Cost of Debt (%):	4.88%
➢ Desired Return on Rate base (%):	8.02%
➢ Capitalized Interest Debt Rate (%):	4.88%
➢ Environmental Projects Book Life (years):	20 years
➢ *Environmental Projects Tax Life (years):*	20 years
➢ Annual Fixed O&M escalation rate (%):	1.6% (prorated for mid-year installs)
➢ Annual Variable O&M escalation rate (%):	1.6%

- No unit retirements occur on the Companies' generating system within the study period.

- SO_2 Emission Costs (Base Assumption)
  Note that the effects of CAIR are reflected in the forecasted price of SO_2 emissions allowances

	SO_2 Price (\$/ton emitted)
2008	457
2009	455
2010	480
2011	624
2012	649
2013	673
2014	733
2015	794
2016	855
2017	916
2018	977
2019	1038
2020	1099
2021	1160
2022	1221
2023	1282
2024	1343
2025	1404
2026	1426
2027	1449
2028	1472

Forecasted SO_2 Emissions Allowance Prices



- Fuel Forecast (Base Assumptions) – Confidential information redacted
  - Fuel cost savings associated with serving native load will be returned to the ratepayer though the Fuel Adjustment Clause mechanism.

[redacted]

Appendix 3

Cost Comparison of Alternative SO_2 Compliance Plans

All Costs in 2008 PVRR $ x1000

Price Curve Multipliers	
SO_2	1.00
NO_x	1.00

Base Case - GH1 FGD in 2009 (Brown FGD in 2010)

Fuel Forecast: Base
Load Forecast: Base
SO2 Price Forecast: Base X 1
NOX Price Forecast: Base X 1
Other Description: Brown 123 FGD in '10
0

Cap Cost Sensitivity %:

Environmental Controls:

Unit	SO2 Rem %	SO2 Tech	SO2 In-Serv	NOX Tech	SCR In-Serv	NOx Tech Cost (M$)
Brown 1	98%	Wet FGD	2010	LNB (1993)	0	
Brown 2	98%	Wet FGD	2010	LNCFS I (1994)	0	
Brown 3	98%	Wet FGD	2010	LNCFS III (1992)	2012	
Ghent 1	94% / 98%	Existing FGD	1992	LNCFS II	2003	
Ghent 2	94%	FS HS+Wet FGD	2009	LNCFS III (2000)/SCR (2009)	2015	
Ghent 3	98%	FS HS+Wet FGD	2007	LNB & OFA (1998)	2003	
Ghent 4	98%	FS HS+Wet FGD	2008	LNB & OFA (1999)	2003	

SO_2 Allowances Purchased: 172,908
SO_2 Tons Emitted: 1,632,776
Largest Annual SO_2 Purchase (as a % of EPA Allocation): 56%
Ann+Oz Seas NO_x Allow Purch: 4,838
Ann+Oz Seas NO_x Tons Emit: 734,601

Without GH1 FGD (Brown FGD in 2010)

Fuel Forecast: Base
Load Forecast: Base
SO2 Price Forecast: Base X 1
NOX Price Forecast: Base X 1
Other Description: Walkaway from GH1 FGD
0

Cap Cost Sensitivity %:

Environmental Controls:

Unit	SO2 Rem %	SO2 Tech	SO2 In-Serv	NOX Tech	SCR In-Serv	NOx Tech Cost (M$)
Brown 1	98%	Wet FGD	2010	LNB (1993)	0	
Brown 2	98%	Wet FGD	2010	LNCFS I (1994)	0	
Brown 3	98%	Wet FGD	2010	LNCFS III (1992)	2012	
Ghent 1	94%	Existing FGD	1992	LNCFS II	2003	
Ghent 2	0%	FS HS+Wet FGD	0	LNCFS III (2000)/SCR (2009)	2015	
Ghent 3	98%	FS HS+Wet FGD	2007	LNB & OFA (1998)	2003	
Ghent 4	98%	FS HS+Wet FGD	2008	LNB & OFA (1999)	2003	

SO_2 Allowances Purchased: 476,493
SO_2 Tons Emitted: 1,936,355
Largest Annual SO_2 Purchase (as a % of EPA Allocation): 90%
Ann+Oz Seas NO_x Allow Purch: 7,357
Ann+Oz Seas NO_x Tons Emit: 737,929

	Base Case: Emission Price (Nominal $/ton emit)			Base Case: Combined Company Allow. Value				Without GH1 FGD: Emission Price (Nominal $/ton emit)			Without GH1 FGD: Combined Company Allow. Value				DIFFERENCE CALCULATIONS	
Year	NOx	SO2	Production $	NOx $	SO2 $	Capital $	PVRR Total $	NOx	SO2	Production $	NOx $	SO2 $	Capital $	PVRR Total $	Total $	Cumulative Total $
2008	988	457	[redacted]	1,039	982	821	[redacted]	988	457	[redacted]	1,039	982	-	[redacted]	821	821
2009	951	455	[redacted]	2,632	(6,752)	7,298	[redacted]	951	455	[redacted]	2,352	(2,060)	-	[redacted]	(5,054)	(4,233)
2010	2366	480	[redacted]	2,846	11,069	7,262	[redacted]	2366	480	[redacted]	2,667	17,362	-	[redacted]	(10,523)	(14,756)
2011	2369	624	[redacted]	3,069	(1,105)	6,432	[redacted]	2369	624	[redacted]	3,038	6,403	-	[redacted]	(11,771)	(26,527)
2012	2372	649	[redacted]	(6,687)	(1,001)	5,695	[redacted]	2372	649	[redacted]	(6,898)	5,630	-	[redacted]	(7,770)	(34,297)
2013	2274	673	[redacted]	(4,900)	(321)	5,039	[redacted]	2274	673	[redacted]	(5,169)	6,606	-	[redacted]	(8,603)	(42,900)
2014	2250	733	[redacted]	(4,021)	(263)	4,456	[redacted]	2250	733	[redacted]	(4,206)	6,682	-	[redacted]	(11,399)	(54,299)
2015	3098	794	[redacted]	(3,925)	9,311	3,938	[redacted]	3098	794	[redacted]	(3,548)	16,466	-	[redacted]	(12,412)	(66,711)
2016	3092	855	[redacted]	(2,223)	8,702	3,477	[redacted]	3092	855	[redacted]	(1,396)	15,679	-	[redacted]	(13,015)	(79,726)
2017	3086	916	[redacted]	(729)	10,137	3,063	[redacted]	3086	916	[redacted]	(16)	17,301	-	[redacted]	(13,284)	(93,010)
2018	3122	977	[redacted]	(469)	9,724	2,691	[redacted]	3122	977	[redacted]	151	16,774	-	[redacted]	(13,156)	(106,165)
2019	3149	1038	[redacted]	(1,542)	8,823	2,357	[redacted]	3149	1038	[redacted]	(1,052)	15,416	-	[redacted]	(10,700)	(116,865)
2020	3177	1099	[redacted]	(2,331)	8,443	2,059	[redacted]	3177	1099	[redacted]	(1,833)	15,078	-	[redacted]	(13,486)	(130,352)
2021	3250	1160	[redacted]	(1,063)	9,270	1,791	[redacted]	3250	1160	[redacted]	(730)	15,784	-	[redacted]	(12,947)	(143,298)
2022	3282	1221	[redacted]	2,125	8,971	1,552	[redacted]	3282	1221	[redacted]	2,410	15,617	-	[redacted]	(13,242)	(156,541)
2023	3281	1282	[redacted]	2,060	9,180	1,339	[redacted]	3281	1282	[redacted]	2,388	15,603	-	[redacted]	(12,352)	(168,893)
2024	3123	1343	[redacted]	2,579	9,256	1,149	[redacted]	3123	1343	[redacted]	2,757	15,484	-	[redacted]	(12,332)	(181,225)
2025	2970	1404	[redacted]	2,371	9,731	979	[redacted]	2970	1404	[redacted]	2,546	15,815	-	[redacted]	(11,953)	(193,178)
2026	3018	1426	[redacted]	2,819	8,831	829	[redacted]	3018	1426	[redacted]	2,923	14,199	-	[redacted]	(10,155)	(203,332)
2027	3066	1449	[redacted]	3,016	9,071	696	[redacted]	3066	1449	[redacted]	3,098	14,550	-	[redacted]	(10,950)	(214,283)
2028	3115	1472	[redacted]	1,855	7,369	578	[redacted]	3115	1472	[redacted]	2,055	12,150	-	[redacted]	(9,334)	(223,617)
2029			[redacted]			106	[redacted]			[redacted]			-	[redacted]	106	(223,511)
2030			[redacted]			-	[redacted]			[redacted]			-	[redacted]	-	(223,511)
2031			[redacted]			-	[redacted]			[redacted]			-	[redacted]	-	(223,511)
2032			[redacted]			-	[redacted]			[redacted]			-	[redacted]	-	(223,511)
2033			[redacted]			-	[redacted]			[redacted]			-	[redacted]	-	(223,511)
2034			[redacted]			-	[redacted]			[redacted]			-	[redacted]	-	(223,511)
2035			[redacted]			-	[redacted]			[redacted]			-	[redacted]	-	(223,511)
2036			[redacted]			-	[redacted]			[redacted]			-	[redacted]	-	(223,511)
2037			[redacted]			-	[redacted]			[redacted]			-	[redacted]	-	(223,511)
2038			[redacted]				[redacted]			[redacted]				[redacted]		(223,511)
Totals			13,809,531	(1,479)	129,426	63,607	14,001,086			13,964,500	2,575	257,521	-	14,224,597	(223,511)	
								Delta (PVRR $000)		(154,969)	(4,054)	(128,095)	63,607	(223,511)		

Cost Comparison of Alternative SO_2 Compliance Plans

All Costs in 2008 PVRR $ x1000

Base Case - Brown FGD in 2010 (GH1 FGD in 2009)

Fuel Forecast: Base
Load Forecast: Base
SO2 Price Forecast: Base X 1
NOX Price Forecast: Base X 1
Other Description: Brown 123 FGD in '10
0

Cap Cost Sensitivity %:

Environmental Controls:

Unit	SO2 Rem %	SO2 Tech	SO2 In-Serv	NOX Tech	SCR In-Serv	NOx Tech Cost (M$)
Brown 1	98%	Wet FGD	2010	LNB (1993)	0	
Brown 2	98%	Wet FGD	2010	LNCFS I (1994)	0	
Brown 3	98%	Wet FGD	2010	LNCFS III (1992)	2012	
Ghent 1	94% / 98%	Existing FGD	1992	LNCFS II	2003	
Ghent 2	94%	FS HS+Wet FGD	2009	LNCFS III (2000)/SCR (2009)	2015	
Ghent 3	98%	FS HS+Wet FGD	2007	LNB & OFA (1998)	2003	
Ghent 4	98%	FS HS+Wet FGD	2008	LNB & OFA (1999)	2003	

SO_2 Allowances Purchased: 172,908
SO_2 Tons Emitted: 1,632,776
Largest Annual SO_2 Purchase (as a % of EPA Allocation): 56%
Ann+Oz Seas NO_x Allow Purch: 4,838
Ann+Oz Seas NO_x Tons Emit: 734,601

Without Brown FGD (GH1 FGD in 2009)

Fuel Forecast: Base
Load Forecast: Base
SO2 Price Forecast: Base X 1
NOX Price Forecast: Base X 1
Other Description: Brown 123 FGD in '11
0

Cap Cost Sensitivity %:

Environmental Controls:

Unit	SO2 Rem %	SO2 Tech	SO2 In-Serv	NOX Tech	SCR In-Serv	NOx Tech Cost (M$)
Brown 1	98%	Wet FGD	2011	LNB (1993)	0	
Brown 2	98%	Wet FGD	2011	LNCFS I (1994)	0	
Brown 3	98%	Wet FGD	2011	LNCFS III (1992)	2012	
Ghent 1	94% / 98%	Existing FGD	1992	LNCFS II	2003	
Ghent 2	94%	FS HS+Wet FGD	2009	LNCFS III (2000)/SCR (2009)	2015	
Ghent 3	98%	FS HS+Wet FGD	2007	LNB & OFA (1998)	2003	
Ghent 4	98%	FS HS+Wet FGD	2008	LNB & OFA (1999)	2003	

SO_2 Allowances Purchased: 229,275
SO_2 Tons Emitted: 1,689,143
Largest Annual SO_2 Purchase (as a % of EPA Allocation): 56%
Ann+Oz Seas NO_x Allow Purch: 4,860
Ann+Oz Seas NO_x Tons Emit: 734,760

Price Curve Multipliers
SO_2 1.00
NO_x 1.00

	Base Case							Without Brown FGD							DIFFERENCE CALCULATIONS	
	Emission Price (Nominal $/ton emit)			Combined Company Allow. Value				Emission Price (Nominal $/ton emit)			Combined Company Allow. Value					
Year	NOx	SO2	Production $	NOx $	SO2 $	Capital $	PVRR Total $	NOx	SO2	Production $	NOx $	SO2 $	Capital $	PVRR Total $	Total $	Cumulative Total $
2008	988	457	[redacted]	1,039	982	13,545	[redacted]	988	457	[redacted]	1,039	982	13,609	[redacted]	(64)	(64)
2009	951	455	[redacted]	2,632	(6,752)	34,610	[redacted]	951	455	[redacted]	2,632	(6,752)	26,571	[redacted]	8,039	7,975
2010	2366	480	[redacted]	2,846	11,069	57,479	[redacted]	2366	480	[redacted]	3,978	23,956	35,909	[redacted]	18,717	26,692
2011	2369	624	[redacted]	3,069	(1,105)	57,998	[redacted]	2369	624	[redacted]	2,319	11,291	58,672	[redacted]	(19,101)	7,591
2012	2372	649	[redacted]	(6,687)	(1,001)	51,374	[redacted]	2372	649	[redacted]	(6,687)	(1,001)	58,972	[redacted]	(7,598)	(7)
2013	2274	673	[redacted]	(4,900)	(321)	45,487	[redacted]	2274	673	[redacted]	(4,900)	(321)	52,225	[redacted]	(6,228)	(6,235)
2014	2250	733	[redacted]	(4,021)	(263)	40,255	[redacted]	2250	733	[redacted]	(4,021)	(263)	46,233	[redacted]	(6,450)	(12,685)
2015	3098	794	[redacted]	(3,925)	9,311	35,603	[redacted]	3098	794	[redacted]	(3,925)	9,311	40,907	[redacted]	(5,304)	(17,989)
2016	3092	855	[redacted]	(2,223)	8,702	31,472	[redacted]	3092	855	[redacted]	(2,223)	8,702	36,180	[redacted]	(4,708)	(22,697)
2017	3086	916	[redacted]	(729)	10,137	27,801	[redacted]	3086	916	[redacted]	(729)	10,137	31,980	[redacted]	(4,179)	(26,876)
2018	3122	977	[redacted]	(469)	9,724	24,510	[redacted]	3122	977	[redacted]	(469)	9,724	28,251	[redacted]	(3,741)	(30,617)
2019	3149	1038	[redacted]	(1,542)	8,823	21,555	[redacted]	3149	1038	[redacted]	(1,542)	8,823	24,907	[redacted]	(3,352)	(33,969)
2020	3177	1099	[redacted]	(2,331)	8,443	18,902	[redacted]	3177	1099	[redacted]	(2,331)	8,443	21,902	[redacted]	(3,000)	(36,969)
2021	3250	1160	[redacted]	(1,063)	9,270	16,525	[redacted]	3250	1160	[redacted]	(1,063)	9,270	19,207	[redacted]	(2,682)	(39,651)
2022	3282	1221	[redacted]	2,125	8,971	14,396	[redacted]	3282	1221	[redacted]	2,125	8,971	16,790	[redacted]	(2,394)	(42,045)
2023	3281	1282	[redacted]	2,060	9,180	12,493	[redacted]	3281	1282	[redacted]	2,060	9,180	14,628	[redacted]	(2,135)	(44,180)
2024	3123	1343	[redacted]	2,579	9,256	10,792	[redacted]	3123	1343	[redacted]	2,579	9,256	12,693	[redacted]	(1,901)	(46,081)
2025	2970	1404	[redacted]	2,371	9,731	9,276	[redacted]	2970	1404	[redacted]	2,371	9,731	10,965	[redacted]	(1,689)	(47,771)
2026	3018	1426	[redacted]	2,819	8,831	7,925	[redacted]	3018	1426	[redacted]	2,819	8,831	9,425	[redacted]	(1,500)	(49,271)
2027	3066	1449	[redacted]	3,016	9,071	6,845	[redacted]	3066	1449	[redacted]	3,016	9,071	8,173	[redacted]	(1,328)	(50,599)
2028	3115	1472	[redacted]	1,855	7,369	7,167	[redacted]	3115	1472	[redacted]	1,855	7,369	8,337	[redacted]	(1,170)	(51,769)
2029			[redacted]			5,141	[redacted]			[redacted]			6,155	[redacted]	(1,014)	(52,783)
2030			[redacted]			944	[redacted]			[redacted]			5,095	[redacted]	(4,151)	(56,934)
2031			[redacted]			-	[redacted]			[redacted]			936	[redacted]	(936)	(57,870)
2032			[redacted]			-	[redacted]			[redacted]			-	[redacted]	-	(57,870)
2033			[redacted]			-	[redacted]			[redacted]			-	[redacted]	-	(57,870)
2034			[redacted]			-	[redacted]			[redacted]			-	[redacted]	-	(57,870)
2035			[redacted]			-	[redacted]			[redacted]			-	[redacted]	-	(57,870)
2036			[redacted]			-	[redacted]			[redacted]			-	[redacted]	-	(57,870)
2037			[redacted]			-	[redacted]			[redacted]			-	[redacted]	-	(57,870)
2038			[redacted]				[redacted]			[redacted]				[redacted]		
Totals			13,809,531	(1,479)	129,426	552,095	14,489,574			13,805,108	(1,096)	154,710	588,722	14,547,444	(57,870)	
								Delta (PVRR $000)		4,424	(383)	(25,284)	(36,627)	(57,870)		

Cost Comparison of Alternative SO_2 Compliance Plans

All Costs in 2008 PVRR $ x1000

Base Case - Brown FGD in 2010 (GH1 FGD in 2009)

Fuel Forecast: Base
Load Forecast: Base
SO2 Price Forecast: Base X 1
NOX Price Forecast: Base X 1
Other Description: Brown 123 FGD in '10
0

Cap Cost Sensitivity %:

Environmental Controls:

Unit	SO2 Rem %	SO2 Tech	SO2 In-Serv	NOX Tech	SCR In-Serv	NOx Tech Cost (M$)
Brown 1	98%	Wet FGD	2010	LNB (1993)	0	
Brown 2	98%	Wet FGD	2010	LNCFS I (1994)	0	
Brown 3	98%	Wet FGD	2010	LNCFS III (1992)	2012	
Ghent 1	94% / 98%	Existing FGD	1992	LNCFS II	2003	
Ghent 2	94%	FS HS+Wet FGD	2009	LNCFS III (2000)/SCR (2009)	2015	
Ghent 3	98%	FS HS+Wet FGD	2007	LNB & OFA (1998)	2003	
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SO_2 Allowances Purchased: 172,908
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Ann+Oz Seas NO_x Allow Purch: 4,838
Ann+Oz Seas NO_x Tons Emit: 734,601

Without Brown FGD (GH1 FGD in 2009)

Fuel Forecast: Base
Load Forecast: Base
SO2 Price Forecast: Base X 1
NOX Price Forecast: Base X 1
Other Description: Walkaway from BR FGD
Recovery on $174M

Cap Cost Sensitivity %:

Environmental Controls:

Unit	SO2 Rem %	SO2 Tech	SO2 In-Serv	NOX Tech	SCR In-Serv	NOx Tech Cost (M$)
Brown 1	0%	n/a	0	LNB (1993)	0	
Brown 2	0%	n/a	0	LNCFS I (1994)	0	
Brown 3	0%	n/a	0	LNCFS III (1992)	2012	
Ghent 1	94% / 98%	Existing FGD	1992	LNCFS II	2003	
Ghent 2	94%	FS HS+Wet FGD	2009	LNCFS III (2000)/SCR (2009)	2015	
Ghent 3	98%	FS HS+Wet FGD	2007	LNB & OFA (1998)	2003	
Ghent 4	98%	FS HS+Wet FGD	2008	LNB & OFA (1999)	2003	

SO_2 Allowances Purchased: 1,207,820
SO_2 Tons Emitted: 2,667,690
Largest Annual SO_2 Purchase (as a % of EPA Allocation): 179%
Ann+Oz Seas NO_x Allow Purch: 4,427
Ann+Oz Seas NO_x Tons Emit: 731,616

Price Curve Multipliers
SO_2 1.00
NO_x 1.00

	Base Case: Emission Price (Nominal $/ton emit)			Base Case: Combined Company Allow. Value				Without Brown FGD: Emission Price (Nominal $/ton emit)			Without Brown FGD: Combined Company Allow. Value				DIFFERENCE CALCULATIONS	
Year	NOx	SO2	Production $	NOx $	SO2 $	Capital $	PVRR Total $	NOx	SO2	Production $	NOx $	SO2 $	Capital $	PVRR Total $	Total $	Cumulative Total $
2008	988	457	[redacted]	1,039	982	13,545	[redacted]	988	457	[redacted]	1,039	939	13,062	[redacted]	(152)	(152)
2009	951	455	[redacted]	2,632	(6,752)	34,610	[redacted]	951	455	[redacted]	2,852	(6,084)	16,453	[redacted]	18,028	17,876
2010	2366	480	[redacted]	2,846	11,069	57,479	[redacted]	2366	480	[redacted]	4,014	23,930	14,582	[redacted]	40,889	58,766
2011	2369	624	[redacted]	3,069	(1,105)	57,998	[redacted]	2369	624	[redacted]	2,748	25,624	12,919	[redacted]	18,213	76,979
2012	2372	649	[redacted]	(6,687)	(1,001)	51,374	[redacted]	2372	649	[redacted]	(6,243)	24,062	11,439	[redacted]	12,892	89,871
2013	2274	673	[redacted]	(4,900)	(321)	45,487	[redacted]	2274	673	[redacted]	(4,311)	25,447	10,122	[redacted]	6,973	96,845
2014	2250	733	[redacted]	(4,021)	(263)	40,255	[redacted]	2250	733	[redacted]	(3,624)	25,929	8,951	[redacted]	315	97,159
2015	3098	794	[redacted]	(3,925)	9,311	35,603	[redacted]	3098	794	[redacted]	(3,608)	35,316	7,908	[redacted]	(2,732)	94,427
2016	3092	855	[redacted]	(2,223)	8,702	31,472	[redacted]	3092	855	[redacted]	(2,227)	32,980	6,973	[redacted]	(4,270)	90,157
2017	3086	916	[redacted]	(729)	10,137	27,801	[redacted]	3086	916	[redacted]	(941)	36,118	6,132	[redacted]	(9,170)	80,987
2018	3122	977	[redacted]	(469)	9,724	24,510	[redacted]	3122	977	[redacted]	(706)	35,327	5,378	[redacted]	(11,692)	69,295
2019	3149	1038	[redacted]	(1,542)	8,823	21,555	[redacted]	3149	1038	[redacted]	(1,899)	32,307	4,703	[redacted]	(10,676)	58,619
2020	3177	1099	[redacted]	(2,331)	8,443	18,902	[redacted]	3177	1099	[redacted]	(2,652)	31,886	4,098	[redacted]	(15,070)	43,549
2021	3250	1160	[redacted]	(1,063)	9,270	16,525	[redacted]	3250	1160	[redacted]	(1,554)	32,913	3,557	[redacted]	(16,702)	26,847
2022	3282	1221	[redacted]	2,125	8,971	14,396	[redacted]	3282	1221	[redacted]	1,655	32,783	3,073	[redacted]	(18,669)	8,178
2023	3281	1282	[redacted]	2,060	9,180	12,493	[redacted]	3281	1282	[redacted]	1,652	31,837	2,642	[redacted]	(18,525)	(10,347)
2024	3123	1343	[redacted]	2,579	9,256	10,792	[redacted]	3123	1343	[redacted]	2,109	31,637	2,258	[redacted]	(19,840)	(30,187)
2025	2970	1404	[redacted]	2,371	9,731	9,276	[redacted]	2970	1404	[redacted]	1,928	31,631	1,916	[redacted]	(20,727)	(50,914)
2026	3018	1426	[redacted]	2,819	8,831	7,925	[redacted]	3018	1426	[redacted]	2,369	28,391	1,613	[redacted]	(18,508)	(69,422)
2027	3066	1449	[redacted]	3,016	9,071	6,845	[redacted]	3066	1449	[redacted]	2,584	28,873	1,344	[redacted]	(19,918)	(89,340)
2028	3115	1472	[redacted]	1,855	7,369	7,167	[redacted]	3115	1472	[redacted]	1,590	24,673	964	[redacted]	(15,366)	(104,707)
2029			[redacted]			5,141	[redacted]			[redacted]			-	[redacted]	5,141	(99,566)
2030			[redacted]			944	[redacted]			[redacted]			-	[redacted]	944	(98,622)
2031			[redacted]			-	[redacted]			[redacted]			-	[redacted]	-	(98,622)
2032			[redacted]			-	[redacted]			[redacted]			-	[redacted]	-	(98,622)
2033			[redacted]			-	[redacted]			[redacted]			-	[redacted]	-	(98,622)
2034			[redacted]			-	[redacted]			[redacted]			-	[redacted]	-	(98,622)
2035			[redacted]			-	[redacted]			[redacted]			-	[redacted]	-	(98,622)
2036			[redacted]			-	[redacted]			[redacted]			-	[redacted]	-	(98,622)
2037			[redacted]			-	[redacted]			[redacted]			-	[redacted]	-	(98,622)
2038			[redacted]				[redacted]			[redacted]			-	[redacted]	-	(98,622)
Totals			13,809,531	(1,479)	129,426	552,095	14,489,574			13,884,815	(3,226)	566,519	140,087	14,588,196	(98,622)	
								Delta (PVRR $000)		(75,284)	1,747	(437,093)	412,008	(98,622)		

Appendix 4

Base Case - GH1 FGD in 2009 (Brown FGD in 2010)

	Owner	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
FUEL SO2 Content (#/MBTU)																							
Brown 1	KU		2.7	2.7	117.8	5.8	5.8	5.9	5.8	5.8	5.8	5.8	5.8	5.9	5.8	5.8	5.9	5.9	5.9	5.9	5.9	5.8	5.9
Brown 2	KU		2.7	2.7	107.5	5.9	5.9	5.9	5.9	5.8	5.8	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.8	5.8	5.9	5.8	5.8
Brown 3	KU		2.7	2.7	38.7	5.9	5.8	5.9	5.9	5.8	5.8	5.8	5.8	5.9	5.8	5.8	5.8	5.9	5.8	5.8	5.9	5.8	5.9
Ghent 1	KU		6.1	9.0	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Ghent 2	KU		1.2	8.7	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Ghent 3	KU		6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Ghent 4	KU		19.2	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Green River 3	KU		4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Green River 4	KU		4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Tyrone 3	KU		1.5	1.5	1.5	1.5	1.4	1.4	1.5	1.4	1.4	1.5	1.4	1.4	1.4	1.5	1.4	1.4	1.4	1.5	1.5	1.4	1.4
Cane Run 4	LGE		5.8	5.8	5.8	5.8	5.8	5.9	5.9	5.9	5.8	5.8	5.9	5.8	5.8	5.9	5.8	5.8	5.8	5.9	5.8	5.9	5.9
Cane Run 5	LGE		5.8	5.8	5.8	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.8	5.8	5.8	5.9	5.8	5.9	5.8	5.9	5.9	5.8
Cane Run 6	LGE		5.9	5.8	5.9	5.8	5.9	5.9	5.9	5.8	5.8	5.9	5.9	5.8	5.9	5.8	5.8	5.8	5.9	5.9	5.8	5.8	5.9
Mill Creek 1	LGE		5.8	5.9	5.8	5.8	5.9	5.8	5.9	5.9	5.8	5.9	5.8	5.8	5.8	5.9	5.9	5.8	5.8	5.8	5.8	5.8	5.8
Mill Creek 2	LGE		5.9	5.9	5.9	5.8	5.9	5.8	5.8	5.9	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.8	5.9	5.8	5.8	5.8	5.8
Mill Creek 3	LGE		5.8	5.9	5.9	5.9	5.9	5.8	5.8	5.9	5.9	5.8	5.8	5.8	5.9	5.8	5.9	5.9	5.9	5.9	5.8	5.9	5.9
Mill Creek 4	LGE		5.9	5.8	5.8	5.9	5.9	5.8	5.8	5.9	5.9	5.8	5.9	5.9	5.8	5.8	5.9	5.8	5.8	5.8	5.9	5.8	5.9
Trimble County 1	LGE		5.9	5.9	5.9	5.8	5.8	5.9	5.9	5.8	5.8	5.9	5.9	5.8	5.9	5.8	5.9	5.9	5.8	5.9	5.9	5.8	5.8
Trimble County 2	KU		0.0	0.0	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Trimble County 2	LGE		0.0	0.0	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
GFCU 1	KU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.4
GFCU 1	LGE		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.4
SCRUBBER REMOVAL EFF.																							
Brown 1			0%	0%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Brown 2			0%	0%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Brown 3			0%	0%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Ghent 1			94%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Ghent 2			0%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%
Ghent 3			98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Ghent 4			98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Green River 3			0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Green River 4			0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Tyrone 3			0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Cane Run 4			85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Cane Run 5			85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Cane Run 6			90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Mill Creek 1			93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%
Mill Creek 2			98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Mill Creek 3			89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%
Mill Creek 4			91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%
Trimble County 1			99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%
Trimble County 2			0%	0%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Trimble County 2			0%	0%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
GFCU 1			0%	0%	0%	0%	0%	0%	0%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
GFCU 1			0%	0%	0%	0%	0%	0%	0%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
TONS SO2 EMITTED			2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Brown 1	KU		7,829	7,794	5,976	312	323	312	304	324	313	340	338	350	326	318	355	362	367	379	395	393	328
Brown 2	KU		14,639	13,106	11,654	688	687	687	693	699	603	695	691	699	676	685	699	624	692	689	700	704	649
Brown 3	KU		36,261	35,366	10,065	1,723	1,587	1,755	1,779	1,748	1,654	1,718	1,719	1,535	1,672	1,736	1,764	1,769	1,768	1,799	1,621	1,825	1,704
Ghent 1	KU		6,870	3,142	2,238	2,190	2,249	2,231	2,011	2,239	2,233	2,235	2,232	2,242	2,237	2,011	2,239	2,239	2,230	2,235	2,237	2,239	1,976
Ghent 2	KU		16,890	7,563	5,225	5,693	4,967	5,738	5,809	5,836	5,963	5,980	5,985	5,338	5,957	5,966	5,957	5,963	5,930	5,897	5,322	5,945	5,748
Ghent 3	KU		2,424	2,392	2,066	2,309	2,317	2,307	2,312	2,318	2,245	2,052	2,283	2,293	2,271	2,285	2,301	2,301	2,081	2,312	2,325	2,338	2,268
Ghent 4	KU		5,029	2,336	2,276	2,256	2,269	2,274	2,292	2,048	2,236	2,259	2,256	2,261	2,235	2,247	2,041	2,263	2,267	2,270	2,284	2,289	2,235
Green River 3	KU		6,824	6,994	7,085	5,544	5,868	5,643	6,100	5,611	4,773	5,595	5,523	5,663	4,511	5,024	5,396	5,050	5,651	5,868	6,519	6,424	5,306
Green River 4	KU		12,819	12,371	10,369	8,049	7,271	8,182	8,347	8,924	8,333	9,604	9,693	7,936	8,444	9,217	9,486	9,701	9,544	10,876	9,499	11,095	9,079
Tyrone 3	KU		2,701	3,283	2,709	2,505	2,585	2,594	2,675	2,631	2,626	2,795	2,748	2,858	2,628	2,999	3,094	3,064	2,857	3,204	3,358	3,384	2,876
Cane Run 4	LGE		3,959	3,951	3,772	2,900	3,322	3,185	3,406	3,174	3,314	3,410	3,062	3,587	3,362	3,591	3,591	3,669	3,762	3,453	3,901	3,949	3,654
Cane Run 5	LGE		3,780	4,154	3,685	3,278	3,352	3,327	3,423	2,994	3,398	3,558	3,592	3,641	3,468	3,634	3,411	3,753	3,820	3,074	4,012	4,064	3,627
Cane Run 6	LGE		4,197	3,847	4,122	3,482	3,553	3,427	3,523	3,581	3,585	4,192	4,119	4,344	4,119	4,292	4,362	4,038	4,615	4,692	4,732	4,765	4,565
Mill Creek 1	LGE		4,052	4,234	3,522	3,912	3,716	3,914	3,719	3,772	3,463	3,699	3,189	3,742	3,455	3,743	3,527	3,769	3,615	3,872	3,374	3,920	3,577
Mill Creek 2	LGE		1,101	1,012	958	969	1,032	968	1,043	950	980	853	995	942	986	943	1,007	957	1,025	886	1,041	984	1,013
Mill Creek 3	LGE		9,177	8,900	9,518	8,208	9,516	8,950	9,514	8,880	9,387	8,858	9,398	8,098	9,368	8,827	9,409	8,876	9,503	8,962	9,535	8,231	9,455
Mill Creek 4	LGE		9,536	10,161	9,588	10,091	9,479	10,062	8,678	9,972	9,290	9,945	9,230	9,868	9,201	9,846	8,518	9,952	9,460	10,073	9,476	10,119	9,337
Trimble County 1	LGE		650	544	646	593	648	593	647	592	645	542	646	592	647	593	646	593	649	544	648	595	647
Trimble County 2	KU		0	0	776	1,472	1,547	1,540	1,543	1,540	1,542	1,546	1,544	1,544	1,543	1,545	1,549	1,550	1,557	1,555	1,555	1,557	1,537
Trimble County 2	LGE		0	0	182	345	363	361	362	361	362	363	362	362	362	363	363	364	365	365	365	365	361
GFCU 1	KU		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,024
GFCU 1	LGE		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	576
SO2 EMISSIONS (TONS) Total			140,646	131,151	96,629	66,518	66,650	68,049	68,181	68,201	66,945	70,236	69,604	67,936	67,466	69,864	69,713	70,855	71,759	73,804	72,899	75,184	71,490
ALLOWANCES																							
KU EPA Allocated SO2 Allowances			83,343	83,343	38,768	38,768	38,768	38,768	38,768	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110
LGE EPA Allocated SO2 Allowances			62,456	62,456	29,983	29,983	29,983	29,983	29,983	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967
Total KU/LGE EPA Allocated SO2 Allowances			145,799	145,799	68,751	68,751	68,751	68,751	68,751	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077
KU/LGE Extension			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KU's Portion of OMU Surplus/Shortfall			1,698	1,382	972	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Company Purchases			0	0	0	0	0	0	0	0	0	0	0	0	0	3,746	21,636	22,778	23,682	25,727	24,821	27,106	23,413
Sell			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
			######	######	######	######	######	######	######	######	######	######	######	######	######	######	######	######	######	######	######	######	######
TOTAL KU/LGE ALLOWANCES			147,497	147,181	69,722	68,751	68,751	68,751	68,751	48,077	48,077	48,077	48,077	48,077	48,077	51,823	69,713	70,855	71,759	73,804	72,899	75,184	71,490
EOY Increase (+)/Decrease in Bank			-2,149	16,030	-26,907	2,232	2,101	702	570	-20,123	-18,867	-22,159	-21,527	-19,858	-19,388	-18,040	0	0	0	0	0	0	0
ALLOWANCE BANK																							
Total KU/LGE Allowance Bank (End of Year)		147,384	145,235	161,265	134,358	136,590	138,691	139,393	139,962	119,839	100,972	78,813	57,287	37,429	18,040								
Allocated Allowances		147,384	147,497	147,181	69,722	68,751	68,751	68,751	68,751	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077
Emissions			(140,646)	(131,151)	(96,629)	(66,518)	(66,650)	(68,049)	(68,181)	(68,201)	(66,945)	(70,236)	(69,604)	(67,936)	(67,466)	(69,864)	(69,713)	(70,855)	(71,759)	(73,804)	(72,899)	(75,184)	(71,490)
NET OF ALLOCATIONS - EMISSIONS		147,384	(2,149)	16,030	(26,907)	2,232	2,101	702	570	(20,123)	(18,867)	(22,159)	(21,527)	(19,858)	(19,388)	(21,786)	(21,636)	(22,778)	(23,682)	(25,727)	(24,821)	(27,106)	(23,413)

Withouth GH1 FGD (Brown FGD in 2010)	Owner	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
FUEL SO2 Content (#/MBTU)																							
Brown 1	KU		2.7	2.7	115.7	5.8	5.8	5.9	5.9	5.9	5.8	5.8	5.8	5.8	5.9	5.8	5.8	5.8	5.9	5.8	5.9	5.9	5.9
Brown 2	KU		2.7	2.7	107.5	5.9	5.9	5.8	5.9	5.9	5.8	5.9	5.9	5.9	5.9	5.9	5.8	5.8	5.9	5.9	5.8	5.8	5.6
Brown 3	KU		2.7	2.7	38.0	5.8	5.9	5.8	5.9	5.9	5.8	5.8	5.8	5.9	5.8	5.8	5.8	5.8	5.8	5.9	5.9	5.8	5.9
Ghent 1	KU		6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Ghent 2	KU		1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Ghent 3	KU		6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Ghent 4	KU		19.2	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Green River 3	KU		4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Green River 4	KU		4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Tyrone 3	KU		1.5	1.4	1.5	1.4	1.4	1.5	1.5	1.5	1.5	1.4	1.4	1.4	1.5	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.4
Cane Run 4	LGE		5.8	5.8	5.9	5.8	5.8	5.8	5.9	5.9	5.8	5.9	5.9	5.8	5.8	5.8	5.8	5.9	5.8	5.9	5.9	5.8	5.8
Cane Run 5	LGE		5.8	5.8	5.8	5.8	5.8	5.9	5.8	5.9	5.8	5.8	5.8	5.8	5.9	5.8	5.8	5.9	5.9	5.9	5.8	5.9	5.8
Cane Run 6	LGE		5.9	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.9	5.9	5.9	5.8	5.8	5.8	5.9	5.9	5.8	5.9	5.8	5.9	5.9
Mill Creek 1	LGE		5.8	5.9	5.9	5.8	5.8	5.9	5.8	5.8	5.8	5.9	5.9	5.9	5.9	5.8	5.9	5.8	5.8	5.9	5.9	5.8	5.8
Mill Creek 2	LGE		5.9	5.9	5.8	5.8	5.8	5.9	5.9	5.8	5.9	5.9	5.9	5.9	5.8	5.8	5.9	5.9	5.8	5.8	5.9	5.9	5.8
Mill Creek 3	LGE		5.8	5.8	5.8	5.9	5.9	5.9	5.9	5.8	5.8	5.9	5.9	5.8	5.9	5.9	5.8	5.8	5.8	5.9	5.9	5.8	5.9
Mill Creek 4	LGE		5.9	5.9	5.9	5.8	5.8	5.9	5.9	5.8	5.8	5.8	5.9	5.9	5.9	5.9	5.9	5.8	5.8	5.9	5.9	5.9	5.9
Trimble County 1	LGE		5.9	5.8	5.8	5.9	5.8	5.9	5.8	5.8	5.9	5.8	5.8	5.8	5.8	5.8	5.9	5.9	5.9	5.9	5.8	5.8	5.8
Trimble County 2	KU		0.0	0.0	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Trimble County 2	LGE		0.0	0.0	4.9	4.9	4.8	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
GFCU 1	KU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.4
GFCU 1	LGE		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.4
SCRUBBER REMOVAL EFF.																							
Brown 1			0%	0%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Brown 2			0%	0%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Brown 3			0%	0%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Ghent 1			94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%
Ghent 2			0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Ghent 3			98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Ghent 4			98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Green River 3			0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Green River 4			0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Tyrone 3			0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Cane Run 4			85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Cane Run 5			85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Cane Run 6			90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Mill Creek 1			93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%
Mill Creek 2			98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Mill Creek 3			89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%
Mill Creek 4			91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%
Trimble County 1			99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%
Trimble County 2			0%	0%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Trimble County 2			0%	0%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
GFCU 1			0%	0%	0%	0%	0%	0%	0%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
GFCU 1			0%	0%	0%	0%	0%	0%	0%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
TONS SO2 EMITTED			**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Brown 1	KU		7,829	7,688	5,947	337	340	330	328	335	319	346	347	358	337	329	367	377	381	392	409	406	342
Brown 2	KU		14,639	13,211	11,926	698	697	702	708	712	616	708	705	710	689	700	711	638	708	705	714	719	670
Brown 3	KU		36,261	35,294	10,158	1,775	1,020	1,801	1,824	1,790	1,718	1,772	1,770	1,583	1,733	1,791	1,818	1,825	1,810	1,845	1,651	1,667	1,760
Ghent 1	KU		6,870	6,729	6,669	6,501	6,675	6,646	6,006	6,668	6,640	6,640	6,654	6,667	6,662	5,970	6,657	6,656	6,637	6,659	6,668	6,676	5,076
Ghent 2	KU		16,890	15,545	15,342	15,763	13,820	15,658	16,151	16,391	15,765	16,448	16,346	15,060	16,095	16,760	17,054	16,932	17,244	17,332	10,015	17,017	16,426
Ghent 3	KU		2,424	2,406	2,060	2,334	2,337	2,334	2,339	2,343	2,293	2,091	2,320	2,327	2,309	2,323	2,336	2,339	2,109	2,349	2,347	2,367	2,313
Ghent 4	KU		5,929	2,345	2,285	2,275	2,283	2,290	2,305	2,063	2,269	2,288	2,283	2,285	2,265	2,277	2,061	2,294	2,295	2,285	2,301	2,311	2,268
Green River 3	KU		6,824	6,771	7,040	5,502	5,817	5,583	6,014	5,562	4,799	5,542	5,580	5,634	4,474	4,958	5,407	5,038	5,534	5,840	6,306	6,439	5,322
Green River 4	KU		12,819	12,134	10,452	7,900	7,139	8,025	8,236	8,734	8,114	9,503	9,533	7,899	8,277	9,145	9,369	9,610	9,420	10,769	9,474	10,039	9,067
Tyrone 3	KU		2,701	3,207	2,707	2,498	2,536	2,552	2,657	2,589	2,584	2,797	2,744	2,874	2,585	2,915	3,096	3,046	2,847	3,174	3,357	3,345	2,863
Cane Run 4	LGE		3,959	3,969	3,872	3,175	3,533	3,479	3,620	3,337	3,590	3,589	3,243	3,720	3,550	3,687	3,695	3,784	3,838	3,501	3,932	3,980	3,749
Cane Run 5	LGE		3,789	4,147	4,034	3,562	3,608	3,625	3,702	3,032	3,684	3,772	3,773	3,856	3,611	3,807	3,477	3,895	3,900	3,996	4,078	4,101	3,837
Cane Run 6	LGE		4,197	3,892	4,220	3,720	3,780	3,652	3,744	3,826	3,601	4,403	4,327	4,482	4,343	4,443	4,484	4,130	4,675	4,723	4,750	4,783	4,592
Mill Creek 1	LGE		4,052	4,261	3,536	3,953	3,746	3,974	3,760	3,876	3,515	3,766	3,257	3,784	3,505	3,779	3,557	3,804	3,638	3,690	3,385	3,930	3,596
Mill Creek 2	LGE		1,101	1,016	962	976	1,040	978	1,052	966	989	861	1,001	946	994	946	1,011	961	1,030	890	1,044	987	1,018
Mill Creek 3	LGE		9,177	8,918	9,512	8,203	9,539	8,969	9,524	8,904	9,436	8,897	9,445	8,124	9,415	8,870	9,452	8,923	9,531	8,968	9,544	8,235	9,467
Mill Creek 4	LGE		9,536	10,208	9,582	10,106	9,492	10,099	8,715	10,044	9,390	10,028	9,336	9,973	9,311	9,965	8,605	10,036	9,515	10,096	9,496	10,139	9,366
Trimble County 1	LGE		650	544	646	592	648	593	648	592	646	542	645	597	646	593	646	593	649	544	648	595	648
Trimble County 2	KU		0	0	775	1,470	1,549	1,538	1,541	1,541	1,542	1,545	1,544	1,543	1,542	1,545	1,548	1,550	1,558	1,555	1,556	1,557	1,539
Trimble County 2	LGE		0	0	182	345	363	361	362	362	362	362	362	362	362	363	363	364	365	365	365	365	361
GFCU 1	KU		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,024
GFCU 1	LGE		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	576
SO2 EMISSIONS (TONS) Total			149,646	142,283	111,927	81,683	80,561	83,187	83,232	83,666	82,070	85,897	85,213	82,777	82,703	85,172	85,742	86,794	87,693	89,888	87,986	91,557	86,679
ALLOWANCES																							
KU EPA Allocated SO2 Allowances			83,343	83,343	38,768	38,768	38,768	38,768	38,768	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110
LGE EPA Allocated SO2 Allowances			62,456	62,456	29,983	29,983	29,983	29,983	29,983	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967
Total KU/LGE EPA Allocated SO2 Allowances			145,799	145,799	68,751	68,751	68,751	68,751	68,751	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077
KU/LGE Extension			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KU's Portion of OMU Surplus/Shortfall			1,698	1,376	972	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Company Purchases			0	0	0	0	0	0	0	0	15,321	37,020	37,136	34,700	34,625	37,094	37,664	38,717	39,616	41,810	39,908	43,480	38,602
Sell			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
			******	******	******	******	******	******	******	******	******	******	******	******	******	******	******	******	******	******	******	******	******
TOTAL KU/LGE ALLOWANCES			147,497	147,175	69,722	68,751	68,751	68,751	68,751	48,077	63,398	85,897	85,213	82,777	82,703	85,172	85,742	86,794	87,693	89,888	87,986	91,557	86,679
EOY Increase (+)/Decrease in Bank			-2,149	4,892	-42,205	-12,933	-11,810	-14,437	-14,482	-35,588	-18,672	0	0	0	0	0	0	0	0	0	0	0	0
ALLOWANCE BANK																							
Total KU/LGE Allowance Bank (End of Year)		147,384	145,235	150,127	107,922	94,989	83,179	68,742	54,260	18,672													
Allocated Allowances		147,384	147,497	147,175	69,722	68,751	68,751	68,751	68,751	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077
Emissions			(149,646)	(142,283)	(111,927)	(81,683)	(80,561)	(83,187)	(83,232)	(83,666)	(82,070)	(85,897)	(85,213)	(82,777)	(82,703)	(85,172)	(85,742)	(86,794)	(87,693)	(89,888)	(87,986)	(91,557)	(86,679)
NET OF ALLOCATIONS - EMISSIONS		147,384	(2,149)	4,892	(42,205)	(12,933)	(11,810)	(14,437)	(14,482)	(35,588)	(33,993)	(37,820)	(37,136)	(34,700)	(34,625)	(37,094)	(37,664)	(38,717)	(39,616)	(41,810)	(39,908)	(43,480)	(38,602)

Brown FGD in 2011 (GH1 FGD in 2009)

FUEL SO2 Content (#/MBTU)	Owner	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Brown 1	KU		2.7	2.7	2.7	120.0	5.8	5.9	5.8	5.8	5.8	5.8	5.8	5.9	5.8	5.8	5.9	5.9	5.9	5.9	5.9	5.8	5.9
Brown 2	KU		2.7	2.7	2.7	121.6	5.9	5.9	5.9	5.8	5.8	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.8	5.8	5.9	5.8	5.8
Brown 3	KU		2.7	2.7	2.7	30.4	5.8	5.9	5.9	5.8	5.8	5.8	5.8	5.9	5.8	5.8	5.8	5.9	5.8	5.8	5.9	5.8	5.9
Ghent 1	KU		6.1	9.0	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Ghent 2	KU		1.2	8.7	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Ghent 3	KU		6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Ghent 4	KU		19.2	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Green River 3	KU		4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Green River 4	KU		4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Tyrone 3	KU		1.5	1.5	1.5	1.4	1.4	1.4	1.5	1.4	1.4	1.5	1.4	1.4	1.4	1.5	1.4	1.4	1.4	1.5	1.5	1.4	1.4
Cane Run 4	LGE		5.8	5.8	5.8	5.9	5.8	5.9	5.9	5.9	5.8	5.8	5.9	5.8	5.8	5.9	5.8	5.8	5.8	5.9	5.8	5.9	5.9
Cane Run 5	LGE		5.8	5.8	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.8	5.8	5.8	5.9	5.8	5.9	5.8	5.9	5.9	5.8
Cane Run 6	LGE		5.9	5.8	5.8	5.8	5.9	5.9	5.9	5.8	5.8	5.9	5.9	5.8	5.9	5.8	5.8	5.8	5.9	5.9	5.8	5.8	5.9
Mill Creek 1	LGE		5.8	5.9	5.8	5.9	5.9	5.8	5.9	5.9	5.8	5.9	5.8	5.8	5.8	5.9	5.9	5.8	5.8	5.8	5.8	5.8	5.8
Mill Creek 2	LGE		5.9	5.9	5.8	5.9	5.9	5.8	5.8	5.9	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.8	5.9	5.8	5.8	5.8	5.8
Mill Creek 3	LGE		5.8	5.9	5.8	5.8	5.9	5.8	5.8	5.9	5.9	5.8	5.8	5.8	5.9	5.8	5.9	5.9	5.9	5.9	5.8	5.9	5.9
Mill Creek 4	LGE		5.9	5.8	5.9	5.9	5.9	5.8	5.8	5.9	5.9	5.8	5.9	5.9	5.8	5.8	5.9	5.9	5.8	5.8	5.9	5.8	5.9
Trimble County 1	LGE		5.9	5.9	5.8	5.9	5.8	5.9	5.9	5.8	5.8	5.9	5.9	5.8	5.9	5.8	5.9	5.8	5.8	5.9	5.9	5.8	5.8
Trimble County 2	KU		0.0	0.0	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Trimble County 2	LGE		0.0	0.0	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
GFCU 1	KU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.4
GFCU 1	LGE		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.4
SCRUBBER REMOVAL EFF.																							
Brown 1			0%	0%	0%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Brown 2			0%	0%	0%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Brown 3			0%	0%	0%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Ghent 1			94%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Ghent 2			0%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%
Ghent 3			98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	95%	98%	98%
Ghent 4			98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Green River 3			0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Green River 4			0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Tyrone 3			0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Cane Run 4			85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Cane Run 5			85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Cane Run 6			90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Mill Creek 1			93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%
Mill Creek 2			98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Mill Creek 3			89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%
Mill Creek 4			91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%
Trimble County 1			99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%
Trimble County 2			0%	0%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Trimble County 2			0%	0%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
GFCU 1			0%	0%	0%	0%	0%	0%	0%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
GFCU 1			0%	0%	0%	0%	0%	0%	0%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
TONS SO2 EMITTED			2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Brown 1	KU		7,829	7,794	6,842	5,698	323	312	304	324	313	340	338	350	326	318	355	362	367	379	395	393	328
Brown 2	KU		14,639	13,106	14,234	11,769	687	687	693	699	603	695	691	699	676	665	699	624	692	689	700	704	649
Brown 3	KU		36,261	35,366	37,905	7,516	1,587	1,755	1,779	1,748	1,654	1,716	1,719	1,535	1,672	1,738	1,764	1,769	1,768	1,709	1,621	1,625	1,704
Ghent 1	KU		6,870	3,142	2,237	2,192	2,249	2,231	2,011	2,239	2,233	2,235	2,232	2,242	2,237	2,011	2,239	2,239	2,230	2,235	2,237	2,239	1,976
Ghent 2	KU		16,890	7,563	5,209	5,756	4,907	5,738	5,809	5,836	5,963	5,980	5,985	5,338	5,957	5,966	5,957	5,963	5,930	5,897	5,322	5,945	5,748
Ghent 3	KU		2,424	2,392	2,056	2,329	2,317	2,307	2,312	2,318	2,245	2,052	2,283	2,293	2,271	2,285	2,301	2,301	2,081	2,312	2,325	2,338	2,268
Ghent 4	KU		5,929	2,336	2,274	2,277	2,269	2,274	2,292	2,048	2,236	2,259	2,256	2,261	2,235	2,247	2,041	2,263	2,267	2,270	2,284	2,289	2,235
Green River 3	KU		6,824	6,994	6,711	5,765	5,868	5,643	6,100	5,611	4,773	5,595	5,523	5,663	4,511	5,024	5,396	5,050	5,651	5,868	6,519	6,424	5,306
Green River 4	KU		12,610	12,371	10,662	9,152	7,271	8,182	8,347	8,924	8,330	9,604	9,693	7,939	8,444	9,217	9,486	9,701	9,544	10,678	9,499	11,055	9,029
Tyrone 3	KU		2,701	3,283	2,687	2,755	2,565	2,594	2,675	2,631	2,626	2,795	2,748	2,898	2,628	2,999	3,064	3,064	2,857	3,204	3,358	3,384	2,876
Cane Run 4	LGE		3,959	3,951	3,815	3,181	3,322	3,185	3,406	3,174	3,314	3,410	3,062	3,587	3,362	3,591	3,591	3,669	3,762	3,453	3,901	3,949	3,654
Cane Run 5	LGE		3,789	4,154	3,998	3,655	3,352	3,327	3,423	2,994	3,398	3,558	3,592	3,641	3,468	3,634	3,411	3,753	3,820	3,874	4,012	4,064	3,627
Cane Run 6	LGE		4,197	3,847	4,147	3,788	3,553	3,427	3,523	3,581	3,585	4,192	4,119	4,344	4,119	4,292	4,362	4,038	4,615	4,692	4,732	4,765	4,565
Mill Creek 1	LGE		4,052	4,234	3,615	3,984	3,716	3,914	3,719	3,772	3,463	3,099	3,189	3,742	3,455	3,743	3,527	3,769	3,615	3,872	3,374	3,920	3,577
Mill Creek 2	LGE		1,101	1,012	959	977	1,032	908	1,043	956	980	853	995	942	986	943	1,007	957	1,025	888	1,041	984	1,013
Mill Creek 3	LGE		9,177	8,900	9,521	8,213	9,516	8,950	9,514	8,880	9,387	8,858	9,398	8,098	9,368	8,827	9,409	8,876	9,503	8,952	9,535	8,231	9,455
Mill Creek 4	LGE		9,536	10,161	9,582	10,140	9,478	10,062	8,678	9,972	9,290	9,945	9,730	9,868	9,201	9,846	8,518	9,952	9,460	10,073	9,476	10,119	9,337
Trimble County 1	LGE		650	544	646	594	648	593	647	592	645	542	646	592	647	593	646	593	649	544	648	595	647
Trimble County 2	KU		0	0	776	1,471	1,547	1,540	1,543	1,540	1,542	1,546	1,544	1,544	1,543	1,545	1,549	1,550	1,557	1,555	1,555	1,557	1,537
Trimble County 2	LGE		0	0	182	345	363	361	362	361	362	363	362	362	362	363	363	364	365	365	365	365	361
GFCU 1	KU		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,024
GFCU 1	LGE		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	576
SO2 EMISSIONS (TONS)																							
Total			149,646	131,151	127,957	91,557	68,650	68,049	68,181	68,201	66,945	70,236	69,604	67,936	67,466	69,864	69,713	70,855	71,759	73,804	72,899	75,184	71,490
ALLOWANCES																							
KU EPA Allocated SO2 Allowances			83,343	83,343	38,768	38,768	38,768	38,768	38,768	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110
LGE EPA Allocated SO2 Allowances			62,456	62,456	29,983	29,983	29,983	29,983	29,983	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967
Total KU/LGE EPA Allocated SO2 Allowances			145,799	145,799	68,751	68,751	68,751	68,751	68,751	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077
KU/LGE Extension			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KU's Portion of OMU Surplus/Shortfall			1,698	1,382	972	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Company Purchases			0	0	0	0	0	0	0	0	0	0	0	18,939	19,368	21,786	21,636	22,778	23,682	25,727	24,821	27,106	23,413
Sell			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
			######	######	######	######	######	######	######	######	######	######	######	######	######	######	######	######	######	######	######	######	######
TOTAL KU/LGE ALLOWANCES			147,497	147,181	69,722	68,751	68,751	68,751	68,751	48,077	48,077	48,077	48,077	67,016	67,466	69,864	69,713	70,855	71,759	73,804	72,899	75,184	71,490
EOY Increase (+)/Decrease in Bank			-2,149	16,030	-58,235	-22,807	2,101	702	570	-20,123	-18,667	-22,159	-21,527	-920	0	0	0	0	0	0	0	0	0
ALLOWANCE BANK																							
Total KU/LGE Allowance Bank (End of Year)		147,384	145,235	161,265	103,030	80,223	82,324	83,026	83,595	63,472	44,605	22,446	920										
Allocated Allowances		147,384	147,497	147,181	69,722	68,751	68,751	68,751	68,751	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077
Emissions			(149,646)	(131,151)	(127,957)	(91,557)	(68,650)	(68,049)	(68,181)	(68,201)	(66,945)	(70,236)	(69,604)	(67,936)	(67,466)	(69,864)	(69,713)	(70,855)	(71,759)	(73,804)	(72,899)	(75,184)	(71,490)
NET OF ALLOCATIONS - EMISSIONS		147,384	(2,149)	16,030	(58,235)	(22,807)	2,101	702	570	(20,123)	(18,867)	(22,159)	(21,527)	(19,858)	(19,388)	(21,786)	(21,636)	(22,778)	(23,682)	(25,727)	(24,821)	(27,106)	(23,413)

Withouth GH1 FGD (Brown FGD in 2010)

FUEL SO2 Content (#/MBTU)	Owner	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Brown 1	KU		2.7	2.7	115.7	5.8	5.8	5.9	5.9	5.9	5.8	5.8
Brown 2	KU		2.7	2.7	107.5	5.9	5.9	5.8	5.9	5.9	5.8	5.9
Brown 3	KU		2.7	2.7	38.0	5.8	5.9	5.8	5.9	5.9	5.8	5.8
Ghent 1	KU		6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Ghent 2	KU		1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Ghent 3	KU		6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Ghent 4	KU		19.2	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Green River 3	KU		4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Green River 4	KU		4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Tyrone 3	KU		1.5	1.4	1.5	1.4	1.4	1.5	1.5	1.5	1.5	1.4
Cane Run 4	LGE		5.8	5.8	5.9	5.8	5.8	5.8	5.9	5.9	5.8	5.9
Cane Run 5	LGE		5.8	5.8	5.8	5.8	5.8	5.9	5.8	5.9	5.6	5.8
Cane Run 6	LGE		5.9	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.9	5.9
Mill Creek 1	LGE		5.8	5.9	5.9	5.8	5.8	5.9	5.8	5.8	5.8	5.9
Mill Creek 2	LGE		5.9	5.9	5.8	5.8	5.8	5.9	5.9	5.8	5.9	5.9
Mill Creek 3	LGE		5.8	5.8	5.8	5.9	5.9	5.9	5.9	5.8	5.8	5.9
Mill Creek 4	LGE		5.9	5.9	5.9	5.8	5.8	5.9	5.9	5.8	5.8	5.8
Trimble County 1	LGE		5.9	5.8	5.8	5.9	5.8	5.9	5.8	5.8	5.9	5.8
Trimble County 2	KU		0.0	0.0	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Trimble County 2	LGE		0.0	0.0	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
GFCU 1	KU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GFCU 1	LGE		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SCRUBBER REMOVAL EFF.												
Brown 1			0%	0%	98%	98%	98%	98%	98%	98%	98%	98%
Brown 2			0%	0%	98%	98%	98%	98%	98%	98%	98%	98%
Brown 3			0%	0%	98%	98%	98%	98%	98%	98%	98%	98%
Ghent 1			94%	94%	94%	94%	94%	94%	94%	94%	94%	94%
Ghent 2			0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Ghent 3			98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Ghent 4			98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Green River 3			0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Green River 4			0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Tyrone 3			0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Cane Run 4			85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Cane Run 5			85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Cane Run 6			90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Mill Creek 1			93%	93%	93%	93%	93%	93%	93%	93%	93%	93%
Mill Creek 2			98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Mill Creek 3			89%	89%	89%	89%	89%	89%	89%	89%	89%	89%
Mill Creek 4			91%	91%	91%	91%	91%	91%	91%	91%	91%	91%
Trimble County 1			99%	99%	99%	99%	99%	99%	99%	99%	99%	99%
Trimble County 2			0%	0%	98%	98%	98%	98%	98%	98%	98%	98%
Trimble County 2			0%	0%	98%	98%	98%	98%	98%	98%	98%	98%
GFCU 1			0%	0%	0%	0%	0%	0%	0%	98%	98%	98%
GFCU 1			0%	0%	0%	0%	0%	0%	0%	98%	98%	98%
TONS SO2 EMITTED			2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Brown 1	KU		7,829	7,688	5,947	337	340	330	328	335	319	348
Brown 2	KU		14,639	13,211	11,926	698	697	702	708	712	616	708
Brown 3	KU		36,281	35,294	10,158	1,775	1,620	1,801	1,824	1,790	1,718	1,772
Ghent 1	KU		6,870	6,729	6,669	6,501	6,675	6,646	6,006	6,668	6,640	6,640
Ghent 2	KU		16,890	15,545	15,342	15,763	13,820	15,658	16,151	16,391	15,765	16,448
Ghent 3	KU		2,474	2,406	2,080	2,334	2,337	2,334	2,339	2,343	2,203	2,091
Ghent 4	KU		5,929	2,345	2,285	2,275	2,283	2,290	2,305	2,053	2,269	2,286
Green River 3	KU		6,824	6,771	7,040	5,502	5,817	5,583	6,014	5,562	4,709	5,542
Green River 4	KU		12,810	12,134	10,452	7,900	7,139	8,025	8,236	8,734	8,114	9,503
Tyrone 3	KU		2,701	3,207	2,707	2,498	2,536	2,552	2,657	2,589	2,584	2,797
Cane Run 4	LGE		3,959	3,969	3,872	3,175	3,533	3,479	3,620	3,337	3,590	3,589
Cane Run 5	LGE		3,789	4,147	4,034	3,562	3,608	3,625	3,702	3,032	3,684	3,772
Cane Run 6	LGE		4,187	3,892	4,220	3,720	3,780	3,652	3,744	3,826	3,801	4,403
Mill Creek 1	LGE		4,052	4,261	3,536	3,953	3,746	3,974	3,760	3,876	3,515	3,766
Mill Creek 2	LGE		1,101	1,016	962	876	1,040	978	1,052	966	989	861
Mill Creek 3	LGE		9,177	8,918	9,512	8,203	9,539	8,969	9,524	8,904	9,436	8,897
Mill Creek 4	LGE		9,536	10,208	9,582	10,106	9,492	10,099	8,715	10,044	9,390	10,028
Trimble County 1	LGE		650	544	646	592	648	593	640	592	646	542
Trimble County 2	KU		0	0	775	1,470	1,549	1,538	1,541	1,541	1,542	1,545
Trimble County 2	LGE		0	0	182	345	363	361	362	362	362	362
GFCU 1	KU		0	0	0	0	0	0	0	0	0	0
GFCU 1	LGE		0	0	0	0	0	0	0	0	0	0
SO2 EMISSIONS (TONS) Total			149,646	142,283	111,927	81,683	80,561	83,187	83,232	83,668	82,070	85,697
ALLOWANCES												
KU EPA Allocated SO2 Allowances			83,343	83,343	38,768	38,768	38,768	38,768	38,768	27,110	27,110	27,110
LGE EPA Allocated SO2 Allowances			62,456	62,456	29,983	29,983	29,983	29,983	29,983	20,967	20,967	20,967
Total KU/LGE EPA Allocated SO2 Allowances			145,799	145,799	68,751	68,751	68,751	68,751	68,751	48,077	48,077	48,077
KU/LGE Extension			0	0	0	0	0	0	0	0	0	0
KU's Portion of OMU Surplus/Shortfall			1,698	1,378	972	0	0	0	0	0	0	0
Combined Company Purchases			0	0	0	0	0	0	0	0	15,321	37,820
Sell			0	0	0	0	0	0	0	0	0	0
			******	******	******	******	******	******	******	******	******	******
TOTAL KU/LGE ALLOWANCES			147,497	147,175	69,722	68,751	68,751	68,751	68,751	48,077	63,398	85,697
EOY Increase (+)/Decrease in Bank			-2,149	4,892	-42,205	-12,933	-11,810	-14,437	-14,482	-35,588	-18,672	0
ALLOWANCE BANK												
Total KU/LGE Allowance Bank (End of Year)		147,384	145,235	150,127	107,922	94,989	83,179	68,742	54,260	18,672		
Allocated Allowances		147,384	147,497	147,175	69,722	68,751	68,751	68,751	68,751	48,077	48,077	48,077
Emissions			(149,646)	(142,283)	(111,927)	(81,683)	(80,561)	(83,187)	(83,232)	(83,668)	(82,070)	(85,697)
NET OF ALLOCATIONS - EMISSIONS		147,384	(2,149)	4,892	(42,205)	(12,933)	(11,810)	(14,437)	(14,482)	(35,588)	(33,993)	(37,820)

FUEL SO2 Content (#/MBTU)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Brown 1	5.8	5.8	5.9	5.8	5.8	5.8	5.9	5.8	5.9	5.9	5.9
Brown 2	5.9	5.9	5.9	5.9	5.8	5.8	5.9	5.9	5.8	5.8	5.8
Brown 3	5.8	5.9	5.8	5.8	5.8	5.8	5.8	5.9	5.9	5.8	5.9
Ghent 1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Ghent 2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Ghent 3	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Ghent 4	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Green River 3	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Green River 4	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Tyrone 3	1.4	1.4	1.5	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.4
Cane Run 4	5.9	5.8	5.8	5.8	5.8	5.9	5.8	5.9	5.9	5.8	5.8
Cane Run 5	5.8	5.8	5.9	5.8	5.8	5.9	5.9	5.9	5.8	5.9	5.9
Cane Run 6	5.9	5.8	5.8	5.8	5.9	5.9	5.8	5.9	5.8	5.9	5.9
Mill Creek 1	5.9	5.9	5.9	5.8	5.9	5.8	5.8	5.9	5.9	5.8	5.9
Mill Creek 2	5.9	5.9	5.8	5.8	5.9	5.9	5.8	5.8	5.9	5.9	5.8
Mill Creek 3	5.9	5.8	5.9	5.9	5.8	5.8	5.8	5.9	5.9	5.8	5.9
Mill Creek 4	5.9	5.9	5.9	5.9	5.9	5.8	5.8	5.9	5.9	5.9	5.9
Trimble County 1	5.8	5.8	5.8	5.8	5.9	5.9	5.9	5.9	5.8	5.8	5.8
Trimble County 2	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Trimble County 2	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
GFCU 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
GFCU 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.4
SCRUBBER REMOVAL EFF.											
Brown 1	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Brown 2	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Brown 3	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Ghent 1	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%
Ghent 2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Ghent 3	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Ghent 4	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Green River 3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Green River 4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Tyrone 3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Cane Run 4	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Cane Run 5	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Cane Run 6	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Mill Creek 1	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%	93%
Mill Creek 2	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Mill Creek 3	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%
Mill Creek 4	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%
Trimble County 1	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%
Trimble County 2	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Trimble County 2	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
GFCU 1	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
GFCU 1	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
TONS SO2 EMITTED	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Brown 1	347	358	337	329	367	377	351	392	406	406	342
Brown 2	705	710	689	700	711	638	708	705	714	719	670
Brown 3	1,770	1,583	1,733	1,701	1,818	1,825	1,819	1,845	1,651	1,867	1,760
Ghent 1	6,654	6,667	6,662	5,970	6,657	6,656	6,637	6,659	6,668	6,678	5,876
Ghent 2	16,346	15,060	16,095	16,760	17,084	16,932	17,744	17,332	10,015	17,617	16,420
Ghent 3	2,320	2,327	2,309	2,323	2,336	2,339	2,109	2,349	2,347	2,367	2,313
Ghent 4	2,283	2,285	2,265	2,277	2,061	2,294	2,255	2,295	2,301	2,311	2,268
Green River 3	5,580	5,634	4,474	4,058	5,407	5,038	5,534	5,840	6,306	6,439	5,322
Green River 4	9,533	7,899	8,277	9,145	9,369	9,610	9,420	10,769	9,424	10,039	9,067
Tyrone 3	2,744	2,674	2,565	2,915	3,096	3,048	2,847	3,174	3,357	3,345	2,863
Cane Run 4	3,243	3,720	3,550	3,687	3,695	3,784	3,838	3,501	3,032	3,980	3,749
Cane Run 5	3,773	3,856	3,611	3,807	3,477	3,895	3,900	3,996	4,078	4,101	3,837
Cane Run 6	4,327	4,482	4,343	4,443	4,484	4,130	4,675	4,723	4,750	4,783	4,592
Mill Creek 1	3,257	3,784	3,505	3,779	3,557	3,604	3,638	3,890	3,385	3,930	3,596
Mill Creek 2	1,001	846	994	848	1,011	961	1,030	890	1,044	987	1,018
Mill Creek 3	9,445	8,124	9,415	8,878	9,452	8,923	9,531	8,968	9,544	8,235	9,487
Mill Creek 4	9,336	9,973	9,311	9,965	8,605	10,036	9,515	10,056	9,498	10,139	9,368
Trimble County 1	645	592	640	593	646	593	649	544	648	595	648
Trimble County 2	1,544	1,543	1,542	1,545	1,548	1,550	1,558	1,555	1,556	1,557	1,539
Trimble County 2	362	362	362	363	363	364	365	365	365	365	361
GFCU 1	0	0	0	0	0	0	0	0	0	0	1,024
GFCU 1	0	0	0	0	0	0	0	0	0	0	576
SO2 EMISSIONS (TONS) Total	85,213	82,777	82,703	85,172	85,742	86,794	87,693	89,888	87,986	91,557	86,679
ALLOWANCES											
KU EPA Allocated SO2 Allowances	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110	27,110
LGE EPA Allocated SO2 Allowances	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967	20,967
Total KU/LGE EPA Allocated SO2 Allowances	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077
KU/LGE Extension	0	0	0	0	0	0	0	0	0	0	0
KU's Portion of OMU Surplus/Shortfall	0	0	0	0	0	0	0	0	0	0	0
Combined Company Purchases	37,136	34,700	34,625	37,094	37,664	38,717	39,616	41,810	39,908	43,480	38,602
Sell	0	0	0	0	0	0	0	0	0	0	0
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TOTAL KU/LGE ALLOWANCES	85,213	82,777	82,703	85,172	85,742	86,794	87,693	89,888	87,986	91,557	86,679
EOY Increase (+)/Decrease in Bank	0	0	0	0	0	0	0	0	0	0	0
ALLOWANCE BANK											
Total KU/LGE Allowance Bank (End of Year)											
Allocated Allowances	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077	48,077
Emissions	(85,213)	(82,777)	(82,703)	(85,172)	(85,742)	(86,794)	(87,693)	(89,888)	(87,986)	(91,557)	(86,679)
NET OF ALLOCATIONS - EMISSIONS	(37,136)	(34,700)	(34,625)	(37,094)	(37,664)	(38,717)	(39,616)	(41,810)	(39,908)	(43,480)	(38,602)