This Integrated Resource Plan represents a snapshot of an ongoing resource planning process using current business assumptions. The planning process is constantly evolving and may be revised as conditions change and as new information becomes available. Before embarking on any final strategic decisions or physical actions, the Companies will continue to evaluate alternatives for providing reliable energy while complying with all regulations in a least-cost manner. Such decisions or actions will be supported by specific analyses and will be subject to the appropriate regulatory approval processes.

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Recommendations in PSC Staff Report on the Last IRP – Case No. 2008-00148

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. The load forecast assumes the status quo for our obligations to serve in both Kentucky and Virginia based on existing policy directions in the state and country. Integrated resource planning is based on the assumption of an obligation to serve a specifically defined service territory.

  Future environmental requirements are incorporated in the Base IRP forecast and the High and Low forecast sensitivities using the SAE models for the commercial and industrial sectors, as described in Section 7.7.

- **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 2011 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.

Demand Side Management

- **Staff encourages the Companies to pursue DSM alternatives with industrial and large commercial customers.**
- **Continue aggressively seeking opportunities for new and innovative DSM programs.**
- **The Companies should work to verify (to the extent possible) the actual achieved reduction in energy usage of each of the pilot DSM programs.**

As a result of the Companies' ongoing review of Demand Side Management/Energy Efficiency ("DSM/EE") programs and research into possible new programs, the Companies have formulated concepts for enhanced and additional DSM/EE programs to be included in its DSM/EE Program Plan. This plan was filed with the Commission in Case No. 2011-00134. The Companies received customer feedback that has enabled the Companies to pursue DSM alternatives that are responsive to the increasing number of requests from the commercial customer segment. The proposed DSM/EE filing seeks the inclusion of additional energy efficiency retrofits eligible for incentives such as refrigeration; and to add commercial customized incentives to encourage sustained energy efficient retrofits for customers that are not covered by the existing Commercial Conservation/Incentive Program.

The Companies developed the proposed DSM/EE Plan in collaboration with their Energy Efficiency Advisory Group that seeks opportunities for new and innovative DSM programs for both the residential and commercial customer segment. Upon approval, this Program Plan can further increase program participation opportunities for customers and support the Companies in meeting its 2008 IRP cumulative demand reductions. This Program Plan will enhance the following programs: Residential and Commercial Load Management; Commercial Conservation; Residential Conservation; Residential Low Income Weatherization Program; and Program Development and Administration. In addition to enhancing several currently approved programs, the Companies plan to seek approval for additional DSM programs that will further increase energy and demand savings for the Companies. These programs include the Smart Energy Profile Program, Residential Incentives Program, and a Residential Refrigerator Removal Program.

Supply-Side Resource Assessment

- **In the next IRP, LG&E/KU should specifically discuss the existence of any cogeneration within their service territories and the consideration given to cogeneration in the resource plan.**
- **LG&E and KU should specifically identify and describe the net metering equipment and systems installed on each system. A detailed discussion on the manner in which such resources were considered in the LG&E/KU resource plan should also be provided.**
- **LG&E/KU should provide a detailed discussion of the consideration given to distributed generation in the resource plan.**

The Companies have tariffs that allow for distributed generation to be produced by customers within the service territory as discussed below.

Both KU and LG&E have net metering tariffs which provide customers with the option of generating their own electricity using renewable resources. Net metering measures the difference between the energy a customer purchases from the Companies and the amount of energy the customer generates using their own renewable energy source. Any excess power generated is "banked" as a credit to be applied against the customer's future energy purchases from the Companies. The Companies currently have 88 net metering customers with capacities from 0.875 kW to 29.5 kW. In 2010, those customers generated 84 MWh in excess of their individual energy consumption. Summaries of the Companies' net metering customers for which the Companies have detailed data and the associated capacities by source type are shown in the following tables.

	Solar	Wind	Solar/ Wind	N/A	Total
Customers (#)					
Residential	63	2	1	3	69
Non-Residential	15	2	0	2	19
Total	**78**	**4**	**1**	**5**	**88**

	Solar	Wind	Total
Capacity (kW)			
Residential	135	7	**142**
Non-Residential	195	4	**199**
Total	**329**	**12**	**341**

In addition to the net metering tariffs which limit customers to 30 kW of generating capacity, the Companies also provide tariffs for customers with generating capacities greater than 30 kW. These tariffs allow for cogeneration customers with qualifying facilities to sell all or part of their excess power to the Companies. Successful cogeneration facilities are very site-specific and require an industrial host operating with the appropriate economic factors to make the arrangement cost-effective. Currently, there are no customers on this rate however, the Companies continue to investigate potential opportunities.

Given the very small impact of net metering customers relative to the size of the Companies' generation needs and the lack of cogeneration customers on the Companies' system, these options have not been explicitly included as resources in the resource plan. While these types of generation sources can be somewhat reliable for producing energy, they offer an uncertain contribution to meet peak demand.

In developing the optimal resource plan, a number of small technologies that could be utilized as distributed generation were considered as supply-side options as detailed in the study *Analysis of Supply-Side Technology Alternatives* (March 2011), Volume III, Technical Appendix. The wind conversion and landfill gas options passed the supply-side screening analysis and were included in the options available for the optimal expansion plan. However, due to the relatively high cost for firm capacity contribution and limited opportunities in Kentucky for these resources, they were not chosen as the least-cost means to meet the Companies' expected demand. The Companies will continue to evaluate potential generation opportunities as they arise and as technologies develop further.

LG&E/KU should provide a specific discussion of the improvements to and more efficient utilization of transmission and distribution facilities as required by 807 KAR 5:058, Section 8(2)(a). This information should be provided for the past three years and should address LG&E/KU's plans for the next three years.

The improvements to and more efficient utilization of transmission and distribution facilities are discussed in Section 8.(2)(a) in Volume I. In compliance with the FERC Standards of Conduct, the projects related to the Companies' transmission system are covered in detail in *Transmission Information* of Volume III, Technical Appendix of this Plan.

Companies are strongly encouraged to redouble efforts to pursue viable hydro power opportunities and to report on efforts in 2011 IRP per Change of Control Order (Case No. 2001-00204: Page 16).

The Companies' primary focus for additional hydro opportunities is at the Companies' existing hydro stations. An additional 6 MW of capacity will result from the ongoing upgrades at KU's Dix Dam Station; an additional 16 MW (expected at summer peak) will result from the rehabilitation of the units at the Ohio Falls Station. In addition to these rehabilitation efforts, the Companies continue to monitor potential hydro opportunities. While the Ohio River provides the most realistic potential for developing new hydro projects of significant size, other existing dams on the Ohio River are already licensed by other companies and the high cost of building a new dam makes that option economically unfeasible. Building a new hydro plant at an existing dam requires transmission access, multi-year licensing, and management of environmental concerns which typically drive such projects to be too expensive to be a least-cost option.

In 2008, a feasibility study was commissioned by LG&E to investigate potential expansion alternatives at the Ohio Falls Station. This study considered five configurations of additional units and concluded with the recommendation of a 50 MW bulb unit on Shippingport Island as the most viable and cost-effective alternative. This project was included as one of the technologies considered for further evaluation in the long-term expansion plan but it was not shown to be part of the least-cost plan.

Section 1251(12): Administrative Case No. 2007-00300 (Consideration of the Requirements of the Federal Energy Policy Act of 2005 Regarding Fuel Sources and Fossil Fuel Generation Efficiency – Fuel Sources

In connection with its decision not to mandate adoption of a fuel source standard, the Commission directs the jurisdictional generators to place greater emphasis on research into cost-effective alternatives to generation based on coal, natural gas, and fuel oil. Also, in accordance with 807 KAR 5058, Section 8(2)(b) and (d), the Commission directs the generators to include a full, detailed discussion of such efforts in IRPs filed subsequent to the date of this Order.

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 expansion of the Ohio Falls Station 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* (March 2011) contained in Volume III, Technical Appendix.

<u>Section 1251(13): Administrative Case No. 2007-00300 (Consideration of the Requirements of the Federal Energy Policy Act of 2005 Regarding Fuel Sources and Fossil Fuel Generation Efficiency – Fossil Fuel Generation Efficiency</u>

The Commission does not share the generators' concern that a generation efficiency standard must be not only company-specific but also unit-specific. While the Commission agrees with the premise that generation efficiency needs to be flexible in order to accommodate company-specific and unit-specific circumstances, we believe the requirement to implement a plan as set forth in the proposed standard would allow each generator the flexibility to consider not only the operating characteristics of its generation fleet as a whole but also the specific operating characteristics of each individual generation unit.

As it similarly stated in its fuel source findings, while there is no mandate to adopt a generation efficiency standard, the Commission directs the jurisdictional generators to focus greater research into cost-effective generation efficiency initiatives and to include a full, detailed discussion of such efforts in subsequent IRPs in accordance with Section 8(2)(a).

Generation efficiency and utilization improvements are discussed in Section 8.(2)(a) in Volume I of this Plan.

Kentucky Utilities Company
and
Louisville Gas and Electric Company

Analysis of Supply-Side Technology Alternatives

Prepared by

Generation Planning & Analysis

March 2011

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

Table of Contents

1. EXECUTIVE SUMMARY

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.

The primary source of the data used in this evaluation for mature and developed technologies is the EPRI TAG. The *Cummins and Barnard Generation Options Technology Study* (December 2007) was also consulted to update experimental technologies. The reports provided the following: technology descriptions, detailed capital and O&M cost estimates, and detailed performance and emission results at 59°F (average) at expected operating load for peaking, intermediate and base load options. Other data used in the screening analysis was compiled via contracted studies from MWH Global, Inc.

Fifty-six 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 NO_x and SO_2 are included in the analysis. The environmental cost implications regarding NO_x and SO_2 emissions are accounted for as a variable cost similar to a fuel adder. However, due to anticipated environmental regulations, allowance price forecasts for NO_x and SO_2 are significantly lower in 2011 through 2013 compared to recent years and then are assumed to be zero after 2013. Since there is no market anticipated for CO_2 emissions allowances, due to currently proposed regulations, no environmental cost has been included for CO_2.

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 - 800 MW
3x1 F-Class Combined Cycle Combustion Turbine
2x1 F-Class Combined Cycle Combustion Turbine
1x1 G-Class Combined Cycle Combustion Turbine
GE 7FA CT Simple Cycle Combustion Turbine
Landfill Gas IC Engine
Wind Energy Conversion
Ohio Falls 50MW Bulb Hydro Unit

2. INTRODUCTION

This study evaluated several supply-side technology costs and performance estimates for currently available and emerging technologies. As part of the IRP process, 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 number. The study was conducted by comparing the levelized cost of building and operating each technology at various levels of utilization. A discussion of the data and a brief description of each generating technology are also presented. This is followed by a description of the levelized screening methodology. Finally, the basis for recommending one technology over another is presented and those technologies suggested for additional computer simulation are identified.

3. DATA SOURCES

EPRI TAG, which is a report funded by the sponsors of EPRI's Program 9, was used to provide technical descriptions for the developed and mature technologies, detailed capital costs, performance expectations, emission rates, and O&M costs for conventional generation alternatives (pulverized coal, simple and combined cycle combustion turbines, wind, solar, advanced coal and combustion turbines, and energy storage systems). A study from HDR Inc. was used for the 2x1 and 1x1 7F-Class and 1x1 G-Class combined cycle combustion turbines technologies. The *Cummins and Barnard Generation Options Technology Study* (December 2007) was the basis for the non-conventional technologies (microturbine, Kalina and Cheng cycle combustion turbine, some combustible renewable energy, and waste-to-energy). Data for non-conventional technologies is less detailed than conventional alternatives due to the lower level of maturity and frequency non-conventional technologies. The Companies' analysis and a study from MWH Global, Inc. regarding expansion of LG&E's Ohio Falls hydro station were also 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 four "Greenfield" pulverized coal options, which include two subcritical units 256 MW and 512 MW and two supercritical units 565 MW and 800 MW.

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 SCR.
- Particulate Matter (PM_{10}): Fabric filter.
- Total Mercury (Hg°, Hg^{2+}, $Hg_{(p)}$): Powder Activated Carbon injection, fabric filter and wet limestone 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. More effort has been placed on designing and developing supercritical CFB in recent years, however only one unit currently exists commercially. For this analysis, a 2x250 MW subcritical CFB unit was 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 290 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 HRSGs which produce steam for a conventional steam turbine. With only two commercial-scale IGCC plants on line for over 10 years, significant improvements in efficiency, fuel flexibility and economics will be required to reduce the cost of IGCC. 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 two IGCC options: a 307 MW 1x1 unit (one combustion turbine with one steam turbine), and a 640 MW 2x1 unit (two combustion turbines with one steam turbine). These options utilize emissions controls as follows:

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

4.1.5 Coal Technologies with CO_2 Capture

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. The cost estimates from EPRI TAG for coal units do not include CO_2 sequestration options, so this data was obtained from the Cummins and Barnard report. 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 for sequestration are provided, it should be noted that sequestration technology is still under development. 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 higher price relative to coal or 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 (43, 84, and 206 MW at 59°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 increased exposure to volatile natural gas prices. Six conventional CCCT configurations were evaluated in this study ranging in capacity from 109 MW to 943 MW at 59°F including a single CT (1x1), 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 blown down to maintain water quality and the remainder is cycled back through the HRSG. The HAT reviewed herein is rated at 366 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 282 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 140 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 alternating current ("AC").

Fuel cells are ideal technologies for small distributed power generation due to the high efficiency, low air/noise emissions and limited moving parts. Waste heat can also be effectively used for commercial building heating and cooling. 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. Solid oxide fuel cells ("SOFC") are commercially available for commercial and residential applications. SOFCs are also being used in combination with gas turbines for combined heat and power ("CHP") systems. A 20 MW MCFC and 25 MW SOFC with a 97 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. The potential for wind power production 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 200 MW wind farm 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 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. Six solar options were considered in the evaluation with ratings ranging from 1.2 MW 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 alternatives included in this evaluation are a 514 MW supercritical pulverized coal facility and a 566 MW CFB both co-fired with ten percent biomass fuel by weight. A 100 MW CFBC and a 50 MW wood-fired stoker plant using 100% biomass were also considered. Emissions controls are similar to the coal-only configurations.

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. Therefore, thermal technology was not considered a viable option for Kentucky and was excluded from the screening analysis.

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 new hydroelectric installation considered here is a run-of-river based design sized for 30 MW of generation capacity at an unidentified 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.

Refuse-Derived Fuel

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 economical. 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 MW. 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.

For more than two decades, storage batteries (primarily lead-acid), pumped hydro storage, and compressed air storage have been the primary energy storage methods. Of these, pumped hydro storage and compressed air storage have been traditionally used for large utility-scale storage applications because of their large storage and power capabilities. However, due to their high initial costs, to date they have not been economically applied to small renewable energy systems. The economy of scale strongly favors these technologies for large storage applications. Batteries on the other hand are suitable for medium to small applications because they are modular and are produced and deployed in small units.

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 350 MW PHES unit assumed to recover 70 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.

Advanced Battery Energy Storage Flow batteries are emerging energy storage devices that can serve many purposes in energy delivery systems. They can respond within milliseconds and deliver power for hours. They operate much like a conventional battery, storing and releasing energy through a reversible electrochemical reaction with a large number of charging and discharging cycles. They differ from a conventional battery in two ways 1) the reaction occurs between two electrolytes, rather than between an electrolyte and an electrode and 2) they store the two electrolytes external to the battery and the electrolytes are circulated through the cell stack as required. The great advantage that this system provides is very large electrical storage capacity, the limitation being only the capacity of the electrolyte storage reservoirs.

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. In addition to high initial cost, a battery system will require replacement every 4 to 10 years, depending upon duty cycle. The flow battery storage unit included in this analysis is rated at 100 MW and has a capacity factor of 20 percent and is assumed to recover 80 percent of the energy input.

4.4.2 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 3,500 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 350 MW CAES unit with a 25 percent capacity factor was used in this evaluation.

4.5 Other Technologies

4.5.1 Ohio Falls Expansion

A screening-level study has been carried out to investigate potential Ohio Falls Project expansion alternatives. Four "in-river" development alternatives in the space between the existing powerhouse and the Corps spillway gate structure and one development alternative on Shippingport Island, a manmade island near the Falls of the Ohio, have been considered. The specific alternatives investigated are listed in Table 2.

Table 2
Hydro Electric Alternatives
At Ohio Falls

Alternatives	Capital ($M)	Incremental Energy (GWh)
50 MW Bulb Unit at Shippingport Island*	[redacted]	172.2
Hydroelectric - 14 MW Kaplans Units in Bays 9 & 10	[redacted]	101.6
25 MW Bulb Units in Bays 9 & 10	[redacted]	144.4
50 MW Kaplan Unit in river	[redacted]	144.1
50 MW Propeller Unit in river	[redacted]	123.5

**Cost estimate for Shippingport, does not include the time and costs associated with dealing with the significant archaeological resources known to be present at the site.*

The Ohio Falls Station is considered a run-of-the-river facility where river levels and the Army Corps of Engineers control the water 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 options are based on the cost evaluation supplied to the Companies by MWH Global, Inc.

5. ANALYSIS OVERVIEW

The Companies' screening analysis consists of 56 generation alternatives developed primarily by using EPRI TAG and Cummins & Barnard Report. 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 Eastern bituminous high-sulfur coal. The costs for natural gas units include a firm gas charge of $0.3104 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.

Emissions allowance costs are also included to account for regulations limiting the emission of SO_2 and NO_x from certain generating facilities. However, due to anticipated environmental regulations, allowance price forecasts for NO_x and SO_2 are significantly lower in 2011 through 2013 compared to recent years and then are assumed to be zero after 2013. The emissions allowance costs are calculated by year by multiplying the forecasted market emissions allowance price by the emissions rate. EPRI TAG and Cummins & Barnard Report were used to estimate 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 market quotes through 2013. The emissions allowance price forecasts are shown in Exhibit 2(b).

Also included in the analysis are tax credits for renewable generation projects. A federal production tax credit in the amount of two cents per kWh is included for wind, and one cent per kWh is included for MSW, RDF, TDF, LFG, sewage sludge, biomass and hydropower projects.

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, 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.

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 297 (i.e., 27 cases x 11 capacity factor ranges = 297) "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 least-cost, most viable 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 for construction costs are expected to be more accurate relative to non-conventional alternatives where costs are less certain due to immature 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), and fuel cost.

6.1 Capital Cost

Based on research and experience from 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 estimated 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 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 the heat rate expected during the design phase. A ± 5 percent adjustment to the heat rate specified for each technology 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 which are used for the technologies that utilize coal and natural gas. For MSW, RDF, LFG, TDF, and biomass, 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.

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.

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 59°F. All technologies evaluated in this analysis are shown in this exhibit.

8. SCREENING ANALYSIS

The least-cost operation of each 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 EPRI TAG and 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.

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 six 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 six hydro options were limited to capacity factors between 30 and 40 percent. These limitations were based on the projected energy received from these run-of-the river projects.

Due to limitations in fuel supply, the MSW, 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

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 to 100 percent in 10 percent increments. For each technology, levelized costs in $/kW-yr 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 2010 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 3.

Table 3
Least-Costly Technologies
In At-Least One Sensitivity Case

Combined Cycle 3x1 F-Class Combustion Turbine
Supercritical Pulverized Coal Unit, 800 MW
Landfill Gas IC Engine Simple Cycle GE 7FACombustion Turbine
Wind Energy Conversion
Ohio Falls 50MW Bulb Hydro Unit

Exhibit 7 is a graphical representation of the technologies of these five 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 4 in order of the total number of times selected.

Table 4
Second and Third Least-Costly Technologies
In At-Least One Sensitivity Case

Combined Cycle 3x1 F-Class Combustion Turbine
Combined Cycle 2x1 F-Class Combustion Turbine
Supercritical Pulverized Coal Unit, 800 MW
Subcritical Pulverized Coal Unit, 500 MW
Combined Cycle 1x1 G-Class Combustion Turbine
Supercritical Pulverized Coal, 565 MW
Landfill Gas IC Engine Simple Cycle GE 7FA Combustion Turbine
Wind Energy Conversion
Kalina Cycle Combined Cycle Combustion Turbine
Ohio Falls 50MW Bulb Hydro Unit

The eleven different technology types and sizes specified between Tables 4 and 5 are those that initially 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 297 "opportunities" for each technology to be identified as one of the first three least cost options. Table 5, 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 5 failed to appear as one of the top three least-cost options in any of the cases identified.

Table 5
The Frequency of Occurrence of Each
Technology as First, Second or Third Least Cost

# Occurrences				
1st	**2nd**	**3rd**	**Total**	**Technology Name**
131	73	20	224	Combined Cycle 3x1 F-Class Combustion Turbine
0	119	77	196	Combined Cycle 2x1 F-Class Combustion Turbine
88	27	10	125	Supercritical Pulverized Coal Unit - 800 MW
0	71	18	89	Subcritical Pulverized Coal Unit - 500 MW
0	0	58	58	Combined Cycle 1x1 G-Class Combustion Turbine
0	0	60	60	Supercritical Pulverized Coal - 565 MW
31	3	5	39	Landfill Gas IC Engine
27	0	7	34	Simple Cycle GE 7FA Combustion Turbine
19	4	9	32	Wind Energy Conversion
0	0	30	30	Kalina Cycle Combined Cycle Combustion Turbine
1	0	3	4	Ohio Falls 50MW Bulb Hydro Unit

Table 5 shows that the Combined Cycle 3x1 F-Class Combustion Turbine unit was selected 224 times as the first, second, or third least-cost technology while the 50MW Bulb Hydro Unit was selected only 4 times. Table 5 provides a good starting point for further reducing the list of technologies identified in Tables 3 and 4.

A review of Table 5 reveals that three different coal-fired technologies have been identified among the 11 least cost technologies. They are an 800 MW supercritical r pulverized coal unit, a 565 MW supercritical pulverized coal unit, and a 500 MW subcritical pulverized coal unit. Of these, only the 800 MW 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 simple cycle GE 7FA combustion turbines will be considered for further optimization analysis as it is the only simple cycle configuration among the least cost alternatives. In addition, the combined cycle 3x1 and, 2x1 F-Class combustion turbine configurations and the combined cycle 1x1 G-Class combustion turbine are considered for further optimization analysis. Because the Kalina Cycle CCCT is only in developmental stages and is not commercially available, it is not evaluated further.

Although it only occurred four times, once in first and three times in third place among the least-cost technologies, the expansion of the Ohio Falls hydroelectric station is included for further evaluation. And, while the wind profile for most of Kentucky is not very suitable for power generation, the wind energy conversion option is included for further evaluation for potential opportunities as another renewable alternative.

10. RECOMMENDATIONS

Based on the various analyses discussed above, the technologies listed in Table 6 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 8 is a graphical representation of the least-cost technologies, which will be further evaluated in the Strategist® optimization software modeling.

Table 6
Technologies Suggested for Analysis
Within Strategist®

Supercritical Pulverized Coal Unit - 800 MW
Combined Cycle 3x1 F-Class Combustion Turbine
Combined Cycle 2x1 F-Class Combustion Turbine
Combined Cycle 1x1 G-Class Combustion Turbine
Simple Cycle GE 7FA Combustion Turbine
Landfill Gas IC Engine
Wind Energy Conversion
Ohio Falls 50MW Bulb Hydro Unit

Appendix A

Exhibit 1

Technologies Analyzed in the Screening Process

Technologies Screened

Tech. ID	Technology Description	Category	Sub-Category	Fuel Type	Source
1	Pumped Hydro Energy Storage	Storage	Pumped Hydro	Charging Only	EPRI
2	Advanced Battery Energy Storage	Storage	Battery	Charging Only	EPRI
3	Compressed Air Energy Storage	Storage	Compressed Air	Gas and Charging	EPRI
4	Simple Cycle GE LM6000 CT	Natural Gas	SCCT	Gas	Cummins & Barnard
5	Simple Cycle GE 7EA CT	Natural Gas	SCCT	Gas	Cummins & Barnard
6	Simple Cycle GE 7FA CT	Natural Gas	SCCT	Gas	EPRI
7	Combined Cycle GE 7EA CT	Natural Gas	CCCT	Gas	Cummins & Barnard
8	Combined Cycle 1x1 7F-Class	Natural Gas	CCCT	Gas	HDR
9	Combined Cycle 1x1 G-Class CT	Natural Gas	CCCT	Gas	HDR
10	Combined Cycle 2x1 7F-Class CT	Natural Gas	CCCT	Gas	HDR
11	Combined Cycle 3x1 7F-Class CT	Natural Gas	CCCT	Gas	HDR/EPRI
12	Combined Cycle Siemens 5000F CT	Natural Gas	CCCT	Gas	Cummins & Barnard
13	Humid Air Turbine Cycle CT	Natural Gas	CCCT	Gas	Cummins & Barnard
14	Kalina Cycle CC CT	Natural Gas	CCCT	Gas	Cummins & Barnard
15	Cheng Cycle CT	Natural Gas	CCCT	Gas	Cummins & Barnard
16	Peaking Microturbine	Natural Gas	CT	Gas	Cummins & Barnard
17	Baseload Microturbine	Natural Gas	CT	Gas	Cummins & Barnard
18	Subcritical Pulverized Coal - 256 MW	Coal	Pulverized Coal	Coal	Cummins & Barnard
19	Subcritical Pulverized Coal - 512 MW	Coal	Pulverized Coal	Coal	Cummins & Barnard
20	Circulating Fluidized Bed - 2x 250 MW	Coal	Fluidized Bed Combustion	Coal	EPRI
21	Supercritical Pulverized Coal - 565 MW	Coal	Pulverized Coal	Coal	EPRI
22	Supercritical Pulverized Coal-800 MW	Coal	Pulverized Coal	Coal	EPRI
23	Pressurized Fluidized Bed Combustion	Coal	Fluidized Bed Combustion	Coal	Cummins & Barnard
24	1x1 IGCC	Coal	IGCC	Coal Gasification	Cummins & Barnard
25	2x1 IGCC	Coal	IGCC	Coal Gasification	EPRI
26	Subcritical Pulverized Coal - 502 MW - CCS	Coal	Pulverized Coal	Coal	Cummins & Barnard
27	Circulating Fluidized Bed - CC	Coal	Fluidized Bed Combustion	Coal	EPRI
28	Supercritical Pulverized Coal - 565 MW - CCS	Coal	Pulverized Coal	Coal	EPRI
29	Supercritical Pulverized Coal - 800 MW - CCS	Coal	Pulverized Coal	Coal	EPRI
30	1x1 IGCC - CCS	Coal	IGCC	Coal Gasification	Cummins & Barnard
31	2x1 IGCC - CC	Coal	IGCC	Coal Gasification	EPRI
32	Wind Energy Conversion	Renewable	Wind	No Fuel	EPRI
33	Solar Photovoltaic	Renewable	Solar	No Fuel	EPRI
34	Solar Thermal, Parabolic Trough	Renewable	Solar	No Fuel	EPRI
35	Solar Thermal, Power Tower w Storage	Renewable	Solar	No Fuel	EPRI
36	Solar Thermal, Parabolic Dish	Renewable	Solar	No Fuel	Cummins & Barnard
37	Solar Thermal, Central Receiver	Renewable	Solar	No Fuel	Cummins & Barnard
38	Solar Thermal, Solar Chimney	Renewable	Solar	No Fuel	Cummins & Barnard
39	MSW Mass Burn	Waste To Energy	MSW	MSW	Cummins & Barnard
40	RDF Stoker-Fired	Waste To Energy	RDF	RDF	Cummins & Barnard
41	Wood Fired Stoker Plant	Waste To Energy	Bio Mass	Biomass	EPRI
42	Landfill Gas IC Engine	Waste To Energy	LFG	Landfill Gas	EPRI
43	TDF Multi-Fuel CFB (10% Co-fire)	Waste To Energy	TDF	10% TDF / 90% Coal	Cummins & Barnard
44	Sewage Sludge & Anaerobic Digestion	Waste To Energy	SS	Sewage	Cummins & Barnard
45	Bio Mass (Co-Fire)	Waste To Energy	Bio Mass	10% Renew / 90% Coal	EPRI/Cummins & Barnard
46	Wood-Fired CFBC	Waste To Energy	Fluidized Bed Combustion	Biomass	EPRI
47	Co-Fired CFBC	Waste To Energy	Fluidized Bed Combustion	10% Renew / 90% Coal	EPRI
48	Molten Carbonate Fuel Cell	Natural Gas	Fuel Cell	Gas	EPRI
49	Solid Oxide Fuel Cell	Natural Gas	Fuel Cell	Gas	EPRI
50	Spark Ignition Engine	Natural Gas	Reciprocating Engine	Gas	Cummins & Barnard
51	Hydroelectric - New - 30 MW	Renewable	Hydro	No Fuel	Cummins & Barnard
52	Hydroelectric - 50 MW Bulb Unit	Renewable	Hydro	No Fuel	MWH
53	Hydroelectric - 14 MW Kaplans Units	Renewable	Hydro	No Fuel	MWH
54	Hydroelectric - 25 MW Bulb Units	Renewable	Hydro	No Fuel	MWH
55	Hydroelectric - 50 MW Kaplan Unit	Renewable	Hydro	No Fuel	MWH
56	Hydroelectric - 50 MW Propeller Unit	Renewable	Hydro	No Fuel	MWH

Exhibit 2 (a)

Cost (Capital, Fixed and Variable Operation and Maintenance Cost), Heat Rate and Emission Rates Data

CONFIDENTIAL INFORMATION

Heat Rate and Capital Cost Sensitivity Data

Technology	Rating, MW (60°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	350	-	-	-	0	[redacted]			$5.99	$5.99	1.30	0	0	0
Advanced Battery Energy Storage	100	-	-	-	0				$1.50	$14.97	1.20	0	0	0
Compressed Air Energy Storage	350	3,970	4,169	3,772	0				$30.89	$1.92	1.12	0.001	0.050	118
Simple Cycle GE LM6000 CT	43	9,214	9,675	8,753	0				$19.75	$24.49		0.001	0.050	118
Simple Cycle GE 7EA CT	84	11,740	12,327	11,153	0				$15.04	$25.42		0.001	0.030	118
Simple Cycle GE 7FA CT	206	9,848	10,340	9,356	0				$4.67	$15.12		0.001	0.018	117
Combined Cycle GE 7EA CT	109	8,093	8,498	7,688	0				$36.23	$6.00		0.001	0.007	118
Combined Cycle 1x1 7F-Class	314	6,777	7,116	6,438	0				$10.90	$4.56		0.001	0.016	117
Combined Cycle 1x1 G-Class CT	406	6,725	7,061	6,389	0				$7.93	$4.23		0.001	0.016	117
Combined Cycle 2x1 7F-Class CT	629	6,768	7,106	6,430	0				$6.30	$3.99		0.001	0.016	117
Combined Cycle 3x1 7F-Class CT	943	6,753	7,091	6,415	0				$4.73	$3.96		0.001	0.016	117
Combined Cycle Siemens 5000F CT	251	7,085	7,439	6,731	0				$16.89	$5.20		0.001	0.007	118
Humid Air Turbine Cycle CT	366	10,355	10,873	9,837	0				$8.97	$4.95		0.001	0.018	118
Kalina Cycle CC CT	282	6,348	6,665	6,030	0				$16.12	$2.36		0.001	0.007	118
Cheng Cycle CT	140	7,270	7,634	6,907	0				$14.60	$4.97		0.001	0.024	118
Peaking Microturbine	0	14,561	15,289	13,833	0				$157.12	$34.67		0.001	0.018	118
Baseload Microturbine	0	14,561	15,289	13,833	0				$157.71	$6.88		0.001	0.018	118
Subcritical Pulverized Coal - 256 MW	256	9,287	9,752	8,823	0				$74.43	$2.82		0.090	0.050	197
Subcritical Pulverized Coal - 512 MW	512	9,160	9,618	8,702	0				$62.13	$2.83		0.090	0.050	200
Circulating Fluidized Bed - 2x 250 MW	500	10,155	10,663	9,647	0				$53.25	$6.33		0.119	0.050	216
Supercritical Pulverized Coal - 565 MW	565	9,066	9,519	8,613	0				$53.62	$4.40		0.180	0.070	216
Supercritical Pulverized Coal-800 MW	800	9,036	9,488	8,584	0				$46.06	$3.70		0.180	0.070	216
Pressurized Fluidized Bed Combustion	290	9,048	9,501	8,596	0				$73.04	$2.80		0.120	0.090	197
1x1 IGCC	307	8,456	8,879	8,033	0				$54.83	$2.67		0.050	0.050	197
2x1 IGCC	640	8,889	9,333	8,445	0				$78.93	$1.22		0.180	0.070	216
Subcritical Pulverized Coal - 502 MW - CCS	502	12,906	13,551	12,261	0				$70.23	$5.08		0.090	0.050	20
Circulating Fluidized Bed - CC	572	14,010	14,711	13,310	0				$91.23	$7.15		0.119	0.050	22
Supercritical Pulverized Coal - 565 MW - CCS	565	12,800	13,440	12,160	0				$75.42	$8.22		0.180	0.070	22
Supercritical Pulverized Coal - 800 MW - CCS	800	9,036	9,488.	8,584	0				$62.82	$8.00		0.180	0.070	22
1x1 IGCC - CCS	270	10,069	10,572	9,566	0				$68.86	$3.37		0.050	0.050	20
2x1 IGCC - CC	556	10,463	10,986	9,940	0				$87.33	$1.23		0.024	0.010	22
Wind Energy Conversion	200	-	-	-	0				$11.07	$7.37		0	0	0
Solar Photovoltaic	25	-	-	-	0				$30.48	$0.00		0	0	0
Solar Thermal, Parabolic Trough	100	-	-	-	0				$64.41	$0.84		0	0	0
Solar Thermal, Power Tower w Storage	100	-	-	-	0				$64.41	$0.53		0	0	0
Solar Thermal, Parabolic Dish	1	-	-	-	0				$64.15	$0.01		0	0	0
Solar Thermal, Central Receiver	50	-	-	-	0				$127.17	$0.80		0	0	0
Solar Thermal, Solar Chimney	50	-	-	-	0				$73.78	$0.01		0	0	0
MSW Mass Burn	7	19,160	20,118	18,202	0				$590.49	$39.54		0.060	0.150	215
RDF Stoker-Fired	7	16,558	17,386	15,730	0				$489.98	$12.40		0.060	0.150	219
Wood Fired Stoker Plant	50	13,325	13,991	12,659	0				$131.06	$3.93		0.000	0.100	218
Landfill Gas IC Engine	5	9,500	9,975	9,025	0				$60.96	$15.80		0.000	0.033	187
TDF Multi-Fuel CFB (10% Co-fire)	50	10,669	11,203	10,136	0				$103.63	$3.14		0.090	0.050	196
Sewage Sludge & Anaerobic Digestion	0	9,900	10,395	9,405	0				$228.37	$0.00		0.000	0.210	181
Bio Mass (Co-Fire)	514	9,251	9,713	8,788	0				$66.61	$1.19		0.090	0.050	198
Wood-Fired CFBC	100	11,570	12,149	10,992	0				$86.59	$2.12		0.000	0.030	142
Co-Fired CFBC	566	14,120	14,826	13,414	0				$91.54	$12.21		0.000	0.030	208
Molten Carbonate Fuel Cell	20	5,460	5,733	5,187	0				$8.36	$7.94		0.000	0.010	130
Solid Oxide Fuel Cell	25	6,370	6,689	6,052	0				$14.04	$0.05		0.000	0.010	130
Spark Ignition Engine	5	9,492	9,967	9,017	0				$180.84	$0.00		0.002	0.210	118
Hydroelectric - New - 30 MW	30	-	-	-	0				$41.85	$0.00		0	0	0
Hydroelectric - 50 MW Bulb Unit	50	-	-	-	0				$14.67	$0.00		0	0	0
Hydroelectric - 14 MW Kaplans Units	28	-	-	-	0				$8.66	$0.00		0	0	0
Hydroelectric - 25 MW Bulb Units	50	-	-	-	0				$12.30	$0.00		0	0	0
Hydroelectric - 50 MW Kaplan Unit	50	-	-	-	0				$12.28	$0.00		0	0	0
Hydroelectric - 50 MW Propeller Unit	50	-	-	-	0				$10.52	$0.00		0	0	0

Exhibit 2 (b)

Emissions Allowance Prices

Emissions Allowance Prices

	SO_2 \$/ton	NO_x \$/ton	CO_2 \$/ton
2010	19	460	0
2011	30	340	0
2012	10	100	0
2013	10	50	0
2014+	0	0	0

Example calculation of SO_2 adder:

(NO_x and CO_2 adders are calculated similarly)

Using Supercritical Pulverized Coal Unit - , 800 MW

SO_2 Emission Rate = 0.18 lb SO_2 / MMBtu

2010 SO_2 \$/Ton = \$19

2010 SCPC SO_2 Cost Adder

$$= \frac{0.18\#SO_2}{MMBtu} * \frac{19\ \$}{Ton\ SO_2} * \frac{100\ Cents}{\$} * \frac{1\ ton\ SO_2}{2000\ \#}$$

$$= 0.2 \quad cents/MMBtu$$

Exhibit 3

Fuel Forecast for Screening Analysis

Fuel Forecast for Screening Analysis

(Cents/MBtu)

	Base Fuel Costs								Low Fuel Costs								High Fuel Costs							
	Coal	Gas	MSW Tip Fee	RDF	LFG	TDF	Bio-Mass	Coal Bio-Mass	Coal	Gas	MSW Tip Fee	RDF	LFG	TDF	Bio-Mass	Coal Bio-Mass	Coal	Gas	MSW Tip Fee	RDF	LFG	TDF	Bio-Mass	Coal Bio-Mass
2010	[redacted]																							
2011																								
2012																								
2013																								
2014																								
2015																								
2016																								
2017																								
2018																								
2019																								
2020																								
2021																								
2022																								
2023																								
2024																								
2025																								

Exhibit 4

Levelization Equations

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 ($/MWh)	Exhibit 3
Fix Esc	=	Fixed O&M Escalation Rate (%)	Exhibit 5
Var Esc	=	Variable O&M Escalation Rate (%)	Exhibit 5
Fix Adj L_n	=	Fixed O&M Levelization Factor	Exhibit 5
Var Adj L_n	=	Variable O&M Levelization Factor	Exhibit 5
Fuel Adj L_n	=	Fuel Cost Levelization Factor	Base Fuel Only; Exhibit 5
Charge Adj L_n	=	Charging Cost Levelization Factor	Exhibit 5
CF%	=	Capacity Factor (%)	0-100 %
MW	=	Size of Technology (MW)	Exhibit 2 (a)
HR	=	Heat Rate (Btu/KWh)	Exhibit 2 (a)
FC	=	Fuel Cost ($/MMBtu)	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/MMBtu)	Exhibit 2(b)
NO_x	=	NO_x Adder (Cents/MMBtu)	Exhibit 2(b)
CO_2	=	CO_2 Adder (Cents/MMBtu)	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.

Exhibit 5

Adjusted L_n, Fixed Charge Rates, Escalation Rates and Other Miscellaneous

Adjusted L_n and Other Miscellaneous Data

(All Fuel prices are in Cents/MBtu)

	2.00% F O&M	2.00% V O&M	2.50% Capital	6.71% WACC
	Escalation Rates	**k**	**L_n**	**Adj Ln**
Fuel				
Coal	2.14%	0.9572	1.2787	1.2519
Gas	3.66%	0.9714	1.5451	1.4905
Charging	2.00%	0.9559	1.2572	1.2325
MSW	2.00%	0.9559	1.2572	1.2325
RDF	2.00%	0.9559	1.2572	1.2325
LFG	3.66%	0.9714	1.5451	1.4905
Coal+TDF	2.14%	0.9572	1.2787	1.2519
Sewage	2.00%	0.9559	1.2572	1.2325
Biomass	2.00%	0.9559	1.2572	1.2325
Coal+Bio Mass	2.00%	0.9559	1.2572	1.2325
Emissions				
Annual NOx	0.00%	0.9371	1.0000	1.0000
Ozone Nox	0.00%	0.9371	1.0000	1.0000
SO2	0.00%	0.9371	1.0000	1.0000
CO2	0.00%	0.9371	1.0000	1.0000

Renewables Production Tax Credit	
Assume to continue	Yes
Tax Credit Period (Years)	10
Levelized period (years)	30
Inflation rate (%)	2.00%

Fixed Charge Rates by Technology

Coal	9.00%
Simple Cycle CT	9.62%
Combined Cycle CT	9.01%
Other	9.54%

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 **2010 ($/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	186	227	268	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	156	204	252	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	145	208	271	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	142	239	337	435	532	630	728	825	923	1021	1119
Simple Cycle GE 7EA CT	115	234	352	470	588	707	825	943	1061	1179	1298
Simple Cycle GE 7FA CT	95	188	280	373	465	558	650	743	835	928	1020
Combined Cycle GE 7EA CT	209	278	347	416	485	554	623	692	761	830	899
Combined Cycle 1x1 7F-Class	149	206	264	321	378	436	493	550	608	665	722
Combined Cycle 1x1 G-Class CT	127	184	240	297	354	410	467	523	580	636	693
Combined Cycle 2x1 7F-Class CT	109	165	222	279	335	392	448	505	562	618	675
Combined Cycle 3x1 7F-Class CT	102	158	215	271	328	384	441	497	554	610	667
Combined Cycle Siemens 5000F CT	150	211	271	332	392	452	513	573	634	694	754
Humid Air Turbine Cycle CT	138	223	309	394	480	565	650	736	821	907	992
Kalina Cycle CC CT	147	199	251	302	354	405	457	509	560	612	664
Cheng Cycle CT	153	214	276	337	399	461	522	584	645	707	768
Peaking Microturbine	446	596	746	896	1046	1196	1346	1496	1646	1797	1947
Baseload Microturbine	477	597	717	837	957	1077	1197	1317	1437	1557	1677
Subcritical Pulverized Coal - 256 MW	358	384	410	436	462	488	514	540	566	592	618
Subcritical Pulverized Coal - 512 MW	319	345	370	396	422	448	473	499	525	551	576
Circulating Fluidized Bed - 2x 250 MW	294	326	358	390	422	454	486	518	550	582	614
Supercritical Pulverized Coal - 565 MW	324	352	379	406	433	460	488	515	542	569	596
Supercritical Pulverized Coal-800 MW	284	310	336	363	389	415	442	468	494	521	547
Pressurized Fluidized Bed Combustion	367	392	418	443	469	494	520	545	570	—	—
1x1 IGCC	358	382	406	430	454	477	501	525	549	—	—
2x1 IGCC	399	422	445	469	492	515	539	562	585	—	—
Subcritical Pulverized Coal - 502 MW - CCS	561	598	636	673	710	748	785	823	860	898	935
Circulating Fluidized Bed - CC	502	544	587	629	671	714	756	799	841	883	926
Supercritical Pulverized Coal - 565 MW - CCS	471	512	552	593	633	674	715	755	796	836	877
Supercritical Pulverized Coal - 800 MW - CCS	413	444	475	506	537	568	599	630	661	692	723
1x1 IGCC - CCS	510	538	567	595	624	653	681	710	738	—	—
2x1 IGCC - CC	459	486	513	540	568	595	622	649	676	—	—
Wind Energy Conversion	257	254	251	248	—	—	—	—	—	—	—
Solar Photovoltaic	580	580	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	655	656	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	829	829	830	830	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	764	764	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	808	809	810	811	812	812	813	—	—	—	—
Solar Thermal, Solar Chimney	673	673	673	673	—	—	—	—	—	—	—
MSW Mass Burn	1809	1773	1738	1702	1667	1631	1596	1560	—	—	—
RDF Stoker-Fired	1723	1808	1894	1979	2064	2149	2235	2320	2405	—	—
Wood Fired Stoker Plant	493	526	559	592	624	657	690	723	755	—	—
Landfill Gas IC Engine	275	321	367	412	458	504	549	595	640	686	—
TDF Multi-Fuel CFB (10% Co-fire)	514	544	573	602	631	660	690	719	748	777	806
Sewage Sludge & Anaerobic Digestion	735	730	725	720	714	709	704	698	693	688	—
Bio Mass (Co-Fire)	387	410	433	456	479	503	526	549	572	595	619
Wood-Fired CFBC	506	532	558	585	611	637	664	690	716	743	769
Co-Fired CFBC	620	666	713	760	806	853	900	946	993	1039	1086
Molten Carbonate Fuel Cell	267	318	369	420	470	521	572	623	674	724	—
Solid Oxide Fuel Cell	172	222	271	320	370	419	468	518	567	616	—
Spark Ignition Engine	425	498	572	645	719	792	865	939	1012	1086	—
Hydroelectric - New - 30 MW	493	487	482	476	471	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	434	428	423	418	412	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	566	560	555	550	544	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	532	526	521	516	510	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	503	498	492	487	481	—	—	—	—	—	—
Minimum Levelized $/kW	95	158	215	248	328	384	441	468	494	521	547

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

Capital Cost-Low **2010 ($/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	168	206	244	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	141	186	230	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	135	190	245	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	130	218	305	393	480	567	655	742	829	917	1004
Simple Cycle GE 7EA CT	106	211	317	422	527	632	737	842	947	1052	1157
Simple Cycle GE 7FA CT	87	169	250	331	413	494	576	657	739	820	901
Combined Cycle GE 7EA CT	193	253	313	373	433	493	553	613	673	733	793
Combined Cycle 1x1 7F-Class	136	186	236	286	335	385	435	484	534	584	634
Combined Cycle 1x1 G-Class CT	116	165	214	263	312	361	410	459	508	558	607
Combined Cycle 2x1 7F-Class CT	99	148	197	246	295	345	394	443	492	541	590
Combined Cycle 3x1 7F-Class CT	93	142	191	240	289	338	387	436	484	533	582
Combined Cycle Siemens 5000F CT	139	191	244	296	348	401	453	506	558	611	663
Humid Air Turbine Cycle CT	127	201	275	348	422	496	570	644	717	791	865
Kalina Cycle CC CT	136	180	225	269	314	358	403	447	492	536	581
Cheng Cycle CT	140	194	247	301	354	408	461	514	568	621	675
Peaking Microturbine	422	556	689	823	957	1090	1224	1358	1492	1625	1759
Baseload Microturbine	451	555	658	762	866	969	1073	1177	1281	1384	1488
Subcritical Pulverized Coal - 256 MW	331	354	377	399	422	445	468	490	513	536	558
Subcritical Pulverized Coal - 512 MW	295	317	340	362	384	407	429	452	474	497	519
Circulating Fluidized Bed - 2x 250 MW	271	299	328	356	384	413	441	470	498	526	555
Supercritical Pulverized Coal - 565 MW	299	322	346	370	394	418	442	466	490	514	538
Supercritical Pulverized Coal-800 MW	261	284	307	330	353	376	400	423	446	469	492
Pressurized Fluidized Bed Combustion	325	348	370	392	414	436	459	481	503	—	—
1x1 IGCC	329	350	371	392	412	433	454	475	496	—	—
2x1 IGCC	368	389	409	429	449	469	489	509	530	—	—
Subcritical Pulverized Coal - 502 MW - CCS	513	546	579	612	645	677	710	743	776	809	841
Circulating Fluidized Bed - CC	463	500	538	575	612	650	687	725	762	799	837
Supercritical Pulverized Coal - 565 MW - CCS	452	488	524	560	596	632	668	704	740	776	812
Supercritical Pulverized Coal - 800 MW - CCS	396	424	452	480	507	535	563	591	618	646	674
1x1 IGCC - CCS	488	513	538	563	588	613	638	663	688	—	—
2x1 IGCC - CC	441	464	488	511	535	558	582	605	629	—	—
Wind Energy Conversion	232	229	227	224	—	—	—	—	—	—	—
Solar Photovoltaic	472	472	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	540	541	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	679	679	680	681	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	627	627	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	678	679	680	680	681	682	683	—	—	—	—
Solar Thermal, Solar Chimney	557	557	557	557	—	—	—	—	—	—	—
MSW Mass Burn	1701	1676	1651	1626	1601	1576	1551	1526	—	—	—
RDF Stoker-Fired	1555	1629	1703	1777	1851	1926	2000	2074	2148	—	—
Wood Fired Stoker Plant	444	471	499	527	555	583	611	638	666	—	—
Landfill Gas IC Engine	245	267	290	312	334	356	378	400	422	445	—
TDF Multi-Fuel CFB (10% Co-fire)	476	501	527	552	577	603	628	654	679	704	730
Sewage Sludge & Anaerobic Digestion	667	662	657	651	646	641	636	630	625	620	—
Bio Mass (Co-Fire)	356	376	396	416	436	456	476	496	516	536	556
Wood-Fired CFBC	466	488	510	532	554	576	598	620	642	664	687
Co-Fired CFBC	569	611	653	694	736	778	820	861	903	945	987
Molten Carbonate Fuel Cell	219	263	308	353	397	442	487	531	576	621	—
Solid Oxide Fuel Cell	198	240	282	325	367	409	451	493	535	578	—
Spark Ignition Engine	406	469	532	595	657	720	783	846	908	971	—
Hydroelectric - New - 30 MW	426	421	416	410	405	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	371	366	361	355	350	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	483	478	472	467	462	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	454	449	443	438	433	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	429	424	419	413	408	—	—	—	—	—	—
Minimum Levelized $/kW	87	142	191	224	289	338	378	400	422	445	492

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

Capital Cost-Low **2010 ($/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	168	209	250	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	141	189	237	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	135	196	257	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	130	225	319	413	507	601	695	789	884	978	1072
Simple Cycle GE 7EA CT	106	220	334	448	561	675	789	902	1016	1130	1243
Simple Cycle GE 7FA CT	87	176	264	353	442	530	619	708	796	885	974
Combined Cycle GE 7EA CT	193	259	325	391	457	523	589	655	721	787	853
Combined Cycle 1x1 7F-Class	136	191	246	300	355	410	465	519	574	629	683
Combined Cycle 1x1 G-Class CT	116	170	224	278	332	386	440	494	548	602	656
Combined Cycle 2x1 7F-Class CT	99	153	207	261	315	369	423	477	532	586	640
Combined Cycle 3x1 7F-Class CT	93	147	201	255	309	362	416	470	524	578	632
Combined Cycle Siemens 5000F CT	139	196	254	312	369	427	485	542	600	658	715
Humid Air Turbine Cycle CT	127	208	290	371	453	534	616	697	778	860	941
Kalina Cycle CC CT	136	185	234	283	332	381	431	480	529	578	627
Cheng Cycle CT	140	199	258	317	375	434	493	552	611	669	728
Peaking Microturbine	422	566	711	855	1000	1144	1288	1433	1577	1722	1866
Baseload Microturbine	451	565	680	794	908	1023	1137	1252	1366	1481	1595
Subcritical Pulverized Coal - 256 MW	*331*	*356*	*381*	*406*	*431*	*456*	*481*	*506*	*530*	*555*	*580*
Subcritical Pulverized Coal - 512 MW	295	319	344	368	393	418	442	467	492	516	541
Circulating Fluidized Bed - 2x 250 MW	271	302	333	363	394	425	456	486	517	548	578
Supercritical Pulverized Coal - 565 MW	299	325	351	377	403	429	455	481	507	533	559
Supercritical Pulverized Coal-800 MW	261	286	311	337	362	387	412	438	463	488	513
Pressurized Fluidized Bed Combustion	325	350	374	398	423	447	471	496	520	—	—
1x1 IGCC	329	352	375	398	420	443	466	489	511	—	—
2x1 IGCC	368	391	413	435	457	480	502	524	546	—	—
Subcritical Pulverized Coal - 502 MW - CCS	513	549	585	621	657	693	728	764	800	836	872
Circulating Fluidized Bed - CC	463	503	544	585	626	666	707	748	788	829	870
Supercritical Pulverized Coal - 565 MW - CCS	452	491	530	569	608	647	686	725	764	803	842
Supercritical Pulverized Coal - 800 MW - CCS	396	426	456	486	516	546	576	606	635	665	695
1x1 IGCC - CCS	488	516	543	570	598	625	652	680	707	—	—
2x1 IGCC - CC	441	467	493	519	545	571	597	623	649	—	—
Wind Energy Conversion	232	229	227	224	—	—	—	—	—	—	—
Solar Photovoltaic	472	472	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	540	541	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	679	679	680	681	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	627	627	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	678	679	680	680	681	682	683	—	—	—	—
Solar Thermal, Solar Chimney	557	557	557	557	—	—	—	—	—	—	—
MSW Mass Burn	1701	1669	1637	1605	1573	1542	1510	1478	—	—	—
RDF Stoker-Fired	1555	1637	1718	1799	1881	1962	2044	2125	2206	—	—
Wood Fired Stoker Plant	444	475	506	537	568	599	630	661	692	—	—
Landfill Gas IC Engine	245	289	333	377	421	465	509	553	597	641	—
TDF Multi-Fuel CFB (10% Co-fire)	476	504	531	559	587	615	643	671	699	727	755
Sewage Sludge & Anaerobic Digestion	667	662	657	651	646	641	636	630	625	620	—
Bio Mass (Co-Fire)	356	378	400	422	445	467	489	511	533	555	577
Wood-Fired CFBC	466	491	516	540	565	590	615	640	665	690	714
Co-Fired CFBC	*569*	*614*	*659*	*704*	*749*	*794*	*839*	*884*	*929*	*974*	*1019*
Molten Carbonate Fuel Cell	219	267	316	365	413	462	511	559	608	657	—
Solid Oxide Fuel Cell	198	245	292	339	385	432	479	526	573	620	—
Spark Ignition Engine	406	476	546	616	685	755	825	894	964	1034	—
Hydroelectric - New - 30 MW	426	421	416	410	405	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	371	366	361	355	350	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	483	478	472	467	462	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	454	449	443	438	433	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	429	424	419	413	408	—	—	—	—	—	—
Minimum Levelized $/kW	87	147	201	224	309	362	412	438	463	488	513

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

Capital Cost-Low **2010 ($/kW yr)**
Heat Rate-Low
Fuel Forecast- High

	Capacity Factors										
Technology	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Pumped Hydro Energy Storage	168	213	257	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	141	192	243	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	135	202	269	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	130	231	332	433	534	635	736	837	938	1039	1140
Simple Cycle GE 7EA CT	106	229	351	473	596	718	840	963	1085	1207	1330
Simple Cycle GE 7FA CT	87	183	279	375	471	567	663	758	854	950	1046
Combined Cycle GE 7EA CT	193	265	337	409	481	553	625	697	768	840	912
Combined Cycle 1x1 7F-Class	136	196	256	315	375	435	494	554	614	674	733
Combined Cycle 1x1 G-Class CT	116	175	234	293	352	411	470	529	588	646	705
Combined Cycle 2x1 7F-Class CT	99	158	217	276	335	394	453	512	571	630	689
Combined Cycle 3x1 7F-Class CT	93	152	211	270	328	387	446	505	564	623	682
Combined Cycle Siemens 5000F CT	139	201	264	327	390	453	516	579	642	704	767
Humid Air Turbine Cycle CT	127	216	305	394	483	572	661	750	839	928	1017
Kalina Cycle CC CT	136	189	243	297	351	405	459	512	566	620	674
Cheng Cycle CT	140	204	269	333	397	461	525	589	653	717	782
Peaking Microturbine	422	577	732	887	1042	1197	1353	1508	1663	1818	1973
Baseload Microturbine	451	576	701	826	951	1076	1201	1327	1452	1577	1702
Subcritical Pulverized Coal - 256 MW	331	358	385	413	440	467	494	521	548	575	602
Subcritical Pulverized Coal - 512 MW	295	321	348	375	402	428	455	482	509	536	562
Circulating Fluidized Bed - 2x 250 MW	271	304	337	370	404	437	470	503	536	569	602
Supercritical Pulverized Coal - 565 MW	299	327	355	383	411	440	468	496	524	552	581
Supercritical Pulverized Coal-800 MW	261	288	316	343	370	398	425	452	480	507	535
Pressurized Fluidized Bed Combustion	325	352	378	405	431	458	484	511	537	—	—
1x1 IGCC	329	354	379	403	428	453	478	503	527	—	—
2x1 IGCC	368	393	417	441	466	490	514	539	563	—	—
Subcritical Pulverized Coal - 502 MW - CCS	513	552	591	630	669	708	747	785	824	863	902
Circulating Fluidized Bed - CC	463	507	551	595	639	683	727	771	815	859	903
Supercritical Pulverized Coal - 565 MW - CCS	452	494	536	578	620	662	704	746	788	830	872
Supercritical Pulverized Coal - 800 MW - CCS	396	428	460	492	524	556	588	620	652	684	716
1x1 IGCC - CCS	488	518	548	578	607	637	667	696	726	—	—
2x1 IGCC - CC	441	469	498	526	555	583	611	640	668	—	—
Wind Energy Conversion	232	229	227	224	—	—	—	—	—	—	—
Solar Photovoltaic	472	472	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	540	541	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	679	679	680	681	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	627	627	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	678	679	680	680	681	682	683	—	—	—	—
Solar Thermal, Solar Chimney	557	557	557	557	—	—	—	—	—	—	—
MSW Mass Burn	1701	1662	1623	1585	1546	1507	1468	1429	—	—	—
RDF Stoker-Fired	1555	1644	1733	1821	1910	1999	2088	2176	2265	—	—
Wood Fired Stoker Plant	444	478	512	546	581	615	649	684	718	—	—
Landfill Gas IC Engine	245	320	394	469	543	618	692	767	841	916	—
TDF Multi-Fuel CFB (10% Co-fire)	476	506	536	567	597	628	658	688	719	749	779
Sewage Sludge & Anaerobic Digestion	667	662	657	651	646	641	636	630	625	620	—
Bio Mass (Co-Fire)	356	380	405	429	453	477	501	525	550	574	598
Wood-Fired CFBC	466	494	521	549	576	604	632	659	687	715	742
Co-Fired CFBC	569	617	665	713	762	810	858	906	954	1002	1050
Molten Carbonate Fuel Cell	219	271	324	377	429	482	535	587	640	693	—
Solid Oxide Fuel Cell	198	250	301	353	404	456	507	559	610	662	—
Spark Ignition Engine	406	483	560	636	713	790	867	943	1020	1097	—
Hydroelectric - New - 30 MW	426	421	416	410	405	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	371	366	361	355	350	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	483	478	472	467	462	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	454	449	443	438	433	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	429	424	419	413	408	—	—	—	—	—	—
Minimum Levelized $/kW	87	152	211	224	328	387	425	452	480	507	535

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

Capital Cost-Low 2010 ($/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	168	206	244	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	141	186	230	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	135	191	248	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	131	222	312	403	493	584	675	765	856	946	1037
Simple Cycle GE 7EA CT	107	216	326	435	544	653	762	871	980	1090	1199
Simple Cycle GE 7FA CT	88	173	257	342	427	512	597	682	767	852	936
Combined Cycle GE 7EA CT	194	257	320	383	446	508	571	634	697	760	823
Combined Cycle 1x1 7F-Class	137	189	241	293	345	398	450	502	554	606	658
Combined Cycle 1x1 G-Class CT	117	168	220	271	322	374	425	477	528	579	631
Combined Cycle 2x1 7F-Class CT	100	151	203	254	306	357	409	460	511	563	614
Combined Cycle 3x1 7F-Class CT	94	145	196	248	299	350	402	453	504	555	607
Combined Cycle Siemens 5000F CT	140	195	250	305	359	414	469	524	579	634	689
Humid Air Turbine Cycle CT	129	206	284	361	438	516	593	671	748	825	903
Kalina Cycle CC CT	137	183	230	277	324	370	417	464	510	557	604
Cheng Cycle CT	142	198	253	309	365	421	477	533	589	645	701
Peaking Microturbine	423	562	700	839	978	1117	1256	1394	1533	1672	1811
Baseload Microturbine	453	562	671	780	888	997	1106	1215	1324	1432	1541
Subcritical Pulverized Coal - 256 MW	331	355	379	403	426	450	474	498	521	545	569
Subcritical Pulverized Coal - 512 MW	295	318	342	365	389	412	435	459	482	506	529
Circulating Fluidized Bed - 2x 250 MW	271	301	330	360	389	418	448	477	507	536	566
Supercritical Pulverized Coal - 565 MW	299	323	348	373	398	423	448	473	498	523	548
Supercritical Pulverized Coal-800 MW	261	285	309	333	357	382	406	430	454	478	502
Pressurized Fluidized Bed Combustion	325	349	372	395	418	441	465	488	511	—	—
1x1 IGCC	329	351	373	394	416	438	460	481	503	—	—
2x1 IGCC	368	390	411	432	453	474	495	516	537	—	—
Subcritical Pulverized Coal - 502 MW - CCS	513	548	582	616	650	685	719	753	787	822	856
Circulating Fluidized Bed - CC	463	502	541	580	619	658	696	735	774	813	852
Supercritical Pulverized Coal - 565 MW - CCS	452	490	527	564	602	639	677	714	752	789	826
Supercritical Pulverized Coal - 800 MW - CCS	396	425	454	483	511	540	569	598	626	655	684
1x1 IGCC - CCS	488	515	541	567	593	619	645	671	697	—	—
2x1 IGCC - CC	441	466	490	515	540	564	589	614	638	—	—
Wind Energy Conversion	232	229	227	224	—	—	—	—	—	—	—
Solar Photovoltaic	472	472	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	540	541	—	—	—	—	—	—	—	—	—
Solar Thermal. Power Tower w Storage	679	679	680	681	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	627	627	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	678	679	680	680	681	682	683	—	—	—	—
Solar Thermal, Solar Chimney	557	557	557	557	—	—	—	—	—	—	—
MSW Mass Burn	1701	1673	1644	1616	1588	1560	1532	1503	—	—	—
RDF Stoker-Fired	1555	1633	1710	1788	1865	1943	2020	2098	2175	—	—
Wood Fired Stoker Plant	444	473	502	532	561	590	620	649	678	—	—
Landfill Gas IC Engine	245	268	291	313	336	359	381	404	427	449	—
TDF Multi-Fuel CFB (10% Co-fire)	476	502	529	555	582	609	635	662	688	715	742
Sewage Sludge & Anaerobic Digestion	667	662	657	651	646	641	636	630	625	620	—
Bio Mass (Co-Fire)	356	377	398	419	440	461	482	503	524	545	566
Wood-Fired CFBC	466	489	513	536	559	583	606	630	653	676	700
Co-Fired CFBC	569	612	656	699	742	785	829	872	915	959	1002
Molten Carbonate Fuel Cell	219	266	313	359	406	452	499	546	592	639	—
Solid Oxide Fuel Cell	199	243	288	332	377	421	465	510	554	599	—
Spark Ignition Engine	408	474	540	606	672	738	804	870	936	1002	—
Hydroelectric - New - 30 MW	426	421	416	410	405	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	371	366	361	355	350	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	483	478	472	467	462	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	454	449	443	438	433	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	429	424	419	413	408	—	—	—	—	—	—
Minimum Levelized $/kW	88	145	196	224	299	350	381	404	427	449	502

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

Capital Cost-Low **2010 ($/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	168	209	250	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	141	189	237	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	135	197	260	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	131	229	326	424	522	620	717	815	913	1010	1108
Simple Cycle GE 7EA CT	107	225	344	462	580	698	817	935	1053	1171	1290
Simple Cycle GE 7FA CT	88	180	273	365	458	550	643	735	828	920	1013
Combined Cycle GE 7EA CT	194	264	333	402	471	540	609	678	747	816	885
Combined Cycle 1x1 7F-Class	137	194	252	309	366	424	481	538	596	653	710
Combined Cycle 1x1 G-Class CT	117	174	230	287	343	400	456	513	570	626	683
Combined Cycle 2x1 7F-Class CT	100	157	213	270	327	383	440	497	553	610	666
Combined Cycle 3x1 7F-Class CT	94	150	207	263	320	376	433	489	546	602	659
Combined Cycle Siemens 5000F CT	140	200	261	321	381	442	502	563	623	683	744
Humid Air Turbine Cycle CT	129	214	300	385	470	556	641	727	812	898	983
Kalina Cycle CC CT	137	188	240	292	343	395	446	498	550	601	653
Cheng Cycle CT	142	203	265	326	388	449	511	573	634	696	757
Peaking Microturbine	423	573	723	873	1023	1173	1323	1473	1623	1773	1923
Baseload Microturbine	453	573	693	813	933	1053	1174	1294	1414	1534	1654
Subcritical Pulverized Coal - 256 MW	331	357	383	409	435	462	488	514	540	566	592
Subcritical Pulverized Coal - 512 MW	295	320	346	372	398	423	449	475	501	526	552
Circulating Fluidized Bed - 2x 250 MW	271	303	335	367	399	431	463	495	527	559	591
Supercritical Pulverized Coal - 565 MW	299	326	353	380	407	435	462	489	516	543	571
Supercritical Pulverized Coal-800 MW	261	287	314	340	366	393	419	445	472	498	525
Pressurized Fluidized Bed Combustion	325	351	376	402	427	453	478	503	529	—	—
1x1 IGCC	329	353	377	401	424	448	472	496	520	—	—
2x1 IGCC	368	392	415	438	462	485	508	532	555	—	—
Subcritical Pulverized Coal - 502 MW - CCS	513	551	588	626	663	700	738	775	813	850	888
Circulating Fluidized Bed - CC	463	505	548	590	632	675	717	760	802	845	887
Supercritical Pulverized Coal - 565 MW - CCS	452	493	533	574	615	655	696	736	777	817	858
Supercritical Pulverized Coal - 800 MW - CCS	396	427	458	489	520	551	582	613	644	675	706
1x1 IGCC - CCS	488	517	546	574	603	631	660	688	717	—	—
2x1 IGCC - CC	441	468	495	523	550	577	604	632	659	—	—
Wind Energy Conversion	232	229	227	224	—	—	—	—	—	—	—
Solar Photovoltaic	472	472	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	540	541	—	—	—	—	—	—	—	—	—
Solar Thermal. Power Tower w Storage	679	679	680	681	—	—	—	—	—	—	—
Solar Thermal. Parabolic Dish	627	627	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	678	679	680	680	681	682	683	—	—	—	—
Solar Thermal, Solar Chimney	557	557	557	557	—	—	—	—	—	—	—
MSW Mass Bum	1701	1665	1630	1594	1559	1523	1488	1452	—	—	—
RDF Stoker-Fired	1555	1641	1726	1811	1896	1981	2067	2152	2237	—	—
Wood Fired Stoker Plant	444	476	509	542	575	607	640	673	706	—	—
Landfill Gas IC Engine	245	291	337	382	428	473	519	565	610	656	—
TDF Multi-Fuel CFB (10% Co-fire)	476	505	534	563	592	622	651	680	709	738	768
Sewage Sludge & Anaerobic Digestion	667	662	657	651	646	641	636	630	625	620	—
Bio Mass (Co-Fire)	356	379	403	426	449	472	495	519	542	565	588
Wood-Fired CFBC	466	492	519	545	571	598	624	650	677	703	729
Co-Fired CFBC	569	616	662	709	756	802	849	895	942	989	1035
Molten Carbonate Fuel Cell	219	270	321	372	423	473	524	575	626	677	—
Solid Oxide Fuel Cell	199	248	298	347	396	446	495	544	594	643	—
Spark Ignition Engine	408	481	555	628	702	775	848	922	995	1069	—
Hydroelectric - New - 30 MW	426	421	416	410	405	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	371	366	361	355	350	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	483	478	472	467	462	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	454	449	443	438	433	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	429	424	419	413	408	—	—	—	—	—	—
Minimum Levelized $/kW	88	150	207	224	320	376	419	445	472	498	525

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

Capital Cost-Low **2010 ($/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	168	213	257	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	141	192	243	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	135	203	272	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	131	236	341	446	550	655	760	865	970	1074	1179
Simple Cycle GE 7EA CT	107	235	362	489	616	744	871	998	1126	1253	1380
Simple Cycle GE 7FA CT	88	188	288	388	488	588	688	788	889	989	1089
Combined Cycle GE 7EA CT	194	270	345	420	496	571	646	722	797	872	948
Combined Cycle 1x1 7F-Class	137	200	262	325	387	450	512	575	638	700	763
Combined Cycle 1x1 G-Class CT	117	179	240	302	364	426	488	549	611	673	735
Combined Cycle 2x1 7F-Class CT	100	162	224	286	348	409	471	533	595	657	719
Combined Cycle 3x1 7F-Class CT	94	156	217	279	341	403	464	526	588	649	711
Combined Cycle Siemens 5000F CT	140	206	272	337	403	469	535	601	667	733	799
Humid Air Turbine Cycle CT	129	222	316	409	502	596	689	783	876	970	1063
Kalina Cycle CC CT	137	193	250	306	363	419	476	532	589	646	702
Cheng Cycle CT	142	209	276	343	410	478	545	612	679	746	814
Peaking Microturbine	423	584	745	907	1068	1229	1391	1552	1713	1875	2036
Baseload Microturbine	453	585	716	847	978	1110	1241	1372	1504	1635	1766
Subcritical Pulverized Coal - 256 MW	331	360	388	416	445	473	501	530	558	586	615
Subcritical Pulverized Coal - 512 MW	295	323	351	379	407	435	463	491	519	547	575
Circulating Fluidized Bed - 2x 250 MW	271	306	340	375	409	444	478	513	547	582	616
Supercritical Pulverized Coal - 565 MW	299	328	357	387	416	446	475	505	534	564	593
Supercritical Pulverized Coal-800 MW	261	289	318	347	375	404	433	461	490	518	547
Pressurized Fluidized Bed Combustion	325	353	381	408	436	464	491	519	547	—	—
1x1 IGCC	329	355	381	407	433	459	485	511	537	—	—
2x1 IGCC	368	394	419	445	471	496	522	547	573	—	—
Subcritical Pulverized Coal - 502 MW - CCS	513	554	595	635	676	716	757	798	838	879	920
Circulating Fluidized Bed - CC	463	509	555	600	646	692	738	784	830	876	922
Supercritical Pulverized Coal - 565 MW - CCS	452	496	540	584	627	671	715	759	802	846	890
Supercritical Pulverized Coal - 800 MW - CCS	396	429	463	496	529	562	596	629	662	696	729
1x1 IGCC - CCS	488	520	551	582	613	644	675	706	737	—	—
2x1 IGCC - CC	441	471	501	530	560	590	620	650	680	—	—
Wind Energy Conversion	232	229	227	224	—	—	—	—	—	—	—
Solar Photovoltaic	472	472	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	540	541	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	679	679	680	681	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	627	627	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	678	679	680	680	681	682	683	—	—	—	—
Solar Thermal, Solar Chimney	557	557	557	557	—	—	—	—	—	—	—
MSW Mass Burn	1701	1658	1615	1572	1530	1487	1444	1401	—	—	—
RDF Stoker-Fired	1555	1648	1741	1834	1927	2020	2113	2206	2299	—	—
Wood Fired Stoker Plant	444	480	516	552	588	624	660	697	733	—	—
Landfill Gas IC Engine	245	323	401	479	556	634	712	790	868	945	—
TDF Multi-Fuel CFB (10% Co-fire)	476	507	539	571	603	635	666	698	730	762	794
Sewage Sludge & Anaerobic Digestion	667	662	657	651	646	641	636	630	625	620	—
Bio Mass (Co-Fire)	356	382	407	432	458	483	509	534	559	585	610
Wood-Fired CFBC	466	495	524	554	583	612	642	671	700	729	759
Co-Fired CFBC	569	619	669	719	769	819	869	919	969	1019	1069
Molten Carbonate Fuel Cell	219	275	330	385	440	495	550	605	660	715	—
Solid Oxide Fuel Cell	199	253	308	362	416	470	525	579	633	687	—
Spark Ignition Engine	408	489	569	650	731	812	892	973	1054	1135	—
Hydroelectric - New - 30 MW	426	421	416	410	405	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	371	366	361	355	350	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	483	478	472	467	462	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	454	449	443	438	433	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	429	424	419	413	408	—	—	—	—	—	—
Minimum Levelized $/kW	88	156	217	224	341	403	433	461	490	518	547

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

Capital Cost-Low **2010 ($/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	168	206	244	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	141	186	230	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	135	193	250	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	132	225	319	413	507	601	694	788	882	976	1069
Simple Cycle GE 7EA CT	108	221	334	448	561	674	787	901	1014	1127	1240
Simple Cycle GE 7FA CT	88	177	265	353	442	530	618	706	795	883	971
Combined Cycle GE 7EA CT	196	261	327	392	458	524	589	655	720	786	852
Combined Cycle 1x1 7F-Class	138	192	247	301	356	410	464	519	573	628	682
Combined Cycle 1x1 G-Class CT	118	171	225	279	333	386	440	494	547	601	655
Combined Cycle 2x1 7F-Class CT	101	155	208	262	316	370	423	477	531	585	638
Combined Cycle 3x1 7F-Class CT	95	148	202	256	309	363	417	470	524	577	631
Combined Cycle Siemens 5000F CT	141	198	256	313	371	428	485	543	600	657	715
Humid Air Turbine Cycle CT	130	211	292	374	455	536	617	698	779	860	941
Kalina Cycle CC CT	138	187	236	285	333	382	431	480	529	578	627
Cheng Cycle CT	143	201	260	318	377	435	494	552	611	669	728
Peaking Microturbine	424	568	711	855	999	1143	1287	1431	1575	1718	1862
Baseload Microturbine	456	570	683	797	911	1025	1139	1253	1367	1480	1594
Subcritical Pulverized Coal - 256 MW	331	356	381	406	430	455	480	505	530	554	579
Subcritical Pulverized Coal - 512 MW	295	319	344	368	393	417	442	466	491	515	540
Circulating Fluidized Bed - 2x 250 MW	271	302	332	363	394	424	455	485	516	547	577
Supercritical Pulverized Coal - 565 MW	299	324	350	376	402	428	454	480	506	532	558
Supercritical Pulverized Coal-800 MW	261	286	311	336	361	387	412	437	462	487	512
Pressurized Fluidized Bed Combustion	325	350	374	398	422	446	471	495	519	—	—
1x1 IGCC	329	352	375	397	420	443	465	488	511	—	—
2x1 IGCC	368	391	413	435	457	479	501	523	545	—	—
Subcritical Pulverized Coal - 502 MW - CCS	513	549	585	620	656	692	727	763	799	834	870
Circulating Fluidized Bed - CC	463	503	544	584	625	665	706	746	787	827	868
Supercritical Pulverized Coal - 565 MW - CCS	452	491	530	569	608	646	685	724	763	802	841
Supercritical Pulverized Coal - 800 MW - CCS	396	426	456	486	515	545	575	605	635	664	694
1x1 IGCC - CCS	488	516	543	570	597	624	652	679	706	—	—
2x1 IGCC - CC	441	467	493	518	544	570	596	622	648	—	—
Wind Energy Conversion	232	229	227	224	—	—	—	—	—	—	—
Solar Photovoltaic	472	472	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	540	541	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	679	679	680	681	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	627	627	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	678	679	680	680	681	682	683	—	—	—	—
Solar Thermal, Solar Chimney	557	557	557	557	—	—	—	—	—	—	—
MSW Mass Burn	1701	1669	1638	1606	1575	1543	1512	1480	—	—	—
RDF Stoker-Fired	1555	1636	1717	1798	1879	1960	2041	2122	2203	—	—
Wood Fired Stoker Plant	444	474	505	536	567	598	629	660	691	—	—
Landfill Gas IC Engine	245	268	292	315	338	361	385	408	431	454	—
TDF Multi-Fuel CFB (10% Co-fire)	476	503	531	559	587	615	642	670	698	726	753
Sewage Sludge & Anaerobic Digestion	667	662	657	651	646	641	636	630	625	620	—
Bio Mass (Co-Fire)	356	378	400	422	444	466	488	510	532	554	576
Wood-Fired CFBC	466	491	515	540	565	589	614	639	664	688	713
Co-Fired CFBC	569	614	659	703	748	793	838	883	927	972	1017
Molten Carbonate Fuel Cell	220	269	317	366	414	463	511	560	608	657	—
Solid Oxide Fuel Cell	200	247	293	340	387	433	480	526	573	620	—
Spark Ignition Engine	409	479	548	618	687	756	826	895	964	1034	—
Hydroelectric - New - 30 MW	426	421	416	410	405	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	371	366	361	355	350	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	483	478	472	467	462	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	454	449	443	438	433	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	429	424	419	413	408	—	—	—	—	—	—
Minimum Levelized $/kW	88	148	202	224	309	361	385	408	431	454	512

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

Capital Cost-Low **2010 ($/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	168	209	250	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	141	189	237	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	135	199	263	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	132	233	334	435	537	638	739	840	942	1043	1144
Simple Cycle GE 7EA CT	108	231	354	476	599	722	845	967	1090	1213	1336
Simple Cycle GE 7FA CT	88	185	281	377	474	570	666	762	859	955	1051
Combined Cycle GE 7EA CT	196	268	340	412	484	556	629	701	773	845	917
Combined Cycle 1x1 7F-Class	138	198	258	318	378	438	498	557	617	677	737
Combined Cycle 1x1 G-Class CT	118	177	236	295	354	414	473	532	591	650	709
Combined Cycle 2x1 7F-Class CT	101	160	219	279	338	397	456	516	575	634	693
Combined Cycle 3x1 7F-Class CT	95	154	213	272	331	390	449	509	568	627	686
Combined Cycle Siemens 5000F CT	141	204	267	330	394	457	520	583	646	709	772
Humid Air Turbine Cycle CT	130	220	309	399	488	578	667	756	846	935	1025
Kalina Cycle CC CT	138	192	246	300	354	408	462	516	570	625	679
Cheng Cycle CT	143	207	272	336	400	465	529	594	658	722	787
Peaking Microturbine	424	579	735	891	1046	1202	1358	1513	1669	1825	1980
Baseload Microturbine	456	581	707	833	958	1084	1210	1335	1461	1587	1712
Subcritical Pulverized Coal - 256 MW	331	359	386	413	440	467	494	522	549	576	603
Subcritical Pulverized Coal - 512 MW	295	322	348	375	402	429	456	483	510	537	563
Circulating Fluidized Bed - 2x 250 MW	271	304	338	371	404	437	471	504	537	570	604
Supercritical Pulverized Coal - 565 MW	299	327	355	383	412	440	468	497	525	553	582
Supercritical Pulverized Coal-800 MW	261	288	316	343	371	398	426	453	481	508	536
Pressurized Fluidized Bed Combustion	325	352	379	405	432	458	485	511	538	—	—
1x1 IGCC	329	354	379	404	429	454	478	503	528	—	—
2x1 IGCC	368	393	417	442	466	491	515	539	564	—	—
Subcritical Pulverized Coal - 502 MW - CCS	513	552	591	630	669	708	748	787	826	865	904
Circulating Fluidized Bed - CC	463	507	551	595	639	684	728	772	816	860	904
Supercritical Pulverized Coal - 565 MW - CCS	452	494	537	579	621	663	705	747	790	832	874
Supercritical Pulverized Coal - 800 MW - CCS	396	428	460	493	525	557	589	621	653	685	718
1x1 IGCC - CCS	488	518	548	578	608	638	667	697	727	—	—
2x1 IGCC - CC	441	470	498	527	555	584	612	641	669	—	—
Wind Energy Conversion	232	229	227	224	—	—	—	—	—	—	—
Solar Photovoltaic	472	472	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	540	541	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	679	679	680	681	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	627	627	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	678	679	680	680	681	682	683	—	—	—	—
Solar Thermal, Solar Chimney	557	557	557	557	—	—	—	—	—	—	—
MSW Mass Burn	1701	1662	1623	1583	1544	1505	1466	1427	—	—	—
RDF Stoker-Fired	1555	1644	1734	1823	1912	2001	2090	2179	2268	—	—
Wood Fired Stoker Plant	444	478	512	547	581	616	650	685	719	—	—
Landfill Gas IC Engine	245	293	340	387	435	482	529	577	624	671	—
TDF Multi-Fuel CFB (10% Co-fire)	476	506	537	567	598	628	659	689	720	750	781
Sewage Sludge & Anaerobic Digestion	667	662	657	651	646	641	636	630	625	620	—
Bio Mass (Co-Fire)	356	381	405	429	453	478	502	526	550	575	599
Wood-Fired CFBC	466	494	521	549	577	605	633	660	688	716	744
Co-Fired CFBC	569	617	666	714	762	811	859	907	955	1004	1052
Molten Carbonate Fuel Cell	220	273	326	379	432	485	538	591	644	697	—
Solid Oxide Fuel Cell	200	252	304	355	407	459	511	563	614	666	—
Spark Ignition Engine	409	487	564	641	718	795	872	949	1026	1103	—
Hydroelectric - New - 30 MW	426	421	416	410	405	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	371	366	361	355	350	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	483	478	472	467	462	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	454	449	443	438	433	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	429	424	419	413	408	—	—	—	—	—	—
Minimum Levelized $/kW	88	154	213	224	331	390	426	453	481	508	536

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

Capital Cost-Low *2010 ($/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	168	213	257	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	141	192	243	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	135	205	275	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	132	240	349	458	567	675	784	893	1002	1110	1219
Simple Cycle GE 7EA CT	108	240	373	505	637	770	902	1034	1166	1299	1431
Simple Cycle GE 7FA CT	88	193	297	401	506	610	714	818	923	1027	1131
Combined Cycle GE 7EA CT	196	274	353	432	511	589	668	747	826	904	983
Combined Cycle 1x1 7F-Class	138	203	269	334	400	465	531	596	661	727	792
Combined Cycle 1x1 G-Class CT	118	182	247	312	376	441	505	570	635	699	764
Combined Cycle 2x1 7F-Class CT	101	166	230	295	360	425	489	554	619	684	748
Combined Cycle 3x1 7F-Class CT	95	159	224	289	353	418	482	547	612	676	741
Combined Cycle Siemens 5000F CT	141	210	279	348	417	485	554	623	692	761	830
Humid Air Turbine Cycle CT	130	228	326	424	522	620	717	815	913	1011	1109
Kalina Cycle CC CT	138	197	256	315	375	434	493	552	612	671	730
Cheng Cycle CT	143	213	283	354	424	494	565	635	705	775	846
Peaking Microturbine	424	591	759	926	1094	1261	1429	1596	1764	1931	2099
Baseload Microturbine	456	593	731	868	1006	1143	1281	1418	1556	1693	1831
Subcritical Pulverized Coal - 256 MW	331	361	391	420	450	479	509	539	568	598	627
Subcritical Pulverized Coal - 512 MW	295	324	353	382	412	441	470	499	529	558	587
Circulating Fluidized Bed - 2x 250 MW	271	307	343	379	415	451	486	522	558	594	630
Supercritical Pulverized Coal - 565 MW	299	329	360	391	421	452	483	513	544	575	605
Supercritical Pulverized Coal-800 MW	261	291	321	350	380	410	440	470	500	529	559
Pressurized Fluidized Bed Combustion	325	354	383	412	441	470	499	528	557	—	—
1x1 IGCC	329	356	383	410	437	465	492	519	546	—	—
2x1 IGCC	368	395	422	449	475	502	529	556	582	—	—
Subcritical Pulverized Coal - 502 MW - CCS	513	556	598	640	683	725	768	810	852	895	937
Circulating Fluidized Bed - CC	463	511	558	606	654	702	750	797	845	893	941
Supercritical Pulverized Coal - 565 MW - CCS	452	498	543	589	634	680	725	771	816	862	907
Supercritical Pulverized Coal - 800 MW - CCS	396	431	465	500	534	569	603	638	672	707	741
1x1 IGCC - CCS	488	521	553	586	618	651	683	716	748	—	—
2x1 IGCC - CC	441	472	504	535	566	597	629	660	691	—	—
Wind Energy Conversion	232	229	227	224	—	—	—	—	—	—	—
Solar Photovoltaic	472	472	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	540	541	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	679	679	680	681	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	627	627	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	678	679	680	680	681	682	683	—	—	—	—
Solar Thermal, Solar Chimney	557	557	557	557	—	—	—	—	—	—	—
MSW Mass Burn	1701	1654	1607	1560	1514	1467	1420	1373	—	—	—
RDF Stoker-Fired	1555	1653	1750	1847	1944	2041	2139	2236	2333	—	—
Wood Fired Stoker Plant	444	482	520	558	596	634	672	710	748	—	—
Landfill Gas IC Engine	245	326	407	489	570	651	732	813	894	975	—
TDF Multi-Fuel CFB (10% Co-fire)	476	509	542	575	609	642	675	708	742	775	808
Sewage Sludge & Anaerobic Digestion	667	662	657	651	646	641	636	630	625	620	—
Bio Mass (Co-Fire)	356	383	409	436	463	489	516	542	569	595	622
Wood-Fired CFBC	466	497	528	559	589	620	651	682	713	744	775
Co-Fired CFBC	569	621	673	724	776	828	880	932	984	1035	1087
Molten Carbonate Fuel Cell	220	278	335	392	450	507	564	622	679	737	—
Solid Oxide Fuel Cell	200	257	314	371	428	485	542	599	656	713	—
Spark Ignition Engine	409	494	579	664	749	833	918	1003	1088	1173	—
Hydroelectric - New - 30 MW	426	421	416	410	405	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	371	366	361	355	350	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	483	478	472	467	462	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	454	449	443	438	433	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	429	424	419	413	408	—	—	—	—	—	—
Minimum Levelized $/kW	88	159	224	224	350	410	440	470	500	529	559

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

Capital Cost- Base 2010 ($/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	186	224	261	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	156	201	246	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	145	200	256	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	141	228	316	403	490	578	665	753	840	927	1015
Simple Cycle GE 7EA CT	115	220	325	430	535	640	745	850	955	1060	1165
Simple Cycle GE 7FA CT	95	176	258	339	421	502	583	665	746	828	909
Combined Cycle GE 7EA CT	208	268	328	388	448	508	568	628	688	748	808
Combined Cycle 1x1 7F-Class	148	198	248	298	347	397	447	497	546	596	646
Combined Cycle 1x1 G-Class CT	127	176	225	274	323	372	421	470	519	568	617
Combined Cycle 2x1 7F-Class CT	108	157	206	255	304	353	402	451	500	549	598
Combined Cycle 3x1 7F-Class CT	101	150	199	248	297	345	394	443	492	541	590
Combined Cycle Siemens 5000F CT	149	202	254	307	359	411	464	516	569	621	674
Humid Air Turbine Cycle CT	136	210	284	358	431	505	579	653	727	801	874
Kalina Cycle CC CT	146	191	235	280	324	369	413	458	502	547	591
Cheng Cycle CT	151	205	258	312	365	419	472	525	579	632	686
Peaking Microturbine	445	579	713	846	980	1114	1247	1381	1515	1649	1782
Baseload Microturbine	474	578	682	785	889	993	1096	1200	1304	1408	1511
Subcritical Pulverized Coal - 256 MW	358	381	403	426	449	471	494	517	540	562	585
Subcritical Pulverized Coal - 512 MW	319	341	364	386	409	431	454	476	498	521	543
Circulating Fluidized Bed - 2x 250 MW	294	322	351	379	407	436	464	492	521	549	577
Supercritical Pulverized Coal - 565 MW	324	348	372	396	420	444	468	492	516	540	564
Supercritical Pulverized Coal-800 MW	284	307	330	353	376	399	422	445	469	492	515
Pressurized Fluidized Bed Combustion	367	389	411	434	456	478	500	522	544	—	—
1x1 IGCC	358	379	400	421	441	462	483	504	525	—	—
2x1 IGCC	399	419	439	459	479	499	519	540	560	—	—
Subcritical Pulverized Coal - 502 MW - CCS	561	593	626	659	692	725	758	790	823	856	889
Circulating Fluidized Bed - CC	502	539	576	614	651	689	726	763	801	838	876
Supercritical Pulverized Coal - 565 MW - CCS	471	507	543	579	615	651	687	723	759	795	831
Supercritical Pulverized Coal - 800 MW - CCS	413	441	469	496	524	552	580	607	635	663	691
1x1 IGCC - CCS	510	535	560	585	610	634	659	684	709	—	—
2x1 IGCC - CC	459	482	506	529	552	576	599	623	646	—	—
Wind Energy Conversion	257	254	251	248	—	—	—	—	—	—	—
Solar Photovoltaic	580	580	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	655	656	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	829	829	830	830	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	764	764	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	808	809	810	811	812	812	813	—	—	—	—
Solar Thermal, Solar Chimney	673	673	673	673	—	—	—	—	—	—	—
MSW Mass Burn	1809	1784	1759	1734	1709	1684	1659	1634	—	—	—
RDF Stoker-Fired	1723	1797	1871	1945	2019	2093	2167	2241	2316	—	—
Wood Fired Stoker Plant	493	521	549	577	605	633	660	688	716	—	—
Landfill Gas IC Engine	275	297	320	342	364	386	408	430	452	475	—
TDF Multi-Fuel CFB (10% Co-fire)	514	540	565	591	616	641	667	692	718	743	769
Sewage Sludge & Anaerobic Digestion	735	730	725	719	714	709	704	698	693	688	—
Bio Mass (Co-Fire)	387	407	427	447	467	487	507	527	547	567	587
Wood-Fired CFBC	506	528	550	572	594	616	638	660	682	704	726
Co-Fired CFBC	620	662	703	745	787	829	870	912	954	996	1037
Molten Carbonate Fuel Cell	266	311	356	400	445	490	534	579	624	668	—
Solid Oxide Fuel Cell	171	213	256	298	340	382	424	466	509	551	—
Spark Ignition Engine	423	486	549	612	674	737	800	863	925	988	—
Hydroelectric - New - 30 MW	493	487	482	476	471	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	434	428	423	418	412	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	566	560	555	550	544	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	532	526	521	516	510	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	503	498	492	487	481	—	—	—	—	—	—
Minimum Levelized $/kW	95	150	199	248	297	345	394	430	452	475	515

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

Capital Cost- Base **2010 ($/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	186	227	268	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	156	204	252	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	145	206	267	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	141	235	329	423	518	612	706	800	894	988	1082
Simple Cycle GE 7EA CT	115	228	342	456	569	683	797	910	1024	1138	1252
Simple Cycle GE 7FA CT	95	183	272	361	449	538	627	715	804	893	982
Combined Cycle GE 7EA CT	208	274	340	406	471	537	603	669	735	801	867
Combined Cycle 1x1 7F-Class	148	203	258	313	367	422	477	531	586	641	696
Combined Cycle 1x1 G-Class CT	127	181	234	288	342	396	450	504	558	612	666
Combined Cycle 2x1 7F-Class CT	108	162	216	270	324	378	432	486	540	594	648
Combined Cycle 3x1 7F-Class CT	101	155	209	263	316	370	424	478	532	586	640
Combined Cycle Siemens 5000F CT	149	207	264	322	380	437	495	553	610	668	726
Humid Air Turbine Cycle CT	136	218	299	380	462	543	625	706	788	869	950
Kalina Cycle CC CT	146	195	245	294	343	392	441	490	540	589	638
Cheng Cycle CT	151	210	269	328	386	445	504	563	622	680	739
Peaking Microturbine	445	590	734	878	1023	1167	1312	1456	1600	1745	1889
Baseload Microturbine	474	589	703	817	932	1046	1161	1275	1389	1504	1618
Subcritical Pulverized Coal - 256 MW	358	383	408	433	458	482	507	532	557	582	607
Subcritical Pulverized Coal - 512 MW	319	343	368	393	417	442	467	491	516	540	565
Circulating Fluidized Bed - 2x 250 MW	294	325	355	386	417	448	478	509	540	571	601
Supercritical Pulverized Coal - 565 MW	324	350	376	403	429	455	481	507	533	559	585
Supercritical Pulverized Coal-800 MW	284	309	334	359	385	410	435	460	486	511	536
Pressurized Fluidized Bed Combustion	367	391	416	440	464	489	513	537	561	—	—
1x1 IGCC	358	381	404	427	449	472	495	518	541	—	—
2x1 IGCC	399	421	443	465	487	510	532	554	576	—	—
Subcritical Pulverized Coal - 502 MW - CCS	561	597	632	668	704	740	776	812	847	883	919
Circulating Fluidized Bed - CC	502	542	583	624	664	705	746	787	827	868	909
Supercritical Pulverized Coal - 565 MW - CCS	471	510	549	588	627	666	705	744	783	822	861
Supercritical Pulverized Coal - 800 MW - CCS	413	443	473	503	533	562	592	622	652	682	712
1x1 IGCC - CCS	510	537	564	592	619	646	674	701	728	—	—
2x1 IGCC - CC	459	484	510	536	562	588	614	640	666	—	—
Wind Energy Conversion	257	254	251	248	—	—	—	—	—	—	—
Solar Photovoltaic	580	580	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	655	656	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	829	829	830	830	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	764	764	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	808	809	810	811	812	812	813	—	—	—	—
Solar Thermal, Solar Chimney	673	673	673	673	—	—	—	—	—	—	—
MSW Mass Burn	1809	1777	1745	1713	1682	1650	1618	1586	—	—	—
RDF Stoker-Fired	1723	1805	1886	1967	2049	2130	2211	2293	2374	—	—
Wood Fired Stoker Plant	493	524	555	587	618	649	680	711	742	—	—
Landfill Gas IC Engine	275	319	363	407	451	495	539	583	627	671	—
TDF Multi-Fuel CFB (10% Co-fire)	514	542	570	598	626	654	682	710	738	765	793
Sewage Sludge & Anaerobic Digestion	735	730	725	719	714	709	704	698	693	688	—
Bio Mass (Co-Fire)	387	409	431	453	475	497	519	541	563	586	608
Wood-Fired CFBC	506	531	555	580	605	630	655	680	705	730	754
Co-Fired CFBC	620	665	710	755	800	845	889	934	979	1024	1069
Molten Carbonate Fuel Cell	266	315	364	412	461	510	558	607	656	704	—
Solid Oxide Fuel Cell	171	218	265	312	359	406	452	499	546	593	—
Spark Ignition Engine	423	493	563	633	702	772	842	911	981	1051	—
Hydroelectric - New - 30 MW	493	487	482	476	471	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	434	428	423	418	412	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	566	560	555	550	544	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	532	526	521	516	510	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	503	498	492	487	481	—	—	—	—	—	—
Minimum Levelized $/kW	95	155	209	248	316	370	424	460	486	511	536

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

Capital Cost- Base **2010 ($/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	186	231	275	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	156	207	259	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	145	212	279	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	141	242	343	444	545	646	746	847	948	1049	1150
Simple Cycle GE 7EA CT	115	237	359	482	604	726	848	971	1093	1215	1338
Simple Cycle GE 7FA CT	95	191	287	382	478	574	670	766	862	958	1054
Combined Cycle GE 7EA CT	208	280	352	423	495	567	639	711	783	855	927
Combined Cycle 1x1 7F-Class	148	208	268	327	387	447	507	566	626	686	745
Combined Cycle 1x1 G-Class CT	127	185	244	303	362	421	480	539	598	657	716
Combined Cycle 2x1 7F-Class CT	108	167	226	285	344	403	462	521	580	639	698
Combined Cycle 3x1 7F-Class CT	101	160	219	277	336	395	454	513	572	630	689
Combined Cycle Siemens 5000F CT	149	212	275	338	401	464	526	589	652	715	778
Humid Air Turbine Cycle CT	136	225	314	403	492	581	670	759	848	937	1026
Kalina Cycle CC CT	146	200	254	308	362	415	469	523	577	631	685
Cheng Cycle CT	151	215	280	344	408	472	536	600	664	728	793
Peaking Microturbine	445	600	755	911	1066	1221	1376	1531	1686	1841	1996
Baseload Microturbine	474	599	724	850	975	1100	1225	1350	1475	1600	1725
Subcritical Pulverized Coal - 256 MW	358	385	412	439	466	493	520	547	575	602	629
Subcritical Pulverized Coal - 512 MW	319	346	372	399	426	453	479	506	533	560	587
Circulating Fluidized Bed - 2x 250 MW	294	327	360	393	426	460	493	526	559	592	625
Supercritical Pulverized Coal - 565 MW	324	353	381	409	437	465	494	522	550	578	607
Supercritical Pulverized Coal-800 MW	284	311	338	366	393	420	448	475	503	530	557
Pressurized Fluidized Bed Combustion	367	393	420	446	473	499	526	552	578	—	—
1x1 IGCC	358	383	408	433	457	482	507	532	556	—	—
2x1 IGCC	399	423	447	472	496	520	544	569	593	—	—
Subcritical Pulverized Coal - 502 MW - CCS	561	600	638	677	716	755	794	833	872	911	950
Circulating Fluidized Bed - CC	502	546	590	634	678	722	766	810	854	898	942
Supercritical Pulverized Coal - 565 MW - CCS	471	513	555	597	639	681	723	765	807	849	891
Supercritical Pulverized Coal - 800 MW - CCS	413	445	477	509	541	573	605	637	669	701	733
1x1 IGCC - CCS	510	539	569	599	628	658	688	718	747	—	—
2x1 IGCC - CC	459	487	515	544	572	601	629	657	686	—	—
Wind Energy Conversion	257	254	251	248	—	—	—	—	—	—	—
Solar Photovoltaic	580	580	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	655	656	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	829	829	830	830	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	764	764	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	808	809	810	811	812	812	813	—	—	—	—
Solar Thermal, Solar Chimney	673	673	673	673	—	—	—	—	—	—	—
MSW Mass Burn	1809	1770	1731	1693	1654	1615	1576	1538	—	—	—
RDF Stoker-Fired	1723	1812	1901	1989	2078	2167	2255	2344	2433	—	—
Wood Fired Stoker Plant	493	528	562	596	630	665	699	733	768	—	—
Landfill Gas IC Engine	275	350	424	499	573	648	722	797	871	946	—
TDF Multi-Fuel CFB (10% Co-fire)	514	545	575	605	636	666	697	727	757	788	818
Sewage Sludge & Anaerobic Digestion	735	730	725	720	714	709	704	698	693	688	—
Bio Mass (Co-Fire)	387	411	435	459	483	508	532	556	580	604	628
Wood-Fired CFBC	506	533	561	589	616	644	672	699	727	755	782
Co-Fired CFBC	620	668	716	764	812	860	909	957	1005	1053	1101
Molten Carbonate Fuel Cell	266	319	372	424	477	530	582	635	688	741	—
Solid Oxide Fuel Cell	171	223	274	326	377	429	480	532	584	635	—
Spark Ignition Engine	423	500	577	653	730	807	884	960	1037	1114	—
Hydroelectric - New - 30 MW	493	487	482	476	471	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	434	428	423	418	412	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	566	560	555	550	544	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	532	526	521	516	510	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	503	498	492	487	481	—	—	—	—	—	—
Minimum Levelized $/kW	95	160	219	248	336	395	448	475	503	530	557

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

Capital Cost- Base **2010 ($/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	186	224	261	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	156	201	246	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	145	202	258	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	142	232	323	413	504	594	685	776	866	957	1047
Simple Cycle GE 7EA CT	115	224	334	443	552	661	770	879	989	1098	1207
Simple Cycle GE 7FA CT	95	180	265	350	435	520	605	689	774	859	944
Combined Cycle GE 7EA CT	209	272	334	397	460	523	586	648	711	774	837
Combined Cycle 1x1 7F-Class	149	201	253	305	358	410	462	514	566	618	670
Combined Cycle 1x1 G-Class CT	127	179	230	281	333	384	435	487	538	590	641
Combined Cycle 2x1 7F-Class CT	109	160	211	263	314	366	417	468	520	571	623
Combined Cycle 3x1 7F-Class CT	102	153	204	256	307	358	409	461	512	563	614
Combined Cycle Siemens 5000F CT	150	205	260	315	370	425	480	535	590	645	700
Humid Air Turbine Cycle CT	138	215	293	370	448	525	602	680	757	835	912
Kalina Cycle CC CT	147	194	241	287	334	381	428	474	521	568	615
Cheng Cycle CT	153	209	265	320	376	432	488	544	600	656	712
Peaking Microturbine	446	585	724	863	1001	1140	1279	1418	1556	1695	1834
Baseload Microturbine	477	585	694	803	912	1021	1129	1238	1347	1456	1564
Subcritical Pulverized Coal - 256 MW	358	382	405	429	453	477	500	524	548	572	595
Subcritical Pulverized Coal - 512 MW	319	342	366	389	413	436	460	483	507	530	554
Circulating Fluidized Bed - 2x 250 MW	294	323	353	382	412	441	471	500	530	559	589
Supercritical Pulverized Coal - 565 MW	324	349	374	399	424	449	474	499	524	549	574
Supercritical Pulverized Coal-800 MW	284	308	332	356	380	404	428	452	477	501	525
Pressurized Fluidized Bed Combustion	367	390	413	437	460	483	506	529	552	—	—
1x1 IGCC	358	380	402	423	445	467	489	510	532	—	—
2x1 IGCC	399	420	441	462	483	504	525	546	568	—	—
Subcritical Pulverized Coal - 502 MW - CCS	561	595	629	663	698	732	766	800	835	869	903
Circulating Fluidized Bed - CC	502	541	580	619	658	696	735	774	813	852	891
Supercritical Pulverized Coal - 565 MW - CCS	471	509	546	583	621	658	696	733	770	808	845
Supercritical Pulverized Coal - 800 MW - CCS	413	442	471	499	528	557	586	614	643	672	701
1x1 IGCC - CCS	510	536	562	588	614	640	666	692	718	—	—
2x1 IGCC - CC	459	483	508	532	557	582	606	631	656	—	—
Wind Energy Conversion	257	254	251	248	—	—	—	—	—	—	—
Solar Photovoltaic	580	580	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	655	656	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	829	829	830	830	—	—	—	—	—	—	—
Solar Thermal. Parabolic Dish	764	764	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	808	809	810	811	812	812	813	—	—	—	—
Solar Thermal, Solar Chimney	673	673	673	673	—	—	—	—	—	—	—
MSW Mass Burn	1809	1781	1753	1724	1696	1668	1640	1611	—	—	—
RDF Stoker-Fired	1723	1801	1878	1956	2033	2111	2188	2266	2343	—	—
Wood Fired Stoker Plant	493	523	552	581	611	640	670	699	728	—	—
Landfill Gas IC Engine	275	298	321	343	366	389	411	434	457	480	—
TDF Multi-Fuel CFB (10% Co-fire)	514	541	568	594	621	647	674	700	727	754	780
Sewage Sludge & Anaerobic Digestion	735	730	725	719	714	709	704	698	693	688	—
Bio Mass (Co-Fire)	387	408	429	450	471	492	513	534	555	576	597
Wood-Fired CFBC	506	529	553	576	599	623	646	669	693	716	740
Co-Fired CFBC	620	663	706	750	793	836	879	923	966	1009	1053
Molten Carbonate Fuel Cell	267	314	360	407	454	500	547	593	640	686	—
Solid Oxide Fuel Cell	172	217	261	306	350	394	439	483	527	572	—
Spark Ignition Engine	425	491	557	623	689	755	821	887	953	1019	—
Hydroelectric - New - 30 MW	493	487	482	476	471	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	434	428	423	418	412	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	566	560	555	550	544	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	532	526	521	516	510	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	503	498	492	487	481	—	—	—	—	—	—
Minimum Levelized $/kW	95	153	204	248	307	358	409	434	457	480	525

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

Capital Cost- Base *2010 ($/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	186	231	275	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	156	207	259	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	145	214	283	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	142	246	351	456	561	666	771	875	980	1085	1190
Simple Cycle GE 7EA CT	115	243	370	497	625	752	879	1007	1134	1261	1388
Simple Cycle GE 7FA CT	95	195	296	396	496	596	696	796	896	996	1096
Combined Cycle GE 7EA CT	209	284	359	435	510	585	661	736	811	887	962
Combined Cycle 1x1 7F-Class	149	212	274	337	399	462	525	587	650	712	775
Combined Cycle 1x1 G-Class CT	127	189	251	313	374	436	498	560	621	683	745
Combined Cycle 2x1 7F-Class CT	109	170	232	294	356	418	480	542	604	666	727
Combined Cycle 3x1 7F-Class CT	102	163	225	287	349	410	472	534	596	657	719
Combined Cycle Siemens 5000F CT	150	216	282	348	414	480	546	612	677	743	809
Humid Air Turbine Cycle CT	138	231	325	418	512	605	699	792	885	979	1072
Kalina Cycle CC CT	147	204	260	317	373	430	487	543	600	656	713
Cheng Cycle CT	153	220	287	354	421	489	556	623	690	757	825
Peaking Microturbine	446	608	769	930	1091	1253	1414	1575	1737	1898	2059
Baseload Microturbine	477	608	739	871	1002	1133	1264	1396	1527	1658	1790
Subcritical Pulverized Coal - 256 MW	358	386	415	443	471	500	528	556	585	613	641
Subcritical Pulverized Coal - 512 MW	319	347	375	403	431	459	487	515	543	571	599
Circulating Fluidized Bed - 2x 250 MW	294	328	363	397	432	466	501	535	570	604	639
Supercritical Pulverized Coal - 565 MW	324	354	383	413	442	472	501	530	560	589	619
Supercritical Pulverized Coal-800 MW	284	312	341	369	398	427	455	484	512	541	570
Pressurized Fluidized Bed Combustion	367	395	422	450	478	505	533	561	588	—	—
1x1 IGCC	358	384	410	436	462	488	514	540	566	—	—
2x1 IGCC	399	424	450	475	501	526	552	577	603	—	—
Subcritical Pulverized Coal - 502 MW - CCS	561	601	642	683	723	764	805	845	886	926	967
Circulating Fluidized Bed - CC	502	548	594	639	685	731	777	823	869	915	961
Supercritical Pulverized Coal - 565 MW - CCS	471	515	559	602	646	690	734	777	821	865	909
Supercritical Pulverized Coal - 800 MW - CCS	413	446	479	513	546	579	613	646	679	712	746
1x1 IGCC - CCS	510	541	572	603	634	665	696	727	758	—	—
2x1 IGCC - CC	459	488	518	548	578	608	638	667	697	—	—
Wind Energy Conversion	257	254	251	248	—	—	—	—	—	—	—
Solar Photovoltaic	580	580	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	655	656	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	829	829	830	830	—	—	—	—	—	—	—
Solar Thermal. Parabolic Dish	764	764	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	808	809	810	811	812	812	813	—	—	—	—
Solar Thermal, Solar Chimney	673	673	673	673	—	—	—	—	—	—	—
MSW Mass Burn	1809	1766	1723	1681	1638	1595	1552	1509	—	—	—
RDF Stoker-Fired	1723	1816	1909	2002	2095	2188	2281	2374	2467	—	—
Wood Fired Stoker Plant	493	529	566	602	638	674	710	746	782	—	—
Landfill Gas IC Engine	275	353	431	509	586	664	742	820	898	975	—
TDF Multi-Fuel CFB (10% Co-fire)	514	546	578	610	642	673	705	737	769	801	832
Sewage Sludge & Anaerobic Digestion	735	730	725	720	714	709	704	698	693	688	—
Bio Mass (Co-Fire)	387	412	437	463	488	514	539	564	590	615	640
Wood-Fired CFBC	506	535	564	594	623	652	681	711	740	769	799
Co-Fired CFBC	620	670	720	770	820	870	920	970	1020	1069	1119
Molten Carbonate Fuel Cell	267	322	377	432	487	542	597	652	707	762	—
Solid Oxide Fuel Cell	172	227	281	335	389	444	498	552	606	661	—
Spark Ignition Engine	425	506	586	667	748	829	909	990	1071	1152	—
Hydroelectric - New - 30 MW	493	487	482	476	471	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	434	428	423	418	412	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	566	560	555	550	544	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	532	526	521	516	510	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	503	498	492	487	481	—	—	—	—	—	—
Minimum Levelized $/kW	95	163	225	248	349	410	455	484	512	541	570

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

Capital Cost- Base 2010 ($/kW yr)
Heat Rate- High
Fuel Forecast-Low

Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
	Capacity Factors										
Pumped Hydro Energy Storage	186	224	261	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	156	201	246	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	145	203	261	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	142	236	330	424	517	611	705	799	892	986	1080
Simple Cycle GE 7EA CT	116	229	343	456	569	682	796	909	1022	1135	1249
Simple Cycle GE 7FA CT	96	184	273	361	449	538	626	714	802	891	979
Combined Cycle GE 7EA CT	210	275	341	407	472	538	604	669	735	800	866
Combined Cycle 1x1 7F-Class	150	204	259	313	368	422	477	531	585	640	694
Combined Cycle 1x1 G-Class CT	128	182	235	289	343	397	450	504	558	611	665
Combined Cycle 2x1 7F-Class CT	109	163	217	271	324	378	432	486	539	593	647
Combined Cycle 3x1 7F-Class CT	103	156	210	263	317	371	424	478	532	585	639
Combined Cycle Siemens 5000F CT	152	209	266	324	381	438	496	553	611	668	725
Humid Air Turbine Cycle CT	140	221	302	383	464	545	626	707	788	869	950
Kalina Cycle CC CT	148	197	246	295	344	393	442	491	540	589	638
Cheng Cycle CT	154	212	271	329	388	446	505	563	622	680	739
Peaking Microturbine	447	591	735	879	1023	1166	1310	1454	1598	1742	1886
Baseload Microturbine	479	593	707	821	934	1048	1162	1276	1390	1504	1618
Subcritical Pulverized Coal - 256 MW	358	383	407	432	457	482	507	531	556	581	606
Subcritical Pulverized Coal - 512 MW	319	343	368	392	417	441	466	490	515	539	564
Circulating Fluidized Bed - 2x 250 MW	294	325	355	386	416	447	478	508	539	569	600
Supercritical Pulverized Coal - 565 MW	324	350	376	402	428	454	480	506	532	558	584
Supercritical Pulverized Coal-800 MW	284	309	334	359	384	409	434	460	485	510	535
Pressurized Fluidized Bed Combustion	367	391	415	440	464	488	512	536	561	—	—
1x1 IGCC	358	381	404	426	449	472	494	517	540	—	—
2x1 IGCC	399	421	443	465	487	509	531	553	576	—	—
Subcritical Pulverized Coal - 502 MW - CCS	561	596	632	668	703	739	775	810	846	882	918
Circulating Fluidized Bed - CC	502	542	583	623	664	704	745	785	826	866	907
Supercritical Pulverized Coal - 565 MW - CCS	471	510	549	588	627	665	704	743	782	821	860
Supercritical Pulverized Coal - 800 MW - CCS	413	443	473	502	532	562	592	622	651	681	711
1x1 IGCC - CCS	510	537	564	591	619	646	673	700	727	—	—
2x1 IGCC - CC	459	484	510	536	562	588	613	639	665	—	—
Wind Energy Conversion	257	254	251	248	—	—	—	—	—	—	—
Solar Photovoltaic	580	580	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	655	656	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	829	829	830	830	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	764	764	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	808	809	810	811	812	812	813	—	—	—	—
Solar Thermal, Solar Chimney	673	673	673	673	—	—	—	—	—	—	—
MSW Mass Burn	1809	1777	1746	1714	1683	1651	1620	1588	—	—	—
RDF Stoker-Fired	1723	1804	1885	1966	2047	2128	2209	2290	2371	—	—
Wood Fired Stoker Plant	493	524	555	586	617	648	679	710	740	—	—
Landfill Gas IC Engine	275	299	322	345	368	391	415	438	461	484	—
TDF Multi-Fuel CFB (10% Co-fire)	514	542	570	598	625	653	681	709	736	764	792
Sewage Sludge & Anaerobic Digestion	735	730	725	719	714	709	704	698	693	688	—
Bio Mass (Co-Fire)	387	409	431	453	475	497	519	541	563	585	607
Wood-Fired CFBC	506	530	555	580	605	629	654	679	703	728	753
Co-Fired CFBC	620	665	709	754	799	844	888	933	978	1023	1068
Molten Carbonate Fuel Cell	268	317	365	414	462	511	559	607	656	704	—
Solid Oxide Fuel Cell	173	220	267	313	360	406	453	500	546	593	—
Spark Ignition Engine	427	496	565	635	704	773	843	912	981	1051	—
Hydroelectric - New - 30 MW	493	487	482	476	471	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	434	428	423	418	412	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	566	560	555	550	544	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	532	526	521	516	510	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	503	498	492	487	481	—	—	—	—	—	—
Minimum Levelized $/kW	96	156	210	248	317	371	415	438	461	484	535

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

Capital Cost- Base *2010 ($/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	186	227	268	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	156	204	252	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	145	209	274	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	142	243	345	446	547	648	750	851	952	1054	1155
Simple Cycle GE 7EA CT	116	239	362	484	607	730	853	976	1098	1221	1344
Simple Cycle GE 7FA CT	96	192	289	385	481	577	674	770	866	963	1059
Combined Cycle GE 7EA CT	210	282	354	426	499	571	643	715	787	860	932
Combined Cycle 1x1 7F-Class	150	210	270	330	390	450	510	570	630	689	749
Combined Cycle 1x1 G-Class CT	128	187	246	305	365	424	483	542	601	661	720
Combined Cycle 2x1 7F-Class CT	109	169	228	287	346	406	465	524	583	643	702
Combined Cycle 3x1 7F-Class CT	103	162	221	280	339	398	457	516	575	635	694
Combined Cycle Siemens 5000F CT	152	215	278	341	404	467	530	594	657	720	783
Humid Air Turbine Cycle CT	140	229	319	408	497	587	676	766	855	945	1034
Kalina Cycle CC CT	148	202	256	311	365	419	473	527	581	635	689
Cheng Cycle CT	154	218	283	347	411	476	540	605	669	733	798
Peaking Microturbine	447	603	758	914	1070	1225	1381	1537	1692	1848	2004
Baseload Microturbine	479	605	730	856	982	1107	1233	1359	1484	1610	1736
Subcritical Pulverized Coal - 256 MW	358	385	412	440	467	494	521	548	575	603	630
Subcritical Pulverized Coal - 512 MW	319	346	373	399	426	453	480	507	534	561	588
Circulating Fluidized Bed - 2x 250 MW	294	327	360	394	427	460	493	527	560	593	626
Supercritical Pulverized Coal - 565 MW	324	353	381	409	438	466	494	523	551	579	608
Supercritical Pulverized Coal-800 MW	284	311	339	366	393	421	448	476	503	531	558
Pressurized Fluidized Bed Combustion	367	394	420	447	473	500	526	553	579	—	—
1x1 IGCC	358	383	408	433	458	483	508	532	557	—	—
2x1 IGCC	399	423	447	472	496	521	545	570	594	—	—
Subcritical Pulverized Coal - 502 MW - CCS	561	600	639	678	717	756	795	834	873	912	951
Circulating Fluidized Bed - CC	502	546	590	634	678	722	767	811	855	899	943
Supercritical Pulverized Coal - 565 MW - CCS	471	513	555	598	640	682	724	766	808	851	893
Supercritical Pulverized Coal - 800 MW - CCS	413	445	477	509	542	574	606	638	670	702	734
1x1 IGCC - CCS	510	540	569	599	629	659	689	718	748	—	—
2x1 IGCC - CC	459	487	516	544	573	601	630	658	687	—	—
Wind Energy Conversion	257	254	251	248	—	—	—	—	—	—	—
Solar Photovoltaic	580	580	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	655	656	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	829	829	830	830	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	764	764	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	808	809	810	811	812	812	813	—	—	—	—
Solar Thermal, Solar Chimney	673	673	673	673	—	—	—	—	—	—	—
MSW Mass Burn	1809	1770	1731	1692	1652	1613	1574	1535	—	—	—
RDF Stoker-Fired	1723	1812	1901	1991	2080	2169	2258	2347	2436	—	—
Wood Fired Stoker Plant	493	528	562	597	631	666	700	734	769	—	—
Landfill Gas IC Engine	275	323	370	417	465	512	559	607	654	701	—
TDF Multi-Fuel CFB (10% Co-fire)	514	545	575	606	636	667	697	728	758	789	819
Sewage Sludge & Anaerobic Digestion	735	730	725	720	714	709	704	698	693	688	—
Bio Mass (Co-Fire)	387	411	435	460	484	508	532	557	581	605	630
Wood-Fired CFBC	506	534	561	589	617	645	673	700	728	756	784
Co-Fired CFBC	620	668	716	765	813	861	910	958	1006	1054	1103
Molten Carbonate Fuel Cell	268	321	374	427	480	533	586	639	691	744	—
Solid Oxide Fuel Cell	173	225	277	329	381	432	484	536	588	639	—
Spark Ignition Engine	427	504	581	658	735	812	889	966	1043	1120	—
Hydroelectric - New - 30 MW	493	487	482	476	471	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	434	428	423	418	412	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	566	560	555	550	544	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	532	526	521	516	510	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	503	498	492	487	481	—	—	—	—	—	—
Minimum Levelized $/kW	96	162	221	248	339	398	448	476	503	531	558

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

Capital Cost- Base **2010 ($/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	186	231	275	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	156	207	259	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	145	216	286	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	142	251	360	468	577	686	795	903	1012	1121	1230
Simple Cycle GE 7EA CT	116	248	381	513	645	778	910	1042	1175	1307	1439
Simple Cycle GE 7FA CT	96	200	305	409	513	617	722	826	930	1035	1139
Combined Cycle GE 7EA CT	210	289	367	446	525	604	682	761	840	919	998
Combined Cycle 1x1 7F-Class	150	215	281	346	412	477	543	608	674	739	804
Combined Cycle 1x1 G-Class CT	128	193	257	322	387	451	516	580	645	710	774
Combined Cycle 2x1 7F-Class CT	109	174	239	304	368	433	498	563	627	692	757
Combined Cycle 3x1 7F-Class CT	103	167	232	296	361	426	490	555	619	684	749
Combined Cycle Siemens 5000F CT	152	220	289	358	427	496	565	634	703	772	841
Humid Air Turbine Cycle CT	140	237	335	433	531	629	727	825	922	1020	1118
Kalina Cycle CC CT	148	208	267	326	385	445	504	563	622	682	741
Cheng Cycle CT	154	224	294	365	435	505	576	646	716	787	857
Peaking Microturbine	447	615	782	950	1117	1285	1452	1620	1787	1955	2122
Baseload Microturbine	479	617	754	892	1029	1167	1304	1442	1579	1717	1854
Subcritical Pulverized Coal - 256 MW	358	388	417	447	476	506	536	565	595	624	654
Subcritical Pulverized Coal - 512 MW	319	348	377	407	436	465	494	524	553	582	611
Circulating Fluidized Bed - 2x 250 MW	294	330	366	402	437	473	509	545	581	617	653
Supercritical Pulverized Coal - 565 MW	324	355	386	416	447	478	508	539	570	601	631
Supercritical Pulverized Coal-800 MW	284	313	343	373	403	433	463	492	522	552	582
Pressurized Fluidized Bed Combustion	367	396	425	454	483	511	540	569	598	—	—
1x1 IGCC	358	385	412	439	467	494	521	548	575	—	—
2x1 IGCC	399	425	452	479	506	532	559	586	613	—	—
Subcritical Pulverized Coal - 502 MW - CCS	561	603	645	688	730	773	815	857	900	942	985
Circulating Fluidized Bed - CC	502	550	597	645	693	741	789	836	884	932	980
Supercritical Pulverized Coal - 565 MW - CCS	471	517	562	608	653	699	744	790	835	881	926
Supercritical Pulverized Coal - 800 MW - CCS	413	447	482	516	551	585	620	654	689	723	758
1x1 IGCC - CCS	510	542	575	607	639	672	704	737	769	—	—
2x1 IGCC - CC	459	490	521	552	584	615	646	677	709	—	—
Wind Energy Conversion	257	254	251	248	—	—	—	—	—	—	—
Solar Photovoltaic	580	580	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	655	656	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	829	829	830	830	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	764	764	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	808	809	810	811	812	812	813	—	—	—	—
Solar Thermal, Solar Chimney	673	673	673	673	—	—	—	—	—	—	—
MSW Mass Burn	1809	1762	1715	1669	1622	1575	1528	1481	—	—	—
RDF Stoker-Fired	1723	1820	1918	2015	2112	2209	2306	2404	2501	—	—
Wood Fired Stoker Plant	493	531	569	607	645	683	721	759	797	—	—
Landfill Gas IC Engine	275	356	437	519	600	681	762	843	924	1005	—
TDF Multi-Fuel CFB (10% Co-fire)	514	548	581	614	647	681	714	747	780	813	847
Sewage Sludge & Anaerobic Digestion	735	730	725	720	714	709	704	699	693	688	—
Bio Mass (Co-Fire)	387	413	440	466	493	520	546	573	599	626	653
Wood-Fired CFBC	506	537	568	598	629	660	691	722	753	784	815
Co-Fired CFBC	620	672	723	775	827	879	931	982	1034	1086	1138
Molten Carbonate Fuel Cell	268	325	383	440	497	555	612	670	727	784	—
Solid Oxide Fuel Cell	173	230	287	344	401	458	515	572	629	686	—
Spark Ignition Engine	427	511	596	681	766	850	935	1020	1105	1190	—
Hydroelectric - New - 30 MW	493	487	482	476	471	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	434	428	423	418	412	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	566	560	555	550	544	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	532	526	521	516	510	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	503	498	492	487	481	—	—	—	—	—	—
Minimum Levelized $/kW	96	167	232	248	361	426	463	492	522	552	582

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

Capital Cost- High — **2010 ($/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	249	287	324	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	195	240	284	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	183	238	293	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	162	249	337	424	511	599	686	774	861	948	1036
Simple Cycle GE 7EA CT	131	236	341	446	551	656	761	866	971	1076	1182
Simple Cycle GE 7FA CT	110	192	273	354	436	517	599	680	762	843	925
Combined Cycle GE 7EA CT	236	296	356	416	476	536	596	656	716	776	836
Combined Cycle 1x1 7F-Class	173	222	272	322	371	421	471	521	570	620	670
Combined Cycle 1x1 G-Class CT	147	196	245	294	343	392	441	490	539	588	638
Combined Cycle 2x1 7F-Class CT	125	174	223	272	321	370	419	468	517	566	616
Combined Cycle 3x1 7F-Class CT	117	165	214	263	312	361	410	459	508	557	606
Combined Cycle Siemens 5000F CT	170	223	275	328	380	433	485	538	590	642	695
Humid Air Turbine Cycle CT	155	228	302	376	450	524	598	671	745	819	893
Kalina Cycle CC CT	167	212	256	301	345	390	435	479	524	568	613
Cheng Cycle CT	173	227	280	334	387	441	494	547	601	654	708
Peaking Microturbine	492	626	759	893	1027	1160	1294	1428	1562	1695	1829
Baseload Microturbine	521	625	728	832	936	1039	1143	1247	1351	1454	1558
Subcritical Pulverized Coal - 256 MW	424	447	470	493	515	538	561	583	606	629	652
Subcritical Pulverized Coal - 512 MW	379	402	424	447	469	492	514	537	559	582	604
Circulating Fluidized Bed - 2x 250 MW	351	379	408	436	464	493	521	549	578	606	634
Supercritical Pulverized Coal - 565 MW	389	413	437	461	485	509	533	557	580	604	628
Supercritical Pulverized Coal-800 MW	340	363	386	410	433	456	479	502	525	548	571
Pressurized Fluidized Bed Combustion	464	486	508	530	553	575	597	619	641	—	—
1x1 IGCC	445	466	487	508	529	549	570	591	612	—	—
2x1 IGCC	489	509	529	549	569	590	610	630	650	—	—
Subcritical Pulverized Coal - 502 MW - CCS	727	759	792	825	858	891	923	956	989	1022	1055
Circulating Fluidized Bed - CC	638	675	713	750	788	825	862	900	937	974	1012
Supercritical Pulverized Coal - 565 MW - CCS	604	640	675	711	747	783	819	855	891	927	963
Supercritical Pulverized Coal - 800 MW - CCS	530	558	586	614	642	669	697	725	753	780	808
1x1 IGCC - CCS	658	683	708	733	758	783	808	833	858	—	—
2x1 IGCC - CC	581	605	628	652	675	699	722	746	769	—	—
Wind Energy Conversion	305	302	299	297	—	—	—	—	—	—	—
Solar Photovoltaic	689	689	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	770	771	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	979	979	980	980	—	—	—	—	—	—	—
Solar Thermal. Parabolic Dish	901	901	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	938	939	940	941	942	943	944	—	—	—	—
Solar Thermal, Solar Chimney	790	790	790	790	—	—	—	—	—	—	—
MSW Mass Bum	1917	1892	1867	1842	1817	1792	1767	1742	—	—	—
RDF Stoker-Fired	1891	1965	2039	2113	2187	2261	2335	2409	2483	—	—
Wood Fired Stoker Plant	543	571	599	627	654	682	710	738	766	—	—
Landfill Gas IC Engine	305	327	350	372	394	416	438	460	482	505	—
TDF Multi-Fuel CFB (10% Co-fire)	611	636	662	687	713	738	764	789	814	840	865
Sewage Sludge & Anaerobic Digestion	803	798	793	788	782	777	772	766	761	756	—
Bio Mass (Co-Fire)	463	483	503	523	543	563	583	603	623	643	663
Wood-Fired CFBC	606	628	650	672	694	716	738	760	782	804	826
Co-Fired CFBC	746	788	830	872	914	955	997	1039	1081	1122	1164
Molten Carbonate Fuel Cell	314	359	403	448	493	537	582	627	671	716	—
Solid Oxide Fuel Cell	198	240	282	325	367	409	451	493	535	578	—
Spark Ignition Engine	440	503	566	629	691	754	817	880	942	1005	—
Hydroelectric - New - 30 MW	647	642	636	631	625	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	579	574	568	563	558	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	758	753	748	742	737	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	712	707	702	696	691	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	674	669	664	658	653	—	—	—	—	—	—
Minimum Levelized $/kW	110	165	214	263	312	361	410	459	482	505	571

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

Capital Cost- High **2010 ($/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	249	290	331	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	195	243	291	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	183	244	305	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	162	256	350	444	539	633	727	821	915	1009	1103
Simple Cycle GE 7EA CT	131	245	358	472	586	699	813	927	1040	1154	1268
Simple Cycle GE 7FA CT	110	199	287	376	465	553	642	731	819	908	997
Combined Cycle GE 7EA CT	236	302	368	434	500	566	632	698	764	830	896
Combined Cycle 1x1 7F-Class	173	227	282	337	391	446	501	556	610	665	720
Combined Cycle 1x1 G-Class CT	147	201	255	309	363	417	471	525	579	633	687
Combined Cycle 2x1 7F-Class CT	125	179	233	287	341	395	449	503	557	611	665
Combined Cycle 3x1 7F-Class CT	117	170	224	278	332	386	440	494	548	601	655
Combined Cycle Siemens 5000F CT	170	228	286	343	401	459	516	574	632	689	747
Humid Air Turbine Cycle CT	155	236	317	399	480	562	643	725	806	887	969
Kalina Cycle CC CT	167	217	266	315	364	413	463	512	561	610	659
Cheng Cycle CT	173	232	291	350	409	467	526	585	644	702	761
Peaking Microturbine	492	636	781	925	1070	1214	1358	1503	1647	1792	1936
Baseload Microturbine	521	635	750	864	979	1093	1207	1322	1436	1551	1665
Subcritical Pulverized Coal - 256 MW	*424*	*449*	*474*	*499*	*524*	*549*	*574*	*599*	*624*	*649*	*673*
Subcritical Pulverized Coal - 512 MW	379	404	429	453	478	502	527	552	576	601	626
Circulating Fluidized Bed - 2x 250 MW	351	382	412	443	474	505	535	566	597	628	658
Supercritical Pulverized Coal - 565 MW	389	415	441	467	493	519	545	571	598	624	650
Supercritical Pulverized Coal-800 MW	340	365	391	416	441	466	492	517	542	567	593
Pressurized Fluidized Bed Combustion	464	488	513	537	561	585	610	634	658	—	—
1x1 IGCC	445	468	491	514	537	559	582	605	628	—	—
2x1 IGCC	489	511	533	556	578	600	622	645	667	—	—
Subcritical Pulverized Coal - 502 MW - CCS	727	762	798	834	870	906	942	978	1013	1049	1085
Circulating Fluidized Bed - CC	638	679	719	760	801	841	882	923	963	1004	1045
Supercritical Pulverized Coal - 565 MW - CCS	604	643	682	721	760	799	838	877	916	954	993
Supercritical Pulverized Coal - 800 MW - CCS	530	560	590	620	650	680	710	740	770	800	829
1x1 IGCC - CCS	658	686	713	740	768	795	822	850	877	—	—
2x1 IGCC - CC	581	607	633	659	685	711	737	763	789	—	—
Wind Energy Conversion	305	302	299	297	—	—	—	—	—	—	—
Solar Photovoltaic	689	689	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	770	771	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	979	979	980	980	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	901	901	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	938	939	940	941	942	943	944	—	—	—	—
Solar Thermal. Solar Chimney	790	790	790	790	—	—	—	—	—	—	—
MSW Mass Burn	1917	1885	1853	1821	1790	1758	1726	1694	—	—	—
RDF Stoker-Fired	1891	1972	2054	2135	2217	2298	2379	2461	2542	—	—
Wood Fired Stoker Plant	543	574	605	636	667	698	729	761	792	—	—
Landfill Gas IC Engine	305	349	393	437	481	525	569	613	657	701	—
TDF Multi-Fuel CFB (10% Co-fire)	611	639	667	695	723	750	778	806	834	862	890
Sewage Sludge & Anaerobic Digestion	803	798	793	788	782	777	772	766	761	756	—
Bio Mass (Co-Fire)	463	485	507	529	551	573	595	617	640	662	684
Wood-Fired CFBC	606	630	655	680	705	730	755	780	804	829	854
Co-Fired CFBC	*746*	*791*	*836*	*881*	*926*	*971*	*1016*	*1061*	*1106*	*1151*	*1196*
Molten Carbonate Fuel Cell	314	363	411	460	509	557	606	655	704	752	—
Solid Oxide Fuel Cell	198	245	292	339	385	432	479	526	573	620	—
Spark Ignition Engine	440	510	580	650	719	789	859	928	998	1068	—
Hydroelectric - New - 30 MW	647	642	636	631	625	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	579	574	568	563	558	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	758	753	748	742	737	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	712	707	702	696	691	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	674	669	664	658	653	—	—	—	—	—	—
Minimum Levelized $/kW	110	170	224	278	332	386	440	494	542	567	593

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

Capital Cost- High **2010 ($/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	249	293	338	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	195	246	297	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	183	250	317	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	162	263	364	465	566	667	767	868	969	1070	1171
Simple Cycle GE 7EA CT	131	253	375	498	620	742	865	987	1109	1232	1354
Simple Cycle GE 7FA CT	110	206	302	398	494	590	686	781	877	973	1069
Combined Cycle GE 7EA CT	236	308	380	452	524	596	668	740	811	883	955
Combined Cycle 1x1 7F-Class	173	232	292	352	411	471	531	590	650	710	769
Combined Cycle 1x1 G-Class CT	147	206	265	324	383	442	501	560	619	677	736
Combined Cycle 2x1 7F-Class CT	125	184	243	302	361	420	479	538	597	656	715
Combined Cycle 3x1 7F-Class CT	117	175	234	293	352	411	470	528	587	646	705
Combined Cycle Siemens 5000F CT	170	233	296	359	422	485	548	610	673	736	799
Humid Air Turbine Cycle CT	155	244	333	422	511	600	689	778	867	956	1045
Kalina Cycle CC CT	167	221	275	329	383	437	490	544	598	652	706
Cheng Cycle CT	173	238	302	366	430	494	558	622	686	750	815
Peaking Microturbine	492	647	802	957	1112	1267	1423	1578	1733	1888	2043
Baseload Microturbine	521	646	771	896	1021	1146	1272	1397	1522	1647	1772
Subcritical Pulverized Coal - 256 MW	424	452	479	506	533	560	587	614	641	668	695
Subcritical Pulverized Coal - 512 MW	379	406	433	460	486	513	540	567	594	620	647
Circulating Fluidized Bed - 2x 250 MW	351	384	417	450	484	517	550	583	616	649	682
Supercritical Pulverized Coal - 565 MW	389	417	445	474	502	530	558	586	615	643	671
Supercritical Pulverized Coal-800 MW	340	368	395	422	450	477	504	532	559	587	614
Pressurized Fluidized Bed Combustion	464	490	517	543	570	596	623	649	675	—	—
1x1 IGCC	445	470	495	520	545	569	594	619	644	—	—
2x1 IGCC	489	513	538	562	586	611	635	659	684	—	—
Subcritical Pulverized Coal - 502 MW - CCS	727	765	804	843	882	921	960	999	1038	1077	1115
Circulating Fluidized Bed - CC	638	682	726	770	814	858	902	946	990	1034	1078
Supercritical Pulverized Coal - 565 MW - CCS	604	646	688	730	772	814	856	898	940	982	1024
Supercritical Pulverized Coal - 800 MW - CCS	530	562	594	627	659	691	723	755	787	819	851
1x1 IGCC - CCS	658	688	718	747	777	807	837	866	896	—	—
2x1 IGCC - CC	581	610	638	667	695	723	752	780	809	—	—
Wind Energy Conversion	305	302	299	297	—	—	—	—	—	—	—
Solar Photovoltaic	689	689	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	770	771	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	979	979	980	980	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	901	901	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	938	939	940	941	942	943	944	—	—	—	—
Solar Thermal, Solar Chimney	790	790	790	790	—	—	—	—	—	—	—
MSW Mass Burn	1917	1878	1840	1801	1762	1723	1684	1646	—	—	—
RDF Stoker-Fired	1891	1980	2069	2157	2246	2335	2423	2512	2601	—	—
Wood Fired Stoker Plant	543	577	612	646	680	715	749	783	817	—	—
Landfill Gas IC Engine	305	380	454	529	603	678	752	827	901	976	—
TDF Multi-Fuel CFB (10% Co-fire)	611	641	672	702	732	763	793	824	854	884	915
Sewage Sludge & Anaerobic Digestion	803	798	793	788	782	777	772	767	761	756	—
Bio Mass (Co-Fire)	463	487	511	535	560	584	607.8713	632	656	680	705
Wood-Fired CFBC	606	633	661	688	716	744	771	799	827	854	882
Co-Fired CFBC	746	795	843	891	939	987	1035	1083	1132	1180	1228
Molten Carbonate Fuel Cell	314	367	419	472	525	578	630	683	736	788	—
Solid Oxide Fuel Cell	198	250	301	353	404	456	507	559	610	662	—
Spark Ignition Engine	440	517	594	670	747	824	901	977	1054	1131	—
Hydroelectric - New - 30 MW	647	642	636	631	625	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	579	574	568	563	558	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	758	753	748	742	737	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	712	707	702	696	691	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	674	669	664	658	653	—	—	—	—	—	—
Minimum Levelized $/kW	110	175	234	293	352	411	470	528	559	587	614

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

Capital Cost- High **2010 ($/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	249	287	324	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	195	240	284	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	183	239	296	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	163	253	344	434	525	615	706	797	887	978	1068
Simple Cycle GE 7EA CT	132	241	350	459	568	677	787	896	1005	1114	1223
Simple Cycle GE 7FA CT	111	196	280	365	450	535	620	705	790	875	959
Combined Cycle GE 7EA CT	237	300	363	426	489	551	614	677	740	803	866
Combined Cycle 1x1 7F-Class	173	225	277	330	382	434	486	538	590	642	694
Combined Cycle 1x1 G-Class CT	148	199	251	302	353	405	456	508	559	610	662
Combined Cycle 2x1 7F-Class CT	126	177	229	280	331	383	434	486	537	588	640
Combined Cycle 3x1 7F-Class CT	117	169	220	271	322	374	425	476	528	579	630
Combined Cycle Siemens 5000F CT	172	226	281	336	391	446	501	556	611	666	721
Humid Air Turbine Cycle CT	156	234	311	389	466	543	621	698	776	853	931
Kalina Cycle CC CT	168	215	262	309	355	402	449	496	542	589	636
Cheng Cycle CT	175	231	287	343	398	454	510	566	622	678	734
Peaking Microturbine	493	632	770	909	1048	1187	1326	1464	1603	1742	1881
Baseload Microturbine	523	632	741	850	958	1067	1176	1285	1394	1502	1611
Subcritical Pulverized Coal - 256 MW	*424*	*448*	*472*	*496*	*519*	*543*	*567*	591	614	638	662
Subcritical Pulverized Coal - 512 MW	379	403	426	450	473	497	520	544	567	591	614
Circulating Fluidized Bed - 2x 250 MW	351	380	410	439	469	498	528	557	587	616	646
Supercritical Pulverized Coal - 565 MW	389	414	439	464	489	514	539	564	589	614	639
Supercritical Pulverized Coal-800 MW	340	364	388	413	437	461	485	509	533	557	582
Pressurized Fluidized Bed Combustion	464	487	510	533	557	580	603	626	649	—	—
1x1 IGCC	445	467	*489*	*511*	*532*	*554*	*576*	*598*	*619*	—	—
2x1 IGCC	489	510	531	552	573	595	616	637	658	—	—
Subcritical Pulverized Coal - 502 MW - CCS	727	761	795	829	864	898	932	966	1001	1035	1069
Circulating Fluidized Bed - CC	638	677	716	755	794	833	872	911	950	989	1027
Supercritical Pulverized Coal - 565 MW - CCS	604	641	678	716	753	791	828	865	903	940	978
Supercritical Pulverized Coal - 800 MW - CCS	530	559	588	617	646	674	703	732	761	789	818
1x1 IGCC - CCS	658	684	711	737	763	789	815	841	867	—	—
2x1 IGCC - CC	581	606	631	655	680	705	729	754	779	—	—
Wind Energy Conversion	305	302	299	297	—	—	—	—	—	—	—
Solar Photovoltaic	689	689	—	—	—	—	—	—	—	—	—
Solar Thermal. Parabolic Trough	770	771	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	979	979	980	980	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	901	901	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	938	939	940	941	942	943	944	—	—	—	—
Solar Thermal, Solar Chimney	790	790	790	790	—	—	—	—	—	—	—
MSW Mass Burn	1917	1889	1861	1832	1804	1776	1748	1720	—	—	—
RDF Stoker-Fired	1891	1969	2046	2124	2201	2279	2356	2434	2511	—	—
Wood Fired Stoker Plant	543	572	602	631	661	690	719	749	778	—	—
Landfill Gas IC Engine	305	328	351	373	396	419	441	464	487	510	—
TDF Multi-Fuel CFB (10% Co-fire)	611	638	664	691	717	744	771	797	824	850	877
Sewage Sludge & Anaerobic Digestion	803	798	793	788	782	777	772	766	761	756	—
Bio Mass (Co-Fire)	463	484	505	526	547	568	589	610	631	652	673
Wood-Fired CFBC	606	629	652	676	699	722	746	769	793	816	839
Co-Fired CFBC	*746*	790	833	876	920	963	1006	1049	1093	1136	1179
Molten Carbonate Fuel Cell	315	361	408	455	501	548	594	641	688	734	—
Solid Oxide Fuel Cell	199	243	288	332	377	421	465	510	554	599	—
Spark Ignition Engine	442	508	574	640	706	772	838	904	970	1037	—
Hydroelectric - New - 30 MW	647	642	636	631	625	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	579	574	568	563	558	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	*758*	*753*	*748*	742	737	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	712	707	702	696	691	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	674	669	664	658	653	—	—	—	—	—	—
Minimum Levelized $/kW	111	169	220	271	322	374	425	464	487	510	582

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

Capital Cost- High **2010 ($/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	249	290	331	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	195	243	291	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	183	245	308	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	163	260	358	456	553	651	749	847	944	1042	1140
Simple Cycle GE 7EA CT	132	250	368	486	605	723	841	959	1078	1196	1314
Simple Cycle GE 7FA CT	111	203	296	388	481	573	666	758	851	943	1036
Combined Cycle GE 7EA CT	237	306	376	445	514	583	652	721	790	859	928
Combined Cycle 1x1 7F-Class	173	231	288	345	403	460	517	575	632	689	747
Combined Cycle 1x1 G-Class CT	148	204	261	318	374	431	487	544	601	657	714
Combined Cycle 2x1 7F-Class CT	126	182	239	296	352	409	466	522	579	636	692
Combined Cycle 3x1 7F-Class CT	117	174	230	287	343	400	456	513	569	626	682
Combined Cycle Siemens 5000F CT	172	232	292	353	413	474	534	594	655	715	776
Humid Air Turbine Cycle CT	156	242	327	413	498	583	669	754	840	925	1011
Kalina Cycle CC CT	168	220	272	323	375	427	478	530	582	633	685
Cheng Cycle CT	175	236	298	359	421	483	544	606	667	729	791
Peaking Microturbine	493	643	793	943	1093	1243	1393	1543	1693	1843	1993
Baseload Microturbine	523	643	763	883	1003	1124	1244	1364	1484	1604	1724
Subcritical Pulverized Coal - 256 MW	424	451	477	503	529	555	581	607	633	659	685
Subcritical Pulverized Coal - 512 MW	379	405	431	457	482	508	534	560	585	611	637
Circulating Fluidized Bed - 2x 250 MW	351	383	415	447	479	511	543	575	607	639	671
Supercritical Pulverized Coal - 565 MW	389	416	443	471	498	525	552	579	607	634	661
Supercritical Pulverized Coal-800 MW	340	367	393	419	446	472	498	525	551	578	604
Pressurized Fluidized Bed Combustion	464	489	515	540	566	591	616	642	667	—	—
1x1 IGCC	445	469	493	517	541	565	588	612	636	—	—
2x1 IGCC	489	512	536	559	582	606	629	652	676	—	—
Subcritical Pulverized Coal - 502 MW - CCS	727	764	801	839	876	914	951	989	1026	1064	1101
Circulating Fluidized Bed - CC	638	680	723	765	808	850	892	935	977	1020	1062
Supercritical Pulverized Coal - 565 MW - CCS	604	644	685	725	766	806	847	888	928	969	1009
Supercritical Pulverized Coal - 800 MW - CCS	530	561	592	623	655	686	717	748	779	810	841
1x1 IGCC - CCS	658	687	716	744	773	801	830	858	887	—	—
2x1 IGCC - CC	581	609	636	663	690	718	745	772	799	—	—
Wind Energy Conversion	305	302	299	297	—	—	—	—	—	—	—
Solar Photovoltaic	689	689	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	770	771	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	979	979	980	980	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	901	901	—	—	—	—	—	—	—	—	—
Solar Thermal. Central Receiver	938	939	940	941	942	943	944	—	—	—	—
Solar Thermal, Solar Chimney	790	790	790	790	—	—	—	—	—	—	—
MSW Mass Burn	1917	1882	1846	1811	1775	1740	1704	1669	—	—	—
RDF Stoker-Fired	1891	1976	2062	2147	2232	2317	2403	2488	2573	—	—
Wood Fired Stoker Plant	543	576	609	641	674	707	740	772	805	—	—
Landfill Gas IC Engine	305	351	397	442	488	534	579	625	670	716	—
TDF Multi-Fuel CFB (10% Co-fire)	611	640	669	699	728	757	786	815	845	874	903
Sewage Sludge & Anaerobic Digestion	803	798	793	788	782	777	772	767	761	756	—
Bio Mass (Co-Fire)	463	486	509	532	556	579	602	625	648	672	695
Wood-Fired CFBC	606	632	658	685	711	737	764	790	816	843	869
Co-Fired CFBC	746	793	840	886	933	980	1026	1073	1119	1166	1213
Molten Carbonate Fuel Cell	315	366	417	467	518	569	620	671	721	772	—
Solid Oxide Fuel Cell	199	248	298	347	396	446	495	544	594	643	—
Spark Ignition Engine	442	515	589	662	736	809	882	956	1029	1103	—
Hydroelectric - New - 30 MW	647	642	636	631	625	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	579	574	568	563	558	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	758	753	748	742	737	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	712	707	702	696	691	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	674	669	664	658	653	—	—	—	—	—	—
Minimum Levelized $/kW	111	174	230	287	343	400	456	513	551	578	604

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

Capital Cost- High **2010 ($/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	249	293	338	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	195	246	297	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	183	251	320	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	163	267	372	477	582	687	792	896	1001	1106	1211
Simple Cycle GE 7EA CT	132	259	386	514	641	768	896	1023	1150	1277	1405
Simple Cycle GE 7FA CT	111	211	311	411	511	611	711	811	912	1012	1112
Combined Cycle GE 7EA CT	237	313	388	463	539	614	689	765	840	915	991
Combined Cycle 1x1 7F-Class	173	236	298	361	424	486	549	611	674	736	799
Combined Cycle 1x1 G-Class CT	148	210	271	333	395	457	519	580	642	704	766
Combined Cycle 2x1 7F-Class CT	126	188	249	311	373	435	497	559	621	683	745
Combined Cycle 3x1 7F-Class CT	117	179	241	303	364	426	488	549	611	673	735
Combined Cycle Siemens 5000F CT	172	237	303	369	435	501	567	633	699	764	830
Humid Air Turbine Cycle CT	156	250	343	437	530	624	717	810	904	997	1091
Kalina Cycle CC CT	168	225	282	338	395	451	508	564	621	677	734
Cheng Cycle CT	175	242	309	376	443	511	578	645	712	780	847
Peaking Microturbine	493	654	815	977	1138	1299	1461	1622	1783	1945	2106
Baseload Microturbine	523	655	786	917	1049	1180	1311	1442	1574	1705	1836
Subcritical Pulverized Coal - 256 MW	424	453	481	510	538	566	595	623	651	680	708
Subcritical Pulverized Coal - 512 MW	379	407	435	463	491	519	548	576	604	632	660
Circulating Fluidized Bed - 2x 250 MW	351	386	420	455	489	524	558	593	627	662	696
Supercritical Pulverized Coal - 565 MW	389	418	448	477	507	536	566	595	625	654	683
Supercritical Pulverized Coal-800 MW	340	369	397	426	455	483	512	540	569	598	626
Pressurized Fluidized Bed Combustion	464	492	519	547	575	602	630	658	685	—	—
1x1 IGCC	445	471	497	523	549	575	601	627	653	—	—
2x1 IGCC	489	514	540	566	591	617	642	668	693	—	—
Subcritical Pulverized Coal - 502 MW - CCS	727	767	808	849	889	930	970	1011	1052	1092	1133
Circulating Fluidized Bed - CC	638	684	730	776	822	867	913	959	1005	1051	1097
Supercritical Pulverized Coal - 565 MW - CCS	604	647	691	735	779	822	866	910	954	997	1041
Supercritical Pulverized Coal - 800 MW - CCS	530	564	597	630	663	697	730	763	796	830	863
1x1 IGCC - CCS	658	689	721	752	783	814	845	876	907	—	—
2x1 IGCC - CC	581	611	641	671	701	731	760	790	820	—	—
Wind Energy Conversion	305	302	299	297	—	—	—	—	—	—	—
Solar Photovoltaic	689	689	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	770	771	—	—	—	—	—	—	—	—	—
Solar Thermal. Power Tower w Storage	979	979	980	980	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	901	901	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	938	939	940	941	942	943	944	—	—	—	—
Solar Thermal, Solar Chimney	790	790	790	790	—	—	—	—	—	—	—
MSW Mass Burn	1917	1874	1832	1789	1746	1703	1660	1618	—	—	—
RDF Stoker-Fired	1891	1984	2077	2170	2263	2356	2449	2542	2635	—	—
Wood Fired Stoker Plant	543	579	615	652	688	724	760	796	832	—	—
Landfill Gas IC Engine	305	383	461	539	616	694	772	850	928	1005	—
TDF Multi-Fuel CFB (10% Co-fire)	611	643	675	706	738	770	802	834	865	897	929
Sewage Sludge & Anaerobic Digestion	803	798	793	788	782	777	772	767	761	756	—
Bio Mass (Co-Fire)	463	488	514	539	564	590	615	640	666	691	717
Wood-Fired CFBC	606	635	664	693	723	752	781	810	840	869	898
Co-Fired CFBC	746	796	846	896	946	996	1046	1096	1146	1196	1246
Molten Carbonate Fuel Cell	315	370	425	480	535	590	645	700	755	810	—
Solid Oxide Fuel Cell	199	253	308	362	416	470	525	579	633	687	—
Spark Ignition Engine	442	523	603	684	765	846	926	1007	1088	1169	—
Hydroelectric - New - 30 MW	647	642	636	631	625	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	579	574	568	563	558	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	758	753	748	742	737	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	712	707	702	696	691	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	674	669	664	658	653	—	—	—	—	—	—
Minimum Levelized $/kW	111	179	241	297	364	426	488	540	569	598	626

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

Capital Cost- High **2010 ($/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	249	287	324	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	195	240	284	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	183	241	299	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	163	257	351	445	538	632	726	820	913	1007	1101
Simple Cycle GE 7EA CT	132	246	359	472	585	699	812	925	1038	1152	1265
Simple Cycle GE 7FA CT	111	200	288	376	465	553	641	729	818	906	994
Combined Cycle GE 7EA CT	238	304	370	435	501	567	632	698	763	829	895
Combined Cycle 1x1 7F-Class	174	228	283	337	392	446	501	555	610	664	719
Combined Cycle 1x1 G-Class CT	149	202	256	310	363	417	471	525	578	632	686
Combined Cycle 2x1 7F-Class CT	126	180	234	288	342	395	449	503	557	610	664
Combined Cycle 3x1 7F-Class CT	118	172	226	279	333	386	440	494	547	601	655
Combined Cycle Siemens 5000F CT	173	230	287	345	402	460	517	574	632	689	747
Humid Air Turbine Cycle CT	158	239	320	401	482	563	644	725	806	887	968
Kalina Cycle CC CT	170	218	267	316	365	414	463	512	561	610	659
Cheng Cycle CT	176	234	293	351	410	468	527	585	644	702	761
Peaking Microturbine	494	638	782	925	1069	1213	1357	1501	1645	1788	1932
Baseload Microturbine	526	640	753	867	981	1095	1209	1323	1437	1550	1664
Subcritical Pulverized Coal - 256 MW	424	449	474	499	524	548	573	598	623	647	672
Subcritical Pulverized Coal - 512 MW	379	404	428	453	477	502	526	551	575	600	624
Circulating Fluidized Bed - 2x 250 MW	351	382	412	443	473	504	535	565	596	626	657
Supercritical Pulverized Coal - 565 MW	389	415	441	467	493	519	545	571	597	623	649
Supercritical Pulverized Coal-800 MW	340	365	390	416	441	466	491	516	541	566	592
Pressurized Fluidized Bed Combustion	464	488	512	537	561	585	609	633	657	—	—
1x1 IGCC	445	468	491	513	536	559	582	604	627	—	—
2x1 IGCC	489	511	533	555	577	600	622	644	666	—	—
Subcritical Pulverized Coal - 502 MW - CCS	727	762	798	834	869	905	941	976	1012	1048	1083
Circulating Fluidized Bed - CC	638	678	719	760	800	841	881	922	962	1003	1043
Supercritical Pulverized Coal - 565 MW - CCS	604	642	681	720	759	798	837	875	914	953	992
Supercritical Pulverized Coal - 800 MW - CCS	530	560	590	620	650	679	709	739	769	799	828
1x1 IGCC - CCS	658	686	713	740	767	794	822	849	876	—	—
2x1 IGCC - CC	581	607	633	659	685	710	736	762	788	—	—
Wind Energy Conversion	305	302	299	297	—	—	—	—	—	—	—
Solar Photovoltaic	689	689	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	770	771	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	979	979	980	980	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	901	901	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	938	939	940	941	942	943	944	—	—	—	—
Solar Thermal, Solar Chimney	790	790	790	790	—	—	—	—	—	—	—
MSW Mass Burn	1917	1886	1854	1823	1791	1760	1728	1697	—	—	—
RDF Stoker-Fired	1891	1972	2053	2134	2215	2296	2377	2458	2539	—	—
Wood Fired Stoker Plant	543	574	605	636	667	698	728	759	790	—	—
Landfill Gas IC Engine	305	329	352	375	398	421	445	468	491	514	—
TDF Multi-Fuel CFB (10% Co-fire)	611	639	667	694	722	750	778	805	833	861	889
Sewage Sludge & Anaerobic Digestion	803	798	793	788	782	777	772	766	761	756	—
Bio Mass (Co-Fire)	463	485	507	529	551	573	595	617	639	661	683
Wood-Fired CFBC	606	630	655	680	704	729	754	779	803	828	853
Co-Fired CFBC	746	791	836	881	926	970	1015	1060	1105	1150	1194
Molten Carbonate Fuel Cell	316	364	413	461	510	558	607	655	704	752	—
Solid Oxide Fuel Cell	200	247	293	340	387	433	480	526	573	620	—
Spark Ignition Engine	444	513	582	652	721	790	860	929	998	1068	—
Hydroelectric - New - 30 MW	647	642	636	631	625	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	579	574	568	563	558	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	758	753	748	742	737	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	712	707	702	696	691	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	674	669	664	658	653	—	—	—	—	—	—
Minimum Levelized $/kW	111	172	226	279	333	386	440	468	491	514	592

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

Capital Cost- High — **2010 ($/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	249	290	331	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	195	243	291	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	183	247	311	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	163	264	366	467	568	670	771	872	973	1075	1176
Simple Cycle GE 7EA CT	132	255	378	501	623	746	869	992	1115	1237	1360
Simple Cycle GE 7FA CT	111	208	304	400	497	593	689	785	882	978	1074
Combined Cycle GE 7EA CT	238	311	383	455	527	599	672	744	816	888	960
Combined Cycle 1x1 7F-Class	174	234	294	354	414	474	534	594	654	714	774
Combined Cycle 1x1 G-Class CT	149	208	267	326	385	444	504	563	622	681	740
Combined Cycle 2x1 7F-Class CT	126	186	245	304	364	423	482	541	601	660	719
Combined Cycle 3x1 7F-Class CT	118	177	236	296	355	414	473	532	591	650	709
Combined Cycle Siemens 5000F CT	173	236	299	362	425	488	552	615	678	741	804
Humid Air Turbine Cycle CT	158	248	337	426	516	605	695	784	874	963	1052
Kalina Cycle CC CT	170	224	278	332	386	440	494	548	602	656	710
Cheng Cycle CT	176	240	305	369	433	498	562	627	691	755	820
Peaking Microturbine	494	650	805	961	1117	1272	1428	1584	1739	1895	2051
Baseload Microturbine	526	651	777	903	1028	1154	1280	1405	1531	1657	1782
Subcritical Pulverized Coal - 256 MW	424	452	479	506	533	560	588	615	642	669	696
Subcritical Pulverized Coal - 512 MW	379	406	433	460	487	514	541	568	594	621	648
Circulating Fluidized Bed - 2x 250 MW	351	384	418	451	484	517	551	584	617	650	683
Supercritical Pulverized Coal - 565 MW	389	417	446	474	502	531	559	587	616	644	672
Supercritical Pulverized Coal-800 MW	340	368	395	423	450	478	505	533	560	588	615
Pressurized Fluidized Bed Combustion	464	490	517	544	570	597	623	650	676	—	—
1x1 IGCC	445	470	495	520	545	570	595	620	644	—	—
2x1 IGCC	489	513	538	562	587	611	636	660	684	—	—
Subcritical Pulverized Coal - 502 MW - CCS	727	766	805	844	883	922	961	1000	1039	1078	1117
Circulating Fluidized Bed - CC	638	682	726	770	815	859	903	947	991	1035	1080
Supercritical Pulverized Coal - 565 MW - CCS	604	646	688	730	772	814	857	899	941	983	1025
Supercritical Pulverized Coal - 800 MW - CCS	530	563	595	627	659	691	723	755	788	820	852
1x1 IGCC - CCS	658	688	718	748	778	807	837	867	897	—	—
2x1 IGCC - CC	581	610	638	667	696	724	753	781	810	—	—
Wind Energy Conversion	305	302	299	297	—	—	—	—	—	—	—
Solar Photovoltaic	689	689	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	770	771	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	979	979	980	980	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	901	901	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	938	939	940	941	942	943	944	—	—	—	—
Solar Thermal, Solar Chimney	790	790	790	790	—	—	—	—	—	—	—
MSW Mass Burn	1917	1878	1839	1800	1761	1721	1682	1643	—	—	—
RDF Stoker-Fired	1891	1980	2069	2158	2248	2337	2426	2515	2604	—	—
Wood Fired Stoker Plant	543	578	612	646	681	715	750	784	819	—	—
Landfill Gas IC Engine	305	353	400	447	495	542	589	637	684	731	—
TDF Multi-Fuel CFB (10% Co-fire)	611	641	672	702	733	763	794	824	855	886	916
Sewage Sludge & Anaerobic Digestion	803	798	793	788	782	777	772	767	761	756	—
Bio Mass (Co-Fire)	463	487	511	536	560	584	609	633	657	681	706
Wood-Fired CFBC	606	633	661	689	717	745	772	800	828	856	884
Co-Fired CFBC	746	795	843	891	940	988	1036	1085	1133	1181	1229
Molten Carbonate Fuel Cell	316	369	422	475	527	580	633	686	739	792	—
Solid Oxide Fuel Cell	200	252	304	355	407	459	511	563	614	666	—
Spark Ignition Engine	444	521	598	675	752	829	906	983	1060	1137	—
Hydroelectric - New - 30 MW	647	642	636	631	625	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	579	574	568	563	558	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	758	753	748	742	737	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	712	707	702	696	691	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	674	669	664	658	653	—	—	—	—	—	—
Minimum Levelized $/kW	111	177	236	296	355	414	473	532	560	588	615

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

Capital Cost- High **2010 ($/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	249	293	338	—	—	—	—	—	—	—	—
Advanced Battery Energy Storage	195	246	297	—	—	—	—	—	—	—	—
Compressed Air Energy Storage	183	253	324	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT	163	272	381	489	598	707	816	924	1033	1142	1251
Simple Cycle GE 7EA CT	132	265	397	529	662	794	926	1059	1191	1323	1455
Simple Cycle GE 7FA CT	111	216	320	424	529	633	737	841	946	1050	1154
Combined Cycle GE 7EA CT	238	317	396	475	554	632	711	790	869	947	1026
Combined Cycle 1x1 7F-Class	174	239	305	370	436	501	567	632	698	763	829
Combined Cycle 1x1 G-Class CT	149	213	278	343	407	472	536	601	666	730	795
Combined Cycle 2x1 7F-Class CT	126	191	256	321	386	450	515	580	645	709	774
Combined Cycle 3x1 7F-Class CT	118	183	247	312	377	441	506	570	635	700	764
Combined Cycle Siemens 5000F CT	173	242	310	379	448	517	586	655	724	793	862
Humid Air Turbine Cycle CT	158	256	354	452	549	647	745	843	941	1039	1136
Kalina Cycle CC CT	170	229	288	347	407	466	525	584	644	703	762
Cheng Cycle CT	176	246	316	387	457	527	598	668	738	809	879
Peaking Microturbine	494	661	829	996	1164	1331	1499	1666	1834	2001	2169
Baseload Microturbine	526	663	801	938	1076	1213	1351	1488	1626	1763	1901
Subcritical Pulverized Coal - 256 MW	424	454	484	513	543	573	602	632	661	691	721
Subcritical Pulverized Coal - 512 MW	379	409	438	467	496	526	555	584	614	643	672
Circulating Fluidized Bed - 2x 250 MW	351	387	423	459	495	530	566	602	638	674	710
Supercritical Pulverized Coal - 565 MW	389	420	450	481	512	542	573	604	634	665	696
Supercritical Pulverized Coal-800 MW	340	370	400	430	460	489	519	549	579	609	639
Pressurized Fluidized Bed Combustion	464	493	522	551	580	608	637	666	695	—	—
1x1 IGCC	445	473	500	527	554	581	608	635	662	—	—
2x1 IGCC	489	516	542	569	596	623	649	676	703	—	—
Subcritical Pulverized Coal - 502 MW - CCS	727	769	811	854	896	939	981	1023	1066	1108	1151
Circulating Fluidized Bed - CC	638	686	734	781	829	877	925	973	1020	1068	1116
Supercritical Pulverized Coal - 565 MW - CCS	604	649	695	740	786	831	877	922	967	1013	1058
Supercritical Pulverized Coal - 800 MW - CCS	530	565	599	634	668	703	737	772	806	841	875
1x1 IGCC - CCS	658	691	723	756	788	821	853	885	918	—	—
2x1 IGCC - CC	581	613	644	675	706	738	769	800	831	—	—
Wind Energy Conversion	305	302	299	297	—	—	—	—	—	—	—
Solar Photovoltaic	689	689	—	—	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough	770	771	—	—	—	—	—	—	—	—	—
Solar Thermal, Power Tower w Storage	979	979	980	980	—	—	—	—	—	—	—
Solar Thermal, Parabolic Dish	901	901	—	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver	938	939	940	941	942	943	944	—	—	—	—
Solar Thermal, Solar Chimney	790	790	790	790	—	—	—	—	—	—	—
MSW Mass Burn	1917	1870	1824	1777	1730	1683	1636	1590	—	—	—
RDF Stoker-Fired	1891	1988	2086	2183	2280	2377	2474	2572	2669	—	—
Wood Fired Stoker Plant	543	581	619	657	695	733	771	809	847	—	—
Landfill Gas IC Engine	305	386	467	549	630	711	792	873	954	1035	—
TDF Multi-Fuel CFB (10% Co-fire)	611	644	677	711	744	777	810	844	877	910	943
Sewage Sludge & Anaerobic Digestion	803	798	793	788	782	777	772	767	761	756	—
Bio Mass (Co-Fire)	463	489	516	543	569	596	622	649	676	702	729
Wood-Fired CFBC	606	636	667	698	729	760	791	822	853	884	914
Co-Fired CFBC	746	798	850	902	954	1006	1057	1109	1161	1213	1265
Molten Carbonate Fuel Cell	316	373	431	488	545	603	660	717	775	832	—
Solid Oxide Fuel Cell	200	257	314	371	428	485	542	599	656	713	—
Spark Ignition Engine	444	528	613	698	783	867	952	1037	1122	1207	—
Hydroelectric - New - 30 MW	647	642	636	631	625	—	—	—	—	—	—
Hydroelectric - 50 MW Bulb Unit	579	574	568	563	558	—	—	—	—	—	—
Hydroelectric - 25 MW Bulb Units	758	753	748	742	737	—	—	—	—	—	—
Hydroelectric - 50 MW Kaplan Unit	712	707	702	696	691	—	—	—	—	—	—
Hydroelectric - 50 MW Propeller Unit	674	669	664	658	653	—	—	—	—	—	—
Minimum Levelized $/kW	111	183	247	297	377	441	506	549	579	609	639

Exhibit 7

Graph - Least Costly Technologies in All Cases

Least Costly Technologies In All Cases

Base Capital, Base Heatrate, Base Fuel

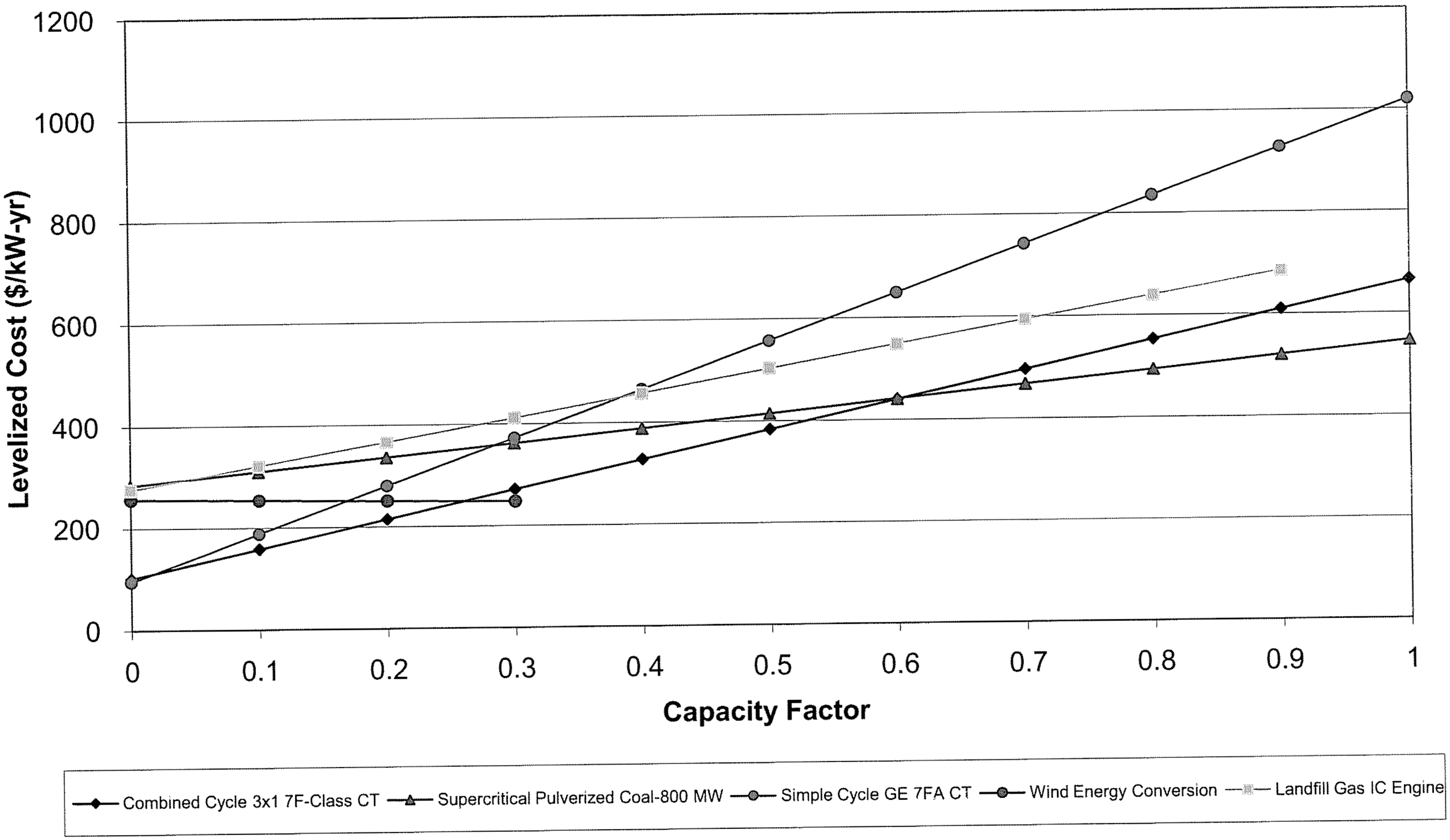
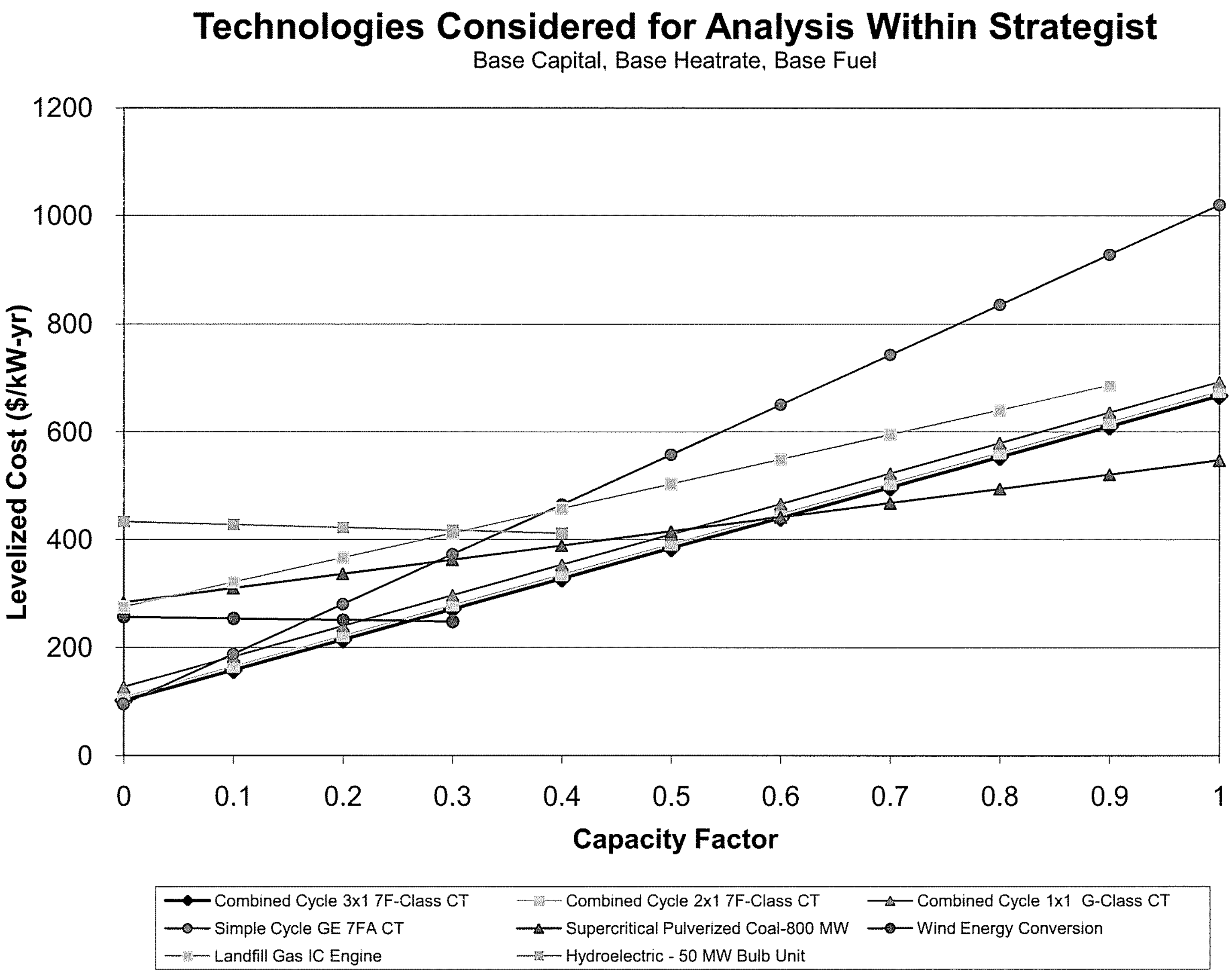


Exhibit 8

Graph - Technologies for Analysis within Strategist


Technologies Considered for Analysis Within Strategist
Base Capital, Base Heatrate, Base Fuel
Levelized Cost ($/kW-yr)
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
Combined Cycle 3x1 7F-Class CT
Combined Cycle 2x1 7F-Class CT
Combined Cycle 1x1 G-Class CT
Simple Cycle GE 7FA CT
Supercritical Pulverized Coal-800 MW
Wind Energy Conversion
Landfill Gas IC Engine
Hydroelectric - 50 MW Bulb Unit

2011

LG&E and KU 2011 Reserve Margin Study

Astrape Consulting
4/8/2011

Contents

Executive Summary

The purpose of this study is to determine the optimum planning reserve margin for the Louisville Gas & Electric Company and Kentucky Utilities (the "Companies") based on estimated total costs and risks to customers. Customers generally expect power to be available 24 hours a day, 365 days a year, but due to excessive costs it is imprudent for a load serving entity to hold enough reserves to always meet this expectation. Therefore, it is necessary for utilities to understand their risks relative to resource adequacy by determining the expected frequency and cost of reliability events. As a load serving entity increases its planning reserve margin, the total cost of carrying reserves rises while the costs related directly to reliability events decrease. The optimal planning reserve margin is the reserve margin where the cost of carrying reserves plus the cost of reliability events (or reliability energy) is minimized.

In determining the optimum reserve margin, SERVM[1] (Strategic Energy and Risk Valuation Model) was used to model the uncertainty in weather, unit performance, load growth, and import capability from interconnected regions. Other key inputs include the value of unserved energy, the cost of expensive market purchases, and the cost of new peaking capacity[2]. As additional peaking capacity is installed, the Companies can expect to reduce the following:

- Cost of Unserved Energy Events
- Cost of Expensive Purchased Power
- Cost of Dispatching Expensive Peaking Resources

[1] SERVM has been used extensively by large utilities in the south-eastern U.S. for economic reserve margin studies, demand side resource evaluation, cost of intermittent or energy limited resources, and the economic and reliability value of tie line capacity to neighboring power systems.

[2] In this study, the cost of new peaking capacity is the cost of a new combustion turbine.

In this analysis, these costs are collectively referred to as "reliability energy costs". When using SERVM, reliability energy costs were computed over thousands of scenarios and various reserve margin levels (from 10 to 24 percent) to determine how these costs decrease as reserves increase. The reliability energy costs are then added to the cost of carrying reserves and the point at which these total reliability costs are minimized is the optimal reserve margin.

The resulting distributions of reliability energy costs and cost of carrying reserves were utilized to determine the optimal reserve margin level. Figure ES1 plots the distributions of reliability energy costs while Figure ES2 plots the cost for carrying reserves. Both are plotted at varying reserve margin levels. It is seen that reliability energy costs are extremely volatile across scenarios while the cost of carrying reserves is fixed. Reliability energy costs are relatively small in 50% of all scenarios. However, when combinations of extreme events such as generation outages, severe weather, load forecast error, and low import capability occur, these costs can be substantial. For a 12% reserve margin level, reliability energy costs can range from 200 thousand dollars to 900 million dollars for a single year. As illustrated in Figure ES2, the cost of carrying reserves increase as reserve margin increases. These costs are fixed across all scenarios because additional capacity can be constructed or purchased through a bilateral contract effectively locking in that cost for many years.

Figure ES1. Distribution of Reliability Energy Costs

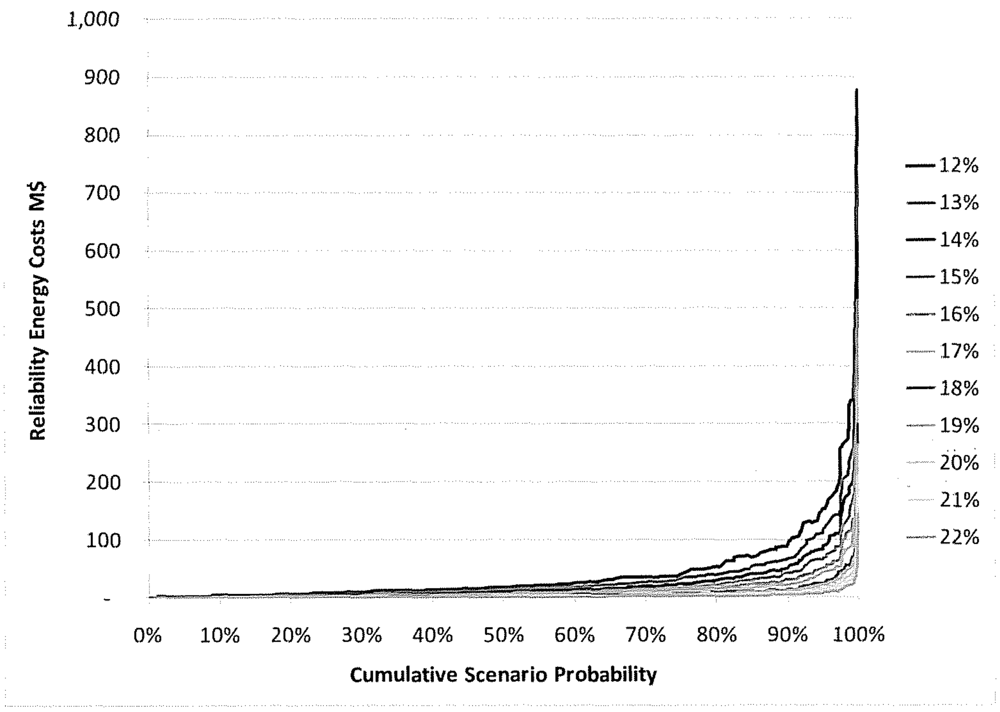
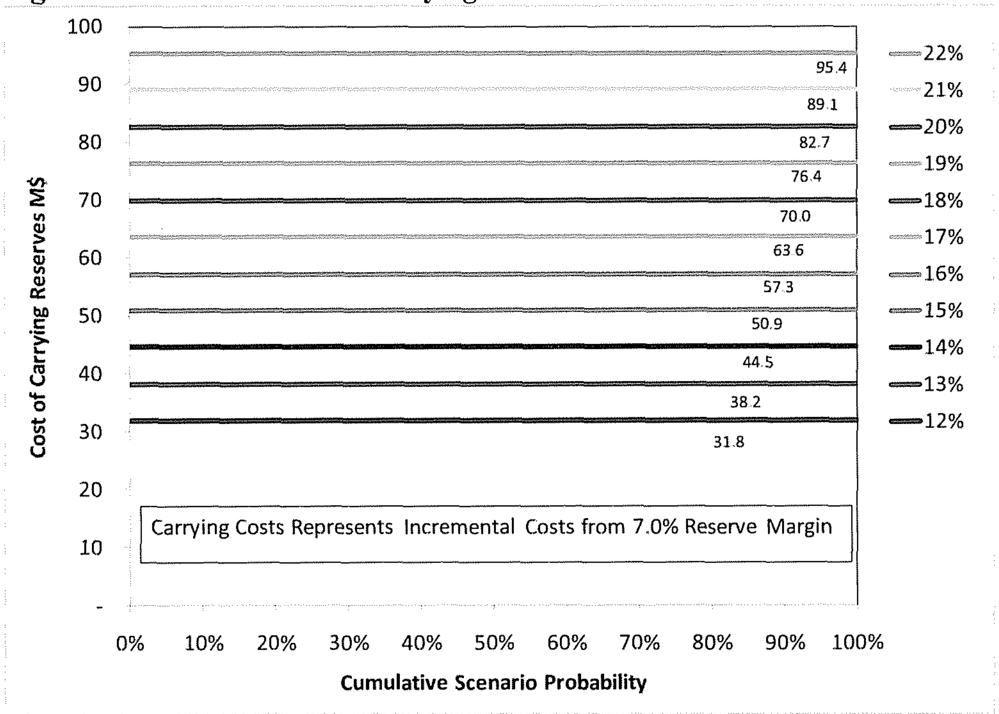
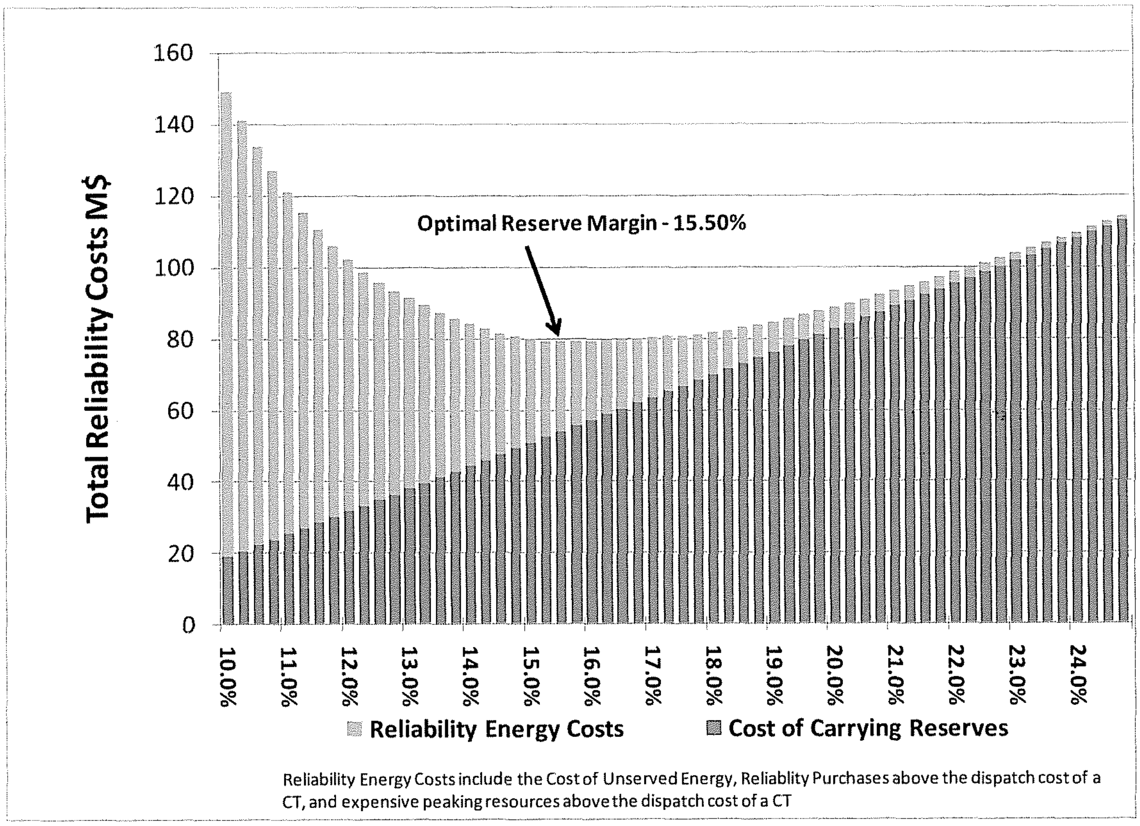


Figure ES2. Fixed Cost of Carrying Reserves



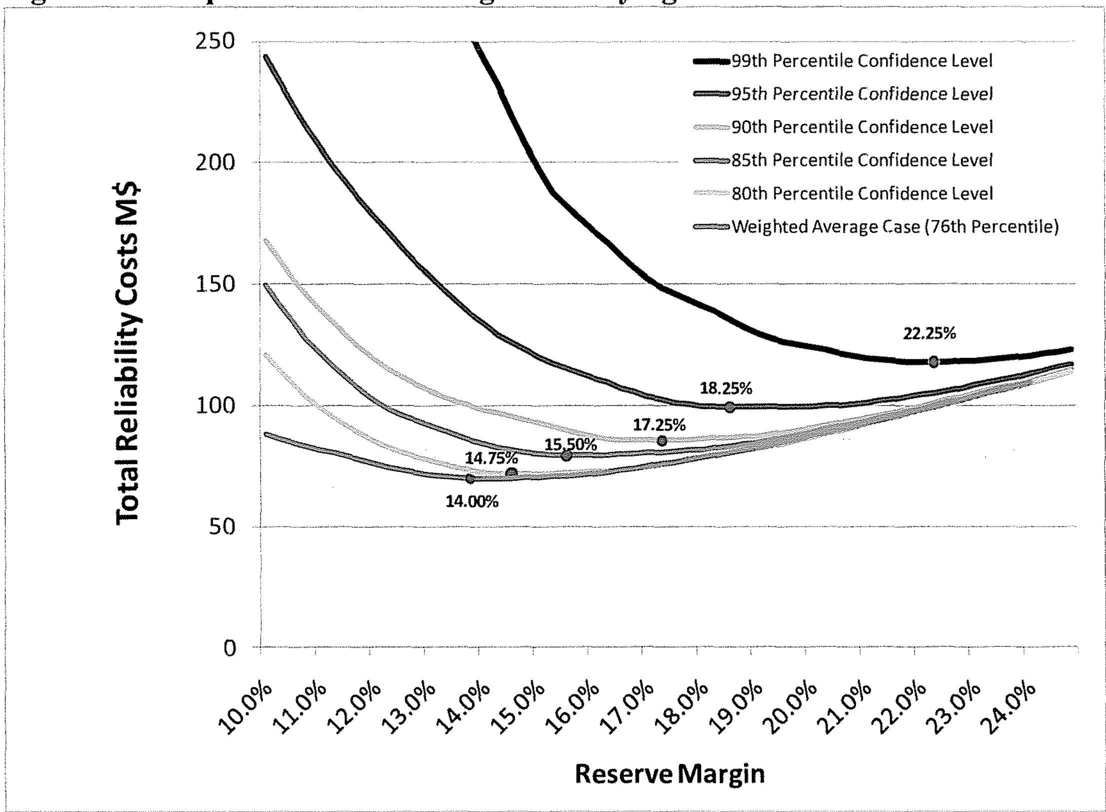
The optimal reserve margin is where the sum of the cost of reliability energy costs (Distributions from ES1) and the cost of carrying reserves (Distributions from ES2) is minimized. However, since reliability costs are extraordinarily volatile but capacity costs are fixed, a conversion is necessary to put the two on the same basis. The casualty insurance industry faces a similar issue in computing a fixed premium for which it can viably accept the risk associated with potentially volatile casualty payouts. In this industry, the premium that best mitigates the company's exposure to the distribution of casualty payouts is typically computed as a value between the 85th and 95th percent confidence levels on this distribution. Therefore, in this example, if an insurance company were assuming the risks shown in Figure ES1, then an approximate premium would equal the 85th - 95th confidence level of the distribution. Astrape Consulting recommends a similar risk adjustment using reliability energy costs at the 85th to 90th confidence level range based on its experience in performing reserve margin studies for other jurisdictions within the southeast because these levels have resulted in the lowest cost resource plans that also avoid unreasonable risk for utilities, regulators, and customers. Figure ES3 summarizes total reliability costs assuming reliability energy costs at the 85th percentile. As reserve margin increases, reliability energy costs decrease and the cost of carrying reserves increase. With this assumption, total reliability costs are minimized at a reserve margin of 15.50%.

Figure ES3. Optimal Reserve Margin with Reliability Energy Costs at 85th Percentile Confidence Level



Next, total reliability costs were calculated assuming reliability energy costs at various confidence levels to understand how the least cost reserve margin is impacted by this assumption. Figure ES4 displays these results without the individual components being shown.

Figure ES4. Optimal Reserve Margin at Varying Confidence Intervals



	Weighted Average (76th Percentile)	85% Confidence Level	90% Confidence Level	95% Confidence Level	99% Confidence Level
Optimal Reserve Margin	14.00%	15.50%	17.25%	18.25%	22.25%

The recommended range of reserve margin assuming the 85th and 90th confidence levels of reliability energy costs is between 15.50% and 17.25%. The weighted average case assumes the reliability energy costs are weighted based on the probability of each scenario which happens to fall out at the 76th percentile point on the distribution. However, it is Astrape Consulting's experience that assuming this as a long term planning reserve margin provides more risk than utilities and regulators are willing to take in a given year even though it may minimize average costs in the long run. Based on Figure ES1, a 14.00% reserve margin results in a risk that in 5% of all scenarios reliability energy costs would exceed 90 million dollars and 1% of the time they would exceed $200 million dollars. A 15.50% reserve margin lowers this exposure to 60 million dollars and 140 million dollars respectively. In contrast, the 99 percentile confidence level reserve margin of 22.25% eliminates almost all risk but puts an unreasonable amount of cost on customers as shown in Figure ES4.

It is recognized that many inputs used to set the target reserve margin could vary more than expected introducing more reliability events. Several sensitivities were performed to understand how major assumptions impact the results. These sensitivities included varying the cost of carrying reserves, varying the cost of expected unserved energy, removing all tie assistance, increasing unit forced outage rates, decreasing neighbor reserve capacity, decreasing transmission limits, and increasing market prices during scarce conditions. Table ES5 shows the sensitivity of the minimum cost reserve margin to various input assumptions at several confidence levels of reliability energy costs. It is seen that the cost of EUE has little impact on the overall results. This is due to the fact that unserved energy events are short and infrequent events. The remaining sensitivities are discussed in greater detail in the full report.

Table ES5. Sensitivity Analysis

	Weighted Average	85% Confidence Level	90% Confidence Level	95% Confidence Level
EUE = $5,000/MWh	13.75%	15.50%	17.00%	18.00%
Base Case Optimal Reserve Margin (EUE = $16,600/MWh)	**14.00%**	**15.50%**	**17.25%**	**18.25%**
EUE = $30,000/MWh	14.25%	16.00%	17.75%	18.75%
Cost of Capacity - $110/kW-yr	13.25%	15.25%	16.50%	18.00%
Base Case Optimal Reserve Margin (Cost of Capacity = $88.42/kW-yr)	**14.00%**	**15.50%**	**17.25%**	**18.25%**
Cost of Capacity - $70/kW-yr	14.75%	17.25%	18.50%	20.75%

	Weighted Average (76th Percentile)	85% Confidence Level	90% Confidence Level	95% Confidence Level
Optimal Reserve Margin	14.00%	15.50%	17.25%	18.25%
Scarcity Pricing Sensitivity - Increase by 50%	15.25%	17.50%	19.00%	20.25%
EFOR Sensitivity - Increase by 50%	17.00%	19.00%	21.25%	22.75%
Neighbor Reserve Margin Sensitivity - 15% RM to 12% RM	16.00%	18.00%	20.25%	22.00%
Transmission Sensitivity - Decrease by 50%	15.00%	16.75%	18.25%	19.50%
Island Sensitivity - No Interconnection Ties	21.75%	23.75%	24.75%	26.00%

In conclusion, the simulation results demonstrate the Companies' potential risk due to lower planning reserve margins and show that low probability, high impact cost exposures exist at all reserve margin levels. No system is 100% reliable and this reliability assessment has quantified the frequency and duration of major events and their economic impact on customers under a full distribution of weather years, unit performance, and load forecast uncertainty. The study also demonstrates the value of capacity reserve margins to the extent they protect customers from extreme, high cost outcomes. Based on the simulations and sensitivities, the precedent set by other industries, and experience in other jurisdictions, Astrape Consulting recommends that the Companies set a long-term target reserve margin using the 85^{th} to 90^{th} percentile of reliability energy costs which results in reserve margins between 15% and 17%.

I. List of figures

II. List of tables

III. Input Assumptions

A. Study Year

The selected study year is 2016. The year was chosen because it typically takes a utility 4 to 5 years to develop and install capacity once a decision to build new generation is confirmed. This process includes necessary regulatory approvals, air permits, engineering and design, construction, and startup and testing. Due to changing load forecasts, load shapes, outage data, resource mix, and other factors, the study results should be updated periodically.

B. Load Modeling

Table 1. 2016 Load Forecast

Month	Energy (MWh)	Peak Demand (MW)	Peak Demand (MW)*
1	3,692,991	7269	7144
2	3,332,365	6962	6726
3	3,217,290	6205	6205
4	2,913,918	5297	5297
5	2,785,636	5611	5611
6	3,231,899	6592	6528
7	3,539,916	7011	6886
8	3,627,576	7196	7070
9	2,947,541	6536	6471
10	2,766,808	5103	5103
11	2,736,902	5186	5186
12	3,191,820	6061	6061

*Assumes Reduction For Interruptible Loads

Table 1 displays the monthly peak and energy forecast for 2016 under normal weather conditions. To model the effects of weather uncertainty, 35 synthetic load shapes based on 35 years of historical weather were created to reflect the impact of weather on load. The frequency and duration of severe weather has a significant impact on load shape and therefore reliability simulations. Based on the last seven years of historical weather and load, a neural network program was used to develop relationships between weather observations, such as temperature, and load. This relationship was then used to develop 35 unique load shapes based on the last 35 years of weather. The synthetic load shapes were then scaled so that the average summer and winter peaks are equivalent to the 2016 forecasted summer and winter peaks. Equal probabilities were given to each of the 35 load shapes in the simulation. Table 2 summarizes the 35 synthetic weather year peaks (not reduced by interruptible load). It is seen that in the most severe weather conditions, the summer peak can be 7% higher than normal weather conditions whereas the most extreme winter peak is only 5% higher than normal weather conditions. The last section of the table represents the distribution of annual energy values seen over the last 35 years.

Table 2. 2016 Peak Load Rankings for All Weather Years

Summer Peaks (MW)

Max	7,729	107%
Average	7,196	
Min	6,699	93%

Rank	Year	Peak (MW)
1	1983	7,729
2	1999	7,727
3	2007	7,648
4	1995	7,555
5	2005	7,503
6	1980	7,480
7	1990	7,474
8	1988	7,473
9	1978	7,401
10	1991	7,376
11	2002	7,374
12	2006	7,373
13	1993	7,323
14	1977	7,270
15	1987	7,232
16	1994	7,223
17	1979	7,154
18	1998	7,150
19	1997	7,134
20	2000	7,132
21	1981	7,109
22	1996	7,080
23	1986	7,061
24	2001	7,049
25	1989	7,044
26	2008	7,024
27	1976	7,004
28	1975	6,979
29	2003	6,934
30	2009	6,877
31	1992	6,849
32	1985	6,839
33	1984	6,806
34	2004	6,763
35	1982	6,699

Winter Peaks (MW)

Max	7,621	105%
Average	7,269	
Min	6,714	92%

Rank	Year	Peak (MW)
1	1977	7,621
2	2003	7,557
3	2009	7,556
4	1982	7,514
5	1978	7,489
6	1981	7,484
7	1992	7,469
8	2000	7,463
9	1984	7,460
10	2004	7,440
11	1994	7,436
12	1995	7,429
13	1979	7,416
14	1997	7,399
15	1987	7,393
16	1999	7,335
17	1976	7,323
18	2001	7,319
19	2005	7,299
20	2008	7,254
21	2007	7,220
22	1989	7,199
23	1983	7,190
24	1998	7,169
25	1991	7,144
26	1980	7,102
27	2006	7,098
28	1986	7,090
29	1985	7,081
30	1988	7,040
31	1993	6,980
32	2002	6,941
33	1996	6,911
34	1975	6,884
35	1990	6,714

Annual Energy (GWh)

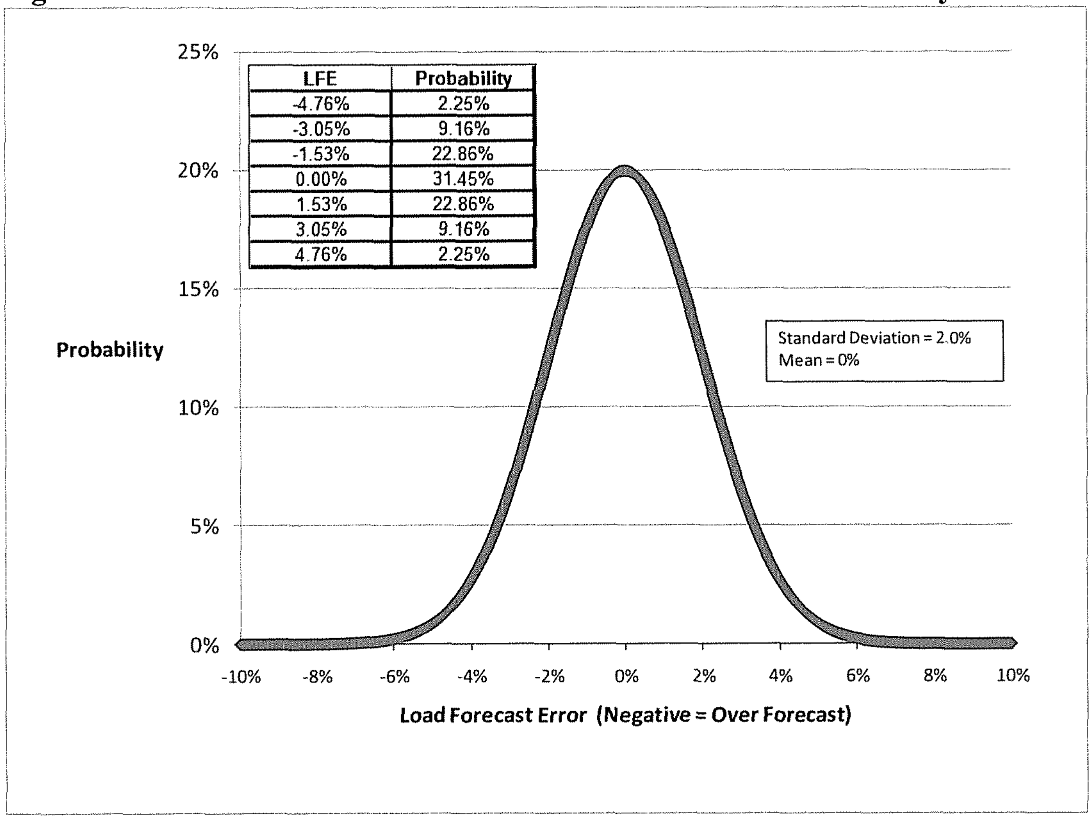
Max	39,102	103%
Average	37,925	
Min	36,822	97%

Rank	Year	Energy (GWh)
1	1977	39,102
2	1978	38,814
3	1980	38,757
4	2007	38,693
5	2002	38,670
6	1983	38,597
7	1988	38,542
8	2008	38,457
9	1995	38,356
10	2005	38,205
11	1991	38,140
12	1993	38,041
13	1989	38,018
14	1987	38,004
15	1981	37,994
16	1986	37,994
17	1979	37,974
18	1999	37,963
19	1985	37,896
20	1996	37,844
21	2000	37,801
22	1975	37,753
23	1994	37,675
24	2003	37,663
25	1984	37,624
26	1982	37,615
27	2001	37,539
28	1998	37,496
29	1997	37,404
30	2009	37,305
31	2004	37,296
32	2006	37,276
33	1976	37,163
34	1990	36,868
35	1992	36,822

C. Load Forecast Error due to Economic Growth Uncertainty

Based on the observed load forecast error using 4 and 5 year load forecasts compared to normalized peak loads for the same periods, the following distribution was created to represent load forecast error relative to economic growth uncertainty. The continuous normal distribution was converted into a discrete distribution with the 7 points shown in the table below for use in determining discrete scenarios to be modeled. In the most extreme cases modeled, load can be as much at 4.76% higher than the 5 year forecast due to economic growth assumptions. This scenario has a 2.25% probability of occurring.

Figure 1. Load Forecast Error Due to Economic Growth Uncertainty



LFE	Probability
-4.76%	2.25%
-3.05%	9.16%
-1.53%	22.86%
0.00%	31.45%
1.53%	22.86%
3.05%	9.16%
4.76%	2.25%

SERVM utilized each of the 35 weather years and applied each of these 7 load forecast error points to create 245 different load scenarios. Given that SERVM matches load and generation perfectly, every MW of load above the available capacity is calculated as EUE, but no adjustment is made for shedding more load than is required. In actual practice, load would be curtailed in large blocks and would be off longer than necessary. This limitation was offset by adding 50 MW of load to each hour in the study above the load forecast error assumption.

D. Resources

The resources and assumed monthly capacities for the 2016 study are shown in the following tables. For the simulation, the amounts of peaking units were varied to achieve different reserve margin levels. Once all existing peaking resources were utilized, a generic combustion turbine was used which is documented in Part J of the input section.

Table 3. Summary of Resources

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Base Load and Intermediate Capacity	5,688	5,688	5,658	5,599	5,599	5,568	5,568	5,568	5,599	5,658	5,656	5,686
Peaking Capacity	2,341	2,341	2,166	2,238	2,238	2,115	2,115	2,115	2,238	2,166	2,166	2,341
Hydro Capacity	130	130	130	130	130	130	130	130	130	130	130	130
Total	8,159	8,159	7,954	7,967	7,967	7,813	7,813	7,813	7,967	7,954	7,952	8,157

Table 4. Base load and Intermediate Capacity

Base Load and IntermediateCapacity	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Brown.1	107	107	107	105	105	105	105	105	105	107	107	107
Brown.2	167	167	167	165	165	165	165	165	165	167	167	167
Brown.3	407	407	407	403	403	403	403	403	403	407	407	407
Ghent.1	481	481	481	488	488	488	488	488	488	481	481	481
Ghent.2	476	476	476	486	486	486	486	486	486	476	476	476
Ghent.3	480	480	465	465	465	449	449	449	465	465	465	480
Ghent.4	491	491	487	487	487	483	483	483	487	487	487	491
Mill.Creek.1	300	300	300	300	300	300	300	300	300	300	298	298
Mill.Creek.2	296	296	296	298	298	298	298	298	298	296	296	296
Mill.Creek.3	393	393	393	387	387	387	387	387	387	393	393	393
Mill.Creek.4	487	487	487	472	472	472	472	472	472	487	487	487
Trimble.County.1	381	381	381	378	378	378	378	378	378	381	381	381
Trimble.County.2	571	571	560	560	560	549	549	549	560	560	560	571
Tyrone.3	0	0	0	0	0	0	0	0	0	0	0	0
Combined.Cycle.2016 (2x1)	651	651	651	605	605	605	605	605	605	651	651	651
Total	5,688	5,688	5,658	5,599	5,599	5,568	5,568	5,568	5,599	5,658	5,656	5,686

Table 5. Peaking Capacity

Peaking Capacity	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Brown.10	129	129	116	116	116	102	102	102	116	116	116	129
Brown.11	129	129	116	116	116	102	102	102	116	116	116	129
Brown.5	131	131	122	122	122	112	112	112	122	122	122	131
Brown.6	163	163	155	155	155	146	146	146	155	155	155	163
Brown.7	163	163	155	155	155	146	146	146	155	155	155	163
Brown.8	129	129	116	116	116	102	102	102	116	116	116	129
Brown.9	129	129	116	116	116	102	102	102	116	116	116	129
Cane.Run.11	14	14	14	14	14	14	14	14	14	14	14	14
Haefling	42	42	42	36	36	36	36	36	36	42	42	42
Paddys.Run.11T	13	13	13	12	12	12	12	12	12	13	13	13
Paddys.Run.12T	28	28	28	23	23	23	23	23	23	28	28	28
Paddys.Run.13T	175	175	167	167	167	158	158	158	167	167	167	175
Trimble.Co.05T	180	180	165	165	165	160	160	160	165	165	165	180
Trimble.Co.06T	180	180	165	165	165	160	160	160	165	165	165	180
Trimble.Co.07T	180	180	165	165	165	160	160	160	165	165	165	180
Trimble.Co.08T	180	180	165	165	165	160	160	160	165	165	165	180
Trimble.Co.09T	180	180	165	165	165	160	160	160	165	165	165	180
Trimble.Co.10T	180	180	165	165	165	160	160	160	165	165	165	180
Zorn.1	16	16	16	14	14	14	14	14	14	16	16	16
Brown.ICE.Units	0	0	0	86	86	86	86	86	86	0	0	0
Total	2,341	2,341	2,166	2,238	2,238	2,115	2,115	2,115	2,238	2,166	2,166	2,341

Table 6. Hydro Capacity

Hydro	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Ohio.Falls	100	100	100	100	100	100	100	100	100	100	100	100
Dix.Dam	30	30	30	30	30	30	30	30	30	30	30	30
Total*	130	130	130	130	130	130	130	130	130	130	130	130

*Expected Capacity Available during Summer Peak hours is 94 MW

E. Unit Outage Data

Generating units typically operate for a period of time, fail and are repaired, and then operate again. SERVM uses historical outage events for each unit representing both full outages and partial outages. SERVM then randomly selects operating events from the historical events to determine generator availability. For every hour, each unit will be on reserve shutdown, operating, partially failed, completely failed, or on scheduled maintenance. GADS data was available for all units and data from 2007 – 2010 was used for this study to accurately represent the frequency and duration of full and partial outages. An example of the outage data input into SERVM is below.

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Table 7. Full Outage Example

		Summer Time to Fail Hours	Summer Time to Repair Hours	Winter Time to Fail Hours	Winter Time to Repair Hours	Off Peak Time to Fail Hours	Off Peak Time to Repair Hours
Ghent 1		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ghent 1		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ghent 1		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ghent 1		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 8. Partial Outage Example

		Summer Time to Fail Hours	Summer Time to Repair Hours	Summer Derate %	Winter Time to Fail Hours	Winter Time to Repair Hours	Winter Derate %	Off Peak Time to Fail Hours	Off Peak Time to Repair Hours	Off Peak Derate %
Ghent 1		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ghent 1		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ghent 1		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ghent 1		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The following Equivalent Forced Outage Rates were targeted for each unit.

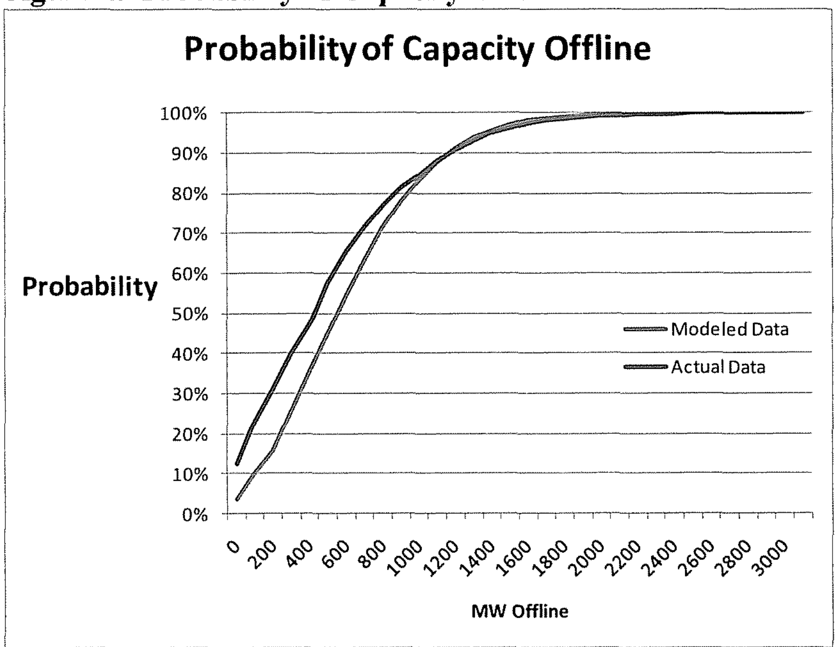
Table 9. Equivalent Forced Outage Rate

Unit	EFOR
Brown 5	[redacted]
Brown 6	[redacted]
Brown 7	[redacted]
Brown 8	[redacted]
Brown 9	[redacted]
Brown 10	[redacted]
Brown 11	[redacted]
Trimble Co 5	[redacted]
Trimble Co 6	[redacted]
Trimble Co 7	[redacted]
Trimble Co 8	[redacted]
Trimble Co 9	[redacted]
Trimble Co 10	[redacted]
Paddy's Run 13	[redacted]
Cane Run 11	[redacted]
Haefling 1	[redacted]
Haefling 2	[redacted]
Haefling 3	[redacted]
Paddy's Run 11	[redacted]
Paddy's Run 12	[redacted]
Zorn 1	[redacted]

Unit	EFOR
Brown 1	[redacted]
Brown 2	[redacted]
Brown 3	[redacted]
Ghent 1	[redacted]
Ghent 2	[redacted]
Ghent 3	[redacted]
Ghent 4	[redacted]
Mill Creek 1	[redacted]
Mill Creek 2	[redacted]
Mill Creek 3	[redacted]
Mill Creek 4	[redacted]
Trimble County 1	[redacted]
Trimble County 2	[redacted]
Tyrone 3	[redacted]

Figure 2 shows the total capacity offline as a percentage of total time. The chart compares the actual 2007 – 2010 data to the simulated distribution created within SERVM. This comparison demonstrates the ability of the model to accurately predict the frequency and duration of generator outages based on history to ensure that the tails of the distribution are reasonable. It is seen that approximately 20% of the time, there are at least 1,000 MW offline due to generator outages or 80% of the time that there are less than 1,000 MW offline.

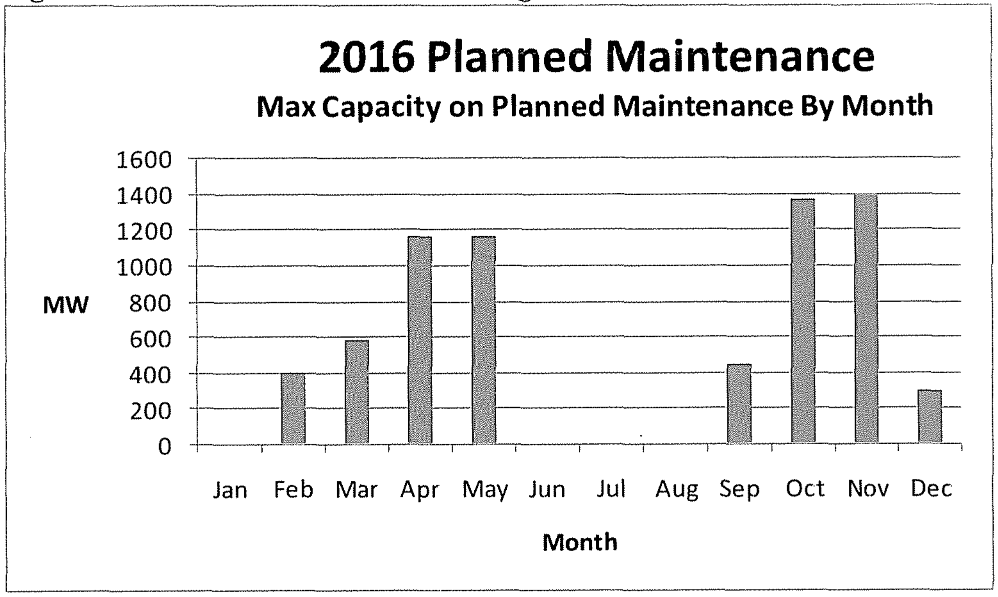
Figure 2. Probability of Capacity Offline



F. Planned Outage Data

The planned outage schedule for 2016 was incorporated into the analysis. Figure 3 shows the planned outages modeled in the simulation.

Figure 3. Planned Maintenance Outages



G. Hydro Modeling

Based on upgrades planned at Ohio Falls and Dix Dam, it is expected that 130 MW of hydro capacity will exist in 2016. However, it is not expected that all 130 MW of hydro capacity will be available on peak and based on operator input, the units were only dispatched up to 94 MW on peak. SERVM has the ability to divide the hydro energy into run or river, scheduled energy with minimum flow requirements, and emergency energy. Ohio Falls and Dix Dam were modeled as scheduled energy and allowed to be optimally dispatched to peak load while only allowing 94 MW of capacity to be utilized across the peak. Given the small amount of hydro on the system, it unlikely the assumptions regarding hydro would be extremely material.

H. Load Management

A total of 126 MWs of load management were modeled in the simulation to be called upon given a reliability event similarly to a generating resource. These resources are called after all peaking resources are utilized. SERVM takes into account the user input constraints on load management and dispatches accordingly. These constraints include a market price threshold before the interruptible contracts are called, a maximum number of hours per day, days per week, and hours per year. Because most of the company's load management contracts force them to dispatch all existing resources first, the dispatch price was set at $500/MWh. Table 10 summarizes the load management modeling.

Table 10. Load Management Representation

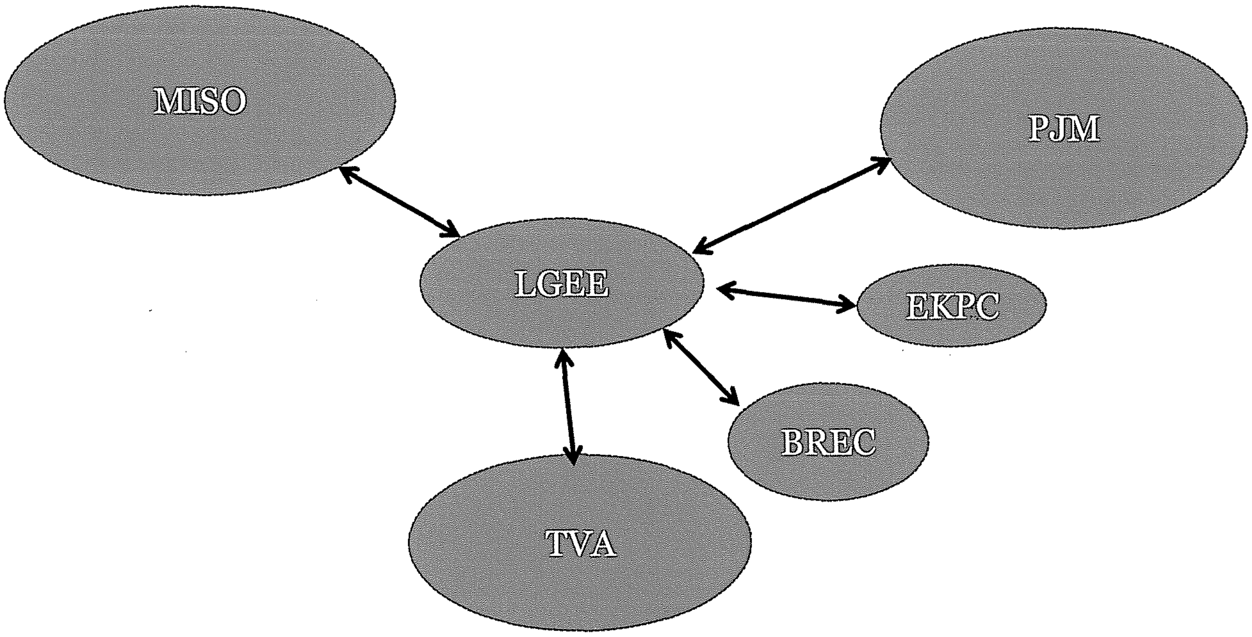
Interruptible Contracts	Capacity MW	Dispatch Constraints Hours Per Year	Hours Per Day	Days Per Week	Dispatch Price $/MWh*
[redacted]		100	14	7	500
		200	14	7	0
		100	14	7	500
		100	14	7	500
		150	14	7	0
		100	14	7	500
Total	125.6				

*$500 /MWh was chosen to ensure that interruptibles were called after all resources and market purchases were dispatched. The contracts that have a $0 dispatch price are called after the last CT is called.

I. Neighbor Representation and Reliability Purchase Modeling

The purpose of the market purchase modeling is to ensure that in a reliability event, SERVM takes into account the ability of a utility to purchase capacity from its neighbors if capacity and transmission are available. It is expected that if a utility is in a reliability event due to high load conditions or extreme weather, then surrounding neighbors will likely be experiencing similar conditions causing capacity to be scarce. SERVM calculates on an hourly basis, the expected capacity that is available in surrounding regions, the expected amount of import capability, and the scarcity premium that will be charged for the reliability purchase. Figure 4 displays the representation of interconnected neighbors.

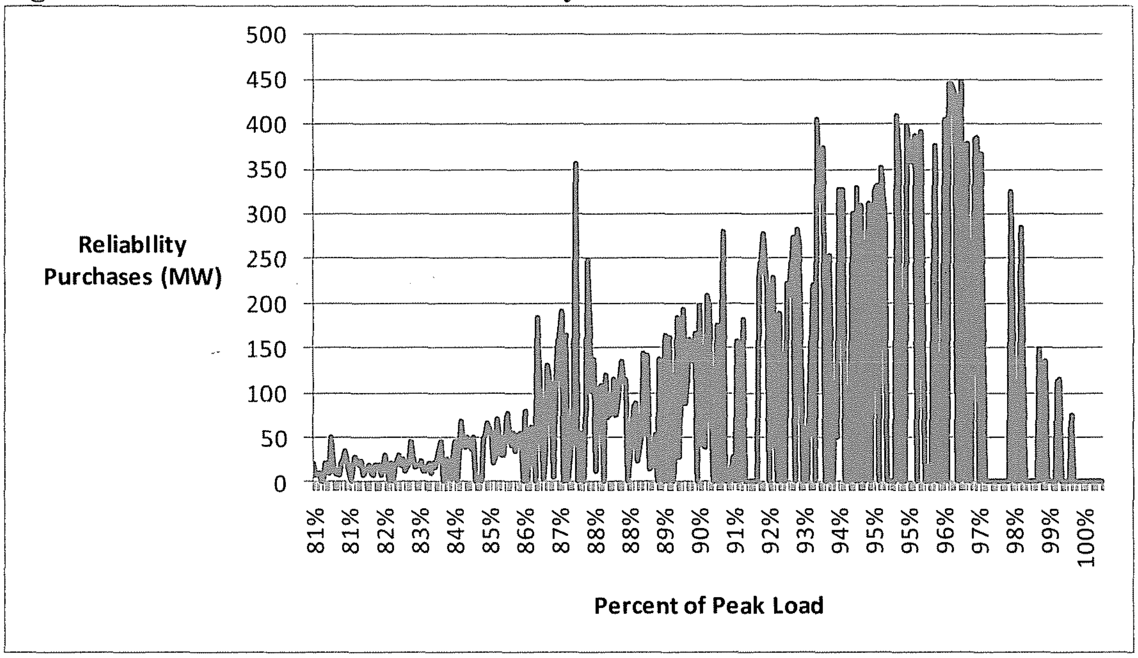
Figure 4. Neighbor Summary



Area	Reference for Capacity	Capacity	Peak Load	Reserve Margin
PJM	PJM 2009 Reserve Margin Study	184,000	160,000	15%
MISO	MISO LOLE Update for 2010, 2014, 2019	125,776	109,370	15%
EKPC	EIA 860 Forms	3,592	3,123	15%
TVA	EIA 860 Forms	40,226	34,979	15%
BREC	EIA 860 Forms	1,971	1,714	15%

The surrounding neighbor capacity information is based on publicly available information and engineering judgment. It was assumed that by 2016, surrounding areas will carry a 15% reserve margin level. Each neighbor's capacity is dispatched to load to determine the hourly available generation at each interface. SERVM is a transportation model in which transmission interface limits are input and varied hourly across each import interface. Historical hourly import capability was analyzed to establish a distribution that was representative of available transmission capacity. Astrape Consulting calibrated the amount of purchases predicted by the model based on historical purchases during high load periods. The amount of purchases that are occurring on average by load level in the simulations can be seen in Figure 5. As load increases, reliability purchases increase but then decrease as the peak load is approached due to overall scarcity in the region.

Figure 5. Simulated Market Purchases by Load Level



The scarcity cost curves in Figure 6 represent the pricing that was assumed for purchases in the model. The prices represent the additional premium for energy above the cost of a CT. As reserve margins in the region for a given year are low and capacity shortages occur, the premium for energy in those hours is substantially higher than in conditions when reserves in the region are high. Reliability purchases are called upon after peaking resources have been dispatched in the system. It should be noted that these curves do not determine whether or not capacity is available, instead the curves are only used for the price if capacity and import capability from another region is available. These curves are based on actual company purchases over the last 6 years and extrapolated to tighter conditions and capped at the cost of unserved energy. As part of the modeling process, Astrape Consulting calibrated the model results to recent years to ensure that SERVM is predicting reliability purchase costs reasonably.

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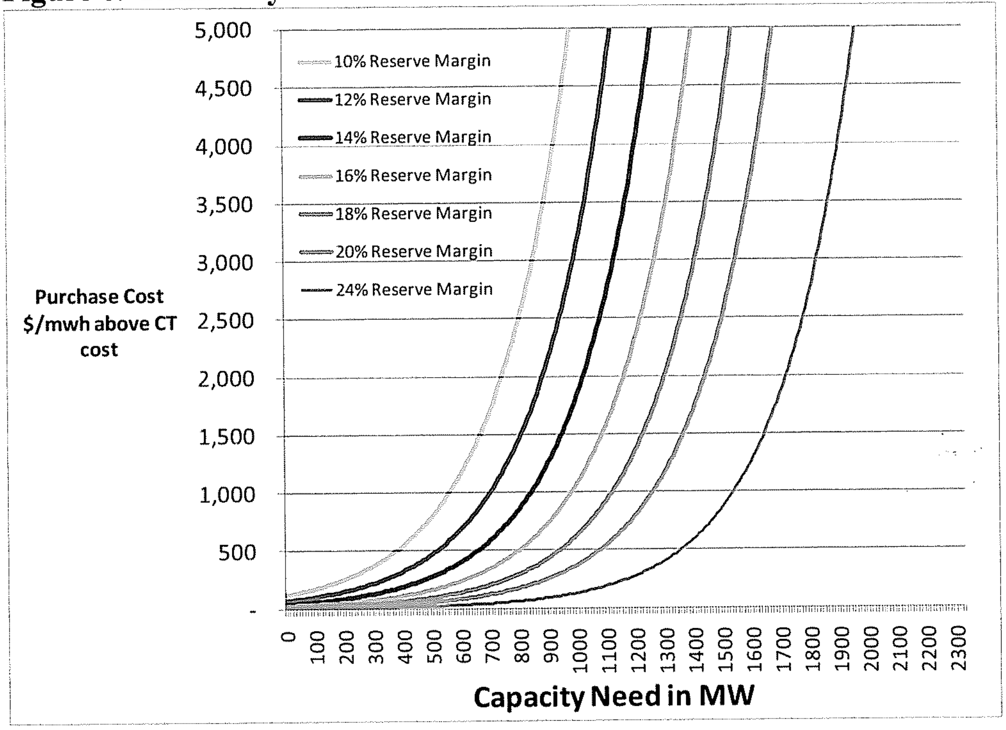
Figure 6. Reliability Purchase Price Model



J. Carrying Cost of Reserves

The cost of carrying incremental reserves was based on the capital and fixed O&M of a new combustion turbine with the following characteristics.

Table 11. Generic Combustion Turbine Characteristics

Marginal Combustion Turbine	
Fixed Charge Rate	10.38%
Capital Cost - 2010 $/kW-yr	[redacted]
Fixed O&M 2010$ $/kW-yr	6.12
Escalation Assumption	2.50%
Discount Rate	6.96%
Variable O&M 2010 $/MWh	25.38
Heat Rate btu/kWh	10,446

For this study additional reserves cost $[redacted]/kW-yr as shown in Table 12.

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Table 12. Carrying Cost of Reserves

	Capital Cost	Fixed O&M	
	$/kW-yr	$/kW-yr	$/kW-yr
2016	[redacted]	$ 7.10	[redacted]

K. Operating Reserve Requirements

The total operating reserve requirement assumed in the study is 287 MW. The spinning reserve requirement is 212 MW. Within the simulation, it is assumed that the company would shed firm load in order to maintain operating reserve requirements.

L. Cost of Unserved Energy (Value of Lost Load)

Some of the impacts of outages on business and residential customers include loss of productivity, interruption of a manufacturing process, lost product, potential damage to electrical services, and inconvenience or discomfort due to loss of cooling, heating, or lighting. While the value of lost load is important to understand, the risk of paying expensive market purchases in the market place impacts results more than the assumption for the value of lost load. For this study, unserved energy costs were derived based on information from four publicly available studies. Two of the studies were performed by the Berkeley National Laboratory for the Department of Energy in 2003 and 2009 respectively. All studies split customers into residential, commercial, and industrial classes which is a typical breakdown of customers in the electric industry. After escalating the costs from each study to 2010 dollars and weighting the cost based on LG&E and KU customer class weightings across all four studies, the cost of unserved energy costs was calculated to be $14.97/kWh. Table 13 shows how the numbers were derived. The range for residential customers varied from $1.1/kWh to $2.82/kWh. The range for commercial customers varied from $20.22/kWh to $29.94/kWh while industrial customers varied from $10.48/kWh to $24.31/kWh. It is expected that commercial and industrial customers would place a much higher value on reliability given the impact of lost production and/or product. The total system cost variance across the four studies was approximately $6,000/MWh. As part of the reserve margin study, an additional sensitivity was performed to analyze how the cost of unserved energy assumption impacts the optimal planning reserve margin. Optimum reserve margins using a range of lost load value from $5000 to $30000/MWh only varied from 0.50% to 0.75% due to the rarity of outage events.

Table 13. Costs of Unserved Energy

	Customer Class Mix	2003 DOE Study $/kWh	2009 DOE Study $/kWh	Christian Associates Study $/kWh	Billinton and Wacker Study $/kWh
Residential	34%	1.32	1.12	2.82	2.47
Commercial	36%	29.94	27.20	20.22	21.01
Industrial	30%	17.27	24.31	10.48	21.01
System Cost of Unserved Energy		16.37	17.46	11.35	14.71

	Customer Class Mix	Min $/kWh	Mean $/kWh	Max $/kWh	Variance $/kWh
Residential	34%	1.12	1.93	2.82	1.69
Commercial	36%	20.22	24.59	29.94	9.72
Industrial	30%	10.48	18.27	24.31	13.83
Average System Cost of Unserved Energy $/kWh			14.97		
All Values Scaled to 2010$					

IV. Simulation Methodology

Since most reliability events are high impact, low probability events, a large number of scenarios must be considered in order to capture these events. Simply constructing worst case scenarios will not give an accurate representation of the operation of any system during such an event, nor would it provide the likelihood of such a scenario. By utilizing 35 years of historical weather, a robust distribution of load shapes will be considered. For each load shape, 7 load growth multipliers are used to represent the uncertainty in the growth of the economy. For each of these 245 cases (35 load shapes * 7 economic forecast uncertainty points), 400 iterations of unit performance were simulated to allow for results to converge in each case resulting in 98,000 hourly simulations for each reserve margin level. From this analysis, an expected reliability energy costs can be calculated and compared to the cost of adding additional reserves which is equal to the carrying cost of a generic CT.

A. Case Probabilities

The probabilities given for each case are shown in Table 14. It is assumed that each weather year is given equal probability and each weather year is multiplied by the probability of each load forecast error point to calculate the overall case probability.

Table 14. Case Probabilities

Weather Year	Weather Year Probability	LDF Errors	LDF Probability	Case Probability	Weather Year	Weather Year Probability	LDF Errors	LDF Probability	Case Probability
1975	2.9%	-4.76%	2.2%	0.1%	1983	2.9%	-4.8%	2.2%	0.1%
1975	2.9%	-3.05%	9.2%	0.3%	1983	2.9%	-3.0%	9.2%	0.3%
1975	2.9%	-1.53%	22.9%	0.7%	1983	2.9%	-1.5%	22.9%	0.7%
1975	2.9%	0.00%	31.5%	0.9%	1983	2.9%	0.0%	31.5%	0.9%
1975	2.9%	1.53%	22.9%	0.7%	1983	2.9%	1.5%	22.9%	0.7%
1975	2.9%	3.05%	9.2%	0.3%	1983	2.9%	3.0%	9.2%	0.3%
1975	2.9%	4.76%	2.2%	0.1%	1983	2.9%	4.8%	2.2%	0.1%
1976	2.9%	-4.8%	2.2%	0.1%	1984	2.9%	-4.8%	2.2%	0.1%
1976	2.9%	-3.0%	9.2%	0.3%	1984	2.9%	-3.0%	9.2%	0.3%
1976	2.9%	-1.5%	22.9%	0.7%	1984	2.9%	-1.5%	22.9%	0.7%
1976	2.9%	0.0%	31.5%	0.9%	1984	2.9%	0.0%	31.5%	0.9%
1976	2.9%	1.5%	22.9%	0.7%	1984	2.9%	1.5%	22.9%	0.7%
1976	2.9%	3.0%	9.2%	0.3%	1984	2.9%	3.0%	9.2%	0.3%
1976	2.9%	4.8%	2.2%	0.1%	1984	2.9%	4.8%	2.2%	0.1%
1977	2.9%	-4.8%	2.2%	0.1%	1985	2.9%	-4.8%	2.2%	0.1%
1977	2.9%	-3.0%	9.2%	0.3%	1985	2.9%	-3.0%	9.2%	0.3%
1977	2.9%	-1.5%	22.9%	0.7%	1985	2.9%	-1.5%	22.9%	0.7%
1977	2.9%	0.0%	31.5%	0.9%	1985	2.9%	0.0%	31.5%	0.9%
1977	2.9%	1.5%	22.9%	0.7%	1985	2.9%	1.5%	22.9%	0.7%
1977	2.9%	3.0%	9.2%	0.3%	1985	2.9%	3.0%	9.2%	0.3%
1977	2.9%	4.8%	2.2%	0.1%	1985	2.9%	4.8%	2.2%	0.1%
1978	2.9%	-4.8%	2.2%	0.1%	1986	2.9%	-4.8%	2.2%	0.1%
1978	2.9%	-3.0%	9.2%	0.3%	1986	2.9%	-3.0%	9.2%	0.3%
1978	2.9%	-1.5%	22.9%	0.7%	1986	2.9%	-1.5%	22.9%	0.7%
1978	2.9%	0.0%	31.5%	0.9%	1986	2.9%	0.0%	31.5%	0.9%
1978	2.9%	1.5%	22.9%	0.7%	1986	2.9%	1.5%	22.9%	0.7%
1978	2.9%	3.0%	9.2%	0.3%	1986	2.9%	3.0%	9.2%	0.3%
1978	2.9%	4.8%	2.2%	0.1%	1986	2.9%	4.8%	2.2%	0.1%
1979	2.9%	-4.8%	2.2%	0.1%	1987	2.9%	-4.8%	2.2%	0.1%
1979	2.9%	-3.0%	9.2%	0.3%	1987	2.9%	-3.0%	9.2%	0.3%
1979	2.9%	-1.5%	22.9%	0.7%	1987	2.9%	-1.5%	22.9%	0.7%
1979	2.9%	0.0%	31.5%	0.9%	1987	2.9%	0.0%	31.5%	0.9%
1979	2.9%	1.5%	22.9%	0.7%	1987	2.9%	1.5%	22.9%	0.7%
1979	2.9%	3.0%	9.2%	0.3%	1987	2.9%	3.0%	9.2%	0.3%
1979	2.9%	4.8%	2.2%	0.1%	1987	2.9%	4.8%	2.2%	0.1%
1980	2.9%	-4.8%	2.2%	0.1%	1988	2.9%	-4.8%	2.2%	0.1%
1980	2.9%	-3.0%	9.2%	0.3%	1988	2.9%	-3.0%	9.2%	0.3%
1980	2.9%	-1.5%	22.9%	0.7%	1988	2.9%	-1.5%	22.9%	0.7%
1980	2.9%	0.0%	31.5%	0.9%	1988	2.9%	0.0%	31.5%	0.9%
1980	2.9%	1.5%	22.9%	0.7%	1988	2.9%	1.5%	22.9%	0.7%
1980	2.9%	3.0%	9.2%	0.3%	1988	2.9%	3.0%	9.2%	0.3%
1980	2.9%	4.8%	2.2%	0.1%	1988	2.9%	4.8%	2.2%	0.1%
1981	2.9%	-4.8%	2.2%	0.1%	1989	2.9%	-4.8%	2.2%	0.1%
1981	2.9%	-3.0%	9.2%	0.3%	1989	2.9%	-3.0%	9.2%	0.3%
1981	2.9%	-1.5%	22.9%	0.7%	1989	2.9%	-1.5%	22.9%	0.7%
1981	2.9%	0.0%	31.5%	0.9%	1989	2.9%	0.0%	31.5%	0.9%
1981	2.9%	1.5%	22.9%	0.7%	1989	2.9%	1.5%	22.9%	0.7%
1981	2.9%	3.0%	9.2%	0.3%	1989	2.9%	3.0%	9.2%	0.3%
1981	2.9%	4.8%	2.2%	0.1%	1989	2.9%	4.8%	2.2%	0.1%
1982	2.9%	-4.8%	2.2%	0.1%	1990	2.9%	-4.8%	2.2%	0.1%
1982	2.9%	-3.0%	9.2%	0.3%	1990	2.9%	-3.0%	9.2%	0.3%
1982	2.9%	-1.5%	22.9%	0.7%	1990	2.9%	-1.5%	22.9%	0.7%
1982	2.9%	0.0%	31.5%	0.9%	1990	2.9%	0.0%	31.5%	0.9%
1982	2.9%	1.5%	22.9%	0.7%	1990	2.9%	1.5%	22.9%	0.7%
1982	2.9%	3.0%	9.2%	0.3%	1990	2.9%	3.0%	9.2%	0.3%
1982	2.9%	4.8%	2.2%	0.1%	1990	2.9%	4.8%	2.2%	0.1%

Weather Year	Weather Year Probability	LDF Errors	LDF Probability	Case Probability	Weather Year	Weather Year Probability	LDF Errors	LDF Probability	Case Probability
1991	2.9%	-4.8%	2.2%	0.1%	1999	2.9%	-4.8%	2.2%	0.1%
1991	2.9%	-3.0%	9.2%	0.3%	1999	2.9%	-3.0%	9.2%	0.3%
1991	2.9%	-1.5%	22.9%	0.7%	1999	2.9%	-1.5%	22.9%	0.7%
1991	2.9%	0.0%	31.5%	0.9%	1999	2.9%	0.0%	31.5%	0.9%
1991	2.9%	1.5%	22.9%	0.7%	1999	2.9%	1.5%	22.9%	0.7%
1991	2.9%	3.0%	9.2%	0.3%	1999	2.9%	3.0%	9.2%	0.3%
1991	2.9%	4.8%	2.2%	0.1%	1999	2.9%	4.8%	2.2%	0.1%
1992	2.9%	-4.8%	2.2%	0.1%	2000	2.9%	-4.8%	2.2%	0.1%
1992	2.9%	-3.0%	9.2%	0.3%	2000	2.9%	-3.0%	9.2%	0.3%
1992	2.9%	-1.5%	22.9%	0.7%	2000	2.9%	-1.5%	22.9%	0.7%
1992	2.9%	0.0%	31.5%	0.9%	2000	2.9%	0.0%	31.5%	0.9%
1992	2.9%	1.5%	22.9%	0.7%	2000	2.9%	1.5%	22.9%	0.7%
1992	2.9%	3.0%	9.2%	0.3%	2000	2.9%	3.0%	9.2%	0.3%
1992	2.9%	4.8%	2.2%	0.1%	2000	2.9%	4.8%	2.2%	0.1%
1993	2.9%	-4.8%	2.2%	0.1%	2001	2.9%	-4.8%	2.2%	0.1%
1993	2.9%	-3.0%	9.2%	0.3%	2001	2.9%	-3.0%	9.2%	0.3%
1993	2.9%	-1.5%	22.9%	0.7%	2001	2.9%	-1.5%	22.9%	0.7%
1993	2.9%	0.0%	31.5%	0.9%	2001	2.9%	0.0%	31.5%	0.9%
1993	2.9%	1.5%	22.9%	0.7%	2001	2.9%	1.5%	22.9%	0.7%
1993	2.9%	3.0%	9.2%	0.3%	2001	2.9%	3.0%	9.2%	0.3%
1993	2.9%	4.8%	2.2%	0.1%	2001	2.9%	4.8%	2.2%	0.1%
1994	2.9%	-4.8%	2.2%	0.1%	2002	2.9%	-4.8%	2.2%	0.1%
1994	2.9%	-3.0%	9.2%	0.3%	2002	2.9%	-3.0%	9.2%	0.3%
1994	2.9%	-1.5%	22.9%	0.7%	2002	2.9%	-1.5%	22.9%	0.7%
1994	2.9%	0.0%	31.5%	0.9%	2002	2.9%	0.0%	31.5%	0.9%
1994	2.9%	1.5%	22.9%	0.7%	2002	2.9%	1.5%	22.9%	0.7%
1994	2.9%	3.0%	9.2%	0.3%	2002	2.9%	3.0%	9.2%	0.3%
1994	2.9%	4.8%	2.2%	0.1%	2002	2.9%	4.8%	2.2%	0.1%
1995	2.9%	-4.8%	2.2%	0.1%	2003	2.9%	-4.8%	2.2%	0.1%
1995	2.9%	-3.0%	9.2%	0.3%	2003	2.9%	-3.0%	9.2%	0.3%
1995	2.9%	-1.5%	22.9%	0.7%	2003	2.9%	-1.5%	22.9%	0.7%
1995	2.9%	0.0%	31.5%	0.9%	2003	2.9%	0.0%	31.5%	0.9%
1995	2.9%	1.5%	22.9%	0.7%	2003	2.9%	1.5%	22.9%	0.7%
1995	2.9%	3.0%	9.2%	0.3%	2003	2.9%	3.0%	9.2%	0.3%
1995	2.9%	4.8%	2.2%	0.1%	2003	2.9%	4.8%	2.2%	0.1%
1996	2.9%	-4.8%	2.2%	0.1%	2004	2.9%	-4.8%	2.2%	0.1%
1996	2.9%	-3.0%	9.2%	0.3%	2004	2.9%	-3.0%	9.2%	0.3%
1996	2.9%	-1.5%	22.9%	0.7%	2004	2.9%	-1.5%	22.9%	0.7%
1996	2.9%	0.0%	31.5%	0.9%	2004	2.9%	0.0%	31.5%	0.9%
1996	2.9%	1.5%	22.9%	0.7%	2004	2.9%	1.5%	22.9%	0.7%
1996	2.9%	3.0%	9.2%	0.3%	2004	2.9%	3.0%	9.2%	0.3%
1996	2.9%	4.8%	2.2%	0.1%	2004	2.9%	4.8%	2.2%	0.1%
1997	2.9%	-4.8%	2.2%	0.1%	2005	2.9%	-4.8%	2.2%	0.1%
1997	2.9%	-3.0%	9.2%	0.3%	2005	2.9%	-3.0%	9.2%	0.3%
1997	2.9%	-1.5%	22.9%	0.7%	2005	2.9%	-1.5%	22.9%	0.7%
1997	2.9%	0.0%	31.5%	0.9%	2005	2.9%	0.0%	31.5%	0.9%
1997	2.9%	1.5%	22.9%	0.7%	2005	2.9%	1.5%	22.9%	0.7%
1997	2.9%	3.0%	9.2%	0.3%	2005	2.9%	3.0%	9.2%	0.3%
1997	2.9%	4.8%	2.2%	0.1%	2005	2.9%	4.8%	2.2%	0.1%
1998	2.9%	-4.8%	2.2%	0.1%	2006	2.9%	-4.8%	2.2%	0.1%
1998	2.9%	-3.0%	9.2%	0.3%	2006	2.9%	-3.0%	9.2%	0.3%
1998	2.9%	-1.5%	22.9%	0.7%	2006	2.9%	-1.5%	22.9%	0.7%
1998	2.9%	0.0%	31.5%	0.9%	2006	2.9%	0.0%	31.5%	0.9%
1998	2.9%	1.5%	22.9%	0.7%	2006	2.9%	1.5%	22.9%	0.7%
1998	2.9%	3.0%	9.2%	0.3%	2006	2.9%	3.0%	9.2%	0.3%
1998	2.9%	4.8%	2.2%	0.1%	2006	2.9%	4.8%	2.2%	0.1%

Weather Year	Weather Year Probability	LDF Errors	LDF Probability	Case Probability
2007	2.9%	-4.8%	2.2%	0.1%
2007	2.9%	-3.0%	9.2%	0.3%
2007	2.9%	-1.5%	22.9%	0.7%
2007	2.9%	0.0%	31.5%	0.9%
2007	2.9%	1.5%	22.9%	0.7%
2007	2.9%	3.0%	9.2%	0.3%
2007	2.9%	4.8%	2.2%	0.1%
2008	2.9%	-4.8%	2.2%	0.1%
2008	2.9%	-3.0%	9.2%	0.3%
2008	2.9%	-1.5%	22.9%	0.7%
2008	2.9%	0.0%	31.5%	0.9%
2008	2.9%	1.5%	22.9%	0.7%
2008	2.9%	3.0%	9.2%	0.3%
2008	2.9%	4.8%	2.2%	0.1%
2009	2.9%	-4.8%	2.2%	0.1%
2009	2.9%	-3.0%	9.2%	0.3%
2009	2.9%	-1.5%	22.9%	0.7%
2009	2.9%	0.0%	31.5%	0.9%
2009	2.9%	1.5%	22.9%	0.7%
2009	2.9%	3.0%	9.2%	0.3%
2009	2.9%	4.8%	2.2%	0.1%

For this study, total reliability costs are defined as the following:

a. Reliability Energy Costs
   i. Cost Unserved Energy Events – The value of lost load to customers.

   ii. Cost of Expensive Purchased Power – defined as the costs of any purchases at prices higher than the generic CT costs

   iii. Cost of Dispatching Expensive Peaking Resources – defined as any costs of the system's physical generation above the dispatch cost of the new capacity resource. This includes the dispatch of higher-cost generators such as oil-fired turbines and old natural gas turbine units.

b. Cost of Carrying Reserves – The carrying cost of adding additional capacity in $/kW-yr.

These components are calculated for each of the above cases weighted based on probability.

B. Reserve Margin Definition

For this study, reserve margin is defined as the following:

- (Resources – Demand) / Demand *100%
    - Resources including Interruptible Capacity
    - Demand is the August Peak Load including Interruptible Load. August Peak Load was chosen because that is the month in which reserves are the lowest since capacity for most thermal resources is much higher in winter months compared to summer months.

V. Base Case Results and Risk Analysis

Figure 7 shows the resulting distribution of reliability energy costs across varying reserve margins. The components include the cost EUE, cost of reliability purchases, and production costs above a CT. As reserve capacity is added, these reliability energy costs are reduced. As seen, more than 70% of the time, the utility is going to pay more in capacity costs than for reliability energy because the reliability energy is concentrated in a few extreme cases when the combination of severe generator outages, weather, and load forecast error, and low import capability occur. It is the risk on the tail end of the distribution that forces a utility to carry reserves. Some years these costs may be close to zero while other years those costs may be orders of magnitude higher than the incremental cost of carrying additional reserves. Assuming a 12% reserve margin level, reliability energy costs can range from 200 thousand dollars to 900 million dollars for a single year.

Figure 7. Distribution of Reliability Energy Costs

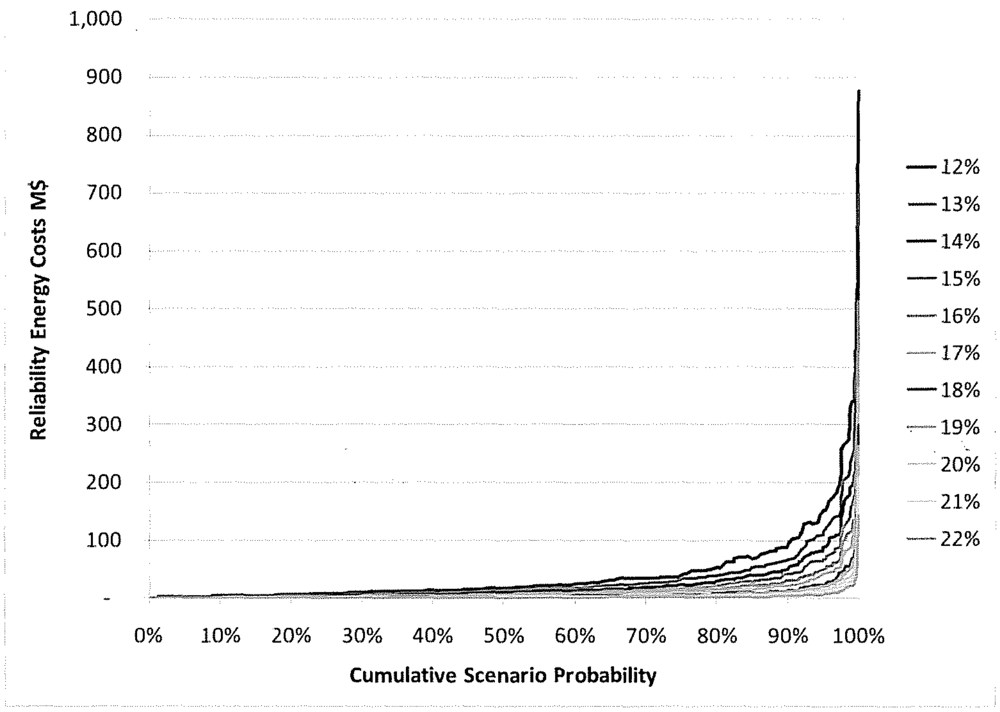
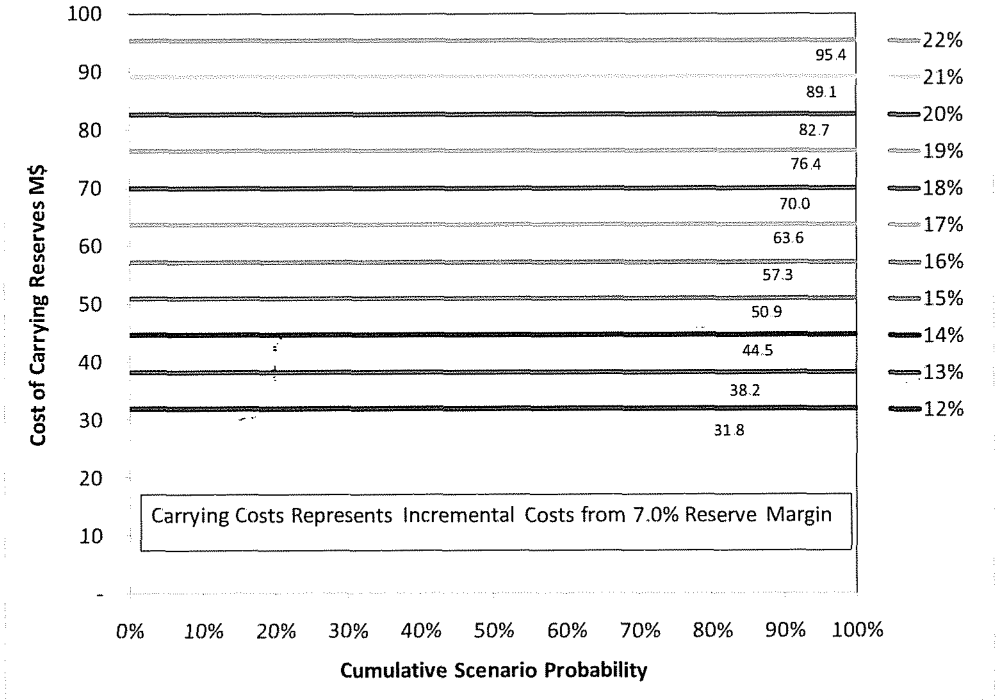


Figure 8 shows the cost of carrying reserves at varying reserve margin levels. As reserve margin increases, the cost of carrying reserves increases. The cost of carrying reserves is fixed for all scenarios because capacity can be constructed or purchased through a bilateral contract which will effectively lock that cost for many years.

Figure 8. Fixed Cost of Carrying Reserves



The optimal reserve margin is where the sum of the cost of reliability energy costs (Distributions from Figure 7) and the cost of carrying reserves (Distributions from Figure 8) is minimized. However, since reliability costs are extraordinarily volatile but capacity costs are fixed, a conversion is necessary to put the two on the same basis. Otherwise, the comparison would inappropriately consider two very different cost structures. The casualty insurance industry faces a similar issue of how to compare fixed premiums with volatile casualty payouts. The typical solution is to remove the risk from the casualty distributions by selecting the 85th to 95th percent costly long-term scenario for comparing to fixed premiums. In other words, premiums are frequently set using anywhere between 85 to 95 percent confidence levels that the insurance company will be covered in the long-term. Therefore, in this example, if an insurance company were assuming the risks shown in Figure 7, then an approximate premium would equal the 85th -

95th confidence level of the distribution. Astrape Consulting recommends a similar risk adjustment using reliability energy costs at the 85th to 90th confidence level range based on its experience in performing reserve margin studies for other jurisdictions within the southeast because these levels have resulted in the lowest cost resource plans that also avoid unreasonable risk for utilities, regulators, and customers. Figure 9 summarizes total reliability costs assuming reliability energy costs at the 85th percentile. As reserve margin increases, reliability energy costs decrease and the cost of carrying reserves increase. With this assumption, total reliability costs are minimized at a reserve margin of 15.50%.

Figure 9. Optimal Reserve Margin with Reliability Energy Costs at 85th Percentile Confidence Level

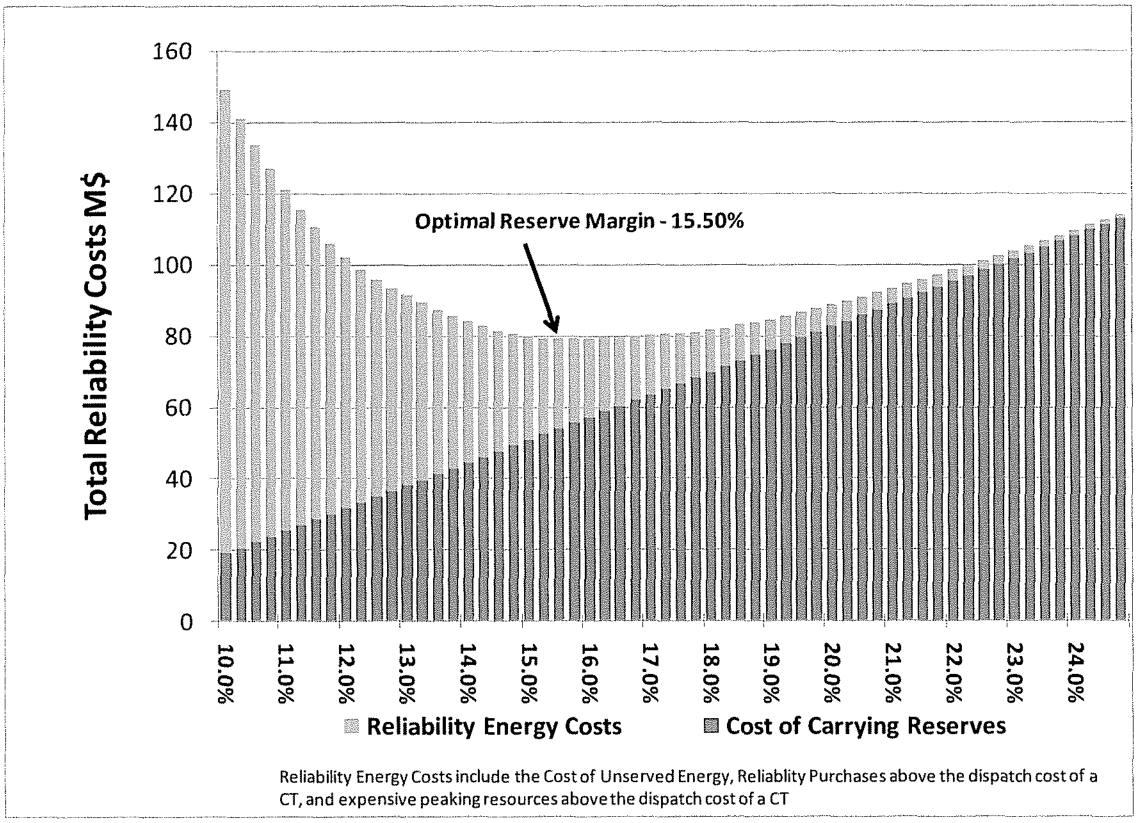
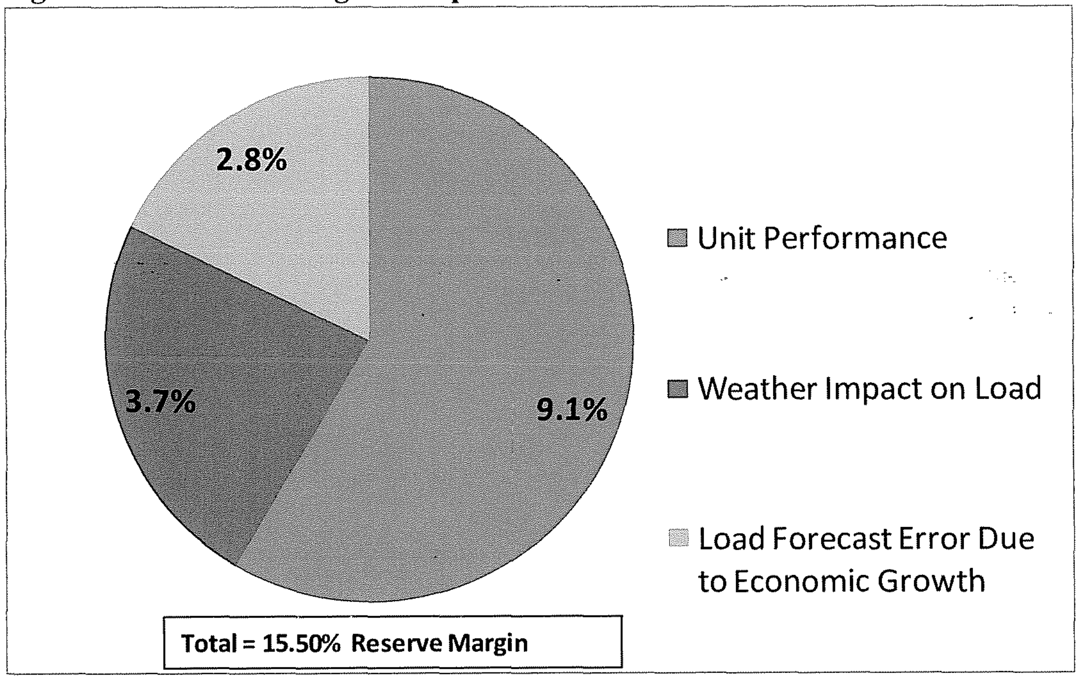


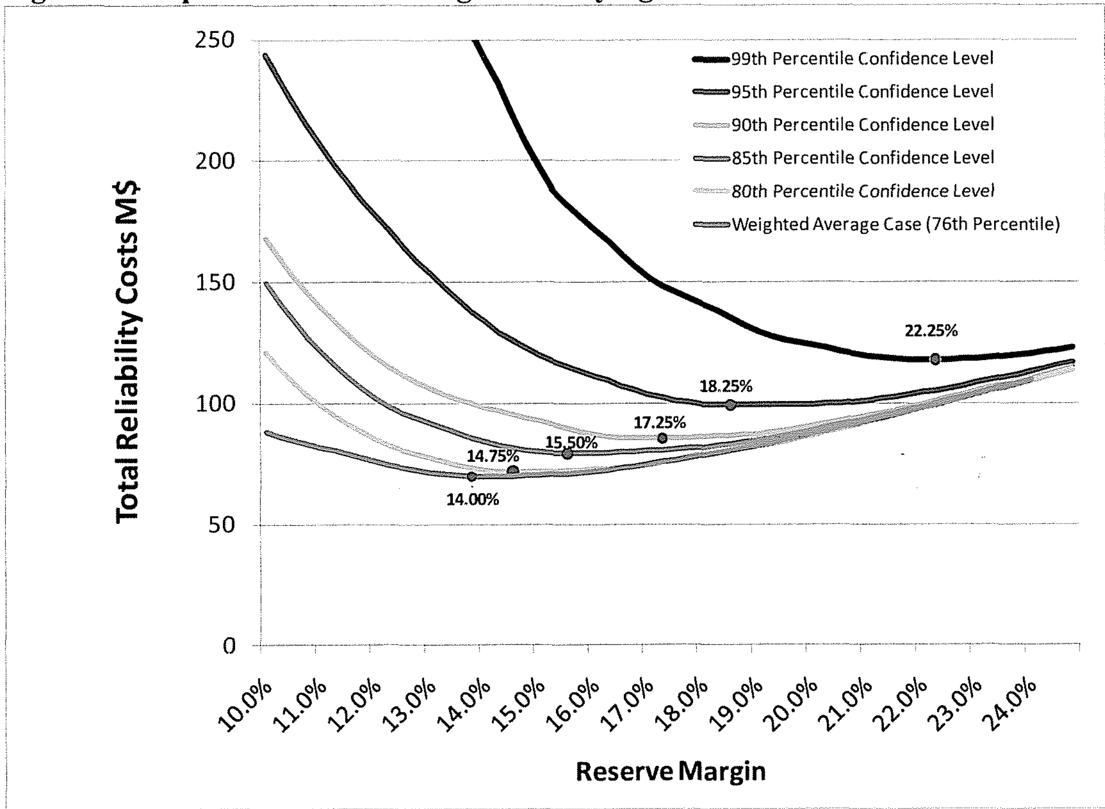
Figure 10 supplies a breakdown of the optimal reserve margin into three components: Unit Performance, Weather Impact on Load, and Load Forecast Error Due to Economic Growth. The largest component is unit performance which is not surprising given the fact that 1,000 MW of capacity are on outage 20% of the time as shown in Figure 2 of the Input Section.

Figure 10. Reserve Margin Components at 85th Percentile Confidence Interval



Next, total reliability costs were calculated assuming reliability energy costs at various confidence levels to understand how the least cost reserve margin is impacted by this assumption. Figure 11 displays these results. The study was performed at the weighted average (76th percentile), 80th, 85th, 90th, 95th, and 99th confidence levels.

Figure 10. Optimal Reserve Margin at Varying Confidence Intervals



	Weighted Average (76th Percentile)	85% Confidence Level	90% Confidence Level	95% Confidence Level	99% Confidence Level
Optimal Reserve Margin	14.00%	15.50%	17.25%	18.25%	22.25%

The recommended range of reserve margin assuming the 85th and 90th confidence levels of reliability energy costs is between 15.50% and 17.25%. The weighted average case assumes the reliability energy costs are weighted based on the probability of each scenario which happens to fall out at the 76th percentile point on the distribution. However, it is Astrape Consulting's experience that assuming this as a planning reserve margin provides more risk than utilities and regulators are willing to take in a given year even though it may minimize average costs in the long run. Based on Figure 7, a 14.00% reserve margin results in a risk that in 5% of all scenarios reliability energy costs would exceed 90 million dollars and 1% of the time they would exceed

$200 million dollars. A 15.50% reserve margin lowers this exposure to 60 million dollars and 140 million dollars respectively. Also, even if the weighted average case is assumed, the increase in total reliability costs between the 14.00% reserve margin and the 15.50% reserve margin is only 1.2 million dollars. In contrast, the 99 percentile confidence level reserve margin of 22.25% eliminates almost all risk but puts an unreasonable amount of cost on customers as shown in Figure 10.

VI. Sensitivity Analysis

In addition to the base case analysis, several sensitivities were performed to test the major assumptions in the base case. These sensitivities included varying the cost of unserved energy, varying the cost of carrying additional capacity reserves, removing all tie assistance, increasing unit forced outage rates, decreasing neighbor capacity, decreasing transmission limits, and increasing market prices during scarce conditions.

Table 15. Sensitivities – Cost of EUE and Carrying Cost of Reserves

	Weighted Average	85% Confidence Level	90% Confidence Level	95% Confidence Level
EUE = $5,000/MWh	13.75%	15.50%	17.00%	18.00%
Base Case Optimal Reserve Margin (EUE = $16,600/MWh)	**14.00%**	**15.50%**	**17.25%**	**18.25%**
EUE = $30,000/MWh	14.25%	16.00%	17.75%	18.75%
Cost of Capacity - $110/kW-yr	13.25%	15.25%	16.50%	18.00%
Base Case Optimal Reserve Margin (Cost of Capacity = $88.42/kW-yr)	**14.00%**	**15.50%**	**17.25%**	**18.25%**
Cost of Capacity - $70/kW-yr	14.75%	17.25%	18.50%	20.75%

As the cost of reserves decreases, it is more economic for the system to carry additional capacity and vice versa if the cost of capacity increases. As shown in the results, the 85th percentile confidence level reserve margin ranges from 15.25% to 17.25% by varying the cost of capacity from $110/kW-yr to $70/kW- yr. Because the risk exposure to reliability energy is exponential and not linear across reserve margins, there is a lesser effect of raising the cost of reserves than there is when lowering the cost of capacity as shown in the results.

As the cost of unserved energy decreases, it is more economic for the system to carry less capacity reserves. Due to the fact that the majority of reliability energy costs come from events in which reliability purchases occurred, the value for the cost of EUE is not a major driver in the analysis. For this sensitivity, the cost of EUE was varied from as much as $5000/MWh to $30,000/MWh and the 85th percentile confidence level reserve margin ranges from 15.50% to 16.00%.

Table 16 shows the results of the remaining sensitivities that were performed individually off of the Base Case.

Table 16. Other Sensitivities

	Weighted Average (76th Percentile)	85% Confidence Level	90% Confidence Level	95% Confidence Level
Optimal Reserve Margin	14.00%	15.50%	17.25%	18.25%
Scarcity Pricing Sensitivity - Increase by 50%	15.25%	17.50%	19.00%	20.25%
EFOR Sensitivity - Increase by 50%	17.00%	19.00%	21.25%	22.75%
Neighbor Reserve Margin Sensitivity - 15% RM to 12% RM	16.00%	18.00%	20.25%	22.00%
Transmission Sensitivity - Decrease by 50%	15.00%	16.75%	18.25%	19.50%
Island Sensitivity - No Interconnection Ties	21.75%	23.75%	24.75%	26.00%

The effect of increasing the scarcity pricing by 50% increased the 85th percentile confidence level reserve margin by 2.00% to 17.50%. However, increasing the unit forced outage rates (FOR) by 50% had a much larger impact of 3.50% resulting in a 19.00% reserve margin. This is logical as increasing the FOR is effectively removing available capacity resulting in not only higher market prices but also more reliability energy. Increasing the scarcity pricing is only increasing the cost of the reliability energy for a specific, but does not affect the energy available.

Market conditions were varied by assuming less reserve margins from existing neighbors (15% reserve margin to 12% reserve margin) and a 50% reduction in transmission import capability. The 85th percentile confidence level reserve margin shifts from 15.50 % to 18.00% for the reserve margin sensitivity and to 16.75% for the transmission reduction sensitivity.

Finally, the 85th percentile confidence level reserve margin point rises to 23.75% if the company is assumed to be an island without any emergency assistance from its neighbors. In this scenario, all reliability purchases are shifted to unserved energy which causes reliability costs to increase substantially. This sensitivity shows the importance that interconnected regions have on the Companies' reliability.

These sensitivities illustrate the potential change in reserve margin due to significant assumptions. Excluding the island sensitivity, the reserve margins only shift by a few percentage points even with significant changes in major inputs.

VII. Conclusions/Recommendations

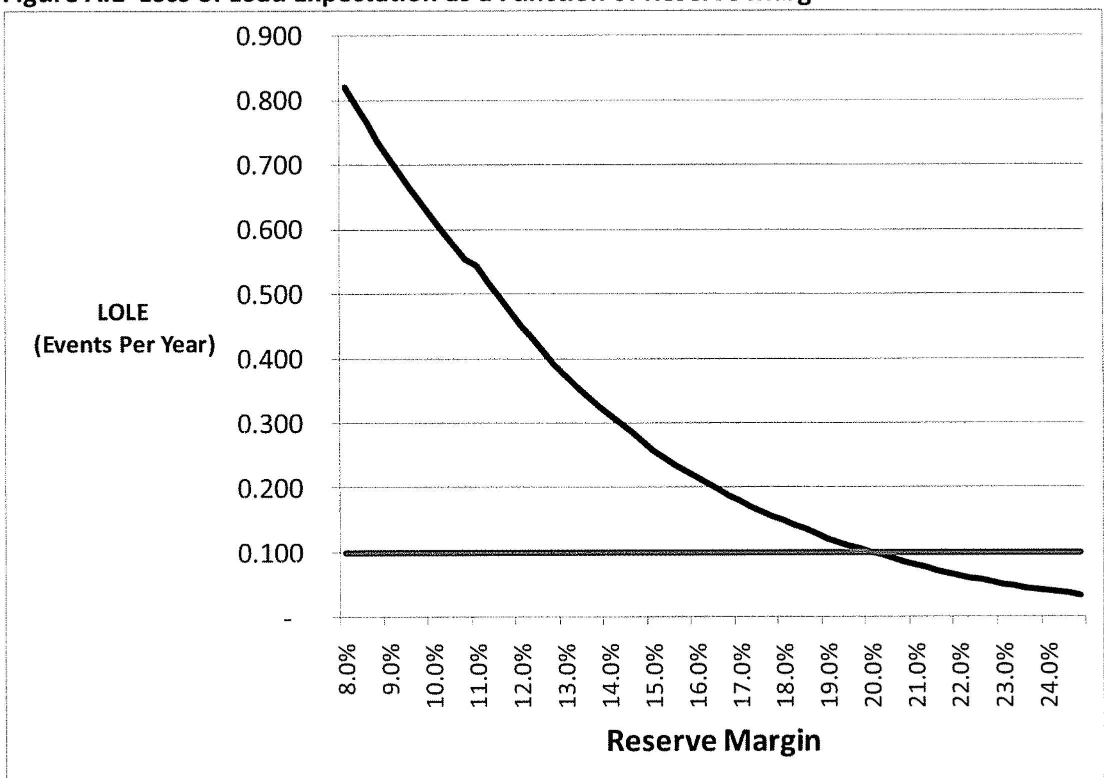
In conclusion, the simulation results demonstrate the Companies' risk due to lower planning reserve margins and show that low probability, high impact cost exposures exist at all reserve margin levels. No system is 100% reliable and this reliability assessment has quantified the frequency and duration of major events and their economic impact on customers under a full distribution of weather years, unit performance, and load forecast uncertainty. The study also demonstrates the value of capacity reserve margins to the extent they protect customers from extreme, high cost outcomes. Based on the simulations and sensitivities, the precedent set by other industries, and experience in other jurisdictions, Astrape Consulting recommends that the Companies set a long-term target reserve margin using the 85th to 90th percentile of reliability energy costs which results in reserve margins between 15% and 17%.

Appendix

Physical Reliability Metrics

Loss of Load Expectation (LOLE) is a common physical reliability metric used when looking at resource adequacy studies. An LOLE of 0.1 events per year or "1 day in 10 years" is a criterion that is used in many jurisdictions. Below is a figure showing the LOLE curve for the base case of this study. The 1 day in 10 year metric occurs at a 20% reserve margin level. For customers to achieve this level of reliability, costs would need to increase substantially which would lead to an inefficient level of reserves. LOLE metrics, especially for relatively smaller systems (less than 10,000 MW) do not always translate to the most economic reserve margin as shown below. Based on the recommended reserve margin Of 15% - 17%, it is expected that there would be on average approximately 2 events every 10 years.

Figure A.1 Loss of Load Expectation as a Function of Reserve Margin



Kentucky Utilities Company

and

Louisville Gas and Electric Company

2011 Optimal Expansion Plan Analysis

Generation Planning and Analysis

April 2011

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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 criterion and subject to certain constraints, including unit operating characteristics and maintaining a target reserve margin of 16%.

As precursors to the optimization process, two independent analyses were conducted, one for screening supply-side alternatives and the other for selecting demand-side management 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 evaluation was conducted on numerous demand-side management options and ultimately recommended new DSM programs and enhancements to exiting programs. This evaluation compared the merits and costs of each program to the avoided cost of building new generation units and resulted in the recommendation of the least-cost options. These programs have been included in the base load forecast that was then used in determining the technology choice and the construction timing of new generation units.

Base case results demonstrate that the plan to construct three 3x1 combined cycle combustion turbines beginning in 2016 provides lowest present value of revenue requirements. In order to consider uncertainty in the process, sensitivity cases were evaluated to demonstrate the effects on the optimal plan of variation in the load forecast and in environmental regulations, and the breakeven points for natural gas prices and coal unit capital costs.

Introduction

The purpose of this study is to produce a multiple year IRP for the companies. The IRP is determined based on a minimum expected PVRR criterion over a 30-year planning horizon and subject to certain constraints, including a target reserve margin of 16% and unit operating characteristics. This plan provides an indicative expansion plan, considering current business planning assumptions. Detailed construction plans would be submitted to the KPSC for approval with a Certificate of Public Convenience and Necessity ("CCN") before the actual implementation of any part of this plan would begin.

This report provides an overview of the Strategist® computer model used in the analysis as well as discussions of the analyses regarding target reserve margin and supply-side screening. Based upon these supporting analyses, initial lists of technologies of various types and capacities were suggested for further analysis within the optimization module of Strategist®. Sensitivities regarding the load forecast and environmental regulations, along with break even analyses on natural gas prices and coal unit construction costs, were evaluated with computer optimizations and the least cost plan is presented for consideration.

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 the Companies' peak and energy load forecasts for multiple years and a load shape. The demand and energy forecasts are modeled to include the peak and energy reductions associated with interruptible or curtailable customers and DSM programs.

The GAF module is used to simulate 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.

The PRV optimization module is used to evaluate 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 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, 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 April 2011, 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 range of 15% to 17% 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 16%. The reserve margin study titled *LG&E and KU 2011 Reserve Margin Study* (April 2011) can be found in Volume III, Technical Appendix.

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 unfeasible. The supply-side screening report titled *Analysis of Supply-Side Technology Alternatives* (March 2011), 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 – Large
3x1 Combined Cycle Combustion Turbine
2x1 Combined Cycle Combustion Turbine
1x1 Combined Cycle Combustion Turbine
Wind Energy Conversion
Simple Cycle Combustion Turbine
Landfill Gas Internal Combustion Engine
Ohio Falls Hydro Expansion at Shippingport Island

The options listed in Table 1 include the options that passed the screening analysis and represent the complete list of supply-side alternatives available to Strategist®. A new run-of-river hydroelectric unit as an expansion of the existing Ohio Falls hydro facility to Shippingport Island was also included in Strategist® as a potential expansion option. Although it did not pass the supply-side screening analysis, it was included for further study as another alternative to fossil fuel based options. The Companies will continue to pursue possible opportunities through a request for proposals 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 new capacity construction for short periods of time, which is already under consideration 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.

Demand-Side Technologies

In addition to the supply-side screening analysis discussed above and as a precursor to developing the optimal supply-side expansion plan, a separate evaluation of demand-side options was performed, as discussed in detail in Sections 8.(3)(e) and 8.(5)(c) in Volume I. The relative costs and impacts of various demand-side options were compared to building new generation capacity. The DSM programs that were shown to be least cost have been included in the base load forecast and have therefore not been included explicitly in the supply-side optimization process. The existing DSM programs are assumed to continue into the future and the new DSM programs are collectively expected to reduce the Companies' coincident system peak by approximately 500 MW by the end of 2017. The uncertainty regarding the level of demand reduction achieved by the DSM programs is considered to be included within the range of uncertainty in load which is discussed in this report in the section titled *Sensitivity: Load.*

Base Case Development

Using the supply-side options identified in Table 1 along with the base assumptions for the fuel forecast, new unit capital costs, and demand and energy forecasts, an initial expansion plan was developed. Appendix A of this report details the existing units' operating characteristics as well as documents the load forecasts (base, high and low) and fuel prices used in this evaluation. Table 2 below details relevant information pertaining to each of the supply-side options evaluated. The cost and performance data for all units except Ohio Falls Station are based on data from the EPRI TAG database, the Cummins and Barnard supply-side report (December 2007), or more project-specific data developed by the Companies' Project Engineering department in conjunction with engineering contractors. Cost and performance data for the Ohio Falls Station option are based on data from of a feasibility study supplied to the Companies in December 2008 by MWH Global, Inc. This study compared five alternatives and recommended a large unit on Shippingport Island that has been included in the expansion plan options. 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* (March 2011) in Volume III, Technical Appendix.

Table 2
Supply-Side Alternatives Data
All costs are in 2010 $

Unit Type	Reference Name[2]	Net Capability[3] Summer (MW)	Net Capability[3] Winter (MW)	Overnight Installed Cost[4] ($/kW)	Total Non-Fuel Variable O&M Non-Ozone Season[5] ($/MWh)	Total Fixed O&M[6] ($M/yr)	Full Load HHV Heat Rate (MMBtu/MWh)	Unavailability[7] (%)
Simple Cycle CT	SCCT	194	228	[redacted]	15.12	3.1	9.85	4.55%
1x1 Combined Cycle CT	1x1C	388	435	[redacted]	4.23	8.0	6.72	5.90%
2x1 Combined Cycle CT	2x1C	605	673	[redacted]	3.99	11.9	6.77	5.90%
3x1 Combined Cycle CT	3x1C	907	1,009	[redacted]	3.96	18.3	6.75	5.90%
Supercritical Coal - Large	LGSC	789	811	[redacted]	3.70	36.8	9.04	7.40%
Wind Turbine	Wind	200	200	[redacted]	7.37	2.2	N/A	69.0%[8]
Landfill Gas IC Engine	LFG	5	5	[redacted]	15.80	0.3	9.50	2.50%
Ohio Falls Unit[1]	Falls	50	50	[redacted]	0.00	0.7	N/A	60.70%

Notes to Table 2:

[1] Expansion of the Ohio Falls facility to Shippingport Island is a 50 MW run-of-river unit.
Winter and summer capacities are expected to average 16 and 20 MW, respectively, with an annual average capacity factor of 39.3%.

[2] Reference names are used to more easily compare sensitivity plans.

[3] For coal units and combustion turbines, summer ratings are used for June - August and winter ratings are used for December - February.

[4] Installed cost is based on net summer capacity.

[5] Variable O&M includes start fuel costs.

[6] Fixed O&M for CTs and combined cycle options include costs associated with reserving firm gas-line capacity.

[7] Unavailability is the long-term steady-state outage rate expected after initial operation for coal, combustion turbine, and landfill gas units.
For wind and Ohio Falls units, unavailability reflects the expected capacity factor (unavailability = 1 - capacity factor).

[8] Wind turbine capacity factor modeled at 31% with 15% of the capacity counting toward reserve margin.

As previously noted, the base assumptions for this IRP include the retirement of the six coal units at the Cane Run, Green River, and Tyrone Stations in 2016 due to the anticipated enactment of more stringent environmental regulations that are discussed in detail in Section 8.(5)(f) of Volume I. The retirement assumptions were based on an analysis that demonstrates that the PVRR of retiring these units and replacing the capacity is lower than the PVRR of keeping them in operation with the appropriate emissions controls. These PVRR calculations included revenue requirements for:

- the capital cost of constructing emissions control equipment to meet the proposed environmental regulations,
- the capital cost of constructing generation capacity to replace retired units to maintain the target reserve margin,
- and the operating costs of both existing and new generation units net of the savings from retired units.

This analysis was conducted by first comparing the PVRR of a plan that included no retirements and the required environmental controls to a plan that included only the retirement of the unit with the highest operating costs. Plans with the retirements of additional units were added incrementally in order of decreasing operating costs. Each incremental plan demonstrated whether the retirement of the specified units resulted in lower PVRR. The result of this analysis is that the least cost plan to maintain the target reserve margin as well as meet the proposed environmental regulations includes

- retiring the coal units at the Cane Run, Green River, and Tyrone Stations,
- replacing this retired capacity in 2016 and installing additional capacity in later years to maintain the target reserve margin,

- and installing the necessary emissions controls on existing units to meet the proposed environmental regulations.

For reference, this least cost base 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 under the base assumptions. As seen in Table 3, optimization results using the base assumptions indicate that the optimal plan is the installation of three 3x1 combined cycle units: one in 2016, one in 2018, and one in 2025.

Table 3
Base Expansion Plan

Plan:	**"A"**
2011	
2012	
2013	
2014	
2015	
2016	3x1C
2017	
2018	3x1C
2019	
2020	
2021	
2022	
2023	
2024	
2025	3x1C

With this plan, there is a 40 MW reserve margin shortfall in 2015 when the summer reserve margin was allowed to drop to approximately 15.4%, as shown in Table 8.(4)(a)-1 in Section 8 of Volume I. In 2015 and in other years with relatively small reserve margin deficits immediately preceding the planned completion of a new generation unit, the possibility of meeting the projected deficit with a power purchase would be evaluated.

Sensitivity Analyses

The supply-side alternatives identified in Table 2 were also evaluated in several other sensitivity cases. Sensitivities were performed regarding uncertainty in the load forecast, coal unit retirements, and proposed environmental regulations. Additionally, break even analyses were performed on gas prices and coal unit capital cost to determine the points at which the PVRR would be similar to the base case for an expansion plan with a coal unit installed in 2018 instead of a gas-fired combined cycle unit.

Sensitivity: Load

The load forecast is a significant factor influencing the Companies' expansion plan. Each supply-side technology is designed for optimal unit performance at various levels of utilization. For example, simple cycle combustion turbines ("CT") are relatively inexpensive to construct; however, compared to coal-fired units, CTs are more costly to operate and maintain given the relative prices of gas and coal. Conversely, coal-fired units are expensive to construct but are relatively inexpensive to operate and maintain. The economics of adding a supply-side option to any generation system is based on the unit's expected fuel and O&M costs 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 that 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 cycle combustion turbines) 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 (1) the expected system load growth case, (2) a case where system load growth exceeds expected growth, and (3) 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 4 shows the optimal expansion plans when optimization runs are made on the low load (Plan "B") and high load (Plan "C") forecasts. For comparison, the optimization of the base load forecast (Plan "A") is also shown.

Table 4
Load Sensitivity

Load Forecast:	**Base**	**Low**	**High**
Plan:	**"A"**	**"B"**	**"C"**
2011			
2012			
2013			
2014			
2015			
2016	3x1C	3x1C	3x1C + 2x1C
2017			
2018	3x1C		
2019			
2020		2x1C	3x1C
2021			
2022			
2023			
2024			
2025	3x1C	3x1C	

As with the base optimization, sensitivity optimizations regarding the Companies' forecasted load continue to show that at least one combined cycle unit is installed in 2016. The first year available for all units is 2016. Allowing for an earlier install would result in the selection of units earlier than 2016 for the high load scenario.

Sensitivity: Environmental Regulations

Several of the environmental regulations discussed in Section 8.(5)(f) of Volume I are not final so there is a possibility that some regulations could change or be delayed. As a sensitivity to the base assumptions regarding proposed environmental regulations, it was assumed that no unit retirements would be required due to new regulations. Table 5 shows that without the unit retirements associated with the proposed EPA regulations, the optimal expansion plan, Plan "D", is to delay the next new unit to 2018 and to build only two 3x1 combined cycle units in the fifteen year planning period.

Table 5
Environmental Regulations Sensitivity

Plan:	Base **"A"**	No Unit Retirements **"D"**
2011		
2012		
2013		
2014		
2015		
2016	3x1C	
2017		
2018	3x1C	3x1C
2019		
2020		
2021		
2022		
2023		
2024		3x1C
2025	3x1C	

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 including the assumption that the first unit to be built in 2016 is a gas-fired combined cycle unit since it is not feasible to construct a coal unit by then. Results indicate that natural gas prices would need to increase throughout the planning period by approximately 30% over those shown in Appendix A, Table 3 before a coal unit becomes economical over a natural gas unit in 2018 as the second unit to be built in the planning period.

Break Even Analysis: Coal Unit Capital Cost

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 as the second unit to be built in the planning period. Results indicate that coal capital costs would need to decrease by approximately 30% before being selected as the 2018 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 3x1 combined cycle units to be constructed in 2016 and 2018, and 2025. This plan is supported by sensitivities regarding assumptions related to the load forecast and environmental regulations and breakeven analyses regarding natural gas prices and coal unit construction costs. In all of the sensitivities, the optimal expansion plan called for the construction of a 3x1 combined cycle unit in 2016 or 2017 plus at least one additional combined cycle unit before 2025.

Considering all options reviewed, this study recommends that the base generation expansion strategy of the Companies be that shown in Plan "A". The Companies will continue to develop the least cost strategy to meet future load requirements by analyzing the economics of various configurations of combined cycle units, monitoring the development of environmental regulations, evaluating the potential for retiring existing units, and reviewing purchased power as an option to delay generation construction.

Appendix A

System Data

The Strategist® computer program is used to simulate the Companies' generating system. The model simulates the dispatch of the Companies' generating units and purchases to serve load while simultaneously maintaining reserve margin requirements. The following sections detail the information used to model Companies' generating systems.

General Data Items

- Base year: 2010
- Study period: 2011 to 2025
- The present value of revenue requirements is calculated by discounting nominal annual revenue requirements for 2011 through 2040 to the base year using a constant discount rate.
- Financial parameters:
    - Discount rate: 6.71%
    - Capital costs escalation rate: 2.5%
    - O&M costs escalation rate: 2%
    - Combined federal and state income tax rate: 38.9%
- Unserved energy cost is $14,970 per MWh (2010 dollars) based on a study provided by Astrape as discussed in the reserve margin study titled *LG&E and KU 2011 Reserve Margin Study* (April 2011).

- Load Forecast: The base load forecast and the high and low sensitivities are based on the LG&E and KU Energy and Demand Forecast data for 2011-2040 contained in Section 7 of Volume I. The load forecasts include the effects of DSM programs. See Appendix A, Table 1.
- Unit Retirements: The base assumption reflects the retirements in 2016 of Cane Run 4, 5, and 6, Green River 3 and 4, and Tyrone 3 that are anticipated as a result of proposed environmental regulations. The operating life of all other existing units is assumed to be beyond the end of the study period.

KU/LG&E Unit Data:

- Capacity: See Appendix A, Table 2.
- Equivalent Forced Outage Rate ("EFOR"): See Appendix A, Table 2. The unit forced outage rates ("FORs") were developed based on benchmark averages for the top quartile. FORs have been increased by inclusion of maintenance outage hours to better reflect actual unit availability. The modeled EFOR is the sum of FOR and the maintenance outage rate.
- Heat Rate: See Appendix A, Table 2.
- Fuel Costs: The fuel price forecast was developed in 2010 and is shown in Appendix A, Table 3.
- Maintenance inputs were determined by reviewing the Companies' projected maintenance as of January 2011. Planned outages are scheduled to optimize reserves and reliability over all months of each year.

- Purchases: OVEC provided a projection of available capacity for 2010-2014 which incorporates seasonal ratings, capacity derates, planned maintenance, and forced outage rates. The monthly capacity levels for 2014 were assumed to continue indefinitely. In addition, OVEC provided a forecast of expected demand charges (including capital improvements, debt costs, operating, and administrative costs) and energy charges (including fuel, emissions allowances, emission control reagents, and coal handling). See Appendix A, Table 4 for annual details.

Table 1 - 2011 Expansion Plan Appendix A
Combined Company Load Forecasts: Peak (MW) /Annual Energy (GWh)

	Base Forecast		High Forecast		Low Forecast	
Year	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)
2011	6,757	35,782	7,011	37,092	6,503	34,471
2012	6,821	36,251	7,084	37,607	6,559	34,894
2013	6,915	36,720	7,180	38,101	6,650	35,339
2014	6,976	37,036	7,246	38,441	6,706	35,632
2015	7,059	37,515	7,333	38,940	6,785	36,091
2016	7,070	37,963	7,346	39,413	6,793	36,513
2017	7,135	38,340	7,416	39,813	6,854	36,867
2018	7,234	38,850	7,519	40,342	6,949	37,357
2019	7,393	39,488	7,684	41,001	7,103	37,974
2020	7,546	40,140	7,843	41,679	7,250	38,602
2021	7,616	40,685	7,916	42,248	7,316	39,121
2022	7,704	41,322	8,006	42,906	7,401	39,737
2023	7,819	41,896	8,126	43,505	7,512	40,287
2024	8,008	42,624	8,321	44,254	7,695	40,993
2025	8,156	43,268	8,476	44,927	7,837	41,610

Forecasts reflect effects of interruptible/CSR and DSM.
Peaks are combined company summer coincident peaks.

Table 2 - 2011 Expansion Plan Appendix A
Louisville Gas and Electric / Kentucky Utilities Generator Data (2011)

Unit	Installed Year	Summer Rating (MW)	EFOR %	Avg Heat Rate at Max Load (MMBtu/MWh)
Brown 1	1957	106	[redacted]	
Brown 2	1963	166		
Brown 3	1971	411		
Brown 5	2001	122		
Brown 6	1999	146		
Brown 7	1999	146		
Brown 8	1995	121		
Brown 9	1994	121		
Brown 10	1995	121		
Brown 11	1996	121		
Ghent 1	1974	493		
Ghent 2	1977	490		
Ghent 3	1981	454		
Ghent 4	1984	487		
Green River 3	1954	68		
Green River 4	1959	95		
Tyrone 3	1953	71		
Dix 1-3	1925	26		
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 2 (75%)	2011	549		
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	52		

Table 3 - 2011 Expansion Plan Appendix A
Louisville Gas and Electric/ Kentucky Utilities Fuel Costs ($/MMBtu)

Year	Brown Units 1-3	Gr River Units 3-4	Tyrone Unit 3	Ghent Units 1-4	Cane Run Units 4-6	Mill Creek Units 1-4	Trimble High SO2	PRB	Oil	Gas *	Haefling Units 1-3 Gas*
2011	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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

Table 4 - 2011 Expansion Plan Appendix A
Kentucky Utilities/Louisville Gas and Electric
OVEC Purchase (2010 $)

Year	Capacity During Peak Month (MW	Demand Cost $ million	Energy Cost $/MWh
2011	155	[redacted]	[redacted]
2012	154	[redacted]	[redacted]
2013	152	[redacted]	[redacted]
2014	152	[redacted]	[redacted]
2015	152	[redacted]	[redacted]
2016	152	[redacted]	[redacted]
2017	152	[redacted]	[redacted]
2018	152	[redacted]	[redacted]
2019	152	[redacted]	[redacted]
2020	152	[redacted]	[redacted]
2021	152	[redacted]	[redacted]
2022	152	[redacted]	[redacted]
2023	152	[redacted]	[redacted]
2024	152	[redacted]	[redacted]
2025	152	[redacted]	[redacted]

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