Kentucky Utilities Company
And
Louisville Gas & Electric Company

Analysis of Supply-Side Technology Alternatives

Prepared by

Generation Systems Planning

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

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EXECUTIVE SUMMARY

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

Black & Veatch supplied the Companies with the bulk of data used in this evaluation, which includes the following: descriptions for all technologies, detailed capital and operation and maintenance (O&M) cost estimates for all conventional technology alternatives, and detailed performance and emission results at ISO (59°F), 20°F, and 90°F at base load, partial load, and minimum load for all conventional technology alternatives. Non-conventional alternative data is not as detailed as the conventional alternative data, but contains all information important in performing a thorough evaluation. Other data used in the screening analysis was compiled via recent contracted studies from Burns & McDonnell, Cummins & Barnard, Voith Siemens, and W.V. Hydro, Inc.

Forty-seven technology alternatives were screened through a levelized screening analysis in which total costs were calculated for each alternative, at various levels of utilization, over a 30-year period and levelized to reflect uniform payment streams in each year. This method tends to be more forward-looking than other methods since it evaluates the economics of owning and operating a unit over a multi-year period. Levelized costs of each alternative, at varying capacity factors, are then compared and the least-cost technologies for capacity factor increments throughout the planning period are determined. The screening analysis considers three sensitivity variables: capital cost, heat rate, and fuel cost. Environmental costs (emissions) pertaining to nitrogen oxides (NO_x), sulfur dioxide (SO_2), and carbon dioxide (CO_2) are included in the analysis in several ways. The costs associated with NO_x emissions are incorporated in the base case as an adder to the variable O&M cost for the coal-fired technologies and in the fuel cost for all other applicable technologies. Also, environmental cost implications regarding SO_2 emissions are included in the base case analysis and accounted for as a fuel adder. Although there remains no current regulation for the emission of CO_2, the impact of potential emission regulations is included as the alternative case to the base analysis.

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

Table 1
Alternatives for Further Consideration

Trimble County 2 Supercritical Pulverized Coal Unit
Supercritical Pulverized Coal, High Sulfur 750 MW Unit
WV Hydro – Purchase Power Agreement
Ohio Falls Units 9 and 10
GE 2x1 7FA Combined Cycle Combustion Turbine
GE 7FA Simple Cycle Combustion Turbine

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INTRODUCTION

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

DATA SOURCES

Black & Veatch gathered information on several technology alternatives and submitted to the Companies a final examination in September 2004. The document included technical descriptions for all technologies, detailed capital costs, performance expectations, emission rates, and O&M costs for conventional generation alternatives (pulverized coal, simple and combined cycle combustion turbines). The non-conventional technologies (renewable energy, waste-to-energy, advanced coal and combustion turbines, and energy storage systems) have the same data as the conventional alternatives but in less detail due to their maturity and infrequent use as generation alternatives. Additional data gathered consists of the Companies' analysis and recently contracted studies. All technologies utilized in the screening analysis are found in Exhibit 1.

TECHNOLOGIES SCREENED

Coal-Fueled Technologies

1. Pulverized Coal

Conventional pulverized coal-fired units supply most of the Companies' present generation needs. State and federal emissions control requirements state that coal-fired units must control air emissions, water discharge, and solid waste disposal. Examples of air emission requirements include the 1979 New Source Performance Standards (NSPS) and the Prevention of Significant Deterioration (PSD) programs requiring new coal-fired units to use flue gas desulfurization (FGD) systems to control SO_2 emissions, selective or selective non-catalytic reduction (SCR/SNCR) to control NO_x emissions, and either electrostatic precipitators (ESPs) or fabric filters to control particulate emissions. Additional requirements came from the Clean Air Act Amendments (CAAA) of 1990 requiring operators of electric power plants to reduce emissions of SO_2 and NO_x (Phase II became effective in 2000) in the NO_x SIP Call, requiring further reductions of NO_x during the months of May through September, beginning in 2004.

Conventional coal-fired generation is a mature technology used throughout the utility industry. Pulverized coal units have the advantage of utilizing a proven technology with a very high reliability level. Additionally, pulverized coal units are easy to operate and maintain. Typically, coal-fired units have high capital costs, long construction periods (up to 10 years) and are economical for baseload duty. Coal-fired unit cycling and load following is detrimental to the economics of coal generation and increases maintenance requirements. The newer pulverized coal boilers can be designed to operate at supercritical steam pressures up to 4,500 psig, compared to

2,400 psig for conventional (subcritical) boiler designs, improving the efficiency by 10 percent (to around 45 percent overall). This evaluation contains seven "Greenfield" pulverized coal options, which include three subcritical units varying from 250 MW to 500 MW and four supercritical units ranging in size from 500 MW to 750 MW. Of the seven coal options, three of these were considered high sulfur (4.5 percent or more sulfur content) and included both a subcritical and a supercritical unit of 500 MW size, and a 750 MW supercritical unit.

2. *Circulating Fluidized Bed Combustion*

Fluidized bed combustion (FBC) boilers with steam turbine generators have been widely used in the United States, Europe, and Japan since the mid-1980s for independent power/cogeneration and utility power. There are two types of FBC: Circulating FBC (CFBC) and Pressurized FBC (PFBC).

CFBC involves injecting a portion of the combustion air through the bottom of a water-cooled bed consisting of fuel, limestone, and ash. This upwardly flowing air causes the layers to mix in a turbulent environment and to behave in a fluid-like manner. CFBC technology allows units to burn a diversity of low-grade coal and non-coal fuels in addition to high-grade coals without costly control equipment such as FGDs and SCRs to satisfy environmental emission limitations. The low combustion temperatures reduce thermal NO_x formation while the ability to introduce limestone directly into the furnace controls SO_2 emissions.

CFBC has matured to where it is now comparable to most modern solid fuel fired plants, including conventional, pulverized coal units. Both a 250-MW unit and 500-MW unit were included in this study, each of which was assumed to have a capacity factor of 100 percent.

3. Pressurized Fluidized Bed Combustion

Pressurized Fluidized Bed Combustion (PFBC) plants have been developed to improve coal energy conversion efficiency and are similar to CFBC plants with the exception that boiler operation occurs under pressure at 10 to 15 atmospheres. PFBC boilers accomplish high-combustion efficiency and excellent sulfur removal during the coal combustion process.

Advantages of PFBC operation include higher thermal efficiency (up to 47 percent) resulting from the unit's modular makeup, and smaller boiler requirements. PFBC operation in combined cycle further improves efficiency because the PFBC exhaust drives both the compressor and gas turbine generator. Heat recovery steam generators produce additional steam from the exhaust to augment the steam generated by the PFBC boiler itself.

PFBC is still in the developmental stage and is not considered to be a mature technology. Nevertheless, a 250-MW PFBC unit with a capacity factor of 70 percent was considered in this evaluation.

4. Integrated Gasification Combined Cycle

Integrated Gasification Combined Cycle (IGCC) is not as commercially mature and more complex than the previously discussed coal technologies. Coal is dried by circulating hot gas through a pulverizer. The dried, pulverized coal is partially oxidized in the gasifier to produce raw synthetic gas (syngas). This raw syngas is treated to remove particulates, ammonia, and sulfur prior to combustion. The clean syngas is diluted with nitrogen and water vapor which enhances unit efficiency and limits NO_x emissions to less than 25 parts per million (ppm) in the flue gas. Advantages of this process are saleable byproducts of flyash, slag, and sulfur that result from the gasification.

The 250-MW unit studied is a single train with one air separation unit, one Shell coal gasifier and a 1x1 combined cycle with a GE 7FA combustion turbine. The 500-MW unit included in the study has two trains, each of which would contain all components listed for the 250-MW unit. A capacity factor of 85 percent was assumed for both units.

Liquid/Gas-Fueled Technologies

1. Reciprocating Engine

Reciprocating engines have been used for a number of years to provide primary and backup sources of electrical generation for power, industrial, and many other applications. Medium speed engines, operating at less than 1,000 rpm, are typically used for power generation because of higher efficiencies and lower O&M costs. Advantages of reciprocating engines are static heat rates from 50 to 100 percent load, excellent load-following characteristics, guaranteed emission rates maintained at operating levels down to 25 percent load, and typical startup times for larger reciprocating engines of only 15 minutes. Disadvantages of reciprocating engines include high uncontrolled air pollutant emission rates and unproven emission control technologies.

Two types of reciprocating engines were included in this study: spark ignition engines and compression ignition engines. Spark ignition engines operate on gaseous fuel such as natural gas, propane, or waste gases from industrial processes while compression ignition engines operate on liquid fuels such as diesel. The study includes a 5-MW spark ignition engine and a 10-MW compression ignition engine. A capacity factor of 50 percent was used for each type of engine.

2. Simple Cycle Combustion Turbines

Simple cycle combustion turbines generate power by compressing ambient air and then heating the pressurized air (to at least 2000°F) 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. Efficiencies of a simple cycle combustion turbine are generally 30 to 35 percent.

Combustion turbines 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, simple cycle units 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 high (compared to coal) price of oil or natural gas making the combustion turbine an economical option for peaking duty. The primary drawback of simple cycle technology is the higher per MWH variable cost compared with coal or combined cycle units. Therefore, simple cycle combustion turbines are often economically beneficial for peaking service, not for either baseload or intermediate usage.

The screening analysis includes three sizes of simple cycle combustion turbines (31, 73, and 148 MW at 90°F) with capacity factors of 100 percent assumed for each iteration.

3. *Combined Cycle Combustion Turbines*

Combined Cycle Combustion Turbine (CCCT) plants consist of one or two combustion turbine unit(s), steam turbine units, and a heat recovery steam generator(s) (HRSG). High-pressure steam is produced when hot exhaust gases from combustion turbines are passed through the HRSG. The steam produced in the HRSG 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, quick construction, and stable, modest natural gas prices. The key advantages of the CCCT, when compared with reciprocating engines and simple cycle combustion turbines, 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, increase in overall staffing requirements due to added plant complexity, and volatility of natural gas prices.

Several combined cycle configurations were evaluated in this study ranging in capacity from 118.5 MW to 483.9 MW at 90°F. A capacity factor of 100 percent was used for each combined cycle configuration evaluated.

Along with the conventional GE and Westinghouse machines currently available, three other advanced combined cycle technologies (humid air turbine, Kalina Cycle, Cheng Cycle) were also included. These technologies are generally considered developmental, but offer significant potential for efficiency improvements over conventional technologies.

The humid air turbine (HAT) cycle utilizes a natural gas-fired intercooled regenerative cycle with a saturator that adds considerable moisture to the compressor discharge air (such that the combustor inlet flow contains 20 to 40 percent water vapor). The turbine exhaust is further heated by a recuperator (using turbine exhaust) before being sent to the combustor. Water vapor adds to the turbine output while intercooling reduces the compressor work requirement. The heat addition in the recuperator reduces the amount of fuel heat input required. The HAT reviewed herein is rated at 450 MW and has a capacity factor of 70 percent.

The Kalina Cycle combustion turbine involves injecting ammonia into the vapor side of the cycle. 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 275 MW with a capacity factor of 70 percent.

The Cheng Cycle combustion turbine, similar to the steam-injected gas turbine, increases efficiency over the gas turbine cycle by injecting large volumes of steam into the combustor and/or turbine section. The basic Cheng Cycle components include a compressor, combustor, turbine, generator, and HRSG. The HRSG provides injection and process steam to the combustor. The amount of steam injection is limited by the load rating of the turbine blades. The Cheng Cycle combustion turbine contained in this analysis is rated at 140 MW and its capacity factor is 70 percent.

Even though the HAT, Kalina Cycle, and Cheng Cycle combustion turbines have been analyzed herein, these technologies are still considered developmental and only the Kalina Cycle has any viable and operating turbines (under 5 MWs each) in existence at this time.

4. Microturbines

Microturbines are similar in concept to the large gas turbines used as conventional generation alternatives. Microturbines typically offer the output ranges from 25 to 60 kW and consists of a compressor, turbine, generator, and power conditioning equipment, which are all housed in a single unit about the size of a refrigerator. Microturbines can operate on a wide range of fuels, including natural gas, ethanol, propane, biogas, and other renewable fuels. Design enhancements such as catalytic combustion and air bearings further reduce already low emissions and maintenance requirements.

The baseload and peaking microturbines considered in this evaluation are each rated 30 kW, and at that size are suitable to supply load to individual customers only. The capacity factor used for the evaluation of microturbines was 10 percent.

5. *Fuel Cell*

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

Each cell consists of an anode, cathode, and an electrolyte. Fuel cells oxidize a fuel at the anode, which releases electrons into an electrical circuit. Simultaneously, water and heat are produced at either the anode or cathode depending on the electrolyte used. Fuel cells, unlike batteries, do not consume their electrodes with use, but only the fuel and oxygen (in the air) supplied to them.

There are four major fuel cell types in development: phosphoric acid, molten carbonate, solid oxide, and proton exchange membrane. The most mature of the four is the phosphoric acid fuel cell (PAFC). PAFC plants range from 200 kW to 11 MW in size and have efficiencies on the order of 40 percent. Since fuel cells operate at constant temperature and pressure regardless of load, the thermal energy liberated by the electrochemical reaction can be used in thermal bottoming cycles or for cogeneration of steam. Efficiencies can approach almost 90 percent when cogeneration is utilized.

In addition to the low operating costs and potential for high efficiencies, the fuel cells are also considered because of their environmental benefits. Typically the commercial stationary fuel cell plants are fueled by natural gas. The only emissions from the natural gas fuel cells are carbon dioxide and water.

A fuel cell size of 200 kW with a 50 percent capacity factor was considered in this screening analysis.

Renewable Resource Technologies

1. Wind Energy

Wind is converted to power via a rotating turbine and generator. Utility-scale wind systems consist of multiple wind turbines ranging in size from 100 kW to 2 MW. A complete wind energy system contains several wind turbines and has a total rating between 5 MW and 300 MW. Capacity factors range from 25 to 40 percent and depend upon the wind regime in the area. Therefore, wind energy is considered an intermediate load technology that cannot be relied upon as firm capacity. Wind power is rated on a scale of Class 1 to Class 7, with Class 7 representing an area with substantial wind speeds (20 to 27 mph). A Class 3 rating or above is needed in order for it to be considered economically feasible. The Companies' service area experiences wind ratings of Class 1 and 2, which restricts the economic feasibility of this technology.

Despite the obvious limitations, a 50 MW wind system with a 33 percent capacity factor was considered for this evaluation.

2. Solar

Solar energy conversion technologies capture the sun's energy and converts it to thermal energy (solar thermal) or electrical energy (solar photovoltaic), which drives the device (turbine, generator, or heat engine) for electrical generation. Sunlight is concentrated with mirrors or lenses to achieve the high temperatures needed for solar thermal power systems. 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 although most of these installations are less than 50 kW. Current grid-connected solar photovoltaic systems are generally below 200 kW with capacity factors of around 20 percent.

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. In order of increasing efficiencies, the main solar photovoltaic cells consist of thin film, polycrystalline silicon, single-crystal silicon, and gallium arsenide. Several support structures (which improve cells' efficiency) are also available such as fixed-tilt, one-axis tracking, and two-axis tracking. The advantages of solar photovoltaic technologies are that they require no fuel, produce no emissions, are highly reliable, and have low O&M cost. The main disadvantages of solar photovoltaic technologies are high capital cost, low production capacity, and large amounts of required land.

To achieve desirable economic returns, high capacity factors must be attainable. According to research reported by Black & Veatch, the Companies are located in an area where solar thermal systems would not be considered viable so the likelihood of achieving high capacity factors is not great.

In spite of the potentially unworkable nature of this source, each of the five solar options was considered in the evaluation. The evaluated options have ratings ranging from 1.2 MW to 200 MW with capacity factors between 20 and 70 percent (intermediate load).

3. *Biomass*

Electrical generation via biomass is the second most prolific source of renewable energy generation, next to hydro. Currently, wood and its by-products are the primary biomass resource used for energy production, but agricultural residues and yard wastes are also utilized. Biomass power plant sizes are typically less than 50 MW, due to the dispersed nature of the feedstock and the large quantities of fuel required. These facilities have capacity factors between 70 and 90 percent. Efficiencies of biomass plants are lower when compared to modern coal units due to lower heating values and higher moisture contents in the fuel. Resources economically located within a deliverable area limit the plant size. The most efficient and economically attractive options for electrical generation from biomass resources include co-fired projects which would only offset fossil fuel consumption. Additionally, there are several concerns about the negative impact of co-firing on plant operations, including impacts on capacity, boiler performance, and premature poisoning of air pollution control equipment.

The biomass alternative included in this evaluation is a co-fired facility with a 27.5 MW output and a capacity factor of 80 percent.

4. Geothermal

Geothermal power plants use heat from the earth to generate steam and drive turbine generators for the production of electricity. The production of geothermal energy in the US currently ranks third in renewable energy sources, following hydroelectric and biomass. There are three types of geothermal power conversion systems in common use, including dry steam, flash steam, and binary cycle steam. Capital costs of geothermal facilities can vary widely as the drilling of individual wells can cost as much as four million dollars, and the number of wells drilled depends on the success of finding the resource. Variable O&M costs include the replacement of production wells.

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 this area. However, the Companies' service territory has a sufficient amount of low-temperature resources to be suitable for heat pump.

A 30 MW binary cycle unit with an 80 percent capacity factor is included in this study.

5. Hydroelectric

Hydroelectric generation is considered a mature technology with several factors, such as unit sizing and capital costs that can vary significantly. New large hydroelectric plant installation can be complicated by environmental concerns and long construction periods. However, a smaller hydro project could be developed in the range of 100 kW to 30 MW. The hydroelectric unit considered for this evaluation is rated at 30 MW with an expected capacity factor ranging from 40 to 60 percent. Construction of such a facility was considered for a Greenfield location. Additionally, expansion at LG&E's existing Ohio Falls Station was screened, and is covered separately under the section titled "***Other Technologies***".

6. Waste to Energy

Waste-to-energy (WTE) technologies can utilize a variety of refuse types to produce electricity. The technologies considered in this evaluation consist of municipal solid waste (MSW), refuse-derived fuel (RDF), landfill gas (LFG), and tire-derived fuel (TDF). The economics associated with WTE facilities are difficult to determine, as costs are dependent upon transportation, processing, and tipping fees for the particular site. Values contained within this analysis are representative of technologies at generic sites.

Converting 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 500 to 3,000 tons of waste per day, which is produced by 200,000 to 1,200,000 residents respectively. Plant capacities are generally less than 50 MW with a capacity factor between 60 and 80 percent. Mass burning of MSW was once seen as an environmentally and economically sound alternative for dealing with the shrinking landfill space in the United States. However, environmental concerns over pollutants, high capital costs, and public opposition make it doubtful that new WTE facilities utilizing MSW will be constructed in the near future.

In spite of the apparent difficulties associated with burned MSW for generation of energy, a 7-MW unit with a 70 percent capacity factor was considered in this evaluation.

RDF is an evolution of MSW technology in which the waste is sorted and processed into fluff or pellets. It is preferred in many refuse-to-energy applications due to its ability to be combusted with technologies traditionally used for coal. Combustion temperatures for MSW and RDF must be kept lower than 800°F to minimize boiler tube degradation caused by chlorine compounds in the flue gas. Unit size, capacity factors, and environmental concerns for RDF are similar to MSW characteristics. As a result, a 7-MW unit fueled by RDF with a capacity factor of 70 percent was also considered in the evaluation process.

LFG is a valuable energy source that can be utilized in several applications, including power production, and is considered to be a mature WTE technology. LFG is produced by the decomposition of wastes stored in landfills where it is collected and piped from wells, filtered, and then compressed. Although gas is produced when decomposition begins within a landfill, it may be several years before there is an adequate supply of gas to fuel an electric generator. Later, as the site ages, gas production (as well as the quality of the gas) declines to the point at which power generation is no longer economic. In the case of a typical well-engineered and well-operated landfill, gas may be produced for as many as 50 to 100 years, but electricity production may be economically feasible for only 10 to 15 years, Power can be generated via a combustion turbine, but internal combustion engines are most commonly used and, even then, such facilities are generally sized at less than 10 MWs.

Black & Veatch indicated Kentucky has several new landfills with long life span expectancy, making it possible to locate a landfill with gas collection in place that would need only the prime movers and gas treatment equipment added for power generation. Therefore, the Companies' specific application assumes existing gas collection and minimal interconnection and transmission costs. This evaluation considers a 5-MW unit with a capacity factor of 80 percent.

TDFs are attractive due to the high heating value, low ash and sulfur content, and low fuel cost. Two options exist concerning TDF: cogeneration and dedicated tire combustion. Co-firing of TDFs with coal or other fuels can be accomplished in some boiler types including cyclonic, fluidized bed, and stoker-fired units with minimal amounts of boiler modification.

Dedicated tire combustion systems are commercially available and are operating today. These operations have experienced several problems, largely resulting from the unique nature of tire based fuels and potential design issues. One such incident involved a massive, toxic tire pile fire in California in 1999. As a result of the fire, a dedicated tire burner has been forced out of business and the industry faces detailed scrutiny.

Additional points of concern complicate the potential use of TDF including the need to set up ancillary operations to process the tires and remove the steel belts and wire prior to combustion. Finally, the use of TDF could result in potential environmental complications related to emissions permitting and ash disposal.

Although new technologies are under development, commercial systems are not yet offered. Moreover, given the negative perception of the aforementioned fire and the uncertainties associated with TDF ash and emissions, securing the necessary permitting for either a dedicated tire burning facility or a co-fired system is expected to be very difficult. A final complicating factor is that the Companies have no boilers in their system that would be similar to any of the styles required to use TDFs.

Nevertheless, the TDF alternative included in this evaluation is a co-fired system and is rated at 50 MW with capacity factor of 70 percent.

Energy Storage Technologies

1. Pumped Hydro Energy Storage (PHES)

Central hydro energy storage 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. Environmental impacts from PHES can be significant if improperly sited and geologic conditions preclude many areas from consideration of this technology. Additionally, 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.

For the PHES unit used in this screening analysis, the nameplate rating corresponds to 500 MW. Pumped hydro is considered a viable option to serve intermediate load levels but the low capacity factor (13 percent in this evaluation) makes it difficult for this technology to compete with other peaking technologies.

2. Battery Energy Storage (BES)

With a BES unit, off-peak energy is used to charge a battery for use during peak periods.

A battery energy storage system consists of the battery, DC switchgear, AC/DC converter/charger, transformer, AC switchgear, and a building to house the components. During peak power demand periods, the battery system can discharge power to the utility system for approximately 4 to 5 hours and then recharge during non-peak hours. The overall efficiency of a BES system is approximately 71 percent from charge to discharge. In addition to high initial cost, a battery system will require replacement every 4 to 10 years, depending upon duty cycle. Only lead-acid systems are commercially available to the utility industry. However, research to develop higher performing and lower cost batteries such as sodium-sulfur and zinc-bromine batteries is underway.

The BES included in this analysis is rated at 5 MW and has a capacity factor of 20 percent.

3. Compressed Air Energy Storage (CAES)

CAES uses an electric motor-driven compressor to pressurize an underground cavern or reservoir with air during off-peak periods typically with power supplied by low cost base loaded units. During peak periods, the compressed air is heated and passed through a gas turbine expander to produce electrical power at an attractive heat rate ranging from 4,000 to 5,000 Btu/kWh. CAES facilities provide more electrical power to the grid than is utilized during cavern charging mode because of fuel that is supplied to the system during the energy generation mode. The necessary geology (including solution-mined reservoirs in salt, conventionally-mined reservoirs in salt or hard rock, and naturally occurring porous media reservoirs [also known as aquifers]) occurs across nearly 75 percent of the United States.

In spite of apparently conducive conditions throughout the United States, only one such system currently exists, though several more plants have been recently announced. Construction periods in excess of 24 months, are another potential limitation of this alternative.

A 500 MW CAES unit with a 25 percent capacity factor was used in this evaluation.

Other Technologies

1. Ohio Falls Expansion

Expansion of the Ohio Falls Station by the additions of Units 9 and 10 into existing empty bays was included as an option in the screening analysis. This expansion included two 209.2" diameter propeller units housed in an extension of the existing powerhouse. These units would rotate at 149 rpm and have a maximum turbine output of 16.8 MW (summer rating of 5 MW and dependant upon river flow) each. Based upon historical river flow, expected energy from the expansion units would be approximately 74 GWH annually. Therefore, the maximum capacity factor would be 25 percent. Estimated capital cost for Units 9 and 10 is $46.7 million combined. The Ohio Falls Station is considered a run-of-the-river facility where nature and the Army Corps of Engineers control the river flow. Therefore, the energy production of the facility can vary significantly and may not be available at the time of the Companies' peak needs.

The additions at the Ohio Falls Station were based upon information from a Voith Siemens Hydro (VSH) report from 2002 and escalated for current day dollars. However, there is the potential that these dollars were significantly underestimated, because that same year, VSH provided data for rehabilitating the existing eight units for the amount of $46M, as mentioned in the Companies' 2002 IRP filing. As stated in Section 6 of this filing, Voith Siemens has increased the projected cost of the eight-unit revitalization to $75.7M. The 65 percent increase in the estimated cost of the rehabilitation project far exceeds the projected rate of inflation and the factors contributing to the increase are also expected to complicate the installation of any new units at the facility. Therefore, the amount in this screening for Ohio Falls 9 and 10 is considered an extremely conservative estimate which has only been increased by inflation costs.

2. Trimble County Coal Unit

As mentioned in the Companies' last IRP, Burns & McDonnell performed a site-specific coal unit evaluation for the Trimble County facility as well as a detailed evaluation of the costs associated with the best technology and size identified. The results of the 2002 IRP verified Burns & McDonnell's results which concluded the 732 MW supercritical unit provided optimal results. Therefore, only one option at Trimble County (the 732 MW supercritical unit) has been evaluated in this screening for Trimble County Unit 2.

3. WV Hydro

W.V. Hydro, Inc. (WV Hydro) has proposed a power purchase agreement to the Companies' for a proposed power sale from three hydro projects. This project could be available beginning in year 2008 for approximately 30 years. The generation would come from the Smithland, Cannelton, and Meldahl hydro projects with annual proposed generation averaging 380 GWh each for a total annual proposed energy of 1140 GWh. The quoted prices are annual fixed O&M costs only and have been modeled as such in this screening analysis.

ANALYSIS OVERVIEW

The Companies screening analysis consists of 47 generation alternatives developed by Burns & McDonnell, Voith Siemens, Cummins & Barnard, WV Hydro and Black & Veatch. The screening process involves utilizing specific unit operating data such as unit ratings, heat rate, operation and maintenance expenses, and capacity factors to accurately assess lifetime costs associated with owning and operating each technology type and size.

Sensitivities are utilized to provide valuable information on how each technology will perform under various operating conditions. Some of the sensitivities contained in this analysis are based on variations in capital cost, technology operating efficiency (measured by heat rate), and fuel cost. Each of the previously mentioned sensitivities has three possible scenarios: base, low, and high, which results in 27 sensitivity combinations. The remaining sensitivity considered in the screening evaluation concerns emissions. The base case analysis includes costs associated with NO_x and SO_2 emissions. CO_2 emissions are a possibility in the future and an evaluation which considers NO_x, SO_2, and CO_2 emissions is included in this analysis as an alternative to the base case.

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

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

SENSITIVITY ANALYSIS

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

Two cases were analyzed in the screening analysis to evaluate the impact of environmental legislation. The emission sensitivity contained in this evaluation is the inclusion of CO_2 emissions (SO_2 and NO_x are part of the base case analysis). SO_2 and CO_2 emissions are included in fuel costs, where applicable, and NO_x emissions are included as a variable O&M expense ($/MWh).

The first case, referred to as the base case analysis, includes the impact that SO_2 and NO_x emissions can have on selecting technologies. Current Clean Air Act and NO_x SIP Call regulations limit the emission of SO_2 from certain generating facilities, and NO_x emissions. As discussed below, the cost adder for SO_2 is applied to the fuel utilized by the technology and emission cost adders for NO_x are applied to the variable O&M expense for all applicable technologies. SO_2 emission costs are based upon the Cantor-Fitzgerald allowances prices and estimates from 2004 through 2010, with prices thereafter assumed to escalate by two percent annually.

A 2004 SO_2 allowance price of $172/ton and a NO_x allowance price of $3125/ton were the starting allowance values used in the analyses (source: Cantor-Fitzgerald).

The second case evaluates potential additional cost of CO_2 emissions in addition to costs associated with SO_2 and NO_x emissions. Rising concentrations of greenhouse gases may be responsible for undesirable climate changes, and legislation to restrict CO_2 emissions (a greenhouse gas) has been *proposed.* One proposed solution is the implementation of a carbon tax which could impact the least-cost options resulting from this screening analysis.

The magnitude of proposed carbon tax varies significantly. A current expectation for a carbon tax is in the range of $10 to $40 per ton of carbon emitted and is based on external analysis. As with the SO_2 adder, the carbon cost adder was added to the fuel cost of the technology as discussed below.

1. Capital Cost Sensitivity

Black & Veatch has two technology ratings that can be used to adjust the capital cost for each technology type. The technologies are classified as either conventional or non-conventional generating alternatives and take into account the maturity level of the technologies. Conventional generation alternatives are currently available, widely-used and proven technologies whereas non-conventional generation alternatives are still in development or have not been widely implemented or operated. Both ratings take into consideration the issue of uncertainty in cost and performance data. From there, the capital costs supplied by Black & Veatch for each technology size are assigned a base, low, and high value. The capital costs for conventional alternatives varied by ± 10 percent (high and low) whereas those for non-conventional alternatives varied by ± 20 percent (high and low).

Capital cost ranges for generating alternatives not supplied by Black & Veatch were based upon the Companies' confidence in the supplied estimates and maturity levels of each technology. A ± 10 percent variance in capital cost was applied to the Trimble County coal option and Ohio Falls Hydro Units 9 and 10.

2. Technology Operating Efficiency

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

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 either used or could be used at existing plants. Sensitivity fuel forecasts are then developed depicting high and low fuel cost scenarios. Base coal price forecasts are adjusted by data received from Global Insight for the high and low fuel cost sensitivities. Representative fuel costs for each technology screened were obtained from the base and sensitivity fuel forecasts and are shown in Exhibit 2(a).

As previously described, in an effort to include the impact of SO_2 emissions in the screening study, an adder was applied to the coal prices shown in Exhibit 2(a). The adder represents, on a cents per MBtu basis, the annual cost of SO_2 allowances. Only technologies whose primary fuel is coal have the adder. The sulfur content of the Low and High Fuel Forecasts was assumed to be equal to that of the Base Fuel Forecast. Therefore, once the adder was determined for the Base Fuel Forecast, it could be applied to both the Low and High Forecasts without any further adjustments. Exhibit 2(b) details the calculation of the SO_2 adder.

Inclusion of the SO_2 adder increases the fuel cost from 0.5 to 6 Cents per MBtu depending on the year and sulfur content. The small impact of the SO_2 adder is due to the fact that all technologies being considered in the analysis have very low SO_2 emissions resulting from either pre/post combustion removal processes. Addition of the SO_2 adder to the Base, Low and High Fuel Forecasts results in the fuel costs used in this analysis. The specific fuels utilized by each technology evaluated in this analysis are identified in Exhibit 2(c).

4. *CO_2 Emissions*

An alternative to the base case was conducted to evaluate the impact of carbon emissions. Carbon emission costs were added to the fuel costs of each technology affected by a carbon tax in a similar manner of that for SO_2. The carbon tax utilized in this evaluation is $10/ton, with sensitivities of $20/ton, and $40/ton. These rates are based on external analysis and *proposed* legislation. Technologies utilizing coal or natural gas are the only technologies in this evaluation to which the carbon tax is applicable. Biomass facilities were assumed to have a net zero CO_2 emission rate. The cost of this tax is quantified on a cents per MBtu basis. Bituminous coal prices are increased by $0.29 per MBtu while natural gas prices are increased by $0.16 per MBtu. These estimates were assumed to represent 2004 costs and no escalation was applied to these values throughout the 30 years included within this study.

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. A separate analysis was performed utilizing the $10 per ton CO_2 cost adder as discussed above. This analysis produced an additional 27 combination of cases to be evaluated.

Exhibit 3 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 90°F. All technologies evaluated in this analysis are shown in this exhibit.

SCREENING ANALYSIS

The least-cost operation of the technologies presented in this study occurs over significantly different capacity factors. Therefore, an analysis that compares the total cost for each technology as a function of capacity factor is required. As previously discussed, the cost data for all technologies in this analysis originate from Black & Veatch or were derived based on information and/or cost estimates received by the Companies.

Based on the results of economic analysis performed in the Companies' 2002 IRP Supply-Side Screening report and using recommendations prepared by Burns & McDonnell, the Companies have selected design parameters for the Trimble County Unit 2. The construction of a 732 MW supercritical pulverized coal unit was determined to represent the most economically viable option and it was evaluated using the same considerations as the other technologies evaluated in the screening process. Beside the Trimble County Unit 2 option, there were several other coal options in the screening analysis for future coal units. Next, each technology listed in Exhibit 3, regardless of viability or technical maturity, was evaluated over a 30-year planning period in all 27 cases for both the Base Case Analysis and the Alternative Analysis with CO_2 Impact.

No technologies were excluded from the screening analysis based solely on technical maturity, practicality, or feasibility. For example, even though climatic information for Kentucky suggests wind turbine technology would not be a practical supply-side option in Kentucky, wind turbine technology was not excluded from the analysis.

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 a 20 percent capacity factor based on design characteristics of the technologies supplied by Black & Veatch. A capacity factor calculation is included below based on the battery energy storage with an expected use of five hours per day and five days per week (during peak hours).

$$[(5 \text{ hrs/day} \times 5 \text{ days/wk} \times 52 \text{ wks/yr}) / 8760 \text{ hrs/yr}] = 14.8\% \approx 15\%$$

A capacity factor of 20 percent will be used to fully capture the technologies' performance in the 10 to 20 percent capacity factor range.

In general, conditions in Kentucky are not conducive to the use of renewable resources which are dependent on the sun and wind for power generation. These climatological disadvantages are reflected by the low capacity factors associated with these technologies which ranged from 20 to 70 percent. Six renewable resources were also limited by their capacity factors. Wind energy was limited to 30 percent. The five solar technologies (thermal) are expected to perform from 20 percent capacity factor for photovoltaic up to 70 percent capacity factor for a solar chimney. For solar power, most of the installations have been in the western part of the United States where solar radiation levels enable economic installation. For the Midwest, solar radiation levels are not ideal for solar technology. Most of the wind turbine sites are located in California with capacity factors in the 20-35 percent range. Kentucky wind speeds are significantly lower than those in California; therefore, a maximum capacity factor of 30 percent for wind technologies is conservative.

The two hydro options, one supplied by Black & Veatch as part of the supply side screening alternatives, and expansion of the Ohio Falls Station were limited to 50 percent and 30 percent capacity factors, respectively. These limitations were based on the projected energy received from these run-of-the river projects.

There were two peaking generating alternatives. The baseload microturbine has a capacity factor on the order of 70 percent whereas the peaking microturbine is limited to a 10 percent capacity factor.

LEVELIZED SCREENING METHODOLOGY AND RESULTS

1. Base Analysis with SO_2 and NO_x Impact

A 30-year levelized cost methodology was utilized in the base analysis. An annual total cost, comprised of capital, fixed O&M, variable O&M, fuel and other costs, is determined for each technology over a range of capacity factors from 0-100 percent in 10 percent increments. For each technology, levelized costs in $/kW at varying capacity factors were then 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. A non-levelized analysis considers costs of owning and operating generating units for only a single year. Comparison of cost over the life of each technology is more accurate because of differing annual escalation rates for fuel, O&M and capital associated with determining the total annual cost of each technology. 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 the Adjusted 30-year Levelization Factor (Adj. L_N) for the Base Fuel Forecast and other miscellaneous information referred to within the equations of Exhibit 4. Adjusted L_Ns for the Low and High Fuel Forecasts can be determined in a similar manner.

Using the equations of Exhibit 4 and data contained within Exhibits 2(a)-2(d), Exhibit 3, and Exhibit 5, the total 30-year levelized cost ($/kW-yr in 2004 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 below in Table 2.

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

Trimble County 2 - 732 MW Supercritical Pulverized Coal
WV Hydro

Exhibit 7 is a graphical representation of the technologies of these two cases with base emissions, which appear as a least cost generation alternative. The intersection of the lines with the vertical axis represents the fixed expenditures (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) that increase in direct proportion to energy produced.

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

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

Trimble County 2 - 732 MW Supercritical Pulverized Coal
Supercritical Pulverized Coal – 750 MW
Supercritical Pulverized Coal, High Sulfur – 750 MW
Ohio Falls 9 and 10 – 10 MW
Humid Air Turbine Cycle CT – 450 MW
Simple Cycle GE 7FA CT – 148 MW
Combined Cycle 2x1 GE 7FA CT – 484 MW
TDF Multi-Fuel CFB (10% Co-fire) – 50 MW
Wind Energy Conversion – 50 MW
Subcritical Pulverized Coal, High Sulfur – 500 MW

The 11 different technology types and sizes specified between Tables 3 and 4 are those, at first glance, that appear to deserve consideration in detailed computer models. However, this list must be examined further before selecting technologies to pass onto the detailed analysis. As previously stated, there are 891 "opportunities" for each technology to be identified as one of the first three least cost options. Table 4, below, identifies how many occurrences a technology appeared as either first, second, or third least cost options over any capacity factor range. All technologies not identified within Table 4 failed to appear as one of the top three least-cost options in any of the cases identified.

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

# Occurences				
1st	**2nd**	**3rd**	**# Occur**	**Technology Name**
135	54	46	235	TC2 732 MW Supercritical Pulverized Coal
162	0	0	162	WV Hydro
0	48	107	155	Supercritical Pulverized Coal - 750 MW
0	82	72	154	Supercritical Pulverized Coal, High Sulfur - 750 MW
0	54	13	67	Ohio Falls 9 and 10
0	27	18	45	Humid Air Turbine Cycle CT - 450 MW
0	27	0	27	Simple Cycle GE 7FA CT - 148 MW
0	0	23	23	Combined Cycle 2x1 GE 7FA CT - 484 MW
0	5	6	11	TDF Multi-Fuel CFB (10% Co-fire) - 50 MW
0	0	8	8	Wind Energy Conversion - 50 MW
0	0	4	4	Subcritical Pulverized Coal, High Sulfur - 500 MW

Table 4 shows that the 732 MW Trimble County Pulverized Coal unit was selected 235 times as the first, second, or third least-cost technology while the conversion to wind energy was selected only eight times. Table 4 provides a good starting point for further reducing the list of technologies identified in Tables 2 and 3.

The wind energy technologies for example, appeared in the levelized analysis as one of the least-costly technologies, but Black & Veatch states that in order for wind technologies to be economically feasible, a wind class rating of at least 3 is necessary for the area. The Companies' service area consists of Class 1 and 2 wind ratings which would result in a very low capacity factor; therefore wind turbine technology may be justifiably removed from the initial list of 11 technologies.

A review of Table 4 reveals that four different coal-fired technologies have been identified among the 11 least cost technologies. They are Trimble County 732 MW supercritical unit, a 750 MW supercritical pulverized coal unit, a 750 MW supercritical high-sulfur pulverized coal unit, and a 500 MW subcritical high-sulfur pulverized coal unit. The 750 MW supercritical unit utilizing coal, the 750 MW supercritical high-sulfur coal and the 500 MW subcritical unit utilizing high-sulfur coal show up only in the second and third place positions among least cost generation alternatives, always following the Trimble County 2 supercritical 732 MW unit. The 750 MW supercritical unit utilizing coal was based on using PRB coal; while the 750 MW supercritical high-sulfur coal would utilize the Appalachian Basin and Kentucky coals. Besides the Trimble County unit, the choice of which of the other three coal options would be best to recommend for further analysis is decided based on outcomes of the sensitivities which follow.

The WV Hydro option is a power purchase agreement that includes only O&M costs and has no capital costs associated with it. This option was selected as first option 162 times and is the only other option besides the TC2 unit to place first among the least cost options.

The GE 7FA 148 MW simple cycle combustion turbines will be considered for further optimization analysis. Conversion to Combined Cycle appeared as a third place generation alternative 23 times. Prior to any installation of a combined cycle unit, the Companies will be able to evaluate the possibility of conversion of existing simple cycle combustion turbines to combined cycle operation.

As stated previously in this report, the Humid Air Turbine Cycle CT is only in developmental stages and is not commercially available. Therefore, even though it shows up as second and third place among the least cost generation alternatives, this option will not be evaluated further.

Similarly, the tire-derived fuel (TDF) multi-fuel combustion fluidized bed shows up in the second and third place positions among least cost generation alternatives. However, this option will not be evaluated further because of numerous potential difficulties as described previously in part 6 under the Renewable Resource Technology section of this report. Each of these issues (e.g. permitting issues, ash disposal, the negative publicity from fires, etc.) potentially presents a significant stumbling block and in total, prevents TDF from being considered as a viable solution to the Companies' forecasted generation shortfall.

2. Alternative Analysis with CO_2 Impact

As previously described, a separate analysis was performed to evaluate the impact of a carbon tax on the outcome of the screening analysis. The same sensitivities (inclusion of the impact of SO_2 and NO_x, variability of capital cost, heat rate, and fuel cost) were performed in this analysis as were performed in the preliminary and base case analysis. After implementing carbon taxes of $10 per ton (and sensitivities of $20 per ton, and $40 per ton) of carbon emitted, the least-cost technologies in at least one sensitivity case over any capacity factor range were determined just as in the analysis previously presented.

As mentioned in the above analysis with only NO_x and SO_2 emissions, by using the equations of Exhibit 4 and data contained within Exhibits 2(a)-2(d) [with the addition of CO_2 adders applied to 2(a) at a rate of $0.29/Mbtu for coal and $0.16/Mbtu for natural gas], Exhibit 3, and Exhibit 5, the total 30-year levelized cost ($/kW-yr in 2004 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 8. Least-cost technologies over all ranges of capacity factors have been identified at the bottom of each case exhibit and are shaded in the tables. Technology capacity factors shown in pages 1 through 27 of Exhibit 8 were limited to the maximum allowed by the technology and/or environment in which they operate as specified by the data sources. For reference, these technologies are listed in Table 5.

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

CO_2 Tax Adder			
$10/ton	$20/ton	$40/ton	Technology
√	√	√	Trimble County 2 – 732 MW Supercritical Pulverized Coal
√	√	√	WV Hydro
	√	√	TDF Multi-Fuel CFB (10% Co-Fire)

A comparison of Table 5 and Table 2 shows that the least cost technologies remain the same as long as the CO_2 tax rate is $10 per ton. When taxed at $20 per ton or more, TDF Multi-Fuel CFB (10 percent Co-fire) is present among the lowest cost technology options.

Table 6 below identifies those technologies that were either identified as a second or third least-costly technology in the scenarios where CO_2 was taxed at a rate of $10 per ton. A comparison of Table 6 and Table 3 from above shows that the technologies remain the same, with the exception of Biomass (Co-Fire) 27.5-MW unit, when a carbon tax of $10 per ton is considered.

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

Trimble County 2 – 732 MW Supercritical Pulverized Coal
Supercritical Pulverized Coal, High Sulfur – 750 MW
Supercritical Pulverized Coal – 750 MW
Ohio Falls 9 and 10 – 10 MW
Humid Air Turbine Cycle Combustion Turbine – 450 MW
Simple Cycle GE 7FA CT – 148 MW
TDF Multi-Fuel CFB (10% Co-Fire)
Combined Cycle 2x1 GE 7FA CT – 484 MW
Wind Energy Conversion – 50 MW
Subcritical Pulverized Coal, High Sulfur-500 MW
Biomass (Co-Fire) – 27.5 MW

Table 7 identifies how many times a technology appeared as either the first, second or third least-cost option over any capacity factor range and with CO_2 emission tax rates. The analysis with a $10 per ton carbon tax has virtually no impact, with the exception of adding the Biomass (Co-Fire) unit to the technology alternatives. The order and number of occurrences is only slightly changed and the Biomass alternative only occurs once in the third least-costly technology rankings. The scenario where the carbon tax is estimated at $10 per ton is shown in Table 7.

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

# Occur				
1st	**2nd**	**3rd**	**Total**	**Technology Name**
135	54	44	233	Trimble County 2 – 732 MW Supercritical Pulverized Coal
162	0	0	162	WV Hydro
0	68	81	149	Supercritical Pulverized Coal, High Sulfur – 750 MW
0	49	98	147	Supercritical Pulverized Coal – 750 MW
0	55	13	68	Ohio Falls 9 and 10
0	26	19	45	Humid Air Turbine Cycle CT – 450 MW
0	27	0	27	Simple Cycle GE 7FA CT – 148 MW
0	18	8	26	TDF Multi-Fuel CFB (10% Co-Fire) – 50 MW
0	0	22	22	Combined Cycle 2x1 GE 7FA CT – 484 MW
0	0	10	10	Wind Energy Conversion – 50 MW
0	0	1	1	Subcritical Pulverized Coal, High Sulfur – 500 MW
0	0	1	1	Biomass (Co-Fire) – 27.5 MW

The technologies suggested by a levelized screening analysis which included a range of taxes on each ton of carbon emitted are not greatly different from those suggested without a carbon tax. As noted previously, the technology options were also evaluated at carbon tax rates between $10 per ton and $40 per ton. In general, the least cost technologies were consistent regardless of the carbon tax rate scenarios, although the overall number and frequency of occurrences varied, as did each option's ranking. The most significant differences among the three carbon tax scenarios showed that at the $20 per ton carbon tax rate the Subcritical Pulverized Coal, High Sulfur (500-MW unit) dropped off the list as a lowest cost technology, and at the $40 per ton carbon tax rate where the ordering varied even further. However, regardless of the carbon tax rate, the top three lowest cost technology alternatives remained the same: 1) TC2 732 MW Supercritical Pulverized Coal unit, 2) WV Hydro, and 3) Supercritical Pulverized Coal, High Sulfur at 750 MW. With this observation, the selected coal option for further analysis became the Supercritical Pulverized Coal unit using high sulfur coal and producing 750 MW.

All eleven of the technologies present in the scenario without carbon adders (shown in Table 4) are the same in the scenario with the $10 per ton carbon tax (shown in Table 7), with the addition of the twelfth technology of Biomass (Co-Fire) at 27.5 MW. The only observable changes in the two scenarios involve the number of occurrences and the resulting ranking. Although the number of occurrences changes between the two cases, the changes are not enough to result in significantly rearranging the order of the least cost units. The ordinal ranking remains the same, with the exception of the 50-MW TDF Multi-Fuel CFB (10 percent Co-fire) unit and the 484-MW Combined Cycle unit swapping places for eighth and ninth ranking.

RECOMMENDATIONS

Based on the various analyses discussed above, the technologies listed in Table 8 are recommended for further analysis in the optimization studies using Strategist, a detailed modeling program. The technologies identified will provide a diverse set of alternatives to be evaluated in production and capital costing computer models. Exhibit 9 is a graphical representation of the least-cost technologies, which will be further evaluated in the Strategist optimization software modeling.

Table 8
Technologies Suggested for Analysis
Within Strategist

Trimble County 2 – 732 MW Supercritical Pulverized Coal Unit
Supercritical Pulverized Coal, High Sulfur – 750 MW
WV Hydro – Power Purchase Agreement
Ohio Falls 9 and 10 – Run of River expansion
Simple Cycle GE 7FA CT – 148 MW
Combined Cycle 2x1 GE 7FA CT – 484 MW

Appendix A

Technologies Screened

Tech. ID	Technology Description	Category	Sub-Category
6.1	Pumped Hydro Energy Storage - 500 MW	Storage	Hydro
6.2	Lead-Acid Battery Energy Storage - 5 MW	Storage	Battery
6.3	Compressed Air Energy Storage - 500 MW	Storage	Compressed Air
2.1.1	Simple Cycle GE LM6000 CT - 31 MW	Natural Gas	SCCT
2.1.2	Simple Cycle GE 7EA CT - 73 MW	Natural Gas	SCCT
2.1.3	Simple Cycle GE 7FA CT - 148 MW	Natural Gas	SCCT
2.2.1	Combined Cycle GE 7EA CT - 119 MW	Natural Gas	CCCT
2.2.2	Combined Cycle GE 7FA CT - 235 MW	Natural Gas	CCCT
2.2.3	Combined Cycle 2x1 GE 7FA CT - 484 MW	Natural Gas	CCCT
2.1.4	W 501F CC CT - 258 MW	Natural Gas	CCCT
2.5.1	Spark Ignition Engine - 5 MW	Natural Gas	Reciprocating Engine
2.5.2	Compression Ignition Engine - 10 MW	Natural Gas	Reciprocating Engine
3.1.1	Wind Energy Conversion - 50 MW	Renewable	Wind
3.2.1	Solar Thermal, Parabolic Trough - 100 MW	Renewable	Solar
3.2.2	Solar Thermal, Parabolic Dish - 1.2 MW	Renewable	Solar
3.2.3	Solar Thermal, Central Receiver - 50 MW	Renewable	Solar
3.2.4	Solar Thermal, Solar Chimney - 200 MW	Renewable	Solar
3.3	Solar Photovoltaic - 50 kW	Renewable	Solar
3.4.1	Biomass (Co-Fire) - 27.5MW	Renewable	BioMass
3.5	Geothermal - 30 MW	Renewable	Geotherm
3.6	Hydroelectric - New - 30 MW	Renewable	Hydro
102	WV Hydro	Renewable	Hydro
4.1	MSW Mass Burn - 7 MW	Waste To Energy	MSW
4.2	RDF Stoker-Fired - 7 MW	Waste To Energy	RDF
4.3	Landfill Gas IC Engine - 5 MW	Waste To Energy	LFG
4.4	TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	Waste To Energy	TDF
4.5	Sewage Sludge & Anaerobic Digestion - .085 MW	Waste To Energy	SS
5.1.1	Humid Air Turbine Cycle CT - 450 MW	Natural Gas	CT
5.1.2	Kalina Cycle CC CT - 275 MW	Natural Gas	CCCT
5.1.3	Cheng Cycle CT - 140 MW	Natural Gas	CCCT
5.2.1	Pressurized Fluidized Bed Combustion - 250 MW	Coal	Fluidized Bed Combustion
5.3.1	IGCC - 267 MW	Coal Gasification	IGCC
5.3.2	IGCC - 534 MW	Coal Gasification	IGCC
5.4	Fuel Cell - 0.2 MW	Storage	Fuel Cell
5.5.1	Peaking Microturbine - 0.03 MW	Natural Gas	CT
5.5.2	Baseload Microturbine - 0.03 MW	Natural Gas	CT
2.3.1	Supercritical Pulverized Coal - 500 MW	Coal	Pulverized Coal
2.3.2	Supercritical Pulverized Coal, High Sulfur - 500 MW	Coal	Pulverized Coal
2.3.3	Supercritical Pulverized Coal - 750 MW	Coal	Pulverized Coal
2.3.4	Subcritical Pulverized Coal - 250 MW	Coal	Pulverized Coal
2.3.5	Subcritical Pulverized Coal - 500 MW	Coal	Pulverized Coal
2.3.6	Subcritical Pulverized Coal, High Sulfur - 500 MW	Coal	Pulverized Coal
2.3.7	Supercritical Pulverized Coal, High Sulfur - 750 MW	Coal	Pulverized Coal
2.4.1	Circulating Fluidized Bed - 250 MW	Coal	Fluidized Bed Combustion
2.4.2	Circulating Fluidized Bed - 500 MW	Coal	Fluidized Bed Combustion
100	Ohio Falls 9 and 10	Renewable	Hydro
101	TC2 732 MW Supercritical Pulverized Coal	Coal	Pulverized Coal

Fuel Forecast for Screening Analysis

(Cents/MBtu)

	Base Fuel Costs				Low Fuel Costs				High Fuel Costs			
	High SO_2	Med SO_2	Low SO_2	Gas	High SO_2	Med SO_2	Low SO_2	Gas	High SO_2	Med SO_2	Low SO_2	Gas
2004	[redacted]											
2005												
2006												
2007												
2008												
2009												
2010												
2011												
2012												
2013												
2014												
2015												
2016												
2017												
2018												
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2021												
2022												
2023												
2024												
2025												
2026												
2027												
2028												
2029												
2030												
2031												
2032												
2033												

Calculation of SO_2 Adder (Cents/MBtu)

(Post FGD:Assume 95% Removal Eff)
$\#SO_2$/MBTU ----> 0.310 | 0.055 | 0.115

	SO_2 $/ton Esc @ VO&M	High SO_2 Base Cost	High SO_2 SO_2 Adder	Low SO_2 Base Cost	Low SO_2 SO_2 Adder	Med SO_2 Base Cost	Med SO_2 SO_2 Adder
2004	172	[redacted]	3	[redacted]	0	[redacted]	1
2005	392	[redacted]	6	[redacted]	1	[redacted]	2
2006	405	[redacted]	6	[redacted]	1	[redacted]	2
2007	412	[redacted]	6	[redacted]	1	[redacted]	2
2008	419	[redacted]	6	[redacted]	1	[redacted]	2
2009	407	[redacted]	6	[redacted]	1	[redacted]	2
2010	536	[redacted]	8	[redacted]	1	[redacted]	3
2011	547	[redacted]	8	[redacted]	2	[redacted]	3
2012	558	[redacted]	9	[redacted]	2	[redacted]	3
2013	569	[redacted]	9	[redacted]	2	[redacted]	3
2014	580	[redacted]	9	[redacted]	2	[redacted]	3
2015	592	[redacted]	9	[redacted]	2	[redacted]	3
2016	604	[redacted]	9	[redacted]	2	[redacted]	3
2017	616	[redacted]	10	[redacted]	2	[redacted]	4
2018	628	[redacted]	10	[redacted]	2	[redacted]	4
2019	641	[redacted]	10	[redacted]	2	[redacted]	4
2020	653	[redacted]	10	[redacted]	2	[redacted]	4
2021	666	[redacted]	10	[redacted]	2	[redacted]	4
2022	680	[redacted]	11	[redacted]	2	[redacted]	4
2023	693	[redacted]	11	[redacted]	2	[redacted]	4
2024	707	[redacted]	11	[redacted]	2	[redacted]	4
2025	721	[redacted]	11	[redacted]	2	[redacted]	4
2026	736	[redacted]	11	[redacted]	2	[redacted]	4
2027	751	[redacted]	12	[redacted]	2	[redacted]	4
2028	766	[redacted]	12	[redacted]	2	[redacted]	4
2029	781	[redacted]	12	[redacted]	2	[redacted]	4
2030	796	[redacted]	12	[redacted]	2	[redacted]	5
2031	812	[redacted]	13	[redacted]	2	[redacted]	5
2032	829	[redacted]	13	[redacted]	2	[redacted]	5
2033	845	[redacted]	13	[redacted]	2	[redacted]	5

Example calculation of SO_2 adder:

Using High Sulfur Coal = 6.2$\#SO_2$/MBtu
2004 SO_2 $/Ton = $172
Scrubber Removal Efficiency = 95% (for each coal burning technology)

2004 High Sulfur SO_2 Cost Adder $= \frac{6.2\#SO_2}{\text{MBtu}} \bullet (1-0.95) \bullet \frac{172\ \$}{\text{Ton } SO_2} * \frac{100\text{ Cents}}{\$} \bullet \frac{1\text{ ton } SO_2}{2000\ \#}$

2004 High Sulfur SO_2 Cost Adder = 2.7 cents/MBtu

Exhibit 2(c)

Fuels Utilized by Technology in 2004 Screening Analysis

Tech ID	Generating/ Storage Station Options	2004 Screening Study Uses
6.1	Pumped Hydro Energy Storage - 500 MW	Charging Only
6.2	Lead-Acid Battery Energy Storage - 5 MW	Charging Only
6.3	Compressed Air Energy Storage - 500 MW	Gas and Charging
2.1.1	Simple Cycle GE LM6000 CT - 31 MW	Gas
2.1.2	Simple Cycle GE 7EA CT - 73 MW	Gas
2.1.3	Simple Cycle GE 7FA CT - 148 MW	Gas
2.2.1	Combined Cycle GE 7EA CT - 119 MW	Gas
2.2.2	Combined Cycle GE 7FA CT - 235 MW	Gas
2.2.3	Combined Cycle 2x1 GE 7FA CT - 484 MW	Gas
2.1.4	W 501F CC CT - 258 MW	Gas
2.5.1	Spark Ignition Engine - 5 MW	Gas
2.5.2	Compression Ignition Engine - 10 MW	Gas
3.1.1	Wind Energy Conversion - 50 MW	Wind
3.2.1	Solar Thermal, Parabolic Trough - 100 MW	Solar
3.2.2	Solar Thermal, Parabolic Dish - 1.2 MW	Solar
3.2.3	Solar Thermal, Central Receiver - 50 MW	Solar
3.2.4	Solar Thermal, Solar Chimney - 200 MW	Solar
3.3	Solar Photovoltaic - 50 kW	Solar
3.4.1	Biomass (Co-Fire) - 27.5MW	Biomass
3.5	Geothermal - 30 MW	Geothermal
3.6	Hydroelectric - New - 30 MW	Water
102	WV Hydro	Water
4.1	MSW Mass Burn - 7 MW	MSW
4.2	RDF Stoker-Fired - 7 MW	RDF
4.3	Landfill Gas IC Engine - 5 MW	LFG
4.4	TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	Tires
4.5	Sewage Sludge & Anaerobic Digestion - .085 MW	Tires
5.1.1	Humid Air Turbine Cycle CT - 450 MW	Gas
5.1.2	Kalina Cycle CC CT - 275 MW	Gas
5.1.3	Cheng Cycle CT - 140 MW	Gas
5.2.1	Pressurized Fluidized Bed Combustion - 250 MW	Gas
5.3.1	IGCC - 267 MW	Coal Gasification
5.3.2	IGCC - 534 MW	Coal Gasification
5.4	Fuel Cell - 0.2 MW	Gas
5.5.1	Peaking Microturbine - 0.03 MW	Gas
5.5.2	Baseload Microturbine - 0.03 MW	Gas
2.3.1	Supercritical Pulverized Coal - 500 MW	Low SO2
2.3.2	Supercritical Pulverized Coal, High Sulfur - 500 MW	High SO2
2.3.3	Supercritical Pulverized Coal - 750 MW	Low SO2
2.3.4	Subcritical Pulverized Coal - 250 MW	Low SO2
2.3.5	Subcritical Pulverized Coal - 500 MW	Low SO2
2.3.6	Subcritical Pulverized Coal, High Sulfur - 500 MW	High SO2
2.3.7	Supercritical Pulverized Coal, High Sulfur - 750 MW	High SO2
2.4.1	Circulating Fluidized Bed - 250 MW	Low SO2
2.4.2	Circulating Fluidized Bed - 500 MW	Low SO2
100	Ohio Falls 9 and 10	Water
101	TC2 732 MW Supercritical Pulverized Coal	High SO2

Calculation of NOx Adder ($/MWh)

Trimble County 2 732 MW Supercritical Coal-fired Unit Data

Uncontrolled NOx Emission Rate:	0.25 lb/MBtu
Controlled NOx Emission Rate:	0.07 lb/MBtu
Base Heat Rate:	8,900 Btu/kWh
2005 NOx Allowance Cost:	$3,125 /ton

NOx lbs/MWh = Controlled Emission Rate x Heat Rate = $\frac{0.07\ \text{lb}}{\text{MBtu}} \times \frac{\text{MBtu}}{1{,}000{,}000\ \text{Btu}} \times \frac{8{,}900\ \text{Btu}}{\text{kWh}} \times \frac{1{,}000\ \text{kWh}}{\text{MWh}}$

= 0.623 lbs/MWh

V O&M Adder = NOx lbs/MWh x 2005 NOx Allowance Cost

= $\frac{0.623\ \text{lbs}}{\text{MWh}} \times \frac{\$3125}{\text{ton}} \times \frac{\text{ton}}{2000\ \text{lbs}}$ = $0.98/MWh

Heat Rate and Capital Cost Sensitivity Data

Technology	Rating, MW (90°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
Pumped Hydro Energy Storage - 500 MW	500	-	-	-	[redacted]	$9.00	$3.50	1.40
Lead-Acid Battery Energy Storage - 5 MW	5	-	-	-	[redacted]	$14.30	$79.50	1.39
Compressed Air Energy Storage - 500 MW	500	4,175	4,384	3,966	[redacted]	$16.00	$6.35	0.93
Simple Cycle GE LM6000 CT - 31 MW	31	10,329	10,845	9,813	[redacted]	$53.60	$3.31	
Simple Cycle GE 7EA CT - 73 MW	73	12,420	13,041	11,799	[redacted]	$39.72	$6.69	
Simple Cycle GE 7FA CT - 148 MW	148	11,132	11,689	10,575	[redacted]	$33.31	$13.37	
Combined Cycle GE 7EA CT - 119 MW	119	7,772	8,161	7,383	[redacted]	$39.95	$4.13	
Combined Cycle GE 7FA CT - 235 MW	235	7,032	7,384	6,680	[redacted]	$35.11	$4.03	
Combined Cycle 2x1 GE 7FA CT - 484 MW	484	6,974	7,323	6,625	[redacted]	$31.80	$4.08	
W 501F CC CT - 258 MW	258	7,337	7,704	6,970	[redacted]	$33.30	$3.75	
Spark Ignition Engine - 5 MW	5	9,700	10,185	9,215	[redacted]	$0.00	$25.00	
Compression Ignition Engine - 10 MW	10	7,800	8,190	7,410	[redacted]	$0.00	$25.00	
Wind Energy Conversion - 50 MW	50	-	-	-	[redacted]	$30.00	$0.00	
Solar Thermal, Parabolic Trough - 100 MW	100	-	-	-	[redacted]	$0.00	$27.50	
Solar Thermal, Parabolic Dish - 1.2 MW	1	-	-	-	[redacted]	$0.00	$15.00	
Solar Thermal, Central Receiver - 50 MW	50	-	-	-	[redacted]	$0.00	$15.00	
Solar Thermal, Solar Chimney - 200 MW	200	-	-	-	[redacted]	$0.00	$15.00	
Solar Photovoltaic - 50 kW	0.1	-	-	-	[redacted]	$20.00	$23.00	
Biomass (Co-Fire) - 27.5MW	28	14,500	15,225	13,775	[redacted]	$60.00	$8.00	
Geothermal - 30 MW	30	-	-	-	[redacted]	$250.00	$0.00	
Hydroelectric - New - 30 MW	30	-	-	-	[redacted]	$15.00	$4.25	
WV Hydro	181	-	-	-	[redacted]	$0.00	$34.10	
MSW Mass Burn - 7 MW	7	17,500	18,375	16,625	[redacted]	$300.00	$75.00	
RDF Stoker-Fired - 7 MW	7	19,300	20,265	18,335	[redacted]	$500.00	$80.00	
Landfill Gas IC Engine - 5 MW	5	9,500	9,975	9,025	[redacted]	$0.00	$15.00	
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	50	12,700	13,335	12,065	[redacted]	$57.50	$4.75	
Sewage Sludge & Anaerobic Digestion - .085 N	0.09	-	-	-	[redacted]	$0.00	$15.00	
Humid Air Turbine Cycle CT - 450 MW	450	6,500	6,825	6,175	[redacted]	$27.67	$2.93	
Kalina Cycle CC CT - 275 MW	275	6,700	7,035	6,365	[redacted]	$27.90	$2.93	
Cheng Cycle CT - 140 MW	140	8,500	8,925	8,075	[redacted]	$30.10	$2.93	
Pressurized Fluidized Bed Combustion - 250 M	250	8,500	8,925	8,075	[redacted]	$29.00	$4.65	
IGCC - 267 MW	267	8,500	8,925	8,075	[redacted]	$47.19	$5.88	
IGCC - 534 MW	534	8,500	8,925	8,075	[redacted]	$32.21	$5.52	
Fuel Cell - 0.2 MW	0.2	8,250	8,663	7,838	[redacted]	$600.00	$7.50	
Peaking Microturbine - 0.03 MW	0.0	12,700	13,335	12,065	[redacted]	$0.00	$15.00	
Baseload Microturbine - 0.03 MW	0.0	12,000	12,600	11,400	[redacted]	$0.00	$15.00	
Supercritical Pulverized Coal - 500 MW	500	9,590	10,070	9,111	[redacted]	$22.30	$2.52	
Supercritical Pulverized Coal, High Sulfur - 500	500	9,398	9,868	8,928	[redacted]	$23.87	$4.10	
Supercritical Pulverized Coal - 750 MW	750	9,383	9,852	8,914	[redacted]	$19.12	$2.52	
Subcritical Pulverized Coal - 250 MW	250	9,976	10,475	9,477	[redacted]	$29.84	$2.64	
Subcritical Pulverized Coal - 500 MW	500	9,756	10,244	9,268	[redacted]	$22.93	$2.49	
Subcritical Pulverized Coal, High Sulfur - 500 N	500	9,560	10,038	9,082	[redacted]	$24.36	$4.10	
Supercritical Pulverized Coal, High Sulfur - 750	750	9,195	9,655	8,735	[redacted]	$20.60	$4.12	
Circulating Fluidized Bed - 250 MW	250	10,034	10,536	9,532	[redacted]	$32.61	$3.05	
Circulating Fluidized Bed - 500 MW	500	9,812	10,303	9,321	[redacted]	$22.46	$2.97	
Ohio Falls 9 and 10	34	-	-	-	[redacted]	$9.84	$0.00	
TC2 732 MW Supercritical Pulverized Coal	732	8,900	9,345	8,455	[redacted]	$9.57	$1.33	

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 ($/MWh)	Exhibit 3
Fix Esc	=	Fixed O&M Escalation Rate (%)	Exhibit 5
Var Esc	=	Variable O&M Escalation Rate (%)	Exhibit 5
Fix Adj L_n	=	Fixed O&M Levelization Factor	Exhibit 5
Var Adj L_n	=	Variable O&M Levelization Factor	Exhibit 5
Fuel Adj L_n	=	Fuel Cost Levelization Factor	Base Fuel Only; Exhibit 5
Charge Adj L_n	=	Charging Cost Levelization Factor	Exhibit 5
CF%	=	Capacity Factor (%)	0-100 %
MW	=	Size of Technology (MW)	Exhibit 3
HR	=	Heat Rate (Btu/KWh)	Exhibit 3
FC	=	Fuel Cost ($/MBtu)	Exhibit 2 (a)
Avg Ld IO	=	Average Load (kWh In/kWh Out)	Exhibit 3
Charge	=	Charging Cost ($/MWh)	Exhibit 5
SO_2	=	SO_2 Adder (Cents/MBtu)	Exhibit 2(b)
NO_x	=	NO_x Adder ($/MWh)	Exhibit 2(d)

Cost Components of Technologies that:

I. Burn Fuel Only

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

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

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

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

1. Burn No Fuel and No Charging Energy

Use Capital, Fixed and Variable Equations from above.

2. Burn No Fuel but Utilize Charging Energy

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

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

3. Burn Fuel and Utilize Charging Energy

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

Adjusted L_n and Other Miscellaneous Data

(All Fuel prices are in Cents/MBtu)

18.19	Base Yr ($/MWh) charging cost
2.00%	Charging Esc.

Year	Cumulative F O&M Esc (2.00%)	Cumulative V O&M Esc (2.00%)	Cumulative Capital Esc (2.00%)	High SO2 6.2#	Gas	Cost Charging	No Fuel	Low SO2 1.15#	Med SO2 2.3#
2004	1.000	1.000	1.000	[redacted]					
2005	1.020	1.020	1.020						
2006	1.040	1.040	1.040						
2007	1.061	1.061	1.061						
2008	1.082	1.082	1.082						
2009	1.104	1.104	1.104						
2010	1.126	1.126	1.126						
2011	1.149	1.149	1.149						
2012	1.172	1.172	1.172						
2013	1.195	1.195	1.195						
2014	1.219	1.219	1.219						
2015	1.243	1.243	1.243						
2016	1.268	1.268	1.268						
2017	1.294	1.294	1.294						
2018	1.319	1.319	1.319						
2019	1.346	1.346	1.346						
2020	1.373	1.373	1.373						
2021	1.400	1.400	1.400						
2022	1.428	1.428	1.428						
2023	1.457	1.457	1.457						
2024	1.486	1.486	1.486						
2025	1.516	1.516	1.516						
2026	1.546	1.546	1.546						
2027	1.577	1.577	1.577						
2028	1.608	1.608	1.608						
2029	1.641	1.641	1.641						
2030	1.673	1.673	1.673						
2031	1.707	1.707	1.707						
2032	1.741	1.741	1.741						
2033	1.776	1.776	1.776						

Fuel Notes:
When utilized, SO_2 cost adder to High SO2, Low SO2 and Med SO2 Coal assumes 95% FGD removal efficiency.
When utilized, the fuel cost adder representing Carbon Tax was applied to High, Low, & Med Sulfur coals, and Natural Gas.
6/29/04 Fuel Forecast Used. All fuel prices in cents per million Btu with the exception of charging which is in $/MWh.
Charging cost base upon average cost of off-peak generation.

		Fixed	*Variable*	*Capital*	High SO2	Gas	Charging	No Fuel	Low SO2	Med SO2
Base Year =	2004									
Levelized Year =	2004									
Ea =		2.00%	2.00%	2.00%	[redacted]					
PV Rate (i) =	7.14%									
k =		0.9520	0.9520	0.9520	[redacted]					
n =	30									
An =	12.2365									
L_n =		1.251	1.251	1.251	[redacted]					
Adj L_n =		1.226	1.226	1.226						

Input
Not an Input
Calculated
Change "Levelized Year" to year desired for "Snapshot" year analysis.
Change "n" to 1 for "Snapshot" year analysis and 30 for levelized analyis.

Fixed Charge Rates by Technology

Coal	9.09%
Simple Cycle CT	10.52%
Combined Cycle CT	9.19%
Other	9.46%
Modification	10.48%

Exhibit 6

30-Year Levelized Cost
For All Technologies Over
All Capacity Factors

Exhibit 6

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

Capital Cost- Base **2004 Dollars ($/kW yr)**
Heat Rate- Base
Fuel Forecast- Base

	Capacity Factors										
Technology	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Pumped Hydro Energy Storage - 500 MW	195	226	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	159	272	384	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	101	152	203	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	157	225	293	361	429	497	565	633	701	769	837
Simple Cycle GE 7EA CT - 73 MW	108	192	277	362	447	531	616	701	785	870	955
Simple Cycle GE 7FA CT - 148 MW	81	165	248	332	416	500	584	667	751	835	919
Combined Cycle GE 7EA CT - 119 MW	145	198	251	304	357	409	462	515	568	621	674
Combined Cycle GE 7FA CT - 235 MW	116	164	212	261	309	357	405	453	502	550	598
Combined Cycle 2x1 GE 7FA CT - 484 MW	96	144	192	240	288	335	383	431	479	527	575
W 501F CC CT - 258 MW	109	159	208	258	308	358	408	457	507	557	607
Spark Ignition Engine - 5 MW	141	228	316	403	491	578	—	—	—	—	—
Compression Ignition Engine - 10 MW	103	178	254	329	405	480	—	—	—	—	—
Wind Energy Conversion - 50 MW	191	191	191	191	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	494	523	553	582	612	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	384	400	416	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	658	674	690	706	723	739	755	771	—	—	—
Solar Thermal, Solar Chimney - 200 MW	439	455	471	487	504	520	536	552	—	—	—
Solar Photovoltaic - 50 kW	958	982	1007	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	321	329	338	346	355	364	372	381	390	—	—
Geothermal - 30 MW	664	664	664	664	664	664	664	664	664	—	—
Hydroelectric - New - 30 MW	402	407	412	416	421	425	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	1026	1106	1187	1268	1348	1429	1509	1590	—	—	—
RDF Stoker-Fired - 7 MW	1491	1577	1663	1749	1835	1921	2007	2093	—	—	—
Landfill Gas IC Engine - 5 MW	219	264	309	353	398	443	488	532	577	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	345	350	355	360	365	370	375	380	385	390	396
Sewage Sludge & Anaerobic Digestion - .085 MW	335	351	367	383	400	416	432	448	464	—	—
Humid Air Turbine Cycle CT - 450 MW	91	135	178	222	266	309	353	397	—	—	—
Kalina Cycle CC CT - 275 MW	114	159	204	249	294	339	384	429	—	—	—
Cheng Cycle CT - 140 MW	140	196	252	308	364	421	477	533	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	213	271	329	387	445	503	561	619	—	—	—
IGCC - 267 MW	237	269	301	333	364	396	428	460	492	—	—
IGCC - 534 MW	207	239	270	302	333	365	396	427	459	—	—
Fuel Cell - 0.2 MW	1394	1453	1512	1572	1631	1691	—	—	—	—	—
Peaking Microturbine - 0.03 MW	122	217	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	122	213	304	395	486	577	668	759	—	—	—
Supercritical Pulverized Coal - 500 MW	167	189	211	233	255	277	299	321	343	364	386
Supercritical Pulverized Coal, High Sulfur - 500 MW	177	196	215	234	253	272	291	310	328	347	366
Supercritical Pulverized Coal - 750 MW	150	172	193	215	236	258	279	301	322	344	365
Subcritical Pulverized Coal - 250 MW	206	228	251	274	297	320	342	365	388	411	434
Subcritical Pulverized Coal - 500 MW	163	185	208	230	252	274	296	319	341	363	385
Subcritical Pulverized Coal, High Sulfur - 500 MW	173	192	211	230	250	269	288	307	326	346	365
Supercritical Pulverized Coal, High Sulfur - 750 MW	159	178	196	215	234	252	271	289	308	327	345
Circulating Fluidized Bed - 250 MW	215	238	262	285	308	331	355	378	401	425	448
Circulating Fluidized Bed - 500 MW	164	186	209	232	255	278	301	324	347	370	393
Ohio Falls 9 and 10	144	144	144	144	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	129	144	159	174	190	205	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	220	235	250	266	281

Exhibit 6

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

Capital Cost-Low **2004 Dollars ($/kW yr)**
Heat Rate-Low
Fuel Forecast-Low

	Capacity Factors										
Technology	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Pumped Hydro Energy Storage - 500 MW	176	207	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	145	258	370	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	93	140	188	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	148	206	265	324	383	441	500	559	617	676	735
Simple Cycle GE 7EA CT - 73 MW	102	175	249	322	395	469	542	616	689	762	836
Simple Cycle GE 7FA CT - 148 MW	77	151	224	298	372	446	520	593	667	741	815
Combined Cycle GE 7EA CT - 119 MW	136	182	228	274	320	365	411	457	503	549	595
Combined Cycle GE 7FA CT - 235 MW	108	150	192	233	275	317	359	401	442	484	526
Combined Cycle 2x1 GE 7FA CT - 484 MW	90	132	173	215	256	298	340	381	423	464	506
W 501F CC CT - 258 MW	102	145	188	231	274	317	360	404	447	490	533
Spark Ignition Engine - 5 MW	127	206	284	363	441	520	—	—	—	—	—
Compression Ignition Engine - 10 MW	92	160	229	297	366	434	—	—	—	—	—
Wind Energy Conversion - 50 MW	160	160	160	160	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	395	424	454	483	513	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	307	323	339	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	527	543	559	575	592	608	624	640	—	—	—
Solar Thermal, Solar Chimney - 200 MW	351	367	383	399	416	432	448	464	—	—	—
Solar Photovoltaic - 50 kW	771	795	820	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	272	280	289	297	306	315	323	332	341	—	—
Geothermal - 30 MW	592	592	592	592	592	592	592	592	592	—	—
Hydroelectric - New - 30 MW	364	369	374	378	383	387	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	895	975	1056	1137	1217	1298	1378	1459	—	—	—
RDF Stoker-Fired - 7 MW	1315	1401	1487	1573	1659	1745	1831	1917	—	—	—
Landfill Gas IC Engine - 5 MW	176	217	257	298	338	379	419	460	500	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	290	295	300	305	310	315	320	325	330	335	341
Sewage Sludge & Anaerobic Digestion - .085 MW	268	284	300	316	333	349	365	381	397	—	—
Humid Air Turbine Cycle CT - 450 MW	80	118	156	193	231	269	307	345	—	—	—
Kalina Cycle CC CT - 275 MW	98	137	176	215	254	292	331	370	—	—	—
Cheng Cycle CT - 140 MW	119	167	216	264	313	361	409	458	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	177	227	277	327	378	428	478	529	—	—	—
IGCC - 267 MW	201	229	257	286	314	342	370	399	427	—	—
IGCC - 534 MW	173	201	229	257	285	312	340	368	396	—	—
Fuel Cell - 0.2 MW	1263	1315	1367	1419	1471	1523	—	—	—	—	—
Peaking Microturbine - 0.03 MW	97	181	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	97	177	257	337	418	498	578	658	—	—	—
Supercritical Pulverized Coal - 500 MW	153	171	189	206	224	242	260	277	295	313	330
Supercritical Pulverized Coal, High Sulfur - 500 MW	163	181	198	216	234	251	269	286	304	322	339
Supercritical Pulverized Coal - 750 MW	137	155	172	190	207	224	242	259	277	294	311
Subcritical Pulverized Coal - 250 MW	189	207	226	244	263	281	300	318	337	355	374
Subcritical Pulverized Coal - 500 MW	149	167	185	203	221	239	257	275	293	311	329
Subcritical Pulverized Coal, High Sulfur - 500 MW	159	177	194	212	230	248	266	283	301	319	337
Supercritical Pulverized Coal, High Sulfur - 750 MW	146	164	181	198	216	233	251	268	285	303	320
Circulating Fluidized Bed - 250 MW	197	216	235	254	273	292	311	330	349	368	387
Circulating Fluidized Bed - 500 MW	150	168	187	205	224	243	261	280	298	317	336
Ohio Falls 9 and 10	130	130	130	130	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	117	131	145	159	173	187	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	201	215	229	243	257

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

Capital Cost-Low **2004 Dollars ($/kW yr)**
Heat Rate-Low
Fuel Forecast- Base

	Capacity Factors										
Technology	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Pumped Hydro Energy Storage - 500 MW	176	207	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	145	258	370	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	93	143	193	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	148	213	277	342	407	472	537	601	666	731	796
Simple Cycle GE 7EA CT - 73 MW	102	183	263	344	425	506	587	667	748	829	910
Simple Cycle GE 7FA CT - 148 MW	77	157	238	318	398	479	559	640	720	800	881
Combined Cycle GE 7EA CT - 119 MW	136	186	237	287	338	388	439	489	540	590	641
Combined Cycle GE 7FA CT - 235 MW	108	154	200	246	292	338	384	430	476	522	568
Combined Cycle 2x1 GE 7FA CT - 484 MW	90	136	181	227	273	318	364	410	456	501	547
W 501F CC CT - 258 MW	102	149	197	244	292	339	387	434	482	529	577
Spark Ignition Engine - 5 MW	127	211	295	380	464	548	—	—	—	—	—
Compression Ignition Engine - 10 MW	92	165	238	311	384	457	—	—	—	—	—
Wind Energy Conversion - 50 MW	160	160	160	160	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	395	424	454	483	513	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	307	323	339	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	527	543	559	575	592	608	624	640	—	—	—
Solar Thermal, Solar Chimney - 200 MW	351	367	383	399	416	432	448	464	—	—	—
Solar Photovoltaic - 50 kW	771	795	820	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	272	280	289	297	306	315	323	332	341	—	—
Geothermal - 30 MW	592	592	592	592	592	592	592	592	592	—	—
Hydroelectric - New - 30 MW	364	369	374	378	383	387	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	895	975	1056	1137	1217	1298	1378	1459	—	—	—
RDF Stoker-Fired - 7 MW	1315	1401	1487	1573	1659	1745	1831	1917	—	—	—
Landfill Gas IC Engine - 5 MW	176	219	263	306	349	392	436	479	522	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	290	295	300	305	310	315	320	325	330	335	341
Sewage Sludge & Anaerobic Digestion - .085 MW	268	284	300	316	333	349	365	381	397	—	—
Humid Air Turbine Cycle CT - 450 MW	80	122	163	205	247	288	330	372	—	—	—
Kalina Cycle CC CT - 275 MW	98	141	184	227	270	312	355	398	—	—	—
Cheng Cycle CT - 140 MW	119	172	226	280	333	387	440	494	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	177	232	287	343	398	454	509	565	—	—	—
IGCC - 267 MW	201	231	262	293	323	354	384	415	446	—	—
IGCC - 534 MW	173	204	234	264	294	324	354	384	414	—	—
Fuel Cell - 0.2 MW	1263	1319	1376	1433	1490	1547	—	—	—	—	—
Peaking Microturbine - 0.03 MW	97	188	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	97	184	272	359	446	533	621	708	—	—	—
Supercritical Pulverized Coal - 500 MW	153	174	195	216	237	258	279	300	321	341	362
Supercritical Pulverized Coal, High Sulfur - 500 MW	163	181	199	218	236	254	272	290	308	326	344
Supercritical Pulverized Coal - 750 MW	137	158	178	199	219	240	260	281	301	322	342
Subcritical Pulverized Coal - 250 MW	189	210	232	254	276	298	319	341	363	385	407
Subcritical Pulverized Coal - 500 MW	149	170	192	213	234	255	276	298	319	340	361
Subcritical Pulverized Coal, High Sulfur - 500 MW	159	177	195	214	232	250	269	287	305	324	342
Supercritical Pulverized Coal, High Sulfur - 750 MW	146	164	182	200	218	236	254	272	289	307	325
Circulating Fluidized Bed - 250 MW	197	219	242	264	286	308	331	353	375	398	420
Circulating Fluidized Bed - 500 MW	150	171	193	215	237	259	280	302	324	346	368
Ohio Falls 9 and 10	130	130	130	130	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	117	131	146	160	175	189	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	204	218	233	247	262

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

Capital Cost-Low **2004 Dollars ($/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 - 500 MW	176	207	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	145	258	370	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	93	145	197	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	148	219	290	360	431	502	573	644	715	786	857
Simple Cycle GE 7EA CT - 73 MW	102	190	278	366	455	543	631	719	807	896	984
Simple Cycle GE 7FA CT - 148 MW	77	164	251	338	425	512	599	686	773	860	947
Combined Cycle GE 7EA CT - 119 MW	136	191	246	301	356	411	467	522	577	632	687
Combined Cycle GE 7FA CT - 235 MW	108	158	208	258	308	359	409	459	509	559	609
Combined Cycle 2x1 GE 7FA CT - 484 MW	90	140	190	240	290	339	389	439	489	539	589
W 501F CC CT - 258 MW	102	154	205	257	309	361	413	464	516	568	620
Spark Ignition Engine - 5 MW	127	217	307	397	487	577	—	—	—	—	—
Compression Ignition Engine - 10 MW	92	170	247	325	402	480	—	—	—	—	—
Wind Energy Conversion - 50 MW	160	160	160	160	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	395	424	454	483	513	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	307	323	339	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	527	543	559	575	592	608	624	640	—	—	—
Solar Thermal, Solar Chimney - 200 MW	351	367	383	399	416	432	448	464	—	—	—
Solar Photovoltaic - 50 kW	771	795	820	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	272	280	289	297	306	315	323	332	341	—	—
Geothermal - 30 MW	592	592	592	592	592	592	592	592	592	—	—
Hydroelectric - New - 30 MW	364	369	374	378	383	387	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	895	975	1056	1137	1217	1298	1378	1459	—	—	—
RDF Stoker-Fired - 7 MW	1315	1401	1487	1573	1659	1745	1831	1917	—	—	—
Landfill Gas IC Engine - 5 MW	176	222	268	314	360	406	452	498	544	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	290	295	300	305	310	315	320	325	330	335	341
Sewage Sludge & Anaerobic Digestion - .085 MW	268	284	300	316	333	349	365	381	397	—	—
Humid Air Turbine Cycle CT - 450 MW	80	125	171	217	262	308	353	399	—	—	—
Kalina Cycle CC CT - 275 MW	98	145	192	239	286	332	379	426	—	—	—
Cheng Cycle CT - 140 MW	119	177	236	295	353	412	470	529	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	177	237	297	358	418	479	539	600	—	—	—
IGCC - 267 MW	201	234	267	300	333	366	399	432	465	—	—
IGCC - 534 MW	173	206	239	271	304	336	369	402	434	—	—
Fuel Cell - 0.2 MW	1263	1324	1386	1448	1510	1572	—	—	—	—	—
Peaking Microturbine - 0.03 MW	97	196	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	97	191	286	380	475	569	664	758	—	—	—
Supercritical Pulverized Coal - 500 MW	153	176	198	221	243	266	288	311	333	356	378
Supercritical Pulverized Coal, High Sulfur - 500 MW	163	184	205	226	247	268	289	310	330	351	372
Supercritical Pulverized Coal - 750 MW	137	160	182	204	226	248	270	292	314	336	358
Subcritical Pulverized Coal - 250 MW	189	212	236	259	283	306	330	353	377	400	424
Subcritical Pulverized Coal - 500 MW	149	172	195	218	241	264	287	309	332	355	378
Subcritical Pulverized Coal, High Sulfur - 500 MW	159	180	201	222	244	265	286	307	328	350	371
Supercritical Pulverized Coal, High Sulfur - 750 MW	146	167	187	208	229	249	270	290	311	332	352
Circulating Fluidized Bed - 250 MW	197	221	245	269	293	317	342	366	390	414	438
Circulating Fluidized Bed - 500 MW	150	173	197	220	244	267	291	314	338	361	385
Ohio Falls 9 and 10	130	130	130	130	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	117	134	151	168	185	202	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	219	236	254	271	288

Exhibit 6

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

Capital Cost-Low **2004 Dollars ($/kW yr)**
Heat Rate- Base
Fuel Forecast-Low

	Capacity Factors										
Technology	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Pumped Hydro Energy Storage - 500 MW	176	207	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	145	258	370	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	93	142	190	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	148	209	271	333	394	456	517	579	641	702	764
Simple Cycle GE 7EA CT - 73 MW	102	179	256	332	409	486	563	640	717	794	871
Simple Cycle GE 7FA CT - 148 MW	77	154	231	308	384	461	538	615	692	769	846
Combined Cycle GE 7EA CT - 119 MW	136	184	232	280	328	376	424	472	520	568	616
Combined Cycle GE 7FA CT - 235 MW	108	152	196	239	283	327	371	415	458	502	546
Combined Cycle 2x1 GE 7FA CT - 484 MW	90	134	177	221	264	308	352	395	439	482	526
W 501F CC CT - 258 MW	102	147	192	237	283	328	373	418	463	509	554
Spark Ignition Engine - 5 MW	127	208	289	371	452	533	—	—	—	—	—
Compression Ignition Engine - 10 MW	92	163	233	304	374	445	—	—	—	—	—
Wind Energy Conversion - 50 MW	160	160	160	160	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	395	424	454	483	513	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	307	323	339	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	527	543	559	575	592	608	624	640	—	—	—
Solar Thermal, Solar Chimney - 200 MW	351	367	383	399	416	432	448	464	—	—	—
Solar Photovoltaic - 50 kW	771	795	820	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	272	280	289	297	306	315	323	332	341	—	—
Geothermal - 30 MW	592	592	592	592	592	592	592	592	592	—	—
Hydroelectric - New - 30 MW	364	369	374	378	383	387	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	895	975	1056	1137	1217	1298	1378	1459	—	—	—
RDF Stoker-Fired - 7 MW	1315	1401	1487	1573	1659	1745	1831	1917	—	—	—
Landfill Gas IC Engine - 5 MW	176	218	260	302	344	385	427	469	511	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	290	295	300	305	310	315	320	325	330	335	341
Sewage Sludge & Anaerobic Digestion - .085 MW	268	284	300	316	333	349	365	381	397	—	—
Humid Air Turbine Cycle CT - 450 MW	80	119	159	199	238	278	317	357	—	—	—
Kalina Cycle CC CT - 275 MW	98	139	180	220	261	302	342	383	—	—	—
Cheng Cycle CT - 140 MW	119	170	221	271	322	373	424	475	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	177	229	282	335	387	440	493	546	—	—	—
IGCC - 267 MW	201	230	260	289	319	348	377	407	436	—	—
IGCC - 534 MW	173	202	231	260	289	318	347	376	405	—	—
Fuel Cell - 0.2 MW	1263	1317	1371	1426	1480	1535	—	—	—	—	—
Peaking Microturbine - 0.03 MW	97	184	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	97	181	264	348	431	515	598	682	—	—	—
Supercritical Pulverized Coal - 500 MW	153	172	191	209	228	246	265	284	302	321	339
Supercritical Pulverized Coal, High Sulfur - 500 MW	163	182	200	218	237	255	274	292	310	329	347
Supercritical Pulverized Coal - 750 MW	137	156	174	192	211	229	247	266	284	302	320
Subcritical Pulverized Coal - 250 MW	189	208	227	247	266	286	305	324	344	363	383
Subcritical Pulverized Coal - 500 MW	149	168	187	206	224	243	262	281	300	318	337
Subcritical Pulverized Coal, High Sulfur - 500 MW	159	177	196	215	233	252	270	289	308	326	345
Supercritical Pulverized Coal, High Sulfur - 750 MW	146	164	182	201	219	237	255	273	291	309	327
Circulating Fluidized Bed - 250 MW	197	217	237	257	277	296	316	336	356	376	396
Circulating Fluidized Bed - 500 MW	150	169	189	208	228	247	267	286	306	325	345
Ohio Falls 9 and 10	130	130	130	130	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	117	131	146	161	175	190	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	204	219	234	248	263