Attachment 2

Supply-Side Resource Analysis (4 CSR 240-22.040)

(portions of which have been removed as "Highly Confidential" pursuant to the terms and conditions of the Commission's Standard Protective Order)

WHITE PAPER:
INTEGRATED COAL GASIFICATION COMBINED CYCLE (IGCC) TECHNOLOGY STATUS

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INTEGRATED COAL GASIFICATION COMBINED CYCLE (IGCC) TECHNOLOGY STATUS

TECHNOLOGY OVERVIEW

Gasification technology has been well established over many years for chemical and refinery processes. While there are 100's of gasification plants world wide, these are predominately small-scale units, which utilize heavy oil as the gasification media, rather than gasifying solid fuels such as coal. The development of IGCC, combining solid fuel (coal) gasification technology with combined cycle technology, is a significant step from the well-established refinery gasification process. Worldwide, there are only four (4) large-scale IGCC demonstration units in operation with coal as the primary fuel (see Exhibit 1, Existing IGCC Demonstration Plants, attached at the end of this report).

One of the most significant issues facing IGCC is the effort to scale-up components to reliably produce and handle large volumes of syngas required to reach economies of scale for an economic IGCC installation. The use of solid fuel instead of heavy oil introduces new requirements for temperature designs and waste product treatment. Material applications are different under a solid fueled IGCC to accommodate temperature and by-product issues as well as to account for the ash and moisture content of coal. Due to the variability of coal quality, maintaining syngas quality to meet the requirements of new high temperature combustion turbines is also an issue for IGCC development. Due to the many differences, there are a limited number of firms with the necessary experience or capability to design, fabricate or construct a coal-fired IGCC unit. There is little operating experience to provide documentation of expected operating costs or unit reliability.

RECENT INDUSTRY DEVELOPMENTS

Interest in IGCC technology is growing rapidly as demonstrated by recent announcements within the industry. In August 2003, Conoco Phillips (COP) purchased the gasification technology from E-Gas and announced an agreement with Fluor to provide development support, conceptual design, detailed engineering and turnkey construction of solid fuel IGCC facilities. In June 2004, GE Energy acquired Chevron Texaco's gasification technology business and soon after signed a letter of intent with Bechtel to "study the feasibility of constructing a commercial, integrated gasification combined cycle (IGCC) generating station".

These are promising developments for the future of IGCC technology due to the available resources these multi-national corporations can devote to the development of IGCC technology. However, the fact remains that the viable cost competitive commercialization of IGCC technology is still very early in the developmental stage. The US DOE has provided funding for the development of this technology through its Clean Coal Power Initiative (CCPI) in early 2002. The CCPI solicited demonstration projects, which potentially could qualify for DOE co-funding of up to 50% of project cost. In the 2002 solicitation, one IGCC project was selected, the WMPI in Pennsylvania. This project utilizes the Shell gasification technology to gasify coal and anthracite waste to produce power, steam and diesel liquids. A second solicitation was issued in 2004 and received 7 IGCC proposed projects. Selection of qualifying projects is expected by the end of 2004.

GASIFICATION PROCESSES & TECHNOLOGIES [1]

Three major types of gasification are used today—moving bed, fluidized bed, and entrained flow. Because pressurized gasification is preferred for IGCC to avoid large auxiliary losses for compression of the syngas up to the gas turbine inlet pressure, all major suppliers of IGCC technology (GE, Shell and E-gas/ConocoPhillips) utilize entrained flow gasification. Lurgi still offers dry ash slagging and moving bed gasifiers for other applications. Other gasification technologies at an early stage of development include[2]:

- KBR transport gasifier (fast fluid bed)
- Foster Wheeler (fluid bed)
- GRI U-Gas (fluid bed)
- HyMelt (molten iron)
- HT Winkler fluid bed (no announced developmental progress)

Future alternatives for IGCC applications appear to rest with the three primary technology suppliers listed below.

1. GE/Becthel alliance: acquired the Texaco Gasification technology from ChevronTexaco
   - Wet coal slurry injected at the top of gasifier (downflow gasifier)
   - Gas passes through a water bed at bottom of gasifier (quench)
   - Radiant Quench is also available, gas passes through a radiant heat exchanger before passing through the water quench
   - Radiant + Convective is also available (convective cooler is added after the radiant cooler)
   - Refractory lined gasifier
2. ConocoPhillips/Fluor alliance: offer the E-gas technology (formerly Destec)
   - Wet coal slurry is injected in 2-stages with the second stage above the first (upflow gasifier)
   - Lower oxygen consumption with 2-stage injectors
   - Refractory lined gasifier
3. Shell/Krupp-Uhde/Black & Veatch alliance: (Note: Krupp-Uhde previously offered the Prenflo gasification technology, which is now being merged with the Shell technology).
   - Dry coal feed gasifier with 4-opposed injectors at bottom of gasifier (upflow)
   - Nitrogen steam is injected with fuel

- Gas recycled at top of gasifier for cooling below coal "sticky-slag" temperature
- Water wall gasifier Vs refractory lined (reduced planned outages)

These three technology alternatives are represented in the four existing IGCC demonstration plants:

1. GE: Tampa Electric Polk Plant, Florida, USA
2. Shell: Nuon, Buggenum, the Netherlands and ELCOGAS, puertollano, Spain (NOTE: the Spain project was originally the Prenflo (Krupp-Uhde) technology, now offered through Shell)
3. ConocoPhillips (COP): Wabash River, Indiana, USA.

COMPARISON OF IGCC AND PC PLANTS—LOW RANK COALS [(2)]

Most IGCC studies have been based on using bituminous coals or pet coke. The entrained flow gasifiers of GE, Shell and COP all perform better with lower ash, lower moisture bituminous coals. Given the abundance and low cost of US resources of low rank fuels, such as Powder River Basin sub-bituminous coal and Texas and North Dakota lignite, there is a great need to demonstrate and improve the performance of IGCC with these fuels. Studies by EPRI and E Gas (COP) indicate that COP IGCC plants do not appear to compete economically with PC plants when using PRB coals and lignites.

Entrained flow gasifiers can process all ranks of coal; however the existing commercial gasifiers all show a marked increase in cost and reduction in performance with low-rank and high-ash coals. For slurry-fed gasifiers (GE and COP) the energy density of the high moisture and/or high ash coal slurries is markedly reduced, which increases the oxygen consumption and reduces the gasification efficiency. For dry-coal-fed gasifiers (Shell) there is an energy penalty for drying the high moisture coals to the low moisture content necessary for reliable feeding via lock hoppers and pneumatic conveying.

Although IGCC is close to being competitive with PC for bituminous coals, the IGCC—PC capital cost and Cost of Energy (COE) gap widens for low rank coals to about $200-$300/kW for PRB coal and approximately $400/kW for US lignites.

Studies by E Gas and We Power evaluated IGCC technology utilizing PRB coals. EPRI compared results of both studies to Pulverized Coal (PC) plants utilizing the same fuel. With a spare gasifier, the COE for both COP and Shell IGCC is $10-$11/MWh higher than subcritical PC. Without the spare gasifier, the Shell COE is still $6/MWh greater than the PC.

IMPACT OF PRB COAL AS PRIMARY FUEL

PRB coals have lower heating values, higher moisture content and different ash characteristics than bituminous coals. These characteristics of PRB coal will increase the cost and reduce the performance of units designed to burn PRB coals. Due to design modifications required to burn the PRB coal, EPRI report # 1009769 indicates that capital costs will increase by factors of 1.13 for supercritical pulverized coal (SCPC) units and 1.22 for IGCC units when compared to cost projections for units burning bituminous coals[1]. Similarly, heat rates increase by factors of 1.06 for SCPC units and 1.14 for IGCC units when compared to heat rates for units burning bituminous coals.

The table below is taken from table 6-1 and table 6-2 of EPRI report # 1009808. In the EPRI report, these tables indicate cost and performance characteristics of the primary IGCC technologies (GE, COP, and Shell) utilizing <u>bituminous</u> coal. The cost factors included in the above paragraph have been applied to the table below so that the results shown are indicative of IGCC cost and performance with PRB fuel.

IGCC COST AND PERFORMANCE (FIRST QUARTER 2004 $'s SHOWN)					
	GE Quench	**GE RQ**	**GE R + C**	**COP**	**Shell**
Average Installed Cost with Spare Gasifier ($/kW)	$ 1,684	$ 2,013	$ 2,013	$ 1,769	$ 2,159
Average Installed Cost NO Spare Gasifier ($/kW)	$ 1,598	$ 1,769	na	$ 1,647	$ 1,928
Net MW	520	550	560	530	530
Capacity Factor	80%	80%	80%	80%	80%
Net Heat Rate Btu/kWh HHV	10,602	9,907	9,690	9,747	9,576
Fixed O&M ($/kW-Year)	$54.40 to $57.30	$60.20 to $68.50	$68.50	$56.00 to $60.20	$63.20 to $70.80
Variable O&M $/MWh	$ 1.10	$ 1.00	$ 1.00	$ 0.90	$ 0.90
COE $/MWh *	$49.40 to $51.30	$52.00 to $57.20	$57.00	$49.10 to $51.70	$54.50 to $59.50
TPC Range With Spare ($/kW)	$1659 to $1708	$1867 to $2159	$1867 to $2135	$1732 to $1800	$2037 to $2281
TPC Range NO Spare ($/kW)	$1574 to $1623	$1671 to$1903	na	$1610 to $1678	$1830 to $2025
Lbs CO2/MWh	2,173	2,031	1,986	1,998	1,963

Factors Applied to EPRI Report # 1009808 Tables 6-1 and 6-2 for PRB coal Vs Bituminous coal
Installed Cost = 1.22
Heat Rate = 1.14

EPRI PC COST AND PERFORMANCE COMPARISON

The table below is taken from Table 4-4 of EPRI report # 1009808, the same report as the above Table of IGCC costs. The SCPC costs are based on a similar Midwest location and include the impacts of sub-bituminous coal as included above.

SCPC PLANT COST AND PERFORMANCE (FIRST QUARTER 2004 $'s SHOWN)		
Plant Size (MW)	**500**	**800**
TPC ($/kW)	$ 1,389	$ 1,205
Fixed O&M ($/kW-Year)	$ 43	$ 36
Variable O&M $/MWh	$ 1.60	$ 1.60
Capacity Factor	80%	80%
Net Heat Rate: Avg. Annual Btu/kWh HHV	9,772	9,619
Net Heat Rate: Full Load Design Btu/kWh HHV	9697	9546
COE $/MWh	45.1	40.3
Lbs CO2/MWh	1,988	1,957

IATAN UNIT 2 COST AND PERFORMANCE

Burns and McDonnell completed a Project Definition Report for the Iatan-2 unit in August 2004. The results of the Burns & McDonnell report are shown in the table below for comparison to the IGCC cost and performance shown in the above table.

IATAN-2 COST AND PERFORMANCE		
Item	**2009 $'s**	**2004 $'s**
Installed Cost ($/kW)	$ 1,435	$ 1,268
Net MW	800	800
Capacity Factor	85%	85%
Net Heat Rate Btu/kWh HHV	9,100	9,100
Fixed O&M ($/kW-Year)	$ 11.06	$ 9.78
Variable O&M $/MWh	$ 2.21	$ 1.95
COE $/MWh*	$ 40.70	$ 35.97
Lbs CO2/MWh	1,866	1,866
*Calculated based on costs included in Burns & McDonnell Iatan-2 Project Definition Report, August 2004		

IGCC EMISSION COMPARISONS

One of the reported benefits of IGCC technology that has been characterized in numerous press releases is that IGCC offers significant environmental benefits over the traditional pulverized coal technology. Most often the emissions of an IGCC plant are compared to existing coal fueled power plants. When the comparison is made between IGCC and a new state-of-the art SCPC the results can be quite different. As shown in, the table below, which compares the emissions data for both technologies, the two technologies are reasonably close in emissions categories. With the newer high efficiency supercritical designs offered today, the pulverized coal projected heat rates have moved much closer to the projected IGCC heat rates which are lower than the traditional natural gas fired combined cycle heat rates due to the addition of the gasifier and emissions controls. In the area of NOx removal, SCPC is projected to achieve lower levels than IGCC technology.

Emission Comparison - IGCC vs. SCPC			
	SO_2 Removal	NOx Emission Rate	Mercury Removal w/o carbon injection
SCPC	95 – 98%	0.08 lb/MMBtu	$\geq$70%
IGCC (without SCR)	99%	$\leq$0.07 lb/MMBtu	>90%

KCP&L FINDINGS AND RECOMMENDATIONS

Although IGCC appears to be a promising new technology, there are still numerous developmental, operational and design/construction cost issues that need to be resolved before large-scale IGCC electric generation facilities utilizing coal as the primary feedstock can become commercially viable. There are significant operating cost, capital cost, and reliability risks associated with adopting this technology over more proven SCPC technology.

As part of KCP&L's Resource Plan's screening process IGCC was thoroughly studied and evaluated. After many months of data acquisition and evaluation IGCC was rejected due to the immaturity of the technology. KCP&L's concerns with premature implementation of IGCC technology are consistent with the concerns expressed by other utilities and regulatory agencies concerning this technology (see Supplemental IGCC Review located at the end of this appendix). KCP&L believes that since no utility scale IGCC plant has been fully developed into a mature, cost competitive and reliable technology, the addition to KCP&L's generating fleet of an IGCC plant instead of a SCPC by the end of this decade is not in the best interest of its customers.

KCP&L recommends the installation of SCPC technology as proposed in the Comprehensive Plan. This alternative will provide KCP&L customers greater protection from exposure to the technology risks associated with IGCC. KCP&L will continue to follow the development of IGCC technology and assess its application for future decisions on generating additions.

(1) EPRI report # 1009808, Updated Cost and Performance Estimates for Clean Coal Technologies including CO2 Capture—2004, Technical Update March 2005, N. Holt and G. Booras
(2) EPRI report # 1009769, Gasification Technology Status—September 2004, N. Holt

EXHIBIT 1: EXISTING IGCC DEMONSTRATION PLANTS

There are only 4 demonstration IGCC units worldwide designed specifically for power generation based on the use of coal as the primary fuel. The location, size and in-service dates are shown below:

1. Wabash River, Indiana (262 MW, October 1995). During the first three quarters of 2003, the gasification unit was online 61.3%, with 15.5 % not required. Syngas availability was 74%.
2. Tampa Electric, Florida (250 MW, September 1996). This unit currently burns a mixture of 55% petroleum coke and 45% coal. Gasifier on-stream time has averaged 75% in 2001-2003.
3. NUON, Buggenum, The Netherlands (253 MW, January 1994). Due to CO2 emission restrictions, this plant now runs on natural gas. Coal gasification is no longer utilized, however, attempts are underway to test the gasifier with biomass fuel.
4. ELCOGAS, Puertollano, Spain (300 MW, December 1997). From August 2003 to July 2004, the gasifier on-steam time averaged 69.2%. Operating hours in IGCC mode peaked at 5,408 hours in 2002 (62%).

All four are demonstration projects designed to test a specific component of the technology and none of the projects are considered to be demonstrations of commercially viable projects. All four use different design technologies. All four included significant cost sharing through governmental and/or developmental grants. In addition to these 4 units, Pinon Pine is a demonstration plant under the DOE CCT demonstration program located at Sierra Pacific's Tracy station near Reno, Nevada. Coal derived fuel gas was never delivered to the combined cycle unit during the demonstration period. The longest gasifier run was conducted in early 2001 for approximately 25 hours. The unit is now operated in combined cycle mode on natural gas.

The table below summarizes design aspects of the 4 demonstration IGCC plants and is taken from Table 3-2 in EPRI report # 1009769.

Design Aspects of Large Scale Demonstration IGCC Units				
Project Name	**Wabash**	**Tampa**	**NUON**	**ELCOGAS**
Location	Indiana, USA	Florida, USA	The Netherlands	Spain
Gasification Technology	ConocoPhillips	Texaco	Shell	Shell
Gasifier Type	2-stage upflow entrained	single stage downflow entrained	single stage upflow entrained	single stage upflow entrained
Feed System	coal water slurry	coal water slurry	dry coal lock hoppers	dry coal lock hoppers
Slag Removal	continuous	lock hoppers	lock hoppers	lock hoppers
Slag Fines Recycle	yes	yes	yes	yes
Recycle Gas Quench	some to second stage	none	large recycle quench to 1472 degrees F	large recycle quench to 1472 degrees F
Syngas Cooler Type	downflow firetube	downflow radiant water tube and convective firetube	downflow concentric coil water tube	upflow/downflow (two pass) radiant water tube and convective water tube
Nitrogen Use	mostly vented	GT NOx control	syngas saturator for GT NOx control	syngas saturator for GT NOx control
Gas Clean Up				
Particulate Removal	candle filter at 350 degrees C	water scrub, no filter	candle filter at 230 degrees C	candle filter at 240 degrees C
Chloride Removal	water scrub added '96	water scrub	water scrub	water scrub
COS hydrolysis	Yes	added in 1999	Yes	Yes
Acid Gas Removal Process Solvent	MDEA	MDEA	Sulfinol M	MDEA
Sulfur Recovery	Claus plant with tail gas recycle to gasifier	Sulfuric acid	Claus plant with tail gas treating unit (SCOT)	Claus plant with tail gas treatment and recycle to COS
Combustors	multiple cans	multiple cans	twin vertical silos	twin horizontal silos
Firing Temperature (degrees F)	2300	2300	2012	2300
NOx Control	saturation and steam injection	saturation and nitrogen dilution	saturation and nitrogen dilution	saturation and nitrogen dilution
Demonstrated Plant Performance (Through 2002)				
Maximum Gasification Hours per Year	5139	6852	5792	5408
Gasification Availability % (Max Hrs/8760)	59%	78%	66%	62%
MW Output Design (Achieved)	192 (192)	192 (192	155 (155)	182 (196)
Aux Load (MW) Design (Achieved)	35 (36)	63 (66)	31 (31)	35 (37)
Net Plant Heat Rate Btu/kWh, HHV Designed (Achieved)	9030 (8600)	8600 (9100)	8240 (8240)	8230 (8190)
Net Plant Efficiency				
LLV Design (Achieved)	39.2 (41.2)	41.2 (38.9)	43 (43)	42.2 (42.4)
HHV Design (Achieved)	37.8 (39.7)	39.7 (37.5)	41.4 (41.4)	41.5 (41.7)

The 4 existing IGCC plants discussed above can be considered the "Alpha version" of IGCC technology. The issues/problems listed below are examples of typical items encountered with the first rollout, or "Alpha version", of a new technology. The next cycle of IGCC units to be built would be considered the "Beta version" of the technology, or the second attempt at commercialization. It is expected that the problems listed below would be corrected in the Beta version of the technology. However, the design changes incorporated to alleviate these problems can often result in new problems. In addition, the Beta versions will be attempts to scale-up the size of the units for economies of scale. Design changes for the scale-up can also introduce new operating issues, material issues, expansion and support issues as well as other problems.

Examples of Developmental Issues at Wabash River

- 1997, main steam piping support systems were modified to allow for needed expansion during start-ups. Tube leaks continued to be a problem after this modification
- 1997, HRSG was planned for replacement due to Foster Wheeler designed support issues.
- 1997, feed water heating problems limited steam turbine output by 9 MW.
- 1999, a 14-week unscheduled outage occurred due to failure of the air compressor rotor
- 1999, a water spray system was added to the air intake to eliminate capacity limitations due to temperature
- 1999, unit set continuous operating record of over 1,300 hours, 128 consecutive days of gasification operation
- 2000, Air Separation Unit (ASU) and power block showed high downtimes, HRSG tube failures caused 19 days of unscheduled outage.
- 2002, unplanned outage rate of 6.5%, planned outage rate of 6%. Syngas unit availability was 78.7% with a forced outage rate of 11%. 4th quarter slag-tap pluggage caused a 10-day forced outage.
- 2003, unplanned outage rate of 13%, planned outage rate of 10.3%
- Syngas Cooler (SGC) requires two outages per year due to fouling.
- Refractory change out required every 2-3 years. Refractory patching required on each outage (planned and unplanned), especially in the slag-tap area.
- Wabash has a spare gasifier, so the outage impact of refractory problems is minimized.

Generic Issues With Existing IGCC Technology

Listed below are various equipment components and their associated operational and developmental issues. Design changes for the Beta version IGCC units will no doubt address these issues; however, the success of design changes cannot be verified until the Beta units accumulate adequate operating experience.

Air Separation Units (ASU)

ASU's are utilized in many industries and numerous applications. Historically, ASU's have experienced high availabilities around 98%, however, the ASU's developed for the Wabash and Tampa IGCC's have experienced unusual problems and outages.

Coal Feeding

Wet coal slurry feed pumps are very reliable at Wabash; however, Tampa made design decisions to eliminate some of the features of the Wabash pumps and has encountered forced outages due to these pumps. Dry coal feed systems used at NUON and ELCOGAS require more maintenance than the wet slurry systems for continuous operation.

Fuel Injector Tip Life

Initial fuel injector life for the wet slurry was initially 60 to 90 days. Modifications have improved performance to over 4,000 hours of operation between replacements. New operating procedures allow tip replacement in as little as 18 hours.

Refractory Life

Refractory life for both Wabash and Tampa is typically 2-3 years, however patching repairs are performed during each outage. Partial replacements require a 12-15 day outage, while full replacement requires 30-35 days.

According to EPRI reports, for future commercial IGCC plants in the 500-600 MW range, spare gasifiers will be required for the Texaco and the E-Gas designs to achieve availabilities in the 90% range. E-Gas presented a paper in 2002 indicating a single gasifier is expected to provide 80% availability in the next generation of IGCC units. However, neither of these projections has been documented in practice.

Circulating Slag Water

Circulating water from the slag quench chamber contains sharp fine solids so erosion is a constant problem. Future designs need to incorporate long radius bends where possible to minimize erosion problems. Acid or Alkali are often required to be added to the quench water to keep pH in a range to avoid corrosion and prevent precipitation.

Slag Tap Blockage

This problem has occurred occasionally at all 4 units. Generally 8-10 days of outage are required to remove the blockage.

Syngas Cooler Fouling and Corrosion

Fouling of this component has lead to forced outages on all 4 existing units. For the NUON and ELCOGAS units, this has not been a significant cause of plant outages.

Salable By-Products

One of the advantages claimed for IGCC is its potential to produce by-products such as slag, elemental sulfur or sulfuric acid, which can be sold as useful commercial materials. This also holds true for SCPC units also can produce by-products such as fly ash for use in concrete and gypsum for the manufacturer of wallboard.

SUPPLEMENTAL IGCC REVIEW

PUBLIC SERVICE COMMISSION OF WISCONSIN, Re: W.E. PROPOSED IGCC PLANT

In testimony before the Public Service Commission of Wisconsin, Docket No. 05-CE-130, Allan Mihm, Director of Engineering for W.E. Power provided the cost estimates shown below:

"The cost in 2003 $'s for both SCPC (Super Critical Pulverized Coal) generating facilities is approximately $1.7 billion or $1,400/kW. The 2003 cost of the single IGCC facility is about $920 million or $1,740/kW." These costs were developed as part of an IGCC Technology Evaluation Study performed by Fluor Corporation.

Mr. Mihm also added the following comments:

"To date, only a few commercial scale coal-based IGCC power plants have been constructed and none at the size contemplated in our application. The engineers and contractors who constructed these (existing) plants were not required to take any significant risk for performance guarantees for the gasification section of the facility, nor the facility as a whole. The EPC industry is not likely to provide total plant guarantees for IGCC plants in today's market. As more experience constructing and operating IGCC plants is acquired, it is believed that the EPC industry may be willing to provide performance guarantees similar to those for conventional power plants....In today's market, it was a general consensus (among several EPC vendors) that a cost adder of at least 10% would be needed to cover the risk associated with cost, schedule and performance guarantees."

Mr. Douglas H. Cortez, Vice President, Project Development and Finance, at Fluor Corporation also testified in front of the PSCW. His response to the question, "How would you answer the arguments of those who support the position that all 3 proposed coal-based units be IGCC," is shown below:

"Although the technology has the potential to deliver these benefits (principally lower air emissions), the technology has yet to be proven as reliable as the SCPC technology on the same commercial scale. In addition, the cost of electricity from the IGCC technology available today is expected to be higher based on currently available equipment...Although W.E. could choose to construct three IGCC units at this time to meet electricity demands, it would place the utility consumers in Wisconsin at a level of risk that may be difficult to measure or control at this time."

The Citizens' Utility Board (CUB, of Wisconsin) filed a brief in Docket 05-CE-130 addressing the substantive issues of W.E.'s proposed construction plans. Key portions of that filing are shown below.

"The commission should reject the proposal for approval of an IGCC unit to be ready for operation by 2011." Technology issues sited as reasons for rejecting the proposed IGCC unit are shown below:

- "There is inadequate information to justify cost, reliability and design and operation of the proposed IGCC unit; and,
- The record does not indicate that an IGCC unit is appropriately added in 2011 (or in fact any year in the study period is an IGCC unit found to be a cost-effective resource option)."

In its final ruling regarding the proposed W.E. IGCC unit, the PSCW determined, "The IGCC unit is not cost-effective at this time."

SUPPLEMENTAL IGCC NEWS:

IGCC PRESS RELEASES

GE Energy, Bechtel Announce Alliance for Cleaner Coal Projects; Companies to Offer Standard, Optimized Package for IGCC Power Projects

ATLANTA & SAN FRANCISCO--(BUSINESS WIRE)--Oct. 4, 2004--GE Energy and Bechtel Corporation today announced their intent to establish an alliance to develop a standard commercial offering for optimized integrated combined-cycle gasification (IGCC) projects in North America.

IGCC systems convert coal and other hydrocarbons into synthetic gas, which after cleanup is used as the primary fuel for a gas turbine in a combined-cycle system. IGCC systems offer significant environmental benefits compared to traditional pulverized coal power plants.

The alliance will integrate the development, marketing, commercialization and implementation of GE's IGCC process with Bechtel's engineering, procurement and construction (EPC) expertise.

Bechtel is one of the world's leading EPC contractors, with significant experience in the design and construction of gasification plants.
GE Energy is a leading supplier of gas turbines for IGCC applications, having provided gas turbines for more than 60 percent of the world's operating IGCC plants. The company also recently purchased the Chevron Texaco gasification technology business, whose technology has been applied to many of the world's IGCC power plants.

GE Energy has worked with Bechtel on a number of IGCC projects, including the 100-megawatt Cool Water plant in California, a demonstration project completed in 1984, and the Tampa Electric Company's 250-megawatt Polk Power Station in Florida, which began operation in 1996.

Edward Lowe, general manager of gasification and product line management for GE Energy, said: "We look forward to our alliance with Bechtel, which will enable both companies to integrate their complementary strengths and resources. The IGCC alliance will benefit our clients through commercialization and execution of IGCC projects, based on a standard GE IGCC product."

Lowe added, "The alliance will initially focus on establishing successful IGCC ventures for the power generation market in the U.S., establish a leadership position in the production of cleaner power from coal and petroleum coke, and bring value to a wide range of customers."

Scott Ogilvie, President of Bechtel Power Corporation, said: "We are very excited to be aligning Bechtel's and GE's expertise and resources to further advance gasification technology, and to provide competitive gasification solutions to the industry. This alliance can significantly improve prospects for developing cleaner coal projects and will enhance the competitiveness of IGCC in the areas of price, performance, schedule, availability and emissions."

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INTRODUCTION

The purpose of this Technology report is to identify and compare economic, environmental, and technical aspects of a wide variety of available energy producing and storage technologies. Economic variables that will be considered include construction, maintenance, operating, and fuel costs. Projected unit life, availability, and efficiency are among the performance characteristics that will be reviewed. Environmental compliance issues will be assessed with regard to scenarios developed by KCP&L's 2004 Strategy Review Teams. Table 1 outlines a list of the technologies that will be reviewed illustrating the current operating duty and the range of available capacities proposed or in use today.

When comparing different technologies it is important to understand the different generating duty each is designed to perform. Base load units generate the bulk of a utilities required energy and generally have high capital cost, low operating costs and are essentially operated around-the-clock. Peaking units are designed to handle short-term system peaks and generally have low capital cost, high operating costs, and are generally required to operate only 1 to 10% of the time. Peak-shaving units are designed to provide emergency and short-term ride-through generation. These units typically have high capital costs, high operating costs, and provide less than ten hours of generating capability annually.

Table 1: Technology Review

Technology	Duty	Capacity Range (MW)	
		Low	High
Pulverized Coal (PC) w/ SCR, FGD, PJBH, and ACI *	Base Load	500	800
Integrated Gasification Combined Cycle (IGCC)	Base Load	260	520
Circulating Fluidized Bed (CFB) w/ FGD, SCR, PJBH, and ACI	Base Load	20	420
Biomass (Utilizing Switchgrass)	Base Load	30	100
Nuclear	Base Load	150	1200
Natural Gas Simple Cycle (NGSC)	Peaking	20	180
Natural Gas Combined Cycle (NGCC)	Intermediate	260	520
Solar	Intermediate		
Energy Storage			
Battery	Peak Shaving	0.5	40
Compressed Air	Peak Shaving	5	350
Pumped Hydro	Peak Shaving	50	350
Flywheel	Peak Shaving	0.1	2
Superconductive Magnetic	Peak Shaving	0.1	6
Distributed Generation	Peak Shaving	1	25

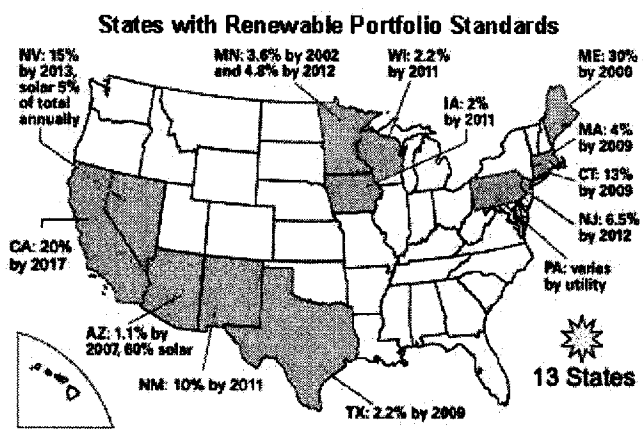
* FGD *Fluidized Gas Desulfurization* *(SOx Control)*
SCR *Selective Catalytic Reduction* *(NOx Control)*
PJBH *Pulse Jet Baghouse* *(Particulate Matter (PM) Control)*
ACI *Activated Carbon Injection* *(Mercury Control)*

Future multi-pollutant emission limits are a very influential economic driver that may dictate the use of one technology over another. The term multi-pollutant control broadly refers to any technology or combination of technologies that achieves significant reductions in SO_x, NO_x, PM, Mercury (Hg), and potentially CO_2 emissions. Table 2 lists the emission limits KCP&L believes will most likely be enforced in future years. The majority of pollutants can be economically controlled using proven technologies. The exceptions are Hg and CO_2. Although Hg removal technologies are yet to prove themselves, preliminary test results indicate that existing technology is able to adequately remove this emission at reasonable cost. CO_2 restrictions are without doubt the most disruptive issue for utilities primarily burning coal for base load energy production. If significant CO_2 reduction is eventually mandated, the high cost of retrofitting existing plants for the recovery of CO_2 from boiler flue gas and the associated parasitic power penalties are expected to be cost prohibitive. Significant CO_2 emission restrictions are expected to force the replacement of some coal-fired units with more efficient, less CO_2 intensive technologies. This is expected to include a combination of renewable generation, major DSM programs, a return to natural gas fuels (NGCC), and possibly the return of nuclear generation to meet future energy needs.[6] An additional technology that may become more commonplace is Integrated Coal Gasified Combined Cycle (IGCC). Although this technology produces the same quantity of CO_2/mmbtu, it is slightly more efficient that supercritical PC generation with most coals and the costs associated with CO_2 capture and sequestration are significantly less than with PC generation. However, IGCC is currently an unproven technology.

Table 2: Expected Environmental Limits

Emission	NO_x	SO_2	Hg		CO_2	
Starting Year	2009 / 2018	2010 / 2015	2010 / 2015 / 2018	2010 / 2015 / 2018	2012 / 2013 / 2015 / 2018 / 2020	
	#/mmbtu	% Reduction	Limit (Tons)	% Reduction	% Below Year →	
Kansas						
Low+	.22 / .22	50 / 67	34 / 34 / 15	30 / 30 / 69	0 / 0 / 0 / 5 / 5	2000
Base	.13 / .09	50 / 67	25 / 10 /10	48 / 80 / 80	0 / 0 / 0 / 0 /10	1990
KCP&L	.22 / .22	50 / 67	34 / 34 / 15	30 / 30 / 69	0 / 0 / 5 / 5 / 10	2000
Missouri						
Best	.22 / .22	50 / 67	34 / 34 / 15	30 / 30 / 69	0 / 0 / 0 / 5 / 5	2000
Worst	.13 / .09	50 / 67	25 / 10 /10	48 / 80 / 80	0 / 0 / 0 / 0 / 10	1990
KCP&L	.13 / .09	50 / 67	34 / 34 / 15	30 / 30 / 69	0 / 0 / 5 / 5 / 10	2000

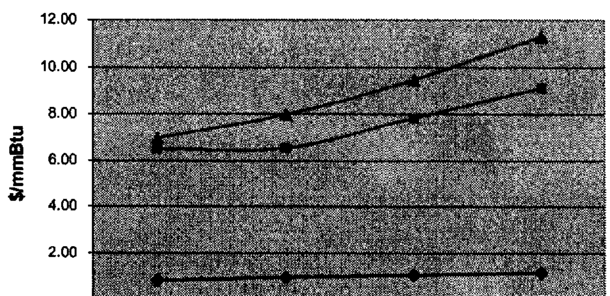
Figure 1: Renewable Portfolio Standards



Another environmental issue that is expected to impact future generation is the Renewable Portfolio Standard (RPS). RPS is a requirement that a small but growing percentage of the nation's electrical energy come from renewable sources like wind, solar, biomass, and geothermal energy. The Union of Concerned Scientists is calling for the minimum level or "standard" to be 2.5% of all electric generation by 2000, 5% by 2005, and 10% by 2010.(3) Several legislative efforts have been introduced in Congress to implement a nationwide RPS. While Kansas and Missouri currently have not imposed RPS, thirteen other states presently enforce some form of RPS that ranges from 1.1% to 12% in 2010.(4) Generally, State and Congressional legislative efforts establish these standards with low initial requirements and gradually increase the requirements annually using a fixed percentage increase.

Future anticipated fuel price and availability is another driver that will influence the selection of one technology over another. The primary fuel burned at KCP&L is low-sulfur Powder River Basin (PRB) coal. Because of KCP&L's geographic location, PRB coal is the most available, abundant, and typically least expensive source of delivered coal. While there may be closer, less expensive sources of high and low sulfur coals, these sources do not exist in large enough quantities to support large base-load units. It is estimated that the largest base-load unit that could be economically installed and supplied by these other sources of coal could be no larger than 100 to 150 MW. KCP&L also has several oil-fired and gas-fired simple and combined cycle combustion turbines used primarily for peak load operations. Expected delivered fuel price and historical fuel usages are shown below in Figure 2.

KCP&L's total generating summer capability, excluding nuclear generation, is estimated to be 4,345 MW. KCP&L's anticipated future generating capacity is also a critical factor which cannot be ignored. Figure 3 below illustrates the level of capacity growth KCP&L expects will be required in future years.



	2005	2010	2015	2020
Coal (98.1%)	0.77	0.90	1.01	1.10
Gas (1.7%)	6.44	6.52	7.81	9.12
Oil (0.1%)	6.94	7.95	9.45	11.27

Year

Figure 2: KCPL Coal Prices

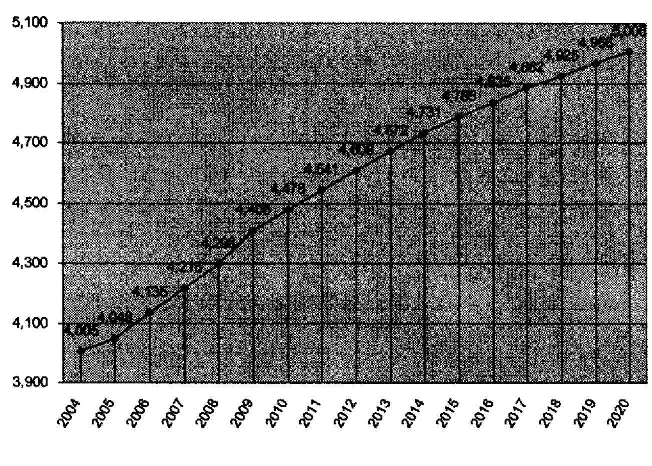


Figure 3: KCPL Capacity Needs (MW)

TECHNOLOGY REVIEW

The uncertainty surrounding future CO_2 restrictions is the primary issue impacting the viability of alternative future generating technologies. While most pollutants can be controlled somewhat economically, CO_2 removal is extremely capital intensive and carries large parasitic power penalties (high Aux loads). At this time there are no economical technologies on the horizon that address CO_2 removal.[6] Currently, the cost of CO_2 capture is high, with estimates ranging from around $60 to $250 per ton of carbon avoided.[9] CO_2 emission rates for various fuel types are shown below:

- PRB Coal = 205 lbs/mmbtu
- Oil = 161lbs/mmbtu
- Natural Gas = 118 lbs/mmbtu

From the above figures, it is clear that natural gas would be the preferred fuel for reducing CO_2; however, the future availability and cost of natural gas is expected to make fuel switching an uneconomic alternative. Obviously, efficiency gains will play a significant role in reducing CO_2 emissions. This can be achieved through uprates on existing units and/or retirement of older, inefficient plants and replacement with newer, more efficient generators. Renewables can also play a key role in reducing CO_2 emissions.

The above discussions indicate the significance future environmental and fuel availability issues will play in KCP&L's selection of new generating technologies. The following portions of this report address individual generating technologies with a focus on these issues. The "Future Status" subsection listed for each technology represents KCP&L's opinion regarding the future use of the specific technology with consideration given to future CO_2 emission restrictions and other key economic drivers.

Pulverized Coal

Future Status:

It is believed that all supercritical (SCPC) or subcritical (SPC) pulverized coal installed in the future will include the addition of SCR, FGD, ACI, and PJBH equipment to comply with current and anticipated environmental emission restrictions other than CO_2 restrictions. This equipment is also required to meet the Best Available Control Technology (BACT) standards. Because SCPC units are typically more efficient than SPC units it is likely that SCPC technology will be the dominant PC generating technology in future years.

If CO_2 emission restrictions are not enforced, or the anticipated level of restrictions is significantly reduced, SCPC units will remain the most economical sources of electrical base load generation. If CO_2 restrictions are imposed, it is believed that new SCPC units will continue to be the economic choice for some time; however, older and less efficient PC units will face potential retirement with replacement capacity being installed in the form of either newer SCPC technology, renewable technologies, DSM programs, and/or new technologies still under development such as IGCC or the new generation of nuclear plants.[6]

General Technology Overview:

Pulverized coal (PC) technology is the workhorse of the electric utility industry. In 1999, approximately 306 GW of conventional coal-fired generation capacity was operating in the United States, contributing about 41% of the national generating capacity and 54% of the annual power generation.[1] Approximately 55% of KCP&L's current base load capacity is supplied by PC units. KCP&L is very familiar with the costs and skills required to operate and maintain PC units.

Other than for CO_2 and mercury emissions, proven equipment currently exists that will enable PC units to meet or beat future anticipated environmental emission requirements. Presently, heat rate improvements seem to be the only viable method for controlling CO_2 emissions from PC units. Co-benefits from SCR's, wet scrubbers and baghouses are anticipated to capture up to 70% of the mercury currently being emitted. Activated carbon injection (ACI) technology looks to be the most promising method of removing higher levels of mercury emission from coal-fired flue gas streams.

Currently PC units are being installed with selective catalytic reduction (SCR) systems to handle NO_x emissions, fluidized gas desulfurization (FGD) scrubbing processes to handle SO_x emissions, and pulse-jet baghouses (PJBH) to handle particulate and minimize mercury emissions. FGD systems can be lime-spray drying (LSD (know as dry)) or limestone-forced oxidation (LSFO (known as wet)) processes. Although opinions vary, at this time KCP&L believes future PC units will utilize wet scrubbing processes because of the increased SO_2 removal characteristic, and the physical placement of the PJBH. Although unproven, data from the EPA's Information Collection Request (ICR) suggests that even without carbon injection, mercury removal for baghouse-equipped units for bituminous and sub-bituminous coal-fired units is greater than or equal to 65%. Thus, ACI equipment upstream of a baghouse can likely achieve mercury removals greater than 90% under most conditions.[5]

Cost And Performance:

Tables 3 and 4 below show the anticipated range of costs and performance characteristics associated with PC technologies.

Table 3: Subcritical Pulverized Coal (SPC)

Description	**Units**	**Range**		**Comments:**				**Reference:**
Duty Cycle		Base						(1)
Technology Rating		Mature						(1)
Capacity	MW	400	1,000					(1)
Fuel								(1)
Primary Type		Coal						(1)
Cost	$/mmBtu	0.071						(1)
Biomass	%	1	10					(1)
Flexibility Level		Low						(1)
Equiv. Planned Outage Rate	%	4.8						(1)
Equiv. Unplanned Outage Rate	%	4.9						(1)
Equivalent Availability	%	92						(1)
Planning Duration	Yrs	1	1.5					(1)
Construction Duration	Yrs	3	4					(1)
Useful Life	Yrs	30	40					(1)
		Base Unit Meeting BACT		90% Mercury Reduction Adder		90% CO_2 Capture & Sequestration Adder		
		Low	High	Low	High	Low	High	
TPC	$/kW	1,095	1,150			623	940	(8,10)
TCR	$/kW	1,553		62		812		(1)
Fixed O&M	$/kW-Yr	36.30		0.20	0.60	6.60		(5)
Variable O&M	$/MWh	2.80	7.40	0.25	1.60	5.50	8.45	(6,10)
Capital Additions	M$/Yr							
Heat Rate	Btu/kWh	9,054*	9,730	10,100		13,622		(1,7)
Marginal Cost	$/MWh							
Efficiency, (LHV)	%		41.2				30.9	(8)
Emissions	Lbs/mmBtu							
SO_2		0.167		0.12				
NO_x		0.104		0.06				
Particulate		0.018						
Hg		65		90				
CO_2		205				20.5		
CO								

* HHV Basis

Table 4: Supercritical Pulverized Coal (SCPC)

Description	**Units**	**Range**		**Comments:**				**Reference:**
Duty Cycle		Base						
Technology Rating		Mature						
Capacity	MW	400	1,300					
Fuel								
Primary Type		Coal						
Cost	$/mmBtu	0.071						
Biomass	%	1	10					
Flexibility Level		Low						
Equiv. Planned Outage Rate	%	4.8						
Equiv. Unplanned Outage Rate	%	4.1						
Equivalent Availability	%	92						
Planning Duration	Yrs	1.5	2.0					
Construction Duration	Yrs	3	4					
Useful Life	Yrs	30	40					
		Base Unit Meeting		90% Mercury		90% CO_2 Capture &		

		BACT		Reduction Adder		Sequestration Adder		
		Low	High	Low	High	Low	High	
TPC	$/kW	1,020	1,215			623	840	(7,8,10)
TCR	$/kW	1,540		52		812		(1)
Fixed O&M	$/kW-Yr	37.60		1.60		6.60		
Variable O&M	$/MWh	3.80	7.40	0.30	1.00	5.50	8.45	(1,10)
Capital Additions	$/Yr							
Heat Rate	Btu/kWh	8,277	8,823	9,100		11,037	12,751	(10)
Marginal Cost	$/MWh							
Efficiency, (LHV)	%	41.2	45.6			30.3	33.0	(8,10)
Emissions	Lbs/mmBtu							
SO_2		0.167		0.12				
NO_x		0.104		0.06				
Particulate		0.018						
Hg		65		90				
CO_2		205				20.5		
CO								

Integrated Gasification Combined Cycle (IGCC)

Future Status:

IGCC is currently a high-cost, high-risk alternative to conventional pulverized coal units equipped with BACT equipment. Significant operational issues remain for this technology, and another five to ten years of successfully demonstrated installed capacity is required before the technology can be considered commercialized. Additionally, future capital replacement costs are largely unknown. Further, the unique nature of IGCC technology will lead to higher training costs, added manpower costs due to required specialization, intense engineering support, and other significant learning curve related costs. The unknown costs described above in combination with the higher known installed and operating costs make IGCC technology an economically undesirable near-term future generating option.

However, if restrictions on mercury and CO_2 emissions become more stringent, IGCC technology will become much more attractive. The primary driver for considering IGCC technology is low air emissions and the ability to more easily control CO_2 and mercury emissions. Because IGCC units typically operate more efficiently than traditional pulverized coal units, IGCC units emit nearly 15% less CO_2 on a megawatt-hour basis. However, it should be noted that this efficiency difference shrinks significantly when comparing units fueled with PRB coals. The increase moisture content of the PRB coal significantly increases the auxiliary load of the gasification process, leaving the efficiency of both SCPC and IGCC essentially equal.

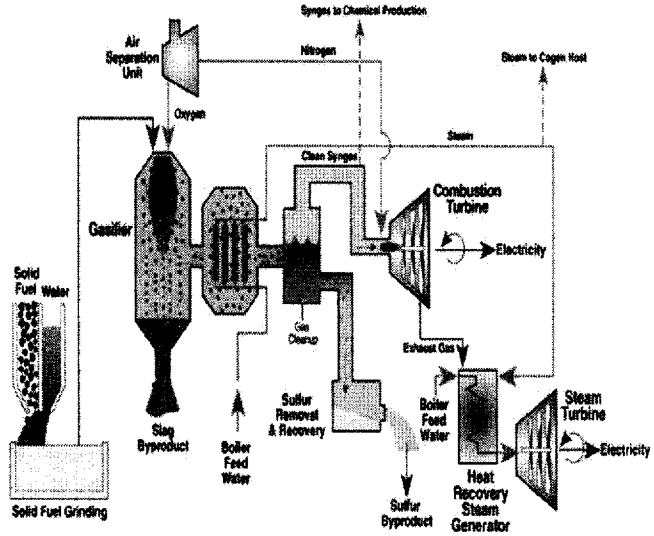
The capture of mercury, CO_2, and other trace elements by traditional, proven methods should be simpler and more economical. Emissions removal from an IGCC unit is expected to be easier because the high-pressure pre-combustion gas stream being treated is much more confined and controllable unlike a pulverized coal unit's exhaust gas stream. Achievable NO_x, SO_2, and particulate emissions from IGCC units are also typical lower than PC units. In ten years this technology is expected to offer a competitive alternative to pulverized coal generation largely based on the benefits of lower emissions, fuel flexibility, and lower installed capital costs.

General Technology Overview:

IGCC is a technology thought to offer numerous benefits including low emissions, the efficiency of a combined cycle unit, and fuel price stability due to reliance on abundant coal resources. However this technology remains unproven. Long-term costs and reliability are not well understood. EPRI still gives IGCC technology a "Demonstration" rating, clearly indicating that although IGCC demonstration plants have been in service for several years, the technology is still developing and not yet ready for full-scale commercial implementation.

Figure 4: IGCC Schematic

Gasification is a process that converts solid coal into a synthetic gas, referred to as syngas, composed mainly of carbon monoxide (CO) and hydrogen. An IGCC plant uses coal gasification to produce fuel for a combined cycle unit. A general flow diagram is shown in Figure 2. The main elements that differ from a typical combined cycle plant are discussed below to provide a basic understanding of the equipment.



The air separation unit (ASU) cryogenically separates ambient air into its major constituents, oxygen (O_2) and nitrogen (N_2). Most of the O_2 is needed in the gasification plant for the production of syngas, and most of the N_2 goes to the combustion turbine to dilute the fuel for NO_x abatement. The gasifier, under high pressure and temperature, converts oxygen and coal slurry into clean syngas and high-pressure steam. The syngas has a heating value that is 70% to 75% of the original fuel's heating value. Gasifiers operate between 2400°F and 2700°F. Pollutants, namely SO_2 and particulates, are efficiently removed from the high-pressure fuel gas stream using an intensive water scrubbing process, and converting any carbonyl sulfide compounds to hydrogen sulfide. The hydrogen sulfide is then removed by circulating an amine (MDEA) solution. Clean gas is reheated, filtered and delivered to the combustion turbine.

Gasifier performance is determined primarily by the quality of the supplied coal and the operating temperature. Carbon conversion and gasifier refractory life are directly related to the operating temperature. The higher the temperature, the more efficient the carbon conversion, and the more damage that is done to the refractory liner. Low-ash bituminous coal is recommended. Sub-bituminous and lignite can be processed; however increased oxygen requirements and loss of efficiencies make these fuels more expensive, unless a mine-mouth operation provides significant fuel savings. Additionally high-ash coals increase the chance of particulate carryover and damage to the combustion turbine. High-ash coal also increases handling and disposal, and contributes to early deterioration of downstream equipment.

Slag and sulfur are waste products derived from the gasification and scrubbing processes that can be made into marketable by-products. Slag can be utilized as aggregate construction material, and sulfur can be processed into 98% sulfuric acid. The quality of the slag, and the market demands for sulfuric acid greatly affect any anticipated financial benefits.

Benefits associated with IGCC technology can be summarized as follows:

- IGCC units exhibit excellent fuel flexibility
- IGCC units have exceptional environmental performance
- The high pressure, isolated gas stream is well suited for removal of CO_2 and Hg
- Coal gasification processes are easily diverted to co-produce methanol, gasoline, urea for fertilizer, hot metal for steel making, and assorted chemicals
- IGCC units can be built and sized as base load units
- IGCC units have higher cycle efficiencies than other coal-fired technologies burning bituminous coals. Current IGCC fuel efficiencies are 40%, and are expected to reach 52% by the year 2010 with bituminous Coals
- IGCC units allow for phased construction

Concerns regarding IGCC technology can be summarized as follows:

- High capital and operating costs

- Current IGCC units have lower equipment availabilities than NGCC units and PC units
- The operation of IGCC units require different technical skills than those typically used by current utilities
- IGCC units require another five to ten years of successfully demonstrated installed capacity before the technology can be considered commercialized
- IGCC units will need to operate as base load units to be economically viable
- IGCC units are regarded as an unproven 'high risk' investment
- Engineering, procurement, and construction (EPC) expertise needs to be developed
- Gasifier carbon conversion rates, refractory life, fuel injector tip life, SGC fouling and corrosion, and dew point (downtime) corrosion are major reliability and future cost concerns

Cost And Performance:

Table 5: Integrated Gasification Combined Cycle (IGCC)

Description	Units	Range		Comments:				Reference:
Duty Cycle		Base						(1)
Technology Rating		Nearly Mature		Only a few base load units in operation				(1)
Capacity	MW	260	520	Determined by CC units sizing				(1)
Fuel								(1)
Primary Type		Low Grade Fuels						(1)
Cost	$/mmBtu	0.071						(1)
Biomass	%	0	100	Fuel blending prior to gasification unlikely				(1)
Flexibility Level		High						(1)
Equiv. Planned Outage Rate	%	4.7						(1)
Equiv. Unplanned Outage Rate	%	10.1						(1)
Equivalent Availability	%	92						(1)
Planning Duration	Yrs	2.5	3.5					(1)
Construction Duration	Yrs	3	4					(1)
Useful Life	Yrs	30	40					(1)
		Base Unit Meeting BACT		90% Mercury Reduction Adder		90% CO_2 Capture & Sequestration Adder		
		Low	High	Low	High	Low	High	
TPC	$/kW	1,260	1,470			314	730	(8,10)
TCR	$/kW	1,540		52		812		(1)
Fixed O&M	$/kW-Yr	37.60		1.60		6.60		(1)
Variable O&M	$/MWh	3.80	7.90	0.30	1.00	3.70	4.60	(1,10)
Capital Additions	$/Yr							(1)
Heat Rate	Btu/kWh	8,081	8,823	9,100		9,462	12,751	(1,10)
Marginal Cost	$/MWh							(1)
Thermal Efficiency, (LHV)	%	42.2	46.3			36.1	38.8	(8)
Emissions	Lbs/mmBtu							
SO_2		0.167		0.12				
NO_x		0.104		0.06				
Particulate		0.018						
Hg		65		90				
CO_2		205				20.5		
CO								

Nuclear

Future Status:

Presently nuclear generation is not economically competitive with other technology alternatives. In addition to higher capital costs, many unknowns exist. A few of these unknowns are nuclear waste storage issues, permitting issues, and the potential reaction of environmental groups. If CO_2 emission restrictions are not imposed it is highly unlikely that nuclear generation will become a viable future generating option.

However, nuclear generation may become economically feasible, and quite possibly preferable, within the next ten to fifteen years if CO_2 emission limitations are imposed. Because nuclear generation is a mature, base-load technology, and is essentially pollution free there is a good chance that nuclear generation will be a dominant generating technology in a CO_2 restrictive environment.

General Technology Overview:

There are 103 reactors currently operational in the United States. The current operating designs are Light Water Reactors (LWR), which generate power through steam turbines. LWRs can be either Pressurized Water Reactors (PWR) or Boiling Water Reactors (BWR). PWRs use nuclear fission to heat water under pressure within the reactor. The water is sent to a heat exchanger (steam generator) where steam is produced to drive an electric generator. PWRs account for 69 of the 103 operable reactors in the United States. BWRs allow heat from the reactor core to boil the coolant water directly into the steam that is used to generate electricity. The typical annual capacity factor for nuclear reactors in the United States was greater than 90% in 2002. Average operating costs are slightly lower for LWRs than for operating coal-fired plants.

Presently there are three certified new reactor designs in the United States: the System 80+, the Advanced Boiling Water Reactor (ABWR), and the AP600. These designs are sometimes called Advanced Light Water Reactors (ALWR) because they incorporate more advanced safety concepts than the reactors previously constructed. The initial ALWR reactors as a group have been praised for their improvements in reactor safety and simplicity, but construction costs on a kilowatt of capacity basis might be a barrier to their success in the U.S. The ABWR design however has many variations and continues to be promoted in the U.S.

The primary source of doubt regarding the potential of nuclear power, at least in the U.S. has been whether the technology is too expensive to compete in the commercial marketplace. Concerns regarding construction costs contrast sharply with the comparatively low operating costs. Overall operating costs for nuclear power plants have been roughly the same as and more recently slightly less than operating costs for coal-fired plants for about two decades. Moreover, the fuel cost component is particularly low, which has helped give nuclear generation a favored position in the provision of base-load electric power.

Market analysis of the U.S. electricity generating market currently indicates that in order for a nuclear generating facility to be an attractive generating option in the future it must have an overnight capital cost of approximately $1000/kW, and a generating cost of less than about $0.03/kW-hr. Presently the AP100, a modified version of the Westinghouse AP600 design, is believed to have a capital cost of $1,365/kW for the first units, and $1,040/kW for the nth unit. Against these standards and discounting the threat of CO_2 emission restrictions, the costs of advanced nuclear power plants currently available are still too high.

Cost And Performance:

Table 6: Nuclear

Description	Units	Range		Comments:				Reference:
Duty Cycle		Base						
Technology Rating		Mature						
Capacity	MW	1,000	1,300					
Fuel								
Primary Type		Uranium						
Cost								
Biomass	%	0	0					
Flexibility Level		Low						
Equiv. Planned Outage Rate	%	8.2						
Equiv. Unplanned Outage Rate	%	9.8						
Equivalent Availability	%	82.8						
Planning Duration	Yrs	4	5					
Construction Duration	Yrs	5	6					
Useful Life	Yrs	30	40					
		Base Unit Meeting BACT		90% Mercury Reduction Adder		90% CO_2 Capture & Sequestration Adder		
		Low	High	Low	High	Low	High	
TCR	$/kW	1,915						
Fixed O&M	$/kW-Yr	69.9						
Variable O&M	$/MWh	0.60						

Capital Additions	$/Yr								
Heat Rate	Btu/kWh	10,200							
Marginal Cost	$/MWh								
Emissions	Lbs/mmBtu								
SO_2		0.0							
NO_x		0.0							
Particulate		0.0							
Hg		0.0							
CO_2		0.0							
CO		0.0							

Circulating Fluidized Bed (CFB) Combustion

Future Status:

CFB boiler technology is emerging as a viable and mature alternative to PC boiler technology under the right conditions. The choice between a CFB or PC boiler depends on site-specific factors such as generating capacity, fuels, fuel flexibility, air emission limits, and solid waste/solid by-products disposal/sale. The competitiveness of CFB technology improves with a requirement for fuel flexibility and an ample supply of low-cost fuel. However, CFB competitiveness falls short when faced with increasingly stringent environmental emission regulations that require the addition of back-end environmental equipment such as SCR, FGD, and ACI systems. Because these same back-end systems will be required for new PC units and because CFB units typically have higher capital costs, lower MW capacities, and are more complicated to operate, it is unlikely that CFB technology will be utilized within the KCP&L generating area. While CFB boilers are very suited to burn biomass, which will help to reduce CO_2 emissions, the level of CO_2 reduction is very small when compared to the level of CO_2 reduction required. This characteristic of CFB boilers alone will most likely not justify building a CFB boiler.

General Technology Overview:

CFB combustion is now well established as a mature power generation technology. There are over 370 units worldwide ranging between 20-320 MW, however, the majority of CFB units are in the 50-165 MW range. In 2003 plans were announce to build a 460-MW supercritical CFB boiler in Poland. A schematic of a CFB boiler system is shown in Figure 5. Except for the large cyclones between the furnace and convection backpass, a CFB boiler closely resembles a conventional PC boiler.

CFB technology utilizes the fluidized bed principle in which crushed (0.5 inch) fuel and (0.04 inch) limestone are injected into the furnace or combustor. The particles are suspended in a stream of upwardly flowing air that enters the bottom of the furnace through air distribution nozzles. Fine particles (<450 microns) are elutriated out of the furnace and then collected by the solids separators and circulated back into the furnace. This circulation provides efficient heat transfer to the furnace walls allows the fuel to circulate longer in the boiler. Similar to PC firing, the controlling parameters in the CFB combustion process are temperature, fuel residence time and turbulence. The combustion temperatures of a CFB boiler (1500-1650 °F) are much lower than a PC boiler (2500-2750 °F), which results in lower NO_x formation and the ability to capture SO_2 with limestone injection in the furnace. Even though the combustion temperature of CFB is low, the fuel residence time is higher than PC, which results in good combustion efficiencies comparable to PC. A turndown capability to about 35% of full load is characteristic of CFB boilers, however, as load is decreased temperature also decreases and there is some reduction in environmental performance.

The CFB can handle a wide range of fuels such as coal, waste coal, anthracite, lignite, petroleum coke, agricultural waste and biomass. Beyond the environmental benefits, fuel flexibility is one of the most important features of CFB technology. Fuel flexibility allows use of opportunity fuels where fuel supply uncertainty exists, or where low quality coals can be economically obtained. This degree of fuel flexibility is not available with competing conventional PC boiler technologies. Another major benefit of CFB technology is the ability to remove SO_2 and NO_x in the combustion process without adding post combustion cleaning equipment.

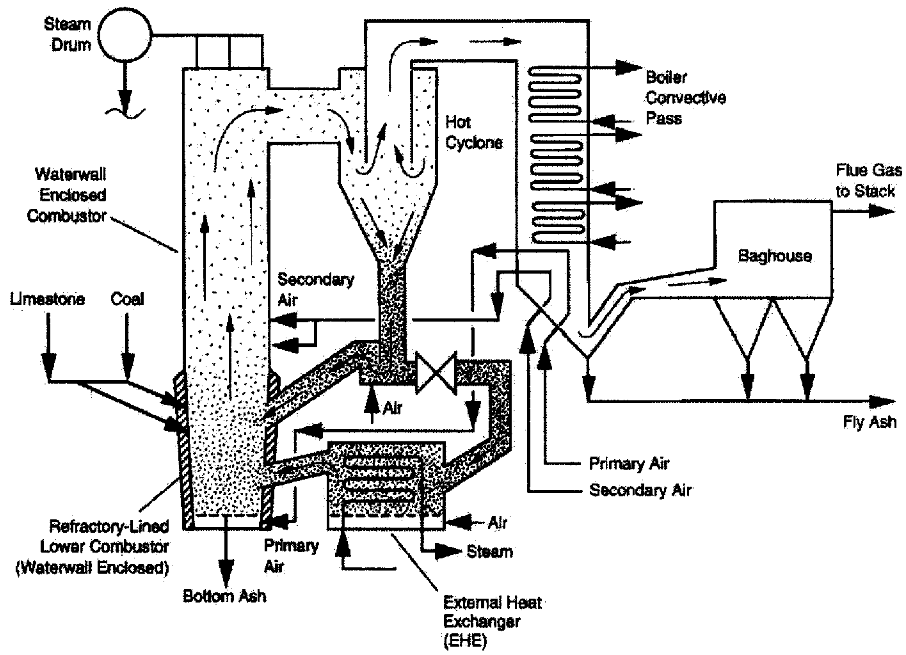


Figure 5: Schematic Of CFB Boiler System w/ External Heat Exchanger

Depending on boiler operating temperatures, which are a function of boiler load, NO_x emissions typically range from 0.10 to 0.20 lbs/mmBtu. To confidently achieve NO_x emissions below 0.10 lbs/mmBtu over the full range of possible boiler temperatures, SCR equipment in addition to, or in place of SNCR equipment will mostly likely be necessary. The cost of adding an SCR is expected to be \$50/kW to \$60/kW. NO_x emissions can also be reduced by limiting the amount of sorbent used for sulfur capture.

The amount of waste ash produced is a drawback of CFB technology. The large amounts of waste ash produced are caused by the inherently inefficient use of sorbent within the boiler. The most attractive means of reducing sorbent usage, thus reducing the amount of waste ash produced, is to incorporate FGD equipment, co-fire biomass, and fire sub-bituminous coal. A CFB boiler produces approximately 30% more ash (sorbent-derived material and coal ash) than a PC boiler with FGD equipment; consequently a CFB boiler has higher ash disposal rates. While regulatory requirements for SO_2 can be achieved by adding more limestone to the boiler, any increase in the percent of sulfur capture requires an exponential increase in the sorbent feed rate. This relationship generally makes a CFB unit uneconomic because of the increased sorbent consumption and solid waste output, as well as the negative impacts to boiler efficiency. In addition, the ash produced has a higher free-lime content and is more reactive making it more difficult to handle.

To achieve higher SO_2 capture rates with low limestone feed rates CFB boilers typically incorporate FGD systems. FGD systems, associated with low-sulfur fuel applications, are typically located before a baghouse or ESP and are now considered a best available control technology (BACT) for SO_2 control with CFB boilers. With no increase in sorbent consumption, FGD equipment is expected to improve overall SO_2 capture to 98% with high-sulfur fuels and greater than 95% with low-sulfur fuels. Also, FGD equipment should enable CFB systems to achieve conventional levels of SO_2 removal (91 to 93%) at reduced limestone consumption rates. Addition of dry or wet FGD equipment to the back-end of a CFB boiler is estimated to cost an additional \$40/kW or \$110/kW respectively to the total project cost. An added incentive for incorporating FGD equipment at the back-end of a CFB boiler is its ability to enhance the removal of mercury and trace elements, HCL, and HF.

When firing most coal varieties, CO emissions typically range from 0.10 lb/mmBtu at full load to 0.24 lb/mmBtu at reduced load. For sub-bituminous coals CO emissions are generally less than or equal to 0.10 lb/mmBtu. Given current efforts to reduce fossil-derived CO_2 emissions, one of the most promising applications of coal-fired CFB boilers may be in co-firing biomass. The outstanding fuel flexibility characteristic of CFB boilers make them well suited to co-fire biomass and so displace coal-derived CO_2.

This can be achieved by designing new CFB boilers to specifically fire biomass as a high percentage of its base fuel.

CFB boiler capital costs, net heat rates, and fixed operation and maintenance (O&M) costs are comparable to PC units. However, because of the higher rates of sorbent feed and ash removal, variable O&M costs for CFB units tend to be higher, although in the case of low sulfur fuels the difference is not significant. CFB boiler experience indicates that operation and maintenance costs are somewhat lower than PC boilers because of the ability to burn lower rank fuels, thus reducing fuel cost escalation uncertainty. Since CFB boiler maintenance areas are very minimal, the availability of the boiler is generally higher than PC boilers. Table xx outlines some advantages and disadvantages of CFB boilers with respect to PC boilers.

Table 7 - CFB Boiler w/o FGD Compared To PC Boiler w/ FGD

ADVANTAGES

- Physically smaller in size
- Well mixed combustion zone at uniform, lower temperature for optimal in-situ SO_2 absorption and NO_x reduction.
- Pulverizers are not required to crush fuel into fine particles
- Less danger of hot spots on boiler surfaces and likelihood of ash slagging and tube fouling problems
- Fuel flexibility (but extent depends on design of unit)
- The bed of hot solids provides thermal "inertia" which moderates upsets due to sudden changes in fuel consumption
- Inherently low NO_x emissions with greater than 50% NO_x reduction possible with a SNCR adding either ammonia or urea ahead of the cyclone(s) to achieve good mixing.

DISADVANTAGES

- Complex operation with more interactive variables that must be controlled for optimal performance
- Sorbent utilization efficiency and SO_2 capture performance depend strongly on the quality of the limestone used, as well as the Ca/S molar ratio. Ca/S molar ratio is 2 to 3 times higher than for FGD
- Spent sorbent tonnage typically exceeds that of PC boiler with FGD (for same percent SO_2 reduction)
- Solid waste disposal is more costly due to large mass and high reactivity. Solid waste utilization applications are limited because the ash, gypsum, and free lime components are not separable
- Slightly lower carbon utilization
- Higher CO emissions
- Higher N_2O levels; potential future regulatory problem
- Higher furnace pressure drop and auxiliary power requirements

Cost And Performance:

Table 7A: Circulating Fluidized Bed (CFB)

Description	**Units**	**Range**		**Comments:**				**Reference:**
Duty Cycle		Base						(1)
Technology Rating		Mature		1. Excellent for use with low quality fuels				(1)
Capacity	MW	20	320	2. Not economical to go higher than 15%				(1)
Fuel								(1)
Primary Type		Coal						(1)
Cost	$/mmBtu	0.071						(1)
Biomass	%	0	50					(1)
Flexibility Level		High						(1)
Equiv. Planned Outage Rate	%	5.7						(1)
Equiv. Unplanned Outage Rate	%	4.1						(1)
Equivalent Availability	%	90.4						(1)
Planning Duration	Yrs	3	4					(1)
Construction Duration	Yrs	3	4					(1)
Useful Life	Yrs	30	40					(1)
		Base Unit Meeting BACT		90% Mercury Reduction Adder		90% CO_2 Capture & Sequestration Adder		
		Low	High	Low	High	Low	High	

TPC	$/kW	1,240						(1,7)
TCR	$/kW	* 1,863		51		812		(1)
Fixed O&M	$/kW-Yr	45.0		1.60		6.60		(1)
Variable O&M	$/MWh	2.8		0.30		8.45		(1)
Capital Additions	$/Yr							(1)
Heat Rate	Btu/kWh	9,692**	10,000			11,000		(1,7)
Marginal Cost	$/MWh							(1)
Emissions	Lbs/mmBtu							
SO_2		0.12						
NO_x		0.06						
Particulate		0.013						
Hg								
CO_2		205.0				20.5		
CO		0.10						

* *Cost includes PJBH, SNCR, FGD and SCR, which are believed to be required under future anticipated environmental constraints.*

** *HHV Basis*

Natural Gas Simple Cycle (NGSC) / Combined Cycle (NGCC)

Future Status:

The operating efficiency of NGCC units continue to improve. New "G" and "H" technology CTs are approaching efficiencies of 58 to 60%. Properly operated NGCC units have annual operating availabilities that exceed 90%. Recently, multiple NGCC plants have been designed specifically for dispatchable intermediate load operation. Excellent heat rates and the low gas prices of past years make NGCC plants appear to be serious contenders for new intermediate load capacity.

There is expected to be an adequate supply of reasonably priced natural gas for at least the next 20 years, however, the significant short-term volatility is expected to persist. The fuel price volatility recently experienced throughout the utility industry in conjunction with the future gas price projections shown in Figure 1, make future NGCC units less attractive than they otherwise would be. In addition, while NGCC units emit much less CO_2 on a kilowatt-hour basis than traditional coal fired units, their CO_2 emissions are still quite significant.

It is likely that NGCC units will be the dominant technology for the next ten years if gas prices remain low, and stringent CO_2 emission restrictions are not enforced. However, if gas supply, price, and availability issues worsen, and CO_2 emission restrictions take the path KCP&L anticipates, existing and new NGCC units may be restricted to peaking and minor intermediate duty.

General Technology Overview:

The key features of simple-cycle CTs include flexibility in siting, low emission levels with natural gas fuel, low capital cost, and short construction time. These advantages make them attractive for peaking duty applications. Peak duty simple-cycle plot arrangements can be designed to allow for later conversion to combined cycle through staged development. The key issues include long-term natural gas availability, transportation, and pricing.

A combined-cycle (CC) gas turbine power plant consists of one or more gas turbine generators equipped with heat recovery steam generators (HRSG) to capture heat from the gas turbine exhaust. Steam produced in the HRSG powers a steam turbine generator to produce additional electric power. Use of the otherwise wasted heat in the turbine exhaust results in high thermal efficiency. Current CC units typically convert about 50% of the chemical energy of natural gas into electricity (on a HHV basis). However, utilizing more advanced "G" and "H" technology combustion turbines, CC efficiency can approach 58 to 60%.

The principle environmental concerns associated with CC gas turbines are emissions of NO_x and CO. NO_x abatement is accomplished by use of "dry low-NOx" combustors and a SCR system within the HRSG. Carbon monoxide emissions are typically controlled by use of an oxidation catalyst within the HRSG. No special controls for particulates and sulfur oxides are used since only trace amounts are produced when operating on natural gas. Gas-fired CC plants produce less CO_2 per unit energy output than other fossil fuel technologies because of the relatively high thermal efficiency of the technology and the high hydrogen-carbon ratio of methane (the primary constituent of natural gas). Because of the high thermal efficiency, low initial cost, high reliability, relatively low gas prices, and low air emissions, NGCC systems have been a popular choice for bulk power generation. Other attractive features include significant operational flexibility, the availability of relatively inexpensive power augmentation for peak period operation, and relatively low CO_2 production. CO_2 is an unavoidable product of any fossil fuel combustion. A typical CC plant produces approximately 40% of the CO_2 emissions on a kilowatt-hour basis as compared to a typical PC plant.

Cost And Performance:

Table 8: Natural Gas Simple Cycle (NGSC)

Description	**Units**	**Range**		**Comments:**				**Reference:**
Duty Cycle		Peaking						(1)
Technology Rating		Mature						(1)
Capacity	MW	20	120					(1)
Fuel								(1)
Primary Type		Natural Gas						(1)
Cost	\$/mmBtu	4.5	6.5					(1)
Biomass	%	0	0					(1)
Flexibility Level		Low						(1)
Equiv. Planned Outage Rate	%	6.9						(1)
Equiv. Unplanned Outage Rate	%	4.6						(1)
Equivalent Availability	%	88.9						(1)
Planning Duration	Yrs	1	1.5					(1)
Construction Duration	Yrs	1	1.5					(1)
Useful Life	Yrs	30	40					(1)
		Base Unit Meeting BACT		SCR For NO_x Control Adder		90% CO_2 Capture & Sequestration Adder		
		Low	High	Low	High	Low	High	
TPC	\$/kW	410	542			380	500	(1,8)
TCR	\$/kW	393						(1)
Fixed O&M	\$/kW-Yr	6.3						(1)
Variable O&M	\$/MWh	13.8						(1)
Capital Additions	\$/Yr							(1)
Heat Rate	Btu/kWh	10,607						(1)
Marginal Cost	\$/MWh							(1)
Efficiency, (LHV)	%	55.0	56.2			43.5	47.8	(8)
Emissions	Lbs/mmBtu							
SO_2		0.000						
NO_x		0.028						
Particulate		0.000						
Hg		0.000						
CO_2		118.0				11.8		
CO								

Table 9: Natural Gas Combined Cycle (NGCC)

Description	**Units**	**Range**		**Comments:**				**Reference:**
Duty Cycle		Intermediate / Base		Base load unit would require SCR equipment				(1)
Technology Rating		Mature						(1)
Capacity	MW	260	320					(1)
Fuel								(1)
Primary Type		Natural Gas						(1)
Cost	\$/mmBtu	4.5	6.5					(1)
Biomass	%	0	00					(1)
Flexibility Level		Low						(1)
Equiv. Planned Outage Rate	%	6.9						(1)
Equiv. Unplanned Outage Rate	%	4.6						(1)
Equivalent Availability	%	88.9						(1)
Planning Duration	Yrs	1	1.5					(1)
Construction Duration	Yrs	1	1.5					(1)
Useful Life	Yrs	30	40					(1)

		Base Unit Meeting BACT		SCR For NO_x Control Adder		90% CO_2 Capture & Sequestration Adder		
		Low	High	Low	High	Low	High	
TPC	$/kW	410	542			380	500	(1,8)
TCR	$/kW	524		8				(1)
Fixed O&M	$/kW-Yr	8.10		0.30				(1)
Variable O&M	$/MWh	2.4	2.5	0.20		2.0	2.6	(1,10)
Capital Additions	$/Yr							(1)
Heat Rate	Btu/kWh	6,201	7,248 *			6,308	7,131	(1,7,10)
Marginal Cost	$/MWh							(1)
Efficiency, (LHV)	%	55.0	56.2			43.5	47.8	(8)
Emissions	Lbs/mmBtu							
SO_2		0.000						
NO_x		0.028						
Particulate		0.000						
Hg		0.000						
CO_2		118.0				11.8		
CO								

*** HHV Basis*

Solar Photovoltaics (PV)

Future Status:

Based on market and policy considerations, grid-connected PV systems for commercial, industrial, and residential uses appears to be entering a period of long-term accelerated growth. PV technology is still evolving and has not reached mature commercial status. It is presently best-suited economically to small (watt to few-kilowatt size) applications. For the near-term PV development will be focused on small-scale distributed generation at the residential, commercial, industrial, institutional, business park, and subdivision scales. EPRI believes that small-scale distributed PV will eventually prove to be practical as the cost of PV falls, but it will most likely not be competitive with other intermediate and peaking supply technologies before 2010. The National Center for Photovoltaics (NCPV) and others believe that by 2020 approximately one-half of the PV market will consist of DG applications, one-third will consist of traditional remote and high-value applications, and one-sixth will consist of wholesale utility-scale grid generation. Large-scale bulk-power PV facilities remain uncompetitive with other intermediate and peaking supply technologies, and it is unlikely that centralized PV facilities larger than 10 MW (ac) will be built in this decade.

General Technology Overview: [1,2]

Solar photovoltaic modules, referred to as photovoltaics (PV), are solid-state semiconductor devices that convert sunlight into direct-current electricity. The average module sales price dropped from $59,000/kW in 1976 to approximately $3,570/kW in 2002, while efficiencies increase from 8% to 15%. There is currently an estimated installed capacity of 2,200 MW worldwide, and 310 MW in the United States. Much of the 310 MW of installed capacity within U.S. is in little-documented small off-grid installations. With growing environmental concerns and the emerging green-power market, PV may play an increasingly important role in meeting the world's energy needs.

On a typical day, the solar radiation per unit area sometimes referred to as "insolation" reaches a maximum of about one kilowatt per square meter (100 W/ft^2) at solar noon. Therefore, the maximum power available with today's typical 50-200 watt commercial solar module is approximately 150 W/m^2, assuming the current 15% efficiency level. Thus, a large number of modules and land area is required to generate significant electric power. For example, a 100-MW power plant would require about one million modules, covering about one square mile. Since PV power output is proportional to the incident insolation, it is not dispatchable for continuous duty without energy storage. However, since PV installations generally produce power during periods of maximum solar radiation, PV technology fits well with the peaking needs of utilities with early to mid-afternoon summer peaks.

There are two principle types of PV array: flat-plate and concentrator. Concentrator designs use lenses or mirrors to increase the amount of sunlight on the active PV device. Flat-plate designs, which use both direct-normal and diffuse insolation, may be mounted in either fixed orientation or moving to track the sun's position. However, concentrator designs having more than a few-fold sunlight concentration must use precise, two-axis tracking to always be perpendicular to the sun's rays, because they can only concentrate the direct-normal insolation. Because flat-plate arrays can use both direct and diffuse sunlight, they can benefit from either one- or two-axis tracking, as compared to fixed mounting. Two-axis tracking captures about 10% more solar radiation than one-axis tracking. An array mounted on a properly functioning one-axis tracker receives about 20% more solar radiation annually than it would on a fixed-tilt mount, while an array on a two-axis tracker would capture approximately 30% more.

Because PV devices generate dc power, electronic interfacing equipment is used to convert the power into ac for connection to the grid. Inverter reliability has been an issue for grid-connected PV systems for the past two decades, making inverter replacement or repair a leading O&M cost component. There is some evidence that this situation is improving. Modern inverters for utility-scale applications typically do not require an added transformer, at least up to tens of kilowatts, however, for larger-scale and higher-than-distribution-level voltages, a transformer is desirable.

PV is typically the lowest maintenance generation technology available. PV modules essentially have no moving parts that require service or replacement, and have a life of several decades. Accumulation of dust and grime is typically washed away by rain, and results in no more than a 10% to 15% efficiency hit. In general, it is only the array tracking system that may require periodic inspections to ensure proper operation of a few moving parts. Experience to date indicates that O&M costs for well-designed systems should be substantially less than 0.5 ¢/kWh.

The interconnection between the distributed source and the larger utility grid is a critical determinant of a project's safety, financial, and technological viability. The promulgation of IEEE 1547, the "Standard for Distributed Resources Interconnected with Electric Power Systems," is expected to provide a universal standard that resolves the current variety of interconnection practices.

The maturing microgrid concept offers new applications and advantages. The microgrid might be envisioned as a residential neighborhood, business park, or commercial district encompassing several on-site distributed generators, not necessarily all PV, networked together and interconnected to the grid as a single distribution-level point. Although a small number of premium power parks have been built to serve businesses with specialized energy needs, the economic viability of and outlook for microgrids in general is uncertain.

The PV market is evolving rapidly. Shipment of PV modules and cells reported by U.S. manufacturers in 2001 reached a record level of 97.7 peak MW, up 11% from 2000. Gains in general, and increases in domestic PV shipments in particular, are attributed to the release of new product lines that achieved sizeable penetration into the U.S. market, growth of and new entrants into the residential market, and increases in domestic sales in a variety of sectors.

Cost And Performance:

Hypothetical case studies performed by EPRI provide cost and performance estimates for a variety of Central Station PV installations through the year 2030. The costs for each case study were scaled to appropriately reflect the relative cost of 5 MW installations. Tables xx and xx show these cost and performance factors for a 5 MW plant, as well as capital and O&M cost scale factors for larger plants.

Table 10: Solar PV Power Plant Capital And O&M Cost Projections

	Fixed Flat-Plate Thin-Film PV Plant				1-Axis Tracking Crystalline Silicon Flat-Plate PV Plant				2-Axis Tracking High Concentration PV Plant			
	2005	2010	2020	2030	2005	2010	2020	2030	2005	2010	2020	2030
System Efficiency (%)	7.7	10.6	13.2	14.2	13.8	14.7	15.7	16.7	17.1	21.7	24.3	26.3
Collector Area (m^2)	65,058	47,019	37,833	35,224	36,356	33,958	31,859	29,940	34,412	27,118	24.206	22,368
Total (\$/kW_{ac})	5,866	3,144	1,427	992	5,188	3,503	2,323	1,552	2,611	2.152	1,584	1,381
O&M (\$/kW_{ac}/yr)	7.936	5.14	3.05	2.83	5.36	4.43	3.17	2.97	34.07	29.57	25.28	18.41

Table 10 A: Solar PV Plant Capital And O&M Cost Scaling Factors (Relative To A 5-MW_{ac} Plant)

	Total Plant Cost Factor				O&M Cost Factor		
Rated Output (kW_{ac})	Fixed Flat Plate	1-Axis Flat Plate	2-Axis HCPV		Fixed Flat Plate	1-Axis Flat Plate	2-Axis HCPV
10	2.33	2.33	2.55		2.75	2.75	2.51
50	1.87	1.87	2.00		2.12	2.12	1.98
100	1.70	1.70	1.80		1.89	1.89	1.78
500	1.37	1.37	1.41		1.45	1.45	1.41
1,000	1.24	1.24	1.27		1.30	1.30	1.27
1,500	1.18	1.18	1.20		1.22	1.22	1.20
2,000	1.13	1.13	1.15		1.16	1.16	1.15
5,000	1.00	1.00	1.00		1.00	1.00	1.00
10,000	0.97	0.97	0.95		0.90	0.90	0.91
20,000	0.95	0.95	0.89		0.82	0.82	0.82
50,000	0.92	0.92	0.83		0.72	0.72	0.73

Biomass

Future Status:

Direct-fired biomass plants are not competitive with coal-fired plants simply because biomass plants are usually limited in size by the proximity of the fuel source that can be economically transported to the plant. The resulting small plants have high labor costs per unit power and are generally less complex, and therefore less efficient

Cofiring is the most economical near-term technology for biomass. The potential economic benefits of cofiring include savings from reduced coal consumption, reduced SO_2 and NO_x emissions, tipping fee revenue received from waste haulers, and positive impacts on local jobs.

For biomass, fuel cost is usually more important than O&M costs. Future large-scale expansion of biomass power generation depends on developing dedicated energy crop production, efficient power plant technology, and larger unit sizes to achieve economies of scale. The current development of fast-growing biomass crops, improved crop production, and better harvesting systems are eventually expected to produce a long-term supply of energy crop fuels with sufficiently low costs. While current energy crop delivered costs range from $2.50 to $4.00/mmBtu, future 2010, 2020, and 2030 delivered costs are estimated to be $1.90, $1.50, and $1.25/mmBtu respectively. The future of a major role for biomass decades from now will depend on energy crop fuel costs.

EPRI studies suggest that the cost of retrofitting to add biomass to a plant's fuel mix would be lowest for cyclone boilers that use the blended-feed approach to co-fire wood at levels in the 1% to 10% range (by heat).

Biomass power, without the help of co-firing may in the near-term continue a gradual decline. Biomass power to the grid has not grown in the U.S. for the past 10 years. As greater emphasis is placed on global carbon and climate change, and biomass fuel prices decline the installation of co-fired units will undoubtedly increase.

General Technology Overview:

Biomass energy is the energy derived from living plants. Most biomass fuels are significantly lower in potential air pollutants than most coals. Biomass has virtually no sulfur (often less than 1% that of coal), low nitrogen (less than 20% that in coal), and low ash content. There are exceptions, but overall biomass is usually superior to coal in terms of its concentrations of sulfur, nitrogen, ash and metals. However, compared to natural gas biomass cannot claim any advantage in terms of emissions, except for greenhouse gas emissions.

According to EPRI, the primary source of biomass fuel in the Midwest would be development of switchgrass agriculture. Biomass can be used as the primary fuel source for small (less than 60 MW) base-load units, but it is most widely utilized as a supplemental fuel source in a co-firing application. In addition to reducing CO_2 emissions, biomass is an alternative for meeting Renewable Portfolio Standards (RPS legislation). Table xx below identifies some of the advantages and disadvantages when co-firing biomass in PC units.

Table 11 - Biomass Advantages & Disadvantages Compared To PC Units
ADVANTAGES
• Biomass is a renewable source of energy • Utilizing biomass reduces coal consumption • Biomass combustion produces 95% less SO_2 and CO_2 emissions than coal on a lbs/mmbtu basis • Utilizing biomass reduces the amount of solid waste disposal / ash production • One ton of CO_2 biomass emissions reduces attributable coal CO_2 emissions by 1.1 tons. The rational for this assumption is that one ton of CO_2 biomass emissions directly offsets one ton of coal CO_2 emissions. Further, an additional 0.1 tons of coal CO_2 emissions is offset by the biomass CO_2 absorption rate during the biomass growth cycle. • There are no expected negative effects on baghouses, and only a slight effect on the performance of electrostatic precipitators
DISADVANTAGES
• Increased capital and O&M costs • Reduced boiler and thermal efficiencies • Potential derating due to ID fan, coal, flue gas, and ash handling limitations • The possibility of fly ash marketability issues • Possible negative effects on SCR catalysts • Increased level of CO emissions from incomplete combustion of biomass related to high biomass moisture content • Potential for little or no NO_x reduction when co-firing switchgrass

Direct-fired biomass plants, i.e., those that are constructed to burn 100% biomass, are not competitive with same-sized coal-fired plants. EPRI estimates the installed cost of a direct-fired biomass plant is $2,400 per kilowatt. In addition, these plants are usually limited in size by the proximity of a fuel source that can be economically transported to the plant. The economic biomass fuel transport distance is approximately 50 to 60 miles. The resulting small, 50 to 60 MW, direct-fired biomass plants have high labor costs per unit of power and are generally less efficient than PC technology. Electricity costs from direct-fired biomass plants fall over a broad range, from as low as $60 to $120/MWh.

Co-firing generally provides a higher-efficiency, lower-cost, and lower-risk method of energy recovery from biomass than building a dedicated biomass-to-energy plant. Retrofitting an existing coal-fired power plant to co-fire biomass is much less expensive on a $/kW basis than to install a direct-fired biomass plant. Biomass co-firing is generally limited to 10% of the plant's rated heat input capacity and generally reduce the power output by 2.3%. [6] Cyclone and CFB boilers can reach the 10% limit by blending fuels using the existing feed system. PC boilers are limited to 3% unless a separate feed system is installed. Preliminary results showed that switchgrass blended with coal would not flow in a bin similar to coal bunkers, thus it is likely that cofiring of switchgrass biomass would require a separate feed system. The capital costs of low to mid volume (1% to 10% unit heat input) blended feed systems are typically $25 to $100/kW, while separate feed systems are $150 to $250/kW.

Current energy crop costs range from $2.50 to $4.00/mmBtu. Switchgrass is the most available and likely source of biomass fuel in the midwest and has an approximate heating value of 15 mmBtu per dry ton. The delivered fuel cost is expected to be $55 per ton ($3.67/mmBtu). Nearly 600 to 800 acres, at 4 to 6 tons per acre, are required to produce one megawatt of electricity. Biomass delivery trucks can haul 17 to 19 tons per load.
Environmentally, firing or co-firing biomass results in some attractive environmental gains. It reduces both greenhouse gas (primarily CO_2), and SO_2 emissions on the order of 95% or more, as can be calculated from the fossil carbon and sulfur content of biomass fuel vs. coal. NO_x emissions can also be reduced, usually by 10% to 30%. Solid waste disposal problems can be mitigated by using biomass as fuel rather than land or landfill disposal.

Based on the estimated installed costs, a direct-fired biomass unit is not cost competitive with other renewable resources such as wind. The primary unknown is the cost to develop a switchgrass agriculture region and the subsequent cost of delivered fuel. Even under the requirements of RPS legislation, biomass may not be a first choice for renewable energy production.

Cost And Performance:

Table xx summarizes the costs related to building and operating a direct-fired biomass plant, modifying an existing PC boiler to co-fire 10% biomass, and constructing a new coal-fired power plant.

Table 12 – Direct And Co-fired Biomass Comparison

Category	Units	Direct Fired Biomass	Co-fired Biomass (Cost Adder)	Coal Fired
Capital Costs	$/kW	2,400	500	1,389
O&M Costs	$/kW-Yr	75.00	5.80	17.80
Fuel Costs	$/mmBtu	3.67	3.67	0.69

Table xx presents the present status and the goal potential for the main categories of biomass technology for dedicated biomass generation, excluding cofiring options.

Table 13: Direct-Fired Biomass Generation Present Status And Goal Potential

	Existing Type (Stoker / FBC)		Integrated Gasification Combined Cycle	
	Current	Goal	Current	Goal
Description	**High Cost**	**Low Cost**	**High Cost**	**Low Cost**
Size (MW)	50	50	50	100
Capital ($/kW)	1,400	1,000	1,600	1,000
Annual O&M ($M)	5.60	3.60	6.00	5.45
Fuel Cost ($/mmBtu)	2.00	1.50	1.80	1.25
Heat Rate (Btu/kWh)	15,000	13,000	9,000	8,000
Capacity Factor	0.698	.0742	0.698	0.742
Fuel ($M/yr)	9.17	6.34	4.95	7.80
Total ($M/yr)	29.47	20.44	27.75	34.25
GWh/yr	306	325	306	650
COE in $/MWh	**96.40**	**62.89**	**90.78**	**52.69**

Table xx displays the costs and performance information for two generic 10% biomass cofiring units, and three generic 100% direct fired units.

Table 14: Co-Fired And Direct-Fired Costs And Performance Summary

	10% Co-Firing		100% Direct-Firing		
	Cyclone *	PC *	Stoker	CFB	Biomass IGCC
Fuel Type	Wood/Coal	Wood/Coal	Wood	Wood	Wood
Biomass Feed System	Blended	Separate			
Plant Size (MW)	200	100	50	50	100
Biomass Faction (%)	10	10	100	100	100
TPC ($/kW)	100	250	2,190	2.569	2,357
TCR ($/kW)	104	260	2,356	2,762	2,589
Fixed ($/kW-yr)	2.0**	5.0**	74.70	82.00	84.30
Incremental (¢/MWh)	0.48	1.2	6.4	6.8	9.4
Average Net Heat Rate (Btu/kWh)	10,100	10,610	14,310	14,280	12,507
Full Load Heat Rate (Btu/kWh)	9,806	10,301	13,894	13,864	12,143
Equivalent Availability (%)			85	85	85
Duty Cycle	Base	Base	Base	Base	Base
Minimum Load (%)	60	60	25	25	25

Tech. Development Rating	Commercial	Commercial	Commercial	Commercial	Demonstration

* *Costs reflect only the biomass portion of the plant*
** *Costs do not include labor*

Energy Storage

Future Status:

Compared to other generation technologies, energy storage technologies have an additional requirement in that their economic operation is dependent on the existence of off-peak electricity for charging. This off-peak electricity is most economical when it comes from a power plant with a low fuel cost that is difficult or expensive to run at low load. Energy storage technology offers the benefit of storing energy during off-peak hours for use during peak periods of demand. Energy storage technologies evaluated include batteries, compressed air energy storage (CAES), pumped hydro, flywheels, and superconducting magnetic energy storage (SMES). These technologies could be applied to enhance the value and effectiveness of wind, solar, and other intermittent technologies.

Battery Energy Storage

Battery energy storage is currently the most utilized energy storage system. Lead-acid battery performance, size, weight, and lifetime improvements have allowed lead-acid batteries to operate as a workhorse within the utility system to provide energy storage and emergency power. Typical batteries used by electric utilities today are the flooded cell battery, which is more robust, and the valve-regulated lead-acid (VRLA) battery, which requires less maintenance. Lead-acid batteries currently have a life expectancy of over 10 years. Manufacturing techniques and material developments have essentially eliminated most occupational and environmental hazards for both flooded cell and VRLA lead-acid batteries today. Battery installations are generally not meant to provide long-term energy storage, but rather to provide short-term ride-through while a reserve power source is brought on line. The environmental emissions of lead-acid battery plants are virtually zero. The cost and performance data associated with lead-acid batteries and other advanced battery systems are shown in Table 1. Lead-acid battery technology is the only mature battery technology in use. All other battery technologies should be considered preliminary.

Table 15 - Cost & Performance Of Battery Technologies

System	Power Capacity (MW)	Stored Energy (MWh)	Useful Life (Yrs)	TPC ($/kW)
Lead-Acid	2.0 - 40	0.6 – 14	> 10	450 - 570
Sodium –Sulfur	0.5 - 6	0.7 - 48	10 - 15	1025
Polysulfide-Bromine	15	120	15	836
Vanadium Redox	.25	2	10 - 15	
Zinc-Bromine		0.5		
Lithium Ion		0.07		

Compressed Air

Air can be compressed and stored as potential energy in airtight caverns or aboveground vessels. When the air is released from storage, it can be expanded through a combustion turbine (CT) to generate electricity. For most CAES plants off-peak power is used to compress the air, and generation is scheduled during on-peak hours. Compressed air energy storage facilities typically contain three major components: a compressor, driven by a motor during off-peak hours; a contained storage volume; and a CT and generator. The electric power generating capacity of the CT is increased because no power is required to drive a compressor.

For power plants with energy storage in excess of 20 MWh, air is stored underground in salt caverns, hard rock caverns, or porous rock formations. Salt caverns are the primary underground energy storage source within KCP&L's present generating area. Salt caverns are also believed to be the most economical and functional underground storage medium. For small CAES systems, 50 kW to 50 MW, it is possible to use buried pipes as the energy storage medium. These pipe typically are 48" in diameter and operate at pressures up to 2,500 psi, which is well over the required pressure. Compressed air storage of up to 350-MW module capacity at 10 hours of storage is available in most regions of the United States.

Emission, NOx and SOx, are similar to typical oil or gas fired CTs.

Table 2 below summarizes the cost and performance of a 350 MW, 10-hour unit utilizing a salt cavern for storage, and a 20 MW, 4-hour unit utilizing above ground piping for storage.

Table 16 - Salt Cavern & Above Ground Compressed Storage Cost And Performance

		Salt Cavern	Above Ground Piping
Plant Size	MW	350	20
Storage	Hrs	10	4
Plant Capital Cost			
Storage	$/kW	16	63
Power – Balance Of Plant	$/kW	266	501
General & Engineering	$/kW	125	56
Contingency	$/kW	104	113
AFUDC	$/kW	54	26
Owners Costs	$/kW	16	31
Total In-Service Cost	$/kW	581	790
Total Capital Replacement For Unit Life			
O&M Costs	$/kW	5.7	
Annual Fixed	$/kW	2.1	8.4
Incremental Includes Consumables	$/MWh		2.1
Unit Availability			
Equivalent Availability	%	97.3	97.3
Duty Cycle		Intermediate	Intermediate
Plant Construction Time	Yrs	3	3
Unit Life	Yrs	30	30
Technology Development Rating		Commercial	Pilot
Design & Cost Estimate Rating		Actual	Preliminary

Other Energy Storage Technologies

Pumped hydro requires sites with two separate locations of water, typically an upper and lower source. When power is needed during peak load conditions, water flows for the upper source through a powerhouse to the lower source. When power is plentiful and comparatively inexpensive, water is pumped from the lower source to the upper source. The lead-time for construction of a pumped hydro plant is several years and includes many environmental and safety issues. Most available sites in the United States are already in use, therefore the prospects for developing new pumped hydro plants is limited. Although technically feasible to build, the current differential between peak and non-peak power prices make pumped hydro technology uneconomic.

Flywheel energy storage is presently being developed to fit niche applications for power quality or ride-through while an emergency generator is being ramped up. To date there has been no practical utility demonstration of flywheels on a large scale. Two general types of flywheels appear to be of interest for utility applications. The first, often referred to as the energy wheel, is efficient and delivers modest power, for example 1 kW for one or two hours. The second, referred to as a power wheel, also stores up to a few kilowatt-hours of energy, but has a power capacity of several hundred kilowatts. Thus it can discharge in a period of seconds. Overall, flywheel systems that are designed for power delivery are not very efficient. Commercially available flywheel systems typically provide 100 to 500 kW for periods ranging between 5 and 50 seconds.

Superconducting magnetic energy storage (SMES) systems for utility applications range from a microSMES unit that delivers 750 kW for a second or two to a diurnal energy storage system that has a 1,000 MW capacity for several hours. Today technology development is focused mainly on small units, the largest of which can provide about 50 MW for 30 seconds. Large-scale SMES for diurnal load leveling is no longer under development. The following factors influenced the end of development of the technology:

- Lengthy design, development, and initial construction time
- High capital cost per kilowatt
- Plant sizes larger than 500 MW are not efficient enough

Table 17 - Pumped Hydro, Flywheel, & SMES Cost And Performance				
		Pumped Hydro	**Flywheel**	**Distributed SMES**
Plant Size	MW	3x350	3x2	4x6
Storage Capacity	Hrs	10	.002	.001
Plant Capital Cost				
Storage	$/kW	125	52	52
Power – Balance Of Plant	$/kW	470	261	261
General & Engineering	$/kW	157	31	10
Contingency	$/kW	84	31	10
AFUDC	$/kW	193	0	0
Owners Costs	$/kW	21	21	10
Total In-Service Cost	$/kW	1,050	396	343
Total Cap. Replacement For Unit Life				
O&M Costs	$/kW			
Annual Fixed	$/kW	4.5	N/A	2.1
Incremental Includes Consumables	$/MWh	1.6	N/A	2.1
Unit Availability				
Equivalent Availability	%	90	98	96
Duty Cycle		Intermediate	Ride-Through	Ride-Through
Plant Construction Time	Yrs	6	1	0
Unit Life	Yrs	50+	30	20
Technology Development Rating		Mature	Mature	Commercial
Design & Cost Estimate Rating		Actual	Actual	Actual

Distributed Generation VS Central Station

Numerous technologies now commercially available to serve the role of Distributed Generation (DG) are:

1. Internal Combustion Engines
2. Combustion Turbines
3. Advanced Combustion Turbines
4. Microturbines
5. Fuel Cells
6. Solar

DG is a generating resource installed at individual sites to solve a site-specific problem or to economically meet a site-specific need. Examples of solutions provided by DG include supply reliability, avoided infrastructure investment, co-generation opportunities, and others. DG is generally considered to cover resources below 25 MW, with most installations being less than 2.5 MW.

Based on the small size of DG resources, a significant commitment to DG would be required to serve as a replacement for Central Station resources. KCP&L's load responsibility is currently projected to grow at an average rate of roughly 70 MW per year. With typical DG installations below 2.5 MW, KCP&L would need to site 30 DG units per year to offset the installation of one Central Station CT.

EPRI has sited the following drivers for DG applications:

- Deregulation is forcing traditional utilities to set up energy services companies, which may offer DG as a package to satisfy customers

- Customer Retention requires least-cost service. As customer requirements change, DG offer flexibility to customize offerings
- Customer Satisfaction driven by power quality and reliability needs
- Regulatory Requirements. Many state regulators allow returns on savings attributable to T&D deferrals and environmental emission reductions
- Risk. The small size of DR resources result in short lead times and small increments of added generation. This reduces uncertainties involved with larger more time consuming installations
- Asset Utilization. More efficient utilization of distribution assets

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