2014

Integrated Resource Plan

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KANSAS CITY BPU
THE POWER OF COMMUNITY

KANSAS CITY, KANSAS, BOARD OF PUBLIC UTILITIES
INTEGRATED RESOURCE PLAN
2014

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I. INTRODUCTION

Integrated resource planning is a process that considers demand-side options in addition to traditional supply-side options to meet the electric power needs of an electrical system. Integrated resource planning is a continual process that focuses on seeking and evaluating opportunities for demand and energy savings in addition to evaluating traditional supply side resources. It is an on-going and evolutionary process calling for a reanalysis of utility system plans as conditions, prices, costs, technologies, and power requirements change. The integrated resource planning process anticipates the future and considers the many uncertainties a utility faces. An objective of integrated resource planning is to find a lowest cost solution that supplies customers the amount and quality of electric service desired while at the same time supports the utility's long term financial health. Solid, long-term integrated resource planning takes into account price elasticity of demand, reliability, and quality of service.

Under an agreement with WAPA, the Board of Public Utilities of Kansas City, Kansas (BPU) is required by law to file an Integrated Resource Plan (IRP) with the Western Area Power Administration (WAPA), an Agency of the U.S. Department of Energy, and update the plan every five years. The BPU is also required to submit annual progress reports on the status of its IRP. In return, the BPU receives an annual allocation of approximately 4.8 megawatts (MW) of capacity and about 14,900 megawatt-hours (MWH) of hydroelectric power. Receiving this power is a valuable benefit to BPU. This document is the BPU's 2014 Integrated Resource Plan report and documents the integrated resource planning the BPU currently has in place.

II. BENEFITS OF IRP PLANNING

There are multiple benefits which can be derived from integrated resource planning. A good practical plan manages risks and seeks to minimize long-run costs. It also encourages energy conservation and the use of renewable energy resources and promotes the use of lower cost and more abundant fuels. Furthermore, it provides a forum for diverse interests and disciplines to communicate and develop a common goal and select an acceptable resource option.

These benefits are derived from the change of focus in planning, where studies and reviews search for ways to improve energy utilization and marginal revenues, and to reduce costs. Some of these benefits to the BPU have been that it has:

1. Deferred new generation capacity additions. In general, aided in stabilizing rates and keeping costs down for customers.
2. Assisted in improving the Utility's system load factor allowing better utilization of generating equipment.
3. Increased the use of more efficient generating equipment thus lowering the cost per unit of power generated.

4. Reduced energy use in certain situations by encouraging the use of more efficient appliances and building additions. Consequently, this has decreased load growth in peak periods, while at the same time increased off peak energy uses.
5. Assisted in improving public relations.
6. Aided in energy conservation.

Such planning benefits all customers and helps to minimize the need for rate increases. To achieve these benefits the BPU applies significant resources to these activities, for instance in 2013 BPU had nearly $10,400,000 in renewable resource expenditures and had allocated nearly $500,000 for the Heat Pump program and another $100,000 for the 2 Degrees 2 Save program.

III. BPU ELECTRIC UTILITY OVERVIEW

The Kansas City Board of Public Utilities (BPU) was established in 1929 to provide the highest quality electric and water services at the lowest possible cost. Currently the BPU serves approximately 65,000 electric and 51,000 water customers. BPU's mission is to be the utility of choice and the workplace of choice, while improving the quality of life in the communities it serves. BPU is a publicly owned administrative agency of the Unified Government of Wyandotte County/Kansas City, Kansas, and is self-governed by an elected six-member board of directors. The Utility serves 155.9 square miles of Wyandotte County. Electric services are provided within Kansas City, Kansas (KCK) and Wyandotte County.

The electric utility was established in late 1912. Current facilities consist of three self-owned power stations, one joint-owned combined cycle, 29 substations and approximately 3,000 miles of electrical lines. The four power stations contain generators with the following approximate capacities:

- Nearman Creek Power Station – capacity 307 MW
- Quindaro Power Station – capacity 304 MW
- Kaw Power Station – capacity 98 MW (currently cold standby)
- Dogwood – own 17% of 650 MW capacity unit

Transmission systems consist of 161 kV and 69 kV transmission lines. The 161 kV system is configured in two loops, establishing a "figure eight" over the entire service territory. Interconnection between the 161 kV and 69 kV systems is made at four locations. Highest peak demand was recorded on August 9, 2006, at 529 MW. Electrical lines interconnect to four Kansas City Power & Light locations and one Westar Energy location.

Thanks to the Western Area Power Administration (WAPA), the Board of Public Utilities of Kansas City, Kansas was among the first municipally owned systems to undertake integrated resource planning. WAPA provided the initial exposure of integrated resource planning to the BPU, and from the beginning WAPA staff has provided invaluable assistance in implementing this program. This planning process continues today. As conditions and technologies change, existing programs are modified and new studies are performed and incorporated into updates of BPU electric power resource plans.

The initial IRP by BPU was completed in 1989. The cost of that IRP was shared between WAPA and BPU with BPU receiving over $100,000 to prepare the study. The Energy Policy Act requiring an IRP was adopted in 1992.

IV. LOAD ANALYSIS & FORECAST

The Board of Public Utilities updates its electric load forecast on an ongoing basis. Short–term peak demand energy forecasts are developed for use in revenue forecasting and budgeting. Long–term energy and peak demand forecasts are developed for use in longer term system planning such as to assess the long-term energy and demand requirements of the BPU and for use in performing analyses of various capacity and/or energy purchase options.

A. Methodology

BPU's forecasting method is a bottom-up approach developed by aggregating customer class specific forecasts. Developing customer class specific forecasts allows for the ability to get a refined estimate of total system demand. The estimates for the individual customer classes are aggregated to develop the estimate for the entire system as a whole. In using this method, the forecast for the system as a whole is typically more accurate since it allows for careful consideration of the change in demand for each of the customer classes and then combining these carefully considered estimates rather than merely making one large system forecast estimate which may not as thoroughly consider all of the factors causing both the change in number of customers in each class and the use per customer of each individual customer class.

Customer class-specific forecast models of the energy requirements were developed by comparing a linear regression technique with the outputs of the Smart forecasting software. Individual energy sales forecast models were prepared for each of the three largest customer classes, which are industrial, commercial, and residential. The forecast models are based on historical and projected future customer class–specific energy requirements. Below are graphs and output of the industrial, commercial, and residential class data. No future major industrial customers have been added beyond the existing known customers.

B. Major Customer Class Historical and Forecast Demand

The individual historical data and forecasts for industrial, commercial, and residential energy consumption are aggregated in the table below:

Table 1
Historical and Forecast Annual Major Customer Class Data (kWh)

Year	INDUSTRIAL	Percent Change	COMMERCIAL	Percent Change	RESIDENTIAL	Percent Change	Major Customer Classes Summed	Percent Change
1998	803,311,850	0.58%	820,089,166	2.46%	543,913,298	6.38%	2,167,314,314	2.70%
1999	857,643,070	6.76%	821,146,470	0.13%	512,421,552	-5.79%	2,191,211,092	1.10%
2000	803,136,767	-6.36%	822,626,899	0.18%	545,307,672	6.42%	2,171,071,338	-0.92%
2001	817,758,956	1.82%	802,679,313	-2.42%	550,869,096	1.02%	2,171,307,365	0.01%
2002	822,335,834	0.56%	806,031,040	0.42%	568,700,840	3.24%	2,193,557,963	1.02%
2003	814,756,414	-0.92%	814,699,133	1.08%	525,368,930	-7.62%	2,131,266,244	-2.84%
2004	932,858,837	14.50%	833,645,939	2.33%	514,886,934	-2.00%	2,222,835,681	4.30%
2005	889,594,504	-4.64%	856,388,086	2.73%	564,944,642	9.72%	2,252,376,120	1.33%
2006	869,655,917	-2.24%	909,404,930	6.19%	564,353,393	-0.10%	2,278,621,843	1.17%
2007	774,211,822	-10.97%	909,219,828	-0.02%	574,127,016	1.73%	2,167,598,240	-4.87%
2008	733,052,531	-5.32%	877,655,653	-3.47%	550,773,920	-4.07%	2,069,014,083	-4.55%
2009	678,327,267	-7.47%	843,231,586	-3.92%	535,690,414	-2.74%	1,964,810,292	-5.04%
2010	757,355,721	11.65%	879,059,973	4.25%	599,167,144	11.85%	2,135,501,779	8.69%
2011	614,559,741	-18.85%	963,117,955	9.56%	588,240,616	-1.82%	2,050,079,776	-4.00%
2012	555,511,201	-9.61%	988,166,817	2.60%	564,029,077	-4.12%	1,973,157,079	-3.75%
2013	544,416,379	-2.00%	963,696,185	-2.48%	556,786,563	-1.28%	1,944,299,731	-1.46%
2014	546,416,379	0.37%	968,481,185	0.50%	584,420,080	4.96%	1,973,933,248	1.52%
2015	546,416,379	0.00%	969,985,080	0.16%	587,672,399	0.56%	1,978,450,213	0.23%
2016	546,416,379	0.00%	971,502,835	0.16%	590,989,766	0.56%	1,983,034,121	0.23%
2017	546,416,379	0.00%	973,035,050	0.16%	594,373,479	0.57%	1,987,686,276	0.23%
2018	546,416,379	0.00%	974,582,356	0.16%	597,824,867	0.58%	1,992,408,009	0.24%
2019	546,416,379	0.00%	976,145,416	0.16%	601,345,282	0.59%	1,997,200,674	0.24%
2020	546,416,379	0.00%	977,724,925	0.16%	604,936,106	0.60%	2,002,065,657	0.24%
2021	546,416,379	0.00%	979,321,613	0.16%	608,598,747	0.61%	2,007,004,367	0.25%
2022	546,416,379	0.00%	980,936,246	0.16%	612,334,640	0.61%	2,012,018,244	0.25%
2023	546,416,379	0.00%	982,569,628	0.17%	616,145,251	0.62%	2,017,108,756	0.25%
2024	546,416,379	0.00%	984,222,604	0.17%	620,032,074	0.63%	2,022,277,400	0.26%
2025	546,416,379	0.00%	985,896,060	0.17%	623,996,634	0.64%	2,027,525,703	0.26%
2026	546,416,379	0.00%	987,590,928	0.17%	628,040,484	0.65%	2,032,855,223	0.26%
2027	546,416,379	0.00%	989,308,184	0.17%	632,165,212	0.66%	2,038,267,548	0.27%
2028	546,416,379	0.00%	991,048,854	0.18%	636,372,435	0.67%	2,043,764,299	0.27%
2029	546,416,379	0.00%	992,814,016	0.18%	640,663,802	0.67%	2,049,347,130	0.27%
2030	546,416,379	0.00%	994,604,800	0.18%	645,040,996	0.68%	2,055,017,724	0.28%

The major customer classes' aggregate number is added to the smaller customer classes' energy forecasts. The smaller customer classes are: schools, local government, highway lighting, and metered and un-metered city government, BPU interdepartmental and borderline customers. Borderline customers' demand is served by BPU through a neighboring utility's distribution system. The customers are billed through the neighboring utility's billing system and BPU is paid by the neighboring utility. The table of historical and forecasted data of the small customer class data appears below:

Table 2
Smaller Customer Class Data (kWh)

Year		SCHOOLS	HIGHWAY LIGHTING	COUNTY	Metered CITY OF KCK	Unmetered City of KCK	BPU Inter-department	Borderline	Village West
1998		53,842,157	3,379,918	9,247,141	34,986,176			15,525,400	
1999		51,810,293	2,972,184	8,911,111	35,355,045			13,925,900	
2000		55,483,018	2,961,610	9,379,719	38,028,632	34,932,504	29,600,000	16,874,842	
2001		60,837,512	2,968,798	9,901,089	35,289,968	34,960,667	33,240,000	16,882,433	
2002		63,612,415	2,973,036	7,871,638	34,794,040	35,181,411	41,911,465	18,221,142	3,509,751
2003		68,937,672	3,072,183	8,620,954	35,052,238	35,663,130	31,387,396	17,338,495	23,558,233
2004		68,937,672	2,665,939	8,438,262	34,401,457	36,041,942	42,938,994	17,805,851	58,556,029
2005		68,272,280	2,665,939	8,756,979	31,743,439	45,027,579	47,626,677	18,765,903	58,551,112
2006		70,866,995	2,665,939	8,782,346	34,427,171	36,782,902	44,616,218	18,678,613	64,792,397
2007		75,577,601	2,664,127	8,663,293	30,522,789	38,716,486	44,996,254	19,313,961	89,960,426
2008		75,239,657	2,646,121	7,864,157	36,320,298	37,424,804	45,882,343	18,482,844	92,468,021
2009		77,430,042	2,556,091	7,637,040	33,103,923	37,433,860	36,999,231	18,429,740	92,438,975
2010		73,706,199	2,556,091	7,965,143	40,639,135	37,754,060	38,331,710	18,625,886	100,081,059
2011		70,174,257	2,556,096	5,768,883	38,462,059	37,640,339	38,405,209	17,381,538	115,838,536
2012		66,077,568	2,556,096	11	42,592,110	38,001,433	37,462,727	17,029,530	134,550,016
2013		69,637,035	2,556,096	-	42,694,440	37,364,538	38,369,477	17,972,281	120,599,396
2014		69,637,035	2,556,096	-	42,694,440	37,364,538	38,753,172	18,107,073	125,384,396
2015		69,637,035	2,556,096	-	42,694,440	37,364,538	39,140,703	18,242,876	125,623,646
2016		69,637,035	2,556,096	-	42,694,440	37,364,538	39,532,111	18,379,698	125,874,859
2017		69,637,035	2,556,096	-	42,694,440	37,364,538	39,927,432	18,517,545	126,138,632
2018		69,637,035	2,556,096	-	42,694,440	37,364,538	40,326,706	18,656,427	126,415,593
2019		69,637,035	2,556,096	-	42,694,440	37,364,538	40,729,973	18,796,350	126,706,403
2020		69,637,035	2,556,096	-	42,694,440	37,364,538	41,137,273	18,937,323	127,011,754
2021		69,637,035	2,556,096	-	42,694,440	37,364,538	41,548,645	19,079,353	127,332,372
2022		69,637,035	2,556,096	-	42,694,440	37,364,538	41,964,132	19,222,448	127,669,020
2023		69,637,035	2,556,096	-	42,694,440	37,364,538	42,383,773	19,366,616	128,022,502
2024		69,637,035	2,556,096	-	42,694,440	37,364,538	42,807,611	19,511,866	128,393,657
2025		69,637,035	2,556,096	-	42,694,440	37,364,538	43,235,687	19,658,205	128,783,370
2026		69,637,035	2,556,096	-	42,694,440	37,364,538	43,668,044	19,805,641	129,192,569
2027		69,637,035	2,556,096	-	42,694,440	37,364,538	44,104,724	19,954,184	129,622,227
2028		69,637,035	2,556,096	-	42,694,440	37,364,538	44,545,772	20,103,840	130,073,369
2029		69,637,035	2,556,096	-	42,694,440	37,364,538	44,991,229	20,254,619	130,547,067
2030		69,637,035	2,556,096	-	42,694,440	37,364,538	45,441,142	20,406,529	131,044,451
2031		69,637,035	2,556,096	-	42,694,440	37,364,538	45,895,553	20,559,578	131,566,704

C. Losses

Losses are estimated based on component losses for transmission, primary, and secondary loads. These loss estimates are applied by customer class as annotated below.

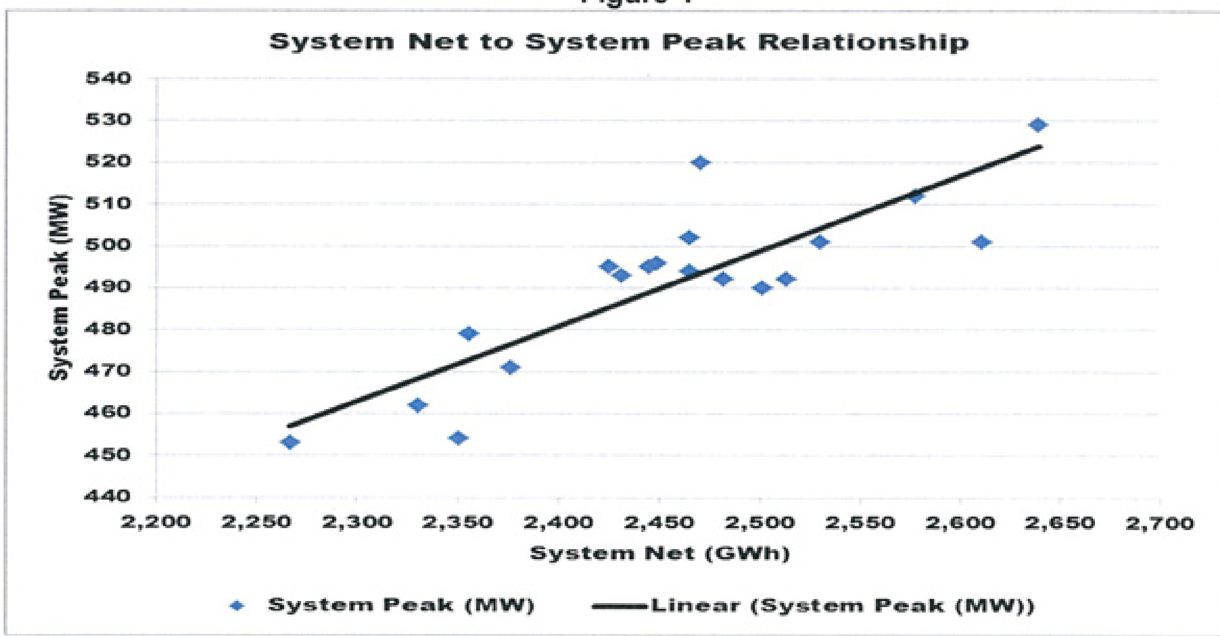
Table 3
LOSSES

Customer Class	Losses Transmission 0.44%	Primary 2.39%	Secondary 4.38%
Industrial	X		
Commercial	X	X	X
Residential	X	X	X
Schools	X	X	X
Hiway Lighting	X	X	X
County	X	X	X
Metered City of KCK	X	X	X
Unmetered City of KCK	X	X	X
BPU Inter-Departmental	X	X	X
Borderline	X	X	
Nearman Participating	X		
Wholesale	X		
Based on loss study completed November 2002 and adjusted for historical trends since the study was completed.			

D. Peak System Demand

Peak system demand is calculated based on linear regression trend modeling of the historical peak plotted against the associated system net for the years 1995 through 2013. Figure 1 contains a plot of the system annual net energy and system annual peak demand. The black line in Figure 1 shows the historical trend line relationship between system annual net energy and system annual peak demand.

Figure 1



In addition to its retail load responsibilities, the BPU has or has had wholesale power supply contracts with Columbia, MO and the Kansas Municipal Energy Agency (KMEA) based on their participation in BPU's Nearman Unit No. 1. The contract with Columbia, MO was terminated effective April 2013 and resulted in an additional capacity of 20 MW. The KMEA contract is also set to expire as of December 31, 2015 and will yield another 37.5 MW of capacity. The additional capacity will help offset expected capacity shortfalls from the retirement of some of the existing CTs. Forecasted Energy sales to KMEA for the remainder of the contract were based on expected unit availability and anticipated SPP pricing. Recent Nearman participating historical data and forecast energy appears in the table below:

Table 4
NEARMAN PARTICIPATING ENERGY

Year	Nearman Participating Energy (kWh)	KMEA	Columbia
2007	434,356,000	275,885,000	158,471,000
2008	398,063,000	247,828,000	150,235,000
2009	296,477,000	149,658,000	146,819,000
2010	296,136,000	145,316,000	150,820,000
2011	277,681,000	131,451,000	146,230,000
2012	101,330,000	50,210,000	51,120,000
2013	93,308,000	86,013,000	7,295,000
2014	110,000,000	110,000,000	
2015	120,000,000	120,000,000	

Historical energy varies from year to year with forecasted energy of approximately 10 GWh/month forecasted for 2015.

E. Forecast Results

The system load forecast developed by the BPU is shown in Table 5. The forecast includes sales to BPU's retail customers, borderline, city, and the BPU. It does not include Nearman Participation customer sales.

Table 5
Load Forecast

Year	System Peak (MW)	System Energy (GWh)	Growth (%)	Load Factor
2009	471	2376		58%
2010	501	2530	6.48%	58%
2011	502	2465	-2.57%	56%
2012	495	2425	-1.62%	56%
2013	454	2350	-3.09%	59%
2014	470	2319	-1.32%	56%
2015	472	2331	0.52%	56%
2016	474	2342	0.48%	56%
2017	475	2354	0.50%	57%
2018	477	2366	0.50%	57%
2019	479	2378	0.50%	57%
2020	481	2389	0.50%	57%
2021	483	2401	0.50%	57%
2022	485	2413	0.50%	57%
2023	487	2425	0.50%	57%
2024	489	2438	0.50%	57%
2025	490	2450	0.50%	57%
2026	492	2462	0.50%	57%
2027	494	2474	0.50%	57%
2028	496	2487	0.50%	57%
2029	498	2499	0.50%	57%

BPU's base energy requirements are projected to grow at an average annual rate of about a 0.5% per year.

V. Current Resource Summary

The BPU's existing power supply resources include 714 MW of accredited generating capacity, 43 MW of hydro capacity purchased from the Southwestern Power Administration (SWPA) and the Western Area Power Administration (WAPA), 25 MW of wind capacity purchased from Smoky Hills wind farm, 7 MW of run-of-river hydro off Bowersock, and 3 MW of Landfill gas generation purchased from Oak Grove. All generation purchases have long-term firm transmission service and thus qualify as firm capacity. Non-Dispatchable variable resources such as wind vary in the amount of capacity that can be counted due to the variability of the generation. According to current standards Smoky Hills cannot be counted as capacity, but capacity rules are still in flux.

BPU's active generating plants include Nearman 1, a 232 MW pulverized coal unit operational in 1981, located at the Nearman Station. Also installed at the Nearman Station is CT 4, a 75 MW GE 7EA simple cycle natural gas combustion turbine commissioned in 2006. The

Quindaro Station consists of a 72 MW pulverized coal steam turbine, Quindaro Unit 1, commissioned in 1966; and a 118 MW part coal fueled and part gas fueled steam turbine, Quindaro Unit 2, commissioned in 1971. Quindaro Unit 2 achieves its 118 MW accredited capacity by using natural gas as a supplemental fuel to Powder River Basin (PRB) coal which, due to coal pulverizer limitations, can only produce 95 MW. Both Quindaro Units 1 and 2 are dual-fuel capable and can be operated on natural gas alone.

The Quindaro Station also includes three simple cycle combustion turbines, CT 1, CT 2, and CT 3 with accredited capacities of 12, 56, and 46 MW, respectively. The online dates for these generators were 1969, 1974, and 1977. CT 1 can burn natural gas or No. 2 fuel oil, while CT 2 and CT 3 burn No. 2 fuel oil.

In addition BPU also purchased a 17% stake in Dogwood in May 2012. The Dogwood plant which became operational in February 2002 is a 650 MW natural gas-fired, combined-cycle electricity generation facility consisting of one power train in a 2 x 1 configuration with Siemens Westinghouse 501F D2 Gas Turbines, a Toshiba HRSG, and one Toshiba steam turbine generator. The Dogwood facility is located in Cass County, Missouri, near the town of Pleasant Hill. Westar is currently responsible for handling all market related activities on the unit. The detailed analysis of the economics of the Dogwood plant purchase is contained in Appendix E of this report.

The BPU system includes the inactive Kaw Station with three coal and/or gas fired steam generating units placed online between 1955 and 1962. All three units are in cold standby and would require extensive capital investment for equipment replacements and additions to be available as reliable generation resources in the future.

Due to environmental concerns the BPU coal resources will be undergoing operating and design modifications in 2015 and 2016. In April 2015 Quindaro Unit 1 and Quindaro Unit 2 will no longer operate on coal and will strictly operate on natural gas. This change will increase operating costs due to additional fuel expenses but may allow the BPU to extend the life of the units. Gas supply issues should not be a concern as the BPU has agreements with two vendors on two paths for gas capacity. Beginning April 2016 Nearman 1 is scheduled to undergo extensive work so as to comply with environmental regulations. These changes are expected to have little impact on efficiency and availability. This work is scheduled to last approximately 7 months and will require the unit to be off-line during that period.

Currently, BPU anticipates retiring CT1, 2, and 3 in 2015, 2020, and 2023, respectively when they reach 45 years of age. Retirements of Quindaro Units 1 and 2 are dependent on economics and future environmental regulations as addressed later in this report. Table 6 contains a summary of the operating characteristics of the existing active BPU generators.

Table 6
Summary Operating Characteristics of Existing Active BPU Generators

Generator	Description	COD[(1)]	Max Net MW[(2)]	Min Net MW[(2)]
Nearman 1	Coal Steam	1981	220	120
Quindaro ST1	Coal / Gas	1966	72	64
Quindaro ST2	Coal / Gas	1971	118	48
Quindaro GT1	Gas CT	1969	12	3
Quindaro GT2	Oil CT	1974	56	10
Quindaro GT3	Oil CT	1977	46	9
Nearman CT4	Gas CT	2006	75	46
Dogwood [(3)]	Gas CC	2002	650	150

[(1)] COD = Commercial Operation Date.
[(2)] Minimum and Maximum Output Capacities reflect the minimum and maximum continuous rating of the generator, in MW, at the conditions which it is expected to operate.
[(3)] Dogwood is a 650 MW joint owned unit with the BPU owning a 17% stake in the unit.

In addition to the active generators operated, the BPU also has a number of long-term Purchase Power agreements (PPA) in place. All long-term PPAs currently in place contribute to the diversity of the power supplied, and therefore the energy curves associated with that type of energy, are green energy sources, and provide a hedge against carbon fuel price and wholesale energy volatility as well as future environmental regulations.

F. Wind Power Energy

In the IRP of August 2005 two recommendations were made relating to wind power. The first recommendation was an evaluation of purchasing commercial wind power energy. Toward that end, the BPU entered into a 20 year Renewable Energy Purchase Agreement and began receiving wind generated energy from Smoky Hills Wind Farm in early 2008; however, due to a transformer failure late in 2008, BPU received only slightly more than 80,000 MWH. BPU is entitled to 25% of the wind farm's output, which has a nameplate capacity of approximately 100 MWs. BPU has been a leader of Kansas municipals with regard to purchasing Kansas wind energy. Smoky Hills makes up over 5% of BPU's 2013 system peak demand, based on nameplate capacity; and approximately 3.7% renewable wind energy based on 2013 retail load energy provided. BPU chose to enter into wind energy at this level to gain experience with the issues related to the variability of wind, wind forecasts, and other related wind integration issues. BPU is currently not required by any regulatory agency or mandate to purchase renewable energy; however, BPU management is committed to meeting the Kansas state Renewable Energy Standard. Kansas' standard is based on generation capacity (Megawatts). The compliance schedule is 10% by 2011, 15% by 2016, and 20% for 2020 and onward. Each MW of eligible capacity installed in Kansas after January 1, 2000 will count as 1.1 MW for the purpose of the Kansas standard. Because the Smoky Hills Wind Farm meets this criterion, its contribution is 27.7 MW. The Kansas standard specifies the percent compliance be based on the average of the three previous year peaks. The average peak over those three years (2011 – 2013) is 484 MW. Therefore the Smoky Hills Wind Farm currently accounts for 5.7% towards the renewable energy standard.

The second recommendation was to evaluate the potential for local wind driven turbine. BPU concluded based on research of both wind options that a commercial scale wind facility was preferable over local community wind because of its lower cost due to wind location and economies of scale. A concern about entering into an agreement to purchase wind energy from a commercial wind facility remote from BPU's service territory was whether the transmission system had the capacity to get the energy to BPU. Therefore, as part of the evaluation of the economics of the wind energy purchase SPP performed an analysis to evaluate the potential for curtailment of flows originating at Smoky Hills and sinking in the KC area. The result of this analysis was that it did not expect the energy flow from Smoky Hills to BPU be curtailed a significant percent of the time.

In addition to Smoky Hills, BPU has a signed contract in place with Own Energy to purchase an additional 25 MW of wind capacity off Alexander wind farm. The Alexander contract is a 20 year flat rate purchase power agreement. The purchase is intended to work as an additional hedge against carbon based fuel appreciation as well as continuing to provide an alternative to fossil fuel based generation. Alexander wind farm is currently under construction near Alexander, KS and has an anticipated operations start date of October 2015. Alexander wind farm is expected to have a name plate of 48.3 MW once operational; with an expected net capacity factor of 49.3%. Alexander will make up over 5% of BPU's 2013 system peak demand, based on nameplate capacity; and approximately 4.4% of the 2013 retail load energy provided. As stated above each MW of eligible capacity installed in Kansas after January 1, 2000 will count as 1.1 MW for the purpose of the Kansas standard. Because the Alexander Wind Farm meets this criterion, its contribution will be 27.7 MW. The Kansas standard specifies the percent compliance be based on the average of the three previous year peaks. The average peak over those three years (2011 – 2013) is 484 MW. Therefore the Alexander Wind Farm will contribute 5.7% towards the current standard.

G. Landfill Gas Generation

The 2003 Master Plan recommended evaluation of Landfill Gas Generation as a renewable energy source but was narrowly focused on the potential for landfill gas generation at a local landfill. In 2009, BPU was approached by a project developer who had secured a source of gas at a private landfill in Arcadia, Kansas managed by Waste Corporation of Kansas. After considerable due diligence and contract negotiation BPU entered into a Renewable Energy Purchase Agreement with the developer, Oak Grove Power Producers, LLC. Beginning March 1, 2010 the Land Fill Gas generator began production with a 1.6 MW Caterpillar G3520. In December 2013 the BPU began receiving an additional 1.4 MW of generation from the Arcadia, Kansas landfill, with a total of 3.55 MW slated for September 2014. The LFG generation is expected to be available 95% of the time and is expected to be able to produce its maximum MW output 90% of the time. These figures make it one of the most reliable and dependable base load generation types available.

The negotiated capacity cost for the Arcadia, Kansas landfill gas capacity is comparable, but slightly less than, the annual capital carry costs for a scrubbed new coal plant on a $/kW-yr basis based on Table 8.2 of the U.S. Energy Information Administration's Annual Energy Outlook 2010 as a reference for overnight construction costs. The negotiated energy cost for generation from the Arcadia, Kansas landfill site, is slightly less than the energy price forecasted by Ventyx in their semi-annual *Power Reference Case Electricity & Fuel Price Outlook*, on a long-term levelized cost basis. Energy deliveries started in March of 2010.
The Oak Grove Landfill Gas Energy purchase agreement is for a period of 20 years. The purchase agreement affords BPU a renewable energy resource without the variability of wind and solar. The methane gas produced in a landfill is a potent greenhouse gas, about 21 times more so than carbon dioxide, so the gases produced in a landfill must be collected and flared off or used to produce heat or electricity preventing the methane from migrating into the

atmosphere where it contributes to local smog and global climate change. Using LFG to produce electricity results in beneficial use of the LFG as well as an opportunity to obtain base load generation without the carbon production from fossil fuel combustion and permitting difficulties of coal fired generation. The LFG generation is expected to produce enough power for about 1,000 homes with an annual reduction of GHG attributable to this project of approximately 1,400 passenger cars.

H. Hydro Generation

The BPU has existing contracts in place with three hydro entities, Southwest Power Administration, Western Area Power Administration, and Bowersock. Hydro generation and especially government hydro works as a cost effective alternative to base load fossil fuel generation. Government based hydro is extremely reliable and can be scheduled in much the same way as alternative generation types due to the size and scope of hydro facilities.

Southwestern Power Administration is one of four power marketing administrations within the U.S. Department of Energy whose role is to market and transmit electricity from 24 U.S. Army Corps of Engineers multipurpose dams. By law, Southwestern's power is marketed and delivered primarily to public bodies such as rural electric cooperatives and municipal utilities. The BPU's contract entitles it to 39 MW of capacity.

Western Area Power Administration is also one of the four power marketing administrations within the U.S. Department of Energy whose role is to market and transmit wholesale electricity from multi-use water projects. The service area encompasses a 15-state region of the central and western U.S. and consists of 56 hydropower plants, with an installed of capacity of 10,504 MW. The BPU's contract entitles it to 4.8 MW of capacity.

In November 2010, the BPU entered into a contract with the Bowersock Mills and Power Company (BMPC) to purchase the capacity and energy of an existing 2.15 MW run of the river hydroelectric facility on the Kansas River in Lawrence, KS and 4.70 MW of capacity from an expansion of Bowersock's existing hydroelectric facilities. The Bowersock agreement is to provide up to 7 MW of power for a period of 25 years. Bowersock is a low-impact hydro facility and has been supplying electricity to Northeast Kansas on a limited basis since 1905. The dam is owned by Bowersock but maintained by the city of Lawrence, which depends on the dam to pool water for its Kaw River Water Treatment plant. As part of the agreement, Bowersock undertook a plant expansion project, building an additional powerhouse on its existing site while tripling the overall energy production capability. The project is expected to maintain Bowersock's current status as a "low-impact" hydropower plant. The Bowersock hydro purchase provides BPU with a renewable energy source without the variability of wind and solar, additional base generation without the carbon production, and hydro energy from the facility for 25 years. The project is expected to produce 33,000 MWh per year of energy (the equivalent of 188 railcars of coal), enough to supply electricity to 3,300 Wyandotte County homes. Moreover, the project will reduce overall CO_2 emissions by more than 44,000 tons.

BPU performed an analysis on the economic feasibility of purchasing energy from the facility that led to the agreement. The expansion will include four turbines that will more than double the amount of electricity produced from the existing plant. Production costs simulations using the ProSym production cost model were used to determine the economics of the hydro generation purchase proposal. The analysis was performed for a combination of future scenarios that assumed two different natural gas price forecasts, and with and without CO_2

emission reduction mandates over a 25 year period. The analysis showed a net positive benefit to BPU, assuming equal likelihood of each scenario.

I. Renewable Energy Standard

The Kansas House enacted a Renewable Energy Standard (RES) in May 2009. The bill established a RES for Kansas that requires the state's investor owned utilities and certain cooperative utilities to generate or purchase certain amounts (10% by 2011; 15% by 2016; and 20% by 2020) of their electricity from renewable resources. Kansas' RES is based on generator nameplate capacity, not on retail electric energy sales. In the Fall of 2010, the Kansas Corporation Commission (KCC) established rules and regulations to administer the RES including equations for calculating capacity for the utilities. The required generation capacity can be produced by wind, solar thermal, photovoltaic (PV), dedicated crops grown for energy production, cellulosic agricultural residues, plant residues, methane from landfills or wastewater treatment, clean and untreated wood products such as pallets, existing hydropower, new hydropower that has a nameplate rating of 10 megawatts (MW) or less, fuel cells using hydrogen produced by an eligible renewable resource, and other sources of energy that become available in the future and are certified as renewable by the KCC. Each MW of eligible capacity installed in Kansas after January 1, 2000 will count as 1.1 MW for the purpose of compliance.

As a municipal utility, BPU is not bound by the Kansas RES. However, BPU is committed to voluntarily meeting the state's RES. BPU currently purchases renewable energy in the form of hydro, wind, and landfill gas, as summarized in Table 13 below, towards voluntarily meeting the state's RES. BPU purchases hydro generation from SWPA, WAPA, and Bowersock, wind energy from the Smoky Hills Wind plant, and land fill gas generation from the Oak Grove LFG facility. An agreement to purchase an additional 25 MW of wind generation off the Alexander wind farm has also recently been completed and is expected to begin production in October 2015.

Table 13
BPU Capacity and Energy from Renewable Resources

	Qualifies for Kansas RES?	EP Act 2005 Renewable?	Name Plate Capacity (MW)	Kansas Accredited Capacity (MW)	Federal Accredited Capacity (MW)	Capacity Factor	Federal Renewable Energy (GWh)
SWPA	Y	N	38.6	38.6	0.0		69.5
WAPA	Y	N	4.8	4.8	0.0		14.9
Bowersock Hydro	Y	Y	7.0	7.7	7.0	55%	97.1
Oak Grove LFG	Y	Y	3.55	3.9	3.55	90%	27.9
Smoky Hills Wind	Y	Y	25.2	27.7	25.2	44%	97.1
Alexander Wind	Y	Y	25.0	27.5	25.0	49%	107.3
Kansas RES Capacity (MW) & Federal RES Energy (GWh)				110.2			413.8*

*Based on expected capacity factor

In regards to the Kansas RES, BPU currently purchases about 17% of capacity by renewable resources towards the Kansas RES (see Table 14 below). This amount of renewable generation voluntarily meets the Kansas RES through 2020. With the addition of the Alexander wind farm purchase, BPU will increases its renewable generation, by capacity, to nearly 23%, based on the average of the last three years MW peaks. This will meet the Kansas RES through 2027, assuming the average three year peak does not exceed 551 MW before then. Based on average annual retail energy sales and estimated capacity factors of existing purchases, the BPU is meeting about 13% of retail sales through current renewable generation purchases. When the Alexander wind farm project comes on line in 2015 the BPU will be meeting about 17% of annual retail sales with renewable generation.

Table 14
BPU Capacity and Energy Summary from Renewable Resources

	Current		with Alexander	
Kansas Accredited Capacity (MW)	82.7	17.1%	110.2	22.8%
Average 3 Years Peak (MW)	484		484	
Federal Renewable Energy (GWh)	306.5*	12.7%	413.8*	17.1%
Average Retail Energy (GWh)	2,414		2,414	

*Based on expected capacity factor

VI. CURRENT DEMAND SIDE PROGRAMS

Screening of demand-side options began at BPU with the first IRP in 1989. Subsequently, XENERGY, INC. of Austin, Texas performed a detail screening and market assessment in 1993. This screening analysis became the implementation guide for many of the programs in place today.

Future Energy Efficiency and Demand Side Management programs will be evaluated with industry specific software such as Demand Side Management Option Risk Evaluator (DSMore™), a powerful financial analysis tool designed to evaluate the costs, benefits, and risks of DSM programs and services. DSMore provides all of the familiar cost effectiveness test results, including Utility Cost Test, Total Resource Cost Test, Ratepayer Impact Measure Test, and Societal Test. Moreover, these test results are provided for various weather conditions, including weather normal, and under a number of wholesale market conditions.

The programs described in this section are a continuation of those started either as a result of IRP or were started earlier as an effort to minimize cost and increase energy efficiency. They continue to be effective and generally require less attention and resources and thus are documented as IRP Programs.

A. System Load Factor Benefits

IRP planning and the programs implemented there under contribute to the system load factor [a quotient of energy used (kWh) divided by the product of peak load (kW) and the number of hours in the year]. Generally speaking, an improvement in system load factor is desirable because it allows for more efficient use of existing equipment and lowers the per unit fuel cost.

An improvement in system load factor occurs when the increase in system energy is greater than the increase in system peak. An improvement in load factor can be due to any number of things, such as: energy management programs that control on-peak use; greater efficiency in appliances; more energy efficient residential, commercial and industrial building additions; increased off-peak use; the addition of large industrial loads with non-coincident peaks or high load factors; and weather factors. Programs implemented since the inception of the integrated resource planning process have aided in obtaining an improved load factor.

Improvements in load factor associated with integrated resource planning result from the fact that some of the programs implemented have increased off-peak use while others have encouraged conservation or the use of more efficient appliances at the time of peak loads. The result is that less fuel is used per kWh generated while at the same time there is an increase in the use of more abundant and less costly fuels – coal versus natural gas. Greater use of more abundant and less costly fuels is primarily due to the reduction of the use of energy in peak periods (because of the increased efficiency of appliances being connected). Reductions in peak demand and use also save in the purchase of off-system power.

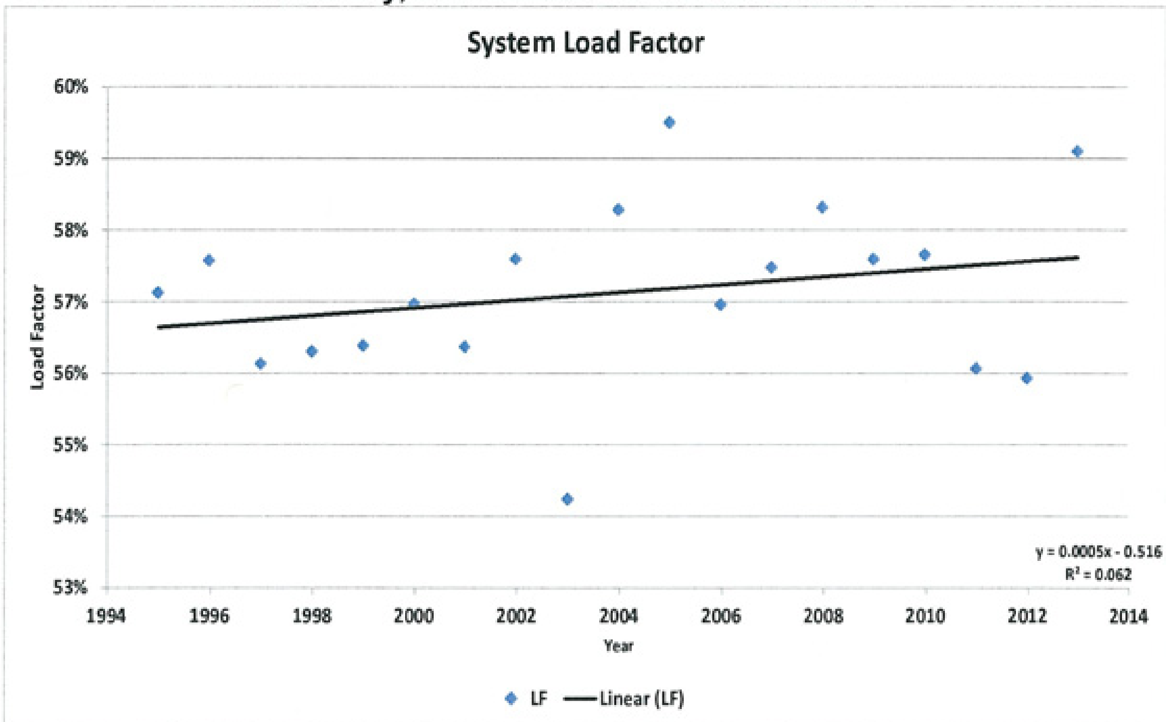
Table 7 lists the system load factor for the past 19 years. As can be seen from this table, the system load factor has improved since 1995. In 1995 the system load factor was 57% and in 2013 it sat at 59%, matching its highest point since the inception of tracking began in 1989. Although the measure has varied over the years due to weather conditions, economic factors within the customer base, as well as other factors, the trend does show a modest gradual improvement over time. This improvement is beneficial, and while not all of the improvement can be attributed to integrated resource planning, a portion can be.

Table 7
System Load Factor
Kansas City, Kansas Board of Public Utilities

Year	System Energy (GWh)	System Peak (MW)	Load Factor
1995	2,267	453	57%
1996	2,330	462	58%
1997	2,355	479	56%
1998	2,431	493	56%
1999	2,445	495	56%
2000	2,465	494	57%
2001	2,449	496	56%
2002	2,482	492	58%
2003	2,470	520	54%
2004	2,501	490	58%
2005	2,611	501	59%
2006	2,639	529	57%
2007	2,578	512	57%
2008	2,513	492	58%
2009	2,376	471	58%
2010	2,530	501	58%
2011	2,465	502	56%
2012	2,425	495	56%
2013	2,350	454	59%

Charting the above data yields the graph shown on Figure 2 on the following page. This graph shows a positive load factor trend line that is gradually increasing. This chart also shows variation associated with weather and other factors.

Figure 2
System Load Factor
Kansas City, Kansas Board of Public Utilities



The apparent random variations in the load factor from year to year are due to a multitude of factors with the predominant reasons being shifting load dynamics and weather variations. The general trend of improvement is due to the success of many of the programs undertaken by BPU. Some of the major contributors to this net change in system load factor have been the following:

1. Electric Heat Pump and Hot Water Heater Rebate Program,
2. Changes in the electric rate structure lowering winter rates thus encouraging winter use and increasing summer rates making energy management programs economically viable.
3. Changes in the standards of the signal light and street light replacement program,
4. Implementation of construction standards emphasizing higher efficiency,

A discussion and documentation of these programs follows.

B. Heat Pump and Hot Water Heater Rebate Programs

This program began in 2001 and continues today. The program is designed for both residential and commercial customers such that rebates are given to customers or builders who install or retro-fit energy efficient heat pumps or hot water heaters. The amount of rebates given to residential and commercial customers is provided on the BPU website, www.BPU.com. The BPU partners with the Energy Star Program and rebates are consistent with Energy Star recommendations.

Table 8 summarizes the rebate program since its inception in 2001. This table shows the revenues associated with the program along with its cost.

Table 8
Estimated Revenues and Cost Summary of the Rebate Program
Kansas City, Kansas Board of Public Utilities

Year	Total Cumulative Annual kWh	Total Cumulative Annual Revenues[1]	Rebates	Admin Labor Costs	Ratio Admin to Rebates	Total Annual Costs	Annual Revenue to Total Costs
2001	506,548	$15,305	$78,868	$124,715	1.58	$203,583	8%
2002	12,906,844	$247,654	$255,383	$241,504	0.95	$496,887	50%
2003	115,796,119	$1,533,554	$807,995	$332,319	0.41	$1,140,314	134%
2004	506,403,743	$811,677	$540,025	$328,386	0.61	$868,411	93%
2005	1,106,800,786	$1,026,336	$475,949	$300,000	0.63	$775,949	132%
2006	1,944,084,781	$1,318,188	$519,558	$297,541	0.57	$817,098	161%
2007	3,066,818,626	$1,875,039	$449,889	$129,261	0.29	$579,150	324%
2008	4,476,432,919	$2,083,524	$363,739	$109,208	0.30	$472,947	441%
2009	6,207,204,621	$2,200,756	$23,085	$148,449	6.43	$171,534	1283%
2010	8,233,144,052	$5,051,879	$165,738	$148,449	0.90	$314,187	1608%
2011	10,588,238,009	$1,794,726	$186,908	$148,449	0.79	$335,357	535%
2012	13,257,124,530	$1,847,516	$129,108	$148,449	1.15	$277,557	666%
2013	16,249,279,287	$2,077,673	$383,938	$148,449	0.39	$532,387	390%
Total	65,764,740,862	21,883,827	**$4,380,180**	**$2,605,179**	0.59	$6,985,360	313%

[1] **Total Annual Revenues based on net marginal revenue and total cumulative kWh**

The total annual revenues, based on total cumulative kWh, since the inception of the program is slightly less than $22,000,000 or more than 3 times the total cost of operation of approximately $6.9 million after 13 years into the program's life cycle. This is not only a benefit to net revenue, but is also a benefit to the system load factor. As discussed earlier, an improved system load factor permits greater usage of more efficient generating equipment thus lowering the unit cost of energy and benefiting all customers. As one reviews Table 8, it is useful to keep in mind that as an electrical piece of equipment is added to the system a revenue stream is generated and continues as long as the equipment is connected and used. For this reason the revenue stream accumulates and the annual accumulated revenue and benefit grows.

Table 9 below illustrates another significant benefit of the BPU Rebate Programs. It shows the estimated capacity reduction associated with retrofitting older less efficient heat pumps and air conditioners with newer appliances. This retrofitting is primarily the result of the rebate program and tax credits by the federal government. Since inception, it is estimated that this program has reduced the capacity requirements by over 2.3 MW and has saved over $370,000.

Table 9
Estimated Capacity Reduction
Kansas City, Kansas Board of Public Utilities

Year	Summer Capacity Reduction (kW)	Cumulative (kW)	Summer Capacity Rate ($/kW-mo)	Annual Capacity Savings[1]
2001	49	24.4	$ 1.85	$ 181
2002	88	92.9	$ 1.85	$ 687
2003	176	224.8	$ 2.25	$ 2,023
2004	258	441.8	$ 4.00	$ 7,069
2005	217	679.4	$ 4.75	$ 12,908
2006	201	888.5	$ 5.09	$ 18,084
2007	186	1,082.1	$ 6.05	$ 26,187
2008	160	1,255.1	$ 6.05	$ 30,374
2009	2	1,336.2	$ 6.05	$ 32,337
2010	125	1,399.8	$ 7.05	$ 39,474
2011	65	1,494.6	$ 8.05	$ 48,126
2012	657	1,855.3	$ 9.05	$ 67,162
2013	102	2,234.6	$ 10.05	$ 89,830
Total	2,285			**$374,441**

[1] Based on a 4 month purchase of summer capacity.

C. Street Light Replacement Program

As technology improved and equipment costs decreased, BPU instituted a program of replacing Mercury Vapor lamps (MV) with more efficient High Pressure Sodium (HPS) lamps in its street light replacement program. Subject to budget constraints, more efficient lamps are utilized when replacement of an existing unit is necessary or when a new lighting facility is installed.

As a result of this program more light (Lumens) per unit of energy is obtained. For example, a 100 Watt High Pressure Sodium Lamp produces approximately 9,500 Lumens, while a 175 Watt Mercury Vapor Lamp produces only 7,850 Lumens. When one considers that a street lighting lamp in the Kansas City area operates approximately 4300 hours per year, there is a substantial savings in energy while providing better illumination. High Pressure Sodium lamps use approximately 70% less watts but produce approximately 75% more lumens on relative basis. This program yields an annual energy savings of approximately 32% compared to 2001 use.

Table 10
Total Illumination
Kansas City, Kansas Board of Public Utilities

Type	Size Watts	Lumens per Lamp[1]	Lamp Units in 2001	Total Lumens 2001	Lamp Units in 2008	Total Lumens 2008	Total Units in 2014	Total Lumens 2014
HPS	70	6300					2,220	13,986,000
HPS	100	9,500	873	8,293,500	1,089	10,345,500	1,328	12,616,000
HPS	150	16,000	0	-	10	160,000	0	0
HPS	250	27,500	4,724	129,910,000	6,536	179,740,000	14,358	394,845,000
HPS	400	50,000	206	10,300,000	219	10,950,000	1,076	53,800,000
Total HPS:			5,803	148,503,500	7,854	201,195,500	18,982	475,247,000
MV	175	7,850	9,530	74,810,500	8,441	66,261,850	5,244	41,165,400
MV	250	12,000	1,714	20,568,000	1,693	20,316,000	256	3,072,000
MV	400	20,500	2,393	49,056,500	2,389	48,974,500	80	1,640,000
MV	1,000	57,000	2,316	132,012,000	2,327	132,639,000	0	0
Total MV:			15,953	276,447,000	14,850	268,191,350	5,580	45,877,400
Grand Total:			21,756	424,950,500	22,704	469,386,850	24,562	521,124,400
Percent Increase from 2001 to 2008:					4.40%	10.50%	12.89%[2]	22.63%[2]
[1] Values of Lumens per lamp are taken from the 8th Edition of the Lighting Handbook published by the Illuminating Engineering Society of North America.							8.2%[3]	11.02%[3]
[2] Percent Increase from 2001 to 2014								
[3] Percent Increase from 2008 to 2014								

As can be seen above in Table 11, the total illumination increased by nearly 23 percent from 2001 to 2014, whereas, during the same time period, the number of light fixtures only increased by about eight percent. Although the street light program has contributed to energy savings, because the BPU system peak has historically occurred during the day when streetlights are not operating, the street light program does not contribute to peak demand reduction.

D. Signal Light Replacement Program

Since December 2003, through the Signal Light Replacement Program, the BPU has replaced incandescent signal lights with LED lamps at approximately 59 locations and realized additional energy savings. The relative difference in power requirement for each head is significant, being in the range of 20 to 1. It is estimated that there is an annual savings of approximately 21,024 kWh at each location where these fixtures are converted.

Since the inception of this program the total energy savings is estimated at nearly 1,400,000 kWh per year. This savings will continue to grow as long as there remain incandescent fixtures to be replaced; after that, the savings will continue on a year to year basis. In addition to the energy savings, the signal light replacement program has reduced the peak demand by approximately 142 kW compared to what peak demand would be assuming continued operation of incandescent signal lights.

E. Home Energy Audit Program

The BPU's Home Energy Audit program was designed to help residential customers better understand and reduce their overall energy consumption while improving the livability and comfort of their homes. Within this program customers receive a comprehensive energy audit by a certified energy auditor, valued at approximately $500. The customer is only required to pay $50 out of pocket while the BPU will pay the difference upon completion of the audit. The Home Energy Audit includes; a blower test to identify air leakage, a combustible appliance zone test to identify harmful carbon monoxide inside the home, a personal energy conservation plan, and twelve compact fluorescent light bulbs. If the consumer makes any of the changes suggested in the audit, the BPU will reimburse that consumer the $50 out of pocket expense. The BPU is expecting to complete approximately 300 audits in 2014.

F. Reactive Adjustment Rider

Customers with low power factors impose a burden on the electrical system causing a utility to increase its generation, transmission, distribution, transformer capacities and energy generation. Power factors are functions of real power (kW) and the apparent power (kVA) a utility must supply to the customer. For any given-metered load in kW, the lower the power factor, the greater the amount of power (kVA) a utility must generate and deliver to the customer. For example, in order to supply a load of 100 kW having a power factor of 85% the utility would have to generate and deliver approximately 117.6 kVA. An 85% power factor would require equipment with 17.6% more capacity to meet this demand. Further, since system losses vary as the square of the amperage required to serve the load, there is at the same time a 36% increase in system losses. BPU rates are designed to permit a customer to have a power factor equal to or greater than 90%. Customers with power factors less than 90% are penalized.

In August 2003 the power factor penalty provision was revised because the rate structure did not adequately address the cost of low power factors and customers in this category continued to impose a burden on the system. A customer with a low power factor can correct its power factor by installing corrective equipment or modifying the use of its equipment. When this new reactive adjustment penalty provision was enacted customers were notified of the change and given a six (6) month grace period in which to take corrective action.

Currently customers are notified if they have a low power factor and given an opportunity to correct the problem. If corrective action is not taken within a reasonable period of time then a penalty is added to their bill. The penalty is the difference between 90% and the actual power factor applied to the total customer's monthly electric billing. For example, if a customer has a power factor of 80% then a penalty of 10% is applied to the bill (90% - 80%). Table 11 below shows the history of the reactive adjustment program since records have been kept for the month of August. August is the month in which the system annual peak most frequently occurs.

Table 11
Power Factor Customer Data for the month of August
Kansas City, Kansas Board of Public Utilities

Year	Total Customers	No. of Customers with Reactive Charges	Percentage of Customers with Reactive Charges	Power Factor Penalty Revenues	Avg Reactive Charge Per Customer with Reactive Charges	Avg Reactive Charge Per Customer
2008	1,066	452	42.4%	$ 147,797	$ 326.98	$ 138.65
2009	1,034	448	43.3%	$ 129,165	$ 288.32	$ 124.92
2010	1,095	455	41.6%	$ 131,281	$ 288.53	$ 119.89
2011	1,121	484	43.2%	$ 174,658	$ 360.86	$ 155.81
2012	1,172	498	42.5%	$ 181,116	$ 363.69	$ 154.54
2013	1,528	682	44.6%	$ 201,957	$ 296.12	$ 132.17

The data shows a flat to slightly increasing trend from 2008 to 2013 in the percent of customers with less desirable power factors. The percentage of customers with low power factors in 2008 was 42.4% of customers with power factor metering compared to 44.6% in 2013. The average reactive charge per customer with reactive charges showed a significant increase in 2011 and 2012 but appears to be falling back toward historical norms. BPU will continue to monitor the trends to see if power factor customers continue to improve their overall power factors.

G. Net Metering

In May 2009, Kansas passed the Net Metering and Easy Connection Act which is applicable to Investor Owned Utilities (IOU's) only. The BPU, as a municipal utility, is not subject to that regulation, but has developed and adopted net metering and connection standards for Large, Medium, and Small Commercial and Residential customers to enable customer owned renewable generation sources. Although the number of customers currently utilizing net metering is small currently, it is expected to continue to slowly climb as prices on renewable distributed generation continue to fall.

H. Smart Meters

The BPU is in the process of bringing AMI smart metering technology to all BPU customers. The goal of the Advanced Metering Infrastructure is to improve customer service, lower the BPU's expense structure, and to provide consumers with the ability to monitor and drive efficiencies within their own system. Some of the benefits of AMI technology include immediate leak detection, reducing the need to access a customer's premises, and a real-time viewing of electric and water usage. The new meters are more accurate, and less prone to failure, and eliminate the potential for reader error that existed with the older electro-mechanical meters. By the end of 2014 the BPU expects to offer customers the ability to access their own individualized online Energy Engage Portal, providing relevant secure information detailing a consumer's electricity and water usage and costs. The AMI smart meters are just another tool that consumers can use that will have a direct impact on their usage and in turn their bill.

I. 2D2S Programmable Thermostat Program

2 DEGREES 2 SAVE™ (2D2S) is a new and innovative way to help the BPU consumers save on heating and cooling costs while also aiding the BPU by reducing summertime peak demand. The BPU is a not-for-profit municipal utility so cutting power supply costs helps keep rates low and allows consumers the ability to keep more money in their pockets.

How the 2D2S Program Works

The program uses a programmable thermostat which allows the BPU to raise the temperature setting by 2 degrees during peak use hours. By doing this, air conditioners work less, and cycle more frequently and when combined with the air conditioners of all participants' means that fewer units are operating at the same time. The BPU will only adjust the temperature of 2D2S customers' home by two degrees from the set point instructions. The temperature will be lowered by two degrees just before the peak event. The intent of the precooling is to provide consumers with limited effects of the peak demand event, where temperatures would be allowed to raise the temperature by two degrees above set point instructions. These adjustments will only happen on weekdays from June through September, and will occur only when an energy emergency event has been enacted. Events are never scheduled on weekends or holidays.

The thermostats reduce peak electricity use in two ways. First, by allowing the temperature to adjust two degrees, air conditioners don't have to work as hard during the few hottest hours of the summer's peak use days. Second, when they are running, the air conditioners of all participants cycle at different times, so that fewer of them are on at the same moment. The cost of producing electricity depends on when it is being used. During periods of moderate demand utilities rely on the most efficient generators with the lowest operating cost, however, on hot, muggy days when load is elevated, utilities are required to meet that load through the use of less efficient resources, and thus the power generated during that period is more expensive than at other points of the day.

Outcome of 2D2S Program Status

Since the program's inception in December 2011, about 3400 customers have signed up for the 2D2S program, which accounts for approximately 5% of the total BPU electric customers. The 2D2S program offers free thermostats to BPU's residential (including multi-families) and small commercial customers residing within Wyandotte County. The initial program ran through March 31, 2013 and was funded in conjunction with the US Department of Energy's Smart Grid Investment Grant Award No. DE-OE0000359. The grant was financed with American Recovery and Reinvestment Act of 2009 (hereinafter, "ARRA") funds. The BPU has spent about $1.5 million over the first three years of the program. Expenses are expected to diminish going forward as the program is in more of a maintenance stage.

2D2S Details	2011	2012	2013	2014	TOTAL
Total Enrollment	23	2372	873	92	3360
Total Amount Spent in $	$ 121,516.54	$ 877,280.54	$ 473,629.23	$ 32,021.29	$ 1,504,447.60

Benefits of 2D2S Program

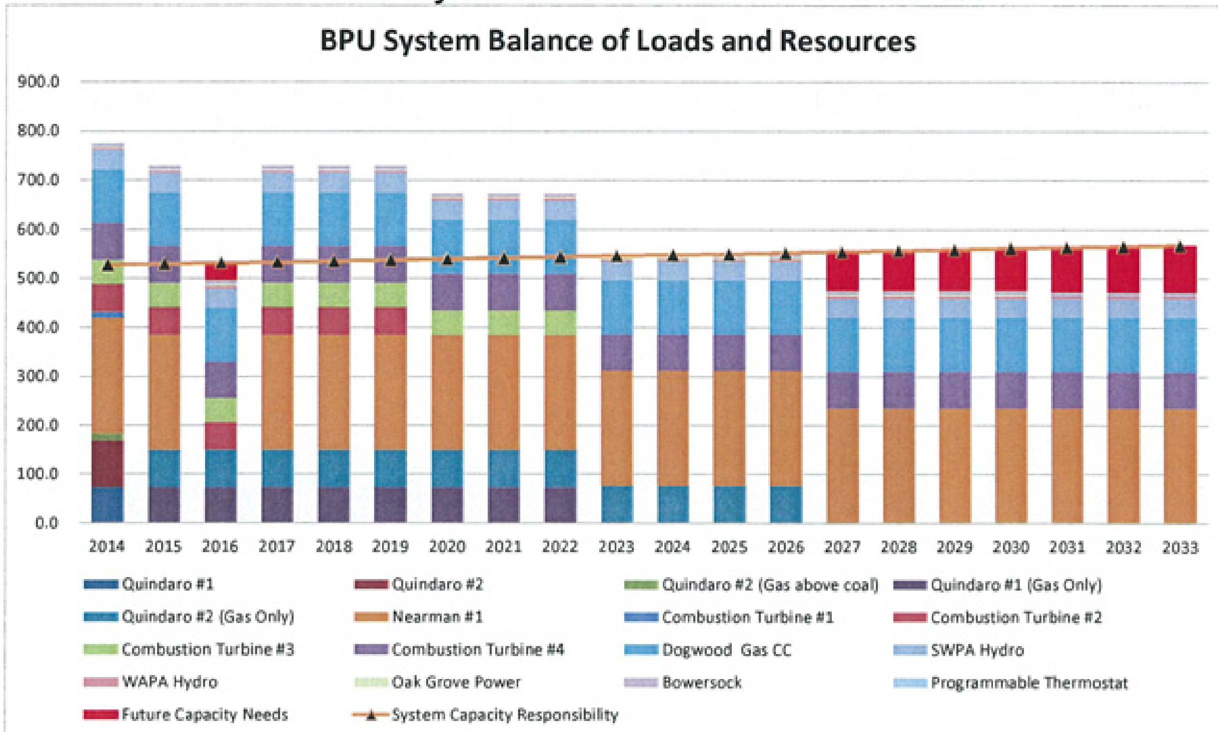
2D2S customers receive a free Honeywell programmable thermostat professionally installed by trained and certified Honeywell employees whom have specific training in the installation of the 900 MHz UtilityPro thermostat. The installers also teach customers how to program and access the thermostat from the web. In addition, 24-hour customer service is also provided for any 2D2S customer service issues or concerns. To be eligible to participate in this program customers must have central air conditioning or heat pump system in good working condition.

The US Department of Energy says that a good programmable thermostat when properly programmed and maintained can save 5% to 15% on heating and cooling costs per year. The average household spends more than $2,200 a year on energy bills - nearly half of which goes to heating and cooling. Homeowners can save about $180 a year by properly setting their programmable thermostats and maintaining those settings. In addition to the energy savings the Honeywell UtilityPro thermostat is easy to use and program.

VII. Future Resource Requirements Summary

The graph below in Figure 3 shows the BPU future resource requirements based on current demand forecasts. BPU currently has sufficient capacity to meet the forecast demand through June of 2016. In 2016 capacity shortfalls are only expected in July and August. The BPU is expected to have sufficient capacity coverage through 2025, possibly 2026 based on current projection parameters. The primary driver behind the capacity shortfall is the retirements of Quindaro Unit #1, currently scheduled for 2022, and Quindaro Unit #2, currently scheduled for 2026. Load dynamics will also be a major contributor to the future system capacity requirements. Capacity concerns will begin to emerge in 2022 with the expected retirement of Quindaro Unit #1, however excluding the addition of a large industrial and/or commercial customer, elevated weather related use, or a meaningful impact related to Nearman auxiliary use the BPU is expected to have marginal capacity coverage through 2026. Any potential capacity shortfalls that do occur prior to 2026 can likely be met through summer capacity purchases. This additional capacity needs are shown in the graph below. Previous planning studies have shown that a simple cycle combustion turbine with a summer capacity rating of about 75 MW to be the most economical resource expansion unit. Because the need for additional capacity is so far in the future, BPU will reevaluate those study results before moving forward.

Figure 3
BPU System Balance of Loads and Resources



BPU recognizes that the expected capacities of existing BPU generators and that the economics of the Quindaro Units' continued operation is a function of potential future environmental regulations. Economic studies have shown that the continued operation of the Quindaro steam coal units are the lower cost options to meet projected demand growth, however, BPU continues to study the costs associated with the continued operation of those units as environmental regulations change such that the BPU can continue to provide safe and reliable service to their customers at the lowest possible costs while complying with existing environmental regulations and other regulatory requirements.

VIII. FUTURE RESOURCE OPTION SUMMARY

BPU's integrated resource planning is a continuous process and the selection of programs to apply scarce resources is a dynamic process. One manifestation of the dynamic nature of this planning is that as programs mature (reach a point of diminishing returns) new initiatives are undertaken, which produce better marginal results. With this dynamic nature of the IRP process, it is not to say that existing programs are discontinued, but are simply allowed to continue (either with or without modification), but are de-emphasized with regard to the use of scarce resources. The new initiatives which appear to be fruitful are implemented with sufficient resources so as to make them effective. Once a program is implemented, then planning goes on to evaluate other options. In the process of developing plans, BPU management personnel are always looking for initiatives which will produce the greatest result with the least long-run investment and expense.

Studies done under the IRP umbrella have produced programs that have yielded cost reductions, increased the use of more efficient generating units, enhanced conservation, and improved net revenues. In general these activities have helped hold down rates. Studies have been made which have focused upon increasing the use of renewable or "green" resources as well as improving energy conservation. An example of an energy conserving program is the Street Lighting and Signal Light Replacement Program where more efficient lamps are being utilized to replace older less efficient lamps while providing the same or greater level of lumens to the area or signal brightness.

Initial efforts by the BPU were aimed at improved energy utilization (increased off peak energy use) and less on conservation and demand reduction. The more recent plan focuses on energy efficiency, demand-side management, as well as long-term green energy initiatives, which act as a hedge against carbon based generation volatility.

Resource options considered viable are screened through cost analysis and penetration studies. Resource options for meeting the power requirements of a system are traditionally screened through a power-supply evaluation program. The equipment to be evaluated for supply-side resource is first screened by an assessment of what options are available and most likely viable. In integrated resource planning demand-side options are also considered. The demand-side options considered to be desirable and workable are generally first screened through an assessment of market opportunities and costs. The viable candidates are then placed into the mix of power-supply options for total resource evaluation. This evaluation will indicate what mix of supply-side and demand-side programs should provide the lowest long term cost and will be pursued. The overall evaluation is typically done through the use of a long-term chronological production cost power supply modeling

Resource planning at the Kansas City Board of Public Utilities (BPU) is an ongoing process. As opportunities for acquiring additional resources are presented, the BPU performs studies and analysis, and then decides how to proceed depending on the results of the analysis. The BPU has completed a great deal of analysis in the past decade to ensure the BPU and its customer base is well insulated from volatility through energy source diversification and hedging while also preparing for inevitable shifts in demand based on population, industry, and technology changes. The following chronicles many of these studies.

In 2006, BPU commissioned a study for an independent review and update of the 2003 Kansas City Board of Public Utilities Electric System Master Plan. A conclusion of the study was that the most economical next new unit for BPU to meet projected demand is a nominal 235 MW pulverized coal unit. Subsequent to the completion of the 2006 Planning Study, in the first half of 2007, in a landmark case, the U.S. Supreme Court ruled that carbon dioxide and other global warming pollutants can be regulated under the Clean Air Act. The court also ruled that the EPA cannot refuse to regulate these pollutants for political reasons. In the first challenge since the ruling, the Sierra Club and Earthjustice petitioned the state of Kansas not to issue a permit for expansion of a coal-fired power plant proposed in Western Kansas unless it requires substantial controls for carbon dioxide. Subsequently, Secretary of the Kansas Department of Health and Environment, Roderick Bremby made an announcement in fall 2007 denying the air quality permit for Sunflower Electric Power Corporation's Holcomb Expansion. Bremby's decision was based on his opinion that additional carbon dioxide in the atmosphere presents a "substantial endangerment" to the public health of Kansans. Current EPA and Kansas regulations do not consider carbon dioxide a pollutant. The Secretary's decision sets aside KDHE professional staff's recommendation to issue the permit and disregards the extensive and exhaustive work completed by the KDHE technical staff to ensure that public health and the environment are protected, public concerns were addressed, and strict state and federal laws were followed.

A consequence of the Bremby decision was concern about the ability to permit a coal fired plant in the state of Kansas. Therefore, in 2008 the Kansas City Board of Public Utilities (BPU) performed a Ten Year Power Supply Plan study which considered natural gas fueled generation future resources capable of meeting the BPU's need for firm generating capacity. One conclusion of the study was that it is less costly to continue to operate Q1 through 2017 rather than to retire it and replace it with a similar amount of combustion turbine based capacity. Of the expansion plans considered, the plans that convert new or existing simple cycle combustion turbines to combined cycle combustion turbines are consistently the most expensive plans because the production cost savings associated with the efficiency of a combined cycle configuration compared to a simple cycle configuration are not sufficient to offset the combined cycle's incremental capital cost. In the least cost plan, BPU meets additional load growth with the addition of a 43 MW LM6000 type aero-derivative combustion turbine in 2011. The second least-cost plan also assumed Q1 remains in service and that two smaller (21 MW) LM2500 type combustion turbines are added for growth, one in 2011 and one in 2015. In the third least cost plan, a 75 MW Frame 7EA combustion turbine is added in 2011.

In 2009, after the completion of the 2008 10-yr Power Supply Plan study, BPU was able to obtain firm transmission service on its SWPA Hydro purchases through the SPP aggregate study process. The ability to obtain firm transmission service from the SWPA Hydro capacity provides 39 MW of accredited capacity to the BPU. Obtaining this capacity moved BPU's need for additional capacity to the year 2016. Therefore, BPU will continue to monitor its demand growth and resource options to determine the most economical way to meet future capacity needs.

Following is additional documentation of many of the studies and analysis performed in the last few years.

J. Electric Master Plan Review and Power Market Assessment

In 2006, BPU commissioned a study for an independent review and update of the 2003 Kansas City Board of Public Utilities Electric System Master Plan. The study was conducted in parallel with a base load generation siting study designed to identify the most feasible site for new base load generation available to the BPU system. A wholesale power market assessment designed to identify neighboring utilities needing additional generation with the common goal of the acquisition of additional generating capacity and energy to meet the needs of a growing service area was performed as a component of this study. The benefits identified in partnering with other utilities are twofold:

- Reduced costs to BPU customers from excess capacity that typically exists in the years immediately following the addition of the next major new generation resource, and

- Potentially significant economies-of-scale associated with the construction of generators larger than would be required to meet BPU's demand alone.

By conducting siting and market assessment studies concurrent with the Master Plan update, the BPU ensured that the costs of new generation resources considered reflect site specific conditions and cost-effective generator unit sizing. The concurrent studies also preserved the lead time required to design, permit, and construct new coal fueled generation for commercial operation in 2012 consistent with what the 2003 Master Plan indicated was needed.

This independent Master Plan review and update of 2006 addressed the future power supply needs of the BPU's native load customers, plus the wholesale power sales commitments under existing contracts through 2021-2022. The study also considered age and ability of the existing BPU generators to continue providing the level of economic and reliable service they have provided over the past 35 or more years. The period of study was the 25-year period 2006 through 2030.

The Master Plan review included the following elements:

- Forecast Need for Power--A review of previous BPU electric load and generating capacity requirement forecasts, a forecast of the capabilities and costs of existing BPU generators and power purchases, and a forecast of the timing and size of additional generating capacity needs.

- Characterization of New Power Supply Resources--Descriptions of the new power supply resources available to the BPU including conventional and renewable supply-side generation options, demand-side management programs designed to reduce the demand for power and possibly delay the need for new generation, and purchased power.

- Supply Side and Demand Side Resource Screening--A qualitative comparison of alternative resources with regard to their applicability to the BPU system along with a lifecycle cost comparison of the applicable options.

- Financial Comparison of Alternative Power Supply Plans--The identification of alternative plans to meet 2006-2030 generating capacity and energy needs and the comparison of these plans on a comparative revenue requirement basis. Includes associated risk and contingency analyses.

- Bilateral Power Market Description--A description of the potential availability of base load purchased power to be acquired in lieu of construction of a new BPU resource, and a description of the initial responses to a bridge power solicitation.

A conclusion of the study was that the most economical next new unit for BPU to meet the projected demand is a nominal 235 MW pulverized coal unit. The Executive Summary from that report is included in Appendix E.

K. 2008 Ten Year Power Supply Plan, updated 12/2012 (The Gas Plan)

Subsequent to the 2006 Master Plan review and update, in late 2008, the Kansas City Board of Public Utilities (BPU) completed a Ten Year Power Supply Plan study. The 10-year power supply study considered natural gas fueled generation resources capable of meeting the BPU's need for firm generating capacity. The need for capacity was identified as the difference between forecast peak demand plus reserve requirements and the capacities of existing power supply resources. The study recognized the expected outputs of existing BPU generators and that the economics of the Quindaro Units' continued operation is a function of potential future environmental regulations, including the Regional Haze Rule and the ozone non-attainment conditions in the Kansas City metropolitan area. The study period was the 10-year period beginning 2008 through 2017. That study identified a need for between 35 and 107 MW of additional firm capacity by 2017, dependent upon whether or not BPU continues to operate Quindaro Unit 1 (Q1). The study consisted of the comparison of ten alternative generation expansion plans. Each plan was based on the use of simple cycle combustion turbines and/or combined cycle units burning natural gas as the primary fuel.

The study objective was to find the power supply plan that minimized overall costs to BPU customers during the ten-year study period under a range of plausible future conditions. The initial set of plan comparisons assumed forecasts of expected fuel prices, power purchase and sales price, load growth, sulfur dioxide (SO_2) allowance prices and carbon dioxide (CO_2) allowance prices. In addition, sensitivity analyses were conducted to compare the costs to customers under the following conditions:

- Gain of a large (28 MW) customer, at a load factor similar to the BPU system load factor.
- Loss of a large (28 MW) customer, at a load factor similar to the system load factor.
- High natural gas and electric market prices.
- A high cost for CO_2 emissions either as a result of a cap & trade program or the application of a carbon tax.
- No purchases of economy energy from the market reflecting an extreme case of transmission congestion.

One conclusion of the study was that it is consistently less costly to continue to operate Q1 through 2017 rather than to retire it and replace it with a similar amount of combustion turbine based capacity. Q1 was assumed to be required to be retrofit with a selective catalytic reduction (SCR) system for nitrogen oxide (NOx) control in order to continue operating through the study period. Of the expansion plans considered, the plans that convert new or existing simple cycle combustion turbines to combined cycle combustion turbines are consistently the most expensive plans because the production cost savings associated with the efficiency of a combined cycle configuration compared to a simple cycle configuration are not sufficient to offset the combined cycle's incremental capital cost during the 10 year planning period. In the least cost plan, BPU meets additional load growth with the addition of a 43 MW LM6000 type aero-derivative combustion turbine in 2011. The second least-cost plan also assumed Q1 remains in service and that two smaller (21 MW) LM2500 type combustion turbines are added for growth, one in 2011 and one in 2015. In the third least cost plan, a 75 MW Frame 7EA combustion turbine is added in 2011.

Because the NPV costs of the three least-cost plans calling for the addition of an LM6000 turbine, two LM2500 turbines or a 7EA turbine were so close, BPU selected the 7EA plan as the basis of the rate impact analysis in order to accommodate what is likely to be the most capital intensive of the least-cost plans and to allow BPU to maintain needed flexibility in procuring turbines.

L. 2008 - 2009 Kansas Municipal Generation Planning

The BPU participated in a joint resource planning study with Kansas Municipal Utilities (KMU), Kansas Public Power (KPP), and Kansas Municipal Energy Agency (KMEA) to determine a viable power supply plan that meets the power supply needs of all the participants at a cost that is more cost-effective than if the participants develop individual plans.

Power supply data was compiled and analyzed for the KMU membership as a whole as well as an approach to the individual agency power supply needs of KMEA, KPP and Kansas City BPU.

M. 2011 Environmental Regulatory Uncertainty Report

In July 2011, Black and Veatch was commissioned to perform a study related to the current and future environmental regulatory climate and how those regulations may affect BPU generation and the utility industry as a whole. This study focused on regulations associated with air quality, solid waste, as well as potentially new water mandates and how these new or potential mandates would affect the current fleet of generation at the BPU.

The study was divided into near term (2012 – 2014) and long term (2015 and beyond) compliance planning to ensure the BPU was taking all necessary steps to be prepared for regulatory changes. In the near term CSAPR or the Cross State Air Pollution Regulations were analyzed, with an expected compliance date of January 1, 2012. Within the CSAPR analysis several alternatives were analyzed including air quality controls on Nearman1, Quindaro1, and Quindaro2, the discontinuation of coal on Quindaro1 and Quindaro2, additional purchase power scenarios including that of the Dogwood combined cycle plant, as well as a discussion related to allowances and the pricing structure that may be established to handle these regulations.

In the long term analysis Black and Veatch reviewed a number of current and potential mandates. Long term compliance planning involved utility MACT or Maximum Achievable Control Technology which anticipated a compliance date of January 1, 2015, the maturing of CSAPR regulations, as well as NAAQS or National Ambient Air Quality Standards which were still pending at the time of the analysis. All potential and upcoming regulations are expected to have moderate to meaningful impacts on the generation side of the BPU and will continue to require continuous monitoring to ensure the BPU is doing everything possible to be compliant under current regulations as well as adapt plans to better position the utility going forward.

IX. PROPOSED FUTURE INITIATIVES

A. General

Utilities face many challenges now and in the future. BPU is constantly evaluating its options with respect to capacity additions in light of regulatory uncertainty. Kansas renewable energy regulations have been enacted that exempt municipal utilities and use a different definition of renewable energy than the federal definition in the Energy Policy Act of 2005. Proposed federal regulations exempt smaller utilities from Renewable Portfolio Standards which may also exempt BPU from the final legislation.

Economic realities have reduced electrical demand and affected the ability of utilities and renewable energy developers to meet the demands imposed by financing entities to see renewable projects through to commercial operation. The possible economic viability of renewable energy projects are further affected by the factors that affect traditional fossil fuel generation resources:

- Escalating material and labor costs.
- Competition for engineering and construction services.
- Procurement lead times and costs.
- Volatile and increasing fuel costs.
- Changing Emissions Regulations.
- Changing Emission Technologies.
- Availability of financing.

The challenges facing new generation are significant and any deferral or reduction of capacity additions will have worthwhile dividends. BPU will continue to systematically challenge capacity addition decisions using available data on proven renewable and energy efficiency alternatives as well as conventional supply side alternatives. Following are examples of ongoing resource studies/analysis at the BPU.

X. ACTION PLAN

The BPU is devoting considerable resources to the programs either operating or being considered as a part of Integrated Resource Planning. The existing programs are yielding beneficial results. These programs are aiding in holding down rates, conserving energy, improving use of power generating equipment and reducing the use of limited and more costly fossil fuels.

The BPU is going to continue to analyze the effectiveness of the current programs while continuing to search for additional programs that have the ability to shave load or drive efficiencies both at the utility level as well as at the customer level. As technology continues to evolve more and more opportunities will become available that allow consumers to make smarter energy choices while also allowing the BPU to make more efficient choices, therefore saving everyone money. All the programs stated above are expected to continue over the next year. Future programs are being evaluated. Future programs considered worthy of consideration will be evaluated and, if implemented, most likely will achieve many of these same results.

Results of recent planning studies indicate that the BPU may need additional supply side resources in the years of 2023 - 2026. Based on current projections, the BPU expects to be within approximately 5 MW of the SPP summer capacity requirement. In 2027 the BPU is expected to have insufficient capacity by approximately 80 MW. The BPU expects to meet the additional capacity needs either through self-build of a new combustion turbine, joint participation in a new-build generator, and/or through the purchase of excess capacity of neighboring utilities. Since the anticipated need for new supply-side resources is greater than five years out, there is sufficient time for the BPU to diligently consider all the options before committing to one or the other. Changes to EPA power plant emission regulations that are currently being considered or under review by the EPA will influence BPU power supply decisions. The rate of recovery and growth of the local economy subsequent to the current climate will also play a role in the decisions going forward. Although plans for new generation are not on the immediate drawing board, as either the opportunity or need for additional generation or purchases avails, the BPU will evaluate and consider the opportunities.

Although the BPU does not have immediate need for additional supply-side resources, the BPU will continue to evaluate opportunities for additional supply-side and demand-side resources for environmental and economic benefit. If the resources are of benefit to the BPU and its customers, the resources will be integrated into the existing resource mix towards meeting current and future needs. BPU will quantify the number of studies completed each year and include a synopsis and the results of evaluations conducted in the comment section of the IRP annual updates.

XI. PUBLIC PARTICIPATION

Communication with its customers has always been a hallmark of the BPU. At the outset of integrated resource planning in 1989, the BPU established a special Community Power Planning Committee. This committee was for the purpose of providing guidance in the development of viable demand-side and supply-side resources. The committee consisted of 10 volunteer representatives from all segments of the utility's customer base. Subsequently there have been numerous ad-hoc committees, focus groups and public forums held to obtain public input into important issues of the BPU. In addition to these public forums and meetings with special groups, there have been numerous communiqués to inform the customer base of important events and the status and condition of the system, and to offer an opportunity for input into major decisions of the utility. As an example, there were 16 meetings concerning the location of a new substation and three meetings with regard to the transmission line to the facility. As conditions change and new programs are considered meetings with BPU's customers will be held to obtain public input and support.

In keeping with this tradition and the Federal Regulations, 10 CFR Part 905.11, governing the public participation requirements in developing BPU's IRP, the BPU is initiating this public process starting with this publication of the IRP:

1. Publication in Draft format posted with a downloadable link at the BPU web site, www.BPU.com, with paper or electronic copies available for the public upon request. Requests should be submitted to:

   Electric Supply Planning
   Kansas City Board of Public Utilities
   Electric Supply Administration Office
   PO Box 2409
   Kansas City, KS 66102

   Attention: Andrew Ferris

   Or by e-mail at:

   aferris@bpu.com

2. Upon posting, a notice will be published in the utilities current Publication of Record for official notices. This notice will open a 30 day public comment period and announce the date and time of the public meeting. At the meeting, BPU staff will explain the IRP process, present information in the IRP and receive comments from the public.

3. At the completion of the public comment period the BPU will have 30 days to incorporate the comments into the report with a full copy of all comments included in the appendix of the IRP.

4. Upon the publication of the IRP the elected members of the Board will have 30 days to approve the Integrated Resource Plan - Final Copy. Approval of the document constitutes the passing of a Board Resolution authorizing the General Manager to certify the submittal to Western Area Power Administration that the IRP meets all requirements set forth in 10 CFR Part 905 applicable to the Board of Public Utilities of Kansas City, Kansas.

5. An executed copy of the Board Resolution and one bound copy of the Integrated Resource Plan will be mailed to WAPA at their current address for legal notices. An electronic copy of the IRP will be made available to WAPA for publication on their web site and the current copy of BPU's WAPA-approved IRP will be maintained on BPU's web site during the term of our agreement with WAPA to meet the requirements of current regulations governing WAPA IRP customer transparency.

Appendix A (Tab A)

PUBLIC COMMENTS

The Board of Public Utilities of Kansas City, Kansas (BPU) published a Notice of Public Comment in *The Kansas City Kansan* on ___________, 2014. This notice stated that public comments would be received for 30 days. A copy of this notice is included in this Section.

Appendix B (Tab B)

LOAD FORECAST

KANSAS CITY, KANSAS, BOARD OF PUBLIC UTILITIES
LOAD FORECAST

I. BPU SYSTEM LOAD FORECAST

A. Introduction

The Board of Public Utilities updates its electric load forecast on an ongoing basis. Short–term peak demand energy forecasts are developed for use in revenue forecasting and budgeting. Long–term energy and peak demand forecasts are developed for use in longer term system planning such as to assess the long-term energy and demand requirements of the BPU and for use in performing analyses of various capacity and/or energy purchase options.

B. Methodology

BPU's forecasting method is a bottom-up approach developed by aggregating customer class specific forecasts. Developing customer class specific forecasts allows for the ability to get a refined estimate of total system demand. The estimates for the individual customer classes are aggregated to develop the estimate for the entire system as a whole. In using this method, the forecast for the system as a whole is typically more accurate since it allows for careful consideration of the change in demand for each of the customer classes and then combining these carefully considered estimates rather than merely making one large system forecast estimate which may not as thoroughly consider all of the factors causing both the change in number of customers in each class and the use per customer of each individual customer class.

Customer class-specific forecast models of the energy requirements were developed by comparing a linear regression technique with the outputs of the Smart forecasting software. Individual energy sales forecast models were prepared for each of the three largest customer classes, which are industrial, commercial, and residential. The forecast models are based on historical and projected future customer class–specific energy requirements. Below are graphs and output of the industrial, commercial, and residential class data. No future major industrial customers have been added beyond the existing known customers.

C. Forecast Results

The individual historical data and forecasts for industrial, commercial, and residential energy consumption are shown graphically in Figures 1 through 3 below.

Figure 1
Industrial Forecast

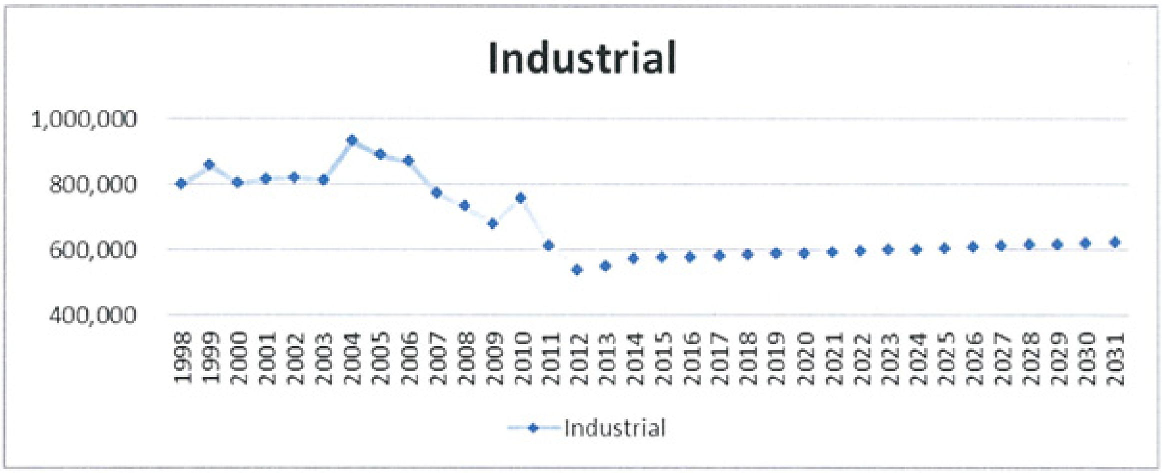


Figure 2
Commercial Forecast

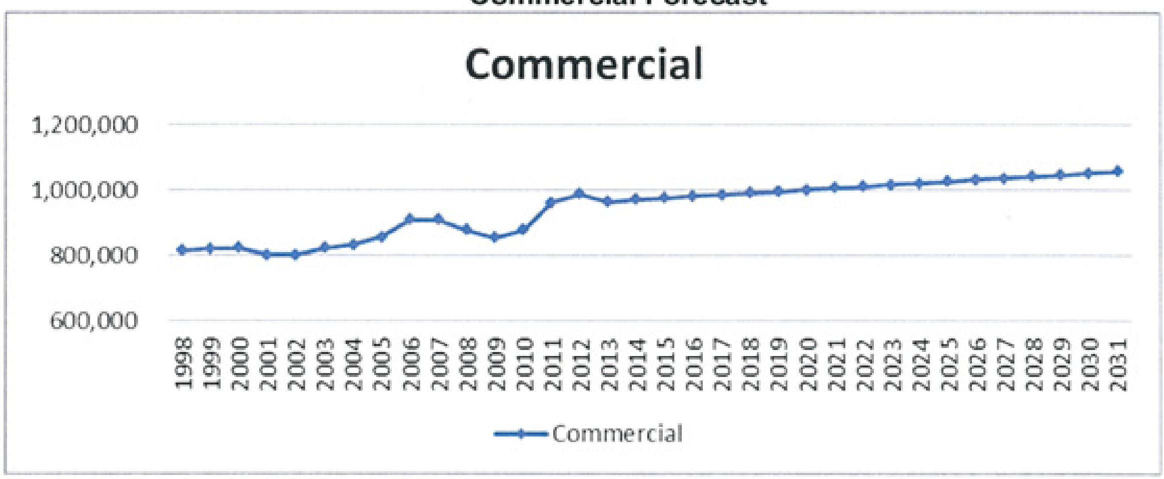
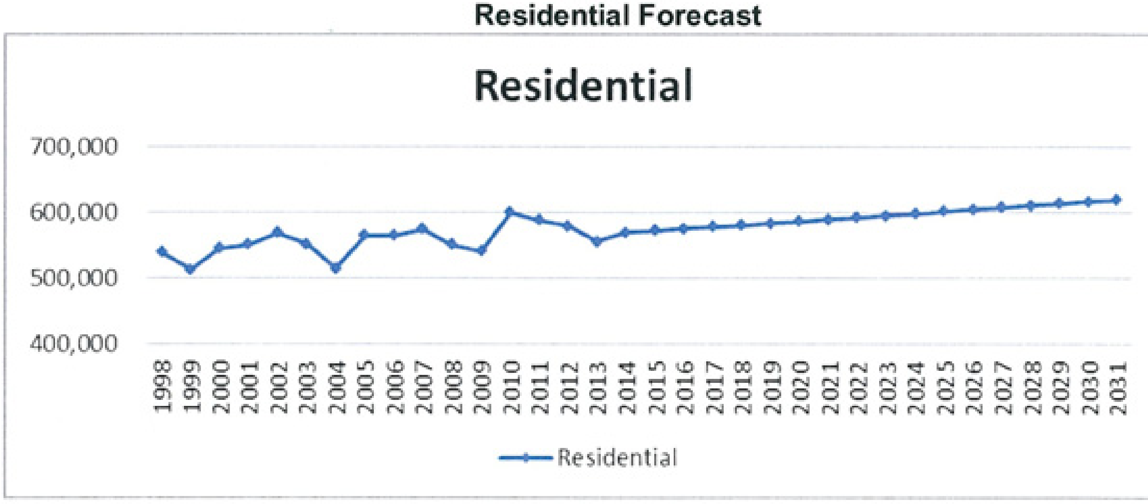


Figure 3
Residential Forecast



D. Major Customer Class Historical and Forecast Demand

The individual historical data and forecasts for industrial, commercial, and residential energy consumption are aggregated in Table 1 below. Aggregated into the Commercial customer class forecast is a forecast of the demand of the developing Village West shopping and entertainment area that was started in 2002. The Village West development includes the International Speedway, the Sporting Kansas City soccer stadium, the Schlitterbahn waterpark, the Cerner complex, the Legends shopping center, dining and entertainment establishments, large retail establishments, and lodging facilities. It is experiencing continued growth in retail shopping and entertainment venues, as well as a U.S. soccer training and development center. The estimates below are attempting to account for the impact on electric demand through the final phases of the development of the Village West District in western Wyandotte County.

Table 1
Historical and Forecast Annual Major Customer Class Data (MWh)

Year	INDUSTRIAL	Percent Change	COMMERCIAL	Percent Change	RESIDENTIAL	Percent Change	Major Customer Classes Summed	Percent Change
1998	803,311,850	0.58%	820,089,166	2.46%	543,913,298	6.38%	2,167,314,314	2.70%
1999	857,643,070	6.76%	821,146,470	0.13%	512,421,552	-5.79%	2,191,211,092	1.10%
2000	803,136,767	-6.36%	822,626,899	0.18%	545,307,672	6.42%	2,171,071,338	-0.92%
2001	817,758,956	1.82%	802,679,313	-2.42%	550,869,096	1.02%	2,171,307,365	0.01%
2002	822,335,834	0.56%	806,031,040	0.42%	568,700,840	3.24%	2,193,557,963	1.02%
2003	814,756,414	-0.92%	814,699,133	1.08%	525,368,930	-7.62%	2,131,266,244	-2.84%
2004	932,858,837	14.50%	833,645,939	2.33%	514,886,934	-2.00%	2,222,835,681	4.30%
2005	889,594,504	-4.64%	856,388,086	2.73%	564,944,642	9.72%	2,252,376,120	1.33%
2006	869,655,917	-2.24%	909,404,930	6.19%	564,353,393	-0.10%	2,278,621,843	1.17%
2007	774,211,822	-10.97%	909,219,828	-0.02%	574,127,016	1.73%	2,167,598,240	-4.87%
2008	733,052,531	-5.32%	877,655,653	-3.47%	550,773,920	-4.07%	2,069,014,083	-4.55%
2009	678,327,267	-7.47%	843,231,586	-3.92%	535,690,414	-2.74%	1,964,810,292	-5.04%
2010	757,355,721	11.65%	879,059,973	4.25%	599,167,144	11.85%	2,135,501,779	8.69%
2011	614,559,741	-18.85%	963,117,955	9.56%	588,240,616	-1.82%	2,050,079,776	-4.00%
2012	555,511,201	-9.61%	988,166,817	2.60%	564,029,077	-4.12%	1,973,157,079	-3.75%
2013	544,416,379	-2.00%	963,696,185	-2.48%	556,786,563	-1.28%	1,944,299,731	-1.46%
2014	546,416,379	0.37%	968,481,185	0.50%	584,420,080	4.96%	1,973,933,248	1.52%
2015	546,416,379	0.00%	969,985,080	0.16%	587,672,399	0.56%	1,978,450,213	0.23%
2016	546,416,379	0.00%	971,502,835	0.16%	590,989,766	0.56%	1,983,034,121	0.23%
2017	546,416,379	0.00%	973,035,050	0.16%	594,373,479	0.57%	1,987,686,276	0.23%
2018	546,416,379	0.00%	974,582,356	0.16%	597,824,867	0.58%	1,992,408,009	0.24%
2019	546,416,379	0.00%	976,145,416	0.16%	601,345,282	0.59%	1,997,200,674	0.24%
2020	546,416,379	0.00%	977,724,925	0.16%	604,936,106	0.60%	2,002,065,657	0.24%
2021	546,416,379	0.00%	979,321,613	0.16%	608,598,747	0.61%	2,007,004,367	0.25%
2022	546,416,379	0.00%	980,936,246	0.16%	612,334,640	0.61%	2,012,018,244	0.25%
2023	546,416,379	0.00%	982,569,628	0.17%	616,145,251	0.62%	2,017,108,756	0.25%
2024	546,416,379	0.00%	984,222,604	0.17%	620,032,074	0.63%	2,022,277,400	0.26%
2025	546,416,379	0.00%	985,896,060	0.17%	623,996,634	0.64%	2,027,525,703	0.26%
2026	546,416,379	0.00%	987,590,928	0.17%	628,040,484	0.65%	2,032,855,223	0.26%
2027	546,416,379	0.00%	989,308,184	0.17%	632,165,212	0.66%	2,038,267,548	0.27%
2028	546,416,379	0.00%	991,048,854	0.18%	636,372,435	0.67%	2,043,764,299	0.27%
2029	546,416,379	0.00%	992,814,016	0.18%	640,663,802	0.67%	2,049,347,130	0.27%
2030	546,416,379	0.00%	994,604,800	0.18%	645,040,996	0.68%	2,055,017,724	0.28%

The major customer classes' aggregate number is added to the smaller customer classes' energy forecasts. The smaller customer classes are: schools, local government, highway lighting, and metered and un-metered city government, BPU interdepartmental and borderline customers. Borderline customers' demand is served by BPU through a neighboring utility's distribution system. The customers are billed through the neighboring utility's billing system and BPU is paid by the neighboring utility. The table of historical and forecasted data of the small customer class data appears below:

Table 2
Smaller Customer Class Data

Year	SCHOOLS	HIGHWAY LIGHTING	COUNTY	Metered CITY OF KCK	Unmetered City of KCK	BPU Inter-department	Borderline	Village West
1998	53,842,157	3,379,918	9,247,141	34,986,176			15,525,400	
1999	51,810,293	2,972,184	8,911,111	35,355,045			13,925,900	
2000	55,483,018	2,961,610	9,379,719	38,028,632	34,932,504	29,600,000	16,874,842	
2001	60,837,512	2,968,798	9,901,089	35,289,968	34,960,667	33,240,000	16,882,433	
2002	63,612,415	2,973,036	7,871,638	34,794,040	35,181,411	41,911,465	18,221,142	3,509,751
2003	68,937,672	3,072,183	8,620,954	35,052,238	35,663,130	31,387,396	17,338,495	23,558,233
2004	68,937,672	2,665,939	8,438,262	34,401,457	36,041,942	42,938,994	17,805,851	58,556,029
2005	68,272,280	2,665,939	8,756,979	31,743,439	45,027,579	47,626,677	18,765,903	58,551,112
2006	70,866,995	2,665,939	8,782,346	34,427,171	36,782,902	44,616,218	18,678,613	64,792,397
2007	75,577,601	2,664,127	8,663,293	30,522,789	38,716,486	44,996,254	19,313,961	89,960,426
2008	75,239,657	2,646,121	7,864,157	36,320,298	37,424,804	45,882,343	18,482,844	92,468,021
2009	77,430,042	2,556,091	7,637,040	33,103,923	37,433,860	36,999,231	18,429,740	92,438,975
2010	73,706,199	2,556,091	7,965,143	40,639,135	37,754,060	38,331,710	18,625,886	100,081,059
2011	70,174,257	2,556,096	5,768,883	38,462,059	37,640,339	38,405,209	17,381,538	115,838,536
2012	66,077,568	2,556,096	11	42,592,110	38,001,433	37,462,727	17,029,530	134,550,016
2013	69,637,035	2,556,096	-	42,694,440	37,364,538	38,369,477	17,972,281	120,599,396
2014	69,637,035	2,556,096	-	42,694,440	37,364,538	38,753,172	18,107,073	125,384,396
2015	69,637,035	2,556,096	-	42,694,440	37,364,538	39,140,703	18,242,876	125,623,646
2016	69,637,035	2,556,096	-	42,694,440	37,364,538	39,532,111	18,379,698	125,874,859
2017	69,637,035	2,556,096	-	42,694,440	37,364,538	39,927,432	18,517,545	126,138,632
2018	69,637,035	2,556,096	-	42,694,440	37,364,538	40,326,706	18,656,427	126,415,593
2019	69,637,035	2,556,096	-	42,694,440	37,364,538	40,729,973	18,796,350	126,706,403
2020	69,637,035	2,556,096	-	42,694,440	37,364,538	41,137,273	18,937,323	127,011,754
2021	69,637,035	2,556,096	-	42,694,440	37,364,538	41,548,645	19,079,353	127,332,372
2022	69,637,035	2,556,096	-	42,694,440	37,364,538	41,964,132	19,222,448	127,669,020
2023	69,637,035	2,556,096	-	42,694,440	37,364,538	42,383,773	19,366,616	128,022,502
2024	69,637,035	2,556,096	-	42,694,440	37,364,538	42,807,611	19,511,866	128,393,657
2025	69,637,035	2,556,096	-	42,694,440	37,364,538	43,235,687	19,658,205	128,783,370
2026	69,637,035	2,556,096	-	42,694,440	37,364,538	43,668,044	19,805,641	129,192,569
2027	69,637,035	2,556,096	-	42,694,440	37,364,538	44,104,724	19,954,184	129,622,227
2028	69,637,035	2,556,096	-	42,694,440	37,364,538	44,545,772	20,103,840	130,073,369
2029	69,637,035	2,556,096	-	42,694,440	37,364,538	44,991,229	20,254,619	130,547,067
2030	69,637,035	2,556,096	-	42,694,440	37,364,538	45,441,142	20,406,529	131,044,451
2031	69,637,035	2,556,096	-	42,694,440	37,364,538	45,895,553	20,559,578	131,566,704

E. Losses

Losses are estimated based on component losses for transmission, primary, and secondary loads. These loss estimates are applied by customer class as annotated below.

Table 3
LOSSES

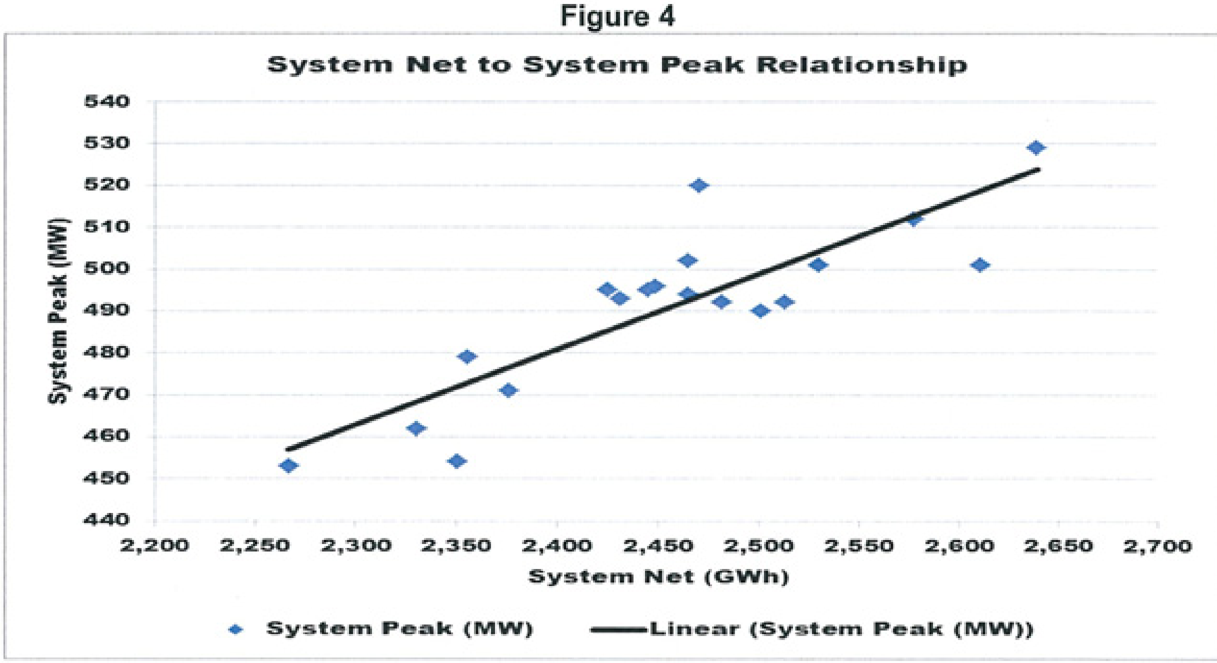
Customer Class	Losses		
	Transmission 0.44%	Primary 2.39%	Secondary 4.38%
Industrial	X		
Commercial	X	X	X
Village West	X	X	X
Residential	X	X	X
Schools	X	X	X
Hiway Lighting	X	X	X
County	X	X	X
Metered City of KCK	X	X	X
Unmetered City of KCK	X	X	X
BPU Inter-Departmental	X	X	X
Borderline	X	X	
Nearman Participating	X		
Wholesale	X		

Based on loss study completed November 2002 and adjusted for historical trends since the study was completed.

F. Peak System Demand

Peak system demand is calculated based on linear regression trend modeling of the historical peak plotted against the associated system net for the years 1995 through 2013. Figure 4 contains a plot of the system annual net energy and system annual peak demand. The black line in Figure 4 shows the historical trend line relationship between system annual net energy and system annual peak demand.

Figure 4



In addition to its retail load responsibilities, the BPU has or has had wholesale power supply contracts with Columbia, MO and the Kansas Municipal Energy Agency (KMEA) based on their participation in BPU's Nearman Unit No. 1. The contract with Columbia, MO was terminated effective April 2013 and resulted in an additional capacity of 20 MW. The KMEA contract is also set to expire as of December 31, 2015 and will yield another 37.5 MW of capacity. The additional capacity will help offset expected capacity shortfalls from the retirement of some of the existing CTs. Forecasted Energy sales to KMEA for the remainder of the contract were based on expected unit availability and anticipated SPP pricing. Recent Nearman participating historical data and forecast energy appears in the table below:

Table 4
NEARMAN PARTICIPATING ENERGY

Year	Nearman Participating Energy (kWh)	KMEA	Columbia
2007	434,356,000	275,885,000	158,471,000
2008	398,063,000	247,828,000	150,235,000
2009	296,477,000	149,658,000	146,819,000
2010	296,136,000	145,316,000	150,820,000
2011	277,681,000	131,451,000	146,230,000
2012	101,330,000	50,210,000	51,120,000
2013	93,308,000	86,013,000	7,295,000
2014	110,000,000	110,000,000	
2015	120,000,000	120,000,000	

Historical energy varies from year to year with forecasted energy of approximately 10 GWh/month forecasted for 2015.

The aggregate peak for Nearman Participants is 58MW, which is the sum of the KMEA and Columbia contract amounts. The historical energy varies from year to year. The energy is forecasted at about 352 GWh/year.

G. Forecast Results

The system load forecast developed by the BPU is shown in Table 5. The forecast includes sales to BPU's retail customers, borderline, city, and BPU interdepartmental. It does not include Nearman Participation customer sales or opportunity sales to the wholesale spot market.

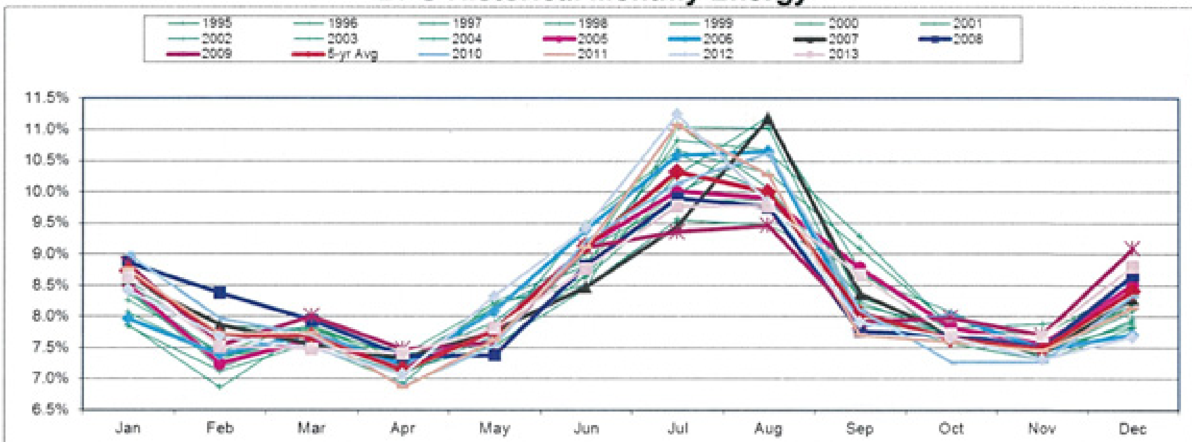
Table 5
Load Forecast

Year	System Peak (MW)	System Energy (GWh)	Growth (%)	Load Factor
2009	471	2376		58%
2010	501	2530	6.48%	58%
2011	502	2465	-2.57%	56%
2012	495	2425	-1.62%	56%
2013	454	2350	-3.09%	59%
2014	470	2319	-1.32%	56%
2015	472	2331	0.52%	56%
2016	474	2342	0.48%	56%
2017	475	2354	0.50%	57%
2018	477	2366	0.50%	57%
2019	479	2378	0.50%	57%
2020	481	2389	0.50%	57%
2021	483	2401	0.50%	57%
2022	485	2413	0.50%	57%
2023	487	2425	0.50%	57%
2024	489	2438	0.50%	57%
2025	490	2450	0.50%	57%
2026	492	2462	0.50%	57%
2027	494	2474	0.50%	57%
2028	496	2487	0.50%	57%
2029	498	2499	0.50%	57%

BPU's base energy requirements are projected to grow at an average annual rate of about 0.5% per year.

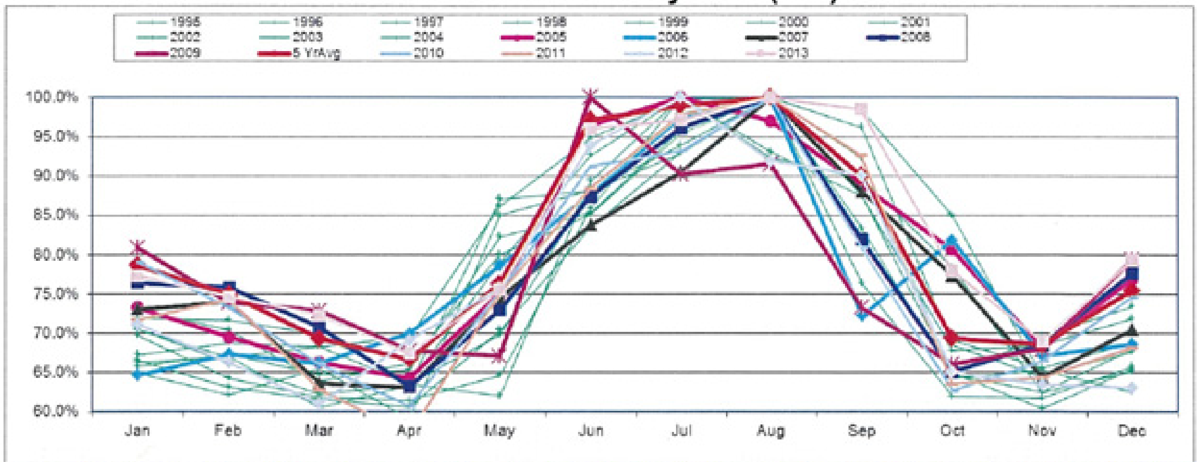
Monthly historical data from 1995 through 2013 was used to allocate energy and peak to each month. A percentage of average monthly system net is used to spread forecasted energy between months in all forecasted years. A percentage of average monthly peak compared to the average annual peak is used to determine monthly peak in all forecasted years. The data tables and graphs appear below:

Figure 5
BPU Historical Monthly Energy



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1995	8.38%	7.30%	7.83%	7.23%	7.50%	8.66%	10.27%	11.21%	8.24%	7.68%	7.58%	8.14%
1996	8.49%	7.68%	7.83%	7.32%	7.90%	9.08%	9.85%	9.88%	8.17%	7.82%	7.88%	8.11%
1997	8.47%	7.36%	7.54%	7.40%	7.57%	9.03%	10.61%	9.99%	8.66%	8.07%	7.41%	7.90%
1998	7.86%	6.86%	7.83%	7.10%	8.23%	8.90%	9.99%	10.64%	9.28%	7.82%	7.41%	8.08%
1999	8.43%	7.17%	7.72%	7.29%	7.84%	9.01%	11.07%	10.06%	8.30%	7.82%	7.33%	7.95%
2000	8.06%	7.36%	7.51%	6.92%	8.18%	8.63%	9.92%	11.12%	8.75%	7.57%	7.59%	8.38%
2001	8.26%	7.43%	7.87%	7.29%	8.14%	8.82%	10.82%	10.66%	8.02%	7.57%	7.30%	7.81%
2002	7.85%	7.11%	7.57%	7.08%	7.68%	9.48%	10.67%	10.29%	9.08%	7.85%	7.49%	7.84%
2003	8.42%	7.37%	7.61%	7.13%	7.53%	8.46%	11.05%	11.02%	8.05%	7.72%	7.46%	8.20%
2004	8.53%	7.85%	7.77%	7.39%	8.22%	8.49%	9.55%	9.46%	8.71%	7.80%	7.71%	8.51%
2005	8.50%	7.23%	7.62%	7.18%	7.77%	9.13%	10.00%	9.90%	8.78%	7.82%	7.55%	8.51%
2006	7.96%	7.39%	7.72%	7.22%	8.08%	9.39%	10.58%	10.65%	7.85%	8.00%	7.47%	7.70%
2007	8.60%	7.86%	7.55%	7.32%	7.77%	8.47%	9.44%	11.18%	8.37%	7.72%	7.41%	8.30%
2008	8.87%	8.37%	7.94%	7.36%	7.37%	8.81%	9.90%	9.75%	7.76%	7.71%	7.50%	8.66%
2009	8.83%	7.53%	8.00%	7.47%	7.58%	9.11%	9.35%	9.46%	7.91%	7.98%	7.69%	9.08%
2010	9.00%	7.96%	7.69%	6.88%	7.53%	9.22%	10.14%	10.61%	8.11%	7.26%	7.27%	8.33%
2011	8.76%	7.72%	7.74%	6.86%	7.62%	9.11%	11.07%	10.27%	7.70%	7.59%	7.45%	8.13%
2012	8.42%	7.67%	7.49%	7.06%	8.32%	9.42%	11.24%	9.83%	7.91%	7.66%	7.31%	7.67%
2013	8.63%	7.51%	7.48%	7.40%	7.81%	8.76%	9.77%	9.77%	8.66%	7.71%	7.68%	8.80%

Figure 6
BPU Historical Monthly Peak (MW)



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Peak MW
1995	70.42%	66.89%	68.21%	63.58%	69.76%	88.52%	98.01%	100.00%	89.85%	69.09%	65.56%	68.87%	453
1996	71.86%	71.65%	69.91%	63.64%	79.00%	92.64%	100.00%	93.07%	87.45%	67.75%	68.40%	71.86%	462
1997	70.56%	66.18%	62.21%	63.47%	62.00%	89.35%	100.00%	92.28%	89.77%	78.29%	62.42%	65.14%	479
1998	64.91%	62.07%	65.52%	59.03%	84.99%	88.24%	93.91%	100.00%	92.29%	64.71%	62.47%	67.95%	493
1999	69.70%	64.24%	61.82%	61.41%	64.65%	85.86%	100.00%	92.32%	89.90%	64.85%	60.40%	65.45%	495
2000	66.19%	67.00%	60.53%	63.36%	87.04%	88.06%	92.91%	100.00%	96.15%	68.42%	64.37%	70.65%	494
2001	65.73%	67.34%	64.72%	65.32%	82.26%	85.28%	95.97%	100.00%	83.27%	64.31%	65.32%	62.50%	496
2002	67.22%	68.68%	68.27%	69.52%	86.22%	94.78%	99.79%	100.00%	98.33%	84.97%	64.51%	67.64%	479
2003	66.54%	63.08%	61.54%	60.58%	70.38%	83.46%	93.08%	100.00%	76.35%	61.92%	61.73%	65.77%	520
2004	73.06%	70.41%	63.88%	66.12%	80.00%	85.10%	95.51%	100.00%	87.55%	64.69%	69.59%	73.47%	490
2005	73.25%	69.46%	66.27%	64.27%	75.05%	96.41%	100.00%	97.01%	88.82%	80.64%	68.06%	76.85%	501
2006	64.65%	67.30%	66.16%	69.94%	78.64%	87.71%	97.35%	100.00%	72.21%	81.85%	67.11%	68.62%	529
2007	73.05%	74.02%	63.67%	63.09%	74.61%	83.79%	90.63%	100.00%	88.09%	77.34%	64.45%	70.51%	512
2008	76.42%	75.81%	70.73%	63.21%	72.97%	87.40%	96.14%	100.00%	81.91%	65.04%	68.50%	77.64%	492
2009	80.89%	73.89%	72.82%	67.73%	67.09%	100.00%	90.23%	91.51%	73.25%	66.03%	67.94%	79.41%	471
2010	79.04%	73.25%	66.07%	60.68%	75.25%	91.22%	93.21%	100.00%	80.84%	62.67%	66.47%	74.65%	501
2011	71.71%	74.30%	62.75%	57.17%	75.10%	88.45%	97.81%	100.00%	92.63%	63.55%	64.34%	68.13%	502
2012	71.11%	66.26%	61.01%	69.09%	75.76%	93.94%	100.00%	91.92%	90.10%	65.05%	63.43%	63.03%	495
2013	77.31%	74.67%	72.25%	67.40%	75.55%	96.04%	97.14%	100.00%	98.46%	77.97%	68.94%	79.30%	454

Appendix C (Tab C)

Dogwood Combined Cycle Analysis

- Final Dogwood Electric Generation Report
- 2012-12-10 – Dogwood Springsted Recommendation
- 2012-04-04 – Dogwood Springsted
- Dogwood Special Session 050312 Minutes

Dogwood Electric Generation Acquisition: Report on Business Case

May 3, 2012

PRESENTATION TO

Unified Government of Wyandotte County and Kansas City, Kansas

PRESENTER: David N. MacGillivray
Chairman
dmacgillivray@springsted.com

Springsted's Tasks

- Examine the financial and related business points relating to acquisition decision
- Describe how the Dogwood acquisition may deviate from current adopted BPU plans
  - Is Dogwood in CIP and Cost of Service Study?
    - Don Gray's remarks covered this question

Financial and Business Points

- BPU positioning in a highly regulated area
- Cost
- BPU employee levels
- Transmission
- Minority ownership and management
- BPU credit rating
- BPU PILOT payments to UG

BPU Electric Generation

- Majority from older coal-fired plants
  - Significant environmental scrutiny
  - Significant BPU required environmental investments
- Natural gas combustion turbines
  - Less environmental issues
  - Not economic to run all of the time: peak power needs
- Purchased power
  - Generally most expensive power source

BPU Customer Base

- Residential customers
  - Vast majority in number of accounts
  - Lower percentage of revenues – 28% (approx)
- Commercial-industrial customers
  - Significant percentage of revenues -60% (approx)
  - Significant Wyandotte County employers
- Customer growth
  - Modest growth
- Costs not funded by significant number of new customers

Dogwood

- 110 Megawatt combined-cycle generation
  - Combined-cycle is natural gas and steam
  - Acquisition price $68 mil; bond size $75 mil
- Natural gas much lower regulatory exposure
  - Significant change in pricing natural gas
    - Was very expensive = much improved situation
    - Can not replace BPU's coal fired generation
- Second 110 Megawatts
  - Current Estimate: No Transmission available to 2018
  - Removed from current financial estimates

BPU Positioning in a Highly Regulated Area

- All options require significant investment in environmental compliance
  - What and how much is required?
  - When the investment is provided?
  - Undefined future regulatory requirements
- Cost of ongoing operations
  - Coal and gas mix
  - Lower need for purchase power

Cost Estimates

- Source: Black & Veatch Consulting
  - March 7, 2012 Report with updates
- Estimates with significant assumptions and options
- Three cost categories
  - Capital cost
  - Operating Costs
  - Purchased Power
- Cost differences expressed as Present Value
  - Today's value---Future numbers will differ
- Time period: 2012 through 2030

Cost of Environmental Compliance
All Present Value Estimates

Category	No Dogwood	Dogwood	Est Savings
Capital	$280	$271	$9
O&M	282	177	105
Purchase Power	270	138	132
Total	**$832**	**$586**	**$246**

Cost Perspectives

- Capital costs: $270-$280 million (PV)
- Dogwood: $68 mil, not a complete solution
- Dogwood PV: $9 mil, capital cost difference = 3%+
- Positive, but not compelling in itself

- Cost improvement driven by non-capital areas

Cost Perspectives- Non-capital: BPU Employee Levels

- O&M: 40%+ of Est. Savings
  - Non-Fuel O&M/Fuel = 50 – 50 split
  - Non-Fuel O&M, includes employees
  - Employment levels slightly decrease over time
- Purchase power: 55% of Est. Savings
- Cost drivers are:
  - Non-fuel O&M
  - Fuel
  - Purchase power

Back to Positioning

- Changed fuel source mix for generation
  - From: Less coal and less purchased power
  - To: More natural gas
- Less coal means less regulatory exposure
- Less purchased power means reduced high-priced energy fuel purchases

What Could Negatively Change These Estimated Costs?

- Regulatory focus changes to natural gas
- Price of natural gas goes up
- O & M estimated savings do not occur

Transmission: 110 Mega Watts

- Transmission: Controlled access to lines from generation point to utility electric distribution system
- Study/approvals being completed in next few months addressing transmission access
- BPU has high level of confidence of approval for this amount of access
  - Second 110 MW, much more complicated now postponed

Minority Ownership and Management

- As minority owner, how will BPU be protected?
- BPU, 17% owner and and other public, 27.5%
- Kelson, private company, at 55.5%
  - "Majority owner of Dogwood gas plant has highly speculative grade characteristics and may expose KPP and the other municipal minority owners to increased costs should the majority owner be unable to cover its share of costs."
    Moody's Report for Kansas Public Power

Minority Ownership and Management

- Springsted: Companion report summarizing generally available financial sources on Kelson/Dogwood
  - Short historical data: No overall conclusions
  - Paying bills on time
- Kelson looking to sell more shares and/or all of their position
  - If so, new majority private owner or new owners
- Numerous contracts negotiated by legal team

BPU Credit Ratings

- BPU Ratings: Generally good but issues exist
  - Regulatory exposure and response investment
  - Improved Liquidity, BPU cash position
  - Customer Revenue Concentration
  - No guarantees by looking at one factor

BPU Credit Ratings *(cont.)*

- Regulatory situation is known by agencies
  - EPA evolving situation over last few years
  - Across the industry: coal generation raises flags
  - Substantial investment required
- Not known how BPU definitely address the issue
- Dogwood is piece of that answer
  - Movement to natural gas reduces exposure
  - Improves cost structure: Purchase power

UG and BPU PILOT Payments

- Dogwood acquisition price includes an upfront payment of PILOT payment to that local jurisdiction
- Question: impact on BPU PILOT payment to UG
- PILOT: billed revenues from BPU customers
  - UG Counsel: Acquisition price payment does not affect UG PILOT

Conclusions on Dogwood Acquisition

- Related business points: Transmission, BPU employee levels, BPU credit rating and UG PILOT
  - Either not an issue or reasonable answers exist
  - Or being answered – transmission
  - Credit Rating: Dogwood, alone less of an issue, maybe plus
- Minority ownership and management
  - How will BPU's best interests be reflected?
  - Any partnership: contract provisions

Conclusion on Dogwood Acquisition *(cont.)*

- Dogwood not a complete solution
  - One part of overall regulatory investment
- Business case more on positioning the BPU than straight cost criteria
  - Reasonable to assume cost savings with Dogwood
    - Estimated Present Value Savings
    - High level of assumptions and estimates in B&V study
  - Cost drivers: Purchase power and O & M
  - Less regulatory exposure

Springsted

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December 10, 2012

Mr. Lew Levin, Chief Financial Officer
Unified Government of Wyandotte County/Kansas City
701 North Seventh Street
Kansas City, Kansas 66101

Ms. Lori C. Austin, Manager of Accounting & Finance/CFO
Board of Public Utilities
540 Minnesota Avenue
Kansas City, Kansas 66101-2930

RE: Recommendation for Award of Sale for the Unified Government of Wyandotte County/Kansas City, Kansas Board of Public Utilities, Kansas
$79,540,000 Utility System Improvement Revenue Bonds, Series 2012B (the "Issue" or "Bonds")

Dear Mr. Levin and Ms. Austin:

This letter summarizes the results of the negotiated sale for the above titled Issue finalized on Thursday, December 6, 2012.

Purposes and Repayment Sources of Issues

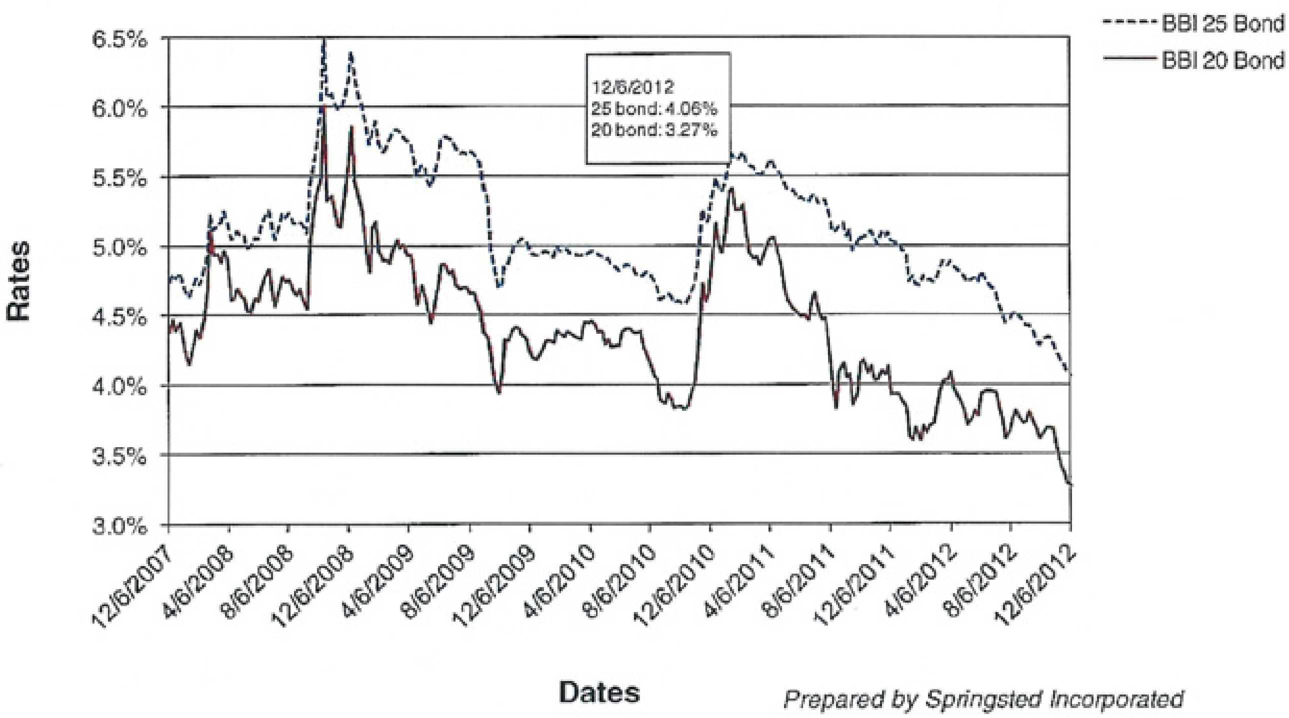
The Unified Government and the Board of Public Utilities (the "BPU") will be acquiring a 17% ownership share of the Dogwood Electric Co-generation Facility. To finance this acquisition and an additional $20,000,000 of electric system improvements, the Unified Government, on behalf of the BPU, is issuing Utility System Improvement Revenue Bonds in the principal amount of $79,540,000. This amount, plus the premium received on the Bonds in the amount of $11,519,682, will fully fund both of these purposes.

The Bonds will be repaid solely by a combined pledge of net revenues of the electric and water systems.

Tax-Exempt Market Rates

The tax-exempt municipal bond market continues to experience ongoing historic market low points. Each week is generally at a lower point than the preceding week. While a number of factors are contributing to this situation, the relative low risk and tax exemption of municipal bonds is continuing to drive this market condition. The graph below shows the intermediate term tracking of the primary municipal bond index.

BBI 25-bond (Revenue) and 20-bond (G.O.) Rates for 5 Years Ending 12/6/2012



Method of Sale and Underwriting

We previously recommended the Bonds be sold in a negotiated sale process. The Unified Government and BPU selected BMO Capital Markets as lead senior managing underwriter through a competitive selection process in early 2011. For this transaction, two co-managers were selected: Ramirez & Co. and George K. Baum. This team was selected to acknowledge the ongoing solid performance from BMO and Ramirez, while seeking to expand the amount of bonds sold in the Kansas City Region through adding George K. Baum. For the Bonds, the underwriter participation was BMO: 75%; Ramierz: 15%; and George K. Baum: 10%. The three firms are collectively termed the "Underwriting Group."

Sale Results

The sale process resulted in the Issue achieving a true interest rate (TIC) of 3.415%. This result was significantly lower than prior estimates and resulted in annual debt service reductions. The final underwriter compensation was $4.444 per $1,000 of bonds issued.

Recommendation

We recommended award of the Bonds to BMO Capital Markets and co-managers Ramirez & Co and George K. Baum.

Basis of Recommendation

Our recommendation is based on the level of investor orders, review of comparable sales, overall market position and ultimate result. Leading up to the day of sale, we researched and conducted analysis of other similar issues in the recent market. We also studied past interest rate trends (pricing) of prior BPU issues. This analysis is conducted by comparing the individual yield interest rates by maturity to the national daily market index, the MMD AAA scale. A copy of our analysis is attached with the final Bond pricing included.

Over the past few weeks, the Unified Government, BPU, BMO and Springsted worked to position this sale for the market. Particularly in the week leading up to the sale, this effort intensified in anticipation of the sale process. The Unified Government and the BPU wanted to obtain as many purchase orders from area retail investors. The approach to the sale process was developed to accommodate this investor segment.

Formal negotiations began on Wednesday, December 5th with the Unified Government and the BPU requesting interest rate reductions in several maturities from the initial offer of the Underwriting Group. On the morning of December 6th, additional negotiations occurred with additional reductions in interest rates. The Bonds then entered the order period. The order period generated substantial investor interest in the Bonds. At the conclusion of the order period, more interest rate reductions occurred with certain maturities having unsold bonds. The negotiations were then concluded and the Unified Government and BPU gave a verbal award to the Underwriting Group.

This final negotiation resulted in the longest maturity being priced at MMD AAA plus 68 basis points. This pricing level is an improvement from the level on the recent refunding issued priced in August, wherein the longest maturity was at plus 76 basis points.

Lastly, the sale results were far under the BPU planning levels used during the Dogwood acquisition study, as well as more favorable than recent market estimates.

Underwriter Performance

The Unified Government and BPU engaged three firms to underwrite this transaction, led by BMO. All firms proactively participated throughout the sale process and, most importantly, obtained investor orders during the pricing period. The Issue received a solid number of retail investor orders, individuals or agents of individuals. Retail orders of Kansas investors received the highest priority of being filled. We acknowledge the work by the Underwriting Group.

Credit Rating

The BPU's credit ratings were reaffirmed by all three rating agencies: A+ from both Standard & Poor's and Fitch Ratings, stable outlook. Moody's rating was affirmed at A2 with a continued negative outlook. As the BPU had just recently completed a rating review in August 2012, this process took the form of an update.

The Dogwood acquisition is a major project for the BPU, with this financing being an essential element to conclude the process. Many individuals were responsible in accomplishing this step, among who were the elected officials and staff of the Unified Government and BPU, as well as the work of the bond counsel firm, Gilmore & Bell. We welcome any questions and congratulate the Unified Government and the Board of Public Utilities on completion of both the successful sale process and moving to finalization of the Dogwood Acquisition.

Respectfully,

David N. MacGillivray, Chairman
Client Representative

dww

Attachment

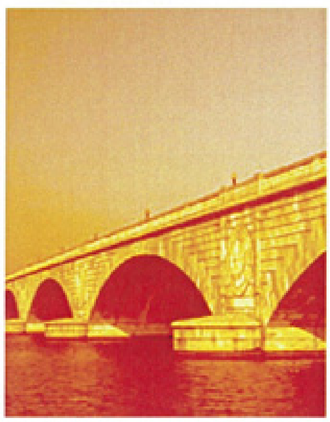
cc: Mr. Ed Meyers, BMO Capital Markets
Ms. Gina Riekhof, Gilmore & Bell, PC

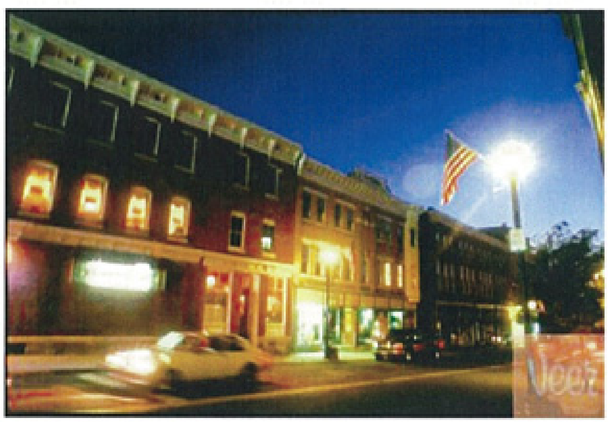
Unified Government 2012 Bond Sales and Comparable Sales Spread to "AAA" MMD

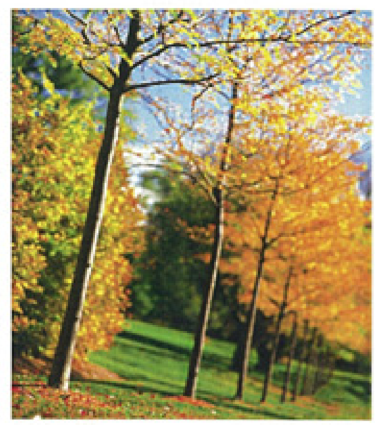
Par:	$79,540,000	$110,830,000	$101,295,000	$152,280,000	$287,460,000
Issuer	Unified Government/BPU 2012-B	Unified Government/BPU 2012-A	North Carolina Mun Power Agency, NC	Lehigh County Purp Auth, PA	LWR Colorado River Auth, TX
Rating:	A+/A+/A2	A+/A+/A2	A/A/A2	A+/A1	A/A/A1
	Not Insured	Not Insured	Not Insured	Not Insured	Not Insured
Sale Date:	08/07/12	08/07/12	11/26/12	11/26/12	11/26/12
Issue	FINAL Utility Imp Revenue	FINAL Utility Imp Revenue Ref	Utility Revenue	Utility Revenue	Utility Revenue
Bank Qualified	Not BQ	Not BQ	Not BQ	Not BQ	Not BQ
Tax Status	Tax-Exempt	Tax-Exempt	Tax-Exempt	Tax-Exempt	Tax-Exempt
Call Date:	10 years @ par	10 years @ par	9 years @ par	9 years @ par	9 years @ par
Underwriter:	BMO	BMO	Bank of America	Bank of America	Bank of America

Maturity	Yield	MMD "AAA"	Spread to MMD	Maturity	Yield	MMD "AAA"	Spread to MMD
	due 9/1				due 9/1		
2013	0.40%	0.20%	0.20%	2013		0.19%	
2014	0.55%	0.30%	0.25%	2014		0.29%	
2015	0.72%	0.42%	0.30%	2015	0.88%	0.38%	0.50%
2016	0.92%	0.52%	0.40%	2016	1.08%	0.48%	0.60%
2017	1.09%	0.64%	0.45%	**2017**	1.37%	0.67%	0.70%
2018	1.26%	0.76%	0.50%	2018	1.63%	0.93%	0.70%
2019	1.45%	0.90%	0.55%	2019	1.91%	1.19%	0.72%
2020	1.67%	1.09%	0.58%	2020	2.17%	1.43%	0.74%
2021	1.90%	1.29%	0.61%	2021	2.38%	1.62%	0.76%
2022	2.11%	1.48%	0.63%	**2022**	2.51%	1.75%	0.76%
2023	2.26%	1.59%	0.67%	2023	2.63%	1.87%	0.76%
2024	2.35%	1.64%	0.71%	2024	2.75%	1.97%	0.78%
2025	2.42%	1.69%	0.73%	2025	2.85%	2.06%	0.79%
2026	2.48%	1.75%	0.73%	2026	2.94%	2.15%	0.79%
2027	2.54%	1.81%	0.73%	**2027**	2.98%	2.22%	0.76%
2028	2.60%	1.87%	0.73%	2028	3.05%	2.29%	0.76%
2029		1.93%		2029		2.36%	
2030		1.99%		2030		2.43%	
2031		2.05%		2031		2.49%	
2032	2.83%	2.11%	0.72%	**2032**	3.31%	2.55%	0.76%
2033		2.17%		2033		2.62%	
2034		2.24%		2034		2.69%	
2035		2.31%		2035		2.76%	
2036		2.38%		2036		2.82%	
2037	3.11%	2.43%	0.68%	**2037**		2.86%	

Maturity	Yield	MMD "AAA"	Spread to MMD	Maturity	Yield	MMD "AAA"	Spread to MMD	Maturity	Yield	MMD "AAA"	Spread to MMD
	due 1/1				due 7/1				due 5/1		
2013		0.20%		2013	0.50%	0.20%	0.30%	2013	0.28%	0.20%	0.08%
2014		0.30%		2014	0.65%	0.30%	0.35%	2014	0.43%	0.30%	0.13%
2015		0.42%		2015	0.87%	0.42%	0.45%	2015	0.67%	0.42%	0.25%
2016		0.52%		2016	1.07%	0.52%	0.55%	2016	0.88%	0.52%	0.36%
2017		0.64%		**2017**	1.29%	0.64%	0.65%	**2017**	1.06%	0.64%	0.42%
2018		0.77%		2018	1.52%	0.77%	0.75%	2018	1.24%	0.77%	0.47%
2019		0.92%		2019	1.72%	0.92%	0.80%	2019	1.41%	0.92%	0.49%
2020		1.11%		2020	1.96%	1.11%	0.85%	2020	1.63%	1.11%	0.52%
2021	1.65%	1.32%	0.33%	2021	2.16%	1.32%	0.84%	2021	1.84%	1.32%	0.52%
2022	1.90%	1.51%	0.39%	**2022**	2.36%	1.51%	0.85%	**2022**	2.05%	1.51%	0.54%
2023	2.05%	1.63%	0.42%	2023	2.56%	1.63%	0.93%	2023	2.20%	1.63%	0.57%
2024	2.15%	1.68%	0.47%	2024	2.73%	1.68%	1.05%	2024	2.29%	1.68%	0.61%
2025	2.21%	1.73%	0.48%	2025	2.83%	1.73%	1.10%	2025	2.36%	1.73%	0.63%
2026	2.29%	1.78%	0.51%	2026	2.93%	1.78%	1.15%	2026	2.44%	1.78%	0.66%
2027	2.35%	1.84%	0.51%	**2027**	3.04%	1.84%	1.20%	**2027**	2.52%	1.84%	0.68%
2028	2.39%	1.90%	0.49%	2028		1.90%		2028	2.58%	1.90%	0.68%
2029	2.43%	1.96%	0.47%	2029		1.96%		2029	2.64%	1.96%	0.68%
2030	2.48%	2.02%	0.46%	2030		2.02%		2030	2.70%	2.02%	0.68%
2031	2.54%	2.08%	0.46%	2031		2.08%		2031	2.75%	2.08%	0.67%
2032	3.05%	2.14%	0.91%	**2032**	3.45%	2.14%	1.31%	**2032**	2.80%	2.14%	0.66%
2033		2.20%		2033	3.53%	2.20%	1.33%	2033	2.85%	2.20%	0.65%
2034		2.27%		2034		2.27%		2034		2.27%	
2035		2.34%		2035		2.34%		2035		2.34%	
2036		2.42%		2036		2.42%		2036	2.97%	2.42%	0.55%
2037		2.47%		**2037**	3.81%	2.47%	1.34%	**2037**		2.47%	







DRAFT Report

Unified Government of Wyandotte County/Kansas City and the Kansas Board of Public Utilities, Kansas

Acquisition of an Ownership Position in Dogwood Generation Facility

April 3, 2012

Springsted

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Mission Statement

Springsted provides high quality, independent financial and management advisory services to public and non-profit organizations, and works with them in the long-term process of building their communities on a fiscally sound and well-managed basis.

1. Introduction

The Kansas Board of Public Utilities (the "BPU") generates the vast majority of its electric power through the operation of coal-fired power plants. Coal-fired power plants have been (and are expected to continue to) facing substantial environmental regulatory actions. These regulatory requirements cause the BPU's investment in significant capital assets. One approach to meeting these regulatory actions is to obtain power generation from non-coal burning facilities, such as natural gas-fired, electric turbine facilities.

The BPU has been in negotiations for the two-phase acquisition of 34% ownership position in the Dogwood Energy Facility (the "Facility"). The Facility is a natural gas combined, cycle generation asset with a capacity of 650 MW, located in Pleasant Hill, Missouri. The Facility is owned by a private firm, Kelson Energy Inc, a Maryland corporation ("Kelson"). Each phase constitutes 17% of the total Facility generation capacity, or 110 megawatts (MW) of electrical generation. If the acquisition moves forward, the first phase would be completed in 2012 and the second phase in 2014, pending the successful resolution of a number of operating situations. Although the acquisition price changes based on the year in which it occurs, the current cost estimate for the first phase acquisition is $_____, which when all financing and security provision cost items are included leads to a bond issue of approximately $90,000,000.

As the BPU is an administrative agency of the Unified Government of Wyandotte County/Kansas City, both the acquisition agreement and any related bond issuance must be executed by the Unified Government.

The Unified Government has asked Springsted to provide information on the financial case for or against proceeding with this acquisition. The financial case involves both direct economic analysis and indirect factors which can impact the overall BPU financial situation.

Lastly, the BPU has previously contracted with Black & Vetch to provide a variety of cost comparisons covering a range of potential outcomes, both with proceeding with the Facility acquisition by phase and not proceeding with operating the existing coal-fired plants while complying with the regulatory actions. Black & Vetch's most recent report is dated March 7, 2012, which has since been amended in certain cases. Springsted has relied on this report, as amended, as the basis for our analysis of the direct economic analyses.

2. Statement of Issues

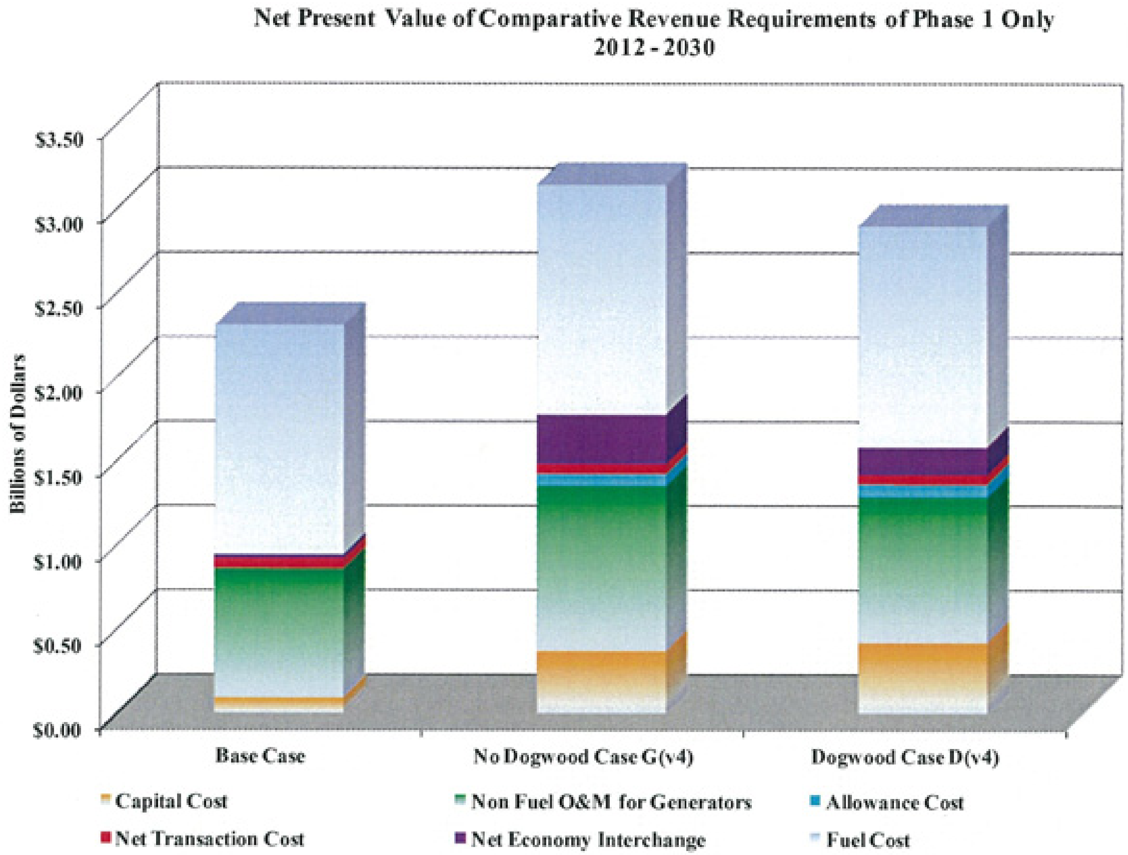
Our report addresses two issues.

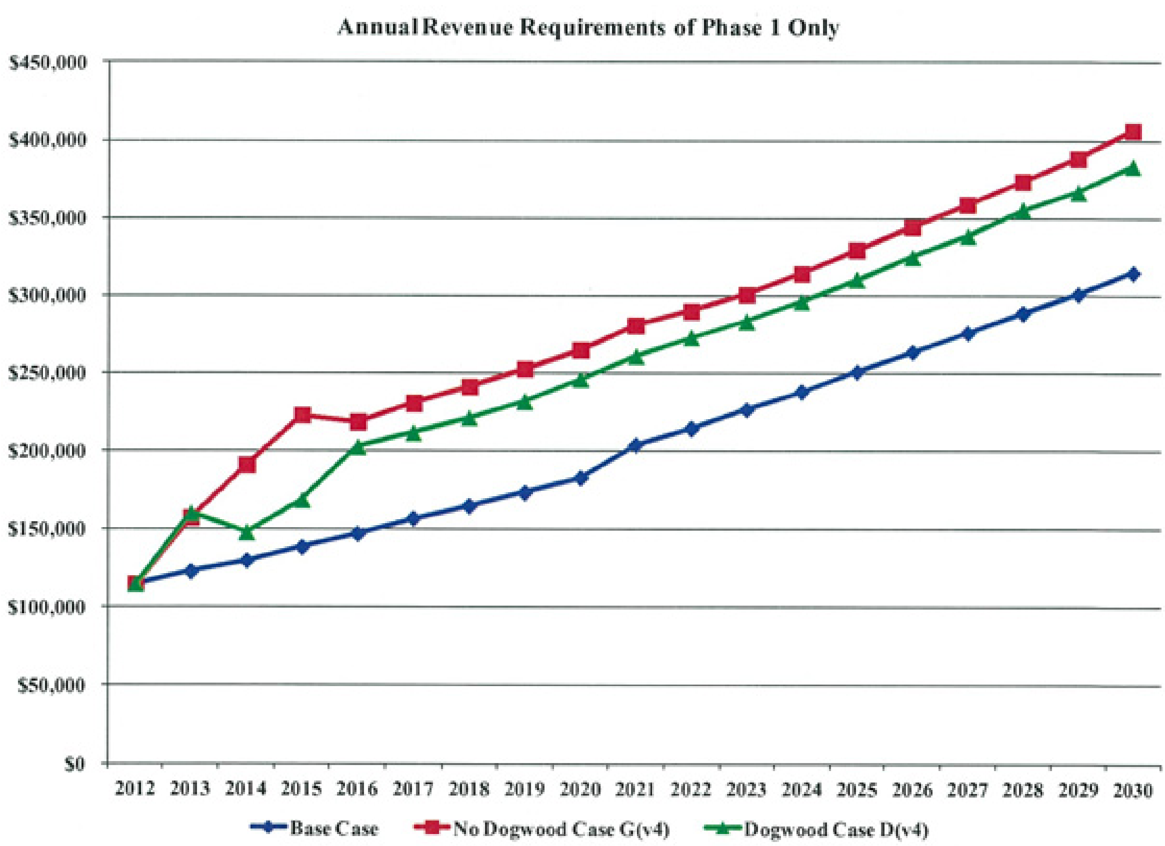
1. What is the financial basis for the entering into a contract for a minority equity ownership participation in the Dogwood Facility?
2. In the intermediate term, 2012-2014, does entering into this contract cause significant financial deviations from the capital plans and user rate studies currently enacted and their perception by BPU customers?

3. Executive Summary

A summary of our report.

1. The criteria for the financial case include:
   a. Direct financial cost comparison of the present value of BPU generation costs over the period 2012 through 2030, taken from the Black & Vetch report for
      i. Base case - No new environmental regulatory expenditures (theoretical)
      ii. Environmental compliance without Dogwood Facility, retrofitting existing facilities
      iii. Environment compliance with Phase 1 and the Phase 2 acquisitions
   b. Indirect financial factors
      i. Minority ownership and governance considerations
      ii. Transmission of acquired Facility electric power
      iii. Environmental Exposure of Facility; Impact on future BPU costs
      iv. BPU credit rating
      v. BPU PILOT payment to Unified Government
2. The BPU, Unified Government's Chief Legal Counsel, other retained counsel and Black &Vetch have been in negotiations with Kelson for a considerable period of time on this acquisition. To date, a Power Purchase Agreement for 110 MW has been executed and a Letter of Intent exists for the acquisition of up to a 34% ownership position.
3. The Black & Vetch analysis yields the following estimates for the present values of the existing situation and alterative regulatory responses for Phase 1 acquisition:
   a. Present Value of Generation Costs Base Case No New Regulatory Regulations: $2.3 billion
   b. Present Value of Regulatory Compliance without Facility (retrofit existing BPU coal-fired plants): $3.1 billion, a $831 million increase over Base Case
   c. Present Value of Regulatory Compliance with just Phase 1 Facility Acquisition: $2.9 billion, a $586 million increase over base case and a $245 million decrease from the without Facility Acquisition option.


Net Present Value of Comparative Revenue Requirements of Phase 1 Only
2012 - 2030
$3.50
$3.00
$2.50
$2.00
$1.50
$1.00
$0.50
$0.00
Billions of Dollars
Base Case
No Dogwood Case G(v4)
Dogwood Case D(v4)
Capital Cost
Non Fuel O&M for Generators
Allowance Cost
Net Transaction Cost
Net Economy Interchange
Fuel Cost


Annual Revenue Requirements of Phase 1 Only
$450,000
$400,000
$350,000
$300,000
$250,000
$200,000
$150,000
$100,000
$50,000
$0
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030
Base Case
No Dogwood Case G(v4)
Dogwood Case D(v4)

If at some future time the Unified Government and the BPU may enter into the Phase 2 acquisition, the above costs are estimated as follows:

d. Present Value of Generation Costs Base Case No New Regulatory Regulations: $2.3 billion, unchanged from (a) above.

e. Present Value of Regulatory Compliance without Facility (retrofit existing BPU coal-fired plants): $3.1 billion, a $831 million increase over Base Case, unchanged from (b) above

f. Present Value of Regulatory Compliance with Phase 1 and Phase 2 Facility Acquisition: $2.85 billion, a $536 million increase over base case and a $295 million decrease from the without Facility Acquisition option.

g. The net present value differences of adding the Phase 2 acquisition over the Phase 1 acquisition is an estimated $50 million reduction in costs.

h. All of these dollar differences are expressed in 2012 values, not in future dollar values which are substantially greater over the 2012 to 2030 study period.

   i. To illustrate this difference in 2020, the total future dollar cost for one scenario is $183 million while the 2012 dollar cost, present value, is $144 million for year 2020.

3. Intermediate term impacts Black & Veatch provided information that enabled the comparison of the 2010 Rate Study with the option of purchasing 110 MW of capacity from Dogwood and without the purchase of capacity from Dogwood. The information covered the period from 2012 through 2014. This information showed the following:

   a. The 2010 Rate Study did not include the purchase of generating capacity of capacity from Dogwood.

      i. Did not include Dogwood

      ii. It include a new combustion turbine (Nearman CT5)

      iii. The study projected rate increases of 7.0% in 2012, 7.0% in 2013 and 0% in 2014.

      iv. Capital outlay was projected to be $210.1 million

      v. New debt was projected to be $126.0 million.

   b. The option of purchasing 110 MW of Dogwood is projected to result in rate increases of 7.0% in 2012, 7.0% in 2013 and 6.0% in 2014.

      i. Capital outlay was projected to be $451.9 million.

      ii. New debt was projected to be $363.2 million.

   c. The no Dogwood option resulted in projected rate increases of 7% in 2012, 7.0% in 2013 and 7.5% in 2014.

      i. Capital outlay was projected to be $451.6 million.

      ii. New debt was projected to be $340.7 million.

4. Minority ownership and governance considerations. By entering into this acquisition agreement, the BPU will be a minority partner in an ownership structure combining three other public entities and a major ownership private sector partner, Kelson. Kelson will be responsible for the operations of the Facility. This arrangement presents questions on the financial standing of Kelson and the manner in which decisions are made among the partners.

a. We have sought information on Kelson's financial standing. In reviewing the Moody's Investors Service credit rating report for one of the public partners who have already sold their debt, they characterize Kelson as having a 'highly speculative' credit quality profile. Highly speculative is normally a term used with entities of having increased financial risk. I spoke with the lead Moody's analyst on this review and he noted their concern with Kelson, but added the potential new ownership arrangement may work to lessen their concern about Kelson. We have also obtained a Dun & Bradstreet (the "D&B") report on Kelson to obtain another related perspective. Our reading of this report is that D&B states that the information received from Kelson does not cover a long enough time period for D&B to form a definitive opinion, and therefore they have no rating. D&B does provide some assessments which could generally be termed "OK" or neutral, because of the lack of a historical perspective. Our report reviewing the D&B report has been provided to Unified Government and BPU staff.

b. Professional parties representing the Unified Government and the BPU have spent a considerable time period negotiating agreement business points which we understand cover governance issues. We have asked questions of the BPU staff covering this topic. Springsted understands they have high confidence that governance issues have been addressed in the various agreements. We recommend these parties directly respond to any questions in this area.

5. **Transmission of acquired Facility electric power.** A key element in acquiring electric power generation capacity at a remote location is the ability to transmit the power to customers. Access to power transmission is controlled both by the presence of appropriate physical facilities and by public regulatory authorities which permit access. Access to transmission facilities has not yet been obtained for either Phase 1 or Phase 2. We understand from BPU staff that a high probability exists that access to Phase 1 transmission will occur in 2012, but that access to Phase 2 transmission may face more challenges given the wide variety of factors affecting the supply of transmission facilities and the evolving demand over the next few years.

6. **Environmental Exposure of Facility Impact on future BPU costs**. We raised the question of the probability of the BPU having to incur future regulatory compliance costs for improvements to the Facility. A future large capital cost at the Facility would offset the reduction of similar future costs at the BPU coal-fired plants.

7. **BPU credit rating**. How will the BPU credit ratings be affected by obtaining a minority ownership position in the Facility? To respond to this question, we interviewed the head of Moody's Public Power Rating Group, Dan Aschenbach. Dan has worked directly on the BPU credit ratings and was part of the rating process of the other existing public partners who have sought ratings. Moody's has not completed a complete review of the BPU rating in several years. Therefore, we positioned his comments on the basis "if everything else affecting the rating was held constant, how would Moody's generally respond to this acquisition and the related debt issuance?" With the appropriate caveats, he believed it would not be a negative. He referenced the lower cost capital costs and switch to more environmentally friendly generation assets would be positive factors. Please note we have not talked to the other two agencies which provide BPU ratings, Standard & Poor's and Fitch. As Moody's

had familiarity, and as we understand the greatest concern with the Kelson situation we approached only them. We caution, as with all credit rating discussions, many things change and no definitive statement is possible until an actual transaction is put forth for a rating.

8. **BPU PILOT payment to Unified Government**. The Unified Government has asked the question of whether this acquisition would have any impact on the PILOT paid to the Unified Government by the BPU. In our questioning of BPU staff and Unified Government counsel, the PILOT payment will not be affected as it is a charge generated from customer revenues.

An understanding of this report can only follow from a complete reading of the full document.

4. Report

The balance of the report provides further description of the points covered in the Executive Summary, where appropriate. For certain criteria listed in the Executive Summary our responses there constitute our full answer in that the point raised is fully addressed in our response. This report has been developed to avoid unnecessary duplication of information previously presented. Therefore the report should be reviewed as a whole document with the following sections as supplemental to the above information.

Sources

For the analytical information on the various cost options, we have relied solely on the Black & Vetch studies. Black & Vetch has spent considerable time and possesses significant expertise in alternative electric generation facilities and their operations. We understand the BPU has had an ongoing dialogue with Black & Vetch with a significantly larger number of options explored and critiqued by the BPU working group. To clarify the decision points for the Unified Government we asked the BPU and Black & Vetch to provide us with their 'most probable' scenarios from which to base our report.

Black & Vetch notes in their March 7, 2012 report four general conditions in reviewing any of the options. Paraphrasing their comments:

a. Some compliance measures are only available after sufficient lead time, which may be 3-5 years (in the future). We interpret this to mean that the report anticipates and tries to estimate expenditure outlays which are yet to be defined by evolving regulatory actions.
b. Initial compliance dates for some of these new regulations are still uncertain.
c. Because compliance measures affect alternative generation options, different remediation measures have different outcomes for Nearman and Quindaro, and vice versa.
d. Retirement of BPU facilities and replacement with purchased power or equity ownership in other off-site generation (the Facility) is an option.

We requested additional information from Black & Vetch addressing a Base Case wherein the regulatory cost impacts are clarified and separated from a theoretical BPU operation without such requirements. Our request was intended to show two items: provide focus on the incremental regulatory compliance costs, and put in perspective the overall very large dollar amounts referenced in their reports.

Capital Cost of Phase 1 and Phase 2, and Debt Issuance

We understand that the acquisition costs for each phase differs as to the year in which the agreement occurs. The phase 1 acquisition payment if it occurs in 2012 would total $_____. The phase 2 acquisition payment would occur

in a future year, for analytical purposes only in 2014. The current estimate of this payment is $_____ The capital cost of each phase includes a pro rata share of the total asset value, for BPU 17% per phase, plus an up-front funding of a _____-year PILOT payment to _____, plus_____.

It is anticipated that the acquisition cost would be funded from the issuance of Utility Revenue Bonds. Any bond issuance would include the capital acquisition cost, if required a debt service reserve, costs of bond issuance and underwriter compensation. A current estimate of the bond amount for phase 1 is $90,000,000. To issue these bonds at the same security level as the outstanding Utility Revenue Bonds certain financial criteria would need to be met to be in compliance with the existing legal covenants covering all such bonds. Springsted has not yet participated in a process of determining if such legal covenant compliance currently exists. These legal covenants are in part based on the completion of last BPU fiscal year, for which definitive, audited numbers do not yet exist.

Response to Issue One: What is the financial basis for the entering into a contract for a minority equity ownership participation in the Dogwood Facility?

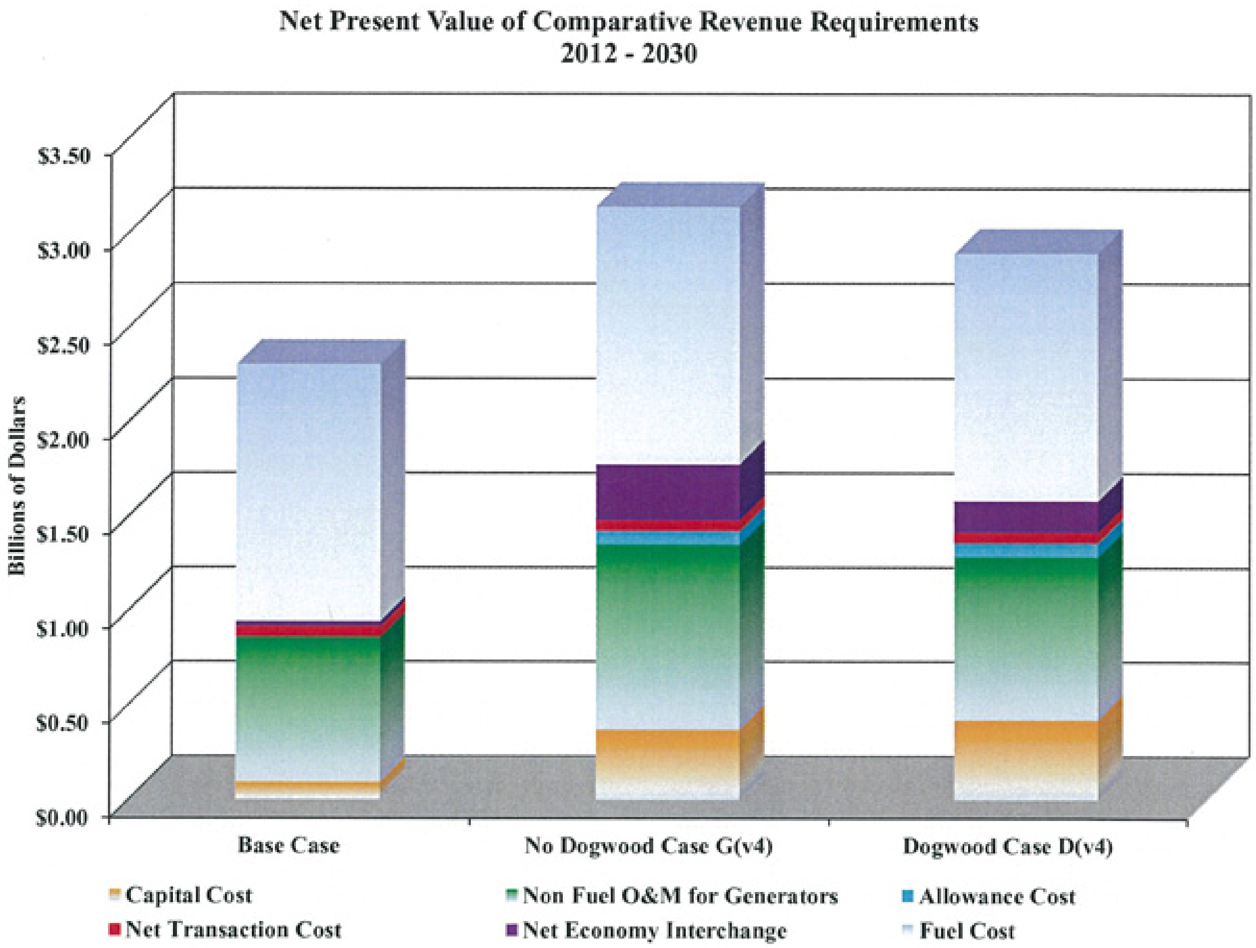
The BPU undertook an analysis to compare various alternatives to meet their future electric capacity and environmental regulatory needs. This analysis included three alternatives relative to electric capacity and three alternatives relative to environmental compliance. The electric capacity alternatives included: 1): Acquire 220 MW from Dogwood; 2) Acquire 110 MW from Dogwood; and 3) Do not acquire any capacity from Dogwood. The environmental alternatives included: 1) Self-Sufficiency Meet July 2011 Emission Budgets; 2) Self-Sufficiency Meet February 2012 Emission Budgets; and 3) Market Dependency Purchase Allowances. The net present value of each alternative over the period from 2012 through 2030 was determined. These net present values showed that the two alternatives based on the acquisition of capacity from Dogwood were lower than the net present value of no Dogwood. For comparison purposes to the Base Case, Black & Veatch provided an Excel file named "BPU Case Comparison" that provided then net present value of the Base Case with two alternatives. The Base Case is an extension of the 2010 Rate Study and does not include the environmental compliance costs included in the two alternatives. The first alternative was based on environmental compliance without acquiring any capacity from Dogwood and was named "No Dogwood Case G(v4). The second alternative was based on environmental compliance by acquiring 110 MW of capacity from Dogwood and was named "Dogwood Case D(v4). The costs included in the net present value analysis were those related to electric generation and did not represent the total cost of

BPU's operation over the period. However, since BPU's other costs would be the same under all of these alternatives, the analysis provides a valid basis of comparison. The costs included in the analysis were:

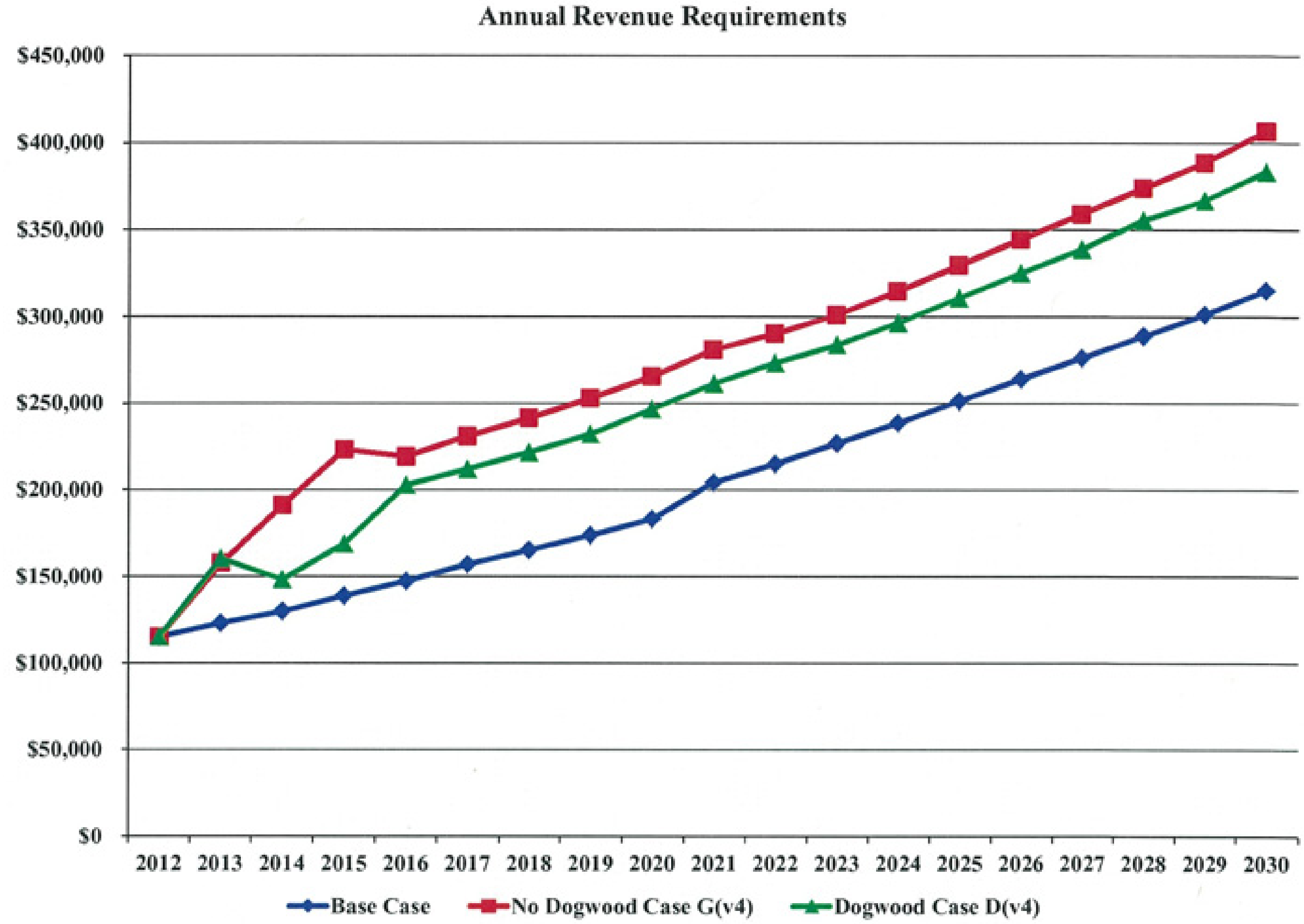
- Capital Cost
- Non Fuel O&M for Generators
- Fuel Cost
- Allowance Cost
- Net Transaction Cost
- Net Economy Interchange

The net present value analysis showed that both the alternatives were more expensive than the Base Case because of the cost of regulatory compliance they included. The Dogwood Case D(v4) had the lowest net present value of the alternatives that provide compliance at $2.89 billion while the No Dogwood Case G(v4) had a net present value of $3.13 billion. These net present values are shown in the table and chart below.

Cost Type	**Base Case**	**No Dogwood Case G(v4)**	**Dogwood Case D(v4)**
Capital Cost	$92,462	$371,603	$421,694
Non Fuel O&M for Generators	$766,910	$977,975	$863,412
Fuel Cost	$1,359,705	$1,359,926	$1,308,468
Allowance Cost	$0	$71,306	$73,591
Net Transaction Cost	$57,385	$57,385	$57,385
Net Economy Interchange	$26,421	$296,066	$164,630
Total Net Present Value	**$2,302,884**	**$3,134,261**	**$2,889,179**



The annual revenue requirements that were the basis for the net present value analysis are shown in the chart below. The Dogwood Case D(v4) has a lower revenue requirement than the No Dogwood Case G(v4) in all but the first two years. It also shows that the cost of environmental compliance will be greater than the cost of continuing the current operations.



Response to Issue Two: In the intermediate term, 2012-2014, does entering into this contract cause significant financial deviations from the capital plans and user rate studies currently enacted and their perception by BPU customers?

Our initial review of the *KANSAS CITY BOARD OF PUBLIC UTILITIES Electric Utility Revenues, Revenue Requirements, Cost of Service, And Rates Final Report October 2010* prepared by Black and Veatch did not find the Dogwood project included in the context of the report. However, in subsequent conversations with Darrell Dorsey he indicated the C.I.P. in this report included a project number 16 which was labeled as Nearman CT5 which was a place holder for the Dogwood purchase.

The C.I.P. shows capital expenditures of $66 million for this project as follows:

YEAR	CAPITAL EXPENDITURE
2012	$ 1,000,000
2013	$ 13,000,000
2014	$ 52,000,000
TOTAL	$ 66,000,000

Excerpt from Page 21 & 22 of *KANSAS CITY BOARD OF PUBLIC UTILITIES Electric Utility Revenues, Revenue Requirements, Cost of Service, And Rates Final Report October 2010.*

3.2.3 Capital Improvement Plan

The baseline Capital Improvement Plan (CIP) is the 2010 Budget, and was reviewed and updated by BPU management in September 2010. The CIP provides a five-year (2010 through 2014) capital plan. The primary and preferred source of funds to finance the electric utility CIP is with annual operating revenues. Because surplus operating revenues are not sufficient to finance the entire CIP, bonds are used to provide financing for the projects. The detailed CIP is shown in Table 3-4. Electric Operations projects are shown on lines 1 through 13. Electric Production projects are shown on lines 14 through 24, plus mandated environmental projects on 26 and 27. Projects common to both the Electric and Water Utilities are shown on lines 29 through 34. The amounts shown for those common projects represent 80 percent of the project costs. The remaining 20 percent is assigned to the Water utility. Major Electric Operations projects over the 5-year period from 2010 through 2014 include $50 million for overhead and underground distribution improvements, $31 million in transmission investment, and $35 million in substation projects. Major Electric Production projects include $20 million in projects at the Nearman Power Complex, $35 million of investment at the Quindaro Power Complex, and the planned construction of a new combustion turbine generator at the Nearman Power Complex (CT5) for $66 million.

The BPU's 2012 C.I.P. also included the Nearman CT5 project with a total cost of $85 million. The difference between this amount and the $66 million for this project shown in the 2010 rate study is because the 2012 C.I.P. extends out two more years, until 2016. The annual capital expenditures included in the 2012 C.I.P are shown in the table below:

YEAR	CAPITAL EXPENDITURE
2012	$ 14,000,000
2013	$ 52,000,000
2014	$ 9,500,000
2015	$ 9,500,000
TOTAL	$85,000,000

For comparison purposes we have shown the projected annual expenditures from each C.I.P. for the period 2012 through 2014 in the table below.

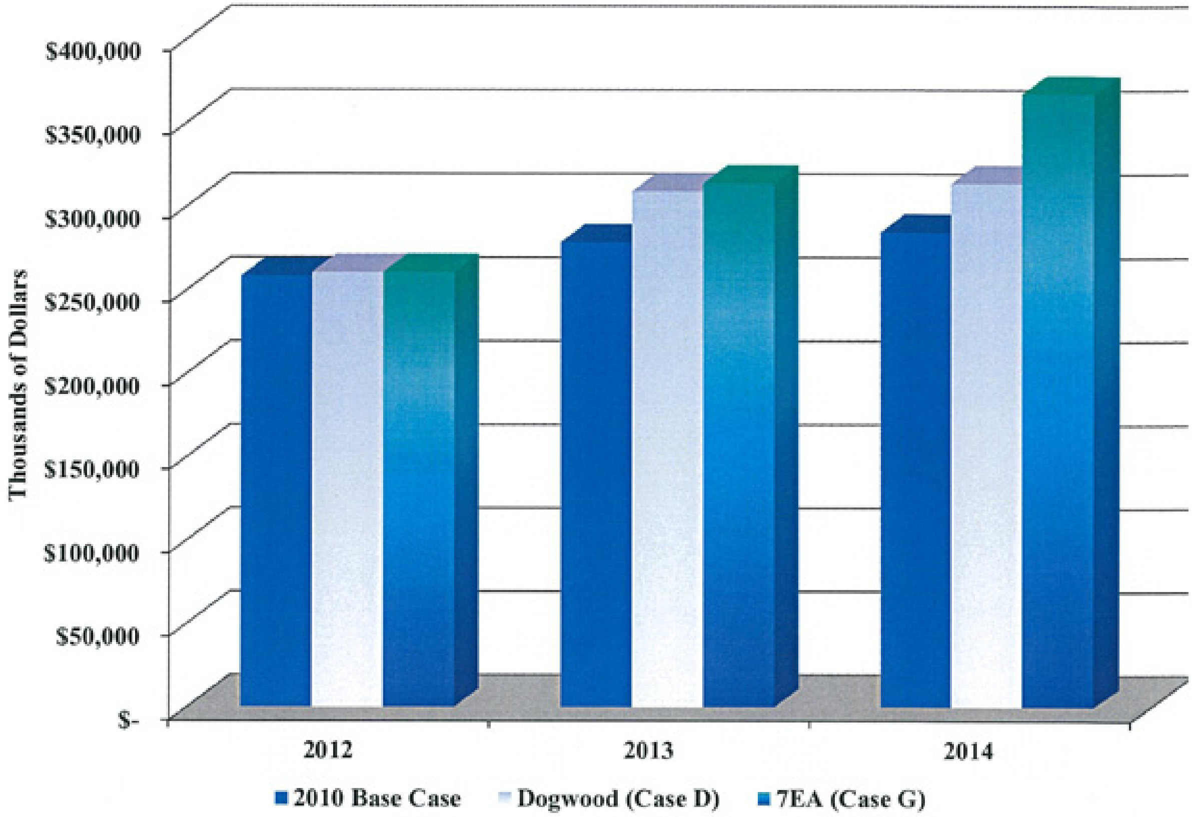
YEAR	2010 RATE STUDY C.I.P.	2012 C.I.P.	DIFFERENCE 2012 - 2010
2012	$ 1,000,000	$ 14,000,000	$ 13,000,000
2013	$ 13,000,000	$ 52,000,000	$ 39,000,000
2014	$ 52,000,000	$ 9,500,000	($ 42,500,000)
TOTAL	$ 66,000,000	$75,500,000	$ 9, 500,000

This capital expenditure is part of the BPU's analysis and strategy for increased capacity while simultaneously complying with new and anticipated environmental regulations. The availability of capacity from the Dogwood facility is consistent with this strategy as a substitution for the construction of Nearman CT5.

In response to a number of questions Springsted raised relative to the Dogwood acquisition, Black & Veatch provided an Excel file named "Dogwood Evaluation Summary" that contained annual revenue requirements for the period 2012through 2014 for two options as a basis of comparison with the 2010 Rate Study which they called the 2010 Base Case. One option was named Dogwood (Case D) which is the purchase of 110 MW of capacity from Dogwood. The other was named 7EA (Case G) which does not include the purchase of capacity from Dogwood. Both of these options provide full compliance with environmental regulations which was not included in the 2010 Base Case. The revenue requirements for the two options are less than the Base Case in 2012, but are greater in the following two years. The 7EA (Case G) option had the greatest revenue requirements. These revenue requirements are shown in the table and chart below.

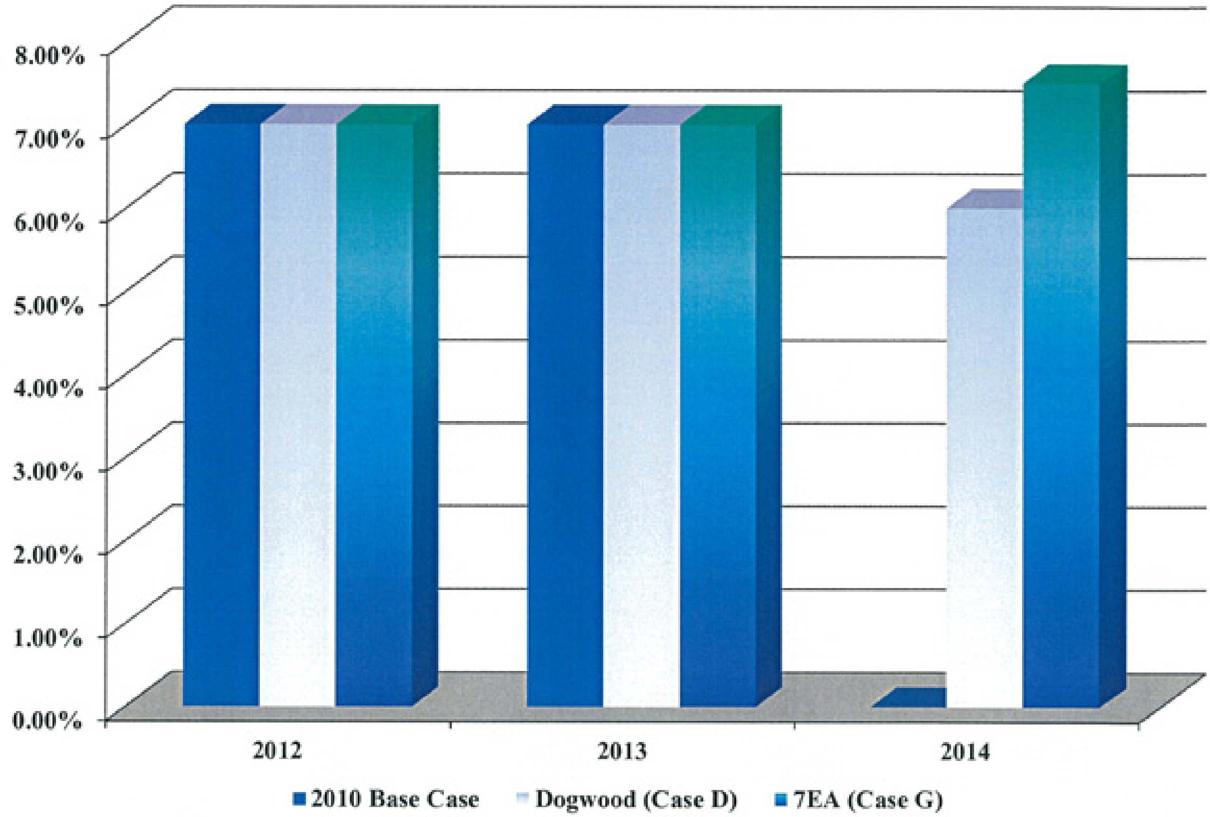
Revenue Requirements	2012	2013	201
2010 Base Case	$257,800	$278,167	$284,10
Dogwood (Case D)	$260,191	$308,415	$313,33
7EA (Case G)	$260,242	$313,265	$366,79

Summary of Total Revenue Requirements



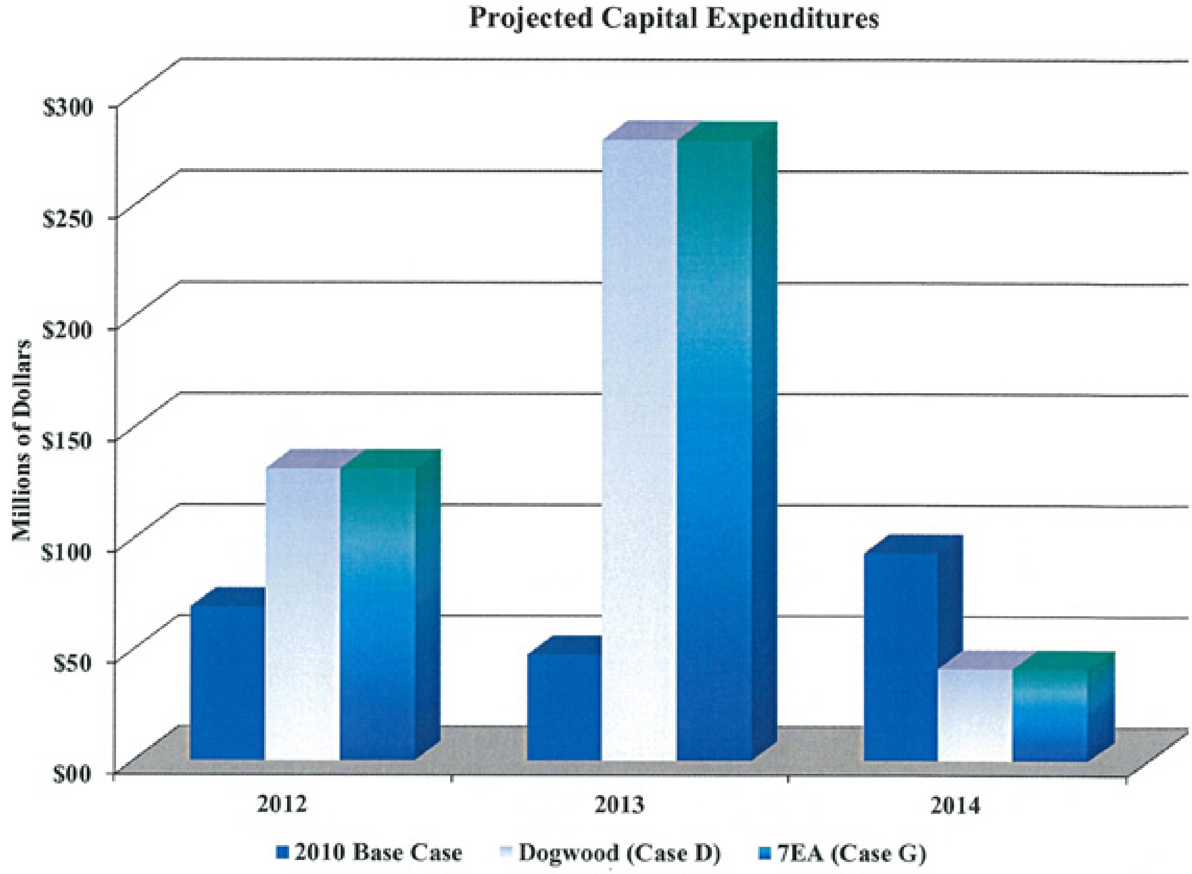
The revenue requirements for these three options resulted in the same projected rate increases in 2012 and 2013. However, while the 2010 Rate Study did not project any rate increases in 2014, the Dogwood (Case D) and the 7EA (Case G) result in projected rate increases of 6.0% and 7.5% as shown in the table and chart below

Projected Rate Increases	2012	2013	2014
2010 Base Case	7.00%	7.00%	0.00%
Dogwood (Case D)	7.00%	7.00%	6.00%
7EA (Case G)	7.00%	7.00%	7.50%



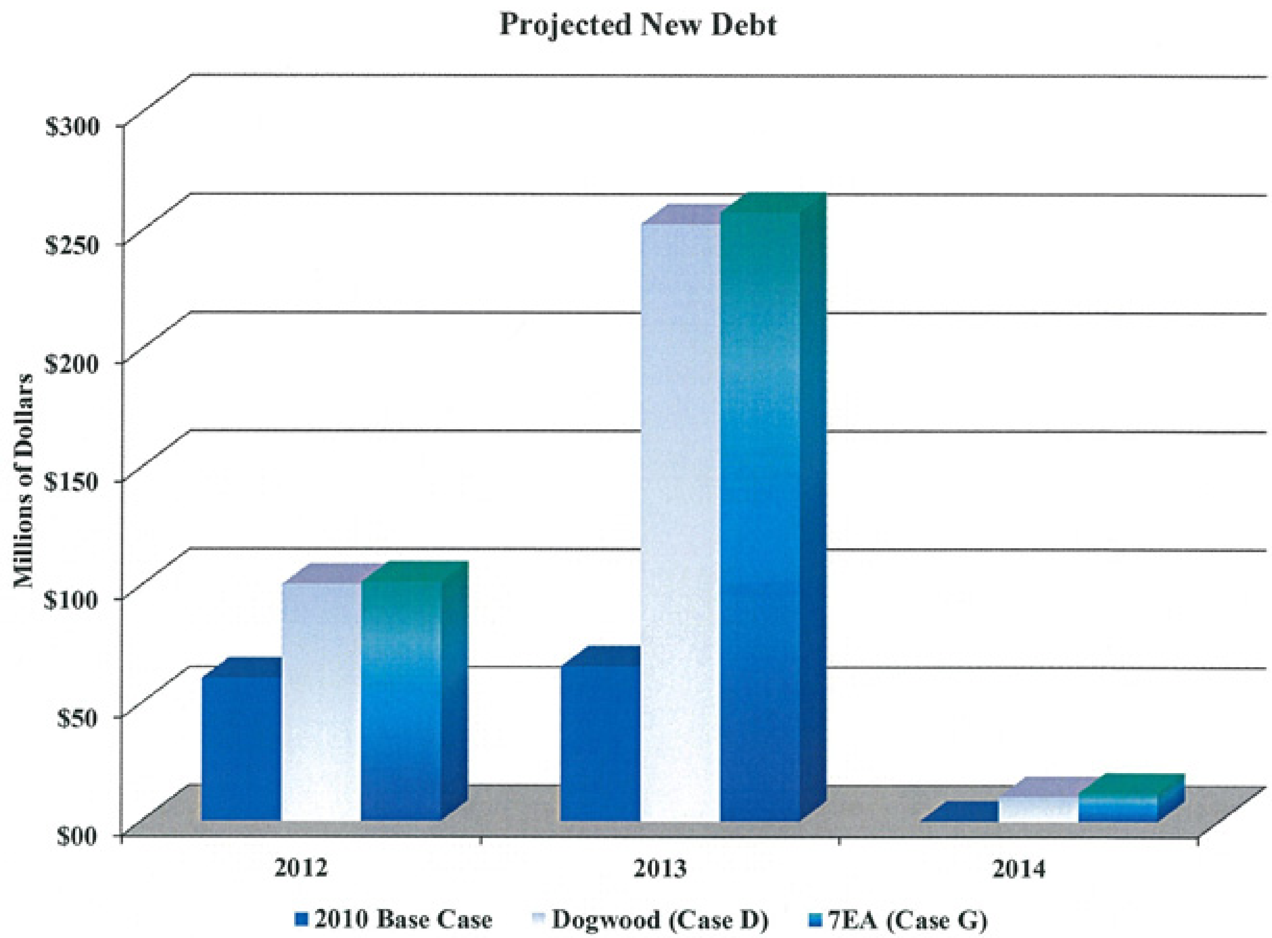
Black & Veatch projected Capital outlay in the 2010 Rate Study to be $210.1 million. They projected capital outlay in the Dogwood (Case D) and the 7EA (Case G) to be $451.9 million and $451.6 million respectively as shown in the table and chart below. However, the increased capital costs for these two options are the result of environmental compliance costs not included in the Base Case.

Total Projected C.I.P.	**2012**	**2013**	**2014**	**Tot**
2010 Base Case	$ 69,041,600	$ 47,636,600	$ 93,411,600	**$210,089,80**
Dogwood (Case D)	$ 131,315,600	$ 279,183,110	$ 41,411,600	**$451,910,31**
7EA (Case G)	$ 131,315,600	$ 278,875,350	$ 41,411,600	**$451,602,55**



Black & Veatch projected new debt to be $126.0 million in the 2010 Rate Study. The projected new debt in the Dogwood (Case D) option was $363.2 million and in the 7EA (Case G) option it was $370.7 million as shown below.

Total Projected New Debt	2012	2013	2014	To
2010 Base Case	$ 60,500,000	$ 65,500,000	$ -	**$126,000,00**
Dogwood (Case D)	$ 100,274,000	$ 252,456,510	$ 10,500,000	**$363,230,51**
7EA (Case G)	$ 101,274,000	$ 257,456,510	$ 12,000,000	**$370,730,51**



Anticipated Partnership Group, Kelson and Governance

Kelson has or is in the process of negotiating acquisition agreements with three other public entities. If the phase one acquisition is completed the four public entities, with the inclusion of the BPU's 17% share, would own a combined 44.5% equity position, with Kelson retaining a 55.5% position. If the phase two acquisition is completed, this same group's share would increase by the second BPU share of 17% to yield a combined 61.5% share, with Kelson owning a 39.5% share.

We understand the agreements provide for Kelson or a Kelson-controlled entity to operate the Facility.

In the credit rating review of municipal bond issues offered by other public entities entering into ownership agreements for the Facility, Moody's Investors Service has indicated a concern about the financial standing of Kelson, terming their creditworthiness as 'highly speculative.' We understand Moody's pursued a comprehensive questioning of 'what if' scenarios should Kelson be placed in receivership, have liquidity issues with funding fixed operating costs, etc. Moody's concerns for the issuers are reduced as more public partners enter into acquisition agreements. With each agreement Kelson receives cash payments to improve their balance sheets, as we understand from our conversations with Moody's. Reduced Kelson ownership positions also mitigate any adverse Kelson financial situations from impacting the other public owners.

In addition to our Moody's discussions we also went to a private industry source, Dun & Bradstreet to obtain their assessment of Kelson. As a general statement Dun & Bradstreet states that their assessment is not based on a long track record of Kelson performance and therefore they do not have a rating. From the information received over a relatively short period Dun & Bradstreet generally assesses the Kelson standing as 'OK' to neutral. We have provided a separate letter of our interpretation of the report to Unified Government and BPU staff.

The negotiations between representatives and legal counsel of the Unified Government –BPU and Kelson to-date have been extensive. For our report we cannot provide legal perspectives of the acknowledgement and risk mitigation language resulting from this process. We recommend that to the extent questions exist Unified Government –BPU staff and legal counsel be directly consulted.

Transmission Access

STATE OF KANSAS)
WYANDOTTE COUNTY)) SS SPECIAL SESSION, THURSDAY, MAY 3, 2012
CITY OF KANSAS CITY, KS)

The Unified Government Commission of Wyandotte County/Kansas City, Kansas, met in special session, Thursday, May 3, 2012, with six members present: Mendez, Commissioner At-Large Second District; Barnes, Commissioner First District; Kane, Commissioner Fifth District; Markley, Commissioner Sixth District; Ellison, Commissioner Eight District; and Reardon, Mayor/CEO; presiding. Holland, Commissioner At-Large First District; McKiernan, Commissioner Second District; Murguia, Commissioner Third District; Maddox, Commissioner Fourth District; and Cooley, Commissioner Seventh District; were absent. The following officials were also in attendance: Dennis Hays, County Administrator; Jody Boeding, Chief Legal Counsel; Bridgette Cobbins, Unified Government Clerk; Gordon Criswell and Gary Ortiz, Asst. County Administrators; and Lew Levin, Chief Financial Advisor.

BPU Representatives: Mary Gonzales and David Alvey, Board Members; Don Gray, BPU General Manager; Dave Mehlhaff, Public Affairs Officer; Randy Otting, Financial Officer; Bob Adam, Acting Manager of Electric Supply; and Dong Quach, Acting Manager of Electric Production.

Others in attendance: David MacGillivray, Springsted; Kathy Peters, Attorney, Kutak Rock; who has been working with BPU on the Dogwood Project; Natalie Rolph, Principal Economist; and Fred Freeland, Associate Vice President; Black & Vetch.

MAYOR REARDON called the meeting to order.

ROLL CALL: Kane, Markley, Ellison, Mendez, Barnes, Reardon.

NOTICE OF SPECIAL MEETING of the Unified Government of Wyandotte County/Kansas City, Kansas, to be held Thursday, May 3, 2012, at 5:00 p.m. in the 9th floor conference room of the Municipal Office Building for BPU facility acquisition. The

Notice of Special Meeting was amended to include an executive session regarding litigation.

CONSENT TO MEETING of the governing body of Wyandotte County/Kansas City, Kansas, accepting service of the foregoing notice, waiving all and any irregularities in such service and in such notice, and consent and agree that the governing body shall meet at the time and place therein specified and for the purpose therein stated.

BPU Board Member David Alvey said I want to take a few minutes to put our request for approval of the Dogwood Project into context. As we discussed in our Joint BPU/UG meeting several months ago, the United States Environmental Protection Agency has begun to roll out in rapid succession a series of environmental rules and regulations which is putting immediate and unrelenting pressure on coal fire generation across the nation. Among others these include CSAPR (Cross-State Air Pollution Rule) which was to be implemented on January 1, 2012; a utility MACT rule which is proposed to go into effect in the summer of 2013; the MACT (Maximum Achievable Control Technology) will include regulations on Greenhouse Gas Emission; another rule deciding whether coal ash will be considered a hazardous material, revisions of Section 316B of the Clean Water Act, affluent guideline limitations controlling the discharge of metals and chloride as well as perhaps even the temperature of the water being discharged on power plant cooling structures. The affect of just one of these rules is enough to cause the shutdown of many coal fired plants across the country. According to the America Public Power Association the combined effect of the CSAPR and the utility MACT rules alone is enough to shutdown 15 to 20% of the coal fired units in the country over the next 1 ½ years. For those coal fired units that do not shutdown, that survive this round of regulations, the cost of controls will result in significant rate increases for customers. Moreover, even though coal is our nation's most abundant and most cost-effective fuel for power generation, the Environmental Protection Agency has recently announced that any new coal plants in the country will have to produce zero greenhouse gas emission. Lisa Jackson, Administrator of the EPA under President Obama, has confidently announced that carbon capture and sequestration technology will be financially available within the next ten years although the evidence in the industry contradicts that claim. Even the National Director of the Sierra Club has stated that this new rule by the EPA will effectively kill any chance of a new coal fired plant being built in our nation.

Clearly the Board of Public Utilities is in a difficult position. Even as this tsunami of regulations heads our way we at the BPU must continue to find ways to provide reliable power at a cost that our customers can sustain. Please be assured that at the BPU we are doing everything we can to protect the ability of the BPU to provide reliable and affordable power. As you know when the CSAPR was announced in early August of last year, we immediately appealed to the Environmental Protection Agency for an administrative stay of enforcement simply in order to give us time to meet the requirement of the regulation. That request for a stay was denied by the EPA. At the same time, however, we joined forces with other utilities and filed suit in federal court asking for relief from the harm that the rule would cause. A decision in this suit is expected to be handed down this summer. Also, we have been in constant communication with our Senators and Representatives who have introduced legislation which, if approved by the House and the Senate and signed by the President, would give to BPU and other utilities in Kansas and other utilities in three other states sufficient time to meet the rules in a way that is operationally and financially feasible. Those efforts, the lobbying, the legislative efforts will continue. Nevertheless we cannot and are not waiting to see what relief that legal or legislative action might provide us. That is why we are here tonight.

The Dogwood Project in the short term is a necessity for the BPU and we are very fortunate that this project has become available to us as I think will become clear in Mr. Gray's presentation.

Don Gray, BPU General Manager, said I would also like to add and I know Dave presented a lot of information about the current regulations that we're facing, but please also understand that all of us in this area of the country use coal primarily for our source of energy and why is that? It was readily available. We had coalmines in Pittsburgh, KS.

We used to buy coal on the spot market from Pittsburgh. As we shifted towards the lower sulfur coal in Wyoming, and it's even estimated in Wyoming they have over a 200 year supply of goal to meet current demands, so it's a readily available fuel but right now with the regulations the way they are coming out I don't see a future very bright at least going forward in trying to build especially new coal plants.

The Dogwood facility is a project that kind of fell into our lap and I have been with the utility probably 40 years now and I feel this Dogwood Project is one of the most important that I have ever been involved in in all the time I have been with the organization. Before I get into Dogwood and kind of explain why that is and why I feel that way I would like to give a little background about our general supply for our community.

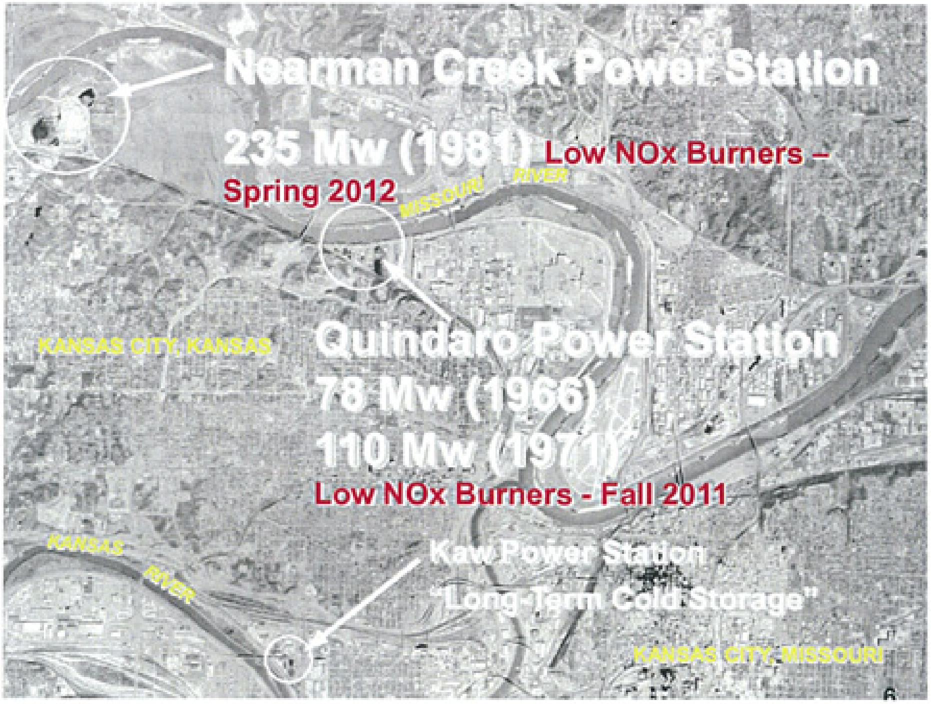
BACKGROUND OF ELECTRIC GENERATION MIX

	Mw	
Coal	362	
Combustion Turbines	189	
Renewables:		
Federal Hydro	44.0	
Wind	25.0	
Landfill Gas	1.5	
Bowersock Mill Hydro	7.0	(Fall 2012)
Total Renewables	77.5	16%

Average Day Demand = 318 Mw

Historical Peak Demand = 529 Mw – August 9, 2006

As you can see we have about 362 Mw of coal. We have gas combustion turbines and we have oil combustion turbines but they are for PP purposes only. Normally they run in the peak of the summer demand. Sometimes we will have them run in the spring or fall when we have outages to our coal plants and if we need the energy, we certainly have them available. Renewables is an area we have been getting into over the last eight years or so. The Hydro for all public power entities--Hydro is available as long as it is an Army Corps of Engineers project and we have tapped into that resource approximately 44 Mw. We got into 25 Mw of wind. The wind farm is out by Salina, KS, the smoking hills is what they call it. A couple years ago we got into 1.5 Mw of landfill gas out of Arcadia, KS which is down by Pittsburgh. The recent project we're excited about is the Bowersock Mill in Lawrence, KS. As you cross the bridge to go into the downtown area of Lawrence, below that bridge is a Hydro Damn that has been there for many years. They are renovating that facility, increasing the capacity up to 7 Mw. We entered into a long-term purchase contract for that energy for 25 years and we expect in the fall of this year that project will be completed, the renovation, and we will start receiving energy from that Hydro plant. Right now our renewables 77.5 Mw or roughly 16% of our resources is renewable energy now. Our goal was 15% right now and then as we approach 2020 the State would like to see us approach 20% so we will be continuing to look at not only renewables, but more of the demand side management programs to continue to reduce our demands. Right now our current average day is 318 Mw and our Historical Peak was 529 Mw. August, 2006 will kind of show you how things have changed in recent years that the historical peak was some years back. Our demands have been flat and I think a lot of our community, our customers have been more conscious about the energy they are using so they are taking measures to conserve more.



To show where our facilities are located, our largest unit is Nearman Creek. It is 235 Mw. It was built and put in service in 1981. You approved $40 million in Capital spending for an environmental project that had to do with the ozone in the Kansas City area. We call it the Low NOx Burners Project. We've modified our burners to reduce the level of NOx being emitted out of our stacks. We did it to Nearman and then also down at Quindaro which is located at the western edge of the Fairfax Industrial District. We have two old coal units there. One was built in 1966 and the other one in 1971. The larger unit we finished the Low NOx Burner Project for it last fall and it is operating now. At the bottom of the picture is our old Kaw Power Station that we phased out of operation probably ten years or so ago and that is located at 18th & Kansas Avenue. We have an active substation down there so we have not made an attempt yet to dismantle that facility but the plant itself is in cold storage.

WHAT IS DOGWOOD?

- 650 Mw Combined Cycle/Natural Gas Plant
- Located in Pleasant Hill, MO; Cass County (36 miles)
- February 2002 – Commercial Operation (Average Life – 50 Years)
- Peak Operation 2008 – 24%
- Aquila & Calpine Built Unit
- Kelson Acquired January 2007
- Staff – 24 Employees
- Located in Southwest Power Pool (SPP) Territory
- Supplied By 2 Independent Gas Suppliers
- Water Supplied By Kansas City, MO
- Connects to KCP&L Transmission Lines

Dogwood is a 650 Mw Combined Cycle/Natural Gas Plant located in Pleasant Hill, MO; Cass County which is roughly 36 miles from here. In February of 2002 it became commercially operated and these combined cycle plants have an average life expectancy, as long as they are well-maintained, of roughly 50 years. It is really in its infancy in terms of its operation. The peak operation occurred in 2008. Normally these turbines are similar to our gas turbines. You use them for peaking purposes primarily or when you might have a lot of outages. For whatever reason they could be forced outages or planned outages, but you could have outages at your big plants and sometimes they have to put a gas plan on them to help pick up the load. The peak operation was 2008 meaning that particular year it operated 24% of the year. All the other years, since 2002 it has operated less than that. I say that because it's in good operating condition and it hasn't had a lot of wear and tear on it in the last ten years. It was initially built by Aquila & Calpine. Kelson which is an investment group acquired the Dogwood facility in January, 2007 and there will be more discussed about that later. It has a current staff of roughly 24 employees. Also, one of the nice features it is located in the Southwest Power Pool which is the transmission operator that we're also in here in Kansas City, KS, Kansas City Power & Light, a lot of western Missouri, most of Kansas, Oklahoma, part of Texas and so forth are all in the Southwest Power Pool system. It is supplied by two independent gas suppliers, natural gas suppliers, which means that you have good competitive bids for the fuel. Water is supplied by Kansas City, MO and it connects to the Kansas City Power & Light transmission line and we have also interconnects with Kansas City Power & Light.

COST OF SERVICE MODEL 2010-2014

- Plans For Natural Gas Combustion Turbine #5
- Simple Cycle
- 75 Mw
- Cost - $75M
- Approximate Finance Date 2013 – 2014
- 3 to 4 Year Construction

People have asked if we buy into Dogwood, are we going to have to raise rates. We did a cost of service model and completed it in 2010. We had rate increases proposed and approved by our Board in 2010, 2011, 2012, 2013 so we are phasing in rate increases to meet our operating maintenance cost and our Capital costs. In that cost of service model we had $75 million identified to build a new gas combustion turbine. We were going to place it at Nearman and call it Gas Combustion Turbine #5 in the lineup because the newer one that we have is what we call the Gas Combustion Turbine #4. It was going to be a simple cycle facility which I will show in a minute. Again 75 Mw at $75 million and we were going to start financing the project starting around 2013-2014 which is in our service model, but it takes three to four years to build one of these units so we were looking at around 2016 or 2017 for it to go into operation.

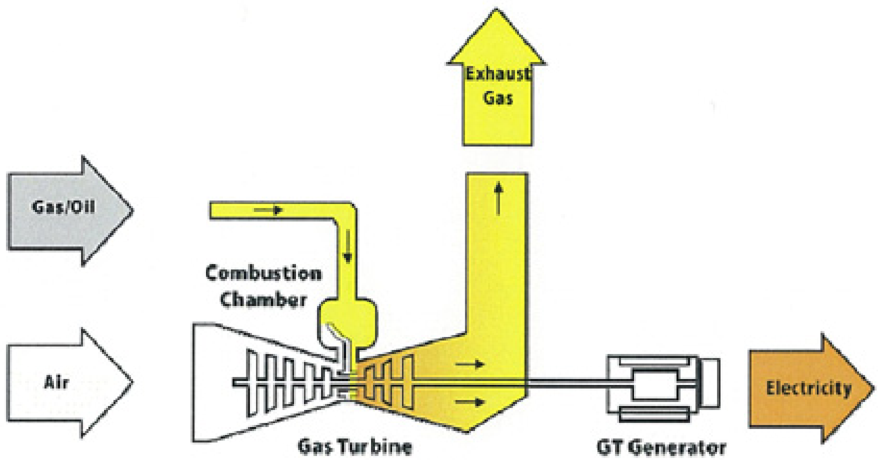
PURCHASE OF DOGWOOD PROVIDES:

- Combined Cycle
- 110 Mw
- Cost - $75M
- 33% More Energy Efficient Than Simple Cycle
- Natural Gas – Stable Price
- Two Major Suppliers To Obtain Gas
- Minimally Operated
- Experienced Operation & Maintenance Staff
- Cost - $75M
- Helps Reduce Overall Environmental Costs
- Cost of Dogwood will Be Covered Under 2010 Approved Rate Increases

The purchase of Dogwood provides the combined cycle which gives us more energy for the dollars. It will get 110 Mw of energy off of Dogwood for the same price that we would have spent to buy our own simple cycle gas turbine and we would have only gotten 75 Mw so we are getting 46% more energy in purchasing the Dogwood for the same price. The Combined Cycle Plant is 33% more energy efficient than a Simple Cycle Plant meaning that we use 1/3 less natural gas to get this output of 110. We have two major suppliers and it's minimally operated, experienced operation and maintenance staff at the facility, the cost is $75 million and it helps reduce our overall environmental costs. Having Dogwood will allow us much more flexibility in how we approach coal plants and putting environmental controls in place. If you would ever like to come down and take a tour we would invite you to come to our Nearman facility and see our Gas Combustion Turbine to kind of get an idea of what we're talking about.

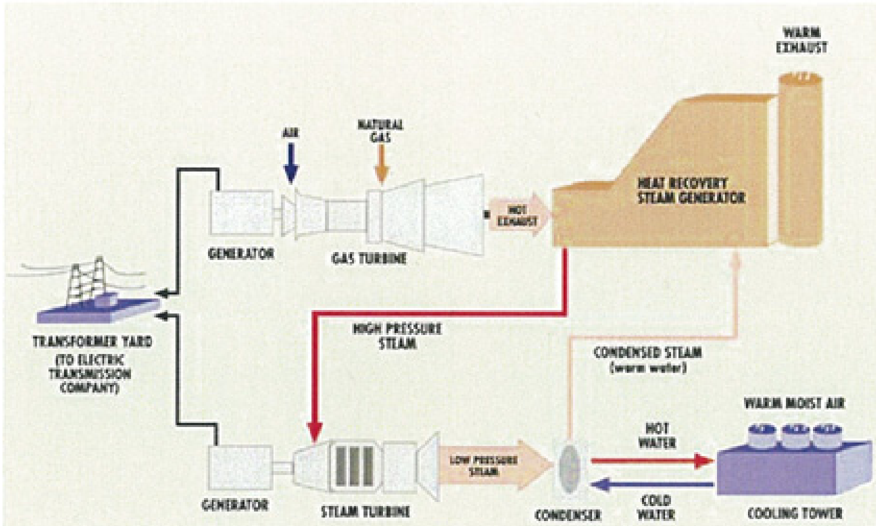
SIMPLE CYCLE

Simple Cycle Process



Essentially you have either natural gas or you can use fuel oil too. Most are natural gas burning systems plus air combustion chamber. It's basically like an airplane turbine engine that runs a generator is all it is and so you then turn the generator and produce electricity, but what's happening with the Simple Cycle, and you will see the stack out at Nearman, when it runs you see a lot of heat and gases coming out of that exhaust just like coming out of your car. That is the wasted energy that goes up into the atmosphere but that is a Simple Cycle. These things are made to put on quickly. You can get them on line in about one hour or so. A coal plant takes a number of hours to get up the pressure and so forth and get on line. Gas plants are almost instantaneous.

COMBINED CYCLE



The Combined Cycle Dogwood is a little different. You have the air, your fuel mix, again you have your jet engine driving the first generator and that is basically where your 75 Mw are coming from. The exhaust instead of getting to the atmosphere now the exhaust goes into a heat recovery steam generator where you are taking water and converting it to steam just like we're doing in the coal plants. We burn coal, convert water to steam, it's the steam that's the energy that is turning the turbine so you have the steam, the high pressure steam that comes over spins the turbine, there is a generator attached and you are producing more energy. Instead of letting all that energy goes through the stack, you are recovering that energy and that's what is making a Combined Cycle Plant much more efficient.

ADDITIONAL BENEFITS

- 1/3 Less Energy Consumed
- Additional 35 Mw More Energy For Similar Cost
- Clean Generation that Could Reduce Future Environmental Control Costs For Existing Units
- Construct Own 75 Mw Gas Turbine 3 - 4 Years
- If Build Own 110 Mw Combined Cycle – Cost = $155M

Additional benefits are 1/3 less energy consumed and we're getting an additional 35 Mw. We were looking at a CT575; with Dogwood we're purchasing 110 Mw for the same money so we are getting 35 more Mw, much more efficient plant. The key thing here too is environmentally the Dogwood Plant is a clean plant. The one thing you worry about with gas combustion turbines is the release of NOx. Here they have controls on it that essentially reduces that methane down to essentially zero so you have very little in the way of emittance of any kind of air pollution. We have regulations that are coming out now. We have the mercury and air toxics; we have the CSAPR which is also similar to looking at SO2 and NO2 compounds and so forth, looking at a lot of air contaminants and controlling those substances. For us to construct a 75 Mw gas plant to help us on the environmental side, because we're talking those three or four years to build it, and we have to meet these regulations and the clock is ticking now. If we were to build our own Combined Cycle Plant, this is the reason why it's tough to build one because of the cost. If we were to build a Combined Cycle 110 Mw our own, in other words buy a 75 and then attach the steam generator on the other end of it, we're looking a $155 million price tag to do that. Here Dogwood already exists; we could buy it for $75 million.

ENVIRONMENTAL ADVANTAGES FROM DOGWOOD

- Dogwood Would Help BPU Meet It's Environmental Obligations In The Future
- Reduces Emissions In Metropolitan Area (Less Operation Of Quindaro Coal Units)
- Reduces Green House Gas (CO2) By 50% Versus Coal
- No Combustion Wastes To Dispose Of
- Allows Flexibility Of Reduced Q2 Operation Burning Gas In Q1
- Reduces Cost of Adding Environmental Controls - $93M Over 5 Years

Dogwood would help BPU meet its environmental obligations in the future, reduce emissions in the metropolitan area. In other words we will be operating our coal plants less. The other key thing is that when Unit 1 at Quindaro or Unit 2 at Quindaro were built, they were designed to burn both coal and natural gas. Burning natural gas you still have the NOx compound emission issue but under the current regulations the way they are written we could run Unit 1 at Quindaro for brief periods of time like during the summer for peaking. We could also run Unit 2 at times. Dogwood allows us that flexibility. Without Dogwood we are looking at perhaps closing at least one of the coal plants and it would be a real challenge in terms of putting a lot of expenditures on the other old coal plant Unit 2 at Quindaro in order to meet these new regulations. Dogwood allows us much more flexibility. The gas facilities verses coal has 50% less green house gas emissions.

I might add something interesting that is going on in this country, more and more electric utilities that have coal facilities are moving and transitioning the gas. The reason is the fracking process that is going on. That is key and I was at a meeting out-of-town where an individual that is an expert in the industry compares fracking as embarking upon a new industrial age. Similar back in the 30's when they discovered shallow oil in

Oklahoma and Texas. This is big and so that's one of the drivers for utilities moving more and more to gas. Our actual coal usage has declined by roughly 5% in this country as we're more and more moving to gas. Globally China, India, South Vietnam, South Korea, all these other countries that are really on the move economically have increased coal consumption by 40% during that same time. That is kind of the dynamic that is happening around the world. We're doing things to try to control contamination more and more, spending the dollars to do it, I'm not sure globally that message is getting across to everybody else. There is no combustion waste to dispose of. When we burn coal we not only have the air contaminants but we have the fly ash and the bottom ash, all the particulates that we have to dispose of so when you burn coal, you do have residue. We have been able to sell our fly ash but I'm worried that EPA if they decline our ash as hazardous waste material then we're in real trouble because then we have to look at hauling it off someplace to an appropriate landfill which could be really expensive. This allows us maximum flexibility in operating both our plants at Quindaro and a key, reduces the cost of adding environmental controls that saves our community $93 million over five years by investing in Dogwood.

CURRENT DOGWOOD PARTNERSHIPS

- Independence Power & Light – 75 Mw
- Missouri Joint Municipal Electric Utility Commission (MJMEUC) – 50 Mw
- Kansas Public Power (KPP) – 40 Mw
- All Have Closed On Their Contracts With Kelson
- BPU – 110 Mw – 17% Ownership
- All Current Parties – 45% Kelson – 55%

The current Dogwood partners are all municipals. Independence Power & Light our neighbor across the river recently purchased an ownership 75 Mw. Missouri Joint Municipal Electric Utility Commission, we call them MJMEUC, they got 50 Mw and Kansas Public Power which is an organization that buys and purchases energy for small cities in more central western Kansas like Larned, Chanute; communities like that; there are about 30 or so communities that they buy energy for and they are under the Kansas Public Power and they all have closed on their contracts with Kelson. Another key is the longer we continue to delay not buying into Dogwood, the price keeps going up. We're looking at 110 Mw, we would have 17% ownership of the facility, all total all the municipals right now with us buying in we would own 45% and Kelson 55%.

HOW WILL DOGWOOD BE OPERATED?

1. Call On Unit To Meet System Demand – Environmental Versus Economic
2. Management Committee – Vote By Percentage Of Ownership – 17%
3. Operation Cost – Based On Amount Of Usage – Pay Cost Of Fuel (Variable Cost)
4. Pay 17% Of Fixed Cost – Labor, Maintenance, Capital Improvements
5. Any Future Organization Must Sign The "Participation Agreement" (Governance Laws)

How will the plant be operated? Naturally we would call on the unit to meet system demand. However, the dynamic of our business is changing. We always dispatch units based on the most economical at the time and now we're going to be looking at dispatching units to meet environmental regulations, a totally different business model in operating our facilities. Dogwood gives us a lot of flexibility in how we meet those changes that are occurring immediately. We have a Management Committee that is established that will have oversight over the operation of the facility and we would have a vote, a percentage of ownership of 17%. The operation cost – if we need Dogwood to operate and we're the only utility that needed it at that given time, we pay all the gas costs, all the fuel costs and that's the variable cost. However, the fixed cost we pay 17% of all fixed costs which would be labor, maintenance and any capital improvements. Any other future organization wanting to buy in ownership of Dogwood would have to sign a Participation Agreement which the Governance Laws would be similar to a new homeowner moving into an area that has a homeowner association and you have bylaws and things that every new homeowner has to abide by. This is the same thing here. That is the protection that all the owners have. Anybody that comes in has to sign this Participation Agreement.

SUMMARY

- Purchase will be covered under 2010 approved rate increases
- 33% More Efficient Over Simple Cycle Natural Gas Plant
- Reduces Environmental Costs To Older Plants - $93M
- Already Built And Being Efficiently Operated
- Reduces Cost To Our Customers
- Provides Flexible Options To Meet Environmental Regulations
- Stable Gas Prices For 18 Years Or More – Fracking
- Very Fortunate To Have This Opportunity (Everything Seems To Be Fully Subscribed Or Spoken For)

In summary, no rate increase to buy into Dogwood, the 110 Mw. It is already in our cost of service. Although the dollars were earmarked for Combustion Turbine Simple Cycle what we were going to call #5 we're just shifting those dollars over and buying a much more efficient plant and getting more Mw of energy. It reduces environmental costs to our older plants by roughly $93 million. It is already built and being efficiently operated, it reduces our costs to our customers, provides flexible options to meet environmental regulations, and I have been hearing that because of the fracking process gas price—you know how they have been pretty volatile over the last ten years or so, but I'm hearing because of the abundance of—in fact we're starting to export gas but we're hearing we're looking at stable gas prices for a minimum of 18 years and more and I've heard this from several experts in the industry. I would like to think that is pretty rock solid. We're looking at some good low cost gas prices for a number of years and we're fortunate to have this opportunity. This is the only thing that we know of that is out in our local regional four/five state area that's available to buy into that is an efficient facility, that's not a coal plant. In fact, there is very little in coal either if we wanted to go that route. This just fell into our lap more or less. That is why I feel so strongly that we need to take advantage of it.

IN THE FUTURE

- Additional 110 Mw Of Dogwood – Perform Transmission Studies
- If Have Transmission Studies Completed Within 2 Years – Would Further Reduce Our Environmental And O&M Costs
- Major Operation Profile For Most Of Year – 110 Mw Dogwood + 235 Mw Nearman
- Future BPU Staffing – Attrition
- Future Environmental Costs? $224M
- Present Refinancing Opportunities
  - $85M-$110M (1998 & 2004 Issues)
  - Approx. NPV Savings $3.9M Total or $250,000 Annually

In the future I'm a proponent that we get as much Dogwood that we can. They are willing to set-aside another 110 Mw block for the BPU. We're interesting in buying another 100 Mw, however, there are some problems with that and that is the transmission. We do not know if the transmission pathway right now is good enough that we could take that additional 110 Mw. They have to go through the study of the models and that is where the Southwest Power Pool, the people that operate and oversee the system in our area, they have to do a lot of modeling to see if there is a good pathway without making modifications for another 110. The challenge is if we could have that 110 within the next year, it would even further help us in meeting future air regulations but we just don't think it can be done that fast. We're going to have to do some things, especially looking at Unit 2 at Quindaro. We're looking at roughly two years perhaps. The result of the study could be that we have to maybe add some money to help do some things to the transmission system to get it in. Would it be cost prohibitive? We don't know because we haven't seen any numbers yet. We would hope they would get it done much sooner rather than later and we don't have to make any major modifications to the transmission system between here and there in order to get it in.

The average operation we're seeing a 235 Mw Nearman operating, still a very efficient plant and then Dogwood basically would meet a lot of our demands through four to six months of the year. People have also asked what does that do about BPU staffing. Certainly over time Quindaro will have more minimal usage, but just like Kaw Station when we gradually started reducing the operation at that plant, we just started phasing our employees over to the other facilities and reassigned them and let attrition naturally take its course over time. That is what we would be looking at here as well.

I know the Mayor has asked what more are you going to be asking for down the road as far as environmental costs or plants. Right now we're estimating with Dogwood, please bear in mind we're saving $93 million over five years with Dogwood, with Dogwood we're looking at roughly $224 million. Right at or a little over $200 million of that is for Nearman alone to put all the environmental controls, scrubbers, and things like that on Nearman. Nearman is one of the most efficient coal plants in the United States. We feel it is well worth the investment. It still has a useful life, 25 years or so, so it is well worth the investment in Nearman. The remaining dollars would go into Unit 2 at Quindaro for some chemical treatment type, there is just kind of a stop gap short-term type projects to help reduce some of the emissions from those plants.

The other thing I wanted to add to the Dogwood that we will be presenting to you for consideration is the Dogwood Project and then we want to do some refinancing on some of our older debt. Right now the market is very favorable and we're looking at about $85 million to $110 million of our existing debt refinancing. Lew Levin has been helping us with that. We're looking at net present value savings of about $3.9 million or a total of about $250,000 annual reduction in principal and interest by doing this if we do it sooner rather than later as the market is still supporting. I really feel this Dogwood, I don't want to call it a miracle, but it's close to it that it came at the time where these regulations are hitting us. Some folks have said you knew the regulations were coming out, why weren't you doing things well before now. The regulations are just now coming out that impact BPU. We cannot go out and borrow money to just think how the regulations are going to be. That wouldn't make sense and we wouldn't be able to borrow money for that so we had to wait until finally the EPA said okay Kansas, okay BPU this is what we expect you to do. It is here now and that is why we're here and Dogwood just happened to fall in at the right time. If we could get 220 Mw of ownership, then the municipals would own over half of the facility and would have primary control of the facility. Kelson said they would hold that 110 for us until we go through all this modeling so they are going to hold it, they are not going to sell it off to any other entity.

Mayor Reardon said before we get into questions let me sort of explain kind of how the rest of the pieces fit together in the presentation. When the BPU came forward with this opportunity which I think commission was generally aware of before tonight, we had asked Lew Levin and David MacGillivray who is here tonight, our financial advisor, to take a look at the project too because as all of us know that sit around the table it's fairly unique. The Board of Public Utilities is operated by a separate board on the day-to-day operation but with respect to indebtedness major expenditures like this are decisions made by our governing body at the Unified Government Commission level. Mr. Gray said they would be making a formal request to us likely at the May 17th meeting to issue bonds for this and the refinancing I'm assuming as well at that time. Our decision-making is multifaceted, we have to know what's going on but it also goes directly back to the financial analysis as well. Mr. MacGillivray has prepared that presentation. You may have some questions for Mr. Gray now but you may want to listen to Mr.

MacGillivray first and then kind of open it up to everybody. I just wanted to make sure that you all understand how the presentations are going to flow.

Commissioner Ellison said we have our own 120 acres in Arkansas where fracking is taking place and reading the *New York Times* last week it looks like the cost of natural gas is going to this because the CEO—I'm sure you have kept up with it. The use of natural gas with the closest of Arkansas which is only 400 miles from here— **Commissioner Barnes** said since he mentioned that I can assure you that there are going to be government regulations on fracking also. So you can't count on it going down. Fracking is just as bad as anything else. The pot ash that you are taking away has all kinds of chemicals in that stuff that they are using for that. I can assure you they are going to catch up with that too so I don't think you can count on gas prices being stable 20 years from now. As soon as we have one disaster I guarantee you they are going to latch onto the fracking people.

Mr. Gray said all I'm presenting is what we know of as of now. You are absolutely right, there could be some environmental issues but all I have to say is this, what energy source are you going to give them. If people don't want nuclear and they don't want coal, gas is the only option you have so they have to be very careful how they regulate gas. At least right now with the way we obtain it, I agree there is probably going to be some restrictions on it which is going to kick the price up some—otherwise you are going to be looking at blackouts and going back to the Eighteenth Century.

Commissioner Barnes said you pointed out $93 million that you are going to save us. Will that savings show up on our light bill? **Mr. Gray** said you won't see an increase covering that additional $93 million cost. **Commissioner Barnes** said but you have already figured that in, that's why you had the four years at 7% going up for four years so you had already anticipated that, is that correct? **Mr. Alvey** said if we don't do the Dogwood, the other mediation we would have to do would increase our environmental controls by $93 million. We have already accounted for—**Mr. Gray** said not the $93 million and our cutoff service. **Mr. Alvey** said not the $93 million but the cost of building the CT5. **Commissioner Barnes** said the light bill will stay the same regardless of what we do here. **Mr. Alvey** said no the light bills will go up. **Commissioner Barnes** said are they going to get higher as a result of doing this right here? **Mr. Alvey** said no. I thought you said if we don't. **Mr. Alvey** said if we do this right here it will help hold rates down. **Commissioner Barnes** said I need a simple way I can explain it to the citizens I represent because even though it's a BPU issue, they are still going to talk to us about it. **Mr. Alvey** said when we come back and start talking about the need for debt financing to cover environmental improvements we will then come to this body, we have to and we will explain everything we have to do to our units in order to keep operating a good safe reliable operation. **Commissioner Barnes** said when it hits the newspaper that we had this discussion today; the conversation is going to start tomorrow with our citizenry. I can't defend that if they are saying—on the one hand you are saying we're going to spend less money and this is a great deal but it's not going to show up on my light bill. That is going to be hard for me to explain. **Mr. Alvey** said I think that's appropriate. I think to be clear this is one thing that we have to do as we move forward trying to meet the regulations coming down hard and fast. If we don't do this, we will have to find other ways to remediate so we can continue to produce power. Using Dogwood rather than other ways to remediate will save us $93 million.

Commissioner Barnes said I asked this question the last time we came to the table and I talked about trending and I think the Mayor touched on that a little earlier. Now we're looking forward to a $224 million deal if everything goes well. Back then when the conversation came up it must have been the $90 million or $80 million whatever it was at that particular time and this happens every three or four years. We're coming back to the table for a multimillion project and so the trending that I was talking about if you just take the simple average of what has happened over the last ten years when we've actually issued bonds or whatever it is over a certain period of time, the trend shows that we're going upwards of $5-$6 million a year, maybe even $8 million a year. That is what I really want to look at so if you come back to the table, I certainly want to see that trending process because I didn't get the information and I certainly want to see the trending of what we're asking for. **Mr. Alvey** said we have projections for our Capital expenditures. **Commissioner Barnes** said you are missing my point. I'm saying you are asking for a bond issuance to this body every so often whether it's every two years or three years. I'm saying what is the trend there so I would like to be armed with that information that I know the BPU is going to be coming every three or four years asking for an average of $40 million. **Mr. Gray** said given the way EPA is lodging these regulations we can't predict that and that is the problem. **Commissioner Barnes** said this is not about prediction. This is about past history. The history would tell us how much money you have asked for over the years. I don't know why this is so confusing for people. If you ask for $5 million in 1990 and you ask for another $5 million in 1995 and you ask for another $5 million in 2000 that is a trend of every five years of you coming and asking for $5 million. All you educated people with all this kind of education that deal with numbers are telling me you can't figure out what a trend is. It doesn't have anything to do with the future. The trend is about what has happened in the past. **Mr. Gray** said I have Randy Otting here my finance officer who will get together our trend of the bond dollars that we have requested for the past 20 years. **Commissioner Barnes** said that will work. I'm trying to establish a trend of what we're actually doing and what we have been doing so when we go forward regardless of what the EPA, the CPA or whoever else throws down on you, I will know what that trend is. I'll know it's going to be going up by $5 million every five years or it's going to be going up $10 million every five years. **Mr. Gray** said we will have that to you by next week.

Mayor Reardon said David MacGillivray will dive more into the financial analysis and the rest of it and I think it will prompt some additional questions.

David MacGillivray, Springsted, said first I want to thank Don and Randy for working with me on the analysis. I think our role as a neutral party some would say here we were asked what is the business case for this and we are going to talk about a variety of items.

Springsted's Tasks

- Examine the financial and related business points relating to acquisition decision
- Describe how the Dogwood acquisition may deviate from current adopted BPU plans
  - Is Dogwood in CIP and Cost of Service Study?
    - Don Gray's remarks covered this question

Public Sector Advisors 1 Springsted

We established a business case of the points that you want to look at. The good thing about positioning is part of the context and Don talked about that being we buy a lot of power now, we have things that are inefficient, how can we make it more efficient, we have regulatory exposure.

Financial and Business Points

- BPU positioning in a highly regulated area
- Cost
- BPU employee levels
- Transmission
- Minority ownership and management
- BPU credit rating
- BPU PILOT payments to UG

Public Sector Advisors 2 Springsted

There is going to be new regulatory exposure. How does the BPU position itself given the regulatory, its cost structure, and purchase a certain amount of power? The cost, employee levels, transmission, minority ownership and Don talked about the Kelson public split, BPU credit rating and the BPU PILOT payments to the Unified Government.

BPU Electric Generation

- Majority from older coal-fired plants
  - Significant environmental scrutiny
  - Significant BPU required environmental investments
- Natural gas combustion turbines
  - Less environmental issues
  - Not economic to run all of the time: peak power needs
- Purchased power
  - Generally most expensive power source

Public Sector Advisors 3 Springsted

Don talked about the older coal-fired, significant environmental scrutiny, and the significant BPU required environmental investments. Dogwood in and of itself doesn't solve this problem. It's a piece of the problem but there is still a lot of other money that is going to have to be spent for more environmental remediation. Natural gas turbines traditionally, this isn't right now, less environmental issues. Generally they haven't been because they don't turn them on all the time because it costs a lot to operate them so they generally view it as peaks. This is a combined cycle with the steam so it doesn't have all the attributes. Purchased power hasn't been talked about a lot. There isn't sufficient generation happening and the BPU has to go out in the market and buy electricity off the market. It's your most expensive. When Nearman had its fire a lot of money went out the door to buy power. This is a big piece of the cost items we're going to talk about. This has been a part of their cost dynamic and when there are problems it is really a big cost because usually when they are going to look for it so is everybody else and the price goes up.

BPU Customer Base

- Residential customers
  - Vast majority in number of accounts
- Commercial-industrial customers
  - Significant percentage of revenues
  - Significant Wyandotte County employers
- Customer growth
  - Modest growth
- Costs not funded by significant number of new customers

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One big thing and everybody knows this but I think as you look at the substantial cost in the future the overwhelming majority of BPU customers in terms of numbers of accounts are residential customers. Where 30 or 40% of the money comes from rates are commercial/industry customers and it's a pretty isolated group. Certain Teed, the GM Plant are major employers so basically if you generate a dollar 30 or 40 cents is coming from here and the other 60 or 70 is from residential. With this utility there is not a lot of customer growth. It's not like we're investing a couple hundred million, we're going to have like 100,000 more people paying for it so whatever you are spending, most of that burden is going to fall on the folks that are here now, commercial/industrial, not residential customers. When you talk about this I think that is part of the picture.

Dogwood

- 110 Megawatt combined-cycle generation
  - Combined-cycle is natural gas and steam
  - Acquisition price $68 mil; bond size $75 mil
- Natural gas much lower regulatory exposure
  - Significant change in pricing natural gas
    - Was very expensive = much improved situation
    - Can not replace BPU's coal fired generation
- Second 110 Megawatts
  - Current Estimate: No Transmission available to 2018
  - Removed from current financial estimates

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I will just go through this and Don did this. The current estimated acquisition price is $68 million and when you turn that into a bond deal it's about $75 million. We talked about more regulatory. Historically the price of natural gas has been very high. That is why the peaking facilities don't get turned on. There has been this new fracking that has brought things down and more exploration so if that situation changes, we can have a debate about where gas prices are going to go. Even with this you are still in a coal fired generation business and that is going to continue. There has been talk on the Second 100 Mw. The last information we had from the group was that right now the transmission would be 2018 and Don said they might pick up the study but from the meeting we had yesterday they are staying with the most probable of 2018. So when we talk about this Second 110 Mw which would be another $75 million plus, that and its impact are not in any of the numbers you are going to see. This assumes for the foreseeable future you have a one Dogwood 110 Mw.

BPU Positioning in a Highly Regulated Area

- All options require significant investment in environmental compliance
  - What and how much is required?
  - When the investment is provided?
  - Undefined future regulatory requirements
- Cost of ongoing operations
  - Coal and gas mix
  - Lower need for purchase power

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This positioning piece when we started with this I had a different concept of how this was going to work out. I thought we're buying something for $70 million, some other piece of Capital is going to go down, you do the math and here's the difference. Actually most of the cost savings are in the operation and maintenance side and in the purchase power side. Part of this thing, as they talked about a lot of these regulations, is before the BPU now and they have a timeframe. You have to spend the money in the next couple of years; therefore, the fact that Dogwood 1 happened that helps some. The fact that Dogwood 2 has moved out, most of the money will be out the door by then and we will have to retrofit the power plants. It's important when these things happen because if it's other than Dogwood there isn't anything right now so you are going to spend a lot of money on the existing coal fired plants just to stay open because there isn't another remedy right now. Undefined future regulatory requirements – coal fired or will it be more natural gas has pollution elements to it. Eventual fracking on where they get the gas, go with the impacts right now. You know it's sort of back there but not coming to the surface but it's a potential. What's happening with the positioning less dependent on coal, more on gas, lower need for purchase of power, lower regulatory exposure. These are all sort of positioning things.

Cost Estimates

- Source: Black & Veatch Consulting
  - March 7, 2012 Report with updates
- Estimates with significant assumptions and options
- Three cost categories
  - Capital cost
  - Operating Costs
  - Purchased Power
- Cost differences expressed as Present Value
  - Today's value---Future numbers will differ
- Time period: 2012 through 2030

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There are a variety of cost estimates. The BPU has hired Black & Veatch to resolve this. That is not our area of expertise. We took their numbers and asked a lot of questions. These were being updated through yesterday and there are a whole lot of different options. We said we would need a most probable because the future over a time period is going to change and we need your most probable on that. There are a whole bunch of assumptions. What is the price of natural gas in 2024? What's the level of regulatory? What's the coal price then? There is a whole raft of assumptions. To me the answer is it's kind of in this neighborhood. We say here is the number and it's kind of in this neighborhood. They have all these spreadsheets, we took all the costs and rolled them into three categories being Capital cost, Operating costs and Purchased Power. I don't have a lot of numbers in here but they are focused in three areas. We had some debate, all the numbers I have here are in today's dollars even though they are going to be spent between 2012 and 2030. We say a number is 100 today and they come back in two years and its 105 or 110, that's because its future value and we express its present value of today's dollars. All these cost things are cost differences between 2012 and 2030 sort of rolled up into one number so they are 18 years across.

Cost of Environmental Compliance
All Present Value Estimates

Category	No Dogwood	Dogwood	Est Savings
Capital	$280	$271	$9
O&M	282	177	105
Purchase Power	270	138	132
Total	**$832**	**$586**	**$246**

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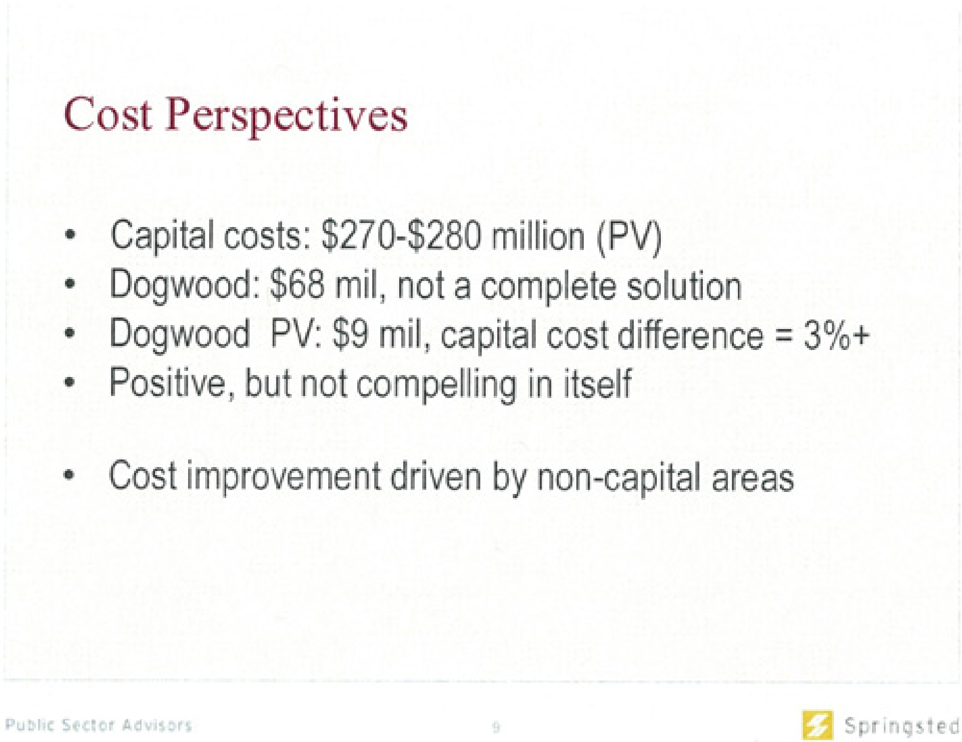
These are in millions and Don's numbers are slightly different from mine. No Dogwood-without Dogwood the utility would be spending $280 million just for electric generation capital cost. With Dogwood $271 million and the difference is $9 million in today's dollars and in the level of assumption that is about a wash. It's slightly positive but Dogwood is $68 million so there is a whole bunch of other money here that is not Dogwood and would have to be invested to meet the regulatory requirements. When you look at savings the latest estimated, most probable $226 million between 2012-2030. You are not going to have to spend money on other Capital. What the Black & Veatch numbers show is that without Dogwood the Operation and Maintenance including fuel cost for $282 million, with Dogwood $177 million with a difference of $105 million savings present value. Purchase Power and look at the magnitude of these numbers. Purchase Power $270 million for no Dogwood. With Dogwood $138 million, 18 years rolled back to today; the difference $132 million. What's the biggest number of savings, Purchase Power. I'm not the best person to explain that in Q&A but what's driving it from a cost standpoint is Purchase Power and O&M.



We started with this Dogwood, is this our answer? I say partial solution. It's 3% on the savings.

Cost Perspectives- Non-capital: BPU Employee Levels

- O&M: 40%+ of Est. Savings
  - Non-Fuel O&M/Fuel = 50 – 50 split
  - Non-Fuel O&M, includes employees
  - Employment levels slightly decrease over time
- Purchase power: 55% of Est. Savings
- Cost drivers are:
  - Non-fuel O&M
  - Fuel
  - Purchase power

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It's positive but in and of itself with just Dogwood and nothing else changed; it's not much so it is really driven by these other Capital areas. 40% of the savings are from O&M and of that non-fuel O&M which is employees and whatever else is in there. Non-Fuel O&M is about 50-50, coal purchases or this or that 20% of the savings relates to the fuel, 20% relates to O&M reductions, staffing and other categories. As Don said we had a direct question from the UG of what happens at employee levels. The BPU believes employment levels slightly decrease over time. The biggest driver is Purchase Power 55% but somebody is going to have to explain how that works because I don't have that expertise but that is what they show as estimated savings. When you go out in that spot market and they have to do this every year but they would have to do it a lot less with this and that is where the bulk of the savings comes from.

Back to Positioning

- Changed fuel source mix for generation
  - From: Less coal and less purchased power
  - To: More natural gas
- Less coal means less regulatory exposure
- Less purchased power means reduced high-priced energy fuel purchases

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Where is the positioning? It's the fuel mix, less coal and less purchased power to more natural gas. Less coal means less regulatory exposure, less purchased power means reduced high-priced energy fuel purchases.

What Could Negatively Change These Estimated Costs?

- Regulatory focus changes to natural gas
- Price of natural gas goes up
- O & M estimated savings do not occur

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I asked what could go wrong with this. Regulatory focus changing to natural gas. We thought we had this gap eight years from now, they change things and natural gas is under the regulatory spotlight and a lot of Capital going there. Price of natural gas goes up and the O&M estimated savings don't happen. There is going to be 20% of non-fuel O&M throughout the time period.

There is a question on transmission on the first 110 Mw and we understand to be approved in the next month or so. There was a question on the first one will you be able to get the juice to the BPU customers. I think a good guess is yes there will be. The second part is I'm staying with 2018 so we think that second 110 would come later and because it comes later you have to spend more money.

Minority Ownership and Management

- As minority owner, how will BPU be protected?
- BPU, 17% owner and and other public, 27.5%
- Kelson, private company, at 55.5%
  - "Majority owner of Dogwood gas plant has highly speculative grade characteristics and may expose KPP and the other municipal minority owners to increased costs should the majority owner be unable to cover its share of costs."
    Moody's Report for Kansas Public Power

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We think this is a topic worth chatting about. Minority Ownership and Management – Don has already laid out the numbers. BPU is 17% and the other three publics are 27.5% and Kelson is 55.5% owner. The other public sector people already went and signed this and already sold their bonds and they got a credit rating. The rate agencies have a lot of questioning about the Kelson people and the relationship between Kelson and the public folks. The majority owner of Dogwood, Kelson, has highly speculative grade characteristics in credit rating lingo. That means they are very poor credit quality risk and may expose the Kansas Public Power and other municipal minority owners to increase costs should the majority owner be unable to cover its share of the costs. That is taken from the Moody's Report 2012 for Kansas Public Power.

Minority Ownership and Management

- Springsted: Companion report summarizing generally available financial sources on Kelson/Dogwood
  - Short historical data: No overall conclusions
  - Paying bills on time
- Kelson looking to sell more shares and/or all of their position
  - If so, new majority private owner or new owners
- Numerous contracts negotiated by legal team

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Springsted did a companion report for privatary information as public about credit worthiness and basically it said Kelson hasn't been around that long so there is no historical trend but the people are paying their bills on time and that sort of thing. I think its common now and Kelson is now looking to sell more shares and/or all of their 55% ownership position. If another private party comes in and purchases 55%, what's that business relationship? We don't have an answer for that. What we have is there has been a whole bunch of lawyers negotiating contracts for a couple of months and I'm sure they have an answer. The BPU will have to answer the question, if this is approved and if they issue bonds, because the rating agencies are all over this.

BPU Credit Ratings

- BPU Ratings: Generally good but issues exist
  - Regulatory exposure and response investment
  - Improved Liquidity, BPU cash position
  - Customer Revenue Concentration
  - No guarantees by looking at one factor

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The BPU credit ratings are A+, A1. They are good. They have been improving. They went negative from outlook to stable outlook. The major reason they did that was they raised rates and they did not have much cash and they are building cash and they raised the rates and that has helped them move from the negative outlook to stable. One of the things is customer revenue concentration. I said there are 10 or 15 that needs to be fund 30% of all the revenues and if something happens to one of those you can have 5% of your revenues go away so this is still a credit rating negative.

BPU Credit Ratings *(cont.)*

- Regulatory situation is known by agencies
  - EPA evolving situation over last few years
  - Across the industry: coal generation raises flags
  - Substantial investment required
- Not known how BPU definitely address the issue
- Dogwood is piece of that answer
  - Movement to natural gas reduces exposure
  - Improves cost structure: Purchase power

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We were asked to look at Dogwood specifically. When they say another $75 million of debt is that going to tip this over one way or the other on the rating? The rating agencies know that the BPU is going to have to spend hundreds of millions of dollars to meet regulatory. It's already on their radar screen. There has been ongoing dialogue with the EPA in a variety of forms so that is already there. They know about coal generation across the country, they know the dollar mark, but what they didn't know is what the BPU is going to do about it. What is their plan, what's their management governance plan? This is considered to be a part of it so you have an answer and it's something that is more acceptable, the movement to natural gas is good for them. Combined Cycles, you have some steam generation that's good for them so that is a positive. If the projections are right, it improves their cost structure.

UG and BPU PILOT Payments

- Dogwood acquisition price includes an upfront payment of PILOT payment to that local jurisdiction
- Question: impact on BPU PILOT payment to UG
- PILOT: billed revenues from BPU customers
  - UG Counsel: Acquisition price payment does not affect UG PILOT

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The liquid acquisition includes an upfront payment of PILOT to the host county which is Cass County and it's in the millions so the UG had a question does this situation cause any impact on the flow of what the BPU pays to the Unified Government, the answer is no. The BPU PILOT paid to the Unified Government is based on billed revenues to your customers so it's a non factor.

Conclusions on Dogwood Acquisition

- Related business points: Transmission, BPU employee levels, BPU credit rating and UG PILOT
  - Either not an issue or reasonable answers exist
  - Or being answered – transmission
  - Credit Rating: Dogwood, alone less of an issue, maybe plus
- Minority ownership and management
  - How will BPU's best interests be reflected?
  - Any partnership: contract provisions

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The items like Transmission, BPU employee levels, BPU credit rating and UG PILOT are either less of an issue or reasonable answers exist. Transmission is being answered. Credit Rating, here again we kind of come back to Minority ownership and management and we think that's an area everybody has to get comfortable with. How will BPU's best interests be reflected and again I will pass that to the lawyers.

Conclusion on Dogwood Acquisition *(cont.)*

- Dogwood not a complete solution
  - One part of overall regulatory investment
- Business case more on positioning the BPU than straight cost criteria
  - Reasonable to assume cost savings with Dogwood
    - Estimated Present Value Savings
    - High level of assumptions and estimates in B&V study
  - Cost drivers: Purchase power and O & M
  - Less regulatory exposure

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Dogwood is not the complete solution. This Business case, the money is based more on positioning. What happens with O&M, what happens with Purchase Power? I think that is BPU staff on the O&M part and Purchase Power I think Black & Veatch.

Mayor Reardon said I'm going to ask you to go back to some slides because they are going to help me, the one with the numbers with Dogwood and without. I will kind of echo a little of Commissioner Barnes frustration in the sense that I feel like our positionary duty is to understand where you all are headed and understand what the finances are behind that and make sure that when we say yes to a bond issue that it is something beneficial to our citizens, it's a good business decision that its leading down a path. One of the things I feel like I get lost in is what is going to come next and I know that is not perfect, that is more of an art than science. You convinced me of that no doubt about it, but when I look at this slide for instance let's say Dogwood, let's say we adopt the Dogwood route, this isn't perfect, it could change but there is some estimate that for a period of time we're going to have Capital cost of $271 million or somewhere in that realm. Is there a way you could sort of chart out, I'm thinking of a line chart that says this year it's $68 million and here is where we know we're going to have to do the next NOx deal and that's going to be in two years and that's somewhere in the range of whatever million and then we know later on we're going to have to do this here and then here comes the Dogwood 2 here and then sort of see that on a timeline and kind of understand how the pieces fall together. As Mr. MacGillivray and Mr. Gray said if you can get Dogwood 2 to come earlier that gets back to saving you money. I feel like if I saw it on a timeline I would know if you had Dogwood 2 here then—I don't know what I'm talking about from a technical standpoint, but I will have to do whatever to Quindaro 2 because I got Dogwood 2 in first and I'm good to go. I would love to see that on a timeline and then I know this imperfect science too, but our citizens want to know what's happening with their rates. If there is some way, and I know it's inevitable, you have to spend the money, but if there is some way to show what is happening to rates over this time along this continual of investment then that is helpful too. Maybe you could run rate scenarios and at some point rate scenarios should be able to show the savings. I'm not really sure when or how but it would seem like it just from these numbers. If you go Dogwood and all our predictions are right, you save $240 some odd million bucks over a period of time. I would like to be able to visibly see this and kind of know where our future is together what we know is likely going to happen. At least we would kind of know where we're trying to go.

The other question I had was if the BPU could try to answer this for me because I don't understand it, maybe if you go forward a couple slides where Dave talked about the O&M part. I think I get it on the Operation & Maintenance side in the savings, but just walk me through how there is a split between how much you save for fuel and how much you save for actual operation which includes employees and whatever it might be. Walk me through how you get to that 100 or whatever 200 number when you take a look at this over time. You don't have to relay it in actual numbers because I will lose you. How do we get to that great place where we're saving $200+ million over this period of time? **Fred Freeland, Black & Veatch,** said if you look at O&M and this concept Dogwood is a cross projection. Last August BPU was given their allowances for 2012. It started January 1 this year and the allowance you were given for NOx were 1/3 of what you put out last year so how are you going to cut out 2/3 of your emission in five months so at that point Black & Veatch was brought in to say what can we do, were our options short-term or long-term so we look at that. Then you put with that with the match regulations which has just been finalized. It has a three year requirement for compliance. If the initiation date is April 16, 2012, you have three years to comply so by April 16, 2015 you have to be in compliance with the Air Toxic Standard Regulations and that is what most of this cost primarily is to meet that regulation. We've looked at all different kinds of options, what can you do to meet the requirements that aren't future, they are there now. Those are timelines now unless the courts or Congress change them. They are here, they are now so we looked over many different scenarios, what options can we do and then modeling those numbers to try to say what is the net present value of this way or that way. The Operation & Maintenance side the air pollution equipment that you are going to have to put on the back end of Nearman, environmental compliance equipment on the backend of coal units is very labor intensive. It takes energy to run it, you have pumps and you've got a lot more ancillary to electric power that you are going to consume to operate that equipment, you have material you have to put into it like a scrubber is required, you have material you have to buy to put into that system and then once it goes through the system you now have new waste that you have to get rid of. If you are putting in hard product, limestone, and you're getting hard product out in addition to the product you already have and that is going to create a situation and a lot of that is going to have to be landfilled somewhere so you have labor and maintenance on the equipment, you have the energy to operate the equipment, you have the material going in and you have to handle the material going out.

Mayor Reardon said so if I go to Dogwood then I avoid some of those costs, is that what you're saying? **Mr. Freeland** said if you go to Dogwood, for instance, right now your base load is coal. If you had 110 Mw of Dogwood, then that is gas. That doesn't have the environmental requirements on it because it is a cleaner product and you don't have the waste and so forth. Let's say you had 100 units that you were emitting in 2011 and you now have 33 you can emit this year. If you just ran your coal units, you would be out of your allowances right now. Now what are you going to do? **Mayor Reardon** said I get that. I'm not asking for it tonight but maybe before the 17th, and you have to make it simple, if you could give me an outline and say if you go Dogwood in O&M here are the things were avoiding or here is how you get—if my neighbor said okay we're buying Dogwood and now I say here is why it's good because we're not doing this or we're not doing the NOx or whatever it might be or we don't have a NOx penalty. If you could knock those out for me, that would be great.

Mayor Reardon said I guess I will get back to Dave's last point which brings out the lawyer in you if you are a lawyer, this is what I think is unique about this. There is definitely an opportunity. I want you to know that. I see that but what is unique to me about this is in my small mind for the first time this public utility that is in Wyandotte County that has pretty much generated almost all the power for our citizens within Wyandotte County is going to purchase an asset outside the county that generates power. For the first time, sort of in a major way, be generating power outside the bounds of our own community. A lot of people do it. It is different than where we have been before. The idea of how we control our interests is to me a really fascinating one so we're 17% owner and Kelson sells to some big bad ugly private investor, how do we make sure if that guy says I'm turning off my 55%, the heck with this thing I'm done, how do we make sure the plant still runs and what interest do we have in that? Then I just have simple questions like are we going to have our BPU guy down there every day making sure the people are actually doing what they ought to do so they don't break some $10 million piece of equipment where we get a call in the middle of the night and they say we need 17% of the $10 million piece of the equipment because we have to replace it. I know this is very complex but if you could talk to me a little bit about how you all feel comfortable with the idea of owning this asset in Cass County that we have adequate controls in place for our $68-$75 million ownership.

Mr. Gray said the one thing I would say the other municipals are looking at us to be one of the primary leaders being involved in this. The other thing is, from what I understand, and Bob can correct me because he has been involved in a lot of the day-to-day discussions, we could actually us as municipals we could be a majority owner if we get the other 110 and supposedly they are going to hold that 110 for us while we evaluate the Transmission study which means no one can come in and be the majority owner as long as the 110 is still open and available. They are not going to be able to sell that to anybody else so at least for the time being we will have 45% plus another potential 17% which gets up to roughly 62% ownership so roughly that is 38% that Kelson can still sell as long as they hold that 110 open for us and they said they would. That gives me a little more comfort level from that alone. The unit is an excellent performing unit, very efficient and with the business we're in right now and the challenges we're facing regulatory wise, this unit is going to operate and there are going to be other entities that are going to need it for the same reasons that we need it to help them mitigate some of the environmental costs that they are facing as well. That's why KPP is in and that's like Independence, they are looking at it too the same way as we are.

Mayor Reardon said you know your go to guys at Nearman. There is a guy at Nearman that knows Nearman like the back of his hand and you rest easy at night because you know that he knows everything that might go wrong. Do you have a role in hiring that go to guy for the Dogwood Plant that would make you sleep easy at night? **Bob Adam** said as an owner we get on the management committee. The management committee hires the company that is going to run the Dogwood facility. It is run by NAES now which is North America Electric Services and they are a national company, they run plants across the country, they do maintenance on plants across the country. They are well established and well known. They have been on Dogwood for several years now. They do the maintenance and operate the unit. The unit is also covered by service contracts. Anything that goes wrong is pretty much covered by a service contract so if they have an outage, they have service contracts in place to cover parts and the labor is there so we're protected that way. You mentioned it is a little different, and it is, we're owning something outside of Wyandotte County, but when Don talked about the pieces of renewable energy that we have, the Hydro, Smokey Hills, the landfill gas, well that is energy we're getting from outside of Wyandotte County bringing to our customers who are residents here. It's a little different. We don't own those facilities but are bringing energy in from outside on a regular basis. The fact that we own it we have a little more control over that piece. We're on the management committee so we get to vote and get 17% of the vote as far as what is going to happen with budget, operation or who is going to run the unit, who is going to be managing the units so we have that ability. **Mayor Reardon** said I agree with you and I don't take anything away from it. The reason I even asked the question, and I understand we want Dogwood 2, because you get into a bottom plant with gas and it gets away from coal. We get to Dogwood 2 and we're at 220 Mw which is almost Nearman so we're talking about the capacity of our largest—we're proud of Nearman, so we're talking about equaling the capacity of our largest facility within the county outside so that is why I raise these questions.

Commissioner Barnes said as we go through this process I hope you don't think we're in an adversary position to what you are trying to do. We're just trying to make certain that all the bases are covered and we can respond to the same client base that you guys are responding to. I will ask all the questions upfront and then you can answer afterwards. I would like to know where we are in the 50 year cycle. You said that plant Dogwood has functioned over 50 years, where are they and what year are they in right now in that 50 year cycle? Does any portion of your contract that you are talking about signing forbid them to go out and purchase new equipment and we would be responsible for 17% of it? This is not the holistic answer for all of our problems at the BPU. If this is not the silver bullet for every issue that we're having at the BPU, then how much additional dollars above and beyond the 200+ even in the best case scenario in purchasing the second 110 Mw, in addition to that what is the dollar value on what we're going to have to address to get back whole with today's standards on where we are with the BPU? All my questions are really about the ratepayer. Where do they figure in to this process and when I say figure into it other than doling out more money, what is the great benefit into it for our ratepayers. You guys are happy with your outside purchases, has that been considered an alternative to purchase all the power from outside from all these great sources you are talking about and not have to put ourselves into this billion dollar hole we're digging for ourselves. You were happy about buying power from outside so do we have the capacity to buy all our power from outside? **Mr. Adam** said you're just asking if we can buy all our energy from outside. The answer is no. There is not enough generation available and there is not enough transmission available to allow us to import that energy into our system. The generation that is out there is fully subscribed. Like Nebraska City there are several owners of that, latan 2 of Kansas City Power & Light; several people own pieces of that so there is no energy available to be brought in. If they could get it here, it would be extremely high priced. It would be marginal gas or oil units that would be running to supply us because they are going to supply their customers with their least cost units first. The major problem is the transmission system is just not geared up to allow us to bring in that much energy into our system on a firm basis where we could count on it day in and day out.

Commissioner Barnes said the ratepayer issue where do they fit into this whole process? **Mr. Alvey** said I think where ratepayers figure into this we are trying to find the most cost effective way to deal with what they call the train wreck EPA regulations. We are trying to find, as you asked for and Mayor Reardon suggested, that we need to know projecting out to the future where we are. We've actually been given that presentation, the best case scenario given the information we have now, about two months ago we had our presentation and we're still trying to digest this, we're still trying to figure it out. The deal is right now is, as Fred said, there are 80 scenarios they had to program in. That is not being exaggerated. You can use this kind of technology to pull some of it out, we can use some lower sulfur coal which cost more, we could buy some credits perhaps if they become available, and we could perhaps get some more power if we could get the transmission path. We could do this, we could do that but the problem now is where the ratepayers are, frankly the EPA is trying to punish coal out of existence. They are making a decision, they made a decision that the cost of environmental compliance does not matter. What matters is eliminating carbon emissions as soon as possible and all the emissions toxic, metals, etc. That is the goal. The goal is to not give us 20 years, not give us 25 years, not give us 50 years to remediate what we've done since the Clean Air Act of 1990, they simply want things done now and that is why they are calling it a train wreck. They are layering these things on so quickly that we are in a position of trying to guess what all this is going to do, how are we going to comply with it. If they would say look we're trying to get to this level over the next 30 years, then you could make an investment in Nearman or Quindaro and over 30 years it would be financially doable. The way the EPA is doing it, that's not a concern for them as I know you are running into it with the Combined Sewer Overflow. They don't care what it costs the community. That's not a concern.

Commissioner Barnes said I just want to say for the record this is a time bomb. We're being competitive with other neighborhoods and I'm talking about the Fairfax Drainage issues. Every time you raise your rates 1% somebody will run as a result of that and so this is a very sensitive issue when we have an industrial area as large as Fairfax that has to deal with these types of issues and when it comes up to renewals of their leases, this comes into consideration. It might be an easy decision but it's not easy when it comes to what we're doing so we want to be very conscious of that. The holistic answer is that question on the holistic approach. What happens after, even if we gave you everything you asked for, that is still not the answer to all the concerns. **Mr. Alvey** said I know we had a presentation about 1.5 months ago that we have been trying to intricate it ourselves. We just got the report and I think that kind of information would be very helpful for the commission because that not only includes all the different options of technology and things we could do, it also includes some cost estimates. **Commissioner Barnes** said I would rather hear a billion dollar request for a state-of-the-art facility that will answer all of our problems than for a piecemeal approach where you are going to get $271 million today and then you are going to be back to the table for another $287 million five years from now or three years from now or two years from now, wherever that cycle is. I would much rather take a harsh field right now that says this is what the numbers are going to take to fix all of our problems then to continue to piecemeal this process as we've done in the past.

Commissioner Barnes said the only question left was the 50 year cycle. Where are we in their 50 year cycle that you spoke about? **Mr. Freeland** said to save 10 years if I can, yes its 10 years old. In 2002 when that unit went commercial was at the time when natural gas prices peaked real high and there were a large number of natural gas units that Black & Veatch completed in 2002/2003 range that were mothballed for a year too because it was cheaper to burn coal so this is a unit that sit here. When they went commercial we hit a period where you could generate energy cheaper with coal during that timeframe plus it had, if it was built by Aquila, Aquila was small, there were issues there so it kind of went into limbo.

Commissioner Barnes said we're going to pay them cash counting a million dollars minimum in PILOT, right? **Mr. Freeland** said I hear it's in the millions. **Commissioner Barnes** said so what I'm saying is how much buying power could we get for a million dollars? **Lew Levin, Chief Financial Officer,** said 12-14 times. **Mr. MacGillivray** said if I had a million dollars how much could I bond for it in 20 years, $10 to $12 million. **Commissioner Barnes** said $10 to $12 million for every million dollars we bond for. I won't hold you to it, just somewhere in the ballpark. I just wanted to put that number on the table so as we pay PILOT in another community. **Mayor Reardon** said what I found interesting about that was is we're purchasing a major asset outside the boundaries of Wyandotte County. We're subject to their tax in Cass County.

Kathy Peters, Attorney with Kutak Rock, said it's a different kind of PILOT. It's an Industrial Revenue Bond PILOT. Cass County issued Industrial Revenue Bonds to finance that Dogwood Plant and they have like you, whenever you do GM or any other Industrial Revenue Bond they say we will take you off the tax rolls but you are going to have to make a payment in lieu of tax over the years. The other taxing jurisdictions get their share, it's a property tax. It's not a PILOT on revenues. It's a property tax PILOT with a 25 year property tax abatement and for the last several years the PILOT is like $1,320,000 per year for 2017 to 2027 which is the final year. What Cass County has said is we know we've got people that are going to buy into that are non profit for their municipalities so they are going to be off the tax rolls one way or the other. We know we've got some municipal entities coming in from Kansas like Kansas Power and BPU that want to keep that property tax abatement in place because they are municipals so we want to make sure other taxing jurisdictions get their share of the property tax and we're going to make you prepay it based on present value. It is a different kind of PILOT.

Mayor Reardon said let me say I'm not as comfortable about coming forward with a billion dollar plan or whatever it might be. I understand the advantage of what you are proposing and I also think I understand there is no one solution because you have all these regulatory things that sort of line themselves up and you are racing against some kind of clock which is why I want to see the timeline because I don't understand it, but I know you do. In an ideal world I would rather have you spend all this money in Wyandotte County and build it here and we would own it and control it. For the long haul that is the better way but I understand the reality of where you are doesn't perhaps afford us that opportunity. Clearly for all kinds of reasons would make us feel more secure I think than marching down this kind of path. I would like to see the timeline before the 17th. I do think it would be good, because we're going to be back together again, and the next time might not even be as fun as this one. It would be interesting before that to sort of get this time of investment and talk about how we keep this utility competitive for the long haul because at the end of the day that is what has to happen. We've got customers that we depend on, you depend on as a ratepayer, we depend on as an employer and a taxpayer in our citizens as well that we have to make sure that we're doing all we can in the context of this to be competitive on our rates for the long haul. That was the promise of this municipality from its conception and I think it's time due to the regulatory requirement for us to be sitting down and be more strategic about that together. I'm hoping we can have that kind of meeting after we get sort of the pieces put together in a way that we can talk in those terms.

Jody Boeding, Chief Legal Counsel, said we will adopt a resolution for the budget and financing by the Unified Government to issue bonds for the purchase of its share of Dogwood. That would come back to you in a normal course and we had said on the 17th but sense there are some commissioners missing and they have to be brought up to speed where you are. That will either involve individual meetings with them or a group meeting if we can get them together. We could have another special session. We could put off the adoption of the bond authorizing resolution beyond the 17th if we have a special session to answer the rest of your questions. After the discussion you mentioned tonight about strategic long-term—**Mayor Reardon** said my petition for that is not for the 17^{th}. I think that is a longer term kind of thing that needs to occur. I do want the information in advance but I think you have sufficient time. If you can't get to the rest of the commissioners, perhaps you will have to look at a different date. The 17^{th} is the timeframe the BPU is requesting for purposes of their potential purpose with Kelson. **Ms. Boeding** said yes, we had an extension of the letter of intent and there is a bit flippage in there but we know the UG is going to get involved in budget following the 17^{th}. **Mayor Reardon** said I think rapidly getting information out to us, commissioners can ask additional questions and maybe an issue that is raised by the other commissioners or someone here that would cause us to have to revisit timely, but we shoot for consideration one way or the other on the 17^{th} unless something comes up in the continued dialogue that causes us to reconsider. **Ms. Boeding** said keep us on the timeframe and track that we are traveling to get the deal closed and get the bonds issued.

Commissioner Markley made a motion, seconded by Commissioner Barnes, to go into executive session at 6:40 p.m. for five minutes regarding litigation. Motion carried unanimously.

MAYOR REARDON RECONVENED INTO SPECIAL SESSION AND ADJOURNED THE MEETING AT 6:45 P.M.

Bridgette Cobbins
Unified Government Clerk

dt

May 3, 2012

Appendix D (Tab D)

Ten Year Power Supply Study 2008 (Updated 12/2012)

- Ten Year Power Supply Site Selection Study (December 2012)

Appendix D (Tab D)

Ten Year Power Supply Study 2008 (Updated 12/2012)

- Ten Year Power Supply Site Selection Study (December 2012)

Kansas City Board of Public Utilities

Ten Year Power Supply Study
Site Selection Study

Black & Veatch Project: 160817
Black & Veatch File No. 41.0040

October 2008/updated December 2012
Revision F

Kansas City Board of Public Utilities

BLACK & VEATCH
Building a world of difference.

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Acronyms

APPS	Application for Package Power Solutions
AQCS	Air Quality Control Systems
BACT	Best Available Control Technology
BPU	Board of Public Utilities
CCCT	Combined Cycle Combustion Turbine
CCG	Combined Cycle Generators
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CPW	Cumulative Present Worth
CTG	Combustion Turbine Generator
EPC	Engineering, Procurement, And Construction
ERC	Energy Rate Component
ESC	Environmental Surcharge
FOM	Fixed Operation And Maintenance
GTPE	Gas Turbine Performance Estimator
HRSGs	Heat Recovery Vapor Generators
IDC	Interest During Construction
ISO	Independent System Operator
LNB	Low NO_x Burners
N1	Nearman Unit 1
NO_2	Nitrogen Dioxide
NO_X	Nitrogen
NPDES	National Pollutant Discharge Elimination System
O&M	Operation And Maintenance
OEM	Original Equipment Manufacturer
OFA	Overfire Air
PM_{10}	Particulate Matter Of 10 Microns Or Less
PPA	Power Purchase Agreement
PSD	Prevention of Significant Deterioration
PWDR	Present Worth Discount Rate
Q1	Quindaro Unit 1
Q2	Quindaro Unit 2
SCCT	Simple Cycle Combustion Turbine
SCR	Selective Catalytic Reduction

SO_2	Sulfur Dioxide
SPP	Southwest Power Pool
SWPA	Southwest Power Administration
VOC	Volatile Organic Compounds
VOM	Variable Operation And Maintenance
WAPA	Western Area Power Administration

Executive Summary

In 2008, the Kansas City Board of Public Utilities (BPU) hired Black & Veatch to support preparation of a Ten Year Power Supply Plan. The plan was developed by conducting a 10-year power supply study along with studies to support implementation of the recommendations resulting from the power supply study. The additional studies were a siting study to determine the best location for new generating units being considered in the power supply study, and a rate impact study to quantify the rate implications of implementing the power supply study recommendations. In addition, Black & Veatch was asked to prepare a list of required permits and construction schedules.

The power supply study was conducted in two phases. Discussion of the initial power supply study process and results is contained in Phase I. The updated power supply study is contained in Phase II. The permit list and schedules related to the next unit addition in the recommend plan are in Appendix F and Appendix G, respectively.

In 2012, Black & Veatch was requested to review the BPU power supply status based upon changes in generation capacities, new generation acquisitions, and changes in Nearman Unit 1 participation sales since 2008 and update this report accordingly.

Major changes since 2008 to BPU's generation resources include the following:

- Addition of 110 MW of gas fired combined cycle combustion turbine generation from the Dogwood Facility in 2013.
- Addition of 7 MW of hydro power from the Bowersock Dam in 2013.
- Addition of landfill gas generation in 2014 and 2015 (2 MW firm).
- Beginning in 2013, the Nearman Unit 1 participation sale of 20 MW to Columbia will be discontinued.
- Beginning in 2015, Quindaro Unit 1 will operate only on gas.
- Beginning in 2015, Quindaro Unit 2 will operate only on gas at a reduced capacity.
- Reduction of Nearman Unit 1 capacity in 2017 due to increased auxiliary load for new air quality control equipment.

Table 3-3 has been added to the report and provides the Forecast Balance of Loads and Resources based upon the current status of the BPU power supply resources. Table 3-3 shows that the total system capacity exceeds the Southwest Power Pool (SPP) system generation capacity requirement of maximum peak demand plus 12 percent in all of the next 10 years with the exception of 2016. The shortage in capacity in 2016 is created by the assumption that Nearman Unit 1 will not be permitted to operate after April 16, 2016 without new air quality control equipment to meet the Mercury and Air Toxics Standard (MATS). New air quality equipment is anticipated to be installed and in service by early 2017.

Phase I of Power Supply Study

The 10-year power supply study was based on the demand and energy forecast developed in 2008 by BPU and considered natural gas fueled generation resources capable of meeting the BPU's need for firm generating capacity. The need for capacity was identified as the difference between forecast peak demand plus reserve requirements and the capacities of existing power supply resources. The study recognized the expected outputs of existing BPU generators and that the economics of the Quindaro Units' continued operation is a function of potential future environmental regulations, including the Regional Haze Rule and the ozone non-attainment conditions in the Kansas City metropolitan area. The study period was the 10-year period beginning 2008 through 2017. As shown in Tables 3-1 and 3-2 of this report, Black & Veatch identified the need for between 35 and 107 MW of additional generating capacity by 2017 depending on whether or not BPU continues to operate Quindaro Unit 1 (Q1). Phase I of the study consisted of the comparison of ten alternative generation expansion plans as shown in Table 5-1. Each plan was based on the use of simple cycle combustion turbines and/or combined cycle units burning natural gas as the primary fuel.

The study objective was to find the power supply plan that minimized overall costs to BPU customers during the ten-year study period under a range of plausible future conditions. The initial set of plan comparisons assumed forecasts of expected fuel prices (Figure 6-1), power purchase and sales prices (Table 6-2), load growth (Table 3-1), sulfur dioxide (SO_2) allowance prices and carbon dioxide (CO_2) allowance prices (Figure 6-2). In addition, sensitivity analyses were conducted to compare the costs to customers under the following conditions:

- Gain of a large (28 MW) customer, at a load factor similar to the BPU system load factor.
- Loss of a large (28 MW) customer, at a load factor similar to the system load factor.
- High natural gas and electric market prices.
- A high cost for CO_2 emissions either as a result of a cap & trade program or the application of a carbon tax.
- No purchases of economy energy from the market reflecting an extreme case of transmission congestion.

One finding of Phase I of the study was that it is consistently less costly to continue to operate Q1 through 2017 rather than to retire it and replace it with a similar amount of combustion turbine based capacity. Q1 was assumed to be retrofit with a selective catalytic reduction (SCR) system for nitrogen oxide (NO_x) control in order to continue operating through the study period. The expansion plans that convert new or existing simple cycle combustion turbines to combined cycle combustion turbines are consistently the most expensive plans because the production cost savings associated with the efficiency of a combined cycle plant are not sufficient to offset a combined cycle's incremental capital cost. In the least cost plan, BPU meets additional load growth with the addition of a 43 MW LM6000 type aero-derivative combustion turbine in 2011. The second least-cost plan also assumed Q1 remains in service and that two smaller (21 MW) LM2500 type combustion turbines are added for growth, one in 2011 and one in 2015. In the third least cost plan, a 75 MW Frame 7EA combustion turbine is added in 2011.

These analyses also indicated that under all sensitivity case assumptions of future conditions, the least-cost 10-year expansion plan is the plan that retains Quindaro Unit 1 and adds an LM6000 or similar simple cycle combustion turbine in 2011. However, the costs of plans that substitute two smaller simple cycle combustion turbines or a larger frame type combustion turbine like the GE 7EA are close enough in NPV cost to warrant BPU's solicitation of both aeroderivative and frame type combustion turbine machines as well as machines of similar size and performance from other manufactures. The continued operation of Q1 with an SCR was estimated to be economical under a variety of sensitivity/risk scenarios.

Phase II of Power Supply Study

The results of the Phase I analysis were used as a starting point for Phase II in which the modeling input assumptions were refined and fuel and market price forecasts were updated. The Phase II analysis considered the top five plans, on a cumulative net present value basis, from the Phase I analysis. The plans considered in Phase II are listed in Table 16-2. Results of the Phase II analysis were consistent with those of Phase I. Because the NPV costs of the three least-cost plans calling for the addition of an LM6000 turbine, two LM2500 turbines or a 7EA turbine were so close, BPU selected the 7EA plan as the basis of the rate impact analysis in order to accommodate what is likely to be the most capital intensive of the least-cost plans and to allow BPU to maintain needed flexibility in procuring a turbine(s).

Rate Impact Forecast

The rate impact study took the forecast of electric sales, operation and maintenance costs, and fuel and purchased power costs from the Phase II results for the selected plan and added debt service on existing capital facilities and forecast debt service on new generation plant additions as well as transmission, distribution, and administrative costs to produce a forecast of total revenue requirements. Included in the financial forecast were the latest forecasts of capital requirements for the existing generators as well as the expected capital and operating costs to meet potential environmental regulations for BPU's existing generators.

The power supply plan that adds a Frame 7EA combustion turbine in 2011 is close in NPV cost to the best plan when Q1 is not retired in 2011 and is the least cost plan on a NPV basis when Q1 is retired in 2011. Therefore, regardless of whether or not Q1 is retired early, a common low cost plan is to install a Frame 7EA in 2011. Accordingly, the financial forecast was developed using the projected costs of that plan and the assumption that Q1 will not be retired until after 2017. The results of the financial forecast indicated a total revenue deficiency under existing base rates of approximately $115 million for the period 2009 through 2013. To offset the annual revenue deficiencies, a series of consecutive annual base rate increases and an environmental surcharge (ESC) to recover the capital portion of potential environmental upgrades are recommended.

A series of three annual six and one quarter percent base rate increases beginning in 2010 is recommended. These recommended increases were determined with the assumption that proposed changes in the Energy Rate Component (ERC) calculation to recover additional energy supply costs is implemented beginning January 1, 2009. In addition, a new environmental surcharge (ESC) designed to recover all debt service payments for environmental capital improvements is also implemented beginning January 1, 2009. The ESC would be adjusted annually to recover the upcoming year's debt service payment on the environmental bonds resulting from the potential emissions control retrofits on the Quindaro and Nearman coal fueled units. The projected ESC is 0.15 ¢/kWh in 2009, 0.40 ¢/kWh in 2010, 0.56 ¢/kWh in 2011, 0.83 ¢/kWh in 2012, and 0.67 ¢/kWh in 2013.

Siting Study

A site selection study was conducted concurrently with Phase I of the power supply study. It considered both combustion turbine based simple cycle and combined cycle units using natural gas as the primary fuel and located at either existing generating stations or substations. Site comparison criteria were developed based on infrastructure and utility requirements for each technology and candidate sites were rated on their ability to meet that criteria. Initially, twenty-nine sites were considered which were screened to ten sites based on the following criteria:

- Sites which do not have current or planned access to 161 kV transmission were eliminated.
- Sites which were farther than one mile from an existing natural gas pipeline were eliminated.

Five additional sites were eliminated because space or neighborhood proximity limitations clearly could not support a new generation facility. The Nearman plant site was ultimately selected as the most suitable site for a new combustion turbine based generator addition based on socioeconomic, land use, air quality, site development, location of personnel and security scoring criteria. The evaluation scores of candidate sites used to select the Nearman site are shown in Tables 16-3 and 16-4.

Permit List

Black & Veatch developed a list of construction and operating permits likely to be required for the construction of the simple cycle combustion turbine addition recommended in the selected plan and included the permit list in Appendix F of this report. The list contains federal, state, and local permits.

Project Schedule

A schedule for the engineering, permitting, construction start-up and testing of the recommended combustion turbine addition was developed and is included in Appendix G to this report. The total project duration is thirty-three months. The air permitting process is estimated to require approximately 18 months beginning with meteorological monitoring activities and ending with receipt of the air permit. Site preparation would be scheduled to begin about twenty-one months into the schedule with construction activity being completed nine months later allowing three months for start-up, testing, and tuning before final acceptance.

1.0 Report Introduction

In 2008, the Kansas City Board of Public Utilities (BPU) hired Black & Veatch to support preparation of a Ten Year Power Supply Plan. The plan was developed by conducting a 10-year power supply study along with studies to support implementation of the recommendations resulting from the power supply study. The additional studies were a siting study to determine the best location for new generating units being considered in the power supply study, and a rate impact study to quantify the rate implications of implementing the power supply study recommendations. In addition, Black & Veatch was asked to prepare a list of required permits and construction schedules.

The power supply study was conducted in two phases. Discussion of the initial power supply study process and results is contained in Phase I. The updated power supply study is contained in Phase II. The permit list and schedules related to the next unit addition in the recommend plan are in Appendix F and Appendix G, respectively. The purpose of the study was to determine the most economical installation of units to provide the future power requirements of BPU customers.

The 10-year power supply study was based on the demand and energy forecast prepared in 2008 and considered alternative natural gas fueled generation resources capable of meeting the BPU's need for firm generating capacity. The power supply study was conducted in two phases with Phase I consisting of the comparison of 10 alternative generation expansion plans using simple cycle combustion turbines and/or combined cycle units to meet growth. The study period is the 10-year period beginning 2008 through 2017.

Phase II of the power supply study used results from Phase I with updated and refined modeling input assumptions. Fuel and purchase power price forecasts were updated for Phase II. Phase II analysis also included estimates for capital expenditures to maintain the safe, efficient, and reliable operation of BPU's existing units. Based on the results of Phase II of the power supply study, a BPU financial forecast for the years 2008 through 2013 was developed using the selected power supply plan. The financial forecast compared forecasts of electric utility revenue under existing rates to revenue requirements of the BPU for the period 2008 through 2013. The forecasts reflect the BPU's proposed capital program including potential environmental upgrades to the Nearman and Quindaro generating units and the addition of a new combustion turbine at Nearman (CT5). Recommend overall rate increases to offset the annual deficiencies under the current rates are detailed in the Financial Forecast of this report.

A site selection study was conducted concurrently with Phase I of the power supply study, it considered both combustion turbine based simple cycle and combined cycle units using natural gas as the primary fuel and located at either existing generating stations or substations. Site comparison criteria were developed based on infrastructure and utility requirements for each technology and candidate sites were rated on their ability to meet that criteria. Initially, twenty-nine sites were considered which were screened to ten sites based on the following criteria:

- Sites which do not have current or planned access to 161 kV transmission were eliminated.
- Sites which were farther than one mile from an existing natural gas pipeline were eliminated.

Five additional sites were eliminated because space or neighborhood proximity limitations clearly could not support a new generation facility. The Nearman plant site was ultimately selected as the most suitable site for a new combustion turbine based generator addition based on socioeconomic, land use, air quality, site development, location of personnel and security scoring criteria. The evaluation scores of candidate sites used to select the Nearman site are shown in Tables 16-3 and 16-4.

Documentation of the Phase I study work begins with an introduction to the Power Supply Study. Following the introduction to the power supply study analysis, the forecast need for power is detailed in Section 3.0, followed by descriptions of future power supply options considered in Section 4.0. Sections describing the alternative capacity expansion plans and a comparison of the NPV costs of the alternative plans are in Sections 5.0 and 6.0. Observations and conclusions resulting from the Phase I analysis are provided in Section 7.0.

The refined and updated Phase II of the Power Supply Study is described beginning in Section 8.0 followed by descriptions of Phase II expansion plans carried forward from Phase I in Section 9.0 and updates to the performance, emissions, and EPC capital cost estimates of the power supply options in Section 10.0. The comparison of the NPV costs of the alternative Phase II plans is contained in Section 11.0.

The rate impact analysis used the results from Phase II of the Power Supply Study and added additional costs to produce a forecast of total revenue requirements. Discussion of the rate impact study is in Section 13.0 of this report. This report concludes with details of the site selection study beginning in Section 14.0.

2.0 Phase I of Power Supply Study

This report describes the development of a 10-year power supply plan for the Kansas City BPU based on the demand and energy forecast prepared in 2008 and considering alternative natural gas fueled generation resources capable of meeting the BPU's need for firm generating capacity. The power supply plan was developed in two phases with Phase I of this study consisting of the comparison of 10 alternative generation expansion plans using simple cycle combustion turbines and/or combined cycle units. The Regional Haze Rule and the ozone non-attainment conditions in the Kansas City metropolitan area and their potential impacts on existing BPU generators are considered in this study. The study period is the 10-year period beginning 2008 through 2017.

This Power Supply Plan addresses the future power supply needs of the BPU's native load customers, plus the wholesale power sales commitments under existing contracts through the term of this study. The Power Supply Plan also considers the age and ability of the existing BPU generators to continue providing the level of economic and reliable service they have provided over the past 35 or more years. Phase I of the Power Supply Study includes the following elements:

- Forecast Need for Power--A comparison of BPU's 2008 electric load forecast to the forecast of the capabilities and costs of existing BPU generators and power purchases to produce a forecast of the timing and size of additional generating capacity needs.
- Characterization of New Power Supply Resources--Description of the new combustion turbine-based power supply resources available to the BPU including simple and combined cycle combustion turbines.
- Alternative Capacity Expansion Plans--The identification of alternative plans to meet the 2008-2017 generating capacity and energy needs.
- Financial Comparison of Alternative Power Supply Plans--The comparison of these plans on a comparative revenue requirement basis.
- An economic evaluation of issues that could affect normally expected (Base Case) forecasts of load growth and costs for fuel and air emissions (sensitivities).
- Conclusions and recommendations for a selected power supply plan.

Phase II of this study consists of refined modeling and the development of a BPU financial forecast based on the selected power supply plan and a cost-of-service study to forecast the impact on rates to retail customers by customer class. Included in the financial forecast were the latest forecast of capital requirements for the existing generators as well as the expected costs of new environmental regulations to the extent they require capital and operating cost additions to BPU's existing generators.

3.0 Forecast Need for Power

The forecast need for additional generation capacity for the BPU system is a function of projected load growth, the future capacity of BPU's existing generation fleet, firm sales of capacity and energy, and firm purchases of capacity and energy currently under contract. Using the latest available population forecast from the Mid America Regional Council and other non-residential development as a basis, the forecast of Net System Energy requirements for the BPU system is projected to increase at an average rate of 0.78 percent per year over the next 10 years from 2,559 GWh in 2008 to 2,745 GWh in 2017. The forecast of normal weather peak demand is also projected to increase at an average rate of 0.72 percent per year from 512 MW forecast for 2008 to 546 MW by 2017. BPU's projected capacity requirements increase from 582 MW in 2008 to 620 MW in 2017, with a 12 percent capacity margin requirement.

The future capacity of existing generators is an issue for this study primarily because after the existing 12 MW CT1, the existing Q1 is the next unit in line for eventual retirement. Q1 is facing increased maintenance costs and may be required to add new air emission control technology to meet future regulatory mandates. The early retirement of Quindaro Unit 1 is a subject of this study and one group of plans evaluate its retirement in 2011 instead of adding new emission control technology. In another group of plans, Quindaro Unit 1 operates throughout the 10-year study period with air quality control equipment added. One of BPU's existing combustion turbine units, CT1, is currently projected to retire during the planning period in 2015.

Continued difficulties obtaining firm transmission service for BPU's existing power purchase arrangement with the Southwest Power Administration (SWPA) have led to the assumption that this 38 MW resource will not be available to BPU on a firm basis until 2010. The 4 MW Western Area Power Administration (WAPA) power purchase, has firm transmission service, and is considered available throughout the study period. In addition, 2 MW of firm capacity is included in association with BPU's purchase of 25 MW of wind generation capacity from the Smoky Hills Wind Farm. The ongoing Nearman 1 Participation Sales agreements with the Columbia, Missouri Electric Department and with the Kansas Municipal Energy Agency are included in the 10-year forecast of BPU's need for power. A 50 MW summer capacity purchase from The Empire District Electric Company in 2008 has also been included in the forecast need for power.

Table 3-1 tabulates the resultant forecast balance of loads and resources for the BPU system for the scenario where Quindaro Unit 1 is retired early in 2011. Table 3-2 tabulates the resultant balance of loads and resources assuming the continued operation of Q1 through 2017. The resulting need for additional generating capacity based on the capacity requirements and capacity of existing supply resources can be seen in Figures 3-1 and 3-2. From the forecast shown in Table 3-1, we can see that if Quindaro Unit 1 is retired early in 2011, the system will have a capacity deficit of 73 MW in 2011 increasing up to 107 MW in 2017. In Table 3-2 if Quindaro Unit 1 continues to operate through 2017 as currently planned, the system will have a capacity deficit of 11 MW in 2011 increasing up to 35 MW by 2017.

Figures 3-1 and 3-2 illustrate the 2008 forecast loads and resources for the scenarios where Quindaro Unit 1 is retired early in 2011 and where Quindaro Unit 1 continues to operate through the planning period, respectively.

Table 3-3 provides the 2012 Forecast Balance of Loads and Resources based upon the current status of the BPU power supply resources.

Table 3-1
Forecast Balance of Loads and Resources - BPU System
Quindaro Unit 1 Retired Early in 2011

Description	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
System Peak Demand	512	515	519	526	528	532	537	542	544	546
System Capacity Responsibility[(a)]	582	585	590	598	600	605	610	616	618	620
Accredited Generating Capacity (Net of Station Service)										
Quindaro #1, Coal	72	72	72							
Quindaro #2, Gas	16	16	16	16	16	16	16	16	16	16
Quindaro #2, Coal	95	95	95	95	95	95	95	95	95	95
Nearman #1	235	235	235	235	235	235	235	235	235	235
Combustion Turbine #1, Gas	12	12	12	12	12	12	12			
Combustion Turbine #2, Oil	56	56	56	56	56	56	56	56	56	56
Combustion Turbine #3, Oil	51	51	51	51	51	51	51	51	51	51
Combustion Turbine #4 Gas & Oil	75	75	75	75	75	75	75	75	75	75
Total Installed Generation	**612**	**612**	**612**	**540**	**540**	**540**	**540**	**528**	**528**	**528**
Purchases										
SWPA Hydro	0	0	38	38	38	38	38	38	38	38
WAPA Hydro	4	4	4	4	4	4	4	4	4	4
Smoky Hills Phase 1	2	2	2	2	2	2	2	2	2	2
Summer Capacity Empire Purchase from Iatan	50									
Future Summer Capacity Purchases										
Total Existing Capacity Purchases	**56**	**6**	**44**	**44**	**44**	**44**	**44**	**44**	**44**	**44**
Nearman #1 Participation Sales										
Columbia	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20
KMEA	-38	-38	-38	-38	-38	-38	-38	-38	-38	-38
Total Capacity Sales	**-58**	**-58**	**-58**	**-58**	**-58**	**-58**	**-58**	**-58**	**-58**	**-58**
Total System Capacity[(b)]	**609**	**559**	**597**	**525**	**525**	**525**	**525**	**513**	**513**	**513**
Capacity Balance[(c)]	**97**	**44**	**78**	**-1**	**-3**	**-7**	**-12**	**-29**	**-31**	**-33**
Percent Capacity Balance (%)[(d)]	**16%**	**8%**	**13%**	**0%**	**-1%**	**-1%**	**-2%**	**-6%**	**-6%**	**-6%**
Capacity Surplus/(Deficit)[(e)]	**27**	**-26**	**7**	**-73**	**-75**	**-80**	**-85**	**-103**	**-105**	**-107**

Capacity Margin: 12%.

[(a)]System Capacity Responsibility = System Peak Demand/1-% Capacity Margin/100)).
[(b)]Total System Capacity = Total Generation + Total Capacity Purchases - Total Capacity Sales.
[(c)]Capacity Balance = Total System Capacity - System Peak Demand.
[(d)]Percent Capacity Balance = Capacity Balance/Total System Capacity) x 100.
[(e)]Capacity Surplus Deficit) = Total System Capacity - System Capacity Responsibility.

Table 3-2
Forecast Balance of Loads and Resources - BPU System
Quindaro Unit 1 Continues Operating Throughout Study Period

Description	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
System Peak Demand	512	515	519	526	528	532	537	542	544	546
System Capacity Responsibility (a)	582	585	590	598	600	605	610	616	618	620
Accredited Generating Capacity (Net of Station Service)										
Quindaro #1, Coal	72	72	72	72	72	72	72	72	72	72
Quindaro #2, Gas	16	16	16	16	16	16	16	16	16	16
Quindaro #2, Coal	95	95	95	95	95	95	95	95	95	95
Nearman #1	235	235	235	235	235	235	235	235	235	235
Combustion Turbine #1, Gas	12	12	12	12	12	12	12			
Combustion Turbine #2, Oil	56	56	56	56	56	56	56	56	56	56
Combustion Turbine #3, Oil	51	51	51	51	51	51	51	51	51	51
Combustion Turbine #4 Gas & Oil	75	75	75	75	75	75	75	75	75	75
Total Installed Generation	**612**	**612**	**612**	**612**	**612**	**612**	**612**	**600**	**600**	**600**
Purchases										
SWPA Hydro	0	0	38	38	38	38	38	38	38	38
WAPA Hydro	4	4	4	4	4	4	4	4	4	4
Smoky Hills Phase 1	2	2	2	2	2	2	2	2	2	2
Summer Capacity Empire Purchase from Iatan	50									
Future Summer Capacity Purchases										
Total Capacity Purchases	**56**	**6**	**44**	**44**	**44**	**44**	**44**	**44**	**44**	**44**
Nearman #1 Participation Sales										
Columbia	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20
KMEA	-38	-38	-38	-38	-38	-38	-38	-38	-38	-38
Total Capacity Sales	**-58**	**-58**	**-58**	**-58**	**-58**	**-58**	**-58**	**-58**	**-58**	**-58**
Total System Capacity (b)	**609**	**559**	**597**	**597**	**597**	**597**	**597**	**585**	**585**	**585**
Capacity Balance (c)	**97**	**44**	**78**	**71**	**69**	**65**	**60**	**43**	**41**	**39**
Percent Capacity Balance (%) (d)	**16%**	**8%**	**13%**	**12%**	**12%**	**11%**	**10%**	**7%**	**7%**	**7%**
Capacity Surplus/(Deficit) (e)	**27**	**-26**	**7**	**-1**	**-3**	**-8**	**-13**	**-31**	**-33**	**-35**

Capacity Margin: 12%.

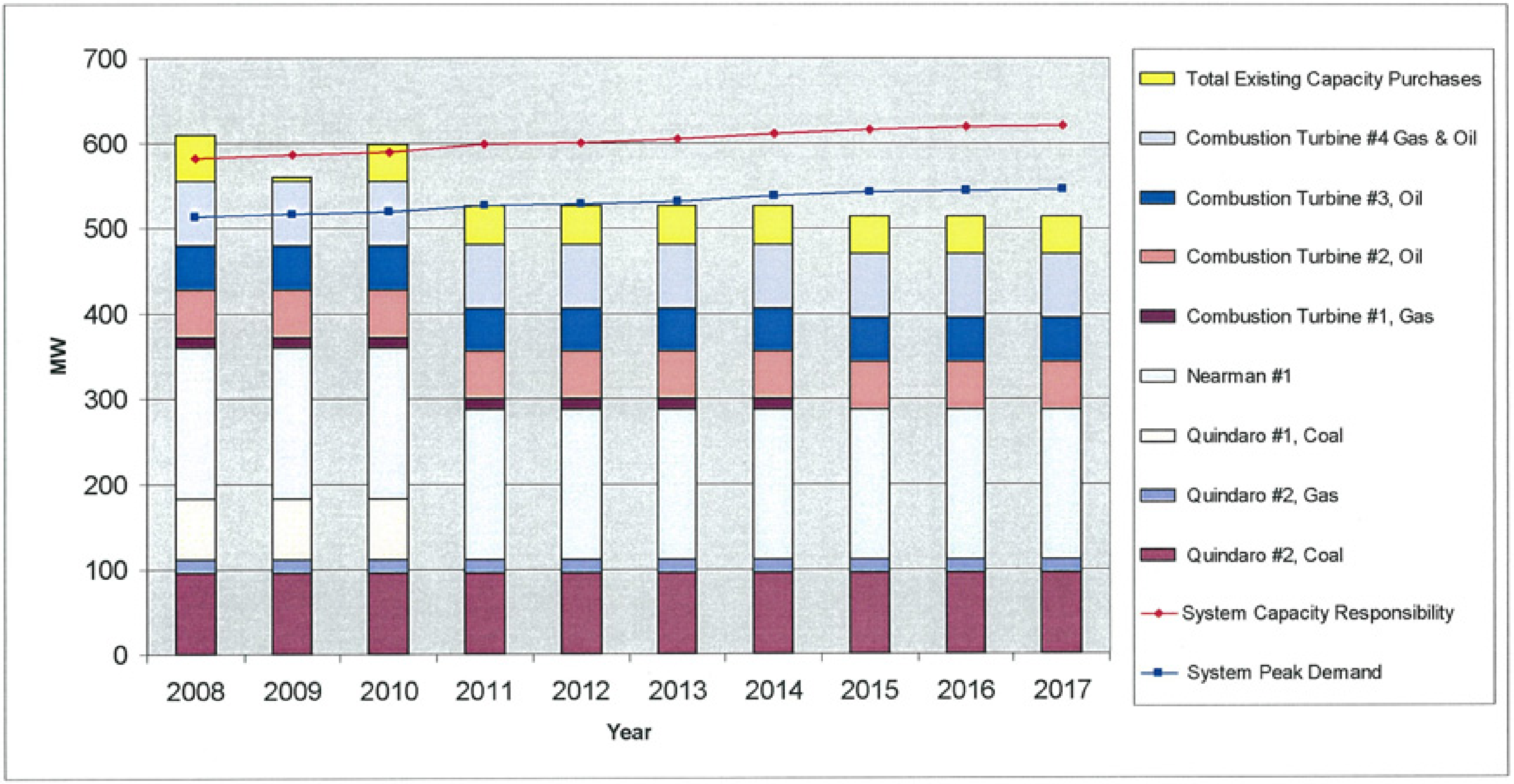
Notes:
(a) System Capacity Responsibility = System Peak Demand/1-% Capacity Margin/100)).
(b) Total System Capacity = Total Generation + Total Capacity Purchases - Total Capacity Sales.
(c) Capacity Balance = Total System Capacity - System Peak Demand.
(d) Percent Capacity Balance = Capacity Balance/Total System Capacity) X 100.
(e) Capacity Surplus Deficit) = Total System Capacity - System Capacity Responsibility.

Table 3-3
Forecast Balance of Loads and Resources -BPU System
2012 Update Based On Changes Since 2008

Description	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
System Peak Demand[a]	500	503	505	508	510	513	515	518	520	523	526
SWPP Capacity Responsibility[b][c]	568	571	574	577	580	583	585	588	591	594	597
Accredited Generating Capacity (Net of Station Service)											
Quindaro #1, Coal	72.5	72.5	72.5								
Quindaro #1, Gas				72	72	72	72	72	72	72	72
Quindaro #2, Coal	110.8	110.8	110.8								
Quindaro #2, Gas				82	82	82	82	82	82	82	82
Nearman #1, Coal	234.8	234.8	234.8	234.8		227	227	227	227	227	227
Combustion Turbine #1, Gas	12.4	12.4	12.4								
Combustion Turbine #2, Oil	56.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1
Combustion Turbine #3, Oil	50.3	50.3	50.3	50.3	50.3	50.3	50.3	50.3	50.3	50.3	50.3
Combustion Turbine #4, Gas & Oil	73.8	73.8	73.8	73.8	73.8	73.8	73.8	73.8	73.8	73.8	73.8
Dogwood 1st Block		110	110	110	110	110	110	110	110	110	110
Dogwood 2nd Block											
New Self Build Combined Cycle											
Total Installed Generation	**610.7**	**720.7**	**720.7**	**679**	**444.2**	**671.2**	**671.2**	**671.2**	**671.2**	**671.2**	**671.2**
Purchases											
SWPA Hydro	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6
WAPA Hydro	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Smokey Hills Phase 1[d]	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Landfill Gas	1.5	1.5	2	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Bowersock Dam Hydro		7	7	7	7	7	7	7	7	7	7
Total Existing Capacity Purchases	**47.4**	**54.4**	**54.9**	**56.4**	**56.4**	**56.4**	**56.4**	**56.4**	**56.4**	**56.4**	**56.4**
Nearman #1 Participation Sales											
Columbia[e]	-20										
KMEA	-38	-38	-38	-38	-38	-38	-38	-38	-38	-38	-38
Total Capacity Sales	**-58**	**-38**	**-38**	**-38**	**-38**	**-38**	**-38**	**-38**	**-38**	**-38**	**-38**
Total System Capacity[f]	**600.1**	**737.1**	**737.6**	**697.4**	**462.6**	**689.6**	**689.6**	**689.6**	**689.6**	**689.6**	**689.6**
Capacity Balance = Total System Capacity - Peak Demand	**100.1**	**234.1**	**232.6**	**189.4**	**-47.4**	**176.6**	**174.6**	**171.6**	**169.6**	**166.6**	**163.6**
Percent Capacity Balance (%)	**17%**	**32%**	**32%**	**27%**	**-10%**	**26%**	**25%**	**25%**	**25%**	**24%**	**24%**
Extra = System Capacity - SWPP Capacity Responsibility	**32.1**	**166.1**	**163.6**	**120.4**	**-117.4**	**106.6**	**104.6**	**101.6**	**98.6**	**95.6**	**92.6**

[a]System peak demand escalated at 0.5 percent.
[b]SWPP Capacity Responsibility = System Peak Demand/(1-(% SWPP Capacity Margin/100)).
[c]SWPP Capacity Margin: 12% of years peak demand.
[d]Smokey Hills Phase 1 – SWPP acknowledges ~10% of total capacity (25 MW).
[e]Columbia sales stop in June 2013.
[f]Total System Capacity = Total Generation + Total Capacity Purchases – Total Capacity Sales.

Notes:
1. In 2015, Q1 and Q2 must run ONLY on GAS due to MATS.
2. In 2016, N1 is assumed to Not Run until AQC project is complete in early 2017.
3. In 2017, N1 is back on line w/ added AQC aux load & assuming no STG upgrade.



Resource Capacities:

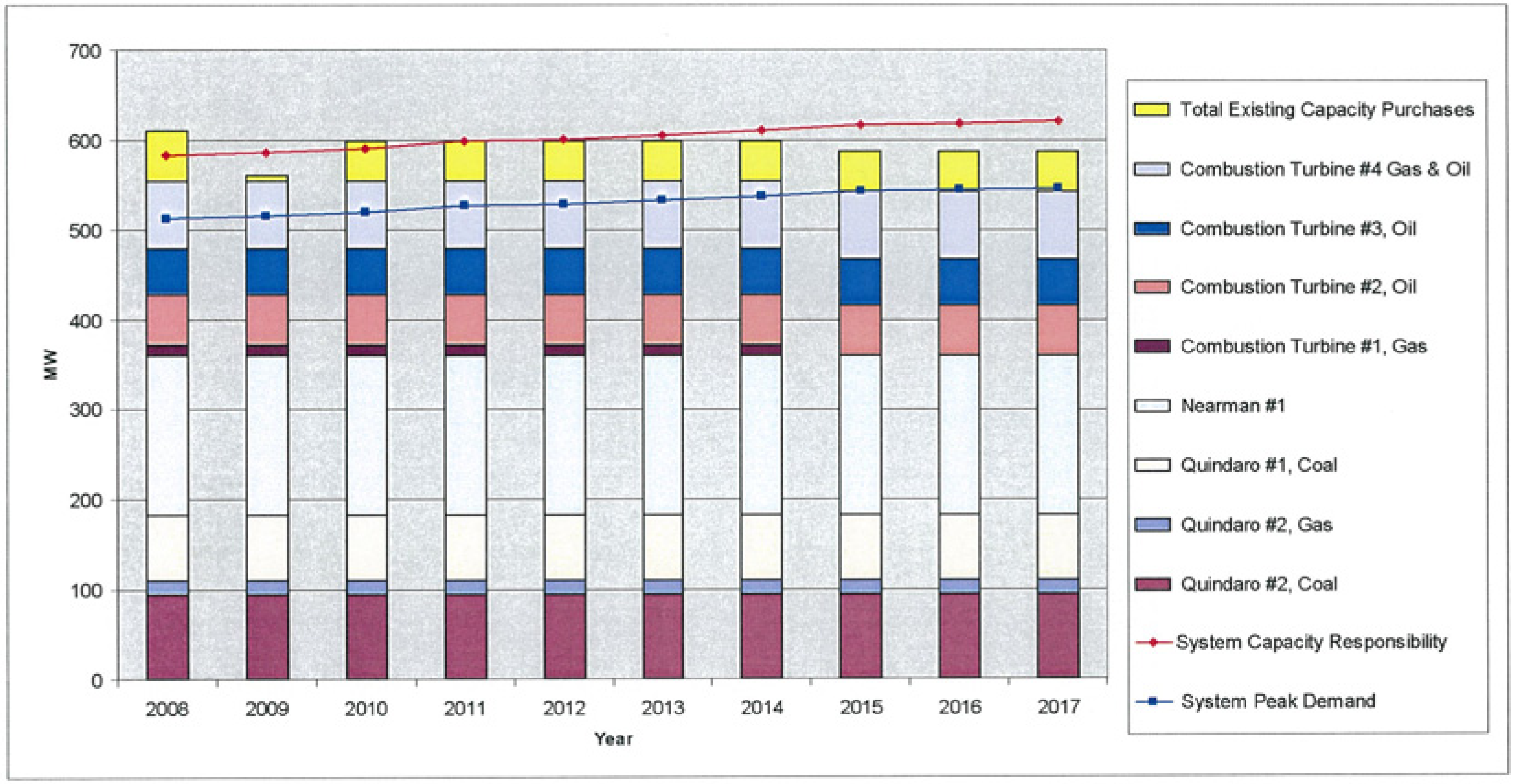
CT 4 - 75 MW
CT 3 - 51 MW
CT 2 - 56 MW
CT 1 - 12 MW

Nearman Unit 1 (BPU share) - 177 MW
Quindaro Unit 2 - 111 MW (16 MW gas, 95 MW coal)
Quindaro Unit 1 - 72 MW

Existing Capacity Purchases:

Summer 2008 Empire Capacity Purchase – 50 MW
SWPA – 38 MW (beginning in 2010)
WAPA – 4 MW
Smoky Hills Wind – 2 MW

Figure 3-1
Forecast Balance of Loads and Resources - Quindaro Unit 1 Retired in 2011



Resource Capacities:

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Quindaro Unit 2 - 111 MW 16 MW gas, 95 MW coal)
Quindaro Unit 1 - 72 MW

Existing Capacity Purchases:

Summer 2008 Empire Capacity Purchase – 50 MW
SWPA – 38 MW (beginning in 2010)
WAPA – 4 MW
Smoky Hills Wind – 2 MW

Figure 3-2
Forecast Balance of Loads and Resources - Quindaro Unit 1 Retiring after 2017

4.0 Future Power Supply Options

Alternative power supply options considered in this study for meeting BPU's need for capacity and energy consist of both simple and combined cycle combustion turbine generator additions. The following simple and combined cycle resource options were considered in this study:

- LM6000PC-Sprint Simple Cycle Combustion Turbine (SCCT).
- 2x1 LM6000PC-Sprint Combined Cycle Combustion Turbine (CCCT).
- 7EA SCCT.
- 1x1 7EA CCCT.
- LM2500 SCCT.

Detailed descriptions of the operating characteristics, capital costs, and operating costs for each of these options are contained below.

The characteristics include estimates of performance (output and heat rates), emissions, and capital and operation and maintenance (O&M) costs. New estimates of performance, emissions, capital costs and O&M maintenance costs were developed to account for changes in LM6000PC-Sprint CTG technology since the original estimates were developed in 2006. This section is organized into the following subsections:

- Section 4.1 - Performance and Emission Estimates.
- Section 4.2 - EPC Capital Cost Estimates.
- Section 4.3 - Operations and Maintenance Cost Estimates.

4.1 Performance and Emissions Estimates

This section contains performance and emission estimates for the combustion turbine technology options listed previously. Assumptions used to develop the performance and emission estimates are provided.

4.1.1 Estimating Assumptions

Performance and emission estimates for both the SCCT and CCCT options were developed using the indicated assumptions. Temperatures used for performance estimates are based on average daily temperatures during anticipated operation. The following seasons and temperatures were used:

SCCT:

- Spring/Fall: February, March, October, and November - 53° F.
- Summer: May 1 to September 30 - 90° F.
- Winter: Need for SCCTs during Winter season is negligible.

- CCCT:
  - Summer: May 1 to September 30 - 83° F.
  - Spring/Fall/Winter: October 1 to April 30 - 50° F.

The following unit arrangement criteria were used during the development of the performance and emission estimates.

- SCCT:
  - Evaporative inlet cooling.
  - Primary fuel is natural gas, back-up fuel is No. 2 fuel oil.
  - No Selective Catalytic Reduction (SCR) nor CO catalyst.
- CCCT:
  - Evaporative inlet cooling.
  - Duct firing capacity is sized to restore the summer day steam turbine generator output to the winter day output without duct firing. The steam turbine generator and steam cycle equipment are sized for the winter day steaming capacity of the heat recovery steam generator without duct firing in operation.
  - Wet mechanical draft cooling tower for Rankine Cycle heat rejection.
  - Primary fuel is natural gas, back-up fuel is No. 2 fuel oil.
  - Includes SCR but no CO catalyst.

4.1.2 Performance Estimates

Full and partial load performance estimates were generated for two seasonal ambient conditions for both the SCCT and CCCT unit. Performance estimates are provided in Tables 4-1 and 4-2 for the SCCT and CCCT technology options, respectively. Operating conditions for each of the cases are defined in a case summary at the top of each of the tables.

4.1.3 Emission Estimates

Full load emission estimates were generated for one seasonal ambient condition for both the SCCT and CCCT technology options. Emission estimates include oxides of nitrogen (NO_X) as nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), carbon dioxide (CO_2), volatile organic compounds (VOC), and particulate matter of 10 microns or less (PM_{10}). Emission estimates are provided on a unitized basis. Emission estimates are provided in Table 4-3 and 4-4 for the SCCT and CCCT technology options, respectively.

Table 4-1
SCCT Performance Estimates

Case Summary	Spring/Fall			Summer		
Elevation, ft amsl	750	750	750	750	750	750
Dry Bulb Temperature, ° F	53	53	53	90	90	90
Relative Humidity, percent	60	60	60	60	60	60
Evaporative Cooling, On/Off	Off	Off	Off	On	On	On
Load, percent	100	75	50	100	75	50
LM6000PC-Sprint						
Gross CTG Output, kW	49,030	36,780	24,520	43,830	32,880	21,930
Auxiliary Load, kW	500	430	370	440	390	330
Net Plant Output, kW	48,530	36,350	24,150	43,390	32,490	21,600
Net Plant Heat Rate (LHV), Btu/kWh	8,608	9,103	10,297	8,716	9,346	10,683
Net Plant Heat Rate (HHV), Btu/kWh	9,563	10,113	11,440	9,683	10,383	11,868
LM2500PE						
Gross CTG Output, kW	23,080	17,320	11,550	21,390	16,060	10,710
Auxiliary Load, kW	240	180	120	220	170	110
Net Plant Output, kW	22,840	17,140	11,430	21,170	15,890	10,600
Net Plant Heat Rate (LHV), Btu/kWh	9,943	10207	11,431	9,993	10,492	11,738
Net Plant Heat Rate (HHV), Btu/kWh	11,047	11340	12701	11,103	11657	13043
GE 7EA						
Gross CTG Output, kW	83,500	62,600	41,600	75,700	56,800	37,800
Auxiliary Load, kW	1,000	900	600	900	1,800	600
Net Plant Output, kW	82,500	61,700	41,000	74,800	55,000	37,200
Net Plant Heat Rate (LHV), Btu/kWh	10,587	11,471	13,982	10,860	11,917	14,521
Net Plant Heat Rate (HHV), Btu/kWh	11,746	12,727	15,513	12,050	13,222	16,112

Notes:
1. Performance data is based on GE turbine estimating software Application for Package Power Solutions (APPS).
2. Estimates are reflective of new and clean conditions and do not included the effects of degradation.
3. Fuel is assumed to be nearly 100 percent methane with a sulfur content of 0.2 grain per 100 SCF.
4. Performance estimates in this table do not include SCR or CO catalyst.
5. The evaporative cooler is assumed to operate with 85% effectiveness when in operation.
6. The average ambient temperature in the spring/fall, 53° F, and the accredited temperature in summer, 90° F, are based on International Station Meteorological Climate Summary, Ver 3.0 March 1995.
7. All data is expected, and not guaranteed, and does not include allowances for margins.

Table 4-2
CCCT Performance Estimates

Case Summary	Spring/Fall/Winter			Summer		
Elevation, ft amsl	750	750	750	750	750	750
Dry Bulb Temperature, ° F	50	50	50	83	83	83
Relative Humidity, percent	60	60	60	60	60	60
Evaporative Cooling, On/Off	Off	Off	Off	On	Off	Off
Duct Firing, On/Off	Off	Off	Off	On	Off	Off
Load, percent	100	75	50	100	75	50
2x1 LM6000PC-Sprint						
Gross CTG Output, kW	98,580	73,950	49,310	89,740	64,770	43,200
Gross STG Output, kW	28,760	22,210	17,720	28,760	21,230	17,460
Gross Plant Output, kW	127,350	96,160	67,040	118,510	86,010	60,660
Auxiliary Load, kW	2,840	2,580	2,350	2,770	2,500	2,300
Net Plant Output, kW	124,520	93,580	64,690	115,750	83,510	58,370
Net Plant Heat Rate (LHV), Btu/kWh	6,753	7,118	7,735	6,871	7,239	7,899
Net Plant Heat Rate (HHV), Btu/kWh	7,503	7,908	8,594	7,634	8,043	8,776
1x1 GE 7EA						
Gross CTG Output, kW	83,460	62,600	41,730	76,580	55,420	36,950
Gross STG Output, kW	44,960	39,560	35,790	44,950	39,190	34,270
Gross Plant Output, kW	128,420	102,160	77,520	121,530	94,610	71,220
Auxiliary Load, kW	3,140	2,810	2,420	3,050	2,710	2,430
Net Plant Output, kW	125,280	99,350	75,100	118,480	91,900	68,790
Net Plant Heat Rate (LHV), Btu/kWh	7,005	7,268	7,734	7,238	7,495	8,079
Net Plant Heat Rate (HHV), Btu/kWh	7,752	8,043	8,558	8,010	8,294	8,940

Notes:
1. Performance and emission data were based on Thermoflow and Application for Package Power Solutions (APPS).
2. Estimates are reflective of new and clean conditions and do not include the effects of degradation.
3. Fuel is assumed to be nearly 100 percent methane with a sulfur content of 0.2 grain per 100 SCF.
4. It is assumed that there would be an SCR but no CO catalyst.
5. The average day time high temperature in the winter, 50° F, and in the summer, 83° F, are based on International Station Meteorological Climate Summary, Ver 3.0 March 1995.
6. The evaporative cooler is assumed to operate with 85% effectiveness when in operation.
7. Duct firing capacity is sized to restore the summer day steam turbine generator output to the winter day output.
8. A wet mechanical draft cooling tower is assumed for Rankine Cycle heat rejection.
9. All data is expected, and not guaranteed, and does not include allowances for margins.

Table 4-3
SCCT Emission Estimates

	NO_x, as NO_2		SO_2	CO		CO_2	VOC		PM_{10}
	ppm	lb/MBtu	lb/MBtu	ppm	lb/MBtu	lb/MBtu	ppm	lb/MBtu	lb/MBtu
LM6000 PC-Sprint	25	0.1	0.0005	18	0.04	128	0.4	0.0006	0.026
LM2500 PE	25	0.1012	0.0006	48	0.1178	128	2.2	0.0031	Unavailable
7EA	9	0.04	0.0005	25.3	0.06	128	1.5	0.002	0.01

Notes:
1. Emission estimates are based on 100 percent load operation at an elevation of 750 ft amsl, a dry bulb temperature of 53° F, a relative humidity of 60 percent, and no evaporative cooling.
2. The dry air composition assumed for emission estimates is 0.98% Ar, 78.03% N_2 and 20.99% O_2.
3. Fuel is assumed to be nearly 100 percent methane with a sulfur content of 0.2 grain per 100 SCF.
4. Emissions data is reflective of a unit without post combustion emissions controls.
5. ppm is pounds per million dry volume at 15 percent O_2.
6. Emissions in lb/MBtu are based on a LHV of fuel input.
7. PM_{10} emissions shown are total emissions (including filterable and condensable particulates).
8. The above estimates are on the assumption that NO_x is controlled through water injection.
9. The VOC/UHC ratio is assumed to be 20% (typical for GE turbines).
10. The SO_2 emission values provided consider that all fuel sulfur was converted to SO_2 with no additional oxidation.
11. CO_2 emissions are based on estimated B&V calculations and are typically not provided by the gas turbine manufacturer.
12. All data is expected, not guaranteed, and does not include allowances for margins.

Table 4-4
CCCT Emission Estimates

	NO_x, as NO_2		SO_2	CO		CO_2	VOC		PM_{10}
	ppm	lb/MBtu	lb/MBtu	ppm	lb/MBtu	lb/MBtu	ppm	lb/MBtu	lb/MBtu
2x1 LM6000 PC-Sprint	2.0	0.01	0.0006	30	0.07	128	0.6	0.0009	0.027
1x1 7EA	2.0	0.01	0.0006	25.5	0.06	128	1.5	0.002	0.010

Notes:

1. Emission estimates are based on 100 percent load operation at an elevation of 750 ft amsl, a dry bulb temperature of 50° F, a relative humidity of 60 percent, no evaporative cooling, and no duct firing.
2. The dry air composition assumed for emission estimates is 0.98% Ar, 78.03% N_2 and 20.99% O_2.
3. Fuel is assumed to be nearly 100 percent methane with a sulfur content of 0.2 grain per 100 SCF.
4. Emissions data is reflective of a unit with an SCR.
5. SCR reduces NO_x to an emission level of 2.0 ppmvd at 15% O_2.
6. ppm is pounds per million dry volume at 15 percent O_2.
7. Emissions in lb/MBtu based on LHV of fuel input.
8. The VOC/UHC ratio is assumed to be 20% (typical for GE turbines).
9. The SO_2 emission values provided consider that all fuel sulfur was converted to SO_2 with no additional oxidation.
10. PM_{10} emissions shown are total emissions (including filterable and condensable particulates).
11. PM_{10} emissions listed in this table are for turbine performance only and does not include particulate matter coming off the cooling tower. PM_{10} emissions from the cooling tower are estimated to represent no more than 33% of turbine emissions. However, since there is no cost associated with particulate matter emissions, this increment does not affect the results of the economic evaluation presented in this report..
12. CO_2 emissions are based on estimated B&V calculations and are typically not provided by the gas turbine manufacturer.
13. All data is expected, not guaranteed, and does not include allowances for margins.

4.2 EPC Capital Cost Estimates

This section provides capital cost estimates for the Combustion Turbine Generator (CTG) technology options outlined previously. Assumptions used to develop the cost estimates are provided below.

4.2.1 Estimating Assumptions

Capital cost estimates for both the SCCT and CCCT units were developed using the same assumptions used in the initial Kansas City BPU Future Generation Planning Technology Study completed in June of 2006.

Capital cost estimates for both the SCCT and CCCT units were developed based on a turnkey engineering, procurement, and construction (EPC) method of contracting, which is exclusive of Owner's costs. Typically, the scope of work for an EPC capital cost estimate is the base plant, which is defined as being "within the fence." Subsection 4.2.3 provides an overview of potential Owners' cost, which are not included in the EPC capital cost estimates.

Assumptions specific to the development of the EPC capital cost estimates are as follows:

- **SCCT General Assumptions**--The following general assumptions were used for the SCCT estimate:
  - The site will be a brownfield site and will be reasonably level and clear with no wetlands. The unit will be an add-on unit to the existing brownfield site. Demolition of any existing structures should be included in Owner's costs.
  - The site has sufficient area available to accommodate construction activities including, but not limited to, offices, lay-down, and staging.
  - Each plant estimate will feature one dual fueled CTG. The primary fuel will be natural gas and the backup fuel will be No 2 fuel oil. The cost of unloading and delivery to the project site is included. The facility site is assumed to be capable of being expanded for duplicate units.
  - The CTG includes a standard sound enclosure.
  - Spread footings were assumed for all equipment foundations. Stabilization of the existing subgrade is not anticipated.
  - Any buildings are pre-engineered.

- The source of water for inlet air fogging system will be city water. If existing water treatment system is not adequate, demineralized water will be provided using an onsite contracted demineralizer trailer(s). A demineralization system is not included.
- A sanitary sewer system is not included. It was assumed that a sanitary treatment system exists, or a sanitary sewer is located at the project boundary.
- Construction power is available at the site boundary.
- Natural gas supply was assumed to be supplied from a pipeline connection at the plant site boundary at the appropriate conditions that meet the CTG vendor requirements. Provision of a natural gas pipeline, compression station, etc., if required, will be included in the Owner's cost (not included here).
- Fuel oil will be delivered by truck to the storage tank. It was assumed that the existing fuel oil unloading, storage, and forwarding system is sufficient for the added unit. It was assumed that the fuel oil storage facility is capable of 48 hours of full-load operation of the combustion turbine.
- Substation and power transmission lines should be included in the Owner's costs.
- A field-erected demineralized water storage tank is included.
- Fire protection will consist of the CTG vendor's standard fire suppression system. Fire protection for major transformers will be a water deluge system.
- Protection or relocation of existing fish and wildlife habitat, wetlands, threatened and endangered species, or historical, cultural, and archaeological artifacts is not included.

* **CCCT General Assumptions**--The following general assumptions were used for the CCCT estimate:
  - The site will be a brownfield site and will be reasonably level and clear with no wetlands. The unit will be an add-on unit to the existing brownfield site. Demolition of any existing structures should be included in Owner's costs.
  - The site has sufficient area available to accommodate construction activities including, but not limited to, offices, lay-down area, and staging.

- The plant will feature dual fueled CTG(s), heat recovery vapor generators (HRSGs) with duct burners, and one condensing STG. The primary fuel will be natural gas and the back-up fuel will be No. 2 fuel oil.
- The CTG(s) will include a standard enclosure. A gantry or bridge crane for servicing the CTG(s) is not included.
- The HRSG(s) will include duct (or supplementary) firing for restoring steam turbine generator output at hot day ambient conditions.
- Bypass dampers and stacks are not included.
- SCR equipment to control NO_x emissions is included.
- Pilings are included under major equipment. Spread footings were assumed for all other foundations. Further stabilization of the existing subgrade is not included.
- The source of water for cooling tower makeup, steam cycle makeup, and inlet air fogging system (if applicable) will be city water.
- It was assumed that the existing water treatment system (clarification and demineralization) will be sufficient.
- A sanitary sewer system is not included. It was assumed that a sanitary treatment system exists, or a sanitary sewer is located at the project boundary.
- Construction power and water is assumed to be available at the site boundary.
- Natural gas supply was assumed to be supplied from a pipeline connection at the plant site boundary at the appropriate conditions that meet the CTG vendor requirements. Provision of a natural gas pipeline, compression station, etc., if required, will be included in the Owner's cost (not included here). No. 2 fuel oil will be delivered by truck to a fuel oil storage tank sized for 3 full-load days' operation of the unit.
- An allowance for a substation is included in the cost estimate. Transmission lines are not included in the base plant cost estimate. This cost will be included in the Owner's cost, if required.

- Automatic fire protection will consist of the CTG Original Equipment Manufacturer (OEM) supplied standard CO_2 fire suppression system, water deluge of the transformers, dry pipe fire protection of the cooling tower, under turbine sprinkler system, sprinkler systems in the buildings except in the control room which will have fire detection equipment only and hydrant protection for site.
- A wet, mechanical draft cooling tower will provide cycle heat rejection.
- Field-erected tanks will consist of a demineralized water storage tank.
- A wastewater collection system is included.
- An emergency diesel generator for safe shutdown is included.
- An auxiliary boiler is not included.
- Protection or relocation of existing fish and wildlife habitat, wetlands, threatened and endangered species, or historical, cultural, and archaeological artifacts is not included.

- **Direct Cost Assumptions**--The following direct cost assumptions were used for both the SCCT and CCCT unit:
  - Total direct capital costs are expressed in first quarter 2008 dollars.
  - Escalation is not included. Estimates are "overnight"* cost estimates to allow for the evaluation of alternative commercial operation dates for the project. Escalation can be included to adjust this assumption based on a schedule provided by the Owner for commercial operation of the unit.
  - Direct costs include the costs associated with the purchase of equipment, erection, and contractors' services.
  - The labor composite wage rate was based on an estimate of current wage rates for a northeastern Kansas site. The average composite wage rate includes burden, which includes fringe benefits, payroll taxes, and social security.

*The overnight cost is frequently used when estimating the cost to build a power plant. It is the cost of construction if no interest was incurred during construction, as if the project was completed "overnight" and it assumes that all the equipment is purchased today at today's cost, and all the construction is completed overnight. In reality, costs are spread out over the entire construction period and the costs when equipment is procured may have escalated since the "overnight" estimate was made. Therefore, allowances for interest, escalation, and other owner's costs are added to the overnight cost estimates to obtain an estimate of total installed cost.

- Construction costs were based on a turnkey EPC philosophy. Construction is assumed to be performed based on a 50 hour workweek. Construction indirect and construction equipment costs are included in the construction and service contracts portion of the estimate.
- Spare parts for startup are included. Spare parts for use during operation should be included in the Owner's costs.
- Permitting and licensing should be included in the Owner's costs.

- **Indirect Cost Assumptions**--The following items of cost are included in the base cost estimate for both the SCCT and CCCT units:
  - General indirect costs including all necessary services required for checkouts, testing services, and commissioning.
  - Insurance including builder's risk and general liability.
  - Engineering and related services costs.
  - Field construction management services including field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control.
  - Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct cost construction contracts, safety and medical services, guards and other security services, insurance premiums, performance bond, and liability insurance for equipment and tools.
  - Contractors' contingency and profit.
  - Transportation costs for delivery to the jobsite.
  - Startup/commissioning spare parts.
  - Contingency for direct and indirect costs.

4.2.2 EPC Capital Cost Estimates

Overnight EPC capital cost estimates are provided in Tables 4-5 and 4-6 for the SCCT and CCCT technology options, respectively. These estimates are based on Black & Veatch's recent experiences and observations of the energy industry. The estimates are screening level, overnight estimates and were developed using the assumptions outlined in the previous sections. The estimates are provided in first quarter 2008 dollars.

Table 4-5
SCCT EPC Capital Cost Estimate

	LM6000PC-Sprint	LM2500PE	7EA
Direct Costs, $1,000			
Purchase Contracts			
Civil/Structural	750	500	850
Mechanical	21,150	14,010	24,300
Electrical	3,600	2,390	5,340
Control	80	50	70
Chemical	20	10	260
Subtotal Purchase Contracts	25,600	16,960	30,820
Construction Contracts			
Civil/Structural Construction	1,250	830	1,830
Mechanical/Chemical Construction	2,350	1,560	1,580
Electrical/Control Construction	700	460	875
Service Contracts/Construction Indirects	2,100	1,390	3,310
Subtotal Construction Contracts	6,400	4,240	7,595
Total Direct Costs	32,000	21,200	38,415
Indirect Costs, $1,000			
Engineering Costs	2,500	1,660	1,955
Construction Management	1,250	820	915
Other Indirects (includes project contingency)	6,520	4,320	7,565
Total Indirect Costs	10,270	6,800	10,435
Net Plant Output, kW	43,390	21,390	74,800
EPC Capital Cost, $1,000	42,270	28,000	48,850
Unit EPC Capital Cost, $/kW	974	1,390	653

Notes:
1. Estimates are screening level overnight estimates in first quarter 2008 dollars.
2. Net plant output and Unit EPC Capital Cost based on performance estimates at the accredited summer temperature, 90° F.

Table 4-6
CCCT EPC Capital Cost Estimate

	2x1 LM6000PC-Sprint	1x1 7EA
Direct Costs, $1,000		
Purchase Contracts		
Civil/Structural	2,800	6,200
Mechanical	67,490	49,600
Electrical	8,400	6,720
Control	1,020	1,310
Chemical	740	1,070
Subtotal Purchase Contracts	80,450	64,900
Construction Contracts		
Civil/Structural Construction	7,800	9,235
Mechanical/Chemical Construction	8,100	11,435
Electrical/Control Construction	4,700	5,320
Service Contracts/Construction Indirects	5,800	5,895
Subtotal Construction Contracts	26,400	31,885
Total Direct Costs	106,850	96,785
Indirect Costs, $1,000		
Engineering Costs	15,200	14,660
Construction Management	4,970	4,325
Other Indirects (includes project contingency)	22,700	20,730
Total Indirect Costs	42,870	39,715
Net Plant Output, MW	115,750	118,480
EPC Capital Cost, $1,000	149,720	136,500
Unit EPC Capital Cost, $/kW	1,293	1,152

Notes:
1. Estimates are screening level overnight estimates in first quarter 2008 dollars
2. Net plant output and Unit EPC Capital Cost for the 2x1 LM6000PC-Sprint and the 1x1 7EA based on performance estimates at the average day time high temperature in the summer, 83° F.

4.2.3 Potential Owner's Cost

The sum of the EPC capital cost and the Owner's cost equals the total project cost or the total capital requirement for the project. A generic list of Owner's costs that may apply is provided in Table 4-7. These costs are not usually included in the EPC capital cost estimate and should be considered by the project developer to determine the total capital requirement for the project. Owner's cost items include costs for "outside the fence" physical assets, project development, financing costs and at times unique inside the fence costs. The order of magnitude of these costs is project-specific and can vary significantly, depending upon technology and project-unique requirements. For a screening-level analysis, the Owner's cost, exclusive of interest during construction (IDC), can be estimated as a percentage of the EPC cost, which is a total of direct and indirect costs. Typically, based on actual project financial data, Owner's costs exclusive of IDC have been found to be in the range of 10 to 20 percent of the EPC capital cost for SCCT projects and 15 to 30 percent for CCCT projects.

4.3 Operation and Maintenance Cost Estimates

This section provides non-fuel O&M cost estimates consisting of fixed operation and maintenance (FOM) costs and variable operation and maintenance (VOM) costs for the CTG technology options outlined previously. Assumptions used to develop the cost estimates are provided below. The estimates of O&M cost are provided in Subsection 4.3.2.

4.3.1 Estimating Assumptions

O&M cost estimates for both the SCCT and CCCT unit were updated using the same methodology used in the initial Kansas City BPU Future Generation Planning Technology Study completed in June of 2006. All assumptions used in the development of the estimates, as provided in Subsection 3.1.1, are applicable to the O&M cost estimates.

All assumptions used in the development of the performance estimates are applicable to the O&M cost estimates. Additional assumptions specific to the development of the FOM and VOM were made.

Fixed O&M costs for both the SCCT and CCCT units were estimated based on the units being "add-on units" at an existing brownfield power generation station. Fixed O&M costs consist primarily of labor costs. Labor costs were calculated based on an assumed plant operator base salary of $65,000/year plus 40 percent in benefits and

Table 4-7
Potential Owner's Costs
Generic

Project Development:
- Site assessment study
- Land purchase/options/rezoning
- Major land modifications and preparation.
- Transmission/gas pipeline rights-of-way
- Off-site road modifications/upgrades
- Demolition (if applicable)
- Air quality & other environmental permitting/offsets
- Public relations/community development
- Legal assistance

Utility Interconnections:
- Natural gas service (if applicable)
- Gas system upgrades (if applicable)
- Gas compression (if applicable)
- Electrical transmission (if required)
- Supply water (if required)
- Wastewater/sewer (if required)

Spare Parts and Plant Equipment:
- Air quality control systems (AQCS) materials, supplies, and parts
- Combustion turbine and steam turbine materials, supplies, and parts
- HRSG materials, supplies, and parts
- Balance-of-plant equipment materials, supplies, and parts
- Rolling stock
- Plant furnishings and supplies
- Operating spares

Owner's Project Management:
- Preparation of bid documents and selection of contractors and suppliers
- Provision of project management
- Performance of engineering due diligence
- Provision of personnel for site construction management

Plant Startup/Construction Support:
- Owner's site mobilization
- O&M staff training
- Supply of trained operators to support equipment testing and commissioning
- Initial test fluids and lubricants
- Initial inventory of chemicals/reagents
- Consumables
- Cost of fuel not recovered in power sales
- Auxiliary power purchase
- Construction all-risk insurance
- Acceptance testing

Taxes/Advisory Fees/Legal:
- Taxes
- Market and environmental consultants
- Owner's legal expenses:
  - Power Purchase Agreement (PPA)
  - Interconnect agreements
  - Contracts--procurement and construction
  - Property transfer

Owner's Contingency:
- Owner's uncertainty and costs pending final negotiation:
- Unidentified project scope increases
- Unidentified project requirements
- Costs pending final agreement (e.g., interconnection contract costs)

Financing:
- Development of financing sufficient to meet project obligations or obtaining alternate sources of funding
- Financial advisor, lender's legal, market analyst, and engineer
- Interest during construction
- Loan administration and commitment fees
- Debt service reserve fund

Miscellaneous
- All costs for above-mentioned contractor-excluded items, if applicable

overhead. According to the particular needs of each generator, other plant personnel were included at relative base salary. Additionally, five percent (5%) overtime was applied to all non-salary positions. It is assumed that staffing plans between the existing unit and add-on unit(s) would overlap.

Variable nonfuel O&M costs primarily consist of the combustion turbine outage maintenance cost, which is driven by the number of operating hours for aeroderivative units and number of starts for frame units. CTG outage maintenance costs include both repair and replacement of components and were based on GE maintenance recommendations and listed prices. The possibility of firing distillate fuel was not factored into the outage maintenance costs. The O&M cost estimates for CCCT configurations include costs associated with an SCR, but do not include costs for a CO catalyst.

Additional assumptions relative to both the FOM and VOM costs are provided in Table 4-8.

Table 4-8
General O&M Cost Estimating Assumptions

Annual Capacity Factor, percentage	
SCCT	10
CCCT	50
Annual Number of Starts, starts/year	
SCCT	120
CCCT	52
Unit Assumptions	
Annual Plant Operator Base Salary Burden Rate (40%), \$/year	65,000
SCR Catalyst Cost, \$/ft^3	283
Water Cost, \$/kGal	1.01
Anhydrous Ammonia Cost*, \$/ton	600

*In SCR as applied for all CCCTs.

4.3.2 O&M Cost Estimates

O&M cost estimates are provided in Tables 4-9 and 4-10 for the SCCT and CCCT technology options, respectively.

Table 4-9
SCCT O&M Cost Estimates

	LM6000PC-Sprint	LM2500PE	7EA
Fixed Costs, $1,000/Yr			
Staffing, count	5	5	5
Labor	490.4	490.4	490.4
Maintenance	54.6	38.5	71.5
Other Expenses	69.5	59.1	77.2
Total Fixed Costs	614.5	587.9	639.1
Variable Costs, $1,000/Yr			
Outage Maintenance	109.3	90.3	223
Utilities	12.4	8.5	3.6
Chemical Usage	0	3.7	0
Total Variable Costs	121.7	102.5	227
Net Plant Output, kW	43,390	21,110	74.782
Annual Generation, MWh	38,000	18,492	65,509
Unit Fixed Cost, $/kW	14.16	27.85	8.55
Unit Variable Costs, $/MWh	3.2	5.54	3.46

Notes:
1. Net plant output based on the accredited temperature in the summer, 90° F.
2. Unit costs based on the net plant output at the accredited temperature in the summer and an assumed annual capacity factor of 10 percent.

Table 4-10
CCCT O&M Cost Estimate

	2x1 LM6000PC-Sprint	1x1 7EA
Fixed Costs, $1,000/Yr		
Staffing, count	17	12
Labor	1,609	1179.4
Maintenance	215	203.8
Other Expenses	223	171.6
Total Fixed Costs	2,047	1554.6
Variable Costs, $1,000/Yr		
Outage Maintenance	1,275	523.4
Utilities	188	240.8
Chemical Usage	259	341.9
Total Variable Costs	1,722	1106
Net Plant Output, MW	115,750	118,480
Annual Generation, MWh	507,000	518,942
Unit Fixed Cost, $/kW	17.68	13.12
Unit Variable Costs, $/MWh	3.40	2.13

Notes:
1. Net plant output based on thermal performance estimates at the average day time high temperature in the summer, 83° F.
2. Unit costs based on the net plant output at the average day time high temperature in the summer and an assumed annual capacity factor of 50 percent.

5.0 Alternative Capacity Expansion Plans

Based on the need for additional generating capacity and the net plant output estimates of the candidate generators, Black & Veatch and BPU personnel identified ten generation expansion plans for comparison on a 10-year forecast basis. New CTG and combined cycle generators (CCG) were available for selection from 2011 onwards. These plans were developed to meet BPU's customer requirements using self generation due to the transmission constraints in the SPP. The plans were hypothesized for purposes of considering the impact of the potential early retirement of Q1 in lieu of major capital expenditures for air quality control equipment should air quality regulations require these expenditures for continued operation of Q1 in 2011 and beyond.

Table 5-1 lists the expansion plans compared for this study.

Table 5-1
Generating Capacity Expansion Plans

SCENARIO 0: Q1 retires in 2011				SCENARIO 1: Q1 not retired during planning period			
Plan	**Net Generation**	**Unit Additions**	**Year**	**Plan**	**Net Generation**	**Unit Additions**	**Year**
Q0-A	**118 MW**	7EA CT	2011	**Q1-A**	**75 MW**	7EA CT	2011
		Convert to CC (1x1)	2012				
Q0-B	**130 MW**	LM6000 CT	2011	**Q1-B**	**43 MW**	LM6000 CT	2011
		Convert CT4 to CC (1x1)	2011				
		LM6000 CT	2015				
Q0-C	**116 MW**	(2) LM6000 CT	2011	**Q1-C**	**43 MW**	LM2500 CT	2011
		Convert to CC (2x1)	2013			LM2500 CT	2015
Q0-D	**118 MW**	7EA CT	2011	**Q1-D**	**44 MW**	Convert CT4 to CC (1x1)	2011
		LM6000 CT	2013				
Q0-E	**130 MW**	(2) LM6000 CT	2011				
		LM6000 CT	2013				
Q0-F	**118 MW**	LM6000 CT	2011				
		7EA CT	2012				

Notes:
1. Unless otherwise noted, assumed retirement of existing units are as follows: CT1 - Year 2015
2. CT4 is an existing 7EA SCCT

6.0 Financial Comparison of Alternative Plans

The initial criterion for the comparison of the alternative capacity expansion plans is the Net Present Value of Comparative Revenue Requirements. This comparative evaluation does not consider all costs common to all plans.

Comparative revenue requirements are defined to include the amortized capital costs associated with all new generation additions and new pollution control equipment for the existing coal units, system-wide energy production costs and wholesale economy energy purchases. They are net of proceeds from wholesale economy energy sales and are also net of the proceeds from the sale of Nearman #1 participation power under the existing wholesale contracts. System-wide production costs consist of fuel, fixed and variable O&M costs including unit startup costs, and air emission costs for all new and existing generators. Debt service associated with existing plants is not included because these costs are expected to be the same for all plans. Similarly, transmission, distribution, and customer service costs are not included because these costs are also assumed to be the same for all expansion plans. For purposes of amortizing the capital costs of alternative generators, the following finance periods and capital charge rates were assumed:

- Combined cycle, financed over 25 years--9.36 percent.
- Combustion turbine, financed over 20 years--10.52 percent.

Table 6-1 shows the forecast of comparative revenue requirements over the ten-year study period for plan Q1-B. A complete set of tables for all plans are included in Appendix B. Variable O&M, fixed O&M, economy purchases, emission allowances, and amortized capital costs are summed and credited with proceeds from economy energy sales and participation sales contracts to produce comparative revenue requirements for the 10-year period 2008 through 2017. Cumulative comparative revenue requirements are shown in the far right column and levelized annual values for each cost or credit column are shown at the bottom of Table 6-1. Levelized values are Present Worth Discount Rate (PWDR) weighted averages over the 10 forecast years. For purposes of the initial expansion plan comparison, BPU's capacity and energy needs prior to 2011 were assumed to be met by short-term (possibly yearly) purchases priced in accordance with the forecast of spot market prices.

The lower right corner of Table 5-1 contains the resultant cumulative present worth (CPW) of comparative revenue requirements for BPU's lowest cost plan over the 2008 - 2017 planning period.

Table 6-1
Comparative Annual Revenue Requirements – LM6000 Addition in 2011, Quindaro 1 Retires After 2017

Q1-B: Add LM6000 in 2011, Q1 Retires after 2017

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
LM6000 SCCT	42,270	10	01/01/2011	51,909	5,461

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q1 SCR	33,877	25	01/01/2012	38,894	6,437
Q2 LNB and OFA	10,701	2	01/01/2010	11,990	1,984
N1 LNB and OFA	20,586	2	01/01/2010	23,065	3,817
N1 Spray Dry Scrubber & Fabric Filter	110,189	25	01/01/2014	118,032	19,534

Unit	Retirement Year	Unit	Retirement Year
CT#1	2015		

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	O&M Variable[2] ($1,000)	O&M Fixed ($1,000)	*Emission Costs*[4] *($1,000)*	Economy Sales ($1000)	Economy Purchase[3] ($1000)	Nearman Participant Sales ($1,000)	Bridge Power Purchase ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost* *($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,127	$3,375	$33,590	$5,338	-$6,147	$10,780	-$14,943	$0	$95,121	$0	$0	$0	$95,121	$95,121
2009	2,570	$62,234	$3,490	$33,713	$5,150	-$5,453	$14,100	-$13,915	$0	$99,318	$0	$0	$0	$99,318	$189,486
2010	2,594	$65,518	$3,701	$34,756	$5,307	-$5,029	$12,100	-$15,122	$0	$101,232	$0	$5,802	$5,802	$107,033	$286,107
2011	2,635	$78,411	$3,781	$36,548	$5,504	-$6,079	$7,279	-$15,771	$0	$109,674	$5,461	$5,802	$11,262	$120,936	$389,834
2012	2,644	$81,739	$4,565	$38,557	$13,608	-$6,483	$10,280	-$14,707	$0	$127,558	$5,461	$12,238	$17,699	$145,258	$508,206
2013	2,669	$83,390	$4,873	$40,087	$14,507	-$6,221	$13,743	-$14,818	$0	$135,561	$5,461	$12,238	$17,699	$153,261	$626,871
2014	2,697	$90,054	$7,362	$43,662	$14,123	-$7,236	$8,653	-$16,415	$0	$140,203	$5,461	$31,773	$37,234	$177,437	$757,401
2015	2,721	$95,059	$7,611	$44,334	$15,628	-$8,033	$8,878	-$16,717	$0	$146,761	$5,461	$31,773	$37,234	$183,994	$886,003
2016	2,733	$96,684	$7,691	$45,169	$17,202	-$7,651	$10,835	-$17,072	$0	$152,858	$5,461	$31,773	$37,234	$190,091	$1,012,240
2017	2,744	$99,404	$7,823	$45,931	$19,006	-$8,460	$12,145	-$17,326	$0	$158,522	$5,461	$31,773	$37,234	$195,756	$1,135,754
Levelized Cost($1000):		$79,639	$5,174	$38,968	$10,809	-$6,543	$10,934	-$15,547	$0	$123,434	$3,521	$14,496	$18,016	$141,450	
NPV:		$639,447	$41,548	$312,886	$86,792	-$52,538	$87,790	-$124,829	$0	$991,096	$28,268	$116,390	$144,658	$1,135,754	
Levelized Cost($/MWh):		$24.07	$1.56	$11.78	$3.27	-$1.98	$3.31	-$4.70	$0.00	$37.31	$1.06	$4.38	$5.45	$42.76	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008).
(2) VOM column includes unit start-up cost including start-up fuel costs and includes additional variable costs associated with AQC retrofits.
(3) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(4) Emissions cost is composed of SO2 allowance and Carbon tax costs. Carbon tax begins in 2012.

6.1 Forecast Fuel Prices

The forecasts of natural gas and coal prices delivered to BPU generators were developed from the Spring 2008 Electricity and Fuel Price Outlook long-term forecast, overlaid with the April 2008 short-term forecast from Ventyx for North Southwest Power Pool (SPP). The short-term forecast goes out two years (April, 2008 through March, 2010). The same Ventyx forecasts of fuel prices was used to drive the Ventyx forecast of North SPP power market prices and the forecast of emission allowance prices used in the BPU expansion plan comparisons in order to maximize consistency. BPU's estimates for expected local distribution costs for natural gas and local rail service for coal based on future contract adjustments were added to the Ventyx forecast to provide total delivered prices to each of the BPU generators. Figure 6-1 shows a comparison of fuel costs for natural gas and coal for the BPU generating plants.

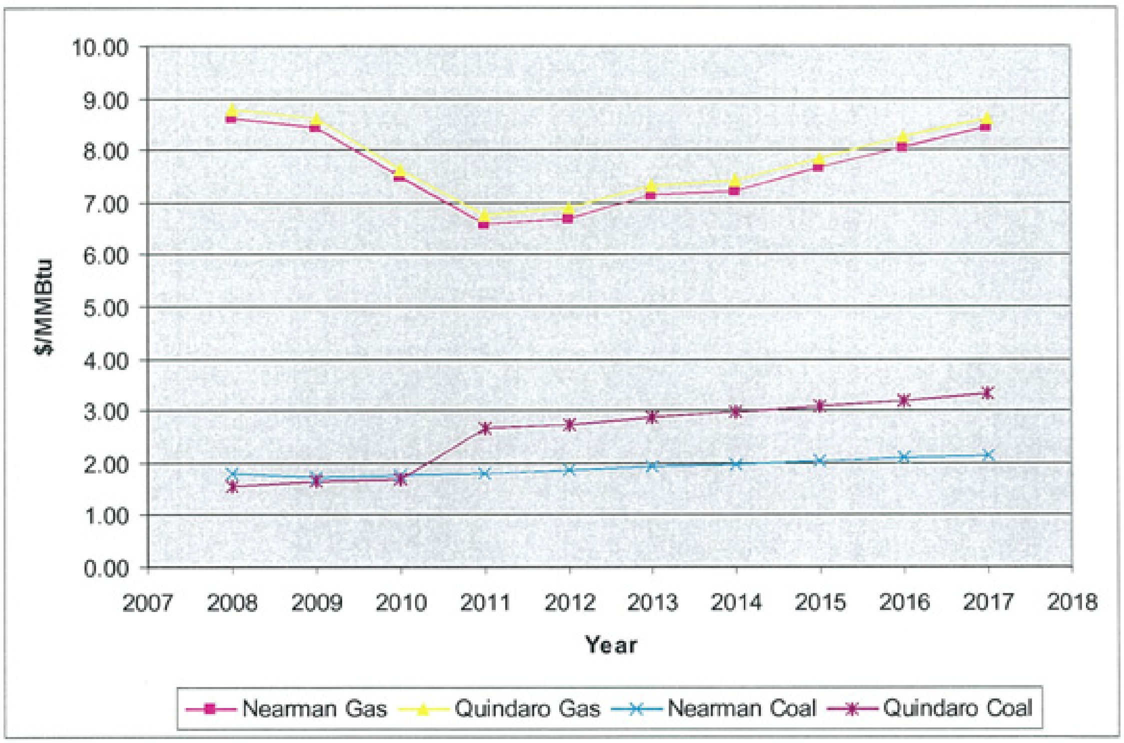


Figure 6-1
Annual Average Fuel Price Forecasts Delivered to BPU Generators

6.2 Environmental Compliance Costs

As stated in Section 3.0, future environmental requirements associated with Quindaro Unit 1 may have a significant impact on the selection of a generation expansion plan over the next 10 years. While the impact of new emission controls for Quindaro Unit 1 was analyzed in this study, the initial assumption is that the unit will operate through the 10-year study period. For purposes of testing the impact of new NO_x emission controls on Quindaro Unit 1, B&V estimated the capital cost for adding SCR to Q1 to be $34 million in 2008 dollars. Unless otherwise noted, all expansion plans and sensitivity cases that retire Q1 by 2011 exclude the SCR cost and all plans that retain Q1 beyond 2017 assume the expenditure for the Q1 SCR is made. Figure 6-2 shows the emission allowance prices forecast for SO_2 and CO_2 used in the study.

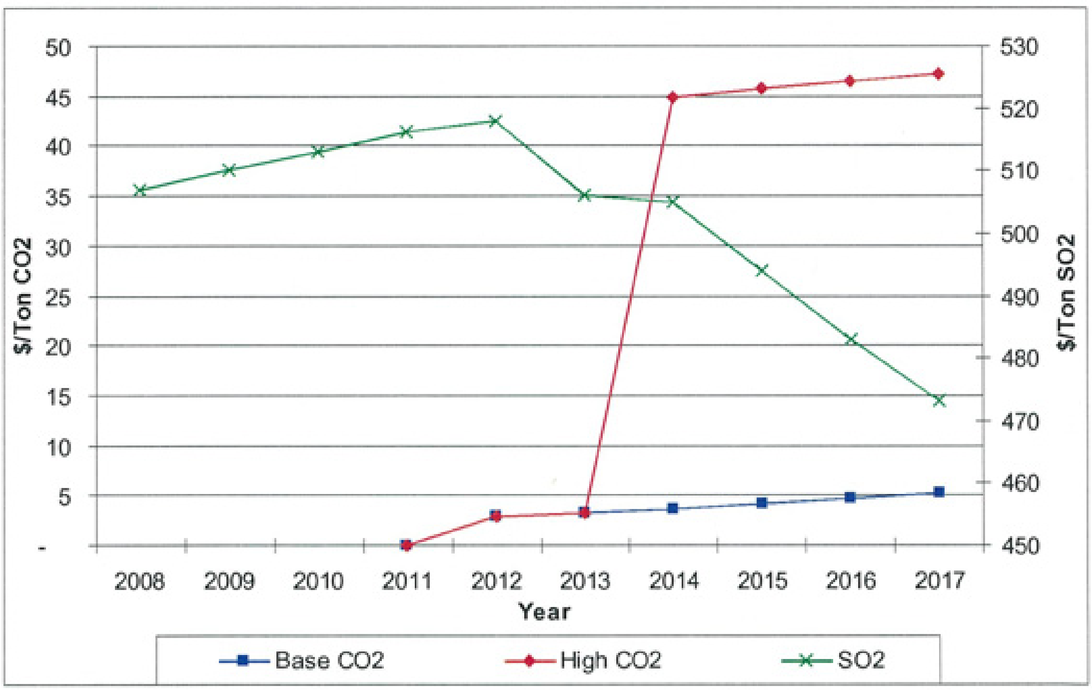


Figure 6-2
SO_2 and CO_2 Allowance Price Forecast - Nominal Dollars

B&V also estimated the capital cost related to the addition of Low NO_x Burners (LNB) and Overfire Air (OFA) to Quindaro Unit 2 and Nearman Unit 1 (N1) to be $10.7 million and $20.6 million respectively, measured in 2008 dollars. A Spray Dry Scrubber and Fabric Filter for N1 were estimated to require $110.2 million ($2008).

6.3 System-Wide Production Costs

B&V projected production revenue requirements for each expansion plan in Table 4-1 using the PROSYM production cost model developed by Ventyx. PROSYM simulated the economic commitment and dispatch of generators in each expansion plan and produced projections of production costs, including interchange power that were used to feed the revenue requirements model. Appendix A contains an overview description of the PROSYM model used for this study.

Production costs were estimated on an hourly chronological basis with BPU generating units dispatched to meet BPU loads considering opportunities to buy power from surrounding markets if interchange power can be obtained at a lower cost and considering opportunities to sell available capacity above BPU loads if the sales can be made at a profit.

Interchange purchases and sales were constrained based on BPU's experience with the maximum effective available capacity on the transmission lines connecting BPU to the surrounding power market. In most cases, BPU's ability to import or export power are determined by other systems transmission limitations within SPP. Market Purchases were limited to a maximum of 250 MW year round. It was assumed that on-peak economy purchases are available 80 percent of the time during non-summer months and 40 percent of the time during summer months (June through September, inclusive). Off-peak economy purchases were assumed to be available 95 percent of the time. Market sales were limited to 50 MW and assumed accessible 55 percent of the time.

6.4 Forecast of Hourly Interchange Prices

The Ventyx Spring 2008 long-term forecast overlaid with the Ventyx April 2008 short-term forecast of hourly interchange prices for the SPP electric market were used in the study and are shown in Table 6-2A. The corresponding market purchase transmission costs are included in Table 6-2B.

Table 6-2A Projected Spot Market Prices in SPP North $/MWh		
	On-Peak	**Off-Peak**
2008	72.83	34.58
2009	74.70	36.31
2010	68.05	34.03
2011	62.96	32.96
2012	65.62	36.19
2013	68.44	36.37
2014	69.72	36.95
2015	73.66	37.85
2016	75.85	38.42
2017	77.52	38.82

Table 6-2B Projected Market Purchase Transmission Costs in SPP North $/MWh		
	On-Peak	**Off-Peak**
2008	6.51	4.58
2009	6.64	4.67
2010	6.76	4.75
2011	6.88	4.84
2012	7.01	4.93
2013	7.13	5.02
2014	7.27	5.11
2015	7.39	5.20
2016	7.53	5.30
2017	7.68	5.39

6.5 Base Case Results

Table 6-3 contains a summary of the 2008-2017 levelized annual costs of ten expansion plans calling for BPU to add new LM2500, LM6000, or 7EA combustion turbine capacity and/or to convert the CTGs including BPU's existing 7EA (CT 4) to combined cycle. Costs are shown by major cost element such as fuel, O&M, economy purchases, emission allowances, amortized capital for new units, and new air quality controls for existing units. Proceeds from economy energy sales are also shown. Quindaro Unit 1 was assumed to be retired by 2011 in six plans which add between 118 and 130 MW of new capacity over the ten-year period. Quindaro Unit 1 continued to operate through the ten-year study period in four plans which add between 43 and 75 MW of new generating capacity. The expansion plans for which revenue requirements are forecast in Table 6-3 are the plans described in Section 5.0 of this report. These Base Case results reflect the comparative revenue requirements assuming the "expected" values of key inputs such as electrical loads, fuel, and spot market prices. Detailed revenue requirement forecasts for each of the Base Case Plans are contained in Appendix B to this report.

The first observation from Table 6-3 is that the three expansion plans with the lowest cumulative present worth revenue requirements were three plans that continued to operate Quindaro 1 through the planning period. Production costs for the continued operation of Q1 tended to be slightly lower than those for the early Q1 retirement plans because Q1 supplies energy at lower cost base load generation prices. In all early Q1 retirement scenarios Q1 energy is replaced with higher cost gas fired generation or wholesale market purchases also based on gas fired generation. In addition, the capital requirements tend to favor continued operation of Q1 because the amortized AQC capital costs associated with the continued operation of Q1 are generally lower than the amortized capital costs of the replacement capacity.

Of the three least-cost plans, the top plan, (Q1-B), adds an LM6000 combustion turbine in 2011 and the next best plan, (Q1-C), adds an LM 2500 in 2011 and again in 2013. The third best plan (Q1-A), adds a 7EA combustion turbine in 2011. The fourth and fifth ranked plans both call for the early retirement of Quindaro 1 and the addition of capacity to meet growth as well as the replacement of retired capacity with a 7EA simple cycle gas turbine. Plan Q0-D adds a 7EA CT in 2011 to replace Q1 and an LM6000 in 2013. Plan Q0-F adds the LM6000 in 2011 and a 7EA in 2012. The expansion plans that convert new or existing simple cycle combustion turbines to combined cycle combustion turbines are consistently the most expensive plans because the production cost savings associated with the efficiency of a combined cycle plant are not sufficient to offset a combined cycle's incremental capital cost.

Table 6-3
Levelized Annual Comparative Revenue Requirements by Expansion Plan - Base Case Conditions (Normally expected loads and costs)

Base Plans	Levelized Annual Production Cost								Levelized Annual Capital Cost			Levelized Total System Cost	Cumulative Present Worth Cost	Rank within Category	Rank within All Plans	% Difference From Least Cost Plan	
	Fuel Cost[1]	O&M Variable[2]	O&M Fixed	Emission Costs	Economy Sales	Economy[3] Purchase	Nearman Participant[4] Sales	Net Production Cost	Unit Additions Capital[5] Cost	AQC Capital Cost	Total Capital Cost						
	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)			Category	All Plans
Q1 Retires in 2011																	
Q0-A	$78,561	$5,439	$36,415	$9,506	$(5,202)	$16,596	$(15,546)	$125,770	$9,109	$11,033	$20,143	$145,912	$1,171,582	5	9	0.93%	3.15%
7EA CT in 2011 convert to CC in 2012 (118 MW)																	
Q0-B	$79,368	$5,569	$36,755	$9,532	$(5,685)	$14,749	$(15,547)	$124,741	$11,971	$11,033	$23,005	$147,745	$1,186,299	6	10	2.20%	4.45%
2 x LM6000 CT in 2011,2015 & CT4 CC in 2011 (130 MW)																	
Q0-C	$79,744	$5,324	$36,781	$9,547	$(5,788)	$14,521	$(15,547)	$124,583	$10,213	$11,033	$21,247	$145,829	$1,170,914	4	8	0.87%	3.10%
2 x LM6000CT in 2011 convert to CC in 2013 (116 MW)																	
Q0-D	$77,771	$4,810	$36,165	$9,509	$(4,352)	$18,902	$(15,546)	$127,259	$6,277	$11,033	$17,311	$144,570	$1,160,805	1	4	**0.00%**	2.21%
7EA CT in 2011 & LM6000 CT in 2013 (118 MW)																	
Q0-E	$79,703	$4,881	$36,589	$9,592	$(5,099)	$15,194	$(15,547)	$125,314	$9,264	$11,033	$20,298	$145,612	$1,169,169	3	7	0.72%	2.94%
3 x LM6000 CT in 2011 & 2013 (130 MW)																	
Q0-F	$78,160	$4,816	$36,230	$9,525	$(4,436)	$18,122	$(15,546)	$126,869	$6,788	$11,033	$17,821	$144,690	$1,161,766	2	5	**0.08%**	2.29%
LM6000CT in 2011 & 7EA CT in 2013 (118 MW)																	
Q1 Retires after 2017																	
Q1-A	$78,432	$5,152	$38,986	$10,779	$(6,303)	$12,931	$(15,546)	$124,432	$4,054	$14,496	$18,550	$142,981	$1,148,049	3	3	1.08%	1.08%
7EA CT in 2011 (75 MW)																	
Q1-B	$79,639	$5,174	$38,968	$10,809	$(6,543)	$10,934	$(15,547)	$123,434	$3,521	$14,496	$18,016	$141,450	$1,135,754	1	1	**0.00%**	**0.00%**
LM6000 CT in 2011 (43 MW)																	
Q1-C	$77,867	$5,068	$39,122	$10,743	$(5,876)	$12,931	$(15,546)	$124,309	$3,140	$14,496	$17,635	$141,944	$1,139,717	2	2	0.35%	0.35%
2 x LM2500 CT in 2011, 2013 (43 MW)																	
Q1-D	$79,680	$5,758	$39,262	$10,764	$(7,017)	$10,217	$(15,546)	$123,117	$7,232	$14,496	$21,727	$144,844	$1,163,005	4	6	2.40%	2.40%
CT4 CC in 2011 (44 MW)																	

[1] Fuel includes emergency purchase for energy not served by BPU.
[2] Variable O&M includes start-up and shut-down related maintenance costs.
[3] Economy Purchase includes Bridge Power purchase assumed to be at spot power prices.
[4] Includes Nearman 1 sales only.
[5] Capital costs are net of Nearman 1 Participation sales capacity proceeds.

A primary conclusion from the comparison of expansion plans in Table 6-3 is that if air quality regulations do require an SCR to be added to Quindaro Unit 1 in order for it to continue operating, it is still more cost effective to expend the capital on Q1 than to replace it with new generation, purchased power and the operation of BPU's more expensive gas fueled generators. Some equipment replacements to maintain reliability would be inevitable if the unit is to continue operating through the study period. From the comparison of the least-cost plan with Q1 retired in 2011 to the least-cost plan with AQC upgrades, it was determined that up to $30 million ($2008) could be spent on Q1 during the planning period before the continued operation of this unit is no longer economically justified. Clearly, if the Regional Haze Rule and/or Kansas City ozone attainment conditions do not require the addition of an SCR, the continued operation of Q1 and the addition of a combustion turbine to keep up with load growth would be the least-cost plan for BPU.

Another major conclusion from the results shown in Table 6-3 is that whether or not future costs for Q1 exceed the level that economically justifies its continued operation, both least cost plans call for the addition of a simple cycle combustion turbine in 2011. Furthermore, the costs of Plans Q0-D and Q0-F where Q1 is retired in 2011 and add either a 7EA or an LM6000 CT in 2011 are so close as to indicate that BPU should solicit bids for both frame and aero-derivative type turbines. In addition, the costs of Plans Q1-B and Q1-C where Q1 continues to operate through the study period are also very close and also call for either the addition of a LM6000 in 2011 or a LM 2500 turbine in 2011 and 2013. In all cases additional CT capacity is required.

6.6 Sensitivity/Risk Results

Each of the plans compared in Table 6-3 were also compared assuming changes in several future underlying conditions that could influence the comparisons. By seeking the least-cost plan under a variety of plausible future conditions, BPU should minimize the risk of adopting a plan that will later cost its customers more than necessary. Each of the plans in Table 6-3 was compared under the following sensitivity/risk scenarios:

- High and Low Load.
- High CO_2 tax.
- High fuel and market conditions.
- No Economy Purchases.

The high and low load scenarios reflect the potential impact of the loss or gain of a large 28 MW customer. The High CO_2 tax case reflects the impact of a market price for or tax on CO_2 emissions which jump from the Base Case assumption of approximately $3.25/ton in 2013 to $45/ton by 2014 and escalates at 1.8 percent thereafter. The high fuel price and electric market conditions reflect the high range of the coordinated forecasts for natural gas and electric market prices as presented by Ventyx in its Spring 2008 forecast. The No Economy Purchases scenario is with sales assumed to be made to the economy market but no economy purchases allowed as would be the extreme case if import transmission constraints became worse.

Table 6-4 lists the ranking of the ten plans under the base case assumptions of future conditions and under each of the sensitivity cases. Also shown in Table 6-4 is an aggregate ranking of plans under the Base Case and all sensitivity cases. As shown, the aggregate ranking under all sensitivities is nearly the same as the Base Case ranking. The loss or gain of a large customer and high fuel and market prices has little impact on the ranking of the four least-cost plans. Under all sensitivity cases the least-cost supply plan is Plan Q1-B that adds an SCR to Q1 in order to continue its operation and adds an LM6000 aero-derivative combustion turbine to meet growth. Even the high carbon tax scenario still favors the continued operation of Q1 and the addition of an LM 6000 in 2011.

Given the lower efficiency of the 7EA, the plans calling for the addition of a 7EA in 2011 in place of an LM6000, drop in rank from third and fourth place to fourth and tenth place in the cases that assume a high carbon tax and assume no economy purchases, respectively. While Plan Q1-D calling for the continued operation of Q1 and the conversion of existing CT 4 to combined cycle moves up to a third place ranking under the assumption of no economy purchases, it is still more expensive than the addition of an LM6000 CT or two LM2500s.

Should later investigations of Q1 reveal necessary expenditures that preclude its continued operation beyond 2011, the addition of a 7EA combustion turbine in 2011 is favored in most sensitivity scenarios except in the case of no economy purchases or a high carbon tax. In both of these cases, the addition of two LM6000 CTs followed by their conversion to combined cycle provides insurance against high CO_2 costs and higher power import constraints.

Table 6-4
Sensitivity/Risk Ranking of Alternative Plans

	Q0-A	Q0-B	Q0-C	Q0-D	Q0-E	Q0-F	Q1-A	Q1-B	Q1-C	Q1-D
	7EA CT in 2011 convert to CC in 2012	2 x LM 6000 CT in 2011, 2015 & CT4 CC in 2011	2 x LM6000CT in 2011 convert to CC in 2013	7EA CT in 2011 & LM6000 CT in 2013	3 x LM6000 CT in 2011 & 2013	LM6000CT in 2011 & 7EA CT in 2013	7EA CT in 2011	LM6000 CT in 2011	2 x LM2500 CT in 2011,2013	CT4 to CC in 2011
	118 MW	130 MW	116 MW	118 MW	130 MW	118 MW	75 MW	43 MW	43 MW	44 MW
Base Case	9	10	8	4	7	5	3	1	2	6
Lose Large Customer	8	10	9	4	6	6	3	1	2	5
Gain Large Customer	9	10	8	5	7	6	3	1	2	4
High Fuel and Market Price	9	10	8	5	7	6	3	1	2	4
High Carbon Tax	7	10	3	4	8	5	6	1	2	9
No Economy Purchases	7	8	5	10	6	9	4	1	2	3
Sum of Rank	49	58	41	32	41	37	22	6	12	31
Combined Rank	9	10	7	5	7	6	3	1	2	4

Note: Refer to Appendix C for detailed costs that determine these rankings.

7.0 Observations and Conclusions Resulting from Phase I Analysis

The following observations and conclusions are derived from the analyses in the previous sections of this report:

- BPU is projected to need between 35 and 107 MW of additional generating capacity to meet its capacity responsibility over the next 10 years depending on whether or not Quindaro Unit 1 remains in operation.
- Comparing the plans that continue Q1 operation with the plans that do not, even with a $34 million ($2008) expenditure for the addition of an SCR, it is less costly to continue to operate Q1 through 2017 than to retire it in 2011.
- In addition to the $34 million SCR, the BPU could afford to spend an additional $30 million ($2008) on reliability maintenance projects before it would be less costly to its customers to retire the unit.
- The least cost plan of the ten alternative plans is the one that adds an SCR to Q1, continues its operation and meets growth with the addition of an LM6000 aero-derivative turbine.
- The second and third least-cost plans add two LM2500 CTs in 2011 and a Frame 7EA CT in 2011, respectively.
- Regardless of whether or not Q1 is retired early, the NPV costs of plans that add a Frame 7EA turbine, an LM6000 turbine, or LM2500 turbines in 2011 are so close as to indicate that BPU should solicit bids for these types of machines.
- The continued operation of Q1 with an SCR is economical under a variety of sensitivity/risk scenarios and as in the Base Case, the least-cost additions to meet growth include a Frame 7EA, LM6000 CT, or two LM2500 CTs.
- Even a high carbon tax favors the continued operation of Q1.
- A high carbon tax and no economy purchases individually favor the use of the more efficient LM6000 CT over the 7EA.

- Should later investigations of Q1 reveal necessary expenditures greater than $30 million may preclude its continued operation beyond 2011, the addition of a 7EA combustion turbine in 2011 is favored in most sensitivity scenarios as the least expensive replacement capacity. However, in the case of no economy purchases or a high carbon tax, the addition of two LM6000 CTs followed by their conversion to combined cycle provides insurance against high CO_2 costs and higher power import constraints.

8.0 Phase II of Power Supply Study/Refinement

Results from Phase I of this study indicated that regardless of whether or not Q1 was retired early, the addition of a simple cycle combustion turbine is the best natural gas plan for enabling BPU to continue to supply its customers with reliable service at the least cost through 2017. Results from Phase I analysis also revealed that plans that keep Q1 in service are of lower cost than retiring Q1 in 2011. While these findings were consistent under a variety of sensitivity conditions, newly available forecasts of key planning inputs and assumptions suggested the need for a final comparison of selected plans in order to further firm up the decision to add a simple cycle combustion turbine and to provide the latest available inputs to the financial forecast and cost-of-service study.

Included in the Phase I assumptions were that the simple cycle combustion turbines, typically used during the highest load hours, would not run enough to require SCR to control NO_x emissions. Results from the Phase I production cost simulations revealed that the simple cycle combustion turbines may run enough hours to require an SCR for NO_x control. Accordingly, new performance, capital and operating cost estimates were developed for the simple cycle combustion turbine alternatives based on the units being configured with SCR. The updated cost and performance estimates were used in the Phase II analysis. Additionally, the Ventyx May 2008 updates to the natural gas and spot market energy price forecasts were used in the Phase II analysis, and the future annual capital expenditures for the existing BPU generators were forecast by BPU and included in the comparison of revenue requirements.

Plans carried forward for analysis in Phase II are the top five plans from the Phase I analysis. The top five plans consist of two plans in which Q1 retires in 2011 and three plans keeping Q1 in service through the end of the study period.

9.0 Phase II Expansion Plans

The plans considered in Phase II of the Power Supply Plan development were the five least-cost plans from the Phase I analysis. Assumed types and operation dates for new generator additions and Q1 retirement assumptions for each plan are contained in Table 9-1.

Table 9-1
Phase II Generating Capacity Expansion Plans

SCENARIO 0: Q1 retires in 2011				SCENARIO 1: Q1 not retired during planning period			
Plan	**Net Generation**	**Unit Additions**	**Year**	**Plan**	**Net Generation**	**Unit Additions**	**Year**
Q0-D	**118 MW**	7EA CT	2011	**Q1-A**	**75 MW**	7EA CT	2011
		LM6000 CT	2013				
Q0-F	**118 MW**	LM6000 CT	2011	**Q1-B**	**43 MW**	LM6000 CT	2011
		7EA CT	2012				
				Q1-C	**42 MW**	LM2500 CT	2011
						LM2500 CT	2015

Notes:
1. Assumed retirement of existing units for both scenarios are as follows: CT1 - Year 2015

10.0 Power Supply Options - Cost and Performance Updates

Updates to the Simple Cycle Combustion Turbines' cost and performance estimates to include SCR for NO_x control were developed for the Phase II analysis. The plans carried forward to the Phase II analysis contain the following units:

- LM6000PC-Sprint SCCT with SCR.
- 7EA SCCT with SCR.
- LM2500 SCCT with SCR.
- Updates to the operating characteristics, capital costs, and operating costs for each of these options are detailed in the following subsections. Consistent with the Phase I analysis, these characteristics include estimates of performance (output and heat rates), emissions, and capital and O&M costs.

10.1 Performance and Emissions Estimates

This section contains performance and emission estimates for the combustion turbine technology options listed previously. Assumptions used to develop the performance and emission estimates are provided.

10.1.1 Estimating Assumptions

The performance and emission estimates for the SCCT options were developed using the same assumptions used in Phase I of this study. The following seasons and temperatures were used:

- Spring/Fall: February, March, October, and November - 53° F (April was not included for estimation of Spring temperature)
- Summer: May 1 to September 30 - 90° F.
- Winter: Need for SCCTs during Winter season is negligible.

The following unit arrangement criteria were used during the development of the performance and emission estimates.

- Evaporative inlet cooling.
- Primary fuel is natural gas, back-up fuel is No. 2 fuel oil.
- SCR but no CO catalyst.

10.1.2 Performance Estimates

Full and partial-load performance estimates were generated for two seasonal ambient conditions. Performance estimates are shown in Table 10-1. Operating conditions are defined in a case summary in the top five rows of the table. When

Table 10-1
SCCT with SCR Performance Estimates

Case Summary	Spring/Fall			Summer		
Elevation, ft amsl	750	750	750	750	750	750
Dry Bulb Temperature, ° F	53	53	53	90	90	90
Relative Humidity, percent	60	60	60	60	60	60
Evaporative Cooling, On/Off	Off	Off	Off	On	On	On
Load, percent	100	75	50	100	75	50
LM6000PC-Sprint						
Gross CTG Output, kW	48,930	36,700	24,470	43,730	32,800	21,870
Auxiliary Load, kW	490	430	370	440	390	330
Net Plant Output, kW	48,440	36,270	24,100	43,290	32,410	21,540
Net Plant Heat Rate (LHV), Btu/kWh	8,625	9,125	10,326	8,736	9,369	10,716
Net Plant Heat Rate (HHV), Btu/kWh	9,582	10,138	11,473	9,705	10,409	11,906
LM2500PE						
Gross CTG Output, kW	23,030	17,280	11,520	21,330	16,010	10,680
Auxiliary Load, kW	240	180	120	220	170	110
Net Plant Output, kW	22,790	17,100	11,400	21,110	15,840	10,570
Net Plant Heat Rate (LHV), Btu/kWh	9,967	10,232	11,459	10,020	10,520	11,770
Net Plant Heat Rate (HHV), Btu/kWh	11,073	11,367	12,731	11,132	11,687	13,077
GE 7EA						
Gross CTG Output, kW	83,260	62,450	41,630	75,440	56,580	37,720
Auxiliary Load, kW	1,000	880	750	910	800	680
Net Plant Output, kW	82,260	61,570	40,880	74,530	55,780	37,040
Net Plant Heat Rate (LHV), Btu/kWh	10,610	11,507	14,035	10,887	11,961	14,584
Net Plant Heat Rate (HHV), Btu/kWh	11,761	12,784	15,593	12,096	13,289	16,203

Notes:
1. All data is expected, and not guaranteed, and does not include allowances for margins.
2. Performance was based on GE's Gas Turbine Performance Estimator (GTPE).
3. Estimates are reflective of new and clean conditions and do not include the effects of degradation.
4. Fuel is assumed to be nearly 100% methane with 0.2 g/100 SCF sulfur.
5. The evaporative cooler is assumed to operate with 85% effectiveness when in operation.
6. Above performance estimates include the effect of a SCR but do not include the effect of a CO catalyst.
7. The dry-bulb temperature in the spring/fall, 53° F, and the accredited temperature in summer, 90° F, are based on International Station Meteorological Climate Summary, Ver 3.0 March 1995.

modeling these units it was assumed that their minimum outputs are the 50 percent load performance estimates shown in Table 10-1. As the output of these units decreases toward 50 percent, the NO_x emissions start to increase rapidly, so it is anticipated that these units will not spend more than a small amount of time operating below 50 percent of full output.

10.1.3 Emission Estimates

Full and part load emission estimates were generated for one seasonal ambient condition for the SCCT technology options considered in Phase II. Emission estimates include oxides of NO_x as NO_2, SO_2, CO, CO_2, VOC, and particulate matter of PM_{10}. Emission estimates are provided on a unitized basis. Updated full load emission estimates for the SCCT with SCR technology options are provided in Table 10-2.

Table 10-2
SCCT with SCR Emission Estimates

	NO_x, as NO_2		SO_2	CO		CO_2	VOC		PM_{10}
	ppm	lb/MBtu	lb/MBtu	ppm	lb/MBtu	lb/MBtu	ppm	lb/MBtu	lb/MBtu
LM6000 PC-Sprint	2.5	0.01	0.0006	18	0.04	128	0.4	0.0006	0.008
LM2500 PE	2.5	0.01	0.0006	48	0.12	128	2.1	0.0031	0.014
7EA	2.5	0.01	0.0006	25.3	0.06	128	1.5	0.0021	0.010

Notes:
1. Emission estimates are based on 100 percent load operation at an elevation of 750 ft amsl, a dry bulb temperature of 53° F, a relative humidity of 60 percent, and no evaporative cooling.
2. The dry air composition assumed for emission estimates is 0.98% Ar, 78.03% N_2 and 20.99% O_2.
3. Fuel is assumed to be nearly 100 percent methane with a sulfur content of 0.2 grain per 100 SCF.
4. Emissions data shown include effects of a SCR but CO catalyst is not included.
5. NO_x emissions are assumed to be controlled to 2ppmvd at 15% O_2 in the SCR. Ammonia slip in the SCR is assumed to be 10 ppmvd at 15% O_2. Estimated ammonia slip is 6.2 lb/h for the LM6000, 3.4 lb/h for the LM2500, and 12.9 lb/h for the 7EA.
6. ppm is pounds per million dry volume at 15 percent O_2.
7. Emissions in lb/MBtu are based on a LHV of fuel input.
8. PM_{10} emissions shown are filterable and condensable particulate catch.
9. The above estimates are on the assumption that NO_x is controlled with SCR.
10. The VOC/UHC ratio is assumed to be 20% (typical for GE turbines).
11. The SO_2 emission values provided do not include oxidation through the gas turbine.
12. CO_2 emissions are based on estimated B&V calculations and are typically not provided by the gas turbine manufacturer.
13. All data is expected and is per stack, not guaranteed, and does not include allowances for margins.
14. Estimated stack flow is 605,694 acfm for the LM6000, 347,504 acfm for the LM2500, and 1,497,070 for the 7EA.

10.2 EPC Capital Cost Estimates

This section provides updates to the capital cost estimates for the CTG technology options considered in Phase II. The assumptions used to develop the capital costs are the same as used to develop the capital costs for Phase I with the exception that it is assumed that SCR will be required on the simple cycle units. An estimate of the cost of the SCR system is included in the capital cost used in the Phase II analysis.

10.2.1 EPC Capital Cost Estimates

An overnight EPC capital cost estimate summary is provided in Table 10-3 for the SCCT options. These estimates are based on Black & Veatch's recent experiences and observations of the energy industry. The estimates are screening level, overnight estimates and were developed using the assumptions outlined in the previous sections. The estimates are provided in first quarter 2008 dollars.

Table 10-3
SCCT with SCR EPC Capital Cost Estimate

	LM6000PC-Sprint	LM2500PE	7EA
Total EPC Costs, $1,000			
Net Plant Output, kW	43,290	21,110	74,530
EPC Capital Cost, $1,000	45,670	30,600	55,560
Unit EPC Capital Cost, $/kW	1,055	1,450	745

Notes:
1. Estimates are screening level overnight estimates in first quarter 2008 dollars.
2. Net plant output and Unit EPC Capital Cost based on performance estimates at the accredited summer temperature, 90° F.

10.3 Operation and Maintenance Cost Estimates

This section provides updated non-fuel O&M cost estimates consisting of FOM costs and VOM costs for the SCCT technology options considered in Phase II. Assumptions used to develop the cost estimates are provided in the Phase I section of this report with the exception that the O&M cost estimates for the SCCT configurations include costs associated with the units having SCR. O&M cost estimates for units including SCR are provided in Table 10-4.

Table 10-4
SCCT with SCR O&M Cost Estimates

	LM6000PC-Sprint	LM2500PE	7EA
Fixed Costs, $1,000/Yr			
Staffing, count	5	5	5
Labor	490.4	490.4	490.4
Maintenance	54.2	38.5	71.3
Other Expenses	69.4	59.1	77.2
Total Fixed Costs	614.0	587.9	638.9
Variable Costs, $1,000/Yr			
Outage Maintenance	134.5	90.3	256.3
Utilities	12.4	8.5	3.6
Chemical Usage	6.8	3.7	6.6
Total Variable Costs	153.7	102.5	266.4
Net Plant Output, kW	43,290	21,110	74,530
Annual Generation, MWh	37,922	18,492	65,288
Unit Fixed Cost, $/kW	14.18	27.85	8.57
Unit Variable Costs, $/MWh	4.05	5.54	4.08

Notes:
1. Net plant output based on the accredited temperature in the summer, 90° F.
2. Unit costs based on the net plant output at the accredited temperature in the summer and an assumed annual capacity factor of 10 percent.

11.0 Phase II Comparison of Alternative Plans

As in Phase I, the initial criterion for the comparison of the alternative capacity expansion plans in Phase II is the Net Present Value of Comparative Revenue Requirements. This comparative evaluation does not consider all the costs that are common to all the plans, such as debt service on existing units, electric distribution costs, and the electric utility's share of administrative and general costs which includes the electric utility's share of BPU's general manager's and other top management's salaries. However, it does include the major future annual capital expenditures associated with each existing BPU generator as forecast by BPU and shown in Table 11-1. These expenditures total $132 million over the 10-year study period. For plans in which Quindaro Unit 1 was assumed to be retired early, the ten-year capital expenditures for the existing generators would be reduced to $103 million.

There were not significant differences in the relative rankings of the plans between Phase I and Phase II. The plan that continues operation of Quindaro 1 through the study period and adds an LM6000 turbine in 2011 was still the plan with the lowest forecast of revenue requirements over the ten-year study period. A tabulation of the net present value costs of each plan by major cost category is contained in Table 11-2. The full comparative revenue requirement tables for each Phase II plan is contained in Appendix D to this report.

Each of the plans compared in Table 11-2 were also compared assuming changes in several future underlying conditions that could influence the comparisons. By seeking the least-cost plan under a variety of plausible future conditions, BPU should minimize the risk of adopting a plan that will later cost its customers more than necessary. Each of the plans in Table 11-2 was compared under the following sensitivity/risk scenarios:

- High and Low Load.
- High CO_2 tax.
- High fuel and market conditions.
- No Economy Purchases.

The relative ranking of the Phase II sensitivity runs is similar to the Phase I ranking. Table 11-3 shows the levelized annual summary for each of the sensitivities performed for each expansion plan analyzed. Table 11-3 summarizes the sensitivity results compared to the Phase II base case conditions. These results show that under base case conditions and all sensitivities that the least-cost 10-year expansion plan is the plan that retains Quindaro Unit 1 and adds an LM6000 or similar simple cycle combustion turbine in 2011.

Table 11-1
Electric Production Forecast Capital Expenditures - Existing Generators, $1,000

Year	Total Quindaro		Total CTs	Total Nearman	Total Electric Production		Comments
	Q1 Out of Service in 2011	with Q1			Q1 Out of Service in 2011	with Q1	
2008	12,282	12,282	0	4,474	16,756	16,756	Q2 Major Overhaul
2009	4,149	5,325	1,120	4,592	9,860	11,036	CT1 Major Overhaul
2010	1,630	4,822	4,436	4,548	10,614	13,806	CT2 & CT3 Majors
2011	1,540	17,108	0	3,438	4,978	20,546	Q1 Major Overhaul
2012	1,316	1,708	112	17,170	18,598	18,990	N1 Major Overhaul
2013	4,368	5,152	0	4,194	8,562	9,346	
2014	12,510	12,846	672	459	13,641	13,977	Q2 Major Overhaul
2015	2,688	3,360	0	6,552	9,240	9,912	
2016	2,912	3,472	0	5,846	8,758	9,318	
2017	1,288	7,896	0	369	1,657	8,265	Q1 Major Overhaul

Table 11-2
Levelized Annual Comparative Revenue Requirements by Expansion Plan - Phase II Base Case[1] Conditions

	Levelized Annual Production Cost									Levelized Annual Capital Cost			Levelized	Cumulative	Rank	Rank	%	
							Nearman	Existing	Net	nit Additior	AQC	*Total*	Total	Present	within	within	Difference	
	Fuel	O&M		*Emission*	Economy	Economy	Participant	Plant O&M	Production	Capital	Capital	*Capital*	System	Worth	Cat-	All	From Least	
Base Plans	Cost	Variable	Fixed	*Costs*	Sales	Purchase	Sales	Capital Cost	Cost	Cost	Cost	*Cost*	Cost	Cost	egory	Plans	Cost Plan	
	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)			Category	All Plans
Q0-D (SCR)	$ 78,335	$ 5,071	$ 42,192	$ 18,796	$ (4,584)	$ 22,874	$ (18,036)	$ 9,739	$ 154,388	$ 8,131	$ 16,714	$ 24,844	$ 179,232	$ 1,439,121	1	4	**0.00%**	2.38%
Q0-F (SCR)	$ 78,148	$ 5,046	$ 42,258	$ 18,805	$ (4,570)	$ 22,570	$ (18,036)	$ 9,739	$ 153,960	$ 8,560	$ 16,714	$ 25,273	$ 179,233	$ 1,439,125	2	5	**0.00%**	2.38%
Q1-A (SCR)	$ 79,655	$ 5,458	$ 45,096	$ 21,483	$ (7,432)	$ 14,513	$ (19,971)	$ 12,210	$ 151,011	$ 4,997	$ 20,589	$ 25,586	$ 176,597	$ 1,417,962	3	3	0.88%	0.88%
Q1-B (SCR)	$ 79,750	$ 5,429	$ 45,519	$ 21,479	$ (7,545)	$ 13,502	$ (19,972)	$ 12,210	$ 150,371	$ 4,098	$ 20,589	$ 24,687	$ 175,058	$ 1,405,604	1	1	**0.00%**	**0.00%**
Q1-C (SCR)	$ 79,339	$ 5,385	$ 45,836	$ 21,401	$ (7,024)	$ 14,384	$ (19,972)	$ 12,210	$ 151,559	$ 4,027	$ 20,589	$ 24,615	$ 176,174	$ 1,414,566	2	2	0.64%	0.64%

Notes:
Phase II Base Case Conditions varied from Phase I Base Case Conditions as follows:

- Updated new unit performance, costs, and emissions estimates to include SCR in the unit configurations.
- Updated short-term natural gas and purchase power price forecasts.
- Added Nearman 1 scrubber landfill costs and moved Nearman 1 scrubber commercial operations date from 2013 to 2014.
- Added costs of ongoing equipment replacements for existing units.

Table 11-3
Phase II - Levelized Annual Comparative Revenue Requirements
by Expansion Plan - Sensitivity Cases

Lose Large Customer

	Levelized Annual Production Cost									Levelized Annual Capital Cost			Levelized	Cumulative	Rank	Rank	%	
							Nearman	Existing	Net	Unit Additions	AOC	*Total*	Total	Present	within	within	Difference	
	Fuel	O&M		*Emission*	Economy	Economy	Participant	Plant O&M	Production	Capital	Capital	*Capital*	System	Worth	Cat-	All	From Least	
Base Plans	Cost	Variable	Fixed	*Costs*	Sales	Purchase	Sales	Capital Cost	Cost	Cost	Cost	*Cost*	Cost	Cost	egory	Plans	Cost Plan	
	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)			Category	All Plans
Q0-D (SCR)	$ 74,794	$ 4,898	$ 42,192	$ 18,464	$ (5,548)	$ 18,936	$ (18,036)	$ 9,739	$ 145,438	$ 8,131	$ 16,714	$ 24,844	$ 170,282	$ 1,367,258	1	4	0.00%	2.00%
Q0-F (SCR)	$ 74,659	$ 4,878	$ 42,258	$ 18,473	$ (5,531)	$ 18,585	$ (18,036)	$ 9,739	$ 145,024	$ 8,560	$ 16,714	$ 25,273	$ 170,297	$ 1,367,375	2	5	0.01%	2.01%
Q1-A (SCR)	$ 76,034	$ 5,256	$ 45,096	$ 20,920	$ (8,280)	$ 11,607	$ (19,972)	$ 12,210	$ 142,870	$ 4,997	$ 20,589	$ 25,586	$ 168,456	$ 1,352,595	3	3	0.91%	0.91%
Q1-B (SCR)	$ 75,798	$ 5,219	$ 45,519	$ 20,902	$ (8,325)	$ 10,904	$ (19,972)	$ 12,210	$ 142,256	$ 4,098	$ 20,589	$ 24,687	$ 166,943	$ 1,340,448	1	1	0.00%	0.00%
Q1-C (SCR)	$ 75,582	$ 5,187	$ 45,836	$ 20,842	$ (7,881)	$ 11,548	$ (19,972)	$ 12,210	$ 143,350	$ 4,027	$ 20,589	$ 24,615	$ 167,966	$ 1,348,657	2	2	0.61%	0.61%

Gain Large Customer

	Levelized Annual Production Cost									Levelized Annual Capital Cost			Levelized	Cumulative	Rank	Rank	%	
							Nearman	Existing	Net	Unit Additions	AOC	*Total*	Total	Present	within	within	Difference	
	Fuel	O&M		*Emission*	Economy	Economy	Participant	Plant O&M	Production	Capital	Capital	*Capital*	System	Worth	Cat-	All	From Least	
Base Plans	Cost	Variable	Fixed	*Costs*	Sales	Purchase	Sales	Capital Cost	Cost	Cost	Cost	*Cost*	Cost	Cost	egory	Plans	Cost Plan	
	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)			Category	All Plans
Q0-D (SCR)	$ 82,336	$ 5,284	$ 42,298	$ 19,013	$ (3,541)	$ 27,776	$ (18,036)	$ 9,739	$ 164,870	$ 8,131	$ 16,714	$ 24,844	$ 189,715	$ 1,523,285	2	5	0.04%	2.78%
Q0-F (SCR)	$ 82,202	$ 5,269	$ 42,258	$ 19,021	$ (3,559)	$ 27,462	$ (18,036)	$ 9,739	$ 164,358	$ 8,560	$ 16,714	$ 25,273	$ 189,631	$ 1,522,614	1	4	0.00%	2.73%
Q1-A (SCR)	$ 83,831	$ 5,665	$ 45,203	$ 21,926	$ (6,119)	$ 17,917	$ (19,972)	$ 12,210	$ 160,662	$ 4,997	$ 20,589	$ 25,586	$ 186,248	$ 1,495,451	3	3	0.90%	0.90%
Q1-B (SCR)	$ 83,667	$ 5,627	$ 45,626	$ 21,879	$ (5,978)	$ 16,842	$ (19,972)	$ 12,210	$ 159,901	$ 4,098	$ 20,589	$ 24,687	$ 184,588	$ 1,482,124	1	1	0.00%	0.00%
Q1-C (SCR)	$ 83,651	$ 5,603	$ 45,942	$ 21,814	$ (5,677)	$ 17,802	$ (19,971)	$ 12,210	$ 161,373	$ 4,027	$ 20,589	$ 24,615	$ 185,989	$ 1,493,371	2	2	0.76%	0.76%

High NG and MCP

	Levelized Annual Production Cost									Levelized Annual Capital Cost			Levelized	Cumulative	Rank	Rank	%	
							Nearman	Existing	Net	Unit Additions	AOC	*Total*	Total	Present	within	within	Difference	
	Fuel	O&M		*Emission*	Economy	Economy	Participant	Plant O&M	Production	Capital	Capital	*Capital*	System	Worth	Cat-	All	From Least	
Base Plans	Cost	Variable	Fixed	*Costs*	Sales	Purchase	Sales	Capital Cost	Cost	Cost	Cost	*Cost*	Cost	Cost	egory	Plans	Cost Plan	
	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)			Category	All Plans
Q0-D (SCR)	$ 80,625	$ 5,014	$ 42,192	$ 18,678	$ (4,667)	$ 26,920	$ (18,036)	$ 9,739	$ 160,465	$ 8,131	$ 16,714	$ 24,844	$ 185,309	$ 1,487,913	2	5	0.04%	4.12%
Q0-F (SCR)	$ 80,286	$ 4,983	$ 42,258	$ 18,683	$ (4,592)	$ 26,632	$ (18,036)	$ 9,739	$ 159,953	$ 8,560	$ 16,714	$ 25,273	$ 185,227	$ 1,487,250	1	4	0.00%	4.07%
Q1-A (SCR)	$ 81,290	$ 5,440	$ 45,096	$ 21,442	$ (7,902)	$ 16,684	$ (19,971)	$ 12,210	$ 154,288	$ 4,997	$ 20,589	$ 25,586	$ 179,874	$ 1,444,275	3	3	1.06%	1.06%
Q1-B (SCR)	$ 80,915	$ 5,394	$ 45,519	$ 21,416	$ (7,937)	$ 15,751	$ (19,972)	$ 12,210	$ 153,296	$ 4,098	$ 20,589	$ 24,687	$ 177,983	$ 1,429,092	1	1	0.00%	0.00%
Q1-C (SCR)	$ 80,673	$ 5,372	$ 45,836	$ 21,369	$ (7,398)	$ 16,379	$ (19,972)	$ 12,210	$ 154,469	$ 4,027	$ 20,589	$ 24,615	$ 179,084	$ 1,437,931	2	2	0.62%	0.62%

High Carbon Tax

	Levelized Annual Production Cost									Levelized Annual Capital Cost			Levelized	Cumulative	Rank	Rank	%	
							Nearman	Existing	Net	Unit Additions	AOC	*Total*	Total	Present	within	within	Difference	
	Fuel	O&M		*Emission*	Economy	Economy	Participant	Plant O&M	Production	Capital	Capital	*Capital*	System	Worth	Cat-	All	From Least	
Base Plans	Cost	Variable	Fixed	*Costs*	Sales	Purchase	Sales	Capital Cost	Cost	Cost	Cost	*Cost*	Cost	Cost	egory	Plans	Cost Plan	
	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)			Category	All Plans
Q0-D (SCR)	$ 77,721	$ 5,020	$ 42,192	$ 73,110	$ (4,947)	$ 30,220	$ (18,036)	$ 9,739	$ 215,018	$ 8,131	$ 16,714	$ 24,844	$ 239,863	$ 1,925,943	1	3	0.00%	0.66%
Q0-F (SCR)	$ 77,531	$ 4,996	$ 42,258	$ 73,170	$ (4,937)	$ 29,879	$ (18,036)	$ 9,739	$ 214,602	$ 8,560	$ 16,714	$ 25,273	$ 239,875	$ 1,926,042	2	4	0.01%	0.67%
Q1-A (SCR)	$ 79,288	$ 5,413	$ 45,096	$ 82,626	$ (8,590)	$ 18,436	$ (19,971)	$ 12,210	$ 214,508	$ 4,997	$ 20,589	$ 25,586	$ 240,094	$ 1,927,800	3	5	0.76%	0.76%
Q1-B (SCR)	$ 79,250	$ 5,383	$ 45,519	$ 82,539	$ (8,721)	$ 17,378	$ (19,972)	$ 12,210	$ 213,595	$ 4,098	$ 20,589	$ 24,687	$ 238,282	$ 1,913,252	1	1	0.00%	0.00%
Q1-C (SCR)	$ 78,986	$ 5,346	$ 45,836	$ 82,281	$ (8,065)	$ 18,201	$ (19,972)	$ 12,210	$ 214,823	$ 4,027	$ 20,589	$ 24,615	$ 239,438	$ 1,922,534	2	2	0.49%	0.49%

No Economy Purchases

	Levelized Annual Production Cost									Levelized Annual Capital Cost			Levelized	Cumulative	Rank	Rank	%	
							Nearman	Existing	Net	Unit Additions	AOC	*Total*	Total	Present	within	within	Difference	
	Fuel	O&M		*Emission*	Economy	Economy	Participant	Plant O&M	Production	Capital	Capital	*Capital*	System	Worth	Cat-	All	From Least	
Base Plans	Cost	Variable	Fixed	*Costs*	Sales	Purchase	Sales	Capital Cost	Cost	Cost	Cost	*Cost*	Cost	Cost	egory	Plans	Cost Plan	
	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)			Category	All Plans
Q0-D (SCR)	$ 117,100	$ 6,569	$ 42,192	$ 20,361	$ (6,784)	$ -	$ (18,038)	$ 9,739	$ 171,138	$ 8,131	$ 16,714	$ 24,844	$ 195,983	$ 1,573,614	2	5	0.50%	5.37%
Q0-F (SCR)	$ 115,399	$ 6,585	$ 42,258	$ 20,375	$ (6,593)	$ -	$ (18,038)	$ 9,739	$ 169,726	$ 8,560	$ 16,714	$ 25,273	$ 194,999	$ 1,565,718	1	4	0.00%	4.84%
Q1-A (SCR)	$ 106,911	$ 6,537	$ 45,096	$ 22,400	$ (9,492)	$ -	$ (19,973)	$ 12,210	$ 163,688	$ 4,997	$ 20,589	$ 25,586	$ 189,274	$ 1,519,751	3	3	1.76%	1.76%
Q1-B (SCR)	$ 103,789	$ 6,464	$ 45,519	$ 22,137	$ (8,832)	$ -	$ (19,973)	$ 12,210	$ 161,314	$ 4,098	$ 20,589	$ 24,687	$ 186,001	$ 1,493,468	1	1	0.00%	0.00%
Q1-C (SCR)	$ 105,716	$ 6,505	$ 45,836	$ 22,108	$ (8,378)	$ -	$ (19,973)	$ 12,210	$ 164,024	$ 4,027	$ 20,589	$ 24,615	$ 188,640	$ 1,514,654	2	2	1.42%	1.42%

Table 11-4
Phase II - Sensitivity/Risk Ranking of Alternative Plans

Plan rankings based on Net CPW Cost	Base Case	Lose Large Customer	Gain Large Customer	High NG and MCP	High Carbon Tax	No Economy Purchases	**Average**	**Ranking**
Q0-D (SCR)	3	4	5	5	3	5	**4.2**	**4**
Q0-F (SCR)	5	5	4	4	4	4	**4.3**	**5**
Q1-A (SCR)	2	3	3	3	5	3	**3.2**	**3**
Q1-B (SCR)	3	1	1	1	1	1	**1.3**	**1**
Q1-C (SCR)	1	2	2	2	2	2	**1.8**	**2**
Plan rankings based on % higher than least cost plan								
Q0-D (SCR)	1.7%	2.0%	2.8%	4.1%	0.7%	5.4%	**2.8%**	**5**
Q0-F (SCR)	1.7%	2.0%	2.7%	4.1%	0.7%	4.8%	**2.7%**	**4**
Q1-A (SCR)	0.2%	0.9%	0.9%	1.1%	0.8%	1.8%	**0.9%**	**3**
Q1-B (SCR)	1.7%	0.0%	0.0%	0.0%	0.0%	0.0%	**0.3%**	**1**
Q1-C (SCR)	0.0%	0.6%	0.8%	0.6%	0.5%	1.4%	**0.6%**	**2**
Percent Higher than base case CPW Cost								
Q0-D (SCR)	0.0%	-5.0%	5.8%	3.4%	34%	9.3%	**9.5%**	**5**
Q0-F (SCR)	0.0%	-5.0%	5.8%	3.3%	34%	8.8%	**9.4%**	**4**
Q1-A (SCR)	0.0%	-4.6%	5.5%	1.9%	36%	7.2%	**9.2%**	**3**
Q1-B (SCR)	0.0%	-6.9%	3.0%	-0.7%	33%	3.8%	**6.4%**	**1**
Q1-C (SCR)	0.0%	-4.7%	5.6%	1.7%	36%	7.1%	**9.1%**	**2**

Plans	**Q1 Retires 2011**		**Q1 retires after 2017**		
	Q0-D	**Q0-F**	**Q1-A**	**Q1-B**	**Q1-C**
7EA CT	**2011**	**2012**	**2011**		
LM6000	**2013**	**2011**		**2011**	
LM2500					**2011 & 2015**

12.0 Observations and Conclusions Resulting from Phase II Analysis

The results of the Phase II analysis show that plan Q1-B, which is the plan that keeps Quindaro Unit 1 in service and adds an LM6000 (or similar simple cycle combustion turbine) in 2011 is the least cost 10-year expansion plan on a NPV basis. This plan is also the least cost on a NPV basis under all sensitivities. In addition, the costs of plans that substitute two smaller simple cycle combustion turbines or a larger combustion turbine like the GE 7EA are close enough in NPV cost, within less that one percent under base case conditions and within about one percent based on the average of the difference between the base case and each sensitivity, to warrant the inclusion of a range in turbine sizes in the solicitation of proposals to supply combustion turbines.

In addition, the following observations and conclusions, many the same as noted in the Observations and Conclusions Section of the Phase I analysis, can be summarized from the analyses in the previous sections of this report:

- BPU is projected to need 35 MW of additional generating capacity if Quindaro Unit 1 remains in service through 2017. If Quindaro Unit 1 is retired in 2011, BPU is projected to need 107 MW of additional generating capacity to meet its capacity responsibility over the next 10 years.
- Comparing the plans that continue Quindaro Unit 1 operation with the plans that do not, even with the addition of an SCR to Quindaro Unit 1, it is less costly to continue to operate Q1 through 2017 than to retire it in 2011. In addition to the $34 million SCR, the BPU could afford to spend an additional $37 million ($2008) on reliability maintenance projects before it would be less costly to its customers to retire the unit.
- Even a high carbon tax favors the continued operation of Q1. Under a high carbon tax scenario, the plans that retire Quindaro 1 in 2011 move ahead in the rankings to third and fourth, ahead of the plan that retains Quindaro 1 in service and adds a 7EA in 2011.
- Regardless of whether or not Q1 is retired early, the NPV costs of plans that add a Frame 7EA turbine, an LM6000 turbine, or LM2500 turbines in 2011 are so close as to indicate that BPU should solicit bids for these types of machines. Should later studies of the cost to keep Quindaro in service reveal that expenditures greater than $37 million are required and preclude its continued operation beyond 2011, the addition of either a simple cycle LM6000 or a simple cycle 7EA combustion turbine in 2011, followed by a

simple cycle 7EA in 2012 or a LM6000 in 2013, respectively, are not significantly different in NPV. Therefore, the decision to retire Quindaro 1 can be made after the decision on which simple cycle combustion turbine to procure as the next unit and the resulting impact on NPV cost will not vary significantly.

13.0 Revenues and Revenue Requirements

The Electric System provides retail service to residential, commercial, industrial, and other customers of the BPU and has contractual agreements for the wholesale sale of electricity. This section summarizes our forecast of Electric Utility revenue and revenue requirements of the BPU for the period 2008 through 2013. The forecasts reflect the BPU's proposed capital program including potential environmental upgrades to existing Nearman and Quindaro generating units and the addition of a new combustion turbine at Nearman (CT5), as recommended in the 10-Year Power Supply Plan. The forecasts reflect BPU plans as of September 1, 2008.

13.1 Sales Forecast

The basis of the sales forecast is the 2008 Load Forecast provided by BPU. The Load Forecast provides an annual forecast of sales in kilowatt-hours (kWh) by principal customer classes (Residential, Commercial, Industrial, etc.). As shown in Table 13-1, line 1, Total Retail sales are forecast to increase from nominally 2,320,000 kWh to 2,424,000 kWh for the period 2008 through 2013. This is approximately a 0.9 percent compound annual growth rate. Because our financial forecast requires sales to be classified into rate classes (Residential, Small General Service, Large General Service, etc.), it was necessary to reconcile the 2008 Load Forecast customer class sales to rate classes. We performed this transition using the 2007 rate class billing determinants and a report provided by BPU that records billing determinants by both customer class and rate class.

A monthly forecast of rate class billing determinants for 2008 through 2013 was developed by applying the percentage increases by rate class for sales and customer growth to the rate class monthly billing determinants for calendar year 2007. For rate classes billed based on kilowatt (kW) demand, demand growth was assumed to equal sales (kWh) growth.

13.2 Revenues Under Existing Rates

The base revenue forecast under existing rates was generated by applying the existing base rates per the Rate Application Manual dated December 20, 2006 to the rate class billing determinants. Revenue related to recovery of fuel and purchased power expenditures is calculated by applying the forecast of seasonal Energy Rate Component (ERC) to the rate class energy billing determinants. BPU developed the ERC Forecast in conjunction with the ProSym production cost modeling.

Table 13-1
Projected Revenues Under Existing Rates

Line	Description	Year					
		2008	2009	2010	2011	2012	2013
1	Retail Sales (MWh)	2,320,022	2,333,647	2,355,536	2,393,412	2,401,571	2,424,278
	REVENUES ($)						
2	**Base:**						
3	Retail Base Revenue	109,974,158	110,799,861	111,878,932	113,910,502	114,946,435	117,730,486
4	Wholesale Base Revenue						
5	Nearman Participants	6,830,098	7,591,992	8,735,629	9,248,972	9,473,981	13,709,450
6	Borderline	325,694	300,914	320,570	284,871	231,338	268,039
7	Off System Sales	2,251,407	2,107,697	1,558,703	2,019,355	2,230,422	2,561,190
8	Total Wholesale Base Revenue	9,407,199	10,000,603	10,614,901	11,553,199	11,935,740	16,538,679
9	**Total Base Revenue**	119,381,357	120,800,463	122,493,833	125,463,701	126,882,175	134,269,165
10	**Fuel:**						
11	Retail ERC Revenue	63,604,470	70,120,698	71,160,861	79,600,913	87,032,392	84,735,970
12	Nearman Participants Fuel Revenue	8,745,421	7,217,780	8,206,782	8,789,648	7,745,899	9,418,350
13	Borderline Fuel Revenue	487,279	520,189	508,744	552,736	614,645	586,404
14	Off System Sales Fuel Revenue	4,717,385	4,405,212	3,488,829	4,309,808	4,705,482	5,506,221
15	**Total Fuel Revenue**	77,554,555	82,263,879	83,365,217	93,253,104	100,098,419	100,246,945
16	Total Retail Rate Revenue	173,578,628	180,920,558	183,039,794	193,511,415	201,978,827	202,466,456
17	Total Wholesale Rate Revenue	23,357,284	22,143,784	22,819,257	25,205,390	25,001,767	32,049,654
18	**Total Rate Revenue**	**196,935,912**	**203,064,342**	**205,859,050**	**218,716,805**	**226,980,594**	**234,516,110**
19	**Other Revenue:**						
20	PILOT	15,185,264	15,694,071	15,987,247	16,938,153	17,559,734	18,091,781
21	Forfeited Discounts	2,100,000	2,142,000	2,184,800	2,228,500	2,273,100	2,318,600
22	Connect/Disconnect Fees	1,000,000	1,020,000	1,040,400	1,061,200	1,082,400	1,104,000
23	Tower/Pole Attachment Rentals	950,000	969,000	988,400	1,008,200	1,028,400	1,049,000
24	Ash Disposal	150,000	153,000	156,100	159,200	162,400	165,600
25	Diversion Fines	60,000	61,200	62,400	63,600	64,900	66,200
26	Service Fees	1,200,000	1,224,000	1,248,500	1,273,500	1,299,000	1,325,000
27	Other Miscellaneous Revenues	142,800	145,700	148,600	151,600	154,600	157,700
28	Rent From Electric Property	411,949	420,200	428,600	437,200	445,900	454,800
29	Margin on EIS Spot Market Sales	975,000	975,000	975,000	975,000	975,000	975,000
30	Investment Income	2,894,059	2,894,059	2,963,288	3,904,686	4,816,686	4,785,774
31	**Total Other Revenue**	**25,069,072**	**25,698,230**	**26,183,335**	**28,200,839**	**29,862,120**	**30,493,456**
32	**Total Revenue**	**222,004,983**	**228,762,572**	**232,042,385**	**246,917,644**	**256,842,714**	**265,009,565**

Retail revenues under existing rates reflect the two current sources of revenue: base rate revenue and ERC revenue, where base rates are the stated tariffs effective January 1, 2007. The forecast of the Electric System's operating revenues under existing rates are shown in Table 13-1. Line 3 shows the forecast of Retail base rate (non-fuel) sales revenue under existing rates and ranges from $110.0 million in 2008 to $117.7 million in 2013. Base rate sales revenue reflects the Retail kWh sales from the 2008 Load Forecast. Base rate sales revenue from wholesale customers is shown in lines 5 through 8 and increases from $9.4 million in 2008 to $16.5 million in 2013. The large increase in Nearman Participant sales in 2013 reflects the adjustment of participants' share of Nearman 1 AQC retrofits.

Charges related to fuel cost recovery are shown in lines 10 through 14. Retail sales fuel expenses are recovered through BPU's ERC rider. The ERC rider is adjusted semi-annually to recover forecast fuel expenditures and trued up for any revenue/cost variance in the prior like season period; summer for summer, winter for winter. For the purposes of this report, ERC revenue is set equal to retail fuel expense for the year.

The forecast of fuel expenses, wholesale sales, purchased power, and the calculation of ERC is forecast using the ProSym Production Cost Model. The model inputs reflect the addition of the recommended power supply plan and environmental upgrades. The hourly load inputs to the ProSym model are based on the same 2008 Load Forecast that is used to forecast sales. Fuel revenue on lines 11 through 14 are divided into ERC (retail) revenue, Nearman Participant fuel, Borderline fuel, and fuel for off-system sales. Nearman Participant, Borderline, and off-system energy sales are outputs of the ProSym model. From those energy sales, an estimate of the cost of fuel to produce wholesale sales is calculated. Total fuel revenue (line 15) ranges from $77.6 million in 2008 to $100.2 million in 2013 and matches fuel expense on Table 13-2, line 11.

Other revenues consist of Payments in Lieu of Taxes (PILOT) revenue; miscellaneous fees and rents such as Connect/Disconnect fees, Tower/Pole Attachment Rental, and Diversion Fines; margin on Energy Imbalance Service (EIS) spot market sales; and interest income. PILOT revenue (line 20) is calculated at the current rate of 7.9 percent of base rate and fuel charges (excluding off-system fuel). A proposed temporary increase in PILOT to 9.9 percent in 2009 and 2010 is not included in this analysis. PILOT is a pass-through revenue, and as such has no effect on the overall rate impact. Other revenue on lines 21 through 28 are based on the 2008 budget and escalated at 2 percent annually. Margin on EIS Spot Market Sales is based on BPU's estimate of $975,000 per year. Investment Income (line 30) is calculated on average balances for BPU's various funds using a 3.5 percent interest rate.

Table 13-2
Projected Revenue Requirements and Surplus/(Deficiency) Under Existing Rates

Line	Description	Year 2008	2009	2010	2011	2012	2013
	REVENUE REQUIREMENTS ($)						
1	**Fuel Expense**						
2	Retail						
3	Generation Fuel Costs	42,489,262	44,987,824	48,426,283	58,513,509	61,065,986	62,260,338
4	Purchased Power	21,115,208	25,132,874	22,734,578	21,087,404	25,966,406	22,475,632
5	Total Retail Fuel	63,604,470	70,120,698	71,160,861	79,600,913	87,032,392	84,735,970
6	Wholesale						
7	Borderline Fuel Costs	487,279	520,189	508,744	552,736	614,645	586,404
8	Nearman Participants Fuel Cost	8,745,421	7,217,780	8,206,782	8,789,648	7,745,899	9,418,350
9	Off System Fuel Costs	4,717,385	4,405,212	3,488,829	4,309,808	4,705,482	5,506,221
10	Total Wholesale Fuel	13,950,085	12,143,181	12,204,356	13,652,191	13,066,027	15,510,975
11	**Total Fuel Expense**	77,554,555	82,263,879	83,365,217	93,253,104	100,098,419	100,246,945
12	**Operation and Maintenance Expense**						
13	Production	34,667,235	36,696,605	36,500,609	37,053,756	38,592,997	38,720,763
14	Transmission	2,684,770	2,807,457	2,913,360	3,036,486	3,165,079	3,299,397
15	Distribution	19,192,856	20,059,030	20,915,854	21,811,446	22,747,669	23,726,483
16	Customer Accounts	5,238,725	5,472,997	5,709,314	5,956,498	6,215,080	6,485,620
17	Sales	719,400	753,472	784,851	817,585	851,735	887,365
18	Administrative and General	22,373,405	23,426,234	24,403,825	25,423,976	26,488,626	27,599,813
19	**Total O&M Expense**	84,876,391	89,215,795	91,227,813	94,099,745	98,061,186	100,719,442
20	**Total Expenses**	162,430,946	171,479,674	174,593,030	187,352,849	198,159,605	200,966,387
21	**Net Revenues**	59,574,038	57,282,899	57,449,355	59,564,795	58,683,109	64,043,178
22	**Debt Service**						
23	Existing Debt Service	24,003,296	20,414,676	20,373,119	19,785,713	19,782,953	19,796,067
24	2008 Bonds ($54.9 million)	-	3,789,732	3,717,269	3,726,762	3,744,474	3,746,927
25	2009 Environmental Bonds ($118.9 million)	-	3,566,520	9,809,373	9,809,373	9,809,373	9,809,373
26	2009 Capital Bonds ($92.9 million)	-	2,862,240	7,463,455	7,463,455	7,463,455	7,463,455
27	2011 Environmental Bonds ($134.9 million)		-	-	4,047,630	10,554,427	10,554,427
28	2011 Capital Bonds ($61.2 million)	-	-	-	1,744,890	4,549,901	4,549,901
29	**Total Debt Service**	24,003,296	30,633,168	41,363,216	46,577,823	55,904,583	55,920,150
30	Revenue After Debt Service Obligation	35,570,741	26,649,731	16,086,140	12,986,972	2,778,526	8,123,028
31	**Debt Service Coverage Under Existing Rates**						
32	Total System Achieved	**2.48**	**1.87**	**1.39**	**1.28**	**1.05**	**1.15**
33	Minimum Coverage Required	1.60	1.60	1.60	1.60	1.60	1.60
34	**Other Expenditures and Transfers**						
35	PILOT	15,185,264	15,694,071	15,987,247	16,938,153	17,559,734	18,091,781
36	Cash Financed Capital Projects	18,250,540	13,192,247	14,970,219	17,121,906	19,360,325	26,640,541
37	Less: Reimbursable Projects	(428,200)	(208,200)	(208,200)	(208,200)	(208,200)	(208,200)
38	Capital Lease Payments	1,103,401	187,671	-	-	-	-
39	Heat Pump Program	558,642	850,000	850,000	850,000	850,000	850,000
40	Economic Development Fund Authorization	525,000	525,000	525,000	525,000	525,000	525,000
41	**Total Other Exp. And Transfers**	**35,194,647**	**30,240,789**	**32,124,266**	**35,226,859**	**38,086,859**	**45,899,122**
42	**Total Revenue Requirement**	221,628,889	232,353,630	248,080,512	269,157,531	292,151,047	302,785,659
43	**Net Revenue Requirement**	196,559,817	206,655,401	221,897,177	240,956,692	262,288,927	272,292,203
44	Revenue Surplus / (Deficiency) Under Existing	376,095	(3,591,058)	(16,038,126)	(22,239,887)	(35,308,333)	(37,776,094)

Total revenue under existing rates and other sources, shown on line 32, is forecast to increase from $222.0 million in 2008 to $265.0 million in 2013.

13.3 Revenue Requirements

The overall adequacy of the existing rates is tested by comparing revenues under existing rates with revenue requirements. Revenue requirements are developed on a cash basis and consist primarily of fuel expenditures, operation and maintenance (O&M) expenses, debt service requirements, cash financed capital projects, PILOT, and other miscellaneous program costs such as the heat pump program. The forecast of annual revenue requirements is shown in Table 13-2 and discussed in the following sections.

13.3.1 Fuel Expenses

As discussed in Section 13.2, the forecast of fuel expenses is based on the ProSym production cost model of the recommended power supply plan. The forecast provides a monthly forecast of generation for each generating unit, fuel costs for each unit, purchased power fuel cost and related production expenses. The forecast of fuel expenses is summarized on lines 1 through 11 of Table 13-2.

13.3.2 Operation and Maintenance Expense

The forecast of operation and maintenance (O&M) expense is based on the 2008 Budget. The 2008 Budget is categorized by FERC account, with additional detail for Dept ID and Class ID. The forecast of O&M expenses for 2009 through 2013 categorized each budget item as Direct Labor, Labor Burden/Benefits, and Non-Labor Expenses. Direct Labor is forecast to increase at 3.5 percent per year. Labor Burden and Benefits are forecast to increase 6 percent annually. Non-Labor Expenses are forecast to increase 5 percent in 2009 and 4 percent for the remaining years in the study period. The 2009 percentage is higher to account for an expected increase in use of contract labor. BPU reviewed the non-fuel production O&M forecast and made adjustments to reflect expected operations under the recommended power supply plan. O&M expenses are summarized on lines 12 through 19 of Table 13-2.

13.3.3 Capital Improvement Plan

The baseline Capital Improvement Plan (CIP) is the 2008 Budget, which provides a five-year (2008 through 2012) capital plan and projection of funding sources. The production budget plan was modified by BPU to incorporate needed equipment replacements for existing units to accommodate the recommended power supply plan including the following capacity addition and environmental projects:

- Construction of a combustion turbine generator at Nearman (CT5) by 2011.
- Low NO_x Burners (LNB) and Over Fire Air (OFA) at Nearman 1 and Quindaro 2 units, with construction completed by 2010.
- Flue Gas Desulfurization (FGD), Fabric Filter, and Landfill improvements at Nearman 1, with construction completed by December 2012.
- Selective Catalytic Reduction (SCR) at Quindaro 1 with construction completed by 2012.

The 2013 CIP was based on the trend of prior years' budgeted projects for routine replacements. Table 13-3 presents the adjusted CIP through 2013.

13.3.4 Debt Service

BPU's Capital Improvement Plan will be financed with a blend of long-term debt (bonds) and cash financing from operating revenues. The CIP projects in Table 13-3 are divided into two groups: environmental projects and all other capital projects. The environmental projects are maintained separately, as we recommend financing these exclusively from a proposed Environmental Surcharge (see Subsection 13.4.1).

The environmental projects are scheduled to be constructed from 2009 through 2012 and total $248.7 million. For purposes of the financial forecast, we assume the projects will be financed with three bond issues. Two bonds will be issued in 2009; one for the first two years of Nearman environmental projects ($62.0 million) and one for Quindaro environmental projects ($56.9 million). For forecast purposes the 2009 bonds are separated into Quindaro projects financed over 20 years (due to the current age and expected remaining life of Quindaro) and all other debt financed projects are financed over 25 years. The remaining Nearman environmental projects will be financed with a $132.9 million issue in 2011. All bond amounts and debt service payments are estimated at 6.0 percent (which was a more recent estimate of interest than what was used in the Phase I and II analyses) interest and 2.0 percent issuance costs. Annual debt service payments for existing and proposed bonds are shown on lines 23 through 28 of Table 13-2. Total debt service increases from $24.0 million in 2008 to $55.9 million in 2013.

Table 13-3
Capital Improvement Plan (2008 through 2013)

Line	Description	Year 2008	2009	2010	2011	2012	2013	Total
	Electric System Capital Projects							
1	Electric Unit Equipment	$ 48,138	$ 901,500	$ 922,000	$ 1,123,000	$ 1,217,000	$ 1,170,000	$ 5,381,638
2	Electric Ops General Construction	682,435	860,000	820,000	720,000	620,000	670,000	4,372,435
3	Electric Supply General Construction	75,000						75,000
4	Electric Accident Claims	108,200	108,200	108,200	108,200	108,200	108,200	649,200
5	Electric Overhead Distribution	3,559,848	4,200,000	5,524,561	6,584,506	2,800,000	4,692,253	27,361,168
6	Electric UG Distribution	1,956,796	2,750,000	4,500,000	4,000,000	3,500,000	3,750,000	20,456,796
7	Electric Reimbursible	100,000	100,000	100,000	100,000	100,000	100,000	600,000
8	Electric Transmission	8,083,000	2,481,500	9,650,000	8,150,000	650,000	4,400,000	33,414,500
9	Electric Transformers	820,000	900,000	900,000	900,000	900,000	900,000	5,320,000
10	Electric Meters	350,000	1,000,000	2,000,000	2,000,000	2,000,000	2,000,000	9,350,000
11	Electric Lighting & Signals	480,715	500,000	600,000	600,000	500,000	550,000	3,230,715
12	Electric Substations	7,431,731	9,620,037	8,550,000	1,800,000	1,800,000	1,800,000	31,001,768
13	Storm Expenses	1,000	1,000	1,000	1,000	1,000	1,000	6,000
14	Nearman Unit 1	2,998,089	2,457,657	2,834,000	3,304,000	16,576,000	532,000	28,701,746
15	Nearman Common	1,475,894	2,134,000	1,714,000	134,000	594,000	3,662,000	9,713,894
16	Nearman CT5		14,736,800	51,578,800	7,368,400			73,684,000
17	Quindaro Unit 1	834,443	168,000	3,192,000	15,400,000	392,000	784,000	20,770,443
18	Quindaro Unit 2	9,159,183	2,339,557	560,000	1,120,000	616,000	2,072,000	15,866,740
19	Quindaro Common	2,288,016	2,817,000	1,070,000	588,000	700,000	2,296,000	9,759,016
20	Quindaro CT1	-	1,120,000	258,000	-	-	-	1,378,000
21	Quindaro CT2	-	-	1,613,000	-	-	-	1,613,000
22	Quindaro CT3	-	-	2,565,000	-	112,000	-	2,677,000
23	Electric Control Center	425,000	500,000	250,000	-	-	-	1,175,000
24	**Total Electric Capital Projects**	**$ 40,877,488**	**$ 49,695,251**	**$ 99,310,561**	**$ 54,001,106**	**$ 33,186,200**	**$ 29,487,453**	**$ 306,558,059**
25	**Environmental/AQC Projects**							
26	N1 LNB & OFA - $23,476,000 (2010$)		21,128,400	2,347,600				23,476,000
27	Q2 LNB & OFA - $12,203,000 (2010$)		10,982,700	1,220,300				12,203,000
28	N1 FGD, FF, & Landfill - $169,516,000 (2012$)		3,390,320	33,903,200	101,709,600	30,512,880		169,516,000
29	Q1 SCR - $43,534,000 (2011$)		8,706,800	15,236,900	15,236,900	4,353,400		43,534,000
30	**Total Environmental/AQC Projects**	**$ -**	**$ 44,208,220**	**$ 52,708,000**	**$ 116,946,500**	**$ 34,866,280**	**$ -**	**$ 248,729,000**
31	Common Furnish and Equipment	5,000	20,000	25,000	25,000	25,000	25,000	125,000
32	Common Facility Improvements	100,873	546,308	261,210	217,400	225,500	221,450	1,572,741
33	Common Grounds	-	10,000	10,000	10,000	10,000	10,000	50,000
34	Common Technology	1,341,263	827,000	815,000	802,000	860,000	831,000	5,476,263
35	Administrative Service Technology	383,600	430,000	435,000	440,000	445,000	450,000	2,583,600
36	**Total Common Projets**	**$ 1,830,736**	**$ 1,833,308**	**$ 1,546,210**	**$ 1,494,400**	**$ 1,565,500**	**$ 1,537,450**	**$ 9,807,604**
37	**Electric Portion of Common Projects @ 75%**	**1,373,052**	**1,374,981**	**1,159,658**	**1,120,800**	**1,174,125**	**1,153,088**	**7,355,703**
38	**Environmental/AQC Projects**							
39	Nearman	-	24,518,720	36,250,800	101,709,600	30,512,880	-	
40	Quindaro	-	19,689,500	16,457,200	15,236,900	4,353,400	-	
		-	44,208,220	52,708,000	116,946,500	34,866,280	-	
41	**Financing Recap**							
42	2008 Debt Issue (Capital)	24,000,000	29,877,985					53,877,985
43	2009 Nearman Environmental		24,518,720	36,250,800				60,769,520
44	2009 Quindaro Environmental		19,689,500	16,457,200	15,236,900	4,353,400		55,737,000
45	2011 Nearman Environmental				101,709,600	30,512,880		132,222,480
46	2009 Capital		8,000,000	85,500,000				93,500,000
47	2011 Capital				38,000,000	15,000,000	4,000,000	57,000,000
48	**Net Amount to Cash Finance**	**18,250,540**	**13,192,247**	**14,970,219**	**17,121,906**	**19,360,325**	**26,640,541**	**109,535,777**

Note: All dollar amounts are shown in real dollars unless otherwise noted.

The remaining capital projects in the CIP, including the construction of CT5 at Nearman, will be financed primarily with proceeds from bond issues in 2008, 2009, and 2011. The currently budgeted Series 2008 Bonds are forecast to provide proceeds of $53.9 million for needed routine replacements. The bond amounts for the 2009 and 2011 series bonds are projected to cover the remaining projects in the CIP, less an amount of annual cash financed capital projects. The $73.7 million in financing for the addition of CT5 is included in the 2009 and 2011 capital bonds. The amount of cash financing (shown on Table 13-3, line 48) varies based on the cash flow capability of BPU and ranges from a low of $13.2 million in 2009 to $26.6 million in 2013. The recent average rate for BPU cash financed projects has been in the $15 to 20 million range. Following the series of base rate increases we recommend, we anticipate BPU can increase the average amount of cash financed projects to approximately $25 million annually.

13.3.5 Other Expenditures and Transfers

Other expenditures, on Table 13-2, lines 37 through 40, include capital lease payments and costs associated with the Heat Pump Program and Economic Development Fund Authorization. Revenue from reimbursable projects is shown as negative and reduces the overall revenue requirement. Payment in lieu of taxes (PILOT) shown on line 35 is the transfer of PILOT funds collected to the Unified Government (UG). The amount of the transfer is equal to the funds collected and as such has no net impact on the revenue requirement. Total Expenditures and Transfers (including cash financed capital projects) shown on line 41 of Table 13-2 ranges from $30.2 million in 2009 to $45.9 million in 2013.

13.3.6 Total Revenue Requirement and Revenue Deficiency

The total revenue requirement of the Electric Utility is the sum of fuel expense, O&M expense, debt service payments, and other expenditures and transfers. As shown on line 42 of Table 13-2, the total revenue requirement is forecast to increase from $221.6 million in 2008 to $302.8 million in 2013. The annual revenue surplus or deficiency is calculated by subtracting this amount from the total revenue under existing rates on line 32 of Table 13-1. The annual surplus/deficiency ranges from a surplus of $0.4 million in 2008, and deficiencies of $3.6 million in 2009, increasing to a deficiency of $37.8 million in 2013.

13.3.7 Debt Service Coverage Under Existing Rates

The stated BPU financial policy regarding debt service coverage states that the BPU maintain minimum debt service coverage such that net revenues are 1.6 times the maximum annual debt service. On line 32 of Table 13-2 is the forecast of debt service coverage under existing rates. Based on the forecast, BPU's debt service coverage under existing rates is below 1.6 in every year from 2010 through 2013.

13.4 Proposed Adjustment to Rates

The total revenue deficiency under existing rates for 2009 through 2013 is projected to be approximately $115 million. To address the significant annual deficiencies we recommend an Environmental Surcharge (ESC) to recover the capital portion of environmental upgrades discussed in Subsection 13.3.3, and a series of consecutive annual base rate increases from 2010 through 2012.

13.4.1 Environmental Surcharge

In order to tie the recovery of capital costs related to required environmental projects we recommend the ESC be implemented beginning in January 2009. The surcharge would be a new rate rider applied on a uniform $/kWh basis to all revenue generating Retail rate classes. The ESC would be designed to recover the annual debt service payment on existing unit's environmental upgrades. The ESC would be adjusted annually to recover upcoming year's debt service payment on the 2009 Nearman, 2009 Quindaro, and 2011 Nearman environmental bonds. The total amount to be recovered from retail ratepayers will be reduced by the required pro-rata contribution of the Nearman Participants.

The projected ESC is $0.0015/kWh in 2009, $0.0040/kWh in 2010, $0.0056/kWh in 2011, $0.0083/kWh in 2012, and $0.0067/kWh in 2013. Revenues generated by the ESC are forecast to increase from $3.6 million in 2009 to $19.9 million in 2012, and $16.3 million in 2013.

13.4.2 Adjustment to Retail Base Rates

The remaining revenue deficiency will need to be recovered through increases to retail base rates. The rate adjustments must be sufficient to meet BPU's stated financial policies for debt service coverage and operating reserve levels. BPU's stated financial policy requires a minimum debt service coverage ratio of 1.60 (net revenues available for debt service must be 1.6 times the annual debt service payment). In addition, BPU has stated financial policies for operating cash reserves and Rate Stabilization Fund balances.

Currently, the fund balances for operating reserve and Rate Stabilization are approximately $10 million underfunded relative to financial policy. To meet BPU financial objectives, address the revenue deficiencies, and lessen the rate impact on retail customers, we recommend a series of annual retail base rate increases of 6.25 percent from 2010 through 2012.

13.5 Revenue and Revenue Requirements Under Proposed Rates

Table 13-4 presents the financial operations of the Electric System under the proposed retail base rate revenue increases and the ESC. Revenue requirements under proposed rates are the same as under existing rates with the exception of PILOT, which is larger because it is calculated on higher revenues. Because PILOT revenue is included in the calculation of debt service coverage, this has the impact of further improving debt service coverage. Debt service coverage in the years following rate adjustment ranges from 1.81 to 2.00.

Total annual revenue surplus or deficiency is shown on line 78 of Table 13-4. The surpluses shown in 2011 and 2012 are used to bring BPU in compliance with its stated financial policies. As shown on line 84, BPU is forecast to be deficient in meeting its financial policies of operating reserve and rate stabilization until 2012.

13.6 Overall Projected Rate Impact

The overall rate impact of the rate proposals is shown in Table 13-5. The average sales rate (in $/kWh) under existing rates (line 6) is calculated by dividing existing revenue (line 5) by Retail sales (line 1) and dividing by 1,000. Projected revenue under proposed rates shown on line 10 is the sum of retail revenue under existing rates (line 5), ESC revenue (line 7), and revenue from proposed base rate increases (line 8). The projected average sales rate is shown on line 11 and increases from an existing $0.0748/kWh in 2008, peaks at $0.1014/kWh in 2012 and declines to $0.0993/kWh in 2013. Year-over-year overall percentage rate increases are shown on line 12. The projected cumulative rate increase for the period 2008 through 2013 is 32.8 percent.

Figure 13-1 presents the projected $/kWh increase by rate components for: existing base, ERC, ESC and projected base rate increases for each of the six years. As shown in the stacked bar chart increases in ERC and the ESC are responsible for over half of the projected increase in rates. Both of these rate components are driven by external factors outside the direct control of the BPU. ERC is driven by the cost of fuels (coal and natural gas) and power market purchases. ESC reflects the projected rate impact of environmental capital expenditures that may be required by state or Federal regulations. Figure 13-2 presents a chart of the projected cumulative percent increase of 32.8 percent by rate component. ERC and ESC account for approximately 58 percent of the overall projected increase. Base rate increases account for the remaining 42 percent of the overall increase and are driven primarily by projected increases in operating and capital expenditures, the need to increase cash reserves to meet financial policy, and debt service on the proposed CT 5. We estimate approximately half of the base rate increase is attributable to CT5. However, without CT5 BPU would need to purchase replacement power off system at potentially higher and more volatile market prices increasing the projected ERC charges and increasing the risk of power delivery unavailability due to external transmission constraints.

Table 13-4
Projected Revenue and Revenue Requirements Under Proposed Rates
Page 1 of 2

Line	Description	Year					
		2008	2009	2010	2011	2012	2013
1	Retail Sales (MWh)	2,320,022	2,333,647	2,355,536	2,393,412	2,401,571	2,424,278
	REVENUES ($)						
2	**Base:**						
3	Retail Base Revenue Existing Rates	109,974,158	110,799,861	111,878,932	113,910,502	114,946,435	117,730,486
4	Proposed Base Rate Revenue Increases			6,992,433	14,238,813	21,552,457	22,074,466
5	Wholesale Base Revenue						
6	Nearman Participants	6,830,098	7,591,992	8,735,629	9,248,972	9,473,981	13,709,450
7	Borderline	325,694	300,914	320,570	284,871	231,338	268,039
8	Off System Sales	2,251,407	2,107,697	1,558,703	2,019,355	2,230,422	2,561,190
9	Total Wholesale Base Revenue	9,407,199	10,000,603	10,614,901	11,553,199	11,935,740	16,538,679
10	**Total Base Revenue**	119,381,357	120,800,463	129,486,267	139,702,514	148,434,632	156,343,631
11	**Fuel:**						
12	Retail ERC Revenue	63,604,470	70,120,698	71,160,861	79,600,913	87,032,392	84,735,970
13	Nearman Participants Fuel Revenue	8,745,421	7,217,780	8,206,782	8,789,648	7,745,899	9,418,350
14	Borderline Fuel Revenue	487,279	520,189	508,744	552,736	614,645	586,404
15	Off System Sales Fuel Revenue	4,717,385	4,405,212	3,488,829	4,309,808	4,705,482	5,506,221
16	**Total Fuel Revenue**	77,554,555	82,263,879	83,365,217	93,253,104	100,098,419	100,246,945
17	Environmental Surcharge Revenue		3,566,520	9,314,193	13,361,823	19,868,620	16,293,076
18	Total Retail Rate Revenue	173,578,628	184,487,078	199,346,420	221,112,051	243,399,904	240,833,998
19	Total Wholesale Rate Revenue	23,357,284	22,143,784	22,819,257	25,205,390	25,001,767	32,049,654
20	**Total Rate Revenue**	**196,935,912**	**206,630,862**	**222,165,677**	**246,317,441**	**268,401,671**	**272,883,652**
21	**Other Revenue:**						
22	PILOT	15,185,264	15,975,826	17,275,471	19,118,603	20,831,999	21,122,817
23	Forfeited Discounts	2,100,000	2,142,000	2,184,800	2,228,500	2,273,100	2,318,600
24	Connect/Disconnect Fees	1,000,000	1,020,000	1,040,400	1,061,200	1,082,400	1,104,000
25	Tower/Pole Attachment Rentals	950,000	969,000	988,400	1,008,200	1,028,400	1,049,000
26	Ash Disposal	150,000	153,000	156,100	159,200	162,400	165,600
27	Diversion Fines	60,000	61,200	62,400	63,600	64,900	66,200
28	Service Fees	1,200,000	1,224,000	1,248,500	1,273,500	1,299,000	1,325,000
29	Other Miscellaneous Revenues	142,800	145,700	148,600	151,600	154,600	157,700
30	Rent From Electric Property	411,949	420,200	428,600	437,200	445,900	454,800
31	Margin on EIS Spot Market Sales	975,000	975,000	975,000	975,000	975,000	975,000
32	Investment Income	2,894,059	2,894,059	2,963,288	3,904,686	4,816,686	4,785,774
33	**Total Other Revenue**	**25,069,072**	**25,979,985**	**27,471,559**	**30,381,289**	**33,134,385**	**33,524,491**
34	**Total Revenue**	**222,004,983**	**232,610,847**	**249,637,236**	**276,698,730**	**301,536,056**	**306,408,143**

Table 13-4 (Continued)
Projected Revenue and Revenue Requirements Under Proposed Rates
Page 2 of 2

Line	Description	Year 2008	2009	2010	2011	2012	2013
35	**REVENUE REQUIREMENTS ($)**						
36	**Fuel Expense**						
37	Retail						
38	Generation Fuel Costs	42,489,262	44,987,824	48,426,283	58,513,509	61,065,986	62,260,338
39	Purchased Power	21,115,208	25,132,874	22,734,578	21,087,404	25,966,406	22,475,632
40	Total Retail Fuel	63,604,470	70,120,698	71,160,861	79,600,913	87,032,392	84,735,970
41	Wholesale						
42	Borderline Fuel Costs	487,279	520,189	508,744	552,736	614,645	586,404
43	Nearman Participants Fuel Cost	8,745,421	7,217,780	8,206,782	8,789,648	7,745,899	9,418,350
44	Off System Fuel Costs	4,717,385	4,405,212	3,488,829	4,309,808	4,705,482	5,506,221
45	Total Wholesale Fuel	13,950,085	12,143,181	12,204,356	13,652,191	13,066,027	15,510,975
46	**Total Fuel Expense**	77,554,555	82,263,879	83,365,217	93,253,104	100,098,419	100,246,945
47	**Operation and Maintenance Expense**						
48	Production	34,667,235	36,696,605	36,500,609	37,053,756	38,592,997	38,720,763
49	Transmission	2,684,770	2,807,457	2,913,360	3,036,486	3,165,079	3,299,397
50	Distribution	19,192,856	20,059,030	20,915,854	21,811,446	22,747,669	23,726,483
51	Customer Accounts	5,238,725	5,472,997	5,709,314	5,956,498	6,215,080	6,485,620
52	Sales	719,400	753,472	784,851	817,585	851,735	887,365
53	Administrative and General	22,373,405	23,426,234	24,403,825	25,423,976	26,488,626	27,599,813
54	**Total O&M Expense**	84,876,391	89,215,795	91,227,813	94,099,745	98,061,186	100,719,442
55	**Total Expenses**	162,430,946	171,479,674	174,593,030	187,352,849	198,159,605	200,966,387
56	**Net Revenues**	59,574,038	61,131,174	75,044,206	89,345,881	103,376,451	105,441,756
57	**Debt Service**						
58	Existing Debt Service	24,003,296	20,414,676	20,373,119	19,785,713	19,782,953	19,796,067
59	2008 Bonds ($54.9 million)	-	3,789,732	3,717,269	3,726,762	3,744,474	3,746,927
60	2009 Environmental Bonds ($118.9 million)	-	3,566,520	9,809,373	9,809,373	9,809,373	9,809,373
61	2009 Capital Bonds ($92.9 million)	-	2,862,240	7,463,455	7,463,455	7,463,455	7,463,455
62	2011 Environmental Bonds ($134.9 million)	-	-	-	4,047,630	10,554,427	10,554,427
63	2011 Capital Bonds ($61.2 million)	-	-	-	1,744,890	4,549,901	4,549,901
64	**Total Debt Service**	24,003,296	30,633,168	41,363,216	46,577,823	55,904,583	55,920,150
65	Revenue After Debt Service Obligation	35,570,741	30,498,006	33,680,990	42,768,058	47,471,868	49,521,606
66	**Debt Service Coverage Under Proposed Rates**						
67	Total System Achieved	**2.48**	**2.00**	**1.81**	**1.92**	**1.85**	**1.89**
68	Minimum Coverage Required	1.60	1.60	1.60	1.60	1.60	1.60
69	**Other Expenditures and Transfers**						
70	PILOT	15,185,264	15,975,826	17,275,471	19,118,603	20,831,999	21,122,817
71	Cash Financed Capital Projects	18,250,540	13,192,247	14,970,219	17,121,906	19,360,325	26,640,541
72	Less: Reimbursable Projects	(428,200)	(208,200)	(208,200)	(208,200)	(208,200)	(208,200)
73	Capital Lease Payments	1,103,401	187,671	-	-	-	-
74	Heat Pump Program	558,642	850,000	850,000	850,000	850,000	850,000
75	Economic Development Fund Authorization	525,000	525,000	525,000	525,000	525,000	525,000
76	**Total Other Exp. And Transfers**	**35,194,647**	**30,522,544**	**33,412,489**	**37,407,309**	**41,359,124**	**48,930,158**
77	**Total Revenue Requirement**	221,628,889	232,635,386	249,368,735	271,337,981	295,423,312	305,816,695
78	Revenue Surplus / (Deficiency) Under Proposed Rates	376,095	(24,538)	268,501	5,360,749	6,112,744	591,449
79	**Operating Cash Balance**						
80	Beg Balance	10,826,298	11,202,393	11,177,854	11,446,355	16,807,104	22,919,848
81	Annual Cash Flow	376,095	(24,538)	268,501	5,360,749	6,112,744	591,449
82	End Balance	11,202,393	11,177,854	11,446,355	16,807,104	22,919,848	23,511,297
83	Target Operating Balance to Meet Financial Policies		20,781,025	20,807,824	21,358,219	22,749,815	23,300,825
84	Target Cash (Deficiency)/Surplus		(9,603,171)	(9,361,469)	(4,551,115)	170,033	210,472

Table 13-5
Overall Retail Rate Impact of Proposed Rates

Line	Description	For the Fiscal Year Ended: 2008	2009	2010	2011	2012	2013
		$	$	$	$	$	$
1	Forecast Retail Sales (MWh)	2,320,022	2,333,647	2,355,536	2,393,412	2,401,571	2,424,278
2	Retail Revenue Under Existing Rates						
3	Base Rates	109,974,158	110,799,861	111,878,932	113,910,502	114,946,435	117,730,486
4	ERC Revenue	63,604,470	70,120,698	71,160,861	79,600,913	87,032,392	84,735,970
5	Total Retail Rate Revenue	173,578,628	180,920,558	183,039,794	193,511,415	201,978,827	202,466,456
6	Average Sales Rate Under Existing Rates ($/kWh)	0.0748	0.0775	0.0777	0.0809	0.0841	0.0835
7	ESC Revenue		3,566,520	9,314,193	13,361,823	19,868,620	16,293,076
8	Proposed Base Rate Increases		-	6,992,433	14,238,813	21,552,457	22,074,466
9	Overall Rate Increases		3,566,520	16,306,627	27,600,636	41,421,077	38,367,542
10	Total Proposed Retail Rate Revenue	173,578,628	184,487,078	199,346,420	221,112,051	243,399,904	240,833,998
11	Average Sales Rate Under Proposed Rates ($/kWh)	0.0748	0.0791	0.0846	0.0924	0.1014	0.0993
12	Annual Percentage Increase Over Existing Rates (1)		5.5%	7.2%	9.6%	10.7%	-2.4%

Notes:
(1) Calculated as current year proposed rate minus previous year proposed rate, divided by current year existing rate
Example: 2010 % Increase = (.0846 - .0791) / .0777 = 7.2%

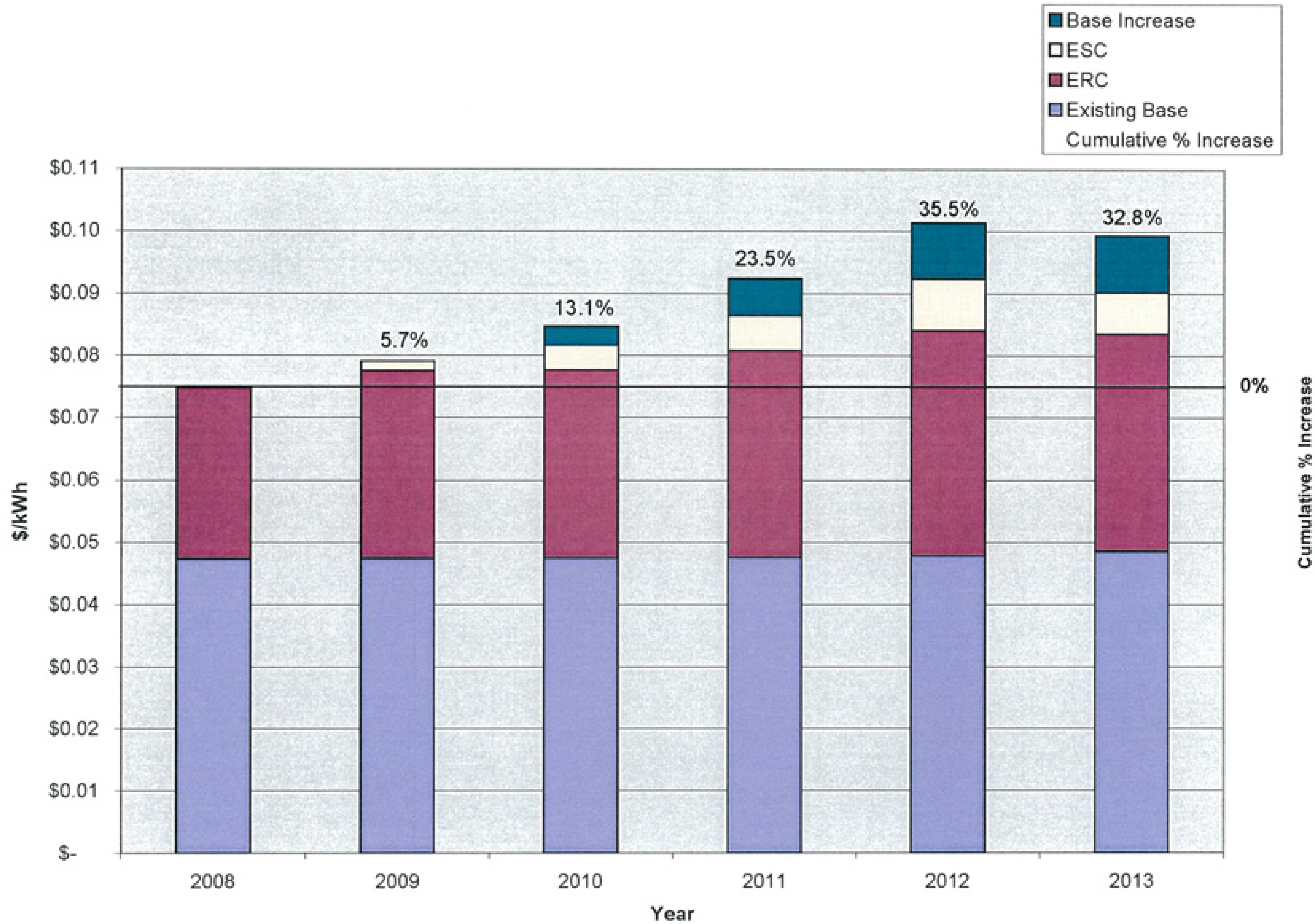


Figure 13-1
Total Projected Rates and Cumulative Percentage Increase

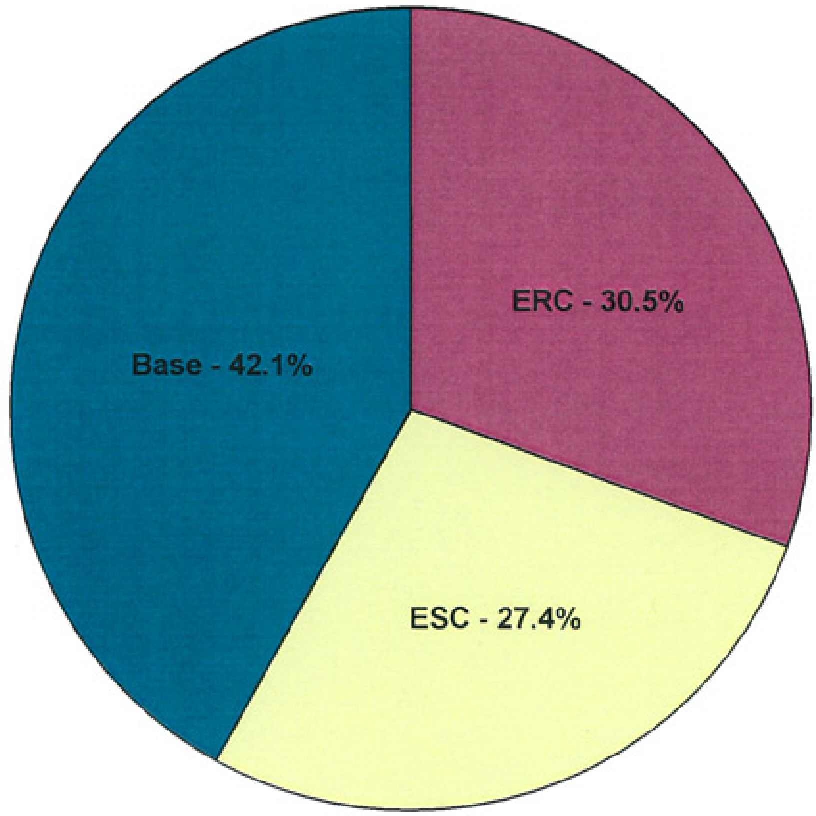


Figure 13-2
Percent of Total 32.8 Percent Increase - 2008 through 2013 - by Rate Component

14.0 Site Selection Introduction

In 2008, the Kansas City BPU retained Black & Veatch to provide services related to conducting a 10 Year Power Supply Study. This included an in-depth analysis of future power supply requirements based upon installation of simple cycle units or combined cycle unit using natural gas as the primary fuel. The purpose of the study was to determine the most economical installation of units to provide the future power requirements of BPU customers.

While BPU and Black & Veatch conducted a review of BPU's future power supply requirements, existing resources, and potential generation additions, Black & Veatch also performed a site selection study to determine the best location for installation of a simple cycle unit or a combined cycle unit.

Criteria were developed to provide adequate information to assess site and resource requirements. The criteria were based on an installation of a simple cycle combustion turbine units in the 20 to 75 MW size range or a combined cycle unit in the 110 to 120 MW range at the selected facility.

This site selection study is based on installing a simple cycle unit or combined cycle unit. Only existing BPU power plants and existing or planned future substation sites within Wyandotte County were identified as the sites for study.

This report documents the procedures and results of the siting study. Evaluation criteria and scoring factors were developed to evaluate the suitability of the identified sites to support the proposed facility. This evaluation was accomplished by first establishing technical parameters. Potential sites were identified and a screening process was then used to identify candidate sites that satisfied the technical requirements. The remaining candidate sites were evaluated using a criteria/scoring system developed specifically for the project. The principal results of the study are the scoring analysis and the identification of preferred and alternate sites.

14.1 Study Approach

Identification of the potential sites was accomplished using the following main tasks:

- Study Area Definition.
- Development of Siting Evaluation Criteria.
- Identification of Potential Sites.
- Initial Screening of Potential Sites.
- Remaining Potential Site Evaluation.
- Identification of Candidate Sites.

- Application of Site Evaluation Criteria.
- Establishment of Site Rankings.
- Identification of Preferred and Alternate Sites.

Black & Veatch used Map Quest to obtain aerial views of the potential sites. A map indicating the existing and planned transmission lines and existing major natural gas supply pipelines locations was provided by BPU to initially assess the sites. The Map Quest aerial views were used to identify the geographical locations and physical attributes of the sites including land availability and closeness of adjacent property owners to determine if the sites were adequate for generation development.

Working closely with BPU personnel, transmission interconnection issues were identified that would further refine the suitability of a potential siting area as a location for a candidate site. Initially, potential sites were defined as the BPU's existing three power plant sites and the 26 existing or future planned substation sites. All potential sites were initially screened and all sites which did not have, or have future planned, 161 kV transmission access or were further than 1 mile from existing adequate natural gas supplies were eliminated. The potential sites then were further evaluated, including some site reconnaissance to determine socioeconomic impacts, land use, and site development issues. The potential sites were further reduced based on this evaluation and the remaining sites were considered candidate sites. The suitability of each candidate site was evaluated using established criteria. Each of the candidate sites was rated and ranked in relation to each other, using a scoring system developed cooperatively by BPU and Black & Veatch personnel. The various evaluation criteria used during the study, as well as the overall site selection methodology, are presented in the following sections of this report. The report also includes a description of the entire site selection process, from the definition of the study area through the overall ranking of the sites and the selection of the preferred and alternate sites.

15.0 Project Description

BPU, working with Black & Veatch, is providing this site selection study to support development of a 10 year combustion turbine based power supply study. The purpose of this study is to determine candidate electrical generating sites for a simple cycle unit or a combined cycle unit. To that end, site selection and rankings were needed to assist in determining the feasibility of the generation sites.

A summary project description of the combustion turbine technology considered is provided herein. The following subsections provide conceptual design information developed to assess site selection and licensing requirements.

15.1 Proposed Project

This section briefly describes the basic requirements of a simple cycle unit and combined cycle unit and identifies the major features of these units.

15.1.1 Facility Size

Simple cycle units of the 20 to 75 MW size and combined cycle units in the 110 to 120 MW size were selected for the siting study. Each of the units was assumed to incorporate Best Available Control Technology (BACT) air quality controls, as appropriate and as required by permitting agencies. Simple cycle units would be installed without SCR or CO catalysts with natural gas as the primary fuel and Number 2 ultra low sulfur fuel oil as backup fuel. Combined cycle units would include a SCR but not a CO catalyst. A minimum of 4 acres has been estimated for land requirements for the simple cycle installation and a minimum of 10 acres has been estimated for land requirements for a combined cycle installation. Figures 15-1 through 15-4 are typical site layouts assumed to support the proposed facility. Land requirements for a combined cycle installation would be adequate for multiple simple cycle units.

15.1.2 Fuel Supply

A suitable supply of natural gas would be needed to ensure project viability. Currently all of the natural gas supply pipelines in Wyandotte County are reportedly fully subscribed, meaning the natural gas supply available for the new unit installation has to be considered interruptible. Therefore, No. 2 ultra low sulfur fuel oil will be required as backup fuel supply for all installations. It has been assumed for this study that a three-day supply of fuel oil is required to be kept onsite in case of natural gas supply interruption.

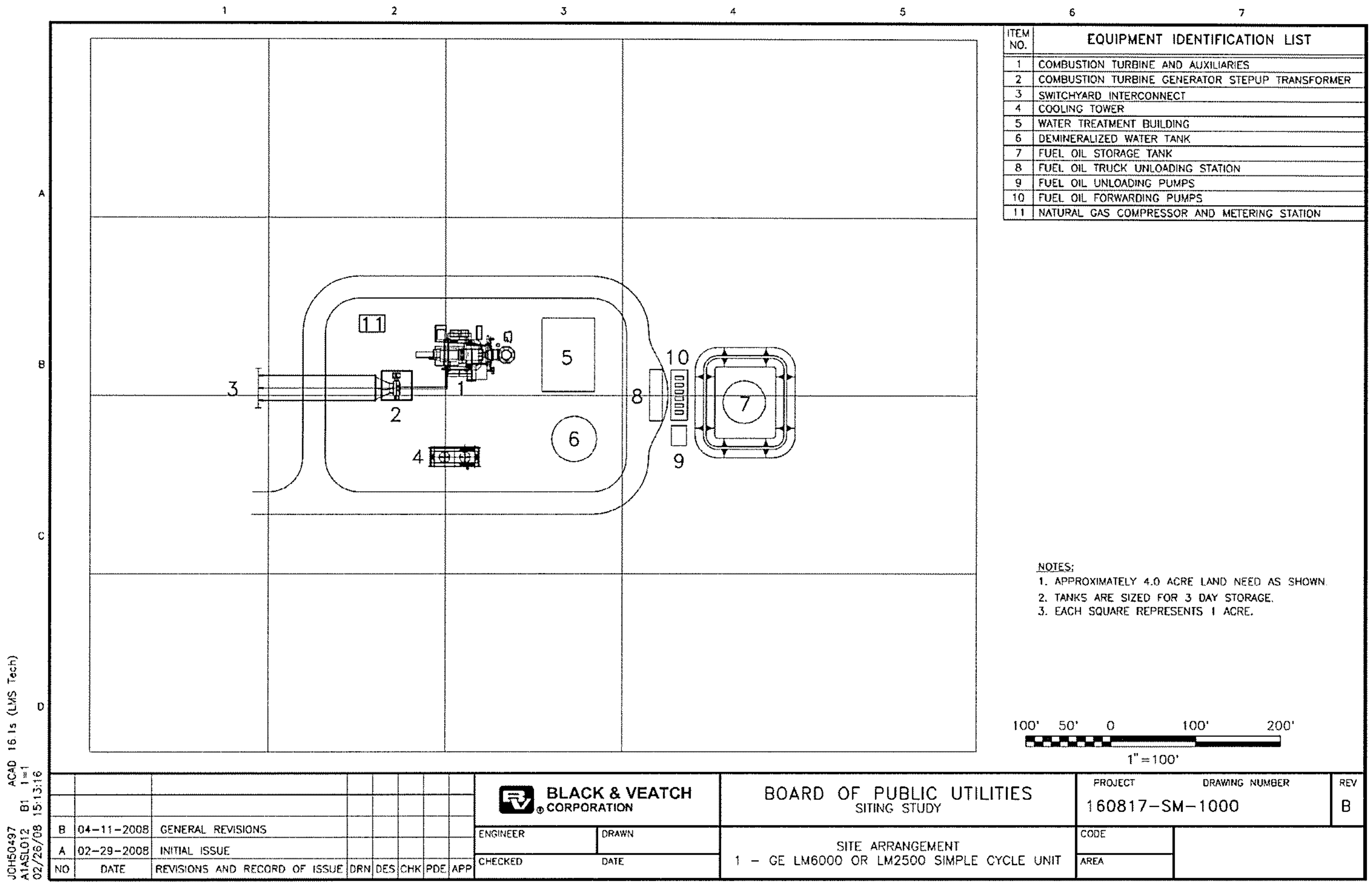


Figure 15-1
Generation Area Arrangement
1- GE LM6000 or LM2500 Simple Cycle Unit

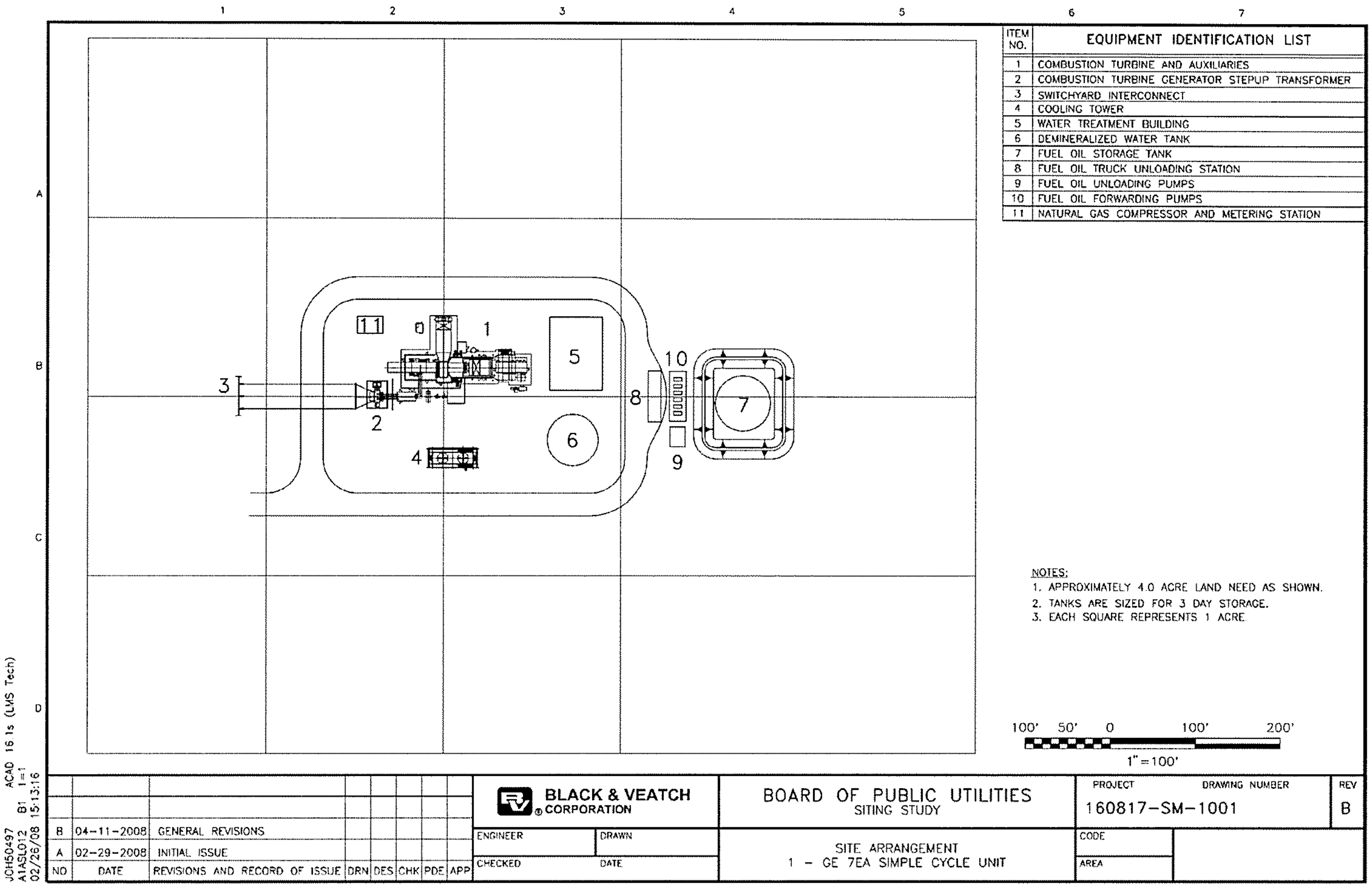


Figure 15-2
Generation Area Arrangement
1- GE 7EA Simple Cycle Unit

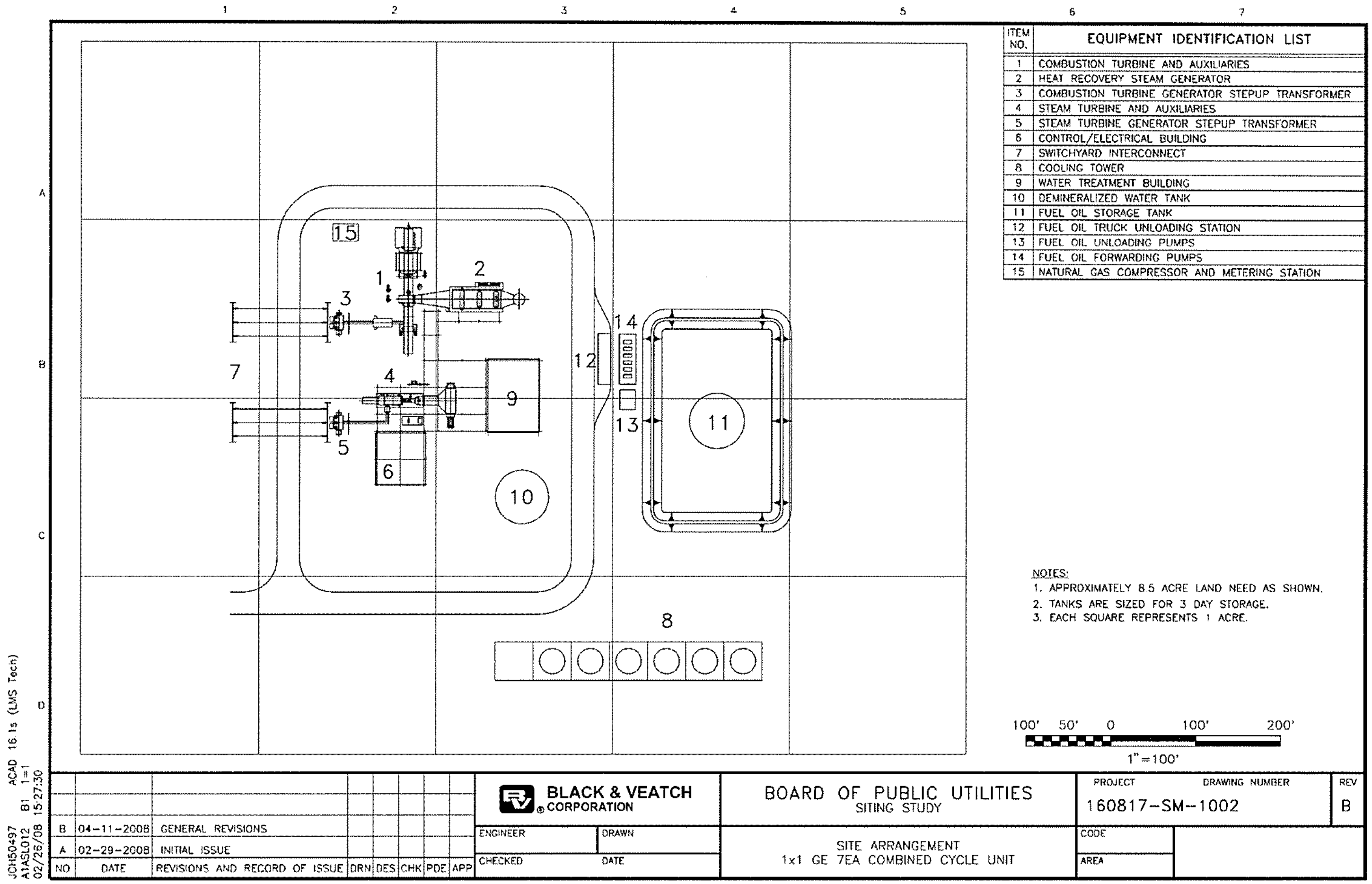


Figure 15-3
Generation Area Arrangement
1x1- GE 7EA Combined Cycle Unit

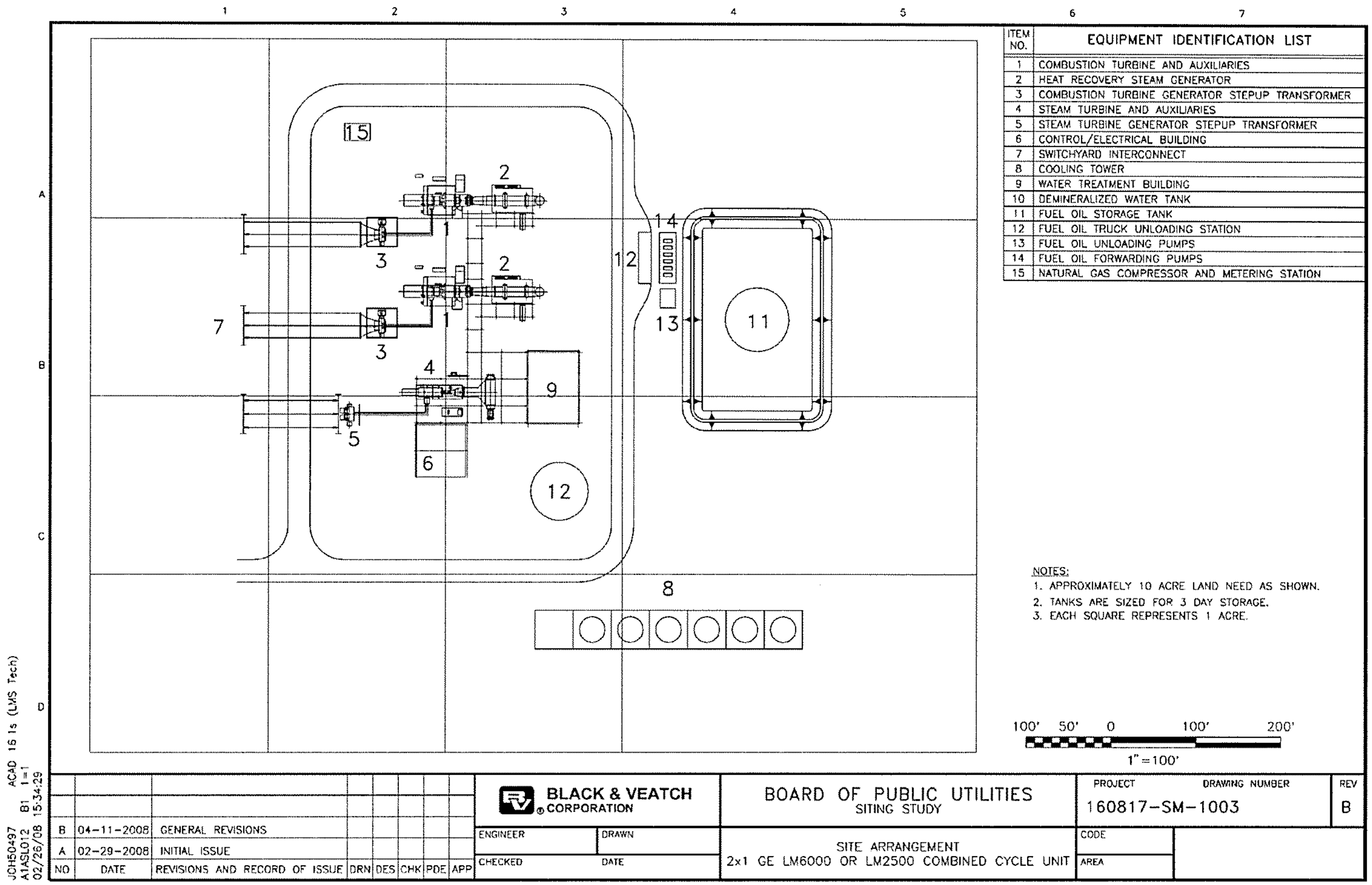


Figure 15-4
Generation Area Arrangement
2x1- GE LM6000 or LM2500 Combined Cycle Unit

15.1.3 Electric Transmission

Based on preliminary analysis of the BPU transmission system, BPU has indicated the new generation should be installed at and connected to the existing transmission system at existing power plant sites or substation sites. BPU has indicated they are currently in the process of upgrading their transmission system and that the new unit should be connected at the 161 kV level. It is anticipated BPU will conduct load flow studies to determine the appropriate interconnection requirements to the existing grid system for the selected site to determine the site-specific impacts. For the purposes of this study, new transmission lines were assumed to connect the generation site to the nearest point of interconnection to the existing BPU grid.

15.1.4 Water

Water consumption for a simple cycle combustion turbine is estimated to be between 60 and 100 gpm (0.09 to 0.15 million gallons per day [mgd]) under normal operation. Water consumption for a combined cycle unit is estimated to be between 120 and 1,700 gpm (0.17 and 2.45 mgd) under normal operation. For the simple cycle unit approximately 90 percent of the water will be used for water injection for NO_x control. For the combined cycle unit between 50 and 80 percent of the water will be used for evaporative cooling purposes and water injection for NO_x control with the remainder being used for boiler feedwater, cleaning, and other miscellaneous uses.

For the combined cycle unit, cooling water is recirculated, but large amounts of water are lost due to evaporation in the cooling towers. The mechanical draft cooling towers proposed for the project are evaporative cooling towers, meaning that water is cooled as heat energy is utilized to vaporize a portion of the circulating water to the atmosphere.

It has been assumed for the purposes of this study that all water requirements will be met by connection to and supply from the BPU city water system.

15.1.5 Storm Water and Wastewater Discharges

Storm water and wastewater from the project will be handled by storm water and wastewater treatment systems. For existing power plant sites, discharge of these wastes will be through permitted discharge points. For existing substation sites it has been assumed for the purposes of this study that all wastewater discharges will be to existing city sewer systems with treatment at the sewage treatment plants. The necessary National Pollutant Discharge Elimination System (NPDES) permits and approvals for the storm water and wastewater discharges will need to be obtained and coordinated with the operators of the wastewater treatment plants.

The primary wastewater discharges from the simple cycle installation will be occasional washdown and process drains for maintenance. Operating drains are normally collected in a drains tank and removed from site by a contractor. The primary wastewater discharges from the combined cycle unit would be blowdown from the cooling tower.

Blowdown from the cooling tower for the combined cycle unit on existing power plant sites will be treated onsite to achieve the water quality required for diversion to a NPDES-permitted discharge point. Blowdown from the cooling tower for a combined cycle unit on an existing substation site will be routed to the municipal sewer system.

Best management practices will be utilized for storm water discharge to ensure that erosion and sedimentation are minimized and applicable water quality standards are met. Sanitary wastes will be treated by an onsite system or discharged to a municipal system.

15.1.6 Economic Considerations

Economic considerations are a key factor in any site selection process. Efforts were made to identify the major cost differentials between the candidate sites. The impacts of site-specific economics were based on the professional judgment of those most knowledgeable of the particular factors.

16.0 Identification of Potential Sites

The study region was defined as the existing power plant sites and existing or planned future substation sites in Wyandotte County as shown on Figure 16-1. The initial screening of the sites narrowed the focus of the study by determining the technical requirements of the project and excluding all sites not having, or planned to have, 161 kV transmission interconnections or adequate natural gas supplies within one mile. The remaining sites were additionally screened by review of available area and some site reconnaissance.

16.1 Evaluation Criteria

Project evaluation criteria are necessary to evaluate the features of a siting area for identification of potential sites. These initial criteria included socioeconomic, land use, air quality, site development, and availability of personal and security.

16.1.1 Socioeconomics

Noise, traffic, and sensitive areas were considered. Information regarding noise, traffic, and residents was gathered during visits to the various sites. Sensitive areas included national, state, and local parks, wilderness areas, and other public use areas. Highway maps, topographic maps, and similar maps were the primary sources used to identify the sensitive resources in the project area.

16.1.2 Land Use/Zoning/Ownership

Land ownership and local zoning/land use compatibility information was gathered from information provided by BPU and during visits to the potential siting areas in February 2008. The information, especially land ownership, should be considered provisional since complete research of county records was not conducted and this information may not be completely up to date.

16.1.3 Air Quality

A new stationary source can be defined as a "major stationary source" if it is classified as any one of the listed major source categories which emits, or has the potential to emit, 100 tpy or more of any regulated pollutant. A new stationary source can also be defined as a "major stationary source" if it does not fall under one of the listed major source categories and which emits, or has the potential to emit, 250 tpy or more of any regulated pollutant.

The new stationary source would be considered a "minor stationary source" if it is not determined to be a major source.

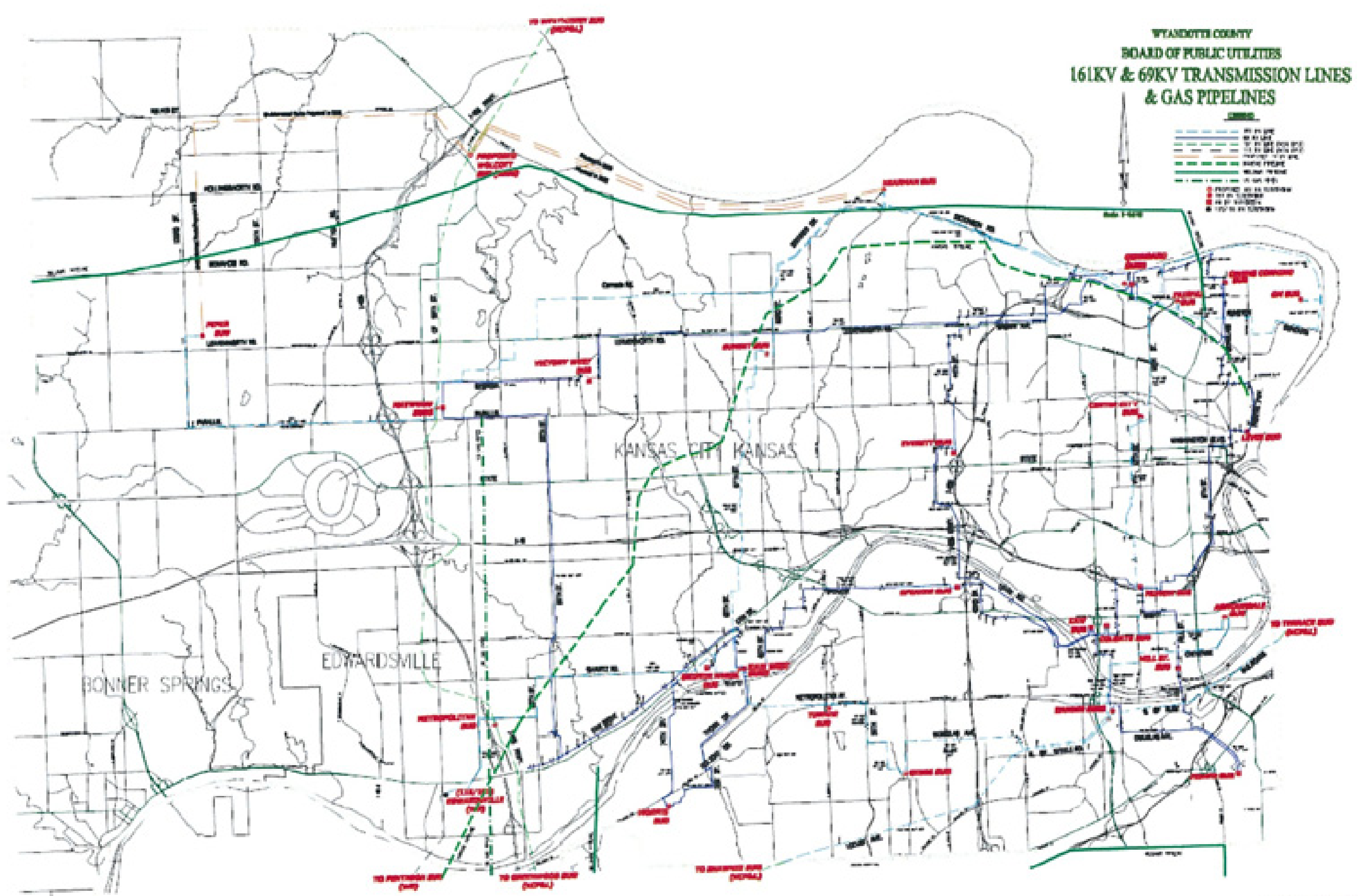


Figure 16-1
Wyandotte County Area 161 kV and 69 kV Transmission Lines and Natural Gas Pipelines

Each candidate site was assessed as to whether a major or minor air construction permit would be required. For the base case, it is assumed that a major air construction permit will be required for installation of a combined cycle unit at any site. For the alternate case for installation of a simple cycle unit, it is assumed that a major air construction permit will be required for installation at an existing power generating site and a minor air construction permit will be required at sites which currently do not have power generating units.

Air quality impact is a broad-ranging topic that can be evaluated with numerous indices of varying levels of importance in the air permitting process. Several air quality indices which were not considered in this evaluation included the presence of nearby nonattainment/maintenance areas, distances to nearby Class I areas, number of Class I areas located within 300 km (approximately 186 miles) of a potential site, and presence of existing nearby sources of air pollution, as the indices are all very similar for the candidate sites because of there relative proximity and not therefore a discriminating factor. Once a unit type and size along with the site is selected, a further detailed analysis of the air permitting and other environmental issues should be completed.

16.1.4 Site Development

Site development factors include the potential ease of development, availability of common facilities, and differential site development costs. Location of natural gas supply, electric transmission system requirements, water supply availability, transportation, and development constraints, are described in the following subsections.

16.1.4.1 Natural Gas Supply. The sites were further refined by identifying sites in close proximity to existing natural gas supplies. There are two viable existing natural gas supply pipeline systems currently installed in Wyandotte County, Williams/Southern Star and Kansas Pipeline. Figure 16-1 depicts the location of these natural gas lines. Gas compression will be required for the LM2500 and LM6000 combustion turbines and may be required for the 7EA combustion turbines.

16.1.4.1.1 Williams/Southern Star Pipeline. The pipeline currently shown as Williams Pipeline on the drawings has become, through a series of name changes, Southern Star. Southern Star is a locally managed, private company owned by GE's Energy Financial Services business and Caisse de dépôt et placement du Québec.

Southern Star is headquartered in Owensboro, Kentucky. Southern Star currently operates one main pipeline generally running east-west across the northern part of Wyandotte County. This pipeline currently operates at 500 psig, but is reported to be upgradeable to 750 psig operating pressure. The Williams/Southern Star line currently supplies natural gas to BPU's Nearman CT-4 and to Quest MidStream Partners, LP who transfers the natural gas through a 3 mile pipeline to Quindaro.

16.1.4.1.2 Kansas Pipeline. Kansas Pipeline Company engages in the owning and operation of regulated natural gas pipeline systems. Kansas Pipeline Company was acquired by Midcoast Energy Resources, Inc. in 1999. Midcoast Energy Resources Inc. was acquired by Enbridge Inc. in 2001 and later rolled into Enbridge Energy Partners, LP in 2002. In 2007 Enbridge began the process of selling its ownership of the Kansas Pipeline Company to Quest MidStream Partners, LP. The Kansas Pipeline currently installed and operating in Wyandotte County enters Wyandotte County from the south near Edwardsville and runs generally in a northeast direction until it gets to the northern side of the county, where it runs east and back to the south. This pipeline currently operates at 500 psig.

16.1.4.1.3 Kansas Gas Service. Kansas Gas Service is the local distribution company supplying natural gas to industrial, commercial, and residential customers in Kansas City, Kansas. The BPU's Kaw Power Station is one of the industrial customers receiving gas from Kansas Gas Service at a 50 psig supply pressure. Kansas Gas Service is connected to both Williams /Southern Star and Kansas Pipelines.

16.1.4.2 Electric Transmission System Requirements. The electrical transmission system that is required for this project will have a voltage of 161 kV. The main electrical transmission system in Wyandotte County area is shown on Figure 16-1. BPU has not conducted preliminary load flow studies to help identify suitable interconnection points to the existing grid system for proposed new capacity. These studies should be completed after the siting study is completed to verify the site interconnection.

16.1.4.3 Water Supply Availability. The primary water resources within the study area were assumed to be available as city water from the BPU water system. Estimates for distance to existing city water sources were made for differential site development costs. Actual distances and availability of water supply will need to be confirmed based on selected unit type and size at the selected site.

16.1.4.4 Development Constraints. Site topography and additional land area availability both need to be considered and may present development constraints or have significant cost impacts. In addition, nearby existing or future development and zoning requirements also may present a development constraint. Major transportation facilities such as highways are a preferred infrastructure resource when selecting siting areas and potential sites. The construction and/or improvement of roads between existing facilities and sites can have significant environmental and cost impacts.

16.2 Environmental Criteria

Only the evaluations of the potential major or minor air construction permit requirements were evaluated in this study. Other than the issues considered under socioeconomics, environmental criteria such as location relative to known environmentally sensitive areas, such as designated parks or recreation areas, wildlife areas, major wetlands areas, major residential areas, Prevention of Significant Deterioration (PSD) Class I areas, and ecologically sensitive areas including protected species habitats and cultural resources were not part of this siting study.

16.3 Identification of Potential Sites

Following the established methodology, the next step in the site selection process was the identification of potential sites within the defined siting areas. All three existing BPU power plant sites were included along with all twenty-six existing or planned BPU substation sites. The drawing included as Figure 16-1 herein identifies all of these locations.

At the gross screening level, all sites were reviewed with respect to the transmission system voltage available and the natural gas supply availability and location. All sites which do not currently have or do not have future planned access to transmission interconnection at 161 kV were eliminated from further consideration. All sites which were further than 1.0 mile from an existing natural gas pipeline were eliminated from further consideration. The results of the gross screening of the potential sites are shown in Table 16-1. Based on the results of the gross screening the following 19 sites were eliminated.

- Maywood
- Edwardsville
- Victory West
- Morris
- Griffin Wheel
- Kaw West
- Turner
- Everett
- Speaker
- Gibbs
- Center City
- Colgate
- Muncie

Table 16-1
Potential Sites – Gross Screening

Site ID	Available Transmission Voltages				Available Natural Gas (Miles)			Consider
	69 kV	115 kV	161 kV	Transmission Comments	Kansas Pipeline	Southern Star	Gas Comments	
Power Plant Sites								
Nearman			X		0.7	0.2		Yes
Quindaro	X		X		0.2	0.9		Yes
Kaw	X		Future		*	*		Yes
Substation Sites								
Piper			X		6.0	1.0		Yes
Wolcott			Future	Build in a year w/ KCPL inter-tie	4.3	0.4		Yes
Maywood	X		X		2.7	2.7	Exceeds 1.0 mile limit	No
Metropolitan			X	BPU & Non-BPU	0.3	1.4		Yes
Edwardsville		X	X	Not a BPU sub	0.5	1.9		No
Victory West	X			No 161 kV	1.4	2.3	Exceeds 1.0 mile limit	No
Morris	X			No 161 kV	2.2	1.0		No
Griffin Wheel	X			Customer Sub**	1.5	1.9	Exceeds 1.0 mile limit	No
Kaw West	X		X	Voltage and Grid support advantage	2.0	2.3	Exceeds 1.0 mile limit	No
Sunset			X		0.3	1.8		Yes
Turner			X		3.1	3.0	Exceeds 1.0 mile limit	No
Everett	X			No 161 kV	2.8	3.2	Exceeds 1.0 mile limit	No
Speaker	X			No 161 kV	4.3	3.7	Exceeds 1.0 mile limit	No
Gibbs			X		4.5	2.0	Exceeds 1.0 mile limit	No
Center City			X		1.4	1.6	Exceeds 1.0 mile limit	No
Colgate	X			No 161 kV	*	*		No
Muncie	X		Future		2.8	3.4	Exceeds 1.0 mile limit	No
Mill Street	X			Customer Sub**	3.6	2.3	Exceeds 1.0 mile limit	No
Barber	X		X	Land is available	4.4	1.8	Exceeds 1.0 mile limit	No

Table 16-1 Continued)
Potential Sites – Gross Screening

Site ID	Available Transmission Voltages: 69 kV	115 kV	161 kV	Transmission Comments	Available Natural Gas (Miles): Kansas Pipeline	Southern Star	Gas Comments	Consider
Fairfax			X		0.2	0.37		Yes
Owens Corning	X			Customer Sub**	0.6	0.3		No
General Motors			X	Positive Grid Load, Land is available	*	*		Yes
Levee	X			Future – Sub to be abandoned	0.5	1.6		No
Armourdale			X		2.9	2.9	Exceeds 1.0 mile limit	No
Fisher	X			No 161 kV	4.8	1.1	Exceeds 1.0 mile limit	No
New East Fairfax			X		*	*		Yes

*These sites are served by Kansas Gas Service distribution system operating at 50 psig.
**Customer Substation serves only a single industrial client.

- Mill Street
- Barber
- Owens Corning
- Levee
- Armourdale
- Fisher

The following 10 sites were identified as potential candidate sites.

- Nearman
- Quindaro
- Kaw
- Piper
- Wolcott
- Metropolitan
- Sunset
- Fairfax
- General Motors
- New East Fairfax

16.4 Identification of Candidate Sites

From the list of potential sites identified in Section 16.3 above, a total of 10 potential sites were identified. The remaining ten sites were reviewed with BPU and in most cases visited to identify sites which clearly can not support a new generation facility because of existing or future transmission system characteristics, space availability, or neighborhood limitations. This evaluation resulted in eliminating the following sites from consideration for new generation as described below.

- Piper is a newer substation located in a rapidly developing residential area. It is very close to existing schools and is not considered suitable for location of future generation.
- Metropolitan is a small substation located in a lightly developed suburban agricultural area with a few houses in the immediate area. The terrain of the site could be modified to tightly install a simple cycle combustion turbine only and is not suitable for multiple simple cycle units or a combined cycle unit.
- Sunset substation is a small existing neighborhood substation which does not have space for future generation. It is located in an existing neighborhood with single family house located immediately adjacent to the site.

- Fairfax is a small substation which is land limited. There is not additional land available to accommodate installation of any future generation.
- A new East Fairfax substation has been considered by BPU which could be located north of the existing Owens Corning Substation and south of the Missouri River. Space is available to accommodate either simple cycle or combined cycle combustion turbine generation. This potential site is very close to the General Motors site, therefore it was eliminated in favor of the General Motors site.

As a result, the initial twenty-nine sites were screened to ten potential sites then screened to five candidate sites after further research and site reconnaissance.

Listed below are the five candidate sites considered favorable for the intended project within the defined study area (i.e., candidate sites):

- Nearman Power Station.
- Quindaro Power Station.
- Kaw Power Station.
- Wolcott Substation.
- General Motors Substation.

The next step in the site selection process was the evaluation of the individual candidate sites using the siting criteria/scoring system described in Section 17.0 to identify the preferred and alternate sites.

17.0 Evaluation of Candidate Sites

The evaluation of candidate sites used a scoring system developed specifically for this siting study as described in this section. Preferred and alternate sites were ultimately identified by the scoring process. The evaluation and scoring criteria are provided in Appendix D.

17.1 Scoring System

The scoring system evaluates the siting objectives, which are predetermined factors or criteria considered to be important during the site selection process. The weighting factors assigned for this activity are based on a judgment of the relative importance for this application. A weighting system (percent format) is applied to the scoring categories to assign a relative level of importance. Each site is evaluated for each siting criterion by assigning a score (1 to 10) for that criterion. Each score is then multiplied by the criterion's percentage weight and summed to determine a total score. The sites can then be ranked based on the numerical scores. The preferred and alternate sites are typically selected from the top ranked sites.

The siting criteria and associated percentage weights are listed below, as agreed upon by the project team:

Evaluation Criteria
Socioeconomics – 15 percent
Land Use – 15 percent
Air Quality – 25 percent
Site Development – 25 percent
Location of Personnel and Security – 20 percent

Site development costs were estimated during the evaluations. These costs considered only those major items determined to be appreciably different between the candidate sites. The items considered are described in Appendix D. The differential site costs are presented in Table 17-1 for Combined Cycle Unit and in Table 17-2 for Simple Cycle Units. Project costs can be separated into two categories: the power block capital costs and site development costs. The total power block capital costs for generating facilities were assumed to be the same for a given type/technology, regardless of location.

Table 17-1
Differential Site Development Costs – Combined Cycle Unit

			Candidate Sites									
			Power Plant Sites						Substation Sites			
			Nearman		Quindaro		Kaw		Wolcott		General Motors	
Site Development Activity	Unit Cost $1,000 (2008)	Unit	Differential Site Amount	Differential Site Cost ($1,000)	Differential Site Amount	Differential Site Cost ($1,000)	Differential Site Amount	Differential Site Cost ($1,000)	Differential Site Amount	Differential Site Cost ($1,000)	Differential Site Amount	Differential Site Cost ($1,000)
Transmission Interconnection (Note 1)	$0	N/A	0	$0	0	$0	0	$0	0	$0	0	$0
Substation Improvements/Exp.												
Existing Substation	$2,000	each	1	$2,000	1	$2,000	1	$2,000			1	$2,000
New Planned Substation	$1,000	each							1	$1,000		
Access Road	$170	mile	0	$0	0	$0	0	$0	0.5	$85	0	$0
Natural Gas Supply Pipeline - 12"	$1,600	mile	0.2	$320	0.2	$320	0.2	$320	0.4	$640	0.2	$320
Natural Gas Compression	$1,300	each	1	$1,300	1	$1,300	1	$1,300	1	$1,300	1	$1,300
Fuel Oil Tank (Note 2) - 500,000 gal.	$750	each	0	$0	0	$0	1	$750	1	$750	1	$750
Water Supply Pipeline - 12"	$500	mile	0.2	$100	0.2	$100	0.2	$100	1	$500	0.2	$100
Demineralizer (Note 3)	$1,000	each	0	$0	0	$0	0	$0	1	$1,000	1	$1,000
Demineralized Water Tank (Note 4) - 500,000 gal.	$1,000	each	0	$0	0	$0	0	$0	1	$1,000	1	$1,000
Wastewater Pipeline - 4"	$450	mile	0.2	$90	0.2	$90	0.2	$90	1	$450	0.2	$90
Land Acquisition (Note 5)	$5	acre	0	$0	0	$0	0	$0	10	$50	10	$50
Site Preparation	$10	acre	0	$0	10	$100	10	$100	10	$100	10	$100
TOTAL SITE DIFFERENTIAL DEVELOPMENT COSTS				$3,810		$3,910		$4,660		$6,875		$6,710
LOWEST SITE DIFFERENTIAL DEVELOPMENT COSTS				Base		$100		$850		$3,065		$2,900
SITE DIFFERENTIAL DEVELOPMENT COST SCORE				10		8		6		2		4

NOTES:
1. Transmission interconnection costs are assumed to be equal at each site.
2. Fuel oil tank assumed for 3 days storage at substation sites and existing fuel oil tanks are sufficient at power plant sites except Kaw.
3. Assume installation of a demineralizer system for the substation sites. A rental demineralizer system can also be used for substation sites. Assumes existing demineralizer systems will be used without modification at power plant sites.
4. Demineralized water tank same size as fuel oil tank for substation sites and existing demineralized tanks are sufficient at power plant sites.
5. Assumes land acquisition at substation sites is available and current owner is willing to sell.

Table 17-2

Differential Site Development Costs – Simple Cycle Unit

			Candidate Sites									
			Power Plant Sites						Substation Sites			
			Nearman		Quindaro		Kaw		Wolcott		General Motors	
Site Development Activity	Unit Cost $1,000 (2008)	Unit	Differential Site Amount	Differential Site Cost ($1,000)	Differential Site Amount	Differential Site Cost ($1,000)	Differential Site Amount	Differential Site Cost ($1,000)	Differential Site Amount	Differential Site Cost ($1,000)	Differential Site Amount	Differential Site Cost ($1,000)
Transmission Interconnection (Note 1)	$0	N/A	0	$0	0	$0	0	$0	0	$0	0	$0
Substation Improvements/Exp.												
Existing Substation	$2,000	each	1	$2,000	1	$2,000	1	$2,000			1	$2,000
New Planned Substation	$1,000	each							1	$1,000		
Access Road	$170	mile	0	$0	0	$0	0	$0	0.5	$85	0	$0
Natural Gas Supply Pipeline - 12"	$1,600	mile	0.2	$320	0.2	$320	0.2	$320	0.4	$640	0.2	$320
Natural Gas Compression	$1,300	each	1	$1,300	1	$1,300	1	$1,300	1	$1,300	1	$1,300
Fuel Oil Tank (Note 2) - 400,000 gal.	$600	each	0	$0	0	$0	1	$600	1	$600	1	$600
Water Supply Pipeline - 6"	$400	mile	0.2	$80	0.2	$80	0.2	$80	1	$400	0.2	$80
Demineralizer (Note 3)	$1,000	each	0	$0	0	$0	0	$0	1	$1,000	1	$1,000
Demineralized Water Tank (Note 4) - 400,000 gal.	$800	each	0	$0	0	$0	0	$0	1	$800	1	$800
Wastewater Pipeline - 4"	$450	mile	0.2	$90	0.2	$90	0.2	$90	1	$450	0.2	$90
Land Acquisition (Note 5)	$5	acre	0	$0	0	$0	0	$0	4	$20	4	$20
Site Preparation	$10	acre	0	$0	10	$100	4	$40	4	$40	4	$40
TOTAL SITE DIFFERENTIAL DEVELOPMENT COSTS				$3,790		$3,890		$4,430		$6,335		$6,250
LOWEST SITE DIFFERENTIAL DEVELOPMENT COSTS				Base		$100		$640		$2,545		$2,460
SITE DIFFERENTIAL DEVELOPMENT COST SCORE				10		8		6		2		4

NOTES:
1. Transmission interconnection costs are assumed to be equal at each site.
2. Fuel oil tank assumed for 3 days storage at substation sites and existing fuel oil tanks are sufficient at power plant sites except Kaw.
3. Assume installation of a demineralizer system for the substation sites. A rental demineralizer system can also be used for substation sites. Assumes existing demineralizer systems will
4. Demineralized water tank same size as fuel oil tank for substation sites and existing demineralized tanks are sufficient at power plant sites.
5. Assumes land acquisition at substation sites is available and current owner is willing to sell.

Table 17-3 and the associated scoring were performed based on the installation of a combined cycle unit. Table 17-4 and the associated scoring were performed based on the installation of a single simple cycle unit. It should be noted that it is not considered practical to explore the effect of varying the weightings assigned to each individual siting factor because of the virtually infinite number of possible combinations.

17.2 Scoring Results

Black & Veatch personnel evaluated each site against the siting criteria and assigned a score (1 to 10) to each siting factor, with 1 representing a worst-case scenario and 10 representing the best case scenario. The scores assigned to each site are presented in Tables 17-3 and 17-4.

The top two sites for both cases were Nearman and Quindaro. The Kaw site ranked third. An explanation of the scoring and ranking for each site is provided in Section 17.3.

17.3 Candidate Site Scoring

An explanation of the scoring of each candidate site is provided in the following subsections.

17.3.1 Nearman Power Plant Site

The Nearman site is an existing BPU power plant located in Wyandotte County, Kansas. This site scored first in both cases.

17.3.1.1 Socioeconomics. The Nearman site scored lower than other candidate sites for noise and sensitive areas. There is a moderate density residential area south of the plant, and several municipal parks in the area. Parkville, Missouri, is located across the Missouri River, north-northeast from the plant. All sites scored high for traffic without any significant traffic impacts other than for short durations during construction activities.

17.3.1.2 Land Use. The Nearman site is currently owned by BPU, contains a 161 kV substation, and is approved, zoned, and used for power generation and was scored the highest in these areas. The areas immediately adjacent to the site are agricultural. Residential areas are located within approximately one mile south and north of the property boundary.

Table 17-3
Evaluation Scores of Candidate Sites – Combined Cycle Unit

		Sites				
		Power Plant Sites			Substation Sites	
Evaluation Criteria	Weighting Factor, %	Nearman	Quindaro	Kaw	Wolcott	GM
1.0 Socioeconomic						
1.1 Noise	5	1	1	6	1	6
1.2 Traffic	5	10	10	10	10	10
1.3 Sensitive Area	5	4	2	6	2	6
Weighted Group Total	15	0.75	0.65	1.10	0.65	1.10
2.0 Land Use						
2.1 Land Ownership	5	10	10	10	10	10
2.2 Site Location	5	10	10	10	5	5
2.3 Zoning/Land Use Compatibility	5	10	10	10	5	10
Weighted Group Total	15	1.50	1.50	1.50	1.00	1.25
3.0 Air Quality						
3.1 Air Permit Required (Major/Minor)	25	5	5	5	5	5
Weighted Group Total	25	1.25	1.25	1.25	1.25	1.25
4.0 Site Development						
4.1 Ease of Development	8	10	5	5	1	10
4.2 Availability of Common Facilities	8	10	10	10	1	1
4.3 Differential Site Development Costs*	9	10	8	6	2	4
Weighted Group Total	25	2.50	1.92	1.74	0.34	1.24
5.0 Availability of Personnel (O&M) & Security						
5.1 Availability of Personnel	10	10	10	5	1	1
5.2 Security	10	10	10	10	1	10
Weighted Group Total	20	2.00	2.00	1.50	0.20	1.10
Weighted Total	100	8.00	7.32	7.09	3.44	5.94

*Refer to Table 17-1.

Table 17-4
Evaluation Scores of Candidate Sites – Simple Cycle Unit

		Sites				
		Power Plant Sites			Substation Sites	
Evaluation Criteria	Weighting Factor, %	Nearman	Quindaro	Kaw	Wolcott	GM
1.0 Socioeconomic						
1.1 Noise	5	1	1	6	1	6
1.2 Traffic	5	10	10	10	10	10
1.3 Sensitive Area	5	4	2	6	2	6
Weighted Group Total	15	0.75	0.65	1.10	0.65	1.10
2.0 Land Use						
2.1 Land Ownership	5	10	10	10	10	10
2.2 Site Location	5	10	10	10	5	5
2.3 Zoning/Land Use Compatibility	5	10	10	10	5	10
Weighted Group Total	15	1.50	1.50	1.50	1.00	1.25
3.0 Air Quality						
3.1 Air Permit Required (Major/Minor)	25	5	5	5	10	10
Weighted Group Total	25	1.25	1.25	1.25	2.50	2.50
4.0 Site Development						
4.1 Ease of Development	8	10	10	10	1	10
4.2 Availability of Common Facilities	8	10	10	10	1	1
4.3 Differential Site Development Costs*	9	10	8	6	2	4
Weighted Group Total	25	2.50	2.32	2.14	0.34	1.24
5.0 Availability of Personnel (O&M) & Security						
5.1 Availability of Personnel	10	10	10	5	1	1
5.2 Security	10	10	10	10	1	10
Weighted Group Total	20	2.00	2.00	1.50	0.20	1.10
Weighted Total	100	8.00	7.72	7.49	4.69	7.19

*Refer to Table 17-2.

17.3.1.3 Air Quality. The base case was for installation of a combined cycle unit. In all cases, installation of a combined cycle unit will require a major air construction permit. All sites were scored the same. For the alternate case, with installation of a simple cycle unit, the Nearman site scored lower than the substation ("Greenfield") sites as a major air construction permit would still be required on a site which already has operating generating units.

17.3.1.4 Site Development. The Nearman site scored the highest in all site development areas. The site is already developed for addition of a second simple cycle or combined cycle unit, has available common facilities, and had the lowest site development costs.

17.3.1.5 Availability of Personnel and Security. The Nearman site is currently an operating power generating site with personnel on site 24 hours a day, 365 days per year. Personnel to support the operation and maintenance of a new natural gas generating unit are available, or would be available with only minor staffing increases. The site is currently secure with boundary fencing and 24-hour security personnel on site.

17.3.2 Quindaro Power Plant Site

The Quindaro site is an existing BPU power plant located in Wyandotte County, Kansas. This site scored second in both cases.

17.3.2.1 Socioeconomics. The Quindaro site scored lower than other candidate sites for noise and sensitive areas. Although located in a primarily industrial area, there is moderate density residential areas near the plant, the Missouri River is adjacent to the site, and there are cultural resources (Quindaro ruins) located near the site. All sites scored high for traffic without any significant traffic impacts other than for short durations during construction activities.

17.3.2.2 Land Use. The Quindaro site is currently owned by BPU, contains a 161 kV substation, and is approved, zoned, and used for power generation and was scored the highest in these areas. The areas immediately adjacent to the site to the north and east are all industrial. Residential areas are located just south of the property boundary.

17.3.2.3 Air Quality. The base case was for installation of a combined cycle unit. In all cases, installation of a combined cycle unit will require a major air construction permit. All sites were scored the same. For the alternate case, with installation of a simple cycle unit, the Quindaro site scored lower than the substation ("Greenfield") sites as a major air construction permit would still be required on a site which already has operating generating units.

17.3.2.4 Site Development. The Quindaro site scored the second highest of all sites in site development areas. The site would require some development for installation of a new simple cycle unit or combined cycle unit, has available common facilities, and had the second lowest site development costs.

17.3.2.5 Availability of Personnel and Security. The Quindaro site is currently an operating power generating site with personnel on site 24 hours a day, 365 days per year. Personnel to support the operation and maintenance of a new natural gas generating unit are available, or would be available with only minor staffing increases. The site is currently secure with boundary fencing and 24-hour security personnel on site.

17.3.3 Kaw Power Plant Site

The Kaw site is an existing BPU power plant located in Wyandotte County, Kansas. This site scored third in both cases.

17.3.3.1 Socioeconomics. The Kaw site scored higher than the other power plant sites and substation sites for noise and sensitive areas. Located in a primarily industrial area, without residential areas near the plant, but the Kansas River is adjacent to the site. All sites scored high for traffic without any significant traffic impacts other than for short durations during construction activities.

17.3.3.2 Land Use. The Kaw site is currently owned by BPU, contains a 69 kV substation, and is approved, zoned, and used for power generation and was scored the highest in these areas. There are plans by BPU to convert the substation to 161 kV in the future.

17.3.3.3 Air Quality. The base case was for installation of a combined cycle unit. In all cases, installation of a combined cycle unit will require a major air construction permit. All sites were scored the same. For the alternate case, with installation of a simple cycle unit, the Kaw site scored lower than the substation ("Greenfield") sites as a major air construction permit would still be required on a site which already has potential to operate existing generating units.

17.3.3.4 Site Development. The Kaw site scored the third highest of all sites in site development areas. The site would require some development for installation of a new simple cycle unit or combined cycle unit, has some available common facilities, and had the third lowest site development costs.

17.3.3.5 Availability of Personnel and Security. The Kaw site is currently a standby (formerly operating) power generating site with limited personnel (one full time and one part time person) onsite for limited periods. Personnel to support the operation and maintenance of a new natural gas generating unit would need to be added or supplemented from existing staff from the other power plants. The site is currently secure with boundary fencing and 24-hour security personnel on site.

17.3.4 Wolcott Substation Site

The Wolcott substation site is a future planned BPU substation site located in Wyandotte County, Kansas. This site scored the lowest in both cases.

17.3.4.1 Socioeconomics. The Wolcott site scored lower than other candidate sites for noise and sensitive areas. Although currently located in a primarily agricultural area, there are residential developments planned nearby, the Missouri river is near the site, and the Wyandotte County Lake and park areas are nearby. All sites scored high for traffic without any significant traffic impacts other than for short durations during construction activities.

17.3.4.2 Land Use. The Wolcott site is currently owned by BPU and is planned to be zoned for use as a substation. Zoning for use for power generation would need to be pursued. In addition, BPU has been approached by a developer requesting the substation be moved to the west side of Interstate 435 to allow for further development on the east side of the highway. The areas immediately around the site are currently undeveloped, but future residential areas are reportedly planned to be located adjacent to or near the property boundary.

17.3.4.3 Air Quality. The base case was for installation of a combined cycle unit. In all cases, installation of a combined cycle unit will require a major air construction permit. All sites were scored the same. For the alternate case, with installation of a simple cycle unit, the Wolcott site scored higher as a greenfield site that the power plant sites as only a minor air construction permit would be required.

17.3.4.4 Site Development. The Wolcott site scored the lowest of all sites in site development areas. The site would require significant development for installation of a new simple cycle unit or combined cycle unit, has no available common facilities, and had the highest site development costs.

17.3.4.5 Availability of Personnel and Security. The Wolcott site is currently an undeveloped site which would need the addition of operating and maintenance personnel. If a combined cycle unit were installed, personnel to support 24 hours a day, 365 days per year would be required. If a simple cycle unit was installed, remote operation could be possible with personnel support for monitoring and maintenance supplied from the existing power plants on a traveling basis. The site would need to be secured with boundary fencing and full time security personnel would need to be added or remote monitored security systems would need to be installed.

17.3.5 General Motors Substation

The General Motors substation site is an existing BPU substation site located in Wyandotte County, Kansas. This site scored fourth in both cases.

17.3.4.1 Socioeconomics. The General Motors site scored higher than other power plant sites and substation sites for noise and sensitive areas. Located in a primarily industrial area, without residential areas near the plant, but the Missouri River is near the site. All sites scored high for traffic without any significant traffic impacts other than for short durations during construction activities.

17.3.4.2 Land Use. The General Motors site is currently owned by General Motors/BPU and is zoned for use as heavy industrial. Purchase of land from General Motors and zoning for use for power generation would need to be pursued. The areas immediately adjacent to the site in all directions are industrial with the Missouri River nearby to the north.

17.3.4.3 Air Quality. The base case was for installation of a combined cycle unit. In all cases, installation of a combined cycle unit will require a major air construction permit. All sites were scored the same. For the alternate case, with installation of a simple cycle unit, the General Motors site scored higher as a greenfield site than the power plant sites as only a minor air construction permit would be required.

17.3.4.4 Site Development. The General Motors site scored next to lowest of all sites in site development areas. The site would require significant development for installation of a new simple cycle unit or combined cycle unit, has no available common facilities, and had the next to highest site development costs.

17.3.4.5 Availability of Personnel and Security. The General Motors site is currently a non-generating site which would need the addition of operating and maintenance personnel. If a combined cycle unit were installed, personnel to support 24 hours a day, 365 days per year would be required. If a simple cycle unit was installed, remote operation could be possible with personnel support for monitoring and maintenance supplied from the existing power plants on a traveling basis. The site is highly secured by General Motors with boundary fencing and full time security personnel.

17.4 Preferred and Alternate Sites

On the basis of the analyses conducted, the Nearman site is the preferred site for the development of additional natural gas fired generation in the siting area. The Nearman site has had the highest weighted score and has the infrastructure in place to support additional natural gas fired generation. It scored better or equal to other sites in almost all criteria and scored better than the other power plant sites in site development.

The alternate site selected is the Quindaro site. The site had the second highest score on both the base case and the alternate case. The site development will be slightly more involved and costly than the Nearman site. Otherwise, it scored similar to the Nearman site in most criteria.

18.0 Site Selection Study
Summary and Conclusions

Black & Veatch, on behalf of BPU, conducted a site selection study to identify potential sites for installation of natural gas fired generating units. Existing power plant sites and substation sites in Wyandotte County were identified as the potential siting areas for study.

Evaluation criteria were developed to provide adequate information to assess site and resource requirements. The criteria were based on an installation of a simple cycle combustion turbine or installation of a combined cycle unit. Potential natural gas fuel sources, water sources, and wastewater discharge facilities were identified. A minimum 161 kV transmission connection was required. A site of at least 4 acres was required for the simple cycle installation and of at least 10 acres for a combined cycle unit. The siting region was screened to determine potential sites, and ultimately candidate sites. The requirements included socioeconomic factors (noise, traffic, and sensitive areas), land use, air permit requirements, site development issues and costs, and availability of personnel and security.

Twenty-nine sites were identified for evaluation based on current or future planned BPU power plant and substation sites. The twenty-nine sites were reduced to ten sites based on available transmission voltages and available natural gas. Evaluation of the ten potential sites, which included reconnaissance of most sites, eliminated five additional sites from further consideration. The remaining five sites were considered the candidate sites.

The candidate sites were evaluated in greater detail using the established evaluation criteria and scoring system. The scores were weighted to assign a relative level of importance. The sites were then ranked based on the scoring results of each scenario.

The preferred site is Nearman for either a simple cycle or combined cycle unit. The Quindaro site was selected as the first alternate site.

Appendix A
PROSYM Electric System Simulation Model

Appendix A
PROSYM Electric System Simulation Model

PROSYM is a general-purpose simulation model capable of representing most electric load and resource situations. PROSYM is a complete electric utility/regional pool analysis and accounting system. It is designed for performing planning and operational studies, and as a result of its chronological structure, accommodates detailed hour-by-hour (or by half hour increments, if desired) investigation of the operations of electric utilities and pools. Because of its ability to handle detailed information in a chronological fashion, planning studies performed with PROSYM closely reflect actual operations. PROSYM was the first second-generation chronological model, with new technology that vastly sped up the simulation process that used open standards for both input and reporting to link up with the latest software tools. Now, it is the first third-generation model, capable of analysis not only in the traditional cost-based world, but also in the rapidly evolving pools and free markets for power worldwide.

The model uses a Microsoft Windows-compatible user interface and file system, which it shares with several other Ventyx models. The interface provides an environment in which data sets are easily created and edited, and simulations run. PROSYM is fully integrated with a database system, which works natively with Microsoft Access 2.0 (and later), but can be tailored to work with any PC or Unix-based database system that is ODBC-compliant (most are).

PROSYM uses a powerful data input method capable of handling the large volume of information required to perform highly detailed studies of electric generation and pool operation. This data input method gives maximum control with a minimum of effort. The grammar enables you to modify key variables as frequently as hourly, and results in a data set which is easy to review and virtually self-documenting. PROSYM is the flagship of a family of related models and add-on modules that use common input-output methods and procedures to solve a host of problems associated with the generation and sale of electricity.

The MULTISYM module converts PROSYM into a true multi-area model with power transport limitations honored. While PROSYM operates in Star mode, with all transmission-limited areas connected to the main system and all power paths predetermined, MULTISYM can additionally operate in Delta mode, in which the system consists of independent, connected transmission areas with various power routes possible, depending on system topology. In Delta mode, transmission areas can be grouped into control areas for additional spinning reserve control. MULTISYM is a superset of PROSYM; it can process any PROSYM data set (in Star mode) in addition to its own.

Another module, ECOSYM, allows the model to perform system dispatch with both economic and environmental factors considered. This helps in emissions studies and expansion planning under the Clean Air Act.

To perform simulations, the PROSYM system requires: at least one basic set of annual hourly loads; projections of peak loads and energies on a weekly, monthly, seasonal or annual basis for the study of any future period; and data representing the physical and economic operating characteristics (the resource mix) of the electric utility or pool, and any relevant pool or ISO rules.

Electric utilities and generation pools operate generation resources, energy storage devices, and load control systems to match generation and load on an instantaneous basis. This real-time operation entails using highly sophisticated control systems which match generation levels with load virtually instantaneously. It is not analytically necessary to represent this level of time detail in performing planning studies which have a time horizon of weeks to years. What is necessary is a level of time detail that allows the planning study to obtain a reasonable approximation of actual system operation. Hourly time steps can accommodate the modeling of virtually any utility or pool situation, so the basic time unit used in PROSYM is one hour (a half-hour version is available for use in certain pools). In each hour of a study period, PROSYM considers a complex set of operating constraints to simulate the least-cost operation of the utility, or least-bid operation of the pool. This hour-by hour simulation, respecting chronological, operational, and other constraints in the case of cost based dispatch, and relevant pool or independent system operator (ISO) rules in the case of bid based dispatch, is the essence of the model.

Appendix B
Comparison of Phase I Revenue Requirements

Q0-A: Q1 Retires in 2011, Add GE 7EA in 2011 and convert the new GE 7EA to Combined Cycle in 2012

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
7EA SCCT	48,850	9	01/01/2011	59,775	5,595
Convert 7EA to 1x1 CC	87,650	24	01/01/2012	109,293	10,230

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q2 LNB and OFA	10,701	2	01/01/2010	11,990	1,984
N1 LNB and OFA	20,586	2	01/01/2010	23,065	3,817
N1 Spray Dry Scrubber & Fabric Filter	110,189	25	01/01/2014	118,032	19,534

Unit	Retirement Year
CT#1	2015
Quindaro #1	2011

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	O&M Variable[2] ($1,000)	O&M Fixed ($1,000)	*Emission Costs[4] ($1,000)*	Economy Sales ($1000)	Economy Purchase[3] ($1000)	Nearman Participant Sales ($1,000)	Bridge Power Purchase ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,127	$3,375	$33,590	$5,338	-$6,147	$10,780	-$14,943	$0	$95,121	$0	$0	$0	$95,121	$95,121
2009	2,570	$62,234	$3,490	$33,713	$5,150	-$5,453	$14,100	-$13,915	$0	$99,318	$0	$0	$0	$99,318	$189,486
2010	2,594	$65,518	$3,701	$34,756	$5,307	-$5,029	$12,100	-$15,122	$0	$101,232	$0	$5,802	$5,802	$107,033	$286,107
2011	2,635	$75,194	$3,597	$32,969	$4,702	-$2,743	$18,441	-$15,771	$0	$116,390	$5,595	$5,802	$11,396	$127,786	$395,709
2012	2,644	$79,262	$4,958	$34,874	$11,618	-$4,898	$19,134	-$14,707	$0	$130,241	$15,825	$5,802	$21,626	$151,868	$519,468
2013	2,669	$79,979	$5,084	$36,108	$12,351	-$4,256	$24,311	-$14,818	$0	$138,760	$15,825	$5,802	$21,626	$160,386	$643,649
2014	2,697	$88,740	$7,916	$39,612	$11,952	-$5,312	$16,033	-$16,415	$0	$142,526	$15,825	$25,336	$41,161	$183,687	$778,777
2015	2,721	$93,954	$8,290	$40,211	$13,250	-$5,877	$16,913	-$16,717	$0	$150,025	$15,825	$25,336	$41,161	$191,186	$912,406
2016	2,733	$96,782	$8,386	$40,972	$14,779	-$6,117	$18,077	-$17,072	$0	$155,808	$15,825	$25,336	$41,161	$196,969	$1,043,210
2017	2,744	$100,101	$8,547	$41,662	$16,437	-$6,627	$19,500	-$17,325	$0	$162,296	$15,825	$25,336	$41,161	$203,456	$1,171,582
Levelized Cost($1000):		$78,561	$5,439	$36,415	$9,506	-$5,202	$16,596	-$15,546	$0	$125,770	$9,109	$11,033	$20,143	$145,912	
NPV:		$630,795	$43,674	$292,392	$76,325	-$41,766	$133,257	-$124,828	$0	$1,009,849	$73,143	$88,590	$161,733	$1,171,582	
Levelized Cost($/MWh):		$23.75	$1.64	$11.01	$2.87	-$1.57	$5.02	-$4.70	$0.00	$38.02	$2.75	$3.34	$6.09	$44.11	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008).
(2) VOM column includes unit start-up cost including start-up fuel costs and includes additional variable costs associated with AQC retrofits.
(3) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(4) Emissions cost is composed of SO2 and Carbon allowance costs. Carbon regulations begins in 2012.

Q0-B: Q1 Retires in 2011, Convert CT4 to Combined Cycle in 2011 and add LM6000s in 2011 and 2015

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate:	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Convert 7EA to 1x1 CC	93,190	24	01/01/2011	119,841	11,217
LM6000 SCCT	42,270	10	01/01/2011	51,909	5,461
LM6000 SCCT	42,270	10	01/01/2015	46,660	4,909

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q2 LNB and OFA	10,701	2	01/01/2010	11,990	1,984
N1 LNB and OFA	20,586	2	01/01/2010	23,065	3,817
N1 Spray Dry Scrubber & Fabric Filter	110,189	25	01/01/2014	118,032	19,534

Unit	Retirement Year
CT#1	2015
Quindaro #1	2011

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	O&M Variable[2] ($1,000)	O&M Fixed ($1,000)	*Emission Costs[4] ($1,000)*	Economy Sales ($1000)	Economy Purchase[3] ($1000)	Nearman Participant Sales ($1,000)	Bridge Power Purchase ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,127	$3,375	$33,590	$5,338	-$6,147	$10,780	-$14,943	$0	$95,121	$0	$0	$0	$95,121	$95,121
2009	2,570	$62,234	$3,490	$33,713	$5,150	-$5,453	$14,100	-$13,915	$0	$99,318	$0	$0	$0	$99,318	$189,486
2010	2,594	$65,518	$3,701	$34,756	$5,307	-$5,029	$12,100	-$15,122	$0	$101,232	$0	$5,802	$5,802	$107,033	$286,107
2011	2,635	$77,107	$4,535	$34,002	$4,683	-$4,292	$12,447	-$15,771	$0	$112,710	$16,678	$5,802	$22,479	$135,190	$402,059
2012	2,644	$80,703	$5,044	$34,939	$11,656	-$5,074	$16,653	-$14,707	$0	$129,215	$16,678	$5,802	$22,479	$151,694	$525,677
2013	2,669	$80,376	$5,114	$36,209	$12,332	-$4,274	$23,145	-$14,818	$0	$138,085	$16,678	$5,802	$22,479	$160,564	$649,996
2014	2,697	$90,002	$7,972	$39,715	$11,945	-$5,671	$14,330	-$16,415	$0	$141,878	$16,678	$25,336	$42,014	$183,892	$785,275
2015	2,721	$94,766	$8,310	$41,017	$13,366	-$7,077	$14,356	-$16,719	$0	$148,019	$21,587	$25,336	$46,922	$194,942	$921,529
2016	2,733	$98,326	$8,448	$41,790	$14,907	-$7,199	$14,935	-$17,071	$0	$154,137	$21,587	$25,336	$46,922	$201,059	$1,055,049
2017	2,744	$101,429	$8,620	$42,496	$16,514	-$7,536	$16,896	-$17,325	$0	$161,095	$21,587	$25,336	$46,922	$208,017	$1,186,299
Levelized Cost($1000):		$79,368	$5,569	$36,755	$9,532	-$5,685	$14,749	-$15,547	$0	$124,741	$11,971	$11,033	$23,005	$147,745	
NPV:		$637,276	$44,715	$295,118	$76,533	-$45,647	$118,421	-$124,829	$0	$1,001,588	$96,121	$88,590	$184,712	$1,186,299	
Levelized Cost($/MWh):		$23.99	$1.68	$11.11	$2.88	-$1.72	$4.46	-$4.70	$0.00	$37.71	$3.62	$3.34	$6.95	$44.66	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008).
(2) VOM column includes unit start-up cost including start-up fuel costs and includes additional variable costs associated with AQC retrofits.
(3) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(4) Emissions cost is composed of SO2 and Carbon allowance costs. Carbon regulations begins in 2012.

Q0-C: Q1 Retires in 2011, Add 2 LM6000s in 2011. Convert the LM6000s to combined cycle in 2012.

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate:	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
LM6000 SCCT	42,270	10	01/01/2011	51,909	4,859
LM6000 SCCT	42,270	10	01/01/2011	51,909	4,859
LM6000 2x1 CC Phased Construction	65,180	14	01/01/2012	78,428	7,341

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q2 LNB and OFA	10,701	2	01/01/2010	11,990	1,984
N1 LNB and OFA	20,586	2	01/01/2010	23,065	3,817
N1 Spray Dry Scrubber & Fabric Filter	110,189	25	01/01/2014	118,032	19,534

Unit	Retirement Year
CT#1	2015
Quindaro #1	2011

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	O&M Variable[2] ($1,000)	O&M Fixed ($1,000)	*Emission Costs[4]* *($1,000)*	Economy Sales ($1000)	Economy Purchase[3] ($1000)	Nearman Participant Sales ($1,000)	Bridge Power Purchase ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost* *($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,127	$3,375	$33,590	$5,338	-$6,147	$10,780	-$14,943	$0	$95,121	$0	$0	$0	$95,121	$95,121
2009	2,570	$62,234	$3,490	$33,713	$5,150	-$5,453	$14,100	-$13,915	$0	$99,318	$0	$0	$0	$99,318	$189,486
2010	2,594	$65,518	$3,701	$34,756	$5,307	-$5,029	$12,100	-$15,122	$0	$101,232	$0	$5,802	$5,802	$107,033	$286,107
2011	2,635	$76,616	$3,606	$33,594	$4,704	-$3,268	$13,733	-$15,771	$0	$113,214	$9,717	$5,802	$15,519	$128,732	$396,521
2012	2,644	$81,119	$4,767	$35,406	$11,686	-$5,648	$16,096	-$14,707	$0	$128,718	$17,058	$5,802	$22,860	$151,578	$520,044
2013	2,669	$84,656	$5,179	$36,650	$12,490	-$5,624	$18,482	-$14,818	$0	$137,015	$17,058	$5,802	$22,860	$159,875	$643,829
2014	2,697	$91,180	$7,699	$40,164	$12,026	-$6,494	$12,890	-$16,416	$0	$141,048	$17,058	$25,336	$42,394	$183,442	$778,777
2015	2,721	$94,365	$7,885	$40,772	$13,307	-$6,464	$15,266	-$16,717	$0	$148,414	$17,058	$25,336	$42,394	$190,808	$912,142
2016	2,733	$97,546	$8,062	$41,543	$14,831	-$7,128	$16,521	-$17,071	$0	$154,305	$17,058	$25,336	$42,394	$196,699	$1,042,767
2017	2,744	$100,982	$8,241	$42,243	$16,499	-$7,628	$17,695	-$17,326	$0	$160,705	$17,058	$25,336	$42,394	$203,099	$1,170,914
Levelized Cost($1000):		$79,744	$5,324	$36,781	$9,547	-$5,788	$14,521	-$15,547	$0	$124,583	$10,213	$11,033	$21,247	$145,829	
NPV:		$640,294	$42,748	$295,325	$76,657	-$46,471	$116,594	-$124,829	$0	$1,000,318	$82,005	$88,590	$170,596	$1,170,914	
Levelized Cost($/MWh):		$24.11	$1.61	$11.12	$2.89	-$1.75	$4.39	-$4.70	$0.00	$37.66	$3.09	$3.34	$6.42	$44.08	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008).
(2) VOM column includes unit start-up cost including start-up fuel costs and includes additional variable costs associated with AQC retrofits.
(3) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(4) Emissions cost is composed of SO2 and Carbon allowance costs. Carbon regulations begins in 2012.

Q0-D: Q1 Retires in 2011, Add GE 7EA in 2011 and LM6000 in 2013

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate:	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
7EA SCCT	48,850	9	01/01/2011	59,775	6,288
LM6000 SCCT	42,270	10	01/01/2013	48,431	5,095

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q2 LNB and OFA	10,701	2	01/01/2010	11,990	1,984
N1 LNB and OFA	20,586	2	01/01/2010	23,065	3,817
N1 Spray Dry Scrubber & Fabric Filter	110,189	25	01/01/2014	118,032	19,534

Unit	Retirement Year
CT#1	2015
Quindaro #1	2011

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	O&M: Variable[2] ($1,000)	O&M: Fixed ($1,000)	*Emission Costs[4]* *($1,000)*	Economy Sales ($1000)	Economy Purchase[3] ($1000)	Nearman Participant Sales ($1,000)	Bridge Power Purchase ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost* *($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,127	$3,375	$33,590	$5,338	-$6,147	$10,780	-$14,943	$0	$95,121	$0	$0	$0	$95,121	$95,121
2009	2,570	$62,234	$3,490	$33,713	$5,150	-$5,453	$14,100	-$13,915	$0	$99,318	$0	$0	$0	$99,318	$189,486
2010	2,594	$65,518	$3,701	$34,756	$5,307	-$5,029	$12,100	-$15,122	$0	$101,232	$0	$5,802	$5,802	$107,033	$286,107
2011	2,635	$75,194	$3,597	$32,969	$4,702	-$2,743	$18,441	-$15,771	$0	$116,390	$6,288	$5,802	$12,090	$128,480	$396,304
2012	2,644	$76,176	$3,796	$33,887	$11,518	-$2,787	$26,896	-$14,707	$0	$134,779	$6,288	$5,802	$12,090	$146,869	$515,989
2013	2,669	$78,867	$4,132	$35,776	$12,363	-$3,361	$27,927	-$14,818	$0	$140,886	$11,383	$5,802	$17,185	$158,071	$638,378
2014	2,697	$88,666	$6,800	$39,274	$12,005	-$3,956	$18,265	-$16,415	$0	$144,639	$11,383	$25,336	$36,719	$181,358	$771,793
2015	2,721	$93,288	$6,996	$39,867	$13,322	-$4,493	$19,668	-$16,717	$0	$151,932	$11,383	$25,336	$36,719	$188,651	$903,650
2016	2,733	$95,162	$7,127	$40,623	$14,801	-$4,300	$22,296	-$17,071	$0	$158,639	$11,383	$25,336	$36,719	$195,358	$1,033,384
2017	2,744	$97,931	$7,266	$41,306	$16,430	-$4,667	$24,289	-$17,326	$0	$165,229	$11,383	$25,336	$36,719	$201,948	$1,160,805
Levelized Cost($1000):		$77,771	$4,810	$36,165	$9,509	-$4,352	$18,902	-$15,546	$0	$127,259	$6,277	$11,033	$17,311	$144,570	
NPV:		$624,453	$38,621	$290,385	$76,351	-$34,945	$151,773	-$124,828	$0	$1,021,811	$50,404	$88,590	$138,994	$1,160,805	
Levelized Cost($/MWh):		$23.51	$1.45	$10.93	$2.87	-$1.32	$5.71	-$4.70	$0.00	$38.47	$1.90	$3.34	$5.23	$43.70	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008).
(2) VOM column includes unit start-up cost including start-up fuel costs and includes additional variable costs associated with AQC retrofits.
(3) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(4) Emissions cost is composed of SO2 and Carbon allowance costs. Carbon regulations begins in 2012.

Q0-E: Q1 Retires in 2011, Add two LM6000 in 2011 and one LM6000 in 2013

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate:	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
LM6000 SCCT	42,270	10	01/01/2011	51,909	5,461
LM6000 SCCT	42,270	10	01/01/2011	51,909	5,461
LM6000 SCCT	42,270	10	01/01/2013	48,431	5,095

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q2 LNB and OFA	10,701	2	01/01/2010	11,990	1,984
N1 LNB and OFA	20,586	2	01/01/2010	23,065	3,817
N1 Spray Dry Scrubber & Fabric Filter	110,189	25	01/01/2014	118,032	19,534

Unit	Retirement Year
CT#1	2015
Quindaro #1	2011

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	O&M Variable[2] ($1,000)	O&M Fixed ($1,000)	*Emission Costs[4] ($1,000)*	Economy Sales ($1000)	Economy Purchase[3] ($1000)	Nearman Participant Sales ($1,000)	Bridge Power Purchase ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,127	$3,375	$33,590	$5,338	-$6,147	$10,780	-$14,943	$0	$95,121	$0	$0	$0	$95,121	$95,121
2009	2,570	$62,234	$3,490	$33,713	$5,150	-$5,453	$14,100	-$13,915	$0	$99,318	$0	$0	$0	$99,318	$189,486
2010	2,594	$65,518	$3,701	$34,756	$5,307	-$5,029	$12,100	-$15,122	$0	$101,232	$0	$5,802	$5,802	$107,033	$286,107
2011	2,635	$76,616	$3,606	$33,594	$4,704	-$3,268	$13,733	-$15,771	$0	$113,214	$10,922	$5,802	$16,723	$129,937	$397,554
2012	2,644	$80,957	$3,980	$34,522	$11,699	-$3,878	$18,434	-$14,707	$0	$131,006	$10,922	$5,802	$16,723	$147,729	$517,940
2013	2,669	$82,241	$4,261	$36,424	$12,496	-$4,453	$22,429	-$14,818	$0	$138,580	$16,016	$5,802	$21,818	$160,398	$642,130
2014	2,697	$91,029	$6,955	$39,934	$12,116	-$5,332	$13,796	-$16,415	$0	$142,083	$16,016	$25,336	$41,352	$183,435	$777,073
2015	2,721	$96,058	$7,132	$40,539	$13,466	-$5,820	$14,418	-$16,717	$0	$149,077	$16,016	$25,336	$41,352	$190,430	$910,174
2016	2,733	$97,688	$7,188	$41,305	$14,943	-$5,485	$16,832	-$17,072	$0	$155,400	$16,016	$25,336	$41,352	$196,752	$1,040,834
2017	2,744	$101,779	$7,375	$42,001	$16,642	-$6,383	$17,955	-$17,326	$0	$162,044	$16,016	$25,336	$41,352	$203,396	$1,169,169
Levelized Cost($1000):		$79,703	$4,881	$36,589	$9,592	-$5,099	$15,194	-$15,547	$0	$125,314	$9,264	$11,033	$20,298	$145,612	
NPV:		$639,961	$39,195	$293,787	$77,015	-$40,939	$122,000	-$124,829	$0	$1,006,190	$74,388	$88,590	$162,978	$1,169,169	
Levelized Cost($/MWh):		$24.09	$1.48	$11.06	$2.90	-$1.54	$4.59	-$4.70	$0.00	$37.88	$2.80	$3.34	$6.14	$44.02	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008).
(2) VOM column includes unit start-up cost including start-up fuel costs and includes additional variable costs associated with AQC retrofits.
(3) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(4) Emissions cost is composed of SO2 and Carbon allowance costs. Carbon regulations begins in 2012.

Q0-F: Q1 Retires in 2011, Add LM6000 in 2011 and GE 7EA in 2012

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate:	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
7EA SCCT	48,850	9	01/01/2012	57,738	6,074
LM6000 SCCT	42,270	10	01/01/2011	51,909	5,461

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q2 LNB and OFA	10,701	2	01/01/2010	11,990	1,984
N1 LNB and OFA	20,586	2	01/01/2010	23,065	3,817
N1 Spray Dry Scrubber & Fabric Filter	110,189	25	01/01/2014	118,032	19,534

Unit	Retirement Year
CT#1	2015
Quindaro #1	2011

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	O&M Variable[2] ($1,000)	O&M Fixed ($1,000)	*Emission Costs[4]* *($1,000)*	Economy Sales ($1000)	Economy Purchase[3] ($1000)	Nearman Participant Sales ($1,000)	Bridge Power Purchase ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost* *($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,127	$3,375	$33,590	$5,338	-$6,147	$10,780	-$14,943	$0	$95,121	$0	$0	$0	$95,121	$95,121
2009	2,570	$62,234	$3,490	$33,713	$5,150	-$5,453	$14,100	-$13,915	$0	$99,318	$0	$0	$0	$99,318	$189,486
2010	2,594	$65,518	$3,701	$34,756	$5,307	-$5,029	$12,100	-$15,122	$0	$101,232	$0	$5,802	$5,802	$107,033	$286,107
2011	2,635	$76,392	$3,543	$32,943	$4,705	-$2,687	$15,942	-$15,771	$0	$115,067	$5,461	$5,802	$11,262	$126,329	$394,460
2012	2,644	$78,740	$3,915	$34,551	$11,668	-$3,674	$21,832	-$14,707	$0	$132,324	$11,535	$5,802	$17,336	$149,660	$516,420
2013	2,669	$78,867	$4,132	$35,776	$12,363	-$3,361	$27,927	-$14,818	$0	$140,886	$11,535	$5,802	$17,336	$158,222	$638,926
2014	2,697	$88,666	$6,800	$39,274	$12,005	-$3,956	$18,265	-$16,415	$0	$144,639	$11,535	$25,336	$36,871	$181,510	$772,452
2015	2,721	$93,288	$6,996	$39,867	$13,322	-$4,493	$19,668	-$16,717	$0	$151,932	$11,535	$25,336	$36,871	$188,802	$904,415
2016	2,733	$95,162	$7,127	$40,623	$14,801	-$4,300	$22,296	-$17,071	$0	$158,639	$11,535	$25,336	$36,871	$195,509	$1,034,250
2017	2,744	$97,931	$7,266	$41,306	$16,430	-$4,667	$24,289	-$17,326	$0	$165,229	$11,535	$25,336	$36,871	$202,100	$1,161,766
Levelized Cost($1000):		$78,160	$4,816	$36,230	$9,525	-$4,436	$18,122	-$15,546	$0	$126,869	$6,788	$11,033	$17,821	$144,690	
NPV:		$627,570	$38,670	$290,903	$76,476	-$35,620	$145,504	-$124,828	$0	$1,018,676	$54,500	$88,590	$143,091	$1,161,766	
Levelized Cost($/MWh):		$23.63	$1.46	$10.95	$2.88	-$1.34	$5.48	-$4.70	$0.00	$38.35	$2.05	$3.34	$5.39	$43.74	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008).
(2) VOM column includes unit start-up cost including start-up fuel costs and includes additional variable costs associated with AQC retrofits.
(3) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(4) Emissions cost is composed of SO2 and Carbon allowance costs. Carbon regulations begins in 2012.

Q1-A: Add GE 7EA in 2011

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
7EA SCCT	48,850	9	01/01/2011	59,775	6,288

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q1 SCR	33,877	25	01/01/2012	38,894	6,437
Q2 LNB and OFA	10,701	2	01/01/2010	11,990	1,984
N1 LNB and OFA	20,586	2	01/01/2010	23,065	3,817
N1 Spray Dry Scrubber & Fabric Filter	110,189	25	01/01/2014	118,032	19,534

Unit	Retirement Year
CT#1	2015

Unit	Retirement Year

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	O&M Variable[2] ($1,000)	O&M Fixed ($1,000)	*Emission Costs[4] ($1,000)*	Economy Sales ($1000)	Economy Purchase[3] ($1000)	Nearman Participant Sales ($1,000)	Bridge Power Purchase ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,127	$3,375	$33,590	$5,338	-$6,147	$10,780	-$14,943	$0	$95,121	$0	$0	$0	$95,121	$95,121
2009	2,570	$62,234	$3,490	$33,713	$5,150	-$5,453	$14,100	-$13,915	$0	$99,318	$0	$0	$0	$99,318	$189,486
2010	2,594	$65,518	$3,701	$34,756	$5,307	-$5,029	$12,100	-$15,122	$0	$101,232	$0	$5,802	$5,802	$107,033	$286,107
2011	2,635	$77,304	$3,817	$36,575	$5,500	-$5,854	$9,223	-$15,771	$0	$110,794	$6,288	$5,802	$12,090	$122,884	$391,504
2012	2,644	$79,170	$4,496	$38,586	$13,555	-$6,262	$14,030	-$14,707	$0	$128,866	$6,288	$12,238	$18,527	$147,393	$511,617
2013	2,669	$82,292	$4,869	$40,114	$14,484	-$6,137	$16,285	-$14,818	$0	$137,089	$6,288	$12,238	$18,527	$155,616	$632,105
2014	2,697	$87,681	$7,279	$43,690	$14,030	-$6,235	$11,811	-$16,414	$0	$141,843	$6,288	$31,773	$38,061	$179,904	$764,450
2015	2,721	$93,175	$7,554	$44,363	$15,580	-$7,766	$12,080	-$16,714	$0	$148,272	$6,288	$31,773	$38,061	$186,333	$894,687
2016	2,733	$94,909	$7,672	$45,200	$17,154	-$7,515	$14,413	-$17,071	$0	$154,762	$6,288	$31,773	$38,061	$192,823	$1,022,738
2017	2,744	$96,943	$7,766	$45,960	$18,932	-$7,696	$15,966	-$17,327	$0	$160,543	$6,288	$31,773	$38,061	$198,604	$1,148,049
Levelized Cost($1000):		$78,432	$5,152	$38,986	$10,779	-$6,303	$12,931	-$15,546	$0	$124,432	$4,054	$14,496	$18,550	$142,981	
NPV:		$629,759	$41,369	$313,033	$86,548	-$50,605	$103,830	-$124,826	$0	$999,107	$32,551	$116,390	$148,942	$1,148,049	
Levelized Cost($/MWh):		$23.71	$1.56	$11.79	$3.26	-$1.91	$3.91	-$4.70	$0.00	$37.61	$1.23	$4.38	$5.61	$43.22	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008).
(2) VOM column includes unit start-up cost including start-up fuel costs and includes additional variable costs associated with AQC retrofits.
(3) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(4) Emissions cost is composed of SO2 allowance and Carbon tax costs. Carbon tax begins in 2012.

Q1-B: Add LM6000 in 2011

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
LM6000 SCCT	42,270	10	01/01/2011	51,909	5,461

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q1 SCR	33,877	25	01/01/2012	38,894	6,437
Q2 LNB and OFA	10,701	2	01/01/2010	11,990	1,984
N1 LNB and OFA	20,586	2	01/01/2010	23,065	3,817
N1 Spray Dry Scrubber & Fabric Filter	110,189	25	01/01/2014	118,032	19,534

Unit	Retirement Year
CT#1	2015

Unit	Retirement Year

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	O&M Variable[2] ($1,000)	O&M Fixed ($1,000)	*Emission Costs[4] ($1,000)*	Economy Sales ($1000)	Economy Purchase[3] ($1000)	Nearman Participant Sales ($1,000)	Bridge Power Purchase ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,127	$3,375	$33,590	$5,338	-$6,147	$10,780	-$14,943	$0	$95,121	$0	$0	$0	$95,121	$95,121
2009	2,570	$62,234	$3,490	$33,713	$5,150	-$5,453	$14,100	-$13,915	$0	$99,318	$0	$0	$0	$99,318	$189,486
2010	2,594	$65,518	$3,701	$34,756	$5,307	-$5,029	$12,100	-$15,122	$0	$101,232	$0	$5,802	$5,802	$107,033	$286,107
2011	2,635	$78,411	$3,781	$36,548	$5,504	-$6,079	$7,279	-$15,771	$0	$109,674	$5,461	$5,802	$11,262	$120,936	$389,834
2012	2,644	$81,739	$4,565	$38,557	$13,608	-$6,483	$10,280	-$14,707	$0	$127,558	$5,461	$12,238	$17,699	$145,258	$508,206
2013	2,669	$83,390	$4,873	$40,087	$14,507	-$6,221	$13,743	-$14,818	$0	$135,561	$5,461	$12,238	$17,699	$153,261	$626,871
2014	2,697	$90,054	$7,362	$43,662	$14,123	-$7,236	$8,653	-$16,415	$0	$140,203	$5,461	$31,773	$37,234	$177,437	$757,401
2015	2,721	$95,059	$7,611	$44,334	$15,628	-$8,033	$8,878	-$16,717	$0	$146,761	$5,461	$31,773	$37,234	$183,994	$886,003
2016	2,733	$96,684	$7,691	$45,169	$17,202	-$7,651	$10,835	-$17,072	$0	$152,858	$5,461	$31,773	$37,234	$190,091	$1,012,240
2017	2,744	$99,404	$7,823	$45,931	$19,006	-$8,460	$12,145	-$17,326	$0	$158,522	$5,461	$31,773	$37,234	$195,756	$1,135,754
Levelized Cost($1000):		$79,639	$5,174	$38,968	$10,809	-$6,543	$10,934	-$15,547	$0	$123,434	$3,521	$14,496	$18,016	$141,450	
NPV:		$639,447	$41,548	$312,886	$86,792	-$52,538	$87,790	-$124,829	$0	$991,096	$28,268	$116,390	$144,658	$1,135,754	
Levelized Cost($/MWh):		$24.07	$1.56	$11.78	$3.27	-$1.98	$3.31	-$4.70	$0.00	$37.31	$1.06	$4.38	$5.45	$42.76	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008).
(2) VOM column includes unit start-up cost including start-up fuel costs and includes additional variable costs associated with AQC retrofits.
(3) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(4) Emissions cost is composed of SO2 allowance and Carbon tax costs. Carbon tax begins in 2012.

Q1-C: Add LM2500s in 2011 and 2015

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
LM2500 SCCT	28,000	10	01/01/2011	34,385	3,617
LM2500 SCCT	28,000	10	01/01/2015	30,908	3,252

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q1 SCR	33,877	25	01/01/2012	38,894	6,437
Q2 LNB and OFA	10,701	2	01/01/2010	11,990	1,984
N1 LNB and OFA	20,586	2	01/01/2010	23,065	3,817
N1 Spray Dry Scrubber & Fabric Filter	110,189	25	01/01/2014	118,032	19,534

Unit	Retirement Year		Unit	Retirement Year	
CT#1	2015				

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	O&M Variable[2] ($1,000)	O&M Fixed ($1,000)	*Emission Costs[4] ($1,000)*	Economy Sales ($1000)	Economy Purchase[3] ($1000)	Nearman Participant Sales ($1,000)	Bridge Power Purchase ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,127	$3,375	$33,590	$5,338	-$6,147	$10,780	-$14,943	$0	$95,121	$0	$0	$0	$95,121	$95,121
2009	2,570	$62,234	$3,490	$33,713	$5,150	-$5,453	$14,100	-$13,915	$0	$99,318	$0	$0	$0	$99,318	$189,486
2010	2,594	$65,518	$3,701	$34,756	$5,307	-$5,029	$12,100	-$15,122	$0	$101,232	$0	$5,802	$5,802	$107,033	$286,107
2011	2,635	$76,635	$3,662	$36,525	$5,505	-$5,265	$9,444	-$15,771	$0	$110,735	$3,617	$5,802	$9,419	$120,154	$389,163
2012	2,644	$78,645	$4,361	$38,533	$13,489	-$5,516	$14,052	-$14,707	$0	$128,857	$3,617	$12,238	$15,856	$144,713	$507,091
2013	2,669	$81,175	$4,734	$40,062	$14,403	-$5,331	$16,538	-$14,818	$0	$136,763	$3,617	$12,238	$15,856	$152,619	$625,259
2014	2,697	$88,047	$7,233	$43,637	$14,005	-$6,164	$11,432	-$16,415	$0	$141,777	$3,617	$31,773	$35,390	$177,167	$755,590
2015	2,721	$91,647	$7,426	$44,984	$15,508	-$6,806	$12,095	-$16,717	$0	$148,137	$6,869	$31,773	$38,642	$186,779	$886,139
2016	2,733	$93,024	$7,483	$45,830	$17,055	-$6,651	$14,599	-$17,071	$0	$154,269	$6,869	$31,773	$38,642	$192,911	$1,014,248
2017	2,744	$95,963	$7,635	$46,603	$18,861	-$7,080	$15,557	-$17,326	$0	$160,213	$6,869	$31,773	$38,642	$198,855	$1,139,717
Levelized Cost($1000):		$77,867	$5,068	$39,122	$10,743	-$5,876	$12,931	-$15,546	$0	$124,309	$3,140	$14,496	$17,635	$141,944	
NPV:		$625,225	$40,691	$314,126	$86,256	-$47,181	$103,831	-$124,828	$0	$998,119	$25,208	$116,390	$141,599	$1,139,717	
Levelized Cost($/MWh):		$23.54	$1.53	$11.83	$3.25	-$1.78	$3.91	-$4.70	$0.00	$37.58	$0.95	$4.38	$5.33	$42.91	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008).
(2) VOM column includes unit start-up cost including start-up fuel costs and includes additional variable costs associated with AQC retrofits.
(3) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(4) Emissions cost is composed of SO2 allowance and Carbon tax costs. Carbon tax begins in 2012.

Q1-D: CT4 Conversion to Combined Cycle in 2011

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Convert 7EA to 1x1 CC	93,190	24	01/01/2011	119,841	11,217

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q1 SCR	33,877	25	01/01/2012	38,894	6,437
Q2 LNB and OFA	10,701	2	01/01/2010	11,990	1,984
N1 LNB and OFA	20,586	2	01/01/2010	23,065	3,817
N1 Spray Dry Scrubber & Fabric Filter	110,189	25	01/01/2014	118,032	19,534

Unit	Retirement Year	Unit	Retirement Year
CT#1	2015		

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	O&M Variable[2] ($1,000)	O&M Fixed ($1,000)	*Emission Costs[4]* *($1,000)*	Economy Sales ($1000)	Economy Purchase[3] ($1000)	Nearman Participant Sales ($1,000)	Bridge Power Purchase ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost* *($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,127	$3,375	$33,590	$5,338	-$6,147	$10,780	-$14,943	$0	$95,121	$0	$0	$0	$95,121	$95,121
2009	2,570	$62,234	$3,490	$33,713	$5,150	-$5,453	$14,100	-$13,915	$0	$99,318	$0	$0	$0	$99,318	$189,486
2010	2,594	$65,518	$3,701	$34,756	$5,307	-$5,029	$12,100	-$15,122	$0	$101,232	$0	$5,802	$5,802	$107,033	$286,107
2011	2,635	$78,580	$4,623	$36,956	$5,470	-$6,929	$6,741	-$15,771	$0	$109,670	$11,217	$5,802	$17,019	$126,689	$394,768
2012	2,644	$81,749	$5,481	$38,974	$13,553	-$7,378	$9,052	-$14,707	$0	$126,725	$11,217	$12,238	$23,456	$150,180	$517,152
2013	2,669	$83,223	$5,620	$40,548	$14,441	-$6,763	$12,871	-$14,818	$0	$135,122	$11,217	$12,238	$23,456	$158,578	$639,933
2014	2,697	$89,796	$8,257	$44,132	$14,010	-$7,842	$7,843	-$16,415	$0	$139,780	$11,217	$31,773	$42,990	$182,770	$774,387
2015	2,721	$94,523	$8,559	$44,812	$15,502	-$8,547	$8,013	-$16,717	$0	$146,145	$11,217	$31,773	$42,990	$189,135	$906,583
2016	2,733	$97,173	$8,683	$45,654	$17,151	-$8,378	$8,647	-$17,071	$0	$151,860	$11,217	$31,773	$42,990	$194,850	$1,035,979
2017	2,744	$100,276	$8,863	$46,425	$18,952	-$9,476	$10,617	-$17,326	$0	$158,332	$11,217	$31,773	$42,990	$201,322	$1,163,005
Levelized Cost($1000):		$79,680	$5,758	$39,262	$10,764	-$7,017	$10,217	-$15,546	$0	$123,117	$7,232	$14,496	$21,727	$144,844	
NPV:		$639,781	$46,230	$315,246	$86,428	-$56,345	$82,036	-$124,828	$0	$988,549	$58,066	$116,390	$174,456	$1,163,005	
Levelized Cost($/MWh):		$24.09	$1.74	$11.87	$3.25	-$2.12	$3.09	-$4.70	$0.00	$37.22	$2.19	$4.38	$6.57	$43.79	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008).
(2) VOM column includes unit start-up cost including start-up fuel costs and includes additional variable costs associated with AQC retrofits.
(3) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(4) Emissions cost is composed of SO2 allowance and Carbon tax costs. Carbon tax begins in 2012.

Appendix C
Phase I Sensitivity Case Revenue Requirements

Scenarios

	Q1 Retires 2011					Q1 No Change			
	Q0-A	Q0-B	Q0-C *	Q0-D	Q0-E	Q1-A	Q1-B	Q1-C	Q1-D
7EA CT	2011			2011		2011			
LM6000		2011 & 2015	2 in 2011	2013	2 in 2011, 2013		2011		
LM2500								2011 & 2015	
1x1 7EA CC	2012	2011							2011
2x1 LM6000 CC			2012						

Sensativities:

High & Low Load: Loss or gain of a large (28 MW) customer, at a load factor similar to system load factor. Buy capacity in the gain case. (SPP allows short term (4 mo.) capacity purchase up to 25% of peak.)
High & Low Fuel and Market: Use Ventyx high and low NG and electric market forecast.
High Carbon Tax: Use Ventyx base and high CO_2 price forecast.
No Economy Purchases

Base Case

Base Plans	Levelized Annual Production Cost: Fuel Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed ($1,000)	*Emission Costs* ($1,000)	Economy Sales ($1,000)	Economy Purchase ($1,000)	Nearman Participant Sales ($1,000)	Net Production Cost ($1,000)	Levelized Annual Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost* ($1,000)	Levelized Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)	Rank within Category	Rank within All Plans	% Difference From Least Cost Plan: Category	All Plans
Q1 Retires in 2011																	
Q0-A	$ 78,561	$ 5,439	$ 36,415	$ 9,506	$ (5,202)	$ 16,596	$ (15,546)	$ 125,770	$ 9,109	$ 11,033	$ 20,143	$ 145,912	$ 1,171,582	5	9	0.93%	3.15%
Q0-B	$ 79,368	$ 5,569	$ 36,755	$ 9,532	$ (5,685)	$ 14,749	$ (15,547)	$ 124,741	$ 11,971	$ 11,033	$ 23,005	$ 147,745	$ 1,186,299	6	10	2.20%	4.45%
Q0-C	$ 79,744	$ 5,324	$ 36,781	$ 9,547	$ (5,788)	$ 14,521	$ (15,547)	$ 124,583	$ 10,213	$ 11,033	$ 21,247	$ 145,829	$ 1,170,914	4	8	0.87%	3.10%
Q0-D	$ 77,771	$ 4,810	$ 36,165	$ 9,509	$ (4,352)	$ 18,902	$ (15,546)	$ 127,259	$ 6,277	$ 11,033	$ 17,311	$ 144,570	$ 1,160,805	1	4	**0.00%**	2.21%
Q0-E	$ 79,703	$ 4,881	$ 36,589	$ 9,592	$ (5,099)	$ 15,194	$ (15,547)	$ 125,314	$ 9,264	$ 11,033	$ 20,298	$ 145,612	$ 1,169,169	3	7	0.72%	2.94%
Q0-F	$ 78,160	$ 4,816	$ 36,230	$ 9,525	$ (4,436)	$ 18,122	$ (15,546)	$ 126,869	$ 6,788	$ 11,033	$ 17,821	$ 144,690	$ 1,161,766	2	5	**0.08%**	2.29%
Q1 Retires after 2017																	
Q1-A	$ 78,432	$ 5,152	$ 38,986	$ 10,779	$ (6,303)	$ 12,931	$ (15,546)	$ 124,432	$ 4,054	$ 14,496	$ 18,550	$ 142,981	$ 1,148,049	3	3	1.08%	1.08%
Q1-B	$ 79,639	$ 5,174	$ 38,968	$ 10,809	$ (6,543)	$ 10,934	$ (15,547)	$ 123,434	$ 3,521	$ 14,496	$ 18,016	$ 141,450	$ 1,135,754	1	1	**0.00%**	**0.00%**
Q1-C	$ 77,867	$ 5,068	$ 39,122	$ 10,743	$ (5,876)	$ 12,931	$ (15,546)	$ 124,309	$ 3,140	$ 14,496	$ 17,635	$ 141,944	$ 1,139,717	2	2	0.35%	0.35%
Q1-D	$ 79,680	$ 5,758	$ 39,262	$ 10,764	$ (7,017)	$ 10,217	$ (15,546)	$ 123,117	$ 7,232	$ 14,496	$ 21,727	$ 144,844	$ 1,163,005	4	6	2.40%	2.40%

Lose Large Customer

Base Plans	Levelized Annual Production Cost: Fuel Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed ($1,000)	*Emission Costs* ($1,000)	Economy Sales ($1,000)	Economy Purchase ($1,000)	Nearman Participant Sales ($1,000)	Net Production Cost ($1,000)	Levelized Annual Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost* ($1,000)	Levelized Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)	Rank within Category	Rank within All Plans	% Difference From Least Cost Plan: Category	All Plans
Q1 Retires in 2011																	
Q0-A	$ 75,456	$ 5,276	$ 36,415	$ 9,333	$ (6,085)	$ 13,298	$ (15,546)	$ 118,147	$ 9,109	$ 11,033	$ 20,143	$ 138,290	$ 1,110,380	4	8	1.14%	2.96%
Q0-B	$ 75,917	$ 5,396	$ 36,755	$ 9,355	$ (6,396)	$ 11,728	$ (15,547)	$ 117,209	$ 11,971	$ 11,033	$ 23,005	$ 140,213	$ 1,125,822	6	10	2.55%	4.39%
Q0-C	$ 76,077	$ 5,102	$ 36,781	$ 9,361	$ (6,546)	$ 11,887	$ (15,546)	$ 117,116	$ 10,213	$ 11,033	$ 21,247	$ 138,362	$ 1,110,960	5	9	1.19%	3.01%
Q0-D	$ 74,298	$ 4,641	$ 36,165	$ 9,334	$ (5,191)	$ 15,722	$ (15,547)	$ 119,422	$ 6,277	$ 11,033	$ 17,311	$ 136,733	$ 1,097,878	1	4	**0.00%**	1.80%
Q0-E	$ 75,876	$ 4,680	$ 36,589	$ 9,404	$ (5,854)	$ 12,462	$ (15,547)	$ 117,611	$ 9,264	$ 11,033	$ 20,298	$ 137,909	$ 1,107,318	2	6	0.86%	2.68%
Q0-F	$ 75,876	$ 4,680	$ 36,589	$ 9,404	$ (5,854)	$ 12,462	$ (15,547)	$ 117,611	$ 9,264	$ 11,033	$ 20,298	$ 137,909	$ 1,107,318	2	6	0.86%	2.68%
Q1 Retires after 2017																	
Q1-A	$ 74,906	$ 4,962	$ 38,986	$ 10,506	$ (7,049)	$ 10,458	$ (15,547)	$ 117,222	$ 4,054	$ 14,496	$ 18,550	$ 135,771	$ 1,090,157	3	3	1.09%	1.09%
Q1-B	$ 75,716	$ 4,969	$ 38,968	$ 10,523	$ (7,233)	$ 8,901	$ (15,547)	$ 116,297	$ 3,521	$ 14,496	$ 18,016	$ 134,314	$ 1,078,452	1	1	**0.00%**	**0.00%**
Q1-C	$ 74,255	$ 4,882	$ 39,122	$ 10,471	$ (6,645)	$ 10,504	$ (15,547)	$ 117,044	$ 3,140	$ 14,496	$ 17,635	$ 134,679	$ 1,081,384	2	2	0.27%	0.27%
Q1-D	$ 76,170	$ 5,524	$ 39,262	$ 10,496	$ (7,769)	$ 7,943	$ (15,546)	$ 116,079	$ 7,232	$ 14,496	$ 21,727	$ 137,806	$ 1,106,497	4	5	2.60%	2.60%

Gain Large Customer

Base Plans	Levelized Annual Production Cost: Fuel Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed ($1,000)	*Emission Costs* ($1,000)	Economy Sales ($1,000)	Economy Purchase ($1,000)	Nearman Participant Sales ($1,000)	Net Production Cost ($1,000)	Levelized Annual Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost* ($1,000)	Levelized Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)	Rank within Cat-egory	Rank within All Plans	% Difference From Least Cost Plan: Category	% Difference From Least Cost Plan: All Plans
Q1 Retires in 2011																	
Q0-A	$ 82,648	$ 5,677	$ 36,522	$ 9,638	$ (4,338)	$ 19,940	$ (15,546)	$ 134,541	$ 9,109	$ 11,033	$ 20,143	$ 154,684	$ 1,242,011	5	9	0.62%	3.28%
Q0-B	$ 83,419	$ 5,814	$ 36,861	$ 9,674	$ (4,847)	$ 17,832	$ (15,546)	$ 133,205	$ 11,971	$ 11,033	$ 23,005	$ 156,210	$ 1,254,264	6	10	1.61%	4.30%
Q0-C	$ 83,609	$ 5,544	$ 36,887	$ 9,670	$ (4,856)	$ 17,906	$ (15,546)	$ 133,214	$ 10,213	$ 11,033	$ 21,247	$ 154,461	$ 1,240,218	4	8	0.48%	3.13%
Q0-D	$ 81,652	$ 5,020	$ 36,272	$ 9,628	$ (3,437)	$ 22,832	$ (15,546)	$ 136,419	$ 6,277	$ 11,033	$ 17,311	$ 153,730	$ 1,234,354	1	5	**0.00%**	2.64%
Q0-E	$ 83,869	$ 5,087	$ 36,696	$ 9,726	$ (4,229)	$ 18,524	$ (15,547)	$ 134,127	$ 9,264	$ 11,033	$ 20,298	$ 154,424	$ 1,239,928	3	7	0.45%	3.11%
Q0-F	$ 82,186	$ 5,044	$ 36,230	$ 9,647	$ (3,557)	$ 21,932	$ (15,546)	$ 135,935	$ 6,788	$ 11,033	$ 17,821	$ 153,756	$ 1,234,561	2	6	**0.02%**	2.66%
Q1 Retires after 2017																	
Q1-A	$ 82,084	$ 5,338	$ 39,093	$ 10,985	$ (5,220)	$ 16,175	$ (15,547)	$ 132,907	$ 4,054	$ 14,496	$ 18,550	$ 151,457	$ 1,216,101	3	3	1.13%	1.13%
Q1-B	$ 83,150	$ 5,353	$ 39,074	$ 11,002	$ (5,196)	$ 13,918	$ (15,546)	$ 131,755	$ 3,521	$ 14,496	$ 18,016	$ 149,771	$ 1,202,568	1	1	**0.00%**	**0.00%**
Q1-C	$ 81,475	$ 5,249	$ 39,229	$ 10,933	$ (4,690)	$ 16,202	$ (15,547)	$ 132,850	$ 3,140	$ 14,496	$ 17,635	$ 150,485	$ 1,208,299	2	2	0.48%	0.48%
Q1-D	$ 83,567	$ 5,993	$ 39,368	$ 10,970	$ (5,909)	$ 12,776	$ (15,547)	$ 131,218	$ 7,232	$ 14,496	$ 21,727	$ 152,946	$ 1,228,055	4	4	2.12%	2.12%

High NG and MCP

Base Plans	Levelized Annual Production Cost: Fuel Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed ($1,000)	*Emission Costs* ($1,000)	Economy Sales ($1,000)	Economy Purchase ($1,000)	Nearman Participant Sales ($1,000)	Net Production Cost ($1,000)	Levelized Annual Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost* ($1,000)	Levelized Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)	Rank within Cat-egory	Rank within All Plans	% Difference From Least Cost Plan: Category	% Difference From Least Cost Plan: All Plans
Q1 Retires in 2011																	
Q0-A	$ 75,592	$ 4,982	$ 36,415	$ 14,355	$ (5,770)	$ 17,120	$ (15,546)	$ 127,148	$ 9,109	$ 11,033	$ 20,143	$ 147,291	$ 1,182,653	5	9	0.98%	3.49%
Q0-B	$ 75,296	$ 5,055	$ 36,755	$ 14,361	$ (6,036)	$ 16,127	$ (15,547)	$ 126,012	$ 11,971	$ 11,033	$ 23,005	$ 149,017	$ 1,196,507	6	10	2.17%	4.71%
Q0-C	$ 76,418	$ 4,863	$ 36,781	$ 14,397	$ (6,319)	$ 15,430	$ (15,546)	$ 126,024	$ 10,213	$ 11,033	$ 21,247	$ 147,270	$ 1,182,486	4	8	0.97%	3.48%
Q0-D	$ 74,659	$ 4,443	$ 36,165	$ 14,386	$ (4,873)	$ 19,311	$ (15,547)	$ 128,545	$ 6,277	$ 11,033	$ 17,311	$ 145,856	$ 1,171,131	1	5	**0.00%**	2.48%
Q0-E	$ 74,658	$ 4,401	$ 36,589	$ 14,406	$ (5,508)	$ 17,599	$ (15,547)	$ 126,597	$ 9,264	$ 11,033	$ 20,298	$ 146,895	$ 1,179,474	3	7	0.71%	3.21%
Q0-F	$ 74,587	$ 4,425	$ 36,230	$ 14,392	$ (4,867)	$ 18,895	$ (15,547)	$ 128,116	$ 6,788	$ 11,033	$ 17,821	$ 145,937	$ 1,171,783	2	6	**0.06%**	2.54%
Q1 Retires after 2017																	
Q1-A	$ 75,335	$ 4,829	$ 38,986	$ 16,751	$ (7,135)	$ 12,315	$ (15,547)	$ 125,534	$ 4,054	$ 14,496	$ 18,550	$ 144,084	$ 1,156,903	3	3	1.24%	1.24%
Q1-B	$ 74,979	$ 4,785	$ 38,968	$ 16,741	$ (7,259)	$ 11,636	$ (15,547)	$ 124,304	$ 3,521	$ 14,496	$ 18,016	$ 142,320	$ 1,142,736	1	1	**0.00%**	**0.00%**
Q1-C	$ 74,525	$ 4,756	$ 39,122	$ 16,731	$ (6,815)	$ 12,194	$ (15,547)	$ 124,966	$ 3,140	$ 14,496	$ 17,635	$ 142,601	$ 1,144,994	2	2	0.20%	0.20%
Q1-D	$ 75,770	$ 5,296	$ 39,262	$ 16,696	$ (7,906)	$ 10,380	$ (15,546)	$ 123,950	$ 7,232	$ 14,496	$ 21,727	$ 145,678	$ 1,169,697	4	4	2.36%	2.36%

Low NG and MCP

Base Plans	Levelized Annual Production Cost: Fuel Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed ($1,000)	*Emission Costs* ($1,000)	Economy Sales ($1,000)	Economy Purchase ($1,000)	Nearman Participant Sales ($1,000)	Net Production Cost ($1,000)	Levelized Annual Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost* ($1,000)	Levelized Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)	Rank within Cat-egory	Rank within All Plans	% Difference From Least Cost Plan: Category	% Difference From Least Cost Plan: All Plans
Q1 Retires in 2011																	
Q0-A	$ 72,591	$ 5,442	$ 36,415	$ 14,125	$ (6,130)	$ 8,446	$ (15,546)	$ 115,342	$ 9,109	$ 11,033	$ 20,143	$ 135,485	$ 1,087,859	5	5	0.98%	0.98%
Q0-B	$ 73,214	$ 5,611	$ 36,755	$ 14,123	$ (6,674)	$ 7,059	$ (15,547)	$ 114,540	$ 11,971	$ 11,033	$ 23,005	$ 137,545	$ 1,104,394	6	8	2.51%	2.51%
Q0-C	$ 73,591	$ 5,357	$ 36,781	$ 14,010	$ (6,702)	$ 6,548	$ (15,546)	$ 114,039	$ 10,213	$ 11,033	$ 21,247	$ 135,286	$ 1,086,258	3	3	0.83%	0.83%
Q0-D	$ 70,132	$ 4,649	$ 36,165	$ 14,415	$ (4,940)	$ 11,985	$ (15,547)	$ 116,860	$ 6,277	$ 11,033	$ 17,311	$ 134,171	$ 1,077,305	1	1	**0.00%**	**0.00%**
Q0-E	$ 71,471	$ 4,747	$ 36,589	$ 14,452	$ (6,031)	$ 9,496	$ (15,547)	$ 115,177	$ 9,264	$ 11,033	$ 20,298	$ 135,475	$ 1,087,777	4	4	0.97%	0.97%
Q0-F	$ 70,522	$ 4,670	$ 36,230	$ 14,434	$ (5,194)	$ 11,351	$ (15,547)	$ 116,467	$ 6,788	$ 11,033	$ 17,821	$ 134,288	$ 1,078,243	2	2	**0.09%**	**0.09%**
Q1 Retires after 2017																	
Q1-A	$ 71,917	$ 4,891	$ 38,986	$ 16,541	$ (5,936)	$ 8,522	$ (15,547)	$ 119,374	$ 4,054	$ 14,496	$ 18,550	$ 137,923	$ 1,107,435	3	9	1.07%	2.80%
Q1-B	$ 72,690	$ 4,940	$ 38,968	$ 16,512	$ (6,335)	$ 7,222	$ (15,547)	$ 118,451	$ 3,521	$ 14,496	$ 18,016	$ 136,467	$ 1,095,745	1	6	**0.00%**	1.71%
Q1-C	$ 72,512	$ 4,892	$ 39,122	$ 16,587	$ (5,835)	$ 7,582	$ (15,547)	$ 119,313	$ 3,140	$ 14,496	$ 17,635	$ 136,948	$ 1,099,605	2	7	0.35%	2.07%
Q1-D	$ 74,144	$ 5,698	$ 39,262	$ 16,128	$ (7,178)	$ 5,578	$ (15,546)	$ 118,085	$ 7,232	$ 14,496	$ 21,727	$ 139,812	$ 1,122,600	4	10	2.45%	4.20%

High Carbon Tax

Base Plans	Fuel Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed ($1,000)	*Emission Costs* ($1,000)	Economy Sales ($1,000)	Economy Purchase ($1,000)	Nearman Participant Sales ($1,000)	Net Production Cost ($1,000)	Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost* ($1,000)	Levelized Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)	Rank within Category	Rank within All Plans	% Difference From Least Cost Plan: Category	% Difference From Least Cost Plan: All Plans
	Levelized Annual Production Cost								Levelized Annual Capital Cost								
Q1 Retires in 2011																	
Q0-A	$ 79,468	$ 5,494	$ 36,415	$ 47,819	$ (6,059)	$ 19,785	$ (15,546)	$ 167,376	$ 9,109	$ 11,033	$ 20,143	$ 187,519	$ 1,505,657	4	7	0.60%	1.10%
Q0-B	$ 80,205	$ 5,624	$ 36,755	$ 47,952	$ (6,605)	$ 17,847	$ (15,547)	$ 166,232	$ 11,971	$ 11,033	$ 23,005	$ 189,236	$ 1,519,444	6	10	1.52%	2.03%
Q0-C	$ 82,710	$ 5,450	$ 36,781	$ 48,063	$ (7,174)	$ 14,877	$ (15,547)	$ 165,160	$ 10,213	$ 11,033	$ 21,247	$ 186,407	$ 1,496,725	1	3	**0.00%**	0.50%
Q0-D	$ 76,954	$ 4,754	$ 36,165	$ 47,660	$ (4,556)	$ 24,256	$ (15,546)	$ 169,687	$ 6,277	$ 11,033	$ 17,311	$ 186,998	$ 1,501,474	2	4	0.32%	0.82%
Q0-E	$ 79,083	$ 4,841	$ 36,589	$ 48,134	$ (5,544)	$ 19,852	$ (15,547)	$ 167,409	$ 9,264	$ 11,033	$ 20,298	$ 187,706	$ 1,507,161	5	8	0.70%	1.21%
Q0-F	$ 77,342	$ 4,760	$ 36,230	$ 47,676	$ (4,640)	$ 23,475	$ (15,546)	$ 169,297	$ 6,788	$ 11,033	$ 17,821	$ 187,118	$ 1,502,435	3	5	0.38%	0.89%
Q1 Retires after 2017																	
Q1-A	$ 77,628	$ 5,095	$ 38,986	$ 52,883	$ (6,877)	$ 16,568	$ (15,546)	$ 168,737	$ 4,054	$ 14,496	$ 18,550	$ 187,286	$ 1,503,788	3	6	0.98%	0.98%
Q1-B	$ 78,825	$ 5,120	$ 38,968	$ 53,070	$ (7,213)	$ 14,232	$ (15,547)	$ 167,454	$ 3,521	$ 14,496	$ 18,016	$ 185,470	$ 1,489,207	1	1	**0.00%**	**0.00%**
Q1-C	$ 77,140	$ 5,015	$ 39,122	$ 52,706	$ (6,392)	$ 16,445	$ (15,546)	$ 168,490	$ 3,140	$ 14,496	$ 17,635	$ 186,125	$ 1,494,463	2	2	0.35%	0.35%
Q1-D	$ 80,283	$ 5,808	$ 39,262	$ 52,823	$ (8,200)	$ 12,197	$ (15,546)	$ 166,627	$ 7,232	$ 14,496	$ 21,727	$ 188,354	$ 1,512,359	4	9	1.55%	1.55%

No Economy Purchases

Base Plans	Fuel Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed ($1,000)	*Emission Costs* ($1,000)	Economy Sales ($1,000)	Economy Purchase ($1,000)	Nearman Participant Sales ($1,000)	Net Production Cost ($1,000)	Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost* ($1,000)	Levelized Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)	Rank within Category	Rank within All Plans	% Difference From Least Cost Plan: Category	% Difference From Least Cost Plan: All Plans
	Levelized Annual Production Cost								Levelized Annual Capital Cost								
Q1 Retires in 2011																	
Q0-A	$ 108,434	$ 6,591	$ 36,415	$ 9,880	$ (7,718)	$ -	$ (15,547)	$ 138,055	$ 9,109	$ 11,033	$ 20,143	$ 158,197	$ 1,270,223	3	7	0.89%	4.14%
Q0-B	$ 105,665	$ 6,635	$ 36,755	$ 9,833	$ (8,065)	$ -	$ (15,548)	$ 135,275	$ 11,971	$ 11,033	$ 23,005	$ 158,280	$ 1,270,884	4	8	0.95%	4.20%
Q0-C	$ 105,609	$ 6,394	$ 36,781	$ 9,916	$ (7,603)	$ -	$ (15,548)	$ 135,548	$ 10,213	$ 11,033	$ 21,247	$ 156,795	$ 1,258,961	1	5	**0.00%**	3.22%
Q0-D	$ 112,143	$ 5,937	$ 36,165	$ 10,134	$ (6,072)	$ -	$ (15,548)	$ 142,759	$ 6,277	$ 11,033	$ 17,311	$ 160,070	$ 1,285,260	6	10	2.09%	5.38%
Q0-E	$ 106,647	$ 6,050	$ 36,589	$ 10,038	$ (6,271)	$ -	$ (15,548)	$ 137,504	$ 9,264	$ 11,033	$ 20,298	$ 157,802	$ 1,267,049	2	6	0.64%	3.88%
Q0-F	$ 110,784	$ 5,934	$ 36,230	$ 10,142	$ (5,945)	$ -	$ (15,548)	$ 141,598	$ 6,788	$ 11,033	$ 17,821	$ 159,418	$ 1,280,028	5	9	1.67%	4.95%
Q1 Retires after 2017																	
Q1-A	$ 103,498	$ 5,915	$ 38,986	$ 11,185	$ (7,986)	$ -	$ (15,548)	$ 136,051	$ 4,054	$ 14,496	$ 18,550	$ 154,600	$ 1,241,340	4	4	1.77%	1.77%
Q1-B	$ 100,875	$ 6,056	$ 38,968	$ 11,065	$ (7,527)	$ -	$ (15,548)	$ 133,889	$ 3,521	$ 14,496	$ 18,016	$ 151,905	$ 1,219,698	1	1	**0.00%**	**0.00%**
Q1-C	$ 101,440	$ 6,046	$ 39,122	$ 11,053	$ (6,711)	$ -	$ (15,548)	$ 135,403	$ 3,140	$ 14,496	$ 17,635	$ 153,038	$ 1,228,795	2	2	0.75%	0.75%
Q1-D	$ 99,203	$ 6,593	$ 39,262	$ 10,889	$ (8,768)	$ -	$ (15,548)	$ 131,631	$ 7,232	$ 14,496	$ 21,727	$ 153,358	$ 1,231,366	3	3	0.96%	0.96%

Appendix D
Site Selection Scoring Criteria

Appendix D
Site Selection Scoring Criteria

This appendix defines the environmental and technical evaluation criteria assigned to the various scores. Best professional judgment was used to select the relative desirability of the criteria. All scoring was based on current conditions at the time of this study.

Socioeconomics

Noise Impacts

Definition: The impacts of increased noise levels resulting from the operation of the proposed plant on nearby residences, sensitive facilities, and population centers (receptors).

Score	Criteria
10	No receptors within 2 miles of the site.
8	One or two receptors within 2 miles of the site.
6	Three to five receptors within 2 miles of the site.
4	One to five receptors within 1 mile of the site.
1	More than five receptors within 1 mile of the site.

Impact of Project Traffic

Definition: The impact of increased traffic related to project construction and operation on existing roads and traffic patterns in site area.

Score	Criteria
10	Minimal increase in total traffic.
7	Moderate increase in total traffic.
4	Major increase in total traffic.

Impact on Sensitive Areas

Definition: Parks; state or federal forests; monuments; and recreational, wildlife, or wilderness areas are considered sensitive areas.

Scoring: Sites will be scored by assessing the potential visibility/aesthetic, noise, and air quality impacts of project operation on sensitive areas in the professional judgment of the evaluator. Sites with no anticipated impact or minimum impact will be assigned the score of 10, with the other sites given relative scores.

Land Use

Land Ownership

Definition:	Private or public property.
Score	**Criteria**
10	Private or BPU ownership.
7	Municipal or Wyandotte County ownership.
5	State ownership.
3	Federal ownership.
1	Multiple owners.

Site Location

Definition:	Location relative to BPU electric facility.
Score	**Criteria**
10	Site at existing power plant.
5	Site at existing or new substation.

Land Use Compatibility

Definition:	Site compatibility with current zoning and local land use.
Score	**Criteria**
10	Compatible with current zoning and land use.
7	Compatible with future zoning and land use.
3	Rezoning required.

Air Quality

Definition:	Probability of air construction permitting requirements.
Score	**Permit required**
10	Minor permit required.
5	Major permit required.

Site Development

Ease of Development

Definition:	Based upon site reconnaissance and aerial photographs, the ease of development was evaluated. Considerations included current site area, topography, and access.
Score	**Ease of Development**
10	Existing site with adequate area, relatively flat topography, and good access.

Score	Ease of Development
5	Existing site with adequate area that requires some demolition or relocation, relatively flat topography, and good access.
1	New site with adequate area that will require complete development, or has un-level topography, and requires new access means to be installed.

Availability of Common Facilities

Definition: If existing common facilities are available, site development is greatly reduced. Conversely if all new facilities are required to be developed as part of the unit installation, site development is greatly increased. Common facilities include water supply systems, water treatment (demineralizer) systems, wastewater collection and treatment systems, and transmission substation and interconnection facilities.

Score	Availability of Common Facilities
10	Existing site with adequate existing common facilities for water, wastewater, transmission, and access.
5	Existing site with some existing common facilities.
1	New site where all facilities will need to be developed.

Differential Site Development Costs

Some of the principal site comparisons during the site selection process are on the basis of estimated costs, such as capital costs to prepare the site (cut/fill), install facilities, transmission facilities, and utilities pipelines. The method used to score each cost-based comparison will be to assign the point value of 10 to the lowest costs, the value of 1 to the highest cost site, and award intermediate scores on the basis of site costs.

Project costs can be separated into two categories: the power block capital costs and site development costs. The total power block capital cost for each site was assumed to be the same at each candidate site. However, each site has specific characteristics that can influence the total site development costs for the proposed power generation facilities at that particular site location. The following paragraphs explain the portions of the site development costs that are not included in the power block capital costs.

Natural Gas Pipeline

Natural gas is required as the main fuel for the new power generating unit. Between 20 and 50 mcf per hour of natural gas is required for a simple cycle unit and between 40 and 100 mcf per hour of natural gas is required for a combined cycle unit.

This quantity of natural gas is available currently on an interruptible basis from the main pipeline systems described in Section 16.1. A 4 inch to 12 inch line, depending on supply pressure, is required for the natural gas supply to a simple cycle unit and 6 inch to 16 inch line would be required for the natural gas supply to a combined cycle unit. In addition, gas compression may be required depending on the natural gas supply pressure and the type of combustion turbine selected. The cost of the natural gas supply line to each site is highly dependent on numerous factors. The length and route of the line would be two of the primary factors in the cost. The estimated cost of a 12 inch natural gas line is $1,600,000 per mile. The capital cost is highly dependent on the length of pipeline required, local terrain and surface conditions, subsurface conditions, proximity to structures, roads and railroad crossings, and numerous other factors.

Water Supply System and Pipeline

Water is required for potable, cooling, and service applications. Approximately 60 to 110 gpm (0.09 to 0.16 mgd) is needed for a simple cycle unit installation and 630 to 1,700 gpm (0.9 to 2.5 mgd) for a combined cycle unit installation. For the purpose of this study, it has been assumed this quantity of water can be furnished from existing BPU municipal water supplies. A minimum 6 inch line could be used for the water supply to a simple cycle unit installation and 12 inch line could be used for the water supply for a combined cycle unit installation. The cost for the water supply pipeline is highly dependent on numerous factors. The length and route of the line would be two of the primary factors in the cost. According to BPU the estimated cost of a 12 inch water supply line is $500,000 per mile and for a 6 inch water line is $400,000 per mile. The capital cost is highly dependent on the length of pipeline required, local terrain and surface conditions, subsurface conditions, proximity to structures, roads and railroad crossings, and numerous other factors.

Sewer Pipeline (Wastewater Discharge System)

A wastewater discharge system is required for the installations. Approximately 16 to 27 gpm (0.009 to .004 mgd) will be discharged from a simple cycle unit installation and 160 to 420 gpm (0.2 to 0.6 mgd) for a combined cycle unit installation. For the purpose of this study, it has been assumed the wastewater can be discharged to existing power plant wastewater facilities or to the municipal sewer system. A minimum 3 or 4 inch line is required for the wastewater discharge from a simple cycle unit installation and 8 or 10 inch line is required for a combined cycle unit installation. The cost for the sewer pipeline is highly dependent on numerous factors. The length and route of the line would be two of the primary factors in the cost. The estimated cost for a 4 inch wastewater line is $450,000 per mile. The capital cost is highly dependent on the length of pipeline required, local terrain and surface conditions, subsurface conditions, proximity to structures, roads and railroad crossings, and numerous other factors.

Access Road

It is assumed that the access road to the site would be asphalt surfaced. The unit cost of new roadway or significant road improvements is $170,000 per mile, based on a 24 foot wide access road with a 10 inch aggregate base and 3 inches of asphalt.

Transmission Interconnection

It has been assumed, since all sites are at existing power generating stations or at existing or new substations, that the costs of the actual transmission interconnection would be similar. Therefore, no differential site development costs were included for transmission interconnections. Also, since the actual site location has not been selected, BPU has not determined if any transmission system upgrades would be necessary with installation of the new generating unit at any particular site. After the site selection is completed and the unit type and size selected, BPU may want to determine if substantial costs are involved with the preferred site.

Substation Improvements

The incremental site substation costs have been estimated to include normal substation upgrades typically associated with installation of a new simple cycle or combined cycle unit. For the purpose of comparisons, the cost of the upgrades has been estimated at $2,000,000 for sites with existing substations and $1,000,000 for new planned substations where the modifications required could be part of the original substation design.

Land Acquisition

The sites were assumed to cost the same per acre for this analysis, due to limits in available estimated land values ($5,000 per acre). For the purposes of this comparison, it will be assumed that 10 acres of land will be required for a combined cycle unit and 4 acres of land will be required for a simple cycle unit. Additional land will only be required at substation sites as there is adequate land available at the existing power generation sites. The actual cost of land will vary at each site in reality.

Site Preparation

Site preparation which includes the work necessary to prepare the site for construction activities is necessary. Existing power generation sites will have little to no site preparation costs. Future planned or existing substation sites will require site clearing, grubbing, and leveling to prepare the site for construction. Site preparation has been estimated to be $10,000 per acre. For the purposes of this comparison, it will be assumed that 10 acres of land will be required for a combined cycle unit and 4 acres of land will be required for a simple cycle unit.

Other Site Development Costs

Costs have been included as required for natural gas compression, demineralizer system, demineralized water storage tank, and fuel oil storage tank.

Availability of Personnel (O&M) and Security

Operation & Maintenance Personnel Considerations

Operations and maintenance of the new unit will be performed by BPU's power plant staff. If the new unit were located at an existing operating power plant site such that operations and maintenance personnel and equipment are available fewer additional staff would be required. Remote operation of simple cycle units is common in the industry and with the proper training, monitoring and control equipment, and routine maintenance, operations should not be a problem. Routine and necessary maintenance could be provided by existing staff on a scheduled basis, but equipment and materials would have to be transported to the site as required. A combined cycle unit installation will need to be staffed with full time operations and maintenance personnel. If the combined cycle unit is installed at an existing operating site, operations and maintenance staff and equipment could be shared and a minimum increase in staff levels would be required. If the combined cycle unit is installed remotely from an existing operating facility, new dedicated operations and maintenance staff and equipment would need to be added to the staff.

Score	Criteria
10	Installation at a currently operating plant.
5	Installation at a partially staffed site.
1	Installation at a remote site not currently staffed.

Security Issues

Security and the ability to provide security for the new installation is an important consideration in the site selection. Safety of the public is of primary importance, with various factors such as vandalism and theft and their impact on BPU costs and ability to run the unit at the most opportune times should all be considered. New units installed on existing plant sites that already have full time security will not require additional and sometimes costly security systems. Remote, normally unattended sites would need to be equipped with state-of-the art security systems which provide both deterrents and remote monitoring to limit public access, vandalism, and theft.

Score	Criteria
10	Installation at currently operating plant.
1	Installation at a remote unattended site.

Appendix E
Comparison of Phase II Revenue Requirements

Q0-D: Q1 Retires in 2011, Add GE 7EA in 2011 and LM6000 in 2013 with SCR

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
Existing Plant O&M Capital FCR:	16.55%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
7EA SCCT	55,650	9	01/01/2011	73,684	7,752
LM6000 SCCT	45,670	10	01/01/2013	68,253	7,180

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q2 LNB and OFA	10,701	2	01/01/2010	12,203	2,020
N1 LNB and OFA	20,586	2	01/01/2010	23,476	3,885
N1 FGD, Fabric Filter, & Landfill	123,283	25	01/01/2013	169,516	28,055

Unit	Retirement Year
CT#1	2015

Unit	Retirement Year
Quindaro #1	2011

		Production Cost									Capital Cost				
Year	Served Load (GWh)	Fuel Cost[1] ($1,000)	Plant O&M & contract purchs incldng trnsmsn[6] Variable[2] ($1,000)	Plant O&M & contract purchs incldng trnsmsn[6] Fixed[3] ($1,000)	*Emission Costs[4] ($1,000)*	Economy Sales ($1000)	Economy Purchase[5] ($1000)	Nearman Participant Sales ($1,000)	Existing Plant O&M Capital Cost ($1,000)	Net Production Cost ($1,000)	Unit Additions Capital Cost ($1,000)	AQC retrofit Capital Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,797	$3,565	$34,478	$4,894	-$6,945	$11,374	-$15,575	$2,773	$98,361	$0	$0	$0	$98,361	$98,361
2009	2,570	$63,118	$3,807	$37,754	$5,624	-$6,492	$15,445	-$14,810	$4,405	$108,852	$0	$0	$0	$108,852	$201,783
2010	2,594	$66,603	$3,940	$42,605	$6,578	-$5,037	$12,987	-$16,447	$6,162	$117,390	$0	$5,905	$5,905	$123,295	$313,084
2011	2,635	$76,490	$3,877	$39,361	$6,022	-$2,620	$22,902	-$17,544	$6,985	$135,474	$7,752	$5,905	$13,657	$149,131	$440,993
2012	2,644	$78,340	$4,108	$40,488	$20,870	-$3,081	$32,241	-$16,725	$10,063	$166,304	$7,752	$5,905	$13,657	$179,961	$587,646
2013	2,669	$80,408	$6,492	$44,323	$24,141	-$3,361	$25,384	-$19,057	$11,480	$169,811	$14,932	$33,960	$48,892	$218,703	$756,979
2014	2,697	$86,792	$6,564	$45,520	$29,841	-$3,443	$26,560	-$19,573	$13,738	$186,000	$14,932	$33,960	$48,892	$234,892	$929,776
2015	2,721	$91,205	$6,612	$46,607	$32,879	-$4,366	$28,878	-$20,419	$15,267	$196,662	$14,932	$33,960	$48,892	$245,554	$1,101,406
2016	2,733	$95,445	$6,787	$47,900	$36,185	-$4,341	$29,904	-$21,367	$16,717	$207,230	$14,932	$33,960	$48,892	$256,121	$1,271,492
2017	2,744	$98,913	$6,852	$49,160	$39,494	-$5,259	$32,874	-$22,243	$16,991	$216,782	$14,932	$33,960	$48,892	$265,674	$1,439,121
Levelized Cost($1000):		$78,335	$5,071	$42,192	$18,796	-$4,584	$22,874	-$18,036	$9,739	$154,388	$8,131	$16,714	$24,844	$179,232	
NPV:		$628,982	$40,719	$338,772	$150,922	-$36,806	$183,667	-$144,820	$78,200	$1,239,636	$65,285	$134,199	$199,484	$1,439,121	
Levelized Cost($/MWh):		$23.68	$1.53	$12.75	$5.68	-$1.39	$6.91	-$5.45	$2.94	$46.67	$2.46	$5.05	$7.51	$54.18	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs on steam units and existing Quindaro CTs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008). Also included are SWPA and WAPA hydro energy costs, Empire energy purchase, and Smoky Hill Wind farm energy purchase.
(2) VOM column includes unit start-up cost (including start-up fuel costs on steam units and existing Quindaro CTs) and includes additional variable costs associated with AQC retrofits. Also included are the variable transmission service costs for the Empire purchase, the SWPA and WAPA hydro purchases, and the Smoky Hills Wind Farm.
(3) FOM column includes capacity and fixed transmission costs associated with the Empire purchase, demand charge and fixed transmission cost for hydro purchases, and transmission demand charge associated with Smoky Hills Wind Farm.
(4) Emissions costs is composed of SO2 allowance and Carbon tax costs. Carbon tax begins in 2012.
(5) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(6) Charges associated with purchase power contracts and start-up fuels are included in the ERC.

Q0-F: Q1 Retires in 2011, Add LM6000 in 2011 and GE 7EA in 2012 with SCR

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
Existing Plant O&M Capital FCR:	16.55%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
7EA SCCT	55,650	9	01/01/2012	78,842	8,294
LM6000 SCCT	45,670	10	01/01/2011	60,429	6,357

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q2 LNB and OFA	10,701	2	01/01/2010	12,203	2,020
N1 LNB and OFA	20,586	2	01/01/2010	23,476	3,885
N1 FGD, Fabric Filter, & Landfill	123,283	25	01/01/2013	169,516	28,055

Unit	Retirement Year
CT#1	2015

Unit	Retirement Year
Quindaro #1	2011

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	Plant O&M & contract purchs incldng trnsmsn[6]: Variable[2] ($1,000)	Fixed[3] ($1,000)	*Emission Costs[4]* *($1,000)*	Economy Sales ($1000)	Economy Purchase[5] ($1000)	Nearman Participant Sales ($1,000)	Existing Plant O&M Capital Cost ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC retrofit Capital Cost ($1,000)	*Total Capital Cost* *($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,797	$3,565	$34,478	$4,894	-$6,945	$11,374	-$15,575	$2,773	$98,361	$0	$0	$0	$98,361	$98,361
2009	2,570	$63,118	$3,807	$37,754	$5,624	-$6,492	$15,445	-$14,810	$4,405	$108,852	$0	$0	$0	$108,852	$201,783
2010	2,594	$66,603	$3,940	$42,605	$6,578	-$5,037	$12,987	-$16,447	$6,162	$117,390	$0	$5,905	$5,905	$123,295	$313,084
2011	2,635	$76,088	$3,709	$39,334	$6,027	-$2,395	$21,607	-$17,544	$6,985	$133,812	$6,357	$5,905	$12,262	$146,074	$438,371
2012	2,644	$76,920	$4,031	$41,174	$20,947	-$3,183	$30,605	-$16,725	$10,063	$163,833	$14,651	$5,905	$20,556	$184,389	$588,632
2013	2,669	$80,408	$6,492	$44,323	$24,141	-$3,361	$25,384	-$19,057	$11,480	$169,811	$14,651	$33,960	$48,611	$218,422	$757,749
2014	2,697	$86,792	$6,564	$45,520	$29,841	-$3,443	$26,560	-$19,573	$13,738	$186,000	$14,651	$33,960	$48,611	$234,611	$930,339
2015	2,721	$91,205	$6,612	$46,607	$32,879	-$4,366	$28,878	-$20,419	$15,267	$196,662	$14,651	$33,960	$48,611	$245,274	$1,101,773
2016	2,733	$95,445	$6,787	$47,900	$36,185	-$4,341	$29,904	-$21,367	$16,717	$207,230	$14,651	$33,960	$48,611	$255,841	$1,271,673
2017	2,744	$98,913	$6,852	$49,160	$39,494	-$5,259	$32,874	-$22,243	$16,991	$216,782	$14,651	$33,960	$48,611	$265,393	$1,439,125
Levelized Cost($1000):		$78,148	$5,046	$42,258	$18,805	-$4,570	$22,570	-$18,036	$9,739	$153,960	$8,560	$16,714	$25,273	$179,233	
NPV:		$627,480	$40,512	$339,308	$150,988	-$36,696	$181,223	-$144,820	$78,200	$1,236,197	$68,729	$134,199	$202,928	$1,439,125	
Levelized Cost($/MWh):		$23.62	$1.53	$12.77	$5.68	-$1.38	$6.82	-$5.45	$2.94	$46.54	$2.59	$5.05	$7.64	$54.18	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs on steam units and existing Quindaro CTs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008). Also included are SWPA and WAPA hydro energy costs, Empire energy purchase, and Smoky Hill Wind farm energy purchase.
(2) VOM column includes unit start-up cost (including start-up fuel costs on steam units and existing Quindaro CTs) and includes additional variable costs associated with AQC retrofits. Also included are the variable transmission service costs for the Empire purchase, the SWPA and WAPA hydro purchases, and the Smoky Hills Wind Farm.
(3) FOM column includes capacity and fixed transmission costs associated with the Empire purchase, demand charge and fixed transmission cost for hydro purchases, and transmission demand charge associated with Smoky Hills Wind Farm.
(4) Emissions costs is composed of SO2 allowance and Carbon tax costs. Carbon tax begins in 2012.
(5) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(6) Charges associated with purchase power contracts and start-up fuels are included in the ERC.

Q1-A: Add GE 7EA in 2011 with SCR

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
Existing Plant O&M Capital FCR:	16.55%
AQC Retrofit Fixed Charge Rate:	16.55%

Unit	Generation Additions: 2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
7EA SCCT	55,650	9	01/01/2011	73,684	7,752

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q1 SCR	33,877	25	01/01/2012	43,534	7,205
Q2 LNB and OFA	10,701	2	01/01/2010	12,203	2,020
N1 LNB and OFA	20,586	2	01/01/2010	23,476	3,885
N1 FGD, Fabric Filter, & Landfill	123,283	25	01/01/2013	169,516	28,055

Unit	Retirement Year
CT#1	2015

Unit	Retirement Year
Quindaro #1	

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	Plant O&M & contract purchs incldng trnsmsn[6]: Variable[2] ($1,000)	Plant O&M & contract purchs incldng trnsmsn[6]: Fixed[3] ($1,000)	*Emission Costs[4] ($1,000)*	Economy Sales ($1000)	Economy Purchase[5] ($1000)	Nearman Participant Sales ($1,000)	Existing Plant O&M Capital Cost ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC retrofit Capital Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,797	$3,565	$34,478	$4,894	-$6,945	$11,374	-$15,575	$2,773	$98,361	$0	$0	$0	$98,361	$98,361
2009	2,570	$63,118	$3,807	$37,754	$5,624	-$6,492	$15,445	-$14,810	$4,600	$109,047	$0	$0	$0	$109,047	$201,968
2010	2,594	$66,603	$3,940	$42,605	$6,578	-$5,037	$12,987	-$16,942	$6,884	$117,617	$0	$5,905	$5,905	$123,522	$313,475
2011	2,635	$77,955	$4,101	$43,367	$7,066	-$6,329	$11,765	-$18,039	$10,285	$130,170	$7,752	$5,905	$13,657	$143,826	$436,834
2012	2,644	$80,070	$4,826	$45,212	$24,466	-$6,936	$16,850	-$17,220	$13,428	$160,695	$7,752	$13,110	$20,861	$181,557	$584,787
2013	2,669	$83,627	$7,222	$48,667	$28,215	-$8,067	$13,317	-$23,128	$14,974	$164,827	$7,752	$41,165	$48,916	$213,743	$750,281
2014	2,697	$88,427	$7,173	$49,984	$34,620	-$7,423	$15,093	-$23,643	$17,288	$181,518	$7,752	$41,165	$48,916	$230,434	$919,798
2015	2,721	$94,836	$7,402	$51,194	$38,286	-$9,264	$14,610	-$24,487	$18,928	$191,505	$7,752	$41,165	$48,916	$240,421	$1,087,840
2016	2,733	$97,039	$7,400	$52,611	$41,659	-$9,364	$17,086	-$25,438	$20,470	$201,462	$7,752	$41,165	$48,916	$250,379	$1,254,113
2017	2,744	$99,918	$7,418	$54,002	$45,296	-$10,354	$18,963	-$26,316	$21,838	$210,767	$7,752	$41,165	$48,916	$259,683	$1,417,962
Levelized Cost($1000):		$79,655	$5,458	$45,096	$21,483	-$7,432	$14,513	-$19,971	$12,210	$151,011	$4,997	$20,589	$25,586	$176,597	
NPV:		$639,575	$43,825	$362,093	$172,493	-$59,674	$116,530	-$160,357	$98,036	$1,212,520	$40,126	$165,316	$205,442	$1,417,962	
Levelized Cost($/MWh):		$24.08	$1.65	$13.63	$6.49	-$2.25	$4.39	-$6.04	$3.69	$45.65	$1.51	$6.22	$7.73	$53.38	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs on steam units and existing Quindaro CTs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008). Also included are SWPA and WAPA hydro energy costs, Empire energy purchase, and Smoky Hill Wind farm energy purchase.
(2) VOM column includes unit start-up cost (including start-up fuel costs on steam units and existing Quindaro CTs) and includes additional variable costs associated with AQC retrofits. Also included are the variable transmission service costs for the Empire purchase, the SWPA and WAPA hydro purchases, and the Smoky Hills Wind Farm.
(3) FOM column includes capacity and fixed transmission costs associated with the Empire purchase, demand charge and fixed transmission cost for hydro purchases, and transmission demand charge associated with Smoky Hills Wind Farm.
(4) Emissions costs is composed of SO_2 allowance and Carbon tax costs. Carbon tax begins in 2012.
(5) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(6) Charges associated with purchase power contracts and start-up fuels are included in the ERC.

Q1-B: Add LM6000 in 2011 with SCR

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
Existing Plant O&M Capital FCR:	16.55%
AQC Retrofit Fixed Charge Rate:	16.55%

Unit	Generation Additions: 2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)	AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
LM6000 SCCT	45,670	10	01/01/2011	60,429	6,357	Q1 SCR	33,877	25	01/01/2012	43,534	7,205
						Q2 LNB and OFA	10,701	2	01/01/2010	12,203	2,020
						N1 LNB and OFA	20,586	2	01/01/2010	23,476	3,885
						N1 FGD, Fabric Filter, & Landfill	123,283	25	01/01/2013	169,516	28,055
							36,986	12	01/01/2011	44,836	7,420

Unit	Retirement Year
CT#1	2015

Unit	Retirement Year
Quindaro #1	

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	Plant O&M & contract purchs incldng trnsmsn[6]: Variable[2] ($1,000)	Fixed[3] ($1,000)	*Emission Costs[4]* *($1,000)*	Economy Sales ($1000)	Economy Purchase[5] ($1000)	Nearman Participant Sales ($1,000)	Existing Plant O&M Capital Cost ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC retrofit Capital Cost ($1,000)	*Total Capital Cost* *($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,797	$3,565	$34,478	$4,894	-$6,945	$11,374	-$15,575	$2,773	$98,361	$0	$0	$0	$98,361	$98,361
2009	2,570	$63,118	$3,807	$37,754	$5,624	-$6,492	$15,445	-$14,810	$4,600	$109,047	$0	$0	$0	$109,047	$201,968
2010	2,594	$66,603	$3,940	$42,605	$6,578	-$5,037	$12,987	-$16,942	$6,884	$117,617	$0	$5,905	$5,905	$123,522	$313,475
2011	2,635	$77,772	$3,986	$43,990	$7,073	-$6,398	$10,787	-$18,984	$10,285	$128,510	$6,357	$13,325	$19,683	$148,192	$440,579
2012	2,644	$79,915	$4,732	$45,847	$24,419	-$7,080	$15,884	-$18,166	$13,428	$158,980	$6,357	$20,530	$26,887	$185,867	$592,044
2013	2,669	$83,366	$7,164	$49,315	$28,190	-$7,942	$12,014	-$24,074	$14,974	$163,008	$6,357	$48,585	$54,942	$217,950	$760,796
2014	2,697	$89,570	$7,202	$50,643	$34,732	-$8,384	$12,981	-$24,589	$17,288	$179,444	$6,357	$48,585	$54,942	$234,386	$933,220
2015	2,721	$94,409	$7,339	$51,864	$38,206	-$9,029	$13,407	-$25,436	$18,928	$189,688	$6,357	$48,585	$54,942	$244,630	$1,104,204
2016	2,733	$97,279	$7,386	$53,293	$41,620	-$9,290	$14,865	-$26,386	$20,470	$199,238	$6,357	$48,585	$54,942	$254,180	$1,273,001
2017	2,744	$100,783	$7,445	$54,695	$45,323	-$10,889	$16,402	-$27,259	$21,838	$208,338	$6,357	$48,585	$54,942	$263,281	$1,439,121
Levelized Cost($1000):		$79,750	$5,429	$45,519	$21,479	-$7,545	$13,502	-$20,581	$12,210	$149,761	$4,098	$25,373	$29,471	$179,232	
NPV:		$640,337	$43,591	$365,491	$172,459	-$60,585	$108,411	-$165,255	$98,036	$1,202,485	$32,908	$203,728	$236,636	$1,439,121	
Levelized Cost($/MWh):		$24.11	$1.64	$13.76	$6.49	-$2.28	$4.08	-$6.22	$3.69	$45.27	$1.24	$7.67	$8.91	$54.18	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs on steam units and existing Quindaro CTs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008). Also included are SWPA and WAPA hydro energy costs, Empire energy purchase, and Smoky Hill Wind farm energy purchase.
(2) VOM column includes unit start-up cost (including start-up fuel costs on steam units and existing Quindaro CTs) and includes additional variable costs associated with AQC retrofits. Also included are the variable transmission service costs for the Empire purchase, the SWPA and WAPA hydro purchases, and the Smoky Hills Wind Farm.
(3) FOM column includes capacity and fixed transmission costs associated with the Empire purchase, demand charge and fixed transmission cost for hydro purchases, and transmission demand charge associated with Smoky Hills Wind Farm.
(4) Emissions costs is composed of SO_2 allowance and Carbon tax costs. Carbon tax begins in 2012.
(5) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(6) Charges associated with purchase power contracts and start-up fuels are included in the ERC.

Q1-C: Add LM2500s in 2011 and 2015 with SCR

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
Existing Plant O&M Capital FCR:	16.55%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
LM2500 SCCT	30,600	10	01/01/2011	40,489	4,259
LM2500 SCCT	30,600	10	01/01/2015	49,012	5,156

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q1 SCR	33,877	25	01/01/2012	43,534	7,205
Q2 LNB and OFA	10,701	2	01/01/2010	12,203	2,020
N1 LNB and OFA	20,586	2	01/01/2010	23,476	3,885
N1 FGD, Fabric Filter, & Landfill	123,283	25	01/01/2013	169,516	28,055

Unit	Retirement Year
CT#1	2015

Unit	Retirement Year
Quindaro #1	

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	Plant O&M & contract purchs incldng trnsmsn[6]: Variable[2] ($1,000)	Plant O&M & contract purchs incldng trnsmsn[6]: Fixed[3] ($1,000)	*Emission Costs[4] ($1,000)*	Economy Sales ($1000)	Economy Purchase[5] ($1000)	Nearman Participant Sales ($1,000)	Existing Plant O&M Capital Cost ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC retrofit Capital Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,797	$3,565	$34,478	$4,894	-$6,945	$11,374	-$15,575	$2,773	$98,361	$0	$0	$0	$98,361	$98,361
2009	2,570	$63,118	$3,807	$37,754	$5,624	-$6,492	$15,445	-$14,810	$4,600	$109,047	$0	$0	$0	$109,047	$201,968
2010	2,594	$66,603	$3,940	$42,605	$6,578	-$5,037	$12,987	-$16,942	$6,884	$117,617	$0	$5,905	$5,905	$123,522	$313,475
2011	2,635	$77,724	$3,963	$43,938	$7,072	-$5,837	$11,497	-$18,039	$10,285	$130,604	$4,259	$5,905	$10,164	$140,769	$434,212
2012	2,644	$79,914	$4,685	$45,794	$24,345	-$6,374	$16,715	-$17,220	$13,428	$161,286	$4,259	$13,110	$17,369	$178,655	$579,800
2013	2,669	$83,248	$7,118	$49,260	$28,118	-$7,516	$13,065	-$23,128	$14,974	$165,140	$4,259	$41,165	$45,424	$210,564	$742,833
2014	2,697	$88,477	$7,102	$50,587	$34,514	-$7,243	$14,832	-$23,643	$17,288	$181,912	$4,259	$41,165	$45,424	$227,336	$910,071
2015	2,721	$94,066	$7,305	$53,193	$38,135	-$8,459	$14,444	-$24,490	$18,928	$193,121	$9,416	$41,165	$50,580	$243,702	$1,080,406
2016	2,733	$95,954	$7,280	$54,654	$41,419	-$8,472	$17,057	-$25,442	$20,470	$202,921	$9,416	$41,165	$50,580	$253,501	$1,248,752
2017	2,744	$98,824	$7,306	$56,085	$45,067	-$9,272	$18,681	-$26,314	$21,838	$212,216	$9,416	$41,165	$50,580	$262,796	$1,414,566
Levelized Cost($1000):		$79,339	$5,385	$45,836	$21,401	-$7,024	$14,384	-$19,972	$12,210	$151,559	$4,027	$20,589	$24,615	$176,174	
NPV:		$637,044	$43,240	$368,030	$171,836	-$56,396	$115,491	-$160,361	$98,036	$1,216,920	$32,330	$165,316	$197,646	$1,414,566	
Levelized Cost($/MWh):		$23.98	$1.63	$13.86	$6.47	-$2.12	$4.35	-$6.04	$3.69	$45.82	$1.22	$6.22	$7.44	$53.26	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs on steam units and existing Quindaro CTs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008). Also included are SWPA and WAPA hydro energy costs, Empire energy purchase, and Smoky Hill Wind farm energy purchase.
(2) VOM column includes unit start-up cost (including start-up fuel costs on steam units and existing Quindaro CTs) and includes additional variable costs associated with AQC retrofits. Also included are the variable transmission service costs for the Empire purchase, the SWPA and WAPA hydro purchases, and the Smoky Hills Wind Farm.
(3) FOM column includes capacity and fixed transmission costs associated with the Empire purchase, demand charge and fixed transmission cost for hydro purchases, and transmission demand charge associated with Smoky Hills Wind Farm.
(4) Emissions costs is composed of SO2 allowance and Carbon tax costs. Carbon tax begins in 2012.
(5) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(6) Charges associated with purchase power contracts and start-up fuels are included in the ERC.

Appendix F
Combustion Turbine Permit List

Agency	Permit/ Approval	Regulated Activity	Required Project Phase	Expected / Typical Review Time	Required for SCCT	Required for CCCT	Comments/Issues
FEDERAL							
COE	Section 10 Permit	Construction activities in navigable waters of the US.	Construction	3 - 9 months for individual 1 - 2 months for nationwide	MAYBE	MAYBE	Typically required for new construction of intake and outfall structures, barge facilities, or loading/unloading docks. *RE: Intake - No new intake required. Assume raw water will be supplied via BPU city water supply, i.e. from horizontal collector wells. See related Water Rights Extension Permit.* *Re: Outfall - Consider existing discharge structure condition to determine whether modification or repairs are necessary to discharge wastewater from new CT.*
COE	Section 404 Permit / NEPA Review	Discharge of dredge or fill material into waters of the US, including jurisdictional wetlands.	Construction	3 - 9 months for individual 1 - 2 months for nationwide	MAYBE	MAYBE	A nationwide permit may be authorized for utility line activities within COE wetlands. An Individual Permit will likely be required for impacts to wetlands greater than .50 acre. *Recommend confirming with the COE that the portion of the Nearman Creek Power Station enclosed within the flood levee is not within COE jurisdiction. The potential for impacting wetlands outside of the levee should be determined.*
DOE	Alternate Fuels Capability Certification	Baseload facility using natural gas.	Operation	Self-certification upon filing Permanent exemption 3-6 months	NO	YES	*SCCT will be a peaking load facility.*
EPA	Title IV Acid Rain Permit	Release of SO_2 from new units > 25 MW.	Operation	24 months	YES	YES	Application must be submitted 24-months prior to operation. *The new unit must submit a revised Phase II EPA Title IV Acid Rain Permit application. This will become part of the BPU Title V Operating Permit.*
EPA	CEMs Monitoring Plan	Indicate how the CEMs will appropriately measure air emissions.	Operation	6 months	YES	YES	Required by Title IV Acid Rain Permit.
EPA	SPCC Plan	Total onsite storage of oil > 1,320 gallons. Only containers of oil with a capacity of 55 gallons or greater are counted.	Construction / Operation	N/A	YES	YES	See also EPA's proposed changes of 10/01/07. *BPU will need to develop and implement an SPCC plan for construction-specific activities. Updates to existing operational plan will include new site arrangement and oil storage quantities.*
EPA	Risk Management Plan (RMP)	Potential accidental releases of hazardous chemicals that are used or stored onsite in greater than threshold quantities.	Post-Operation	3 - 4 months	NO	MAYBE	An RMP must be submitted no later than the date on which a regulated substance is first present above a threshold quantity in a process. Substances regulated under 40 CFR 68 include aqueous ammonia, 20% solution (20,000 lbs threshold) and hydrazine (15,000 lbs threshold). *BPU currently maintains an RMP for chlorine used in cooling tower. Additional ammonia storage required for CCCT air emissions control equipment may trigger RMP for ammonia.*
EPA	Toxic Release Inventory under EPCRA/KEPCRA	TRI Reporting.	Construction / Operation	N/A	YES	YES	Reporting requirements triggered by storage/ handling of toxic chemicals (EPCRA Section 313) above threshold limits; applicable to entire facility.
FAA	Notice of Proposed Construction or Alteration	Construction of tall objects, such as exhaust stacks and construction cranes, that may affect navigable airspace. Objects exceeding 200' or are within 20,000' of an airport typically require notice to FAA.	Construction	3 months	MAYBE	MAYBE	FAA may recommend lighting or marking of tall objects. Even if height or distance threshold is not triggered, Black & Veatch recommends courtesy notice. *Stack height for SCCT is estimated at 100', for CCCT at 170'. A preliminary check of the surrounding airfields indicates that the nearest public-use / military-use airports to the Nearman Creek Power Station is the Charles B. Wheeler Downtown Airport (KMKC), approximately 6 miles east.*
USFWS	Endangered Species Act Section 7 Consultation	Confirmation of no impacts to threatened or endangered species.	Construction	1 - 2 months, initial consultation letter	YES	YES	*USFWS will review project to determine whether activities will impact bald eagle and its habitat, or any listed species or critical habitat.*

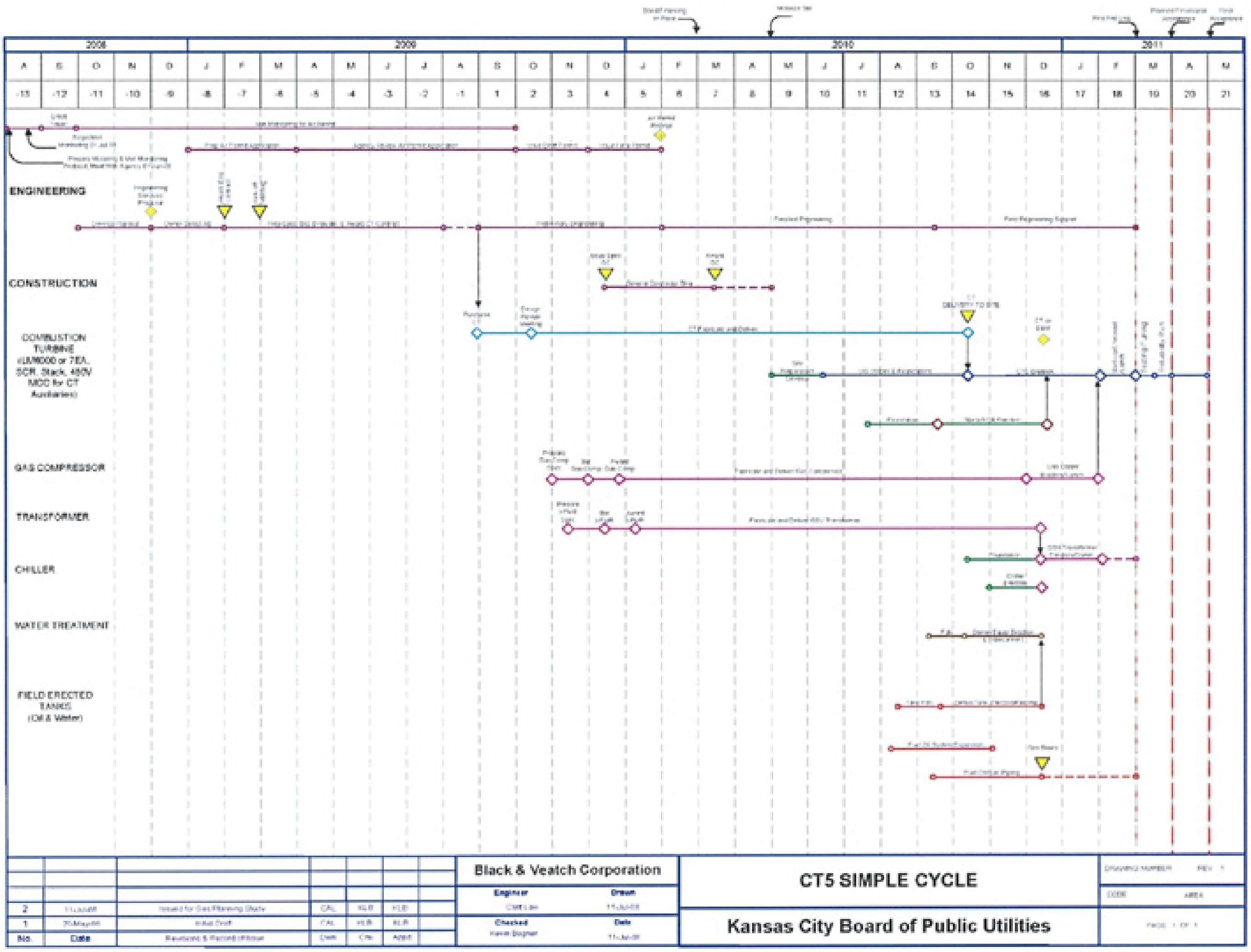
Agency	Permit/ Approval	Regulated Activity	Required Project Phase	Expected / Typical Review Time	Required for SCCT	Required for CCCT	Comments/Issues
STATE							
KDHE	NPDES General Storm Water Permit for Construction	Discharge of storm water runoff during construction activities affecting ≥1 acres.	Construction	2 months, NOI to be submitted at least 60 days before starting construction	YES	YES	The KDHE prefers that a complete application be submitted during the design phase of the project. A complete application consists of a NOI, a summary of the SWPPP, an area map, a site plan, and the first annual permit fee.
KDHE	Construction Storm Water Pollution Prevention Plan	To design, implement, manage, and maintain Best Management Practices to reduce the amount of pollutants in storm water discharges.	Construction	60 days, see above plan	YES	YES	The plan must be developed and implemented within one year of the effective date of the permit.
KDHE	NPDES Individual Permit Modification	Discharge of industrial wastewater and storm water runoff during operation of facility to surface waters.	Operation	6 - 9 months	MAYBE	YES	*The addition of a CCCT unit will require modification of the existing NPDES permit.* *The addition of an SCCT is not expected to result in a wastewater discharge to surface waters, as wastewaters will be collected and hauled off by a contractor. However; for major plant modifications, KDHE recommends a preliminary meeting with the Bureau of Water and permittee to understand the proposal and determine whether or not a permit revision is necessary.*
KDHE	Operational Storm Water Pollution Prevention Plan Modification	To design, implement, manage, and maintain Best Management Practices to reduce the amount of pollutants in storm water discharges.	Operation	6 - 9 months	YES	YES	*Update existing plan to include new unit information.*
KDHE	CWA 316(b) Review and Approval	The location, design, construction and capacity of cooling water intake structures.	Operation	N/A	NO	NO	*Water for the CT unit will be provided by municipal water supply, no new cooling water intake will be required.*
KDHE	NPDES Hydrostatic Test Water Discharge Permit	Hydrostatic test discharges from new pipelines and storage tanks.	Construction	Submit NOI 60 days prior to activity	LIKELY	LIKELY	A separate permit is required for each diversion point.
KDHE	Section 401 Water Quality Certification	Impacts to state waters resulting from federal actions.	Construction	3 - 4 months	MAYBE	MAYBE	See also Section 404 COE permits.
KDHE	Industrial Waste Landfill Construction Permit	The Construction of a solid waste processing facility or a solid waste disposal area of a solid waste management system.	Construction	Hydrogeologic studies and approval 1.5 to 2.5 years. Permit application 9 months after approvals of hydrogeologic studies	NO	NO	
KDHE	AST System Permitting and Registration	Storage of flammable and combustible liquids.	Construction	2 - 3 months	NO	NO	Tanks < 660 gallons are exempt. KSFM approval required in advance of KDHE approval. *Existing fuel oil tanks at BPU Nearman Creek are sufficient to provide for 3 days storage.*
KSFM	AST System Approval	Storage of flammable and combustible liquids.	Construction	2 - 3 months	NO	NO	KSFM will ensure that tanks meet applicable fire codes.
KDWP	Threatened and Endangered Species Evaluation	Protection of endangered species.	Construction	1 - 2 months, initial consultation letter	YES	YES	An action permit may be required, depending upon activities involving the land fill. An action permit application must be submitted no fewer than 90 days before proposed starting date. *KDWP will review project to determine whether activities will impact bald eagle and its habitat, or any listed species or critical habitat.*
KSDA	Floodplain Fill Approval	Activities affecting floodplains.	Construction	3 - 4 months	LIKELY	LIKELY	*Previous agency discussion indicates a permit will be required, even for activities within the levee. See also local permits, Floodplain Certificate.*
KSDA	Water Rights Extension / Change of Use	The appropriate of the right to lawfully divert and use water.	Construction	3 - 4 months	MAYBE	MAYBE	*Municipal city water will be used for CT unit cooling and service requirements. If source of water is from raw water supply, a change in the use of the water (from potable to industrial) may require a modification to BPU's Water Rights Permit.*

Agency	Permit/ Approval	Regulated Activity	Required Project Phase	Expected / Typical Review Time	Required for SCCT	Required for CCCT	Comments/Issues
KSDA	Dewatering Permit	Ground water intrusion.	Construction	60 days	LIKELY	LIKELY	Required for temporary appropriation of state waters resulting from construction dewatering activities. *Likelihood of dewatering activities will depend on location of construction activities, time of year, water level in the Missouri River, and amount of rainfall received.*
KSDA	Stream Obstruction General Permit	Pipeline crossing of stream.	Construction	3 - 4 months	MAYBE	MAYBE	Typically required for new construction of intake and outfall structures, barge facilities, or loading/unloading docks. *This permit list assumes no activities in the Missouri River will be required for construction or operation of a combustion turbine unit. Construction activities impacting Nearman Creek or small tributaries may require permit.*
KSHS	Historical/Archeological Review	Activities that could potentially affect archeological or historical resources.	Construction	1 - 2 months for initial consultation letter.	YES	YES	A SHPO investigation of a project must begin within 30 days following notification of project.
LOCAL							
UG - DAQ	PSD/State Air Permit to Construct	Construction of air pollution control equipment and emission sources.	Construction	8 - 24 months	YES	YES	*Project may require 12 months of meteorological monitoring. Permit may be issued by KDHE.*
UG - DAQ	Title V Operating Permit, Compliance Assurance Monitoring (CAM) Plan	Operation of air pollutant emission sources.	Post-Operation	9 - 12 months	YES	YES	*BPU will be required to modify its Title V permit to include CT-5 emissions no later than 12 months after the Project commences operation. Permit may be issued by KDHE.*
UG - DUP	Conformance with Comprehensive Plan	Required for construction of public utility.	Construction	2 months	YES	YES	
UG - DUP	Development Review / Zoning Conformance Review	Required for new developments in Kansas City, Kansas and Wyandotte County.	Construction	80 days minimum	YES	YES	*BPU Nearman Creek is zoned R-1, Residential Single Family District. BPU facilities are listed as Permitted Uses within this district, so no special use permit or change in zoning will be required.*
UG - DUP	Building Permits	Construction of foundations, electrical wiring, plumbing, etc.	Construction	1 month, each	YES	YES	
UG - DUP	Certificate of Occupancy	Commercial operation of facility.	Operation	1 - 2 months	YES	YES	
UG - DUP	Land Use Permit	Improvement of open, vacant or unimproved land.	Construction	80 days minimum	NOT LIKELY	NOT LIKELY	
UG - DUP	Landfill Siting Approval	60-90 days	Construction	1 - 2 months	NO	NO	
UG - DUP	Noise Limit Approval	Construction and operation of facility.	Construction / Operation	80 days minimum	YES	YES	
UG - DUP	Floodplain Certificate	Construction in floodplains.	Construction	80 days minimum	MAYBE	MAYBE	See also KSDA Floodplain Fill Approval.
UG - DPW	ROW Permit - Driveway Culvert / Driveway	New entrance road, haul road.	Construction	1 - 2 months	MAYBE	MAYBE	*May be required for new access road.*
UG - DPW	ROW Permit - Soil Hauling	Excavation activities.	Construction	1 - 2 months	MAYBE	MAYBE	*May be required for construction activities.*
UG - DPW	ROW Permit - Site Excavation	Excavation activities.	Construction	1 - 2 months	MAYBE	MAYBE	*May be required for construction activities.*
UG - DPW	ROW Permit - Oversize/Overweight Load	Equipment loads, excavation activities.	Construction	1 - 2 months	MAYBE	MAYBE	*May be required for construction activities.*
UG - DPW	ROW Permit - Land Disturbance	Excavation activities.	Construction	1 - 2 months	MAYBE	MAYBE	*May be required for construction activities*
UG - DPW	Traffic Control Plan Approval	Construction affecting more than 500 LF of ROW	Construction	1 - 2 months	NOT LIKELY	NOT LIKELY	The construction of the right-of-way requires the submittal of a traffic control plan and erosion control plan.
UG - DPW	Erosion Control Plan approval	Control of pollutants in storm water runoff.	Construction	1 - 2 months	YES	YES	See also KDHE Construction Storm Water Pollution Prevention Plan (SWPPP)

Agency	Permit/ Approval	Regulated Activity	Required Project Phase	Expected / Typical Review Time	Required for SCCT	Required for CCCT	Comments/Issues
UG - DPW	Fence Permit	The construction of any fence within the city.	Construction / Operation	1 - 2 months	NOT LIKELY	NOT LIKELY	It is unlawful for any person to construct or substantially replace any fence within the city unless a permit to do so is first obtained from the building official. *BPU Nearman Creek is currently surrounded by a security fence.*
UG-HD	Permit and License to Operate Landfill		Operation	1 - 2 months	NO	NO	
UG - FD	Chemical Storage and Fire Inspection	Installation of fire protection system.	Construction	1 - 2 months	YES	YES	
UP	Pipeline and ROW Approval	Activities within the established right-of-way of a railroad track.	Construction	2 - 3 months	MAYBE	MAYBE	*Recommend consultation with UP to determine exact requirements.*
Southern Star Central Gas Pipeline, Inc.	Natural Gas Line Connection Approval	Connection to gas supplier.	Construction	2 - 3 months	YES	YES	*Also consider construction activities affecting existing gas lines.*
BPU Water Division	Water Line Connection	Connection to water supply	Construction	2 - 3 months	YES	YES	

ABBREVIATIONS:
AST - Aboveground Storage Tank
CAIR - Clean Air Interstate Rule
CAM - Compliance Assurance Monitoring
CAMR - Clean Air Mercury Rule
CEMs - Continuous Emissions Monitoring
CERCLA - Comprehensive Environmental Response, Compensation, and Liability Act of 1980
COE - US Army Corps of Engineers
CWA - Clean Water Act
DAQ - UG Department of Air Quality
DPW - UG Department of Public Works
DUP - UG Department of Urban Planning and Land Use
EPA - Environmental Protection Agency
FAA - Federal Aviation Administration
FD - UG Department of Fire
HD - UG Department of Health
KDHE - Kansas Department of Health and Environment
KDWP - Kansas Department of Wildlife and Parks
KSDA - Kansas State Department of Agriculture
KSFM - Kansas State Fire Marshal
LEPC - Local Emergency Planning Committee
NOI - Notice of Intent
NPDES - National Pollutant Discharge Elimination System
PSD - Prevention of Significant Deterioration
ROW - Right of Way
RMP - Risk Management Plan
SARA - Superfund Amendments and Reauthorization Act
SHPO - State Historic Preservation Officer
SPCC -Spill Prevention Control and Countermeasures Plan
SUP - Special Use Permit
SWPPP - Storm Water Pollution Prevention Plan
UP - Union Pacific
UG - Unified Government of Wyandotte County / Kansas City, Kansas
USFWS - United States Fish and Wildlife Service

Appendix G
Combustion Turbine Engineering and Construction Schedule


2008
2009
2010
2011
ENGINEERING
CONSTRUCTION
COMBUSTION TURBINE (LM6000 or 7EA, SCR, Stack, 480V MCC for CT Auxiliaries)
GAS COMPRESSOR
TRANSFORMER
CHILLER
WATER TREATMENT
FIELD ERECTED TANKS (Oil & Water)
Black & Veatch Corporation
Engineer
Drawn
Checked
Date
CT5 SIMPLE CYCLE
Kansas City Board of Public Utilities
No.
Date