Executive Summary

Overview of KEPCo

Pursuant to complying with Western Area Power Administration's (WAPA) Planning and Management Program, Kansas Electric Power Cooperative, Inc. (KEPCo) respectfully submits the following Integrated Resource Plan (IRP) for KEPCo and the City of Seneca, KS, covering the years 2007 thru 2011. The City of Seneca is a wholesale customer of Brown-Atchison Electric Cooperative Association, Inc, one of KEPCo's Member Cooperatives, and has a contractual agreement with KEPCo for KEPCo to satisfy their WAPA IRP reporting requirements.

KEPCo is a not-for-profit generation and transmission cooperative (G&T), headquartered in Topeka, Kansas. KEPCo was incorporated in 1975 to provide its nineteen member distribution cooperatives with a reliable power supply at a reasonable cost.

KEPCo provides the total power requirements for seventeen Member Cooperatives and total power requirements for specific delivery points for two Member Cooperatives. These two cooperatives are also members of Sunflower Electric Power Corporation, a G&T in western Kansas. KEPCo Member Cooperatives provide service to approximately 115,000 member meters and maintain nearly 46,000 miles of electric distribution line.

The combined service territory of the KEPCo Member Cooperatives covers most of the rural area in the eastern two-thirds of Kansas, stretching 350 miles from east to west and 200 miles from north to south, and covering a wide range of physiographic regions.

KEPCo's power supply resources include a six percent ownership in the Wolf Creek Generating Station. Wolf Creek is a reliable nuclear power plant that has provided dependable base load power since it began commercial operation in 1985. The unit has a total rated reliable capacity of 1170 megawatts (MW). KEPCo's share of power to the grid is 70 MW. The plant has a lifetime capacity factor of 85% and furnishes 30% of KEPCo's energy requirements. KEPCo solely owns the Sharpe Generating Station, a peaking facility that is comprised of 10, 2 MW Caterpillar diesel generators that can be remotely operated from KEPCo headquarters. In 2006, KEPCo executed documents to acquire a 3.5% ownership interest (30 MW) of Iatan 2, an 850 MW coal-fired generating facility located in Weston, MO. Iatan 2 is expected to be commercially viable in 2010. KEPCo has hydropower purchases equivalent to 100 MW from the Southwestern Power Administration, and 14 MW from the Western Area Power Administration; plus partial requirement power purchases from regional utilities. KEPCo uses the transmission system of the Southwest Power Pool (SPP) to deliver the power. KEPCo is a member of the SPP and participates in the planning and expansion of the system within Kansas.

The economy of the service territory is primarily agricultural, with the wide variety in the physical landscape of the service territory resulting in a considerable diversity in the type of agriculture and commercial load that each Member Cooperative serves. Much of the new growth within the service area is tied to the oil and natural gas industry, which has a significant effect on the commercial load of a number of Member Cooperatives. The result is large increases in load when energy prices are high, or in significant loss of load when oil and gas prices are low. The rural nature of oil wells and pipeline pumping stations is of direct benefit to these companies in mainly rural areas where other economic opportunities are modest by comparison.

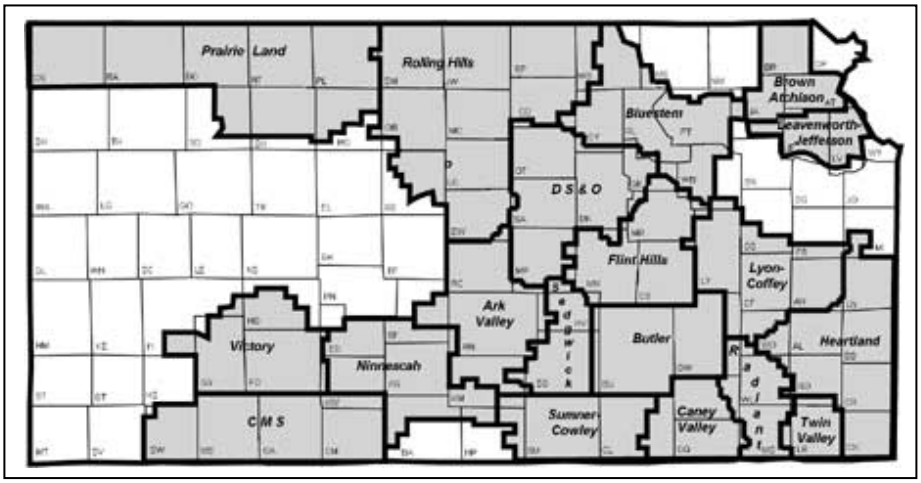
Recently, increases in the price of oil and gas have made production of alternative fuels, such as ethanol and biodiesel, economically attractive. The agricultural nature of the state and close proximity of feed lots has contributed to bringing the possibility of ethanol and biodiesel production to the KEPCo service area. There are two main co-products created in the production of ethanol that may provide additional new load if developed: carbon dioxide and distillers grain.

The geography of southeastern Kansas has led to the development of coal bed methane extraction, a form of natural gas, in that region. This may potentially benefit those Member Cooperatives in areas where pipelines and compressor stations must be located.

Other developments that will influence new load growth in the service area include the expansion and/or construction of several gaming casinos and the expansion of the Ft. Riley military base in Junction City. The Ft. Riley housing expansion is already affecting the growth of three Member Cooperatives with service areas adjacent to the military base.

KEPCo Board of Trustees
KEPCo is governed by a Board of Trustees representing each of its nineteen members The KEPCo Board of Trustees meets regularly to establish policies and act on issues that often include recommendations from working committees of the Board and KEPCo staff. The Board also elects a seven-person Executive Committee which includes the President, Vice President, Secretary, Treasurer, and three additional Executive Committee members.

KEPCo Member Distribution Cooperatives
The following are the nineteen Member Cooperatives that receive service from KEPCo and a map illustrating each of the nineteen Members service territories.



Ark Valley Electric Cooperative Association, Inc.
10 E. 10th Street
South Hutchinson, KS 67505
Miles of Line: 2,096

Bluestem Electric Cooperative, Inc.
614 E. U.S. Highway 24
Wamego, KS 66547
Miles of Line: 2,803

Brown-Atchison Electric Cooperative Association, Inc.
1712 Central
Horton, KS 66439
Miles of Line: 1,124

Butler Rural Electric Cooperative Association, Inc.
216 S. Vine Street
El Dorado, KS 67042
Miles of Line: 1,704

Caney Valley Electric Cooperative Association, Inc.
401 Lawrence
Cedar Vale, KS 67024
Miles of Line: 1,733

CMS Electric Cooperative, Inc.
509 East Carthage
Meade, KS 67864
Miles of Line: 2,529

DS&O Rural Electric Cooperative Association, Inc.
129 W. Main Street
Solomon, KS 67480
Miles of Line: 2,417

Flint Hills Rural Electric Cooperative Association, Inc.
1564 S. 1000 Road
Council Grove, KS 66846
Miles of Line: 2,506

Heartland Rural Electric Cooperative, Inc.
110 N. Enterprise Drive
Girard, KS 66743
Miles of Line: 3,705

Leavenworth-Jefferson Electric Cooperative, Inc.
507 N. Union
McLouth, KS 66054
Miles of Line: 1,536

Lyon-Coffey Electric Cooperative, Inc.
1013 N. 4th Street
Burlington, KS 66839
Miles of Line: 2,460

Ninnescah Electric Cooperative Association, Inc.
20112 W. U.S. 54
Pratt, KS 67124
Miles of Line: 2,132

Prairie Land Electric Cooperative, Inc.
1101 West Hwy. 36
Norton, KS 67654
Miles of Line: 5,379

Radiant Electric Cooperative, Inc.
100 N. 15th
Fredonia, KS 66736
Miles of Line: 1,370

Rolling Hills Electric Cooperative, Inc.
122 W. Main
Mankato, KS 66956
Miles of Line: 6,317

Sedgwick County Electric Cooperative Association, Inc.
1355 S. 383rd Street West
Cheney, KS 67025
Miles of Line: 1,091

Sumner-Cowley Electric Cooperative, Inc.
2223 North A Street
Wellington, KS 67152
Miles of Line: 2,000

Twin Valley Electric Cooperative, Inc.
501 Huston
Altamont, KS 67330
Miles of Line: 948

Victory Electric Cooperative Association, Inc.
3230 N. 14th
Dodge City, KS 67801
Miles of Line: 1,999

Wholesale Rate Competitiveness
KEPCo's wholesale rate, per the 2007 G&T Accounting & Finance Association annual directory (2006 data), was 61.72 mills.. Sunflower Electric Power Corporation, a G&T headquartered in Hays, KS. had an average rate of 50.63 mills. Western Farmers, a G&T headquartered in Anadarko, OK. had an average rate of 57.75 mills. Central Electric Power, a G&T headquartered in Jefferson City, MO. had an average rate of 35.42 mills.

The following are KEPCo's wholesale rates for the years 2002 thru 2006.
2002 – 52.7 mills
2003 – 54.8 mills
2004 – 55 mills
2005 – 59.19 mills
2006 – 61.72 mills

Load Growth
KEPCo energy sales are projected to increase at an average rate of 1.5% per year over the next ten years, based on normal weather conditions. This growth rate is slightly higher than 2004 growth rate of 1.2% due to the planned addition of several large customers. Coincident Peak (CP) demand is expected to increase 2.1% over the forecast period.

KEPCo realized 1.8 million MWh of energy sales in 2006 with a peak demand of 423.1 MW. Approximately 58.5% of KEPCo Member Cooperative 2006 energy sales were in the Residential customer class. This class is expected to increase 1.6% annually.

The Small Commercial class accounted for approximately 24.7% of Member Cooperative energy sales in 2006. Small Commercial energy sales are expected to increase at an average rate of 0.3% annually.

Large Commercial sales accounted for 9.7% of 2006 energy sales.

Sales in the Irrigation, Street Lighting and Public Authority customer classes accounted for approximately 7% of total sales in 2006.

Load Forecast
A load forecast was performed in 2006 using an Econometric Method. The load forecast data will be made available to WAPA upon request.

Peak Reduction Programs
KEPCo operates a Load Management program designed to reduce peak load. In 1990, KEPCo adopted rates to encourage peak demand reduction and also began a Load Management program that involves issuing peak alerts to Member Cooperatives, who in turn provide incentives to large and small commercial customers to reduce usage during peak periods.

In some cases member Cooperatives use radio control to cycle irrigation pumps, oil well pumping, water heaters and central air-conditioners to reduce peak demand. In 2001, KEPCo implemented a state-of-the-art Energy Management and Supervisory Control and Data Acquisition (EMS/SCADA) System which has enabled KEPCo to provide real time monitoring of load data to its Member Cooperatives. KEPCo's current rate design defines CP as a week-day peak. Depending on weather patterns, load management efforts can reduce week-day demand by as much as 20 to 30 MW.

Demand-Side Management
KEPCo continues to employ its Demand-Side Management Program for peak MW reduction. The following are the MW saved, savings in purchase power costs (PPC), and expenditures to achieve those savings, for 2002 thru 2006.

	2002	2003	2004	2005	2006
MW Saved	35	35	30	30	35
PPC Saved	$1,480,000	$1,380,000	$1,800,000	$480,000	$2,100,000
Cost of Savings	$10,500	$11,500	$12,000	$13,000	$14,500

It is important to note that approximately 50% of KEPCo's energy resource mix does not produce any greenhouse gas emissions (nuclear and hydroelectric). However, KEPCo recognizes the heightened political pressure and environmental concerns to reduce greenhouse gas emissions. One of the simplest and most cost effective ways to reduce emissions, for a utility, is to reduce energy consumption. In 2006, KEPCo revamped its rebate program into a program that rewards choosing the most energy efficient, electric heating and cooling systems available. KEPCo, on average, provides rebates for 687 water heaters and 289 heat pumps (air source and ground source combined) annually. To date, KEPCo has provided rebates for over 4,600 heat pumps and over 13,000 water heaters.

Renewable Energy Considerations
Kansas has been identified as one of the windiest areas in the United States and thus has a potential for substantial wind energy development. The utilities in the state of Kansas in meetings with the state government have agreed voluntarily to develop wind resources totaling 10% nameplate capacity of the state's peak load by 2010 and 20% nameplate capacity of the state's peak load in wind resources by 2020. This is equivalent to approximately 1,000 MW of wind by 2010 and 2,000 MW of wind by 2020.

Because KEPCo is a relatively small power supplier without a 24 hour dispatch desk and real-time scheduling capability, KEPCo buys scheduling and balancing service through its power purchase agreements. Since wind is an intermittent resource, the most economical and reliable method for KEPCo to participate in developing wind resources is through the integrated mix of wind energy in the purchase power agreements. KEPCo, in its most recent power purchase agreement with Westar and Sunflower, included the ability to receive energy generated from wind resources as a part of the power supply mix. This partnering ensures that KEPCo is able to help contribute to the development of wind resources in the state in an economical and responsible fashion.

Regulatory Oversight
Pursuant to K.S.A 66-101 *et seq*, KEPCo is under regulatory jurisdiction of the Kansas Corporation Commission and was granted a limited certificate of authority in 1980 to act as a Generation & Transmission public utility.

KEPCo is also under jurisdiction of the Rural Utilities Service (RUS), a department of the United States Department of Agriculture. RUS is KEPCo's primary lender and mortgage holder and as such, approves changes in rates, contracts, generation projects, loans, among others. KEPCo must also meet financial matrix thresholds to remain in compliance with RUS' mortgage requirements.

Plan Components

In September of 2005, Burns & McDonnell completed KEPCo's Long Range Resource Plan and Generation Construction Work Plan. These two plans contain evaluations of KEPCo's future power supply requirements and satisfy the majority of requirements set forth in the regulations regarding information to be included in the IRP. The plans are included in their entirety under Tab 1.

Environmental Impact of Iatan 2

As previously stated, the Iatan 2 project is fully subscribed, all permits have been secured and construction is well underway.

Iatan Unit 2 will be a high-efficiency, coal-fired power plant featuring state-of-the-art emission control equipment designed to exceed current and future clean air requirements.

Earlier this year, KCPL, the Sierra Club, and all other interveners that were protesting the issuance of environmental permits, have agreed to a settlement and all actions have been dismissed.

The most significant element of the agreement is the unprecedented commitment by KCPL to pursue the offset of carbon emissions from its Iatan 2 generating station. The carbon dioxide emissions are targeted to be offset by adding 400 megawatts (MW) of wind power; 300 MW of energy efficiency; and a yet to be determined combination of wind, efficiency, or the closing, altering, re-powering or efficiency improvements at any of its generating units. These proposed offsets will be partially implemented by 2010 and fully implemented by 2012. The parties have also agreed to work together on a series of regulatory and legislative initiatives to achieve an overall reduction in KCPL's carbon dioxide emissions of 20 percent by 2020.

Another part of the agreement is to decrease emissions of nitrogen oxide and sulfur dioxide, and other pollutants at Iatan 1 and 2 and at two units at KCPL's La Cygne, Kan. plant. The new levels of emissions will be among the lowest in the country, according to a statement by the utility and environmental groups.

The following are the Iatan 2 permit emission limits:

SO2 = 0.09 Lbs/mmbtu
NOx = 0.08 Lbs/mmbtu
Hg = 1.705 Lbs/Tbtu (Lesser of 39 x 10 E-6 Lbs/mmbtu or "Site" total of 210 Lbs/year, which equates to the listed emission rate)
PM10 = 0.0236 Lbs/mmbtu (30-day rolling avg.)
Filterable PM 10 = 0.014 Lbs/mmbtu (3-hr rolling avg.)
Filterable PM = 0.015 Lbs/mmbtu (3-hr rolling avg.)
Opacity = 20%
CO = 0.14 Lbs/mmbtu (30-day rolling avg.)
VOC = 0.0036 Lbs/mmbtu (based on 3 test runs)
H2SO4 = 7.16 x 10 E-3 Lbs/mmbtu
Lead = 5.93 x 10 E-6 lbs/mmbtu
HF = 34.43 Lbs/hr.

Heat Rate = 9,000 btu/kWh

Controls: Wet Scrubber, Baghouse, SCR. Mercury sorbents or other means of Hg capture, if required to meet permitted rates.

Public Participation

KEPCo solicited public involvement in the IRP by placing an ad in the Kansas Country Living magazine and 31 newspapers within and surrounding KEPCo's service territory. The Kansas Country Living magazine is distributed to all KEPCo Member Cooperatives except Heartland Rural Electric. Heartland Rural Electric publishes a quarterly newsletter and the ad was placed in the June issue. Please see Tab 2 for a copy of the ad and a list of the selected newspapers.

KEPCo received two comments to the Public Notice. The comment dated July 8 asks for the state of Kansas to develop incentives for the development of renewable energy. The Kansas legislature has established numerous incentives for the development of wind energy and several other incentives were passed in the 2007 legislative session for other types of renewable energy as well. The commenter also asks for informational materials to be developed concerning parallel generation connectivity to the grid. KEPCo is developing procedures that adopt the Small Generator Interconnection Agreements and Procedures contained in Order No. 2006 – Docket No. RM02-12-000-United States of America Federal Energy Regulatory Commission. The commenter also asks for KEPCo and the rural electric cooperatives to construct and own wind generation. Midwest Energy, a cooperative in Hays and Sunflower Electric Power Corporation, a G&T in Hays, both announced in 2007 plans to purchase energy from a proposed wind farm in Ellsworth county. KEPCo's involvement in wind generation is detailed on page 6 of this IRP. Using additional wind generation as a resource was the single concern from the second commenter, dated July 13. Lastly, the commenter asked for KEPCo to provide incentives for members to convert to higher efficiency HVAC systems and water heaters. KEPCo established a rebate program in the 1980's for the purchase and installation of heat pumps and electric water heaters. Each of KEPCo's Member Cooperatives is involved in the program.

Please see Tab 3 for the comments received.

On August 16, 2007, the KEPCo Board of Trustees approved the WAPA IRP. See Tab 4 for the Board Resolution approving the IRP.

Goals and Implementation

Consistent with KEPCo's mission statement is the goal for KEPCo to continue to provide the most economical and reliable power supply possible. To this extent, after enduring the past few years, KEPCo realized that the practice of using short-term purchase power agreements, relying on increasing amounts of natural-gas fired generation, and purchasing power priced by the spot markets are no longer prudent business plans. As such, KEPCo secured a Purchase Power Agreement (PPA) with Sunflower Electric Power Corporation to the year 2018 and secured a PPA with Westar Energy to the year 2045. KEPCo will be able to determine the savings from these two contracts by comparing short-term market prices with the energy prices within the contracts.

As a wholesale provider of electricity, with limited influence or relationship with the end consumer, KEPCo is restricted in the scope of programs that can be offered which would influence energy conservation and energy efficiency. However, KEPCo is exercising the options

it does have and works with its Member Cooperatives on an individual basis on the marketing of programs specific to the Cooperative.

Given the efficiency requirements to qualify for a rebate under the new program have increased, and subsequently KEPCo predicting the amount of rebates will decrease, KEPCo has established a benchmark of 500 water heaters and 175 heat pump rebates annually as its goal.

KEPCo will also continue to be aggressive with its Load Management Program. Over the past five years, KEPCo has been able to shave an average of 33 MW each year and KEPCo will use this figure as its benchmark for subsequent years.

KEPCo will continue to evaluate the blending of renewable energy into its energy portfolio on an economic and reliability basis.

KEPCo will continue to evaluate the feasibility of acquiring of additional generation resources as opportunities are presented.

KEPCo will continue to support initiatives introduced by the Kansas Legislature that promote energy efficiency, as long as the initiatives do not adversely affect in a disproportionate amount, the consumers in the rural areas of Kansas.

Long Range Resource Plan

and

Generation Construction Work Plan

Prepared for

Kansas Electric Power Cooperative
Topeka, Kansas
Kansas 54

September 2005

Project 36913

Burns & McDonnell
SINCE 1898

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Introduction

In anticipation of its future energy and capacity requirements and in recognition of the dynamic nature of the electric power market in Kansas and the surrounding region, the Kansas Electric Power Cooperative (KEPCo) commissioned Burns & McDonnell to perform this Long Range Resource and Generation Construction Work Plan Study (Study). This Study was designed to address a range of KEPCo resource options, including:

- Participation in new generation to be constructed in the region,
- Peaking units constructed by KEPCo, and
- Power supply from purchased power contracts

Key criteria used for evaluating alternative power supply options included:

- Reliability of power supply
- Adequacy of power supply, demand and energy
- Absolute and relative costs of viable resource plan options
- Physical and economic risks and benefits of each viable resource plan

In order to meet the Study objectives a two-phased approach was pursued by Burns & McDonnell. The two phases of the process for preparing the Study were identified as:

- Phase I – Long Range Power Supply Plan
- Phase II – Generation Construction Work Plan

The objective of Phase I was to provide to KEPCo and its Board, a report that would:

- Identify power supply options that had operational and economic potential and that merited more detailed study

- Provide to KEPCo and its Board a report that contained sufficient qualitative and quantitative information for executive decision-making purposes, as those decisions would apply to:

    - Extension of KEPCo membership contracts
    - Selection of a specific resource plan or plans for further study

Phase II was performed subsequent to Phase I and was contingent upon KEPCo's decision to proceed with further analysis of specific resource options. The objective of Phase II was to develop a detailed Generation Construction Work Plan that met KEPCo financing needs as specified by the Rural Utilities Service (RUS) for any recommended projects. Phase II would

build and expand upon the results of Phase I by identifying the specific actions to be taken by KEPCo in meeting its power supply needs for the near term.

This report describes the results of Burns & McDonnell's analysis.

Review of Existing System

A review of the existing KEPCo loads and resource issues was performed to provide a benchmark from which to identify alternative future power supply options. KEPCo has several challenges associated with its operations. These include:

- Member load being served in multiple control areas.
- Dependency on other utilities for transmission delivery and ancillary services, including scheduling,
- Transitioning of the Southwest Power Pool to a Regional Transmission Organization (RTO) and progression towards market operations,
- Lack of a robust wholesale market from which to acquire spot, short term and long term purchases.

KEPCo Peak Demand and Energy Requirements

The most recently approved load forecast was provided by KEPCo for use in this analysis. The forecast projects that the total KEPCo system will continue to see steady though modest growth throughout the planning period.

- Between 2004 and 2040, KEPCo's total system peak load is expected to grow at an annual rate of approximately 1.42 percent, resulting in a system peak load of 669 MW by 2040.

- Between 2004 and 2040, KEPCo's total system energy requirements are expected to grow at an annual rate of 1.28 percent, resulting in an increase of 967,000 MWh of energy requirements.

Table ES-1 presents the KEPCo system peak demand and energy forecast for selected years through 2040.

Table ES-1

Kansas Electric Power Cooperative
Long Range Resource Plan
KEPCo Peak Demand and Energy Requirements

Year	Maximum Peak at KEPCo D.P. Including Weekends MW	Total KEPCo Energy Sales MWh	Annual Load Factor %
1995	308.6	1,343,965	49.7%
2000	371.8	1,547,348	47.5%
2003	392.0	1,633,126	47.6%
2004	405.7	1,674,939	47.1%
2005	411.1	1,693,039	47.0%
2010	439.0	1,787,016	46.5%
2015	469.5	1,889,392	45.9%
2020	502.6	2,000,939	45.4%
2025	538.8	2,122,626	45.0%
2030	579.2	2,280,695	45.0%
2035	622.4	2,450,542	44.9%
2040	668.9	2,633,046	44.9%
Growth Rate %			
1995-2003	2.42%	2.47%	
2004-2025	1.39%	1.16%	
2025-2040	1.45%	1.45%	
2004-2040	1.42%	1.28%	
"Delta" MW, MWh			
1995-2003	83.4	289,161	
2004-2025	135.6	456,134	
2025-2040	130.1	510,420	
2004-2040	265.7	966,554	

Note: **Reference revised KEPCo forecast, dated March 3, 2004**

Forecast of Load and Energy Requirements by Control Area

For purposes of this Study three control areas were assumed to exist during the future planning period. These areas were: (1) Westar, (2) KCPL, and (3) Sunflower. Regarding load growth in each control area, the Phase I Study concluded:

- Between 2004 and 2040, it is estimated that the Westar control area will experience approximately 233 MW of load growth, resulting in a control area peak load of 585 MW by 2040.

- Between 2004 and 2040, it is estimated that the KCPL control area will experience approximately 9 MW of load growth, resulting in a peak load of 24 MW by 2040.

- Between 2004 and 2040, it is estimated that the Sunflower control area will experience approximately 23 MW of load growth, resulting in a peak load of 60 MW by 2040.

Details of the projections can be found in Part II.

KEPCo Capacity Balance

KEPCo meets its power supply requirements through a variety of resources. These include:

Generating Resources

- Wolf Creek Generating Station – KEPCo owns 70MW of Wolf Creek, a nuclear power plant located near Burlington, KS. The unit was brought on line in 1985. An upgrade is planned which would provide KEPCo with an approximate increment of 4 MW of capacity. This upgrade is anticipated to be completed by 2009.
- Sharpe Engines – KEPCo installed 20MW of engine generator sets adjacent to the Sharpe Substation in 2002. The units are 2MW each and are used as peaking and reserve units in the Westar control area.

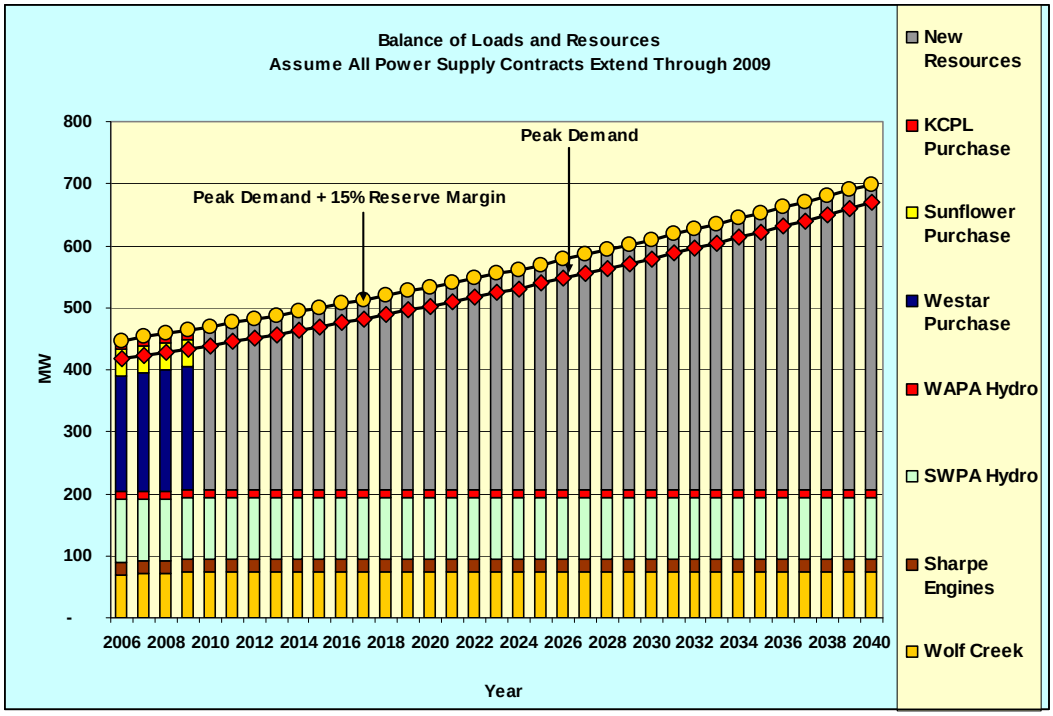
Contracts

- Western Area Power Administration (WAPA) – KEPCo has a contract with WAPA for 13.4MW of capacity and associated peaking energy. The contract has limitations on the amount of energy that can be taken under the contract. It is anticipated that the amount of capacity available will decline slightly over the next several years. The contract has a termination date of 2024; however, the contract can be extended on the mutual consent of both parties. It is assumed to extend through the study period. This energy is scheduled into the Westar and Sunflower control areas.
- Southwestern Power Administration (SWPA) – The contract with SWPA is similar to the WAPA contract in that it has limitations on the amount of energy that can be taken under the contract on a firm basis. The contract provides KEPCo with 100MW of peaking capacity and energy. In addition to this firm capacity and energy, the contract provides KEPCo with supplemental energy on an as available basis. This contract terminates in 2008; however, it will be extended through mutual agreement of the parties. It is assumed to be in affect through the study period.

- Westar – KEPCo has a contract with Westar to provide firm partial requirements capacity and energy above its needs provided by its resources in the Westar control area and by the WAPA and SWPA contracts. This contract also provides for all of the control area and scheduling services needed to manage the day to day activities of scheduling load. This contract also provides for reserve capacity and energy for outages of the Wolf Creek resource. This contract is set to expire in 2008, but is extended until such time as one party gives notice to terminate. The parties are currently in negotiations on new contract terms.
- Sunflower G&T – KEPCo has a firm partial requirements contract with Sunflower which provides firm capacity and energy beyond that provided by the energy from the WAPA contract for KEPCo's load located in the Sunflower control area. The contract provides for all of the ancillary services necessary to manage the load on a day to day basis. This contract is extended by mutual agreement of the parties.
- KCPL – KEPCo has a firm all requirements contract with KCPL for the load served in the KCPL control area. This contract is extended by mutual agreement of the parties.

Figure ES-1 presents the KEPCo system balance of loads and resources through 2040. This depiction assumes that the existing contracts extend throughout the period and increase in capacity to meet the respective load area requirements.

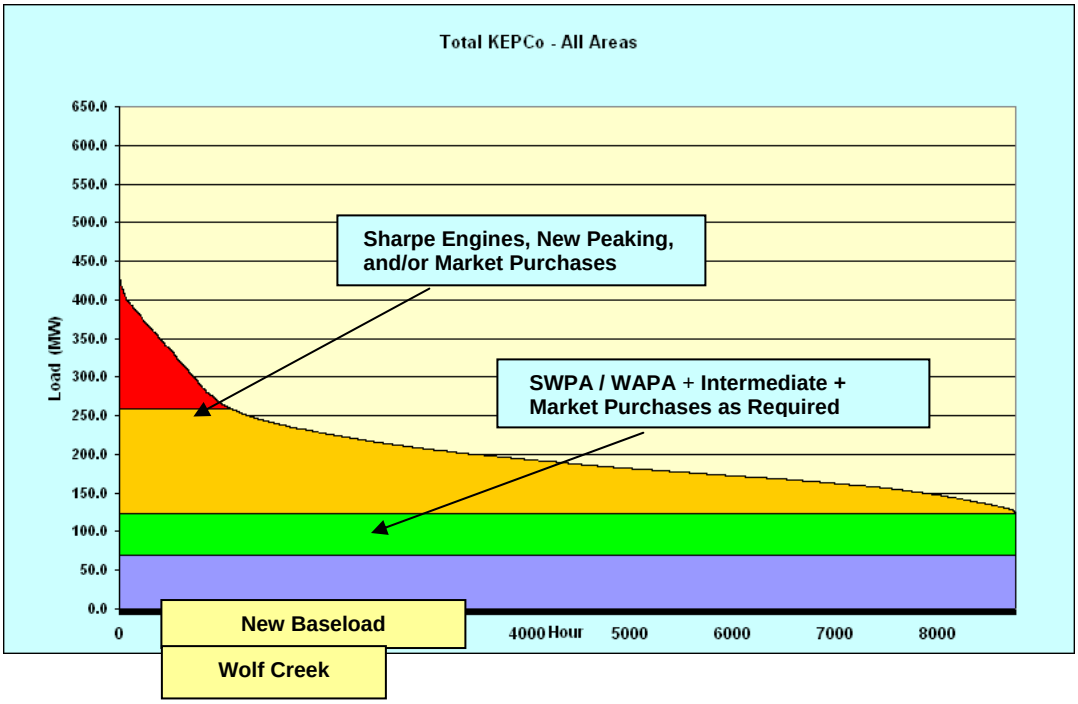
Figure ES-1
Balance of Loads & Resources



Load Duration Curve and Resource Energy Mix

In addition to meeting the capacity needs of the load projections, the increasing energy needs will have to be considered also. The system energy requirements will include a mix of low cost capacity and energy resources. Figures ES-2 and ES-3 provide load duration curves for 2010 and 2030 and show the increasing energy needs. Also shown is the energy available from the Wolf Creek resource. Without additional resources, all of the incremental energy will be supplied under purchase power contracts.

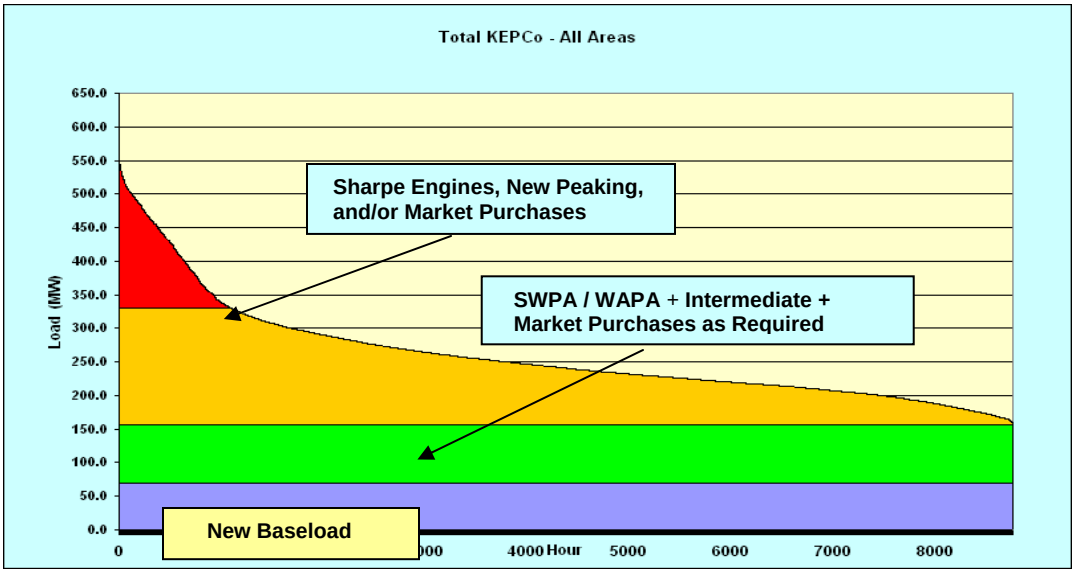
Figure ES-2
Annual Load Duration Curve & Resource Energy Mix - 2010



2010	MW	Act. MWh	Max MWh	CF %
Base	122.8	1,075,376	1,743,240	61.7%
Intermediate	136.0	634,663	1,339,161	47.4%
Peaking	180.2	76,976	1,605,215	4.8%
Total	439.0	1,787,016	4,687,616	38.1%

2010	MW	Act. MWh	Max MWh	CF %
New Base	52.5	459,548	1,095,000	42.0%
New Intermediate	40.4	66,002	353,613	18.7%
New Peaking	163.2	60,198	1,430,015	4.2%
Total New	256.1	585,748	2,878,628	20.3%

Figure ES-3
Annual Load Duration Curve & Resource Energy Mix – 2030



2030	MW	Act. MWh	Max MWh	CF %
Base	156.7	1,372,447	1,743,240	78.7%
Intermediate	173.6	809,988	1,668,263	48.6%
Peaking	249.0	98,260	2,207,194	4.5%
Total	579.2	2,280,695	5,618,697	40.6%

2030	MW	Act. MWh	Max MWh	CF %
New Base	86.4	756,619	1,095,000	69.1%
New Intermediate	77.9	162,758	682,715	23.8%
New Peaking	232.0	81,179	2,031,994	4.0%
Total New	396.3	1,000,556	3,809,709	26.3%

Resource Planning Scenarios

As identified in this Study a number of possible resource planning scenarios were developed for consideration. In total eleven scenarios were modeled and evaluated. These eleven scenarios fell into the following three broad categories:

- Contract Extension Scenarios
  – No new generating resources acquired by KEPCo

- Partner / Own Scenarios
  – Contracts not extended, KEPCo acquires new resources

- Partner / Own and Contract Extension Scenarios
  – Contracts extended or renegotiated to partial requirements and KEPCo acquires new resources

The cases where KEPCo acquired additional resources assume that the partial requirements contracts would reflect current wholesale market conditions, which generally reflect low capacity costs with associated energy costs based on gas-fired resources.

Table ES-2 presents the definition of the resource planning scenarios studied in Phase I.

Table ES-2
Definition of Resource Scenarios

Contract Extension Scenarios		
X1	**Extend Contracts @ Historical Escalation Without WC Uprate**	
X2A	**Extend Contracts @ Historical Escalation**	
X2D	**Extend Contracts @ 6.5% Max Escalation**	
Partner / Own Scenarios		
A	**All New CTs (15 x 40 MW @ 2040)**	
B	**Combined-Cycle (100 MW)**	**CTs (12 x 40 MW @ 2040)**
C	**High Efficiency CT (100 MW)**	**CTs (12 x 40 @ 2040)**
D	**Partner Coal (100 MW)**	**CTs (12 x 40 MW @ 2040)**
E	**Partner Coal (100 MW)**	**IC Engines (241 x 2 MW @ 2040)**
Partner / Own & Contract Scenarios		
F	**Partner Coal (50 MW)**	
	Contracts: KCPL & Sunflower extended	
	Market Purchase to Replace Westar	
G	**Partner Coal (50 MW))**	
	IC Engines (10 x 2 MW @ 2040)	
	Contracts: KCPL & Sunflower extended	
	Market Purchase to Replace Westar	
H	**Partner Coal (100 MW)**	
	IC Engines (10 x 2 MW @ 2040)	
	Contracts: KCPL & Sunflower extended	
	Market Purchase to Replace Westar	
I	**Partner Coal (100 MW)**	
	IC Engines (21 x 2 MW @ 2040)	
	Contracts: KCPL & Westar extended	
	Contracts: Sunflower supplied by new units	

Note: **All scenarios (except X1) include Wolf Creek uprate An initial analysis of the costs and benefits of the Wolf Creek uprate indicated that it was economical to participate in the uprate program.**

Resource Plan Evaluation

The scenarios were analyzed using a custom spreadsheet production costing model developed by Burns & McDonnell to evaluate the relative differences between them. The model replicated the various contracts used by KEPCo. The analysis was performed on an incremental cost basis, which means that the common KEPCo costs between the cases, such as KEPCo administrative and general costs, were not included. Therefore, the economic analysis quantifies only the incremental costs necessary to evaluate the relative ranking and should not be compared to the total KEPCo operating costs for any year.

Table ES-3 presents a summary of estimated costs by resource planning scenario.
In addition to the base case analysis, Burns & McDonnell performed a risk analysis on the scenarios by varying certain input assumptions. Distribution curves were developed for the ranges of values for the following factors:

- Fuel
- Load forecast
- Capital costs
- Interest rates

The resulting distributions of the net present values for the various scenarios are shown in Figure ES-4. In general, the acquisition of coal energy and using a blend of owner built peaking capacity and purchase contracts was attractive as compared to lessening amounts of coal energy and contract purchases.

Based on the detailed economic and risk analyses performed in Phase I, the following conclusions were drawn pertaining to the relative economic and risk merits of each resource plan considered.

1. A comparison of resource plans that did or did not include a Wolf Creek uprate indicated that it would be economically advantageous to uprate Wolf Creek to 74 MW. Total NPV costs without a Wolf Creek uprate were estimated to be approximately 1 percent greater than total NPV costs with a Wolf Creek uprate.

2. All scenarios that included partnering in a new baseload coal unit and using market based peaking contracts (Scenarios D, E, F, G, H, I) proved to be less costly then those scenarios (Scenarios X2D, A, B, C) that used gas based resources or maintained existing contracts.

3. As measured by the NPV of total scenario cost, Scenario H was determined to be the least costly resource option for meeting KEPCo's future load and energy requirements. Scenario H included partnering in a 100 MW baseload coal unit, building ten 2 MW IC engines, extending the KCPL contract, and acquiring market based partial contracts.

4. The probabilistic risk assessment resulted in the same relative cost ranking of the resource scenarios studied as was produced by the deterministic approach. Those scenarios that

include partnering in a coal project had lower "most likely" NPV costs than those scenarios that did not include such a baseload partnering strategy.

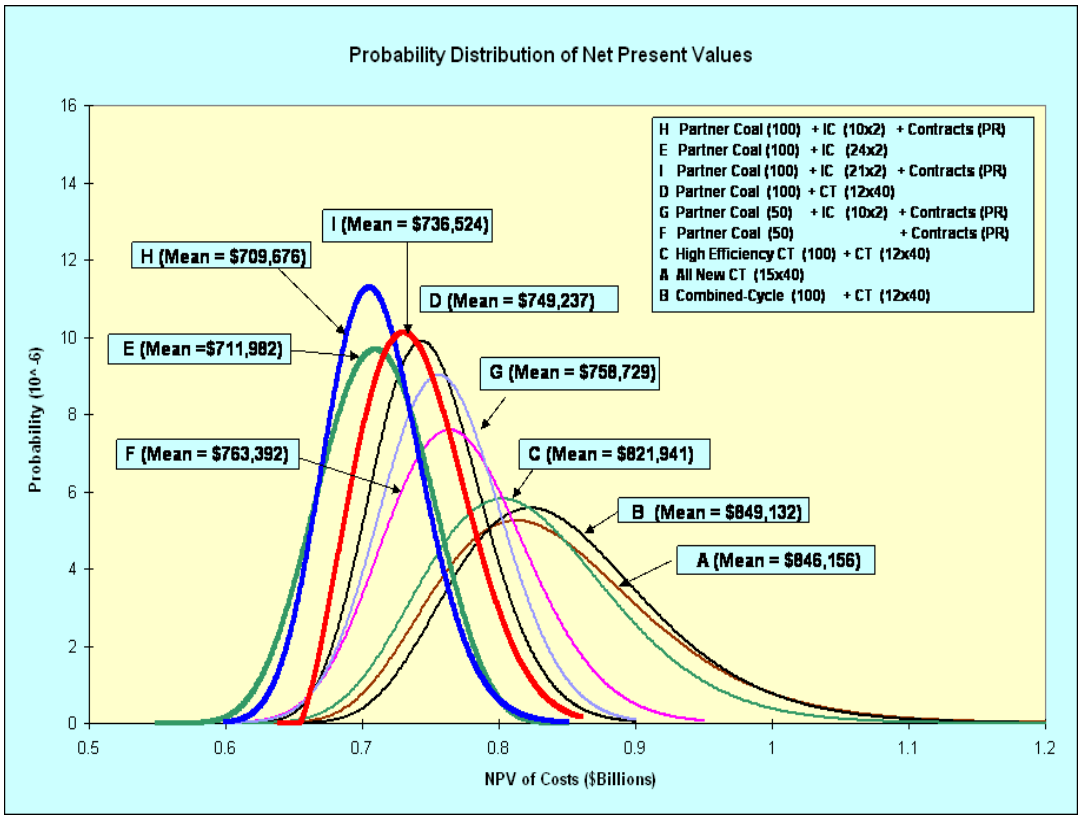
5. As measured by the "cost spread" of the NPV probability distributions, those scenarios that included partnering in a baseload coal resource represented strategies that had lower "downside" cost risk than those strategies that did not include partnering in a coal unit.

Table ES-3
Summary of Costs by Resource Scenario
(Deterministic Cost Results)

Resource Scenario Sorted by Costs		Deterministic Cost Estimates 35-Year NPV 2005 $x1000	Relative Costs Index
H	Partner Coal (100) + IC Engines, Contracts (PR)	$709,676	1.000
E	Partner Coal (100) + IC Engines	$710,726	1.001
I	Partner Coal (100) + IC Engines, Contracts (PR)	$736,524	1.038
D	Partner Coal (100) + CTs	$748,840	1.055
G	Partner Coal (50) + IC Engines, Contracts (PR)	$756,125	1.065
F	Partner Coal (50) + Contracts (PR)	$768,516	1.083
X2D	Extend Contracts @ 6.5% Max Escalation	$813,063	1.146
C	High Efficiency CTs + Peaking CTs (NG)	$816,897	1.151
A	All New CTs (NG)	$831,575	1.172
B	Combined-Cycle + CTs (NG)	$842,977	1.188

Note: All resource plans include the Wolf Creek uprate to 74 MW by 2009

Figure ES-4
Risk Analysis Cost Profiles
(Scenarios A, B, C, D, E, F, G, H, I)



Recommendations for Long Range Resource Plan

Based on the analysis provided herein and the above conclusions, Burns & McDonnell provides the following recommendations for KEPCo's consideration:

1. KEPCo should pursue the Wolf Creek uprate.

2. KEPCo should continue discussions with current suppliers using the Phase I analysis as a guide to terms for extension of the existing contracts.

3. KEPCo should enter into definitive discussions with developers of area coal plants for specific terms, in-service schedules, etc.

4. Based on coal participation options, KEPCo should assess the benefits of smaller, staggered amounts of baseload capacity to be brought into the resource mix.

5. KEPCo should evaluate the benefits of self-build opportunities against the costs of the contract terms as the negotiations with suppliers proceed. Should the benefits of the self-build options appear favorable, KEPCo should pursue the installation of additional peaking capacity at strategic locations.

6. KEPCo should update as needed key Phase I assumptions to reflect latest cost and market conditions.

Generation Construction Work Plan

Area Coal Participation Options

KEPCo solicited information on participation in the following projects:

1. Iatan Unit 2 being developed by KCPL at the existing Iatan power plant site near the Kansas-Missouri border just northwest of Kansas City, MO. The project is an 850MW pulverized coal unit in advanced stages of development. Participation would be through an equity interest. The unit has a scheduled on line date in 2010.

2. Nearman Unit 2 being developed by Board of Municipal Utilities of Kansas City, KS at the site of the existing Nearman power plant, just west of Kansas City, KS. The project is an approximate 250MW pulverized coal unit and is in the early stages of development. Participation would be through an equity interest. No on line date has been determined.

3. Hugo Unit 2 being developed by Western Farmers G&T at the existing Hugo power plant site near Hugo, OK. The project is an approximately 750MW pulverized coal unit in the later stages of development. Participation would be through an equity interest. An on line date of 2011 has been scheduled.

4. Holcomb Unit 2 being developed by Sand Sage LLC (Sunflower Electric G&T) at the existing Holcomb power plant site near Holcomb, KS. The project is a 600MW pulverized

coal unit. Permits have been acquired, but no participants have been attracted to participate. Participation for KEPCo would be through a power purchase agreement. An on line date of 2008 has been proposed, however, this is not likely due to lack of confirmed participation.

In addition to the above options, Westar provided an indicative proposal to sell up to 60MW from the Existing Coal Unit. The offer is structured as a power purchase agreement which could commence in 2008. The proposal allows 20MW to be provided from each of the units at the Existing Coal Unit. Discussions are currently ongoing over the terms of this proposal.

Of the five options, two of the options (Nearman and Holcomb) do not have the necessary participation to move the projects forward in any reliable schedule. The uncertainty associated with the projects when compared to other resource options removed them from immediate consideration.

The Hugo 2 project was not considered due to the transmission problems between the area where the plant is located and the KEPCo load areas. Although discussions within the SPP are ongoing to improve transmission transfer capability, it is not certain when these improvements would actually occur in order to take advantage of the project.

The Iatan 2 project and the Existing Coal Unit proposal both provided pricing, terms and schedules that could be evaluated against the resource options analysis considered in Phase I. A bus bar analysis of the two options is included in Table ES-4.

Table ES-4
Bus Bar Comparison of Iatan 2 and Existing Coal Unit Options
Economic Parameters for the Base Load Options (First yr of operation)

	Iatan 2	Jeffrey
Financed cost ($/kW)	Confidential	Confidential
Annual Cost ($/kW-yr)	Confidential	Confidential
Fixed O&M ($/kW-yr)	Confidential	Confidential
Variable O&M ($/MWh)	Confidential	Confidential
Fuel ($/MWh)	Confidential	Confidential
25 yr levelized bus cost	Confidential	Confidential

Request for Power Supply Proposals

A request for power supply proposals (RFP) was developed to allow a variety of options to be proposed. These would include contract and ownership type offers. The RFP required delivery of the capacity and energy to the KEPCo service territory connections with the control area providers, Westar, KCPL and Aquila. KEPCo's loads are located within the Southwest Power Pool, which is gaining regional transmission operator status. However, it is anticipated that the market will still operate as a traditional wholesale market for some time. It is not known when or if the market will move towards operation under the standard market design type of market.

The RFP was posted on a project web site where prospective bidders could download it. The website was included in the ads placed in *Power Marketer's Week* and *Megawatt Daily*. The ads were placed in the publications for one week between October 28, 2004 and November 2, 2004. In addition to the advertisements, the RFP was emailed directly to 64 firms that were either a utility, developer or power marketer.

There were four notices of intent to bid received. However, there were no subsequent proposals received. Inquiries made to the prospective bidders revealed several concerns. Several prospective bidders were concerned about the inability to have transmission capacity to deliver the capacity and energy. The lack of transmission capacity had been evaluated on previous bids and it was found that firm transmission was unavailable with the existing system.

Also, the bidders were unsure about the upcoming Midwest ISO market modifications expected to take effect on March 1, 2005 (actually took effect on April 1, 2005) and how they would affect the long term value of capacity and energy. Concern was also expressed about the recent RFP issued by KEPCo for short term supply with no purchases taken from the market.

Coal Option Resource Evaluation

The analysis for the Long Range Plan identified a level of 100MW of coal energy to be of benefit in reducing the long range costs of KEPCo. Analysis of various combinations of the Iatan and Existing Coal Unit proposals were developed to identify the more optimum acquisition strategy for the two resources. Since the Iatan offer had the lower bus bar cost analysis, it was assumed that the entire 30MW would be taken as a portion of the 100MW identified in the Phase I assessment. Scenarios were developed with zero, 30, 45, and 60MW of Existing Coal Unit to determine the advantages of various levels of Existing Coal Unit in the supply mix.

The KEPCo system was modeled as the three control areas of Sunflower, Westar and KCPL. The load was allocated among the areas. Resources for the Sunflower area were the Sunflower contract and a portion of the WAPA peaking contract. Resources for the KCPL area were the KCPL contract. The balance of the Sharpe and Wolf Creek resources and WAPA, SWPA and Westar contracts were used to meet load within the Westar area. The results of this analysis with these contracts and the Iatan purchase showed benefits in reducing the NPV with the existing conditions continued. The additional capacity from the Existing Coal Unit option showed reduced benefits. However, assessment of the acquisition of Existing Coal Unit capacity should continue to be considered as terms of the Westar contract are discussed since the amount of baseload energy of benefit is highly sensitive to the Westar contract assumptions.

The RUS prefers the use of hourly production cost modeling in the support of Generation Construction Work Plans. Due to the complexity of modeling the various fixed and variable aspects of the Westar, Sunflower and KCPL contracts, the spreadsheet models from the Long Range Plan were determined by Burns & McDonnell to be better suited to identify the total incremental costs of the system with the Iatan purchase included.

The comparison of the Iatan purchase was made to the contract extension Case X2 from the Long Range Plan. The following sensitivities were performed in addition to the base case. Cases 2-5 were preformed in accordance with RUS guideline.

1. Westar energy costs used in the Long Range Plan were escalated at 2.5 and 6.5 percent, the escalation ranges considered in the Long Rang Plan
2. Iatan fuel costs were increased by 20 percent from the base level.
3. Iatan construction costs were increased by 20 percent from the base level
4. Iatan financing interest rates were increased by 1 percent from the base interest rate.
5. The KEPCo base forecast rate of growth was reduced in half to reflect a low load growth scenario.

The net present value results (2005$s) of the analyses are summarized in Table ES-5.

Table ES-5

Comparison of Iatan 30MW Cases
With the Extension of Existing Contracts
($000's)

	Load Forecast	Base	Interest Rate	Construction Cost	Iatan Fuel
Westar @ 6.5%					
Without Iatan	$755,958	$884,486	$884,486	$884,486	$884,486
With Iatan	$728,450	$856,554	$859,230	$858,317	$859,517
Difference	**$27,508**	**$27,932**	**$25,255**	**$26,169**	**$24,969**
Westar @ 2.5%					
Without Iatan	$651,409	$737,483	$737,483	$737,483	$737,483
With Iatan	$658,684	$744,745	$747,455	$746,541	$747,741
Difference	**($7,275)**	**($7,262)**	**($9,972)**	**($9,058)**	**($10,258)**

The billings from Westar received during the 2005 summer have indicated an energy cost for 2005 greater than that considered in the above analysis. The analysis provided in Table ES-5 was updated with the recent Westar contract energy costs from January 2005 to date. These revised numbers were used as the base Westar energy values and escalated at the same rates of escalation as above. The net present values from this assessment are summarized in Table ES-6.

Table ES-6
Comparison of Iatan 30MW Cases
With the Extension of Existing Contracts
With Revised Westar Energy Costs
($000's)

	Load Forecast	Base	Interest Rate	Construction Cost	Iatan Fuel
Westar @ 6.5%					
Without Iatan	$856,757	$1,018,591	$1,018,591	$1,018,591	$1,018,591
With Iatan	$798,240	$959,322	$962,013	$961,099	$962,299
Difference	**$58,517**	**$59,268**	**$56,578**	**$57,491**	**$56,291**
Westar @ 2.5%					
Without Iatan	$722,776	$825,565	$825,565	$825,565	$825,565
With Iatan	$712,591	$814,717	$817,426	$816,512	$817,712
Difference	**$10,185**	**$10,849**	**$8,139**	**$9,053**	**$7,853**

The analysis indicates that the projections on the Westar energy costs have a significant impact on the variance of the cases. The results of the analysis indicate that the Iatan project can operate as a hedge against escalation of the Westar purchase contract energy pricing.

Iatan Project Status

The Iatan project status is fully described in Part VI. In general, the project is fully subscribed and is in the permitting phase. Once the permits are issued, KCPL is ready to start construction. The owner agreements are being developed and initial financing of the project is being solicited. KEPCo has participated in the drafting of the owner agreements.

Conceptual design for the support of permitting has been completed. The Environmental Assessment (EA) has been submitted to the US Army Corps of Engineers, the federal agency in charge of the EA process. The EA is currently under review. The draft air permit is expected to be issued by the Missouri Department of Natural Resources in the fourth quarter of 2005.

KEPCo has submitted the project to the SPP for transmission service from the Iatan facility to the Westar control area. The request submitted was for a 50MW level of participation. The results of the SPP analysis indicate that there are certain costs necessary to deliver the capacity and energy on a firm basis to the Westar control area. The allocation of these costs is projected to be such that KEPCo's portion of the costs is approximately $3 million for the 50 MW level. It is anticipated that these upgrades will be incorporated into the base expansion plan of the SPP with the cost recovery performed through the system wide SPP rates. Therefore, no financing is expected to be necessary by KEPCo for the transmission service. A reassessment of the 30 MW transfer is being performed by the SPP.

Conclusions

Based on the analysis of loads and resources and the responses to the RFP, KEPCo will continue to be dependent on area utilities to provide capacity and energy to serve its load. Without acquisition of additional baseload resources, KEPCo's cost of power will continue to be on the margin of the utilities' cost of power. For those utilities, such as Westar, this means an increasing proportion of energy being provided by natural gas. The analysis prepared herein has indicated that by blending in additional coal based resources, KEPCo can reduce its exposure to projected energy costs. The most attractive baseload option, based on the assumptions used in the analysis, is the Iatan Unit 2. KEPCo can participate in this project with a nominal 30MW allocation. The project is scheduled to be commercial in 2010. Participation in this project will require obtaining funds for the equity purchase.

Beyond the decision for the participation in the Iatan Unit 2, the option of obtaining up to 60MW of the Existing Coal Unit was found to provide reduced benefits with the assumptions used in the analysis for the extension of the Westar contract. This assessment on acquisition of Existing Coal Unit capacity should continue to be updated as more firm information is obtained on the Westar contract negotiations.

Additional issues that KEPCo should pursue include the upgrade to the Wolf Creek generating station to acquire the estimated 4MW of capacity. This project has been delayed by the other participants. Should it be reinitiated with similar terms as assessed in the Phase I analysis, KEPCo should participate in the project.

As mentioned above, the lack of a robust wholesale market in the KEPCo area will require KEPCo to continue to take power from the area utilities. For the Westar contract, the average cost is based on the amount of energy taken under the contract versus the fixed and variable costs of the contract. KEPCo should continue to evaluate the value of installing peaking capacity in the Westar service area versus the costs of the Westar contract and area non-firm energy market to determine if KEPCo owned peaking capacity could reduce the overall costs of KEPCo's intermediate and peaking energy.

Three Year Generation Work Plan

Based on the analysis developed for this study, review of the market surrounding the KEPCo service areas and other factors affecting the power industry, Burns & McDonnell is of the opinion that KEPCo should:

1. Consider the impact of the acquisition of the Iatan project and other operating costs on member wholesale rates.

2. If the wholesale rate impacts are acceptable, pursue the acquisition of the 30MW of the Iatan Unit 2 capacity offered by KCPL.

3. Obtain the necessary financing to allow participation in the project.

4. Proceed with the negotiations of the various agreements to become a participant in the project.

5. Finalize the transmission service arrangements for the delivery of the power from the project

6. Complete negotiations with the control area service providers for the extension of the existing contracts and for the scheduling and integration of the output of the Iatan capacity to serve the KEPCo load.

7. Pursue the upgrade to the Wolf Creek generating station.

8. Based on the terms resulting from the extension of the Westar and other supplier contracts, compare the value of peaking facilities constructed by KEPCo to offset capacity and energy provided by the suppliers, review acquisition of additional baseload capacity from the Existing Coal Unit, and determine if continued acquisition of the Iatan purchase is still attractive.

* * * *

Part I

Introduction

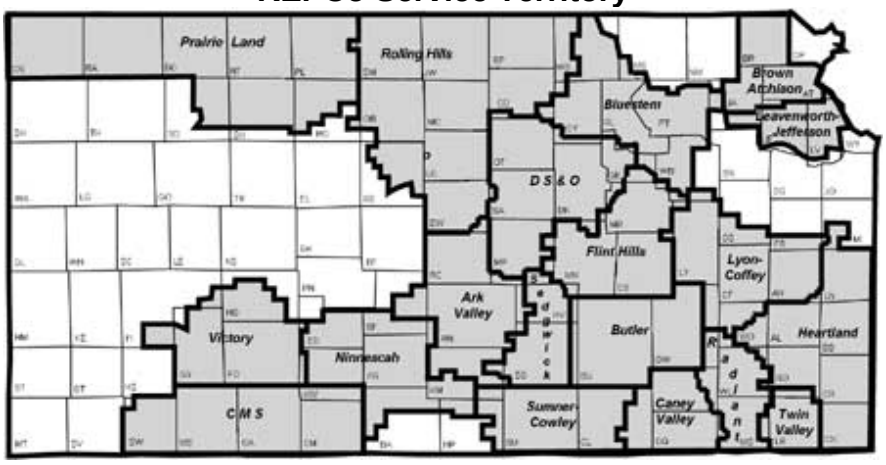
Kansas Electric Power Cooperative

KEPCo is governed by a Board of Trustees representing each of its 19 members which collectively serve more than 100,000 electric meters in two-thirds of rural Kansas. The KEPCo Board of Trustees meets regularly to establish policies and act on issues that often include recommendations from working committees of the Board and KEPCo staff. The Board also elects a seven-person Executive Committee which includes the President, Vice President, Secretary, Treasurer, and three additional Executive Committee members.

KEPCo is under the jurisdiction of the Kansas Corporation Commission (KCC) and was granted a limited certificate of convenience and authority in 1980 to act as a G&T public utility.

KEPCo's power supply resources consist of: 70 MW of owned generation; the 20 MW Sharpe Generating Station in Coffey County; hydropower purchases of an equivalent 100 MW from the Southwestern Power Administration, and 14 MW from the Western Area Power Administration; plus partial requirement power purchases from regional utilities. The service area of KEPCo is shown in Figure I-1.

Figure I-1
KEPCo Service Territory



The distribution member cooperatives of KEPCo are:

Ark Valley Electric Cooperative Association, Inc.
10 E. 10th Street
South Hutchinson, KS 67505
Miles of Line: 2,096

Bluestem Electric Cooperative, Inc.
614 E. U.S. Highway 24
Wamego, KS 66547
Miles of Line: 2,803

Brown-Atchison Electric Cooperative Association, Inc.
1712 Central
Horton, KS 66439
Miles of Line: 1,124

Butler Rural Electric Cooperative Association, Inc.
216 S. Vine Street
El Dorado, KS 67042
Miles of Line: 1,704

Caney Valley Electric Cooperative Association, Inc.
401 Lawrence
Cedar Vale, KS 67024
Miles of Line: 1,733

CMS Electric Cooperative, Inc.
509 East Carthage
Meade, KS 67864
Miles of Line: 2,529

DS&O Rural Electric Cooperative Association, Inc.
129 W. Main Street
Solomon, KS 67480
Miles of Line: 2,417

Flint Hills Rural Electric Cooperative Association, Inc.
1564 S. 1000 Road
Council Grove, KS 66846
Miles of Line: 2,506

Heartland Rural Electric Cooperative, Inc.
110 N. Enterprise Drive
Girard, KS 66743
Miles of Line: 3,705

Leavenworth-Jefferson Electric Cooperative, Inc.
507 N. Union
McLouth, KS 66054
Miles of Line: 1,536

Lyon-Coffey Electric Cooperative, Inc.
1013 N. 4th Street
Burlington, KS 66839
Miles of Line: 2,460

Ninnescah Electric Cooperative Association, Inc.
20112 W. U.S. 54
Pratt, KS 67124
Miles of Line: 2,132

Prairie Land Electric Cooperative, Inc.
1101 West Hwy. 36
Norton, KS 67654
Miles of Line: 5,379

Radiant Electric Cooperative, Inc.
100 N. 15th
Fredonia, KS 66736
Miles of Line: 1,370

Rolling Hills Electric Cooperative, Inc.
122 W. Main
Mankato, KS 66956
Miles of Line: 6,317

Sedgwick County Electric Cooperative Association, Inc.
1355 S. 383rd Street West
Cheney, KS 67025
Miles of Line: 1,091

Sumner-Cowley Electric Cooperative, Inc.
2223 North A Street
Wellington, KS 67152
Miles of Line: 2,000

Twin Valley Electric Cooperative, Inc.
501 Huston
Altamont, KS 67330
Miles of Line: 948

Victory Electric Cooperative Association, Inc.
3230 N. 14th
Dodge City, KS 67801
Miles of Line: 1,999

KEPCo sells wholesale electric power to its distribution member cooperatives through many delivery points located in three different control areas. KEPCo uses the transmission system of the Southwest Power Pool (SPP) to deliver the power. KEPCo is a member of the SPP and participates in the planning and expansion of the system within Kansas.

Study Objective(s)

In anticipation of its future energy and capacity requirements and in recognition of the dynamic nature of the electric power market in Kansas and the surrounding region, the Kansas Electric Power Cooperative (KEPCo) commissioned Burns & McDonnell to perform this Long Range Resource Planning Study and Generation Construction Work Plan (Study). KEPCo desired to develop a comprehensive Long Range Resource Plan to provide its 19 members with the capacity and energy that they will require through the present terms of KEPCo's power supply contracts with its Members and beyond. The resource plan would also address the most economic evaluated course(s) of action, including the associated benefits and risks, to be taken by KEPCo to meet the long range power supply requirements of its members. Given these requirements, this Study addressed a range of KEPCo resource options, including:

- Participation in new generation to be constructed in the region,
- Power supply from new and existing purchased power contracts, and
- KEPCo constructed resources.

Key criteria used for evaluating alternative power supply options included:

- Reliability of power supply
- Adequacy of power supply, demand and energy
- Absolute and relative costs of viable resource plan options
- Physical and economic risks and benefits of each viable resource plan

In order to meet the Study objectives a two-phased approach was pursued by Burns & McDonnell. The objective of the first phase was to review the current status of KEPCo with respect to its most recently approved load forecast and the resources available to meet the projections. A review of the expected capacity and energy needs allowed a determination of the quantity and general types of resources that may be of benefit to KEPCo. Specific objectives of the first phase were to identify power supply options that had operational and economic potential to meet KEPCo's long range requirements. The results of this phase would provide a general direction for KEPCo's power supply plan.

The second phase provided more refinement on the immediate resource decisions facing KEPCo. The objective of Phase II was to prepare the necessary analysis to support a generation construction work plan that met requirements of the Rural Utilities Service (RUS) 7CFR1710 Subpart F. The second phase would build and expand upon the results of the earlier analysis and would specifically include:

- Request for Proposals (RFP) of power supply
- Review of area power resource partnering options
- Extension of existing contracts

The report presented herein describes the results of the Burns & McDonnell analysis.

Data Sources and Study Assumptions

In performing this Study, Burns & McDonnell worked closely with KEPCo staff and relied to a great extent on information provided by KEPCo. This information included load forecasts by member system, KEPCo power supply contract information, KEPCo operating statistics, as well as other historical data. Other sources of information included: Platts/RDI, the U.S. Department of Energy (DOE), commercial information firms, and equipment vendors.

This Study required the development and comparative assessment of long-term resource plans. It was therefore necessary to make numerous assumptions regarding future events. Effort was made to develop reasonable assumptions based upon available historical data as well as realistic expectations of future events. However, given the uncertainties associated with contractual issues, energy prices, and transmission matters, no guarantee can be made that actual events will conform to the assumptions described herein. To the extent that future events may differ from the assumptions contained in this Study, such differences may have a significant effect on the conclusions and recommendations contained herein.

Report Structure

This Report has been organized to present the issues considered, the analysis performed, and the Study findings in a single comprehensive document. The Report includes a Summary, seven parts and an Appendix. This Part I, Introduction, sets forth the objectives of the Study. Part II presents a situational review of KEPCo's current energy requirements, resource mix, operations, and capacity balance. Part III identifies the specific resource plans that were developed and evaluated along with the key assumptions associated with those plans. Part IV presents the economic results that were estimated from computer simulations of each resource plan. Part V presents the results of detailed information about regional opportunities to participate in regional base load projects and the RFP. Part VI provides information about the near term recommended generation option development. Part VII presents our conclusions and recommendations as derived from this study. Appendices are provided which include details supporting the various analyses.

Methodology

The development of the resource plan scenarios and assumptions were reviewed with KEPCo. In evaluating each resource plan both deterministic and probabilistic analyses were performed. The purpose of the probabilistic analyses was to provide a quantitative measure of the risk profiles associated with each resource option considered. In comparing the resource plans, the key measure of economic merit and viability was the net present value (NPV) of the total costs of each plan as determined over a planning horizon extending through 2040.

The probabilistic analysis for the long range study was performed using spreadsheet analysis of the KEPCo system by major control area. Through use of the spreadsheet for the analysis, risk functions were able to be applied directly to the analysis for calculation of distribution profiles for the various plans. This analysis provided the general direction for the more refined analysis performed in the construction work plan on the specific projects identified.

For the construction work plan, detailed modeling of the fixed costs associated with the supplier contracts used by KEPCo created for the long range plan was used. Detailed hourly production cost modeling using ProSym was used to model the variable costs associated with the dispatch of the specific projects identified for the construction work plan. The system was modeled as three control areas in the hourly model. Sensitivities required by the RUS for loan support were applied to the construction work plan analysis.

As required by the RUS, a request for power supply proposals was performed for the construction work plan.

* * * * *

Part II

Existing System

Overview

This section of the report addresses the issues of KEPCo's energy and load requirements, availability of existing resources, and the future balance between available resources and total KEPCo load requirements. These three critical planning factors formed the basis for all subsequent analysis performed in the study.

Load and Energy Requirements

KEPCo Peak Demand and Energy Requirements

As a basis for the analysis performed, Burns & McDonnell relied upon a long-term energy and demand forecast that was independently prepared by KEPCo and which will be presented to the RUS as KEPCo's "official" forecast (see attached CD for forecast). Burns & McDonnell did, however, review this forecast and determined it to be reasonable, given historical load growth within the individual Member service areas. As can be seen in Table II-1, KEPCo's long-term forecast can be summarized as follows:

- Between 2004 and 2040, KEPCo's total system peak load is expected to grow at an annual rate of approximately 1.42 percent, resulting in a system peak load of 669 MW, an increase of 266 MW, by 2040.

- Between 2004 and 2040, KEPCo's total system energy requirements are expected to grow at an annual rate of 1.28 percent, resulting in an increase of 967,000 MWh of energy requirements.

- Between 2004 and 2040, KEPCo's total system annual load factor is projected to decline slightly from 47.2 percent in 2004 to 44.9 percent by 2040.

Table II-1
Long Range Resource Plan
KEPCo Peak Demand & Energy Requirements

Year	Billing Summer CP MW	Maximum Peak at KEPCo D.P. Including Weekends MW	Total Member Sales MWh	Total KEPCo Sales MWh	Annual Load Factor %
1995	308.0	308.6	1,217,367	1,343,965	49.7%
2000	361.5	371.8	1,401,043	1,547,348	47.5%
2003	381.0	392.0	1,501,569	1,633,126	47.6%
2004	393.7	405.7	1,537,594	1,674,939	47.1%
2005	398.6	411.1	1,556,327	1,693,039	47.0%
2010	424.3	439.0	1,642,715	1,787,016	46.5%
2015	452.3	469.5	1,736,824	1,889,392	45.9%
2020	482.7	502.6	1,839,364	2,000,939	45.4%
2025	515.9	538.8	1,951,225	2,122,626	45.0%
2030	554.6	579.2	2,096,530	2,280,695	45.0%
2035	595.9	622.4	2,252,662	2,450,542	44.9%
2040	640.4	668.9	2,420,429	2,633,046	44.9%
Growth Rate %	1995-2003	2.42%		2.47%	
	2004-2025	1.39%		1.16%	
	2025-2040	1.45%		1.45%	
	2004-2040	1.42%		1.28%	
"Delta" MW, MWh	1995-2003	83.4		289,161	
	2004-2025	135.6		456,134	
	2025-2040	130.1		510,420	
	2004-2040	265.7		966,554	
"Delta" MW/yr, MWh/yr	1995-2003	9.3		32,129	
	2004-2025	6.5		21,721	
	2025-2040	8.7		34,028	

Note: Reference revised KEPCo forecast, dated March 3, 2004

Figures II-1 and II-2 present in graphical format KEPCo's long-term forecast of demand and energy requirements. Also shown on each graph are the potential upper and lower boundaries to the Base Case forecast. Additionally, presented on each graph are the historical linear trendlines for peak demand and energy requirements derived from the period 1995 – 2003. As can be seen, future KEPCo demand and energy requirements are expected to fall below what a strict trendline projection might suggest.

Figure II-1
KEPCo Peak Load Requirements

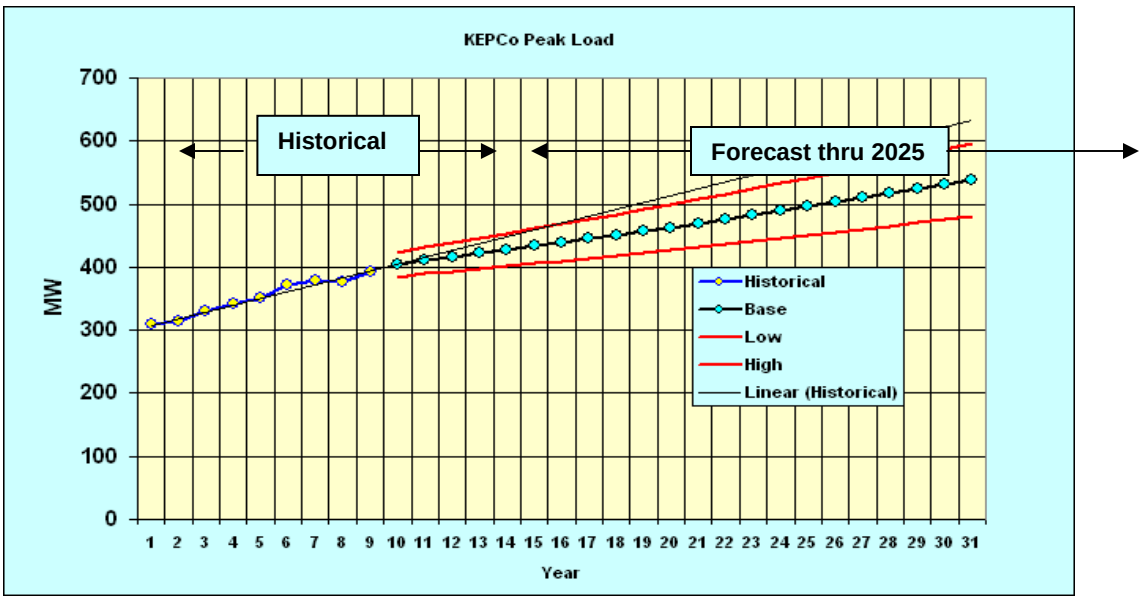
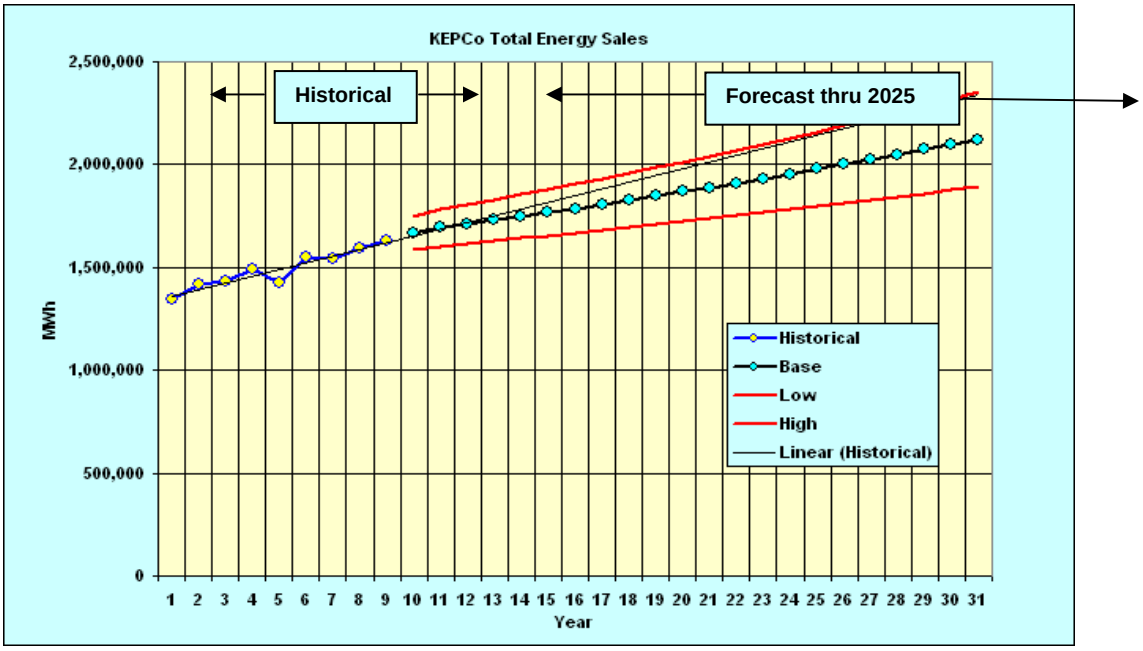


Figure II-2
KEPCo Total Energy Sales



KEPCo Energy Sales by Consumer Class

In developing KEPCo's total peak load and energy requirements, recognition was given to future energy requirements by consumer class. Table II-2 presents the forecast of energy requirements for the aggregate of each consumer class. Key findings include:

- During the planning period through 2040, it is estimated that Rural Residential energy sales will increase in its share of KEPCo's total system energy requirements, growing from 60.5 percent in 2003 to approximately 71.5 percent by 2040. This increased share for Rural Residential represents a contributing factor for the projected decrease in KEPCo's overall annual system load factor.

- Between 2004 and 2040, it is estimated that Small Commercial energy sales will decrease as a share of KEPCo's total system energy requirements, declining from 26.3 percent in 2003 to approximately 18.2 percent by 2040.

Table II-2
KEPCo Energy Sales by Consumer Class

Member Sales - GWh	**2000**	**2003**	**2005**	**2010**	**2020**	**2030**	**2040**
Rural Residential	880.7	909.0	943.0	1022.6	1204.6	1437.9	1729.8
Seasonal Residential	10.8	11.7	12.1	13.1	15.4	18.4	22.2
Irrigation	46.0	49.3	45.7	45.8	45.8	46.4	47.3
Small Commercial	363.1	394.9	416.9	418.7	421.8	429.8	441.2
Large Commercial	73.8	86.9	87.1	87.2	87.3	88.3	90.1
Public Street & Highway	1.2	1.8	1.8	1.8	1.8	1.8	1.8
Sales to Public Authorities	8.9	9.1	9.2	9.8	10.9	12.2	13.8
Sales for Resale-REA	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sales for Resale-Others	16.5	39.0	40.4	43.9	51.7	61.7	74.2
Total Member Sales	**1401.0**	**1501.6**	**1556.3**	**1642.7**	**1839.4**	**2096.5**	**2420.4**

Member Sales Share %	**2000**	**2003**	**2005**	**2010**	**2020**	**2030**	**2040**
Rural Residential	62.9%	60.5%	60.6%	62.2%	65.5%	68.6%	71.5%
Seasonal Residential	0.8%	0.8%	0.8%	0.8%	0.8%	0.9%	0.9%
Irrigation	3.3%	3.3%	2.9%	2.8%	2.5%	2.2%	2.0%
Small Commercial	25.9%	26.3%	26.8%	25.5%	22.9%	20.5%	18.2%
Large Commercial	5.3%	5.8%	5.6%	5.3%	4.7%	4.2%	3.7%
Public Street & Highway	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Sales to Public Authorities	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
Sales for Resale-REA	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Sales for Resale-Others	1.2%	2.6%	2.6%	2.7%	2.8%	2.9%	3.1%
Total Member Sales	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Note: **Reference Revised KEPCo forecast, dated March 3, 2004**

Forecast of Member Load and Energy Requirements

In developing KEPCo's total peak load and energy requirements, recognition was also given to future load and energy requirements for each of KEPCo's 19 member systems. Table II-3 presents the forecast of coincident peak (CP) load and total energy requirements for each member system. Table II-4 presents the forecast of total energy requirements for each member system. The analysis performed in this Study relied heavily upon these member system forecasts, since it was these forecasts which were used to estimate future load and energy requirements by control area.

Table II-3
Long Range Resource Plan
Forecast of Member Coincident Peak Load

	Member	Control Area	Member CP Load, MW			"Delta" CP Load, MW		
			2004	2025	2040	2004-2025	2025-2040	2004-2040
1	Ark Valley	Westar	21.2	28.3	33.8	7.1	5.5	12.6
2	Bluestem	Westar	21.9	29.3	36.8	7.4	7.4	14.9
3	Brown-Atchison	Westar	18.6	24.9	30.4	6.2	5.5	11.8
4	Butler	Westar	30.1	40.2	49.5	10.1	9.3	19.4
5	Caney Valley	Westar	14.4	19.3	25.0	4.9	5.6	10.5
6	CMS	Sunflower	17.0	22.7	28.2	5.7	5.6	11.2
7	DS&O	Westar	30.3	40.5	51.8	10.2	11.2	21.5
8	Flint Hills	Westar	19.5	26.1	33.6	6.6	7.5	14.2
9	Heartland	Westar	34.8	46.4	57.4	11.7	10.9	22.6
		KCPL	0.6	0.8	0.9	0.2	0.2	0.4
10	Leavenworth-Jeff	Westar	31.9	42.6	51.8	10.7	9.2	19.9
11	Lyon-Coffey	Westar	9.7	13.0	16.1	3.3	3.1	6.3
		KCPL	13.7	18.3	22.7	4.6	4.3	8.9
12	Ninnescah	Westar	14.3	19.1	22.8	4.8	3.7	8.5
13	Prairie Land	Westar	4.5	6.1	7.9	1.5	1.9	3.4
14	Radiant	Westar	12.5	16.7	20.4	4.2	3.7	7.9
15	Rolling Hills	Westar	32.5	43.5	54.7	11.0	11.2	22.2
16	Sedgwick	Westar	28.6	38.3	47.6	9.7	9.3	19.0
17	Sumner-Cowley	Westar	18.2	24.3	29.9	6.1	5.6	11.7
18	Twin Valley	Westar	8.8	11.7	15.5	2.9	3.8	6.7
19	Victory	Sunflower	20.0	26.6	32.2	6.6	5.5	12.2
		Total	403.2	538.8	668.9	135.6	130.1	265.7
		Westar	351.9	470.4	584.9	118.5	114.5	233.0
		KCPL	14.3	19.1	23.6	4.8	4.5	9.3
		Sunflower	37.0	49.3	60.4	12.3	11.1	23.4
		Total	403.2	538.8	668.9	135.6	130.1	265.7

Table II-4
Long Range Resource Plan
Forecast of Member Energy Requirements, GWh

	Member	Control Area	Member Energy, GWh			"Delta" Energy, GWh		
			2004	2025	2040	2004-2025	2025-2040	2004-2040
1	Ark Valley	Westar	85.4	108.8	135.0	23.4	26.2	49.5
2	Bluestem	Westar	92.7	118.1	146.5	25.4	28.4	53.8
3	Brown-Atchison	Westar	73.3	93.4	115.8	20.1	22.4	42.5
4	Butler	Westar	113.7	144.9	179.7	31.1	34.8	66.0
5	Caney Valley	Westar	55.0	70.1	86.9	15.1	16.8	31.9
6	CMS	Sunflower	105.9	134.9	167.3	29.0	32.4	61.4
7	DS&O	Westar	115.5	147.2	182.5	31.6	35.4	67.0
8	Flint Hills	Westar	75.2	95.8	118.9	20.6	23.0	43.6
9	Heartland	Westar	139.3	177.4	220.1	38.1	42.7	80.8
		KCPL	2.3	2.9	3.6	0.6	0.7	1.3
10	Leavenworth-Jeff	Westar	110.4	140.7	174.5	30.2	33.8	64.0
11	Lyon-Coffey	Westar	40.8	52.0	64.5	11.2	12.5	23.7
		KCPL	57.5	73.2	90.9	15.7	17.6	33.4
12	Ninnescah	Westar	66.9	85.3	105.8	18.3	20.5	38.8
13	Prairie Land	Westar	23.7	30.2	37.5	6.5	7.3	13.8
14	Radiant	Westar	52.3	66.6	82.7	14.3	16.0	30.3
15	Rolling Hills	Westar	127.5	162.4	201.4	34.9	39.0	73.9
16	Sedgwick	Westar	104.9	133.6	165.7	28.7	32.1	60.8
17	Sumner-Cowley	Westar	71.3	90.8	112.7	19.5	21.8	41.4
18	Twin Valley	Westar	31.1	39.6	49.1	8.5	9.5	18.0
19	Victory	Sunflower	121.7	155.0	192.2	33.3	37.3	70.6
		Total	1,666.5	2,122.6	2,633.0	456.1	510.4	966.6
		Westar	1,379.2	1,756.7	2,179.1	377.5	422.4	799.9
		KCPL	59.8	76.1	94.4	16.4	18.3	34.7
		Sunflower	227.5	289.8	359.5	62.3	69.7	132.0
		Total	1,666.5	2,122.6	2,633.0	456.1	510.4	966.6

Forecast of Load and Energy Requirements by Control Area

Forecasts of load and energy requirements by control area were developed in order to consider their effects on resource plans. KEPCo was operating with member load located in five utility control areas. The load located within the Aquila and Empire control areas has been dynamically scheduled into the Westar control area. Therefore, for purposes of this Study three control areas were assumed to exist during the future planning period. These areas are: (1) Westar, (2) KCPL, and (3) Sunflower. Table II-3 presents anticipated peak load growth in each of these three areas through 2040. Table II-4 presents anticipated energy requirements in each of these areas through 2040.

Table II-5
Balance of Loads and Resources

	Control Area Coincident Peak (MW) Including Weekends				Reserve Requirement on Owned Resources Only	Peak Load Requirement with Reserves	*Resource Capacity, Surpluses, Deficits*								
	Westar	KCPL	Sunflower	Total	15%		Wolf Creek	Sharpe	SWPA	WAPA	Subtotal Capacity	Surplus (Deficit)	Westar	KCPL	Sunflower
2005	358.9	14.6	37.6	411.1	30.5	441.6	70.0	20.0	100.0	13.4	203.4	(238.2)	182.9	14.3	41.0
2006	363.9	14.5	38.2	416.6	30.5	447.1	70.0	20.0	100.0	13.4	203.4	(243.7)	187.6	14.5	41.6
2007	368.7	14.7	38.6	422.0	30.5	452.5	71.6	20.0	100.0	13.4	205.0	(247.5)	190.7	14.7	42.1
2008	373.5	14.8	39.2	427.5	30.5	458.0	71.6	20.0	100.0	13.4	205.0	(253.0)	195.5	14.8	42.7
2009	378.6	15.1	39.6	433.3	30.5	463.8	74.0	20.0	100.0	13.4	207.4	(256.4)	198.2	15.1	43.2
2010	383.7	15.3	40.1	439.1	30.5	469.6	74.0	20.0	100.0	13.3	207.3	(262.3)			
2011	388.8	15.4	40.8	445.0	30.5	475.5	74.0	20.0	100.0	13.3	207.3	(268.2)			
2012	394.1	15.7	41.2	451.0	30.5	481.5	74.0	20.0	100.0	13.3	207.3	(274.2)			
2013	399.5	15.9	41.8	457.1	30.5	487.6	74.0	20.0	100.0	13.3	207.3	(280.3)			
2014	404.7	16.1	42.4	463.2	30.5	493.7	74.0	20.0	100.0	13.3	207.3	(286.4)			
2015	410.2	16.3	43.0	469.5	30.5	500.0	74.0	20.0	100.0	13.1	207.1	(292.8)			
2016	415.8	16.5	43.6	475.9	30.5	506.4	74.0	20.0	100.0	13.1	207.1	(299.2)			
2017	421.6	16.8	44.2	482.5	30.5	513.0	74.0	20.0	100.0	13.1	207.1	(305.8)			
2018	427.3	17.0	44.8	489.1	30.5	519.6	74.0	20.0	100.0	13.1	207.1	(312.4)			
2019	433.1	17.2	45.4	495.7	30.5	526.2	74.0	20.0	100.0	13.1	207.1	(319.0)			
2020	439.3	17.5	46.0	502.8	30.5	533.3	74.0	20.0	100.0	13.0	207.0	(326.2)			
2021	445.2	17.7	46.7	509.6	30.5	540.1	74.0	20.0	100.0	13.0	207.0	(333.0)			
2022	451.6	17.9	47.2	516.8	30.5	547.3	74.0	20.0	100.0	13.0	207.0	(340.2)			
2023	457.7	18.2	48.0	523.9	30.5	554.3	74.0	20.0	100.0	13.0	207.0	(347.3)			
2024	464.1	18.5	48.6	531.2	30.5	561.6	74.0	20.0	100.0	13.0	207.0	(354.6)			
2025	470.9	18.7	49.3	538.9	30.4	569.3	74.0	20.0	100.0	12.9	206.9	(362.4)			
2026	477.8	19.0	50.0	546.7	30.4	577.2	74.0	20.0	100.0	12.9	206.9	(370.3)			
2027	484.8	19.3	50.6	554.7	30.4	585.1	74.0	20.0	100.0	12.9	206.9	(378.2)			
2028	491.8	19.5	51.3	562.7	30.4	593.1	74.0	20.0	100.0	12.9	206.9	(386.3)			
2029	499.0	19.8	52.0	570.9	30.4	601.3	74.0	20.0	100.0	12.9	206.9	(394.4)			
2030	506.3	20.1	52.7	579.2	30.4	609.6	74.0	20.0	100.0	12.8	206.8	(402.8)			
2031	513.7	20.4	53.5	587.6	30.4	618.0	74.0	20.0	100.0	12.8	206.8	(411.2)			
2032	521.2	20.7	54.2	596.1	30.4	626.5	74.0	20.0	100.0	12.8	206.8	(419.7)			
2033	528.9	21.0	54.9	604.7	30.4	635.2	74.0	20.0	100.0	12.8	206.8	(428.4)			
2034	536.6	21.3	55.7	613.5	30.4	643.9	74.0	20.0	100.0	12.8	206.8	(437.2)			
2035	544.4	21.6	56.4	622.4	30.4	652.8	74.0	20.0	100.0	12.6	206.6	(446.2)			
2036	552.4	21.9	57.2	631.5	30.4	661.9	74.0	20.0	100.0	12.6	206.6	(455.2)			
2037	560.5	22.2	58.0	640.6	30.4	671.0	74.0	20.0	100.0	12.6	206.6	(464.4)			
2038	568.6	22.5	58.8	649.9	30.4	680.3	74.0	20.0	100.0	12.6	206.6	(473.7)			
2039	577.0	22.8	59.6	659.4	30.4	689.7	74.0	20.0	100.0	12.6	206.6	(483.1)			
2040	585.4	23.1	60.4	668.9	30.4	699.3	74.0	20.0	100.0	12.5	206.5	(492.8)			

"Delta" Load, MW					
2005-25	112.0	4.1	11.7	127.8	127.7
2025-40	114.5	4.4	11.1	130.0	130.0
2005-40	226.5	8.6	22.8	257.8	257.7

Notes: KEPCo Revised Forecast - March 3, 2004
15% reserve margin based on owned resources only

Balance of Loads and Resources

KEPCo meets its load requirements through a variety of purchase contracts and owned resources. The delivery of the capacity and associated energy to meet its member loads is provided through contracts with the control area operators and the SPP. KEPCo is gradually increasing its involvement in the day to day operations of the resources and contracts.

KEPCo Owned Resources

KEPCo owns baseload capacity through a six percent ownership share of the Wolf Creek Nuclear Power Plant. The Wolf Creek Power Plant is an 1170MW nuclear facility located near Burlington, Kansas. The unit was brought on line in June, 1985. The current license expires in March, 2025. The unit is owned by Kansas Gas & Electric (47%), Kansas City Power and Light (47%) and KEPCo (6%). An upgrade of the unit is being considered, of which KEPCo would acquire an addition of approximately 4MW of capacity and associated energy. This upgrade is anticipated to be competed by 2009. Backup capacity and energy is provided through a contract with Westar for periods when the Wolf Creek generating unit is not available.

KEPCo acquired peaking capacity through the installation of engine generator sets at the Sharpe substation. These engines are approximately 2MW each and are fired on natural gas. There are ten units installed at the facility for a total of 20MW of peaking generation capacity. These units are dispatched by Westar and provide capacity cost reductions from the Westar partial requirements contract.

The KEPCo resources were assumed to be available at the following capacity levels throughout the planning period:

- Wolf Creek, 74 MW by 2009 and beyond
- Sharpe Engines, 20 MW

KEPCo Contracts

KEPCo has acquired firm power supply contacts to provide the balance of its member load requirements not furnished by the above resources. In addition to capacity and energy purchases, KEPCo contracts for a variety of ancillary services necessary for its operations as a utility. The following contracts are currently in effect.

Western Area Power Administration (WAPA) – KEPCo has a contract with WAPA for 13.4MW of capacity and associated peaking energy. The contract has seasonal maxim and minim contract rates of delivery. Energy is delivered on a approximate 80% capacity factor basis by monthly demand. It is anticipated that the amount of capacity available will decline slightly over the next several years. There is no expiration on this contract. This energy is scheduled into the Westar and Sunflower control areas.

Southwestern Power Administration (SWPA) – The contract with SWPA has limitations on the amount of energy that can be taken under the contract on a firm basis. The contract provides

KEPCo with 100MW of peaking capacity and energy at a rate of 1200 MWh per MW per year. In addition to this firm capacity and energy, the contract provides KEPCo with supplemental energy on an as available basis. There is no expiration on this contract. The capacity and energy from this contract is used primarily in the Westar control area.

Westar – KEPCo has a contract with Westar to provide firm requirements capacity and energy above its needs provided by its resources in the Westar control area (Wolf Creek and Sharpe) and by the WAPA and SWPA contracts. This contract also provides for all of the control area and scheduling services needed to manage the day to day activities of scheduling and delivery of capacity and energy to meet the KEPCo load in the Westar control area. This contract also provides for reserve capacity and energy for outages of the Wolf Creek resource. This contract is set to expire in 2008, but may be extended on agreement of the parties.

Sunflower G&T – KEPCo has a firm partial requirements contract with Sunflower which provides firm capacity and energy beyond that provided by the energy from the WAPA contract for KEPCo's load located in the Sunflower control area. This contract also provides for all of the control area and scheduling services needed to manage the day to day activities of scheduling and delivery of capacity and energy to meet the KEPCo load in the Sunflower control area.

KCPL – KEPCo has a firm all requirements contract with KCPL for the load served in the KCPL control area. This contract also provides for all of the control area and scheduling services needed to manage the day to day activities of scheduling and delivery of capacity and energy to meet the KEPCo load in the KCPL control area. This contract is extended by mutual agreement of the parties.

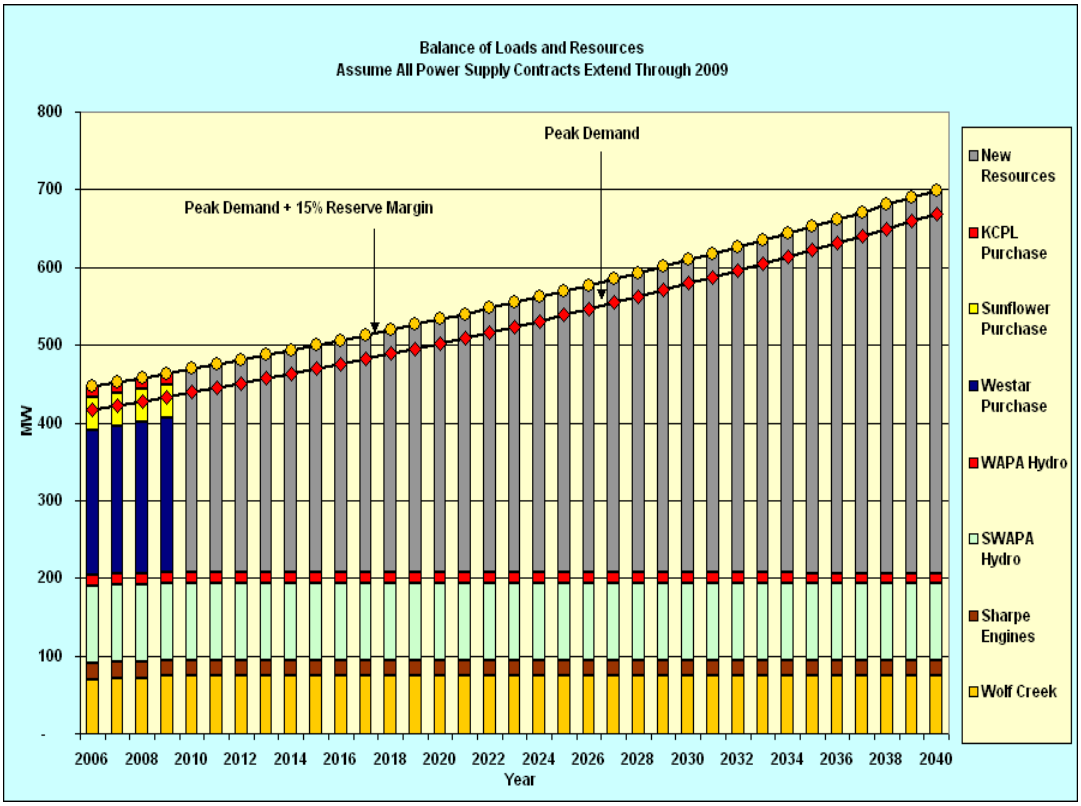
- SWPA Hydro, 100 MW
- WAPA Hydro, 13.4 MW through 2009, decreasing to 12.5 MW by 2040

KEPCo Capacity Balance

Figure II-3 and Table II-5 present the balance of loads and resources that formed the basis for resource plan development. Total KEPCo coincident peak load was computed as the sum of the coincident peak loads of the Westar, KCPL and Sunflower control areas. As shown, this total load was projected to be 669 MW by 2040. A reserve margin was then added to this to total KEPCo load. The reserve margin was computed to be 15 percent of KEPCo-owned resources which were taken as the sum of Wolf Creek, Sharpe engines, SWPA and WAPA. As shown, the reserve requirement throughout the planning period was estimated to be approximately 31 MW.

The system will require approximately 490MW of additional capacity and associated energy by 2040 above the current owned resources.

Figure II-3
Balance of Loads &Resources

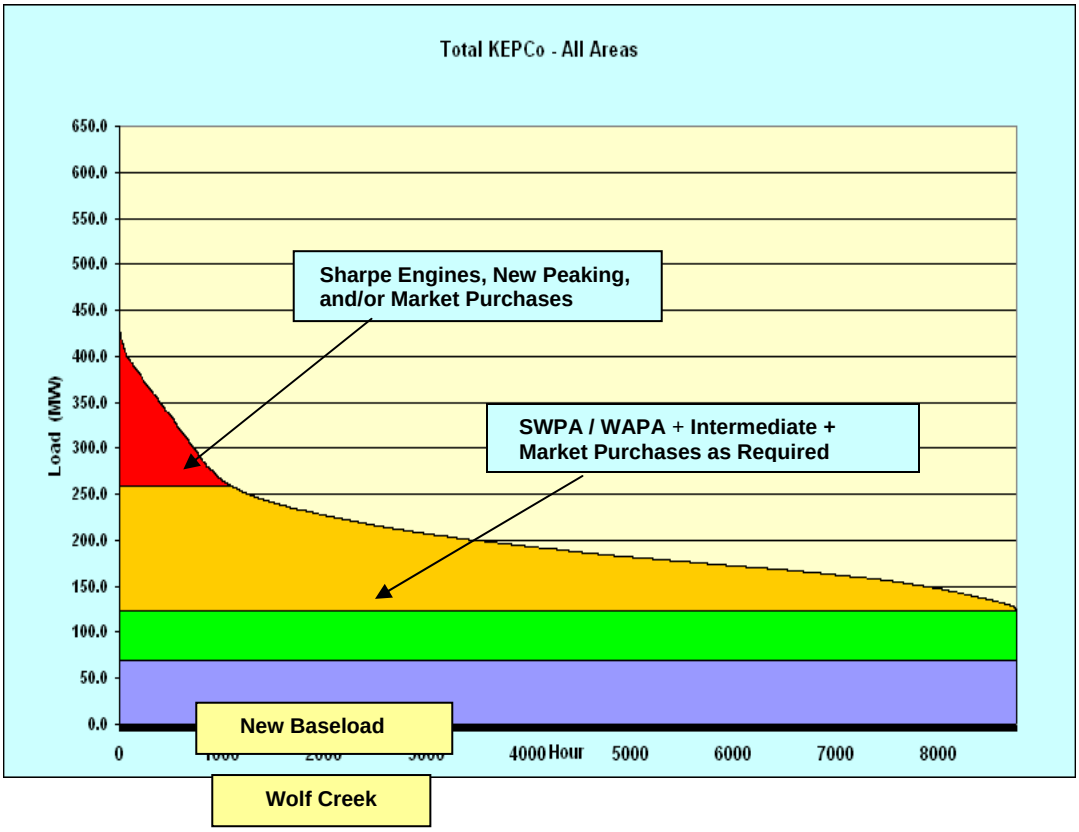


Load Duration Curve and Resource Energy Mix

In addition to evaluating KEPCo's future capacity balance, Burns & McDonnell evaluated resource energy needs by projecting system load duration curves. This type of evaluation lends assistance to the determination of the particular type and quantities of resources that must be included in a future resource portfolio. Figures II-4, II-5, and II-6 present in graphical form the results of this assessment for the years 2010, 2020, and 2040, respectively.

The analysis of the energy needs for KEPCo indicate that base load, intermediate, and peaking type resources will be needed to economically meet the KEPCo load projections. By 2010, KEPCo's resource needs reflect that new base load resources above Wolf Creek will be needed. Intermediate and peaking capacity, including SWPA, WAPA will be required. Approximately 1,500 gigawatt hours of energy will be needed above that provided by the existing resources.

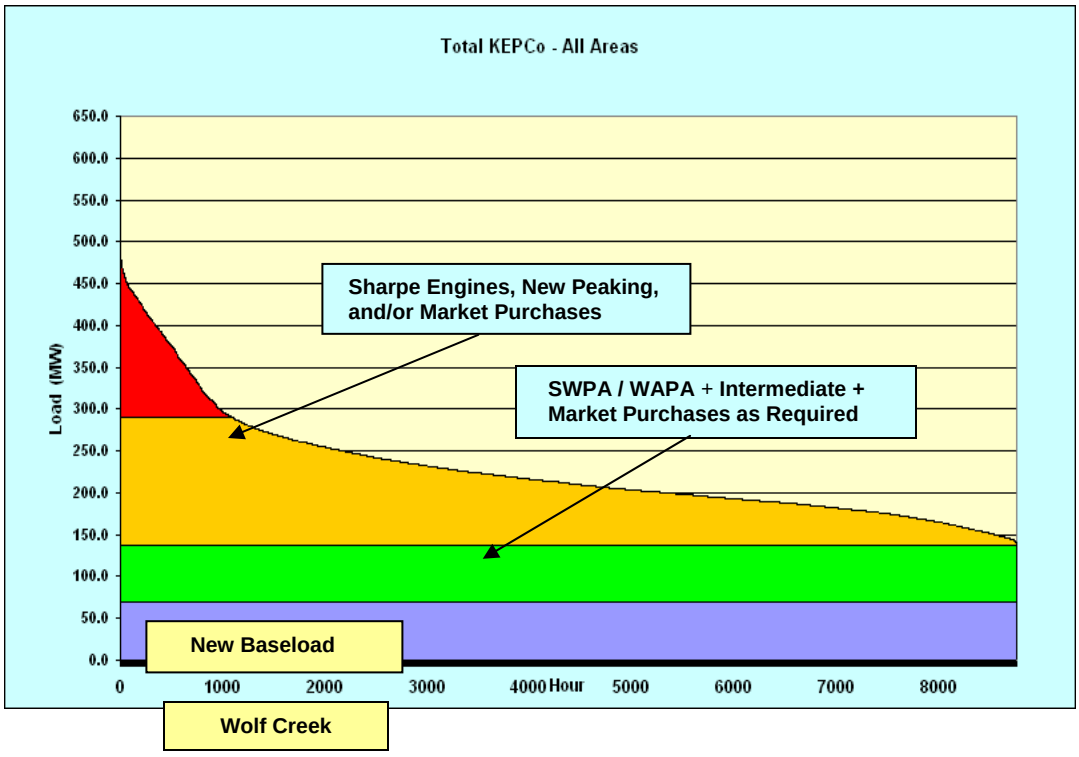
Figure II-4
Annual Load Duration Curve & Resource Energy Mix - 2010



2010	MW	Act. MWh	Max MWh	CF %
Base	122.8	1,075,376	1,743,240	61.7%
Intermediate	136.0	634,663	1,339,161	47.4%
Peaking	180.2	76,976	1,605,215	4.8%
Total	439.0	1,787,016	4,687,616	38.1%

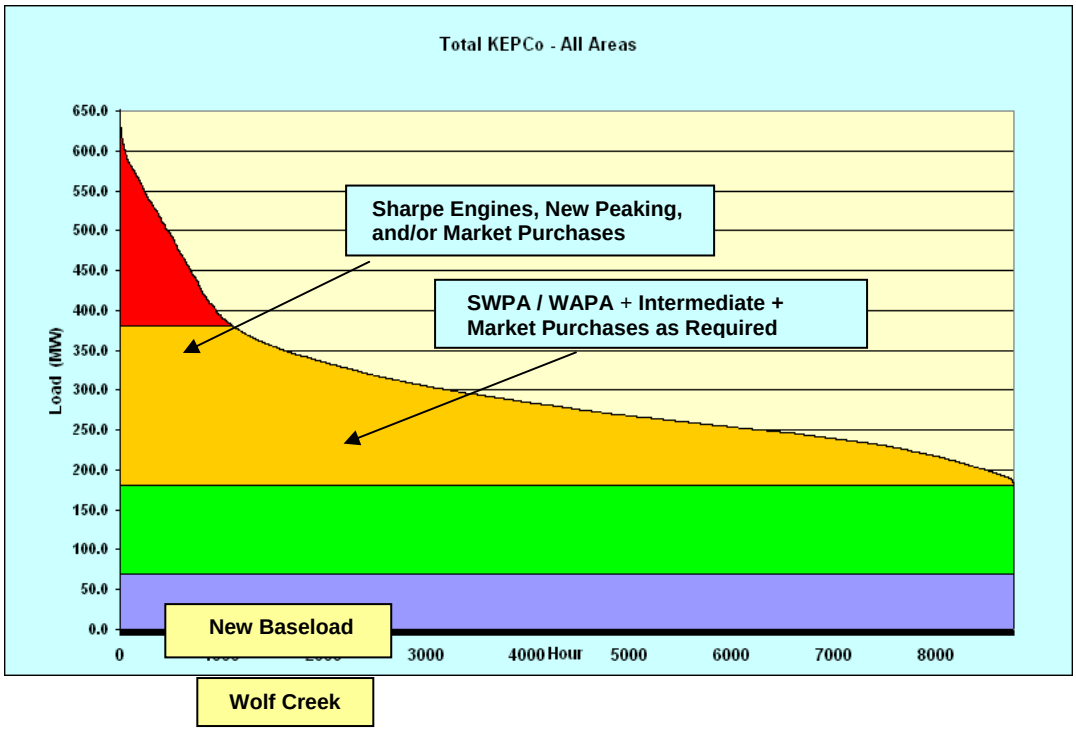
2010	MW	Act. MWh	Max MWh	CF %
New Base	52.5	459,548	1,095,000	42.0%
New Intermediate	40.4	66,002	353,613	18.7%
New Peaking	163.2	60,198	1,430,015	4.2%
Total New	256.1	585,748	2,878,628	20.3%

Figure II-5
Annual Load Duration Curve & Resource Energy Mix - 2020



2020						2020				
Base		MW	Act. MWh	Max MWh	CF %		MW	Act. MWh	Max MWh	CF %
Intermediate	152.3	137.5	1,204,102	1,743,240	69.1%	New Base	67.2	588,274	1,095,000	53.7%
Peaking			710,635	1,481,767	48.0%	New Intermediate	56.6	104,269	496,219	21.0%
Total		212.9	86,202	1,891,019	4.6%	New Peaking	195.9	69,276	1,715,819	4.0%
			2,000,939	5,116,026	39.1%	Total New	319.7	761,819	3,307,038	23.0%

Figure II-6
Annual Load Duration Curve & Resource Energy Mix - 2040



2040	MW	Act. MWh	Max MWh	CF %
Base	180.9	1,584,480	1,743,240	90.9 %
Intermediate	200.4	935,125	1,903,159	49.1 %
Peaking	287.6	113,440	2,546,038	4.5%
Total	668.9	2,633,046	6,192,436	42.5 %

2040	MW	Act. MWh	Max MWh	CF %
New Base	110.6	968,652	1,095,000	88.5 %
New Intermediate	104.8	247,826	917,611	27.0 %
New Peaking	270.6	96,191	2,370,838	4.1%
Total New	486.0	1,312,669	4,383,448	29.9 %

Part III

Resource Planning Scenarios

Overview

This part of the report addresses the various resource planning scenarios that were developed and analyzed for the Long Rang Plan. In developing the scenarios, consideration was given to the existing resources discussed in Part II. In general, there was consideration of scenarios in which

KEPCo met its obligations through extension of existing contracts with its current mix of owned resources, a scenario whereby it met all of its obligations through acquisition of ownership in a mix of baseload and peaking resources and a scenario which included a combination of contract extension with additional strategic resources.

Contract Extension Scenarios

Table III-1 presents the two contract extension scenarios that were studied. These scenarios are identified as Scenario X1 and X2A. Scenario X1 assumed that there would be no Wolf Creek uprate, while Scenario X2A assumed that there would be a Wolf Creek uprate resulting in a Wolf Creek capacity of 74 MW. Both Scenarios X1 and X2A assumed that the WAPA, SWPA, Westar, Sunflower, and KCPL contracts would be extended throughout the planning period.

The major uncertainty associated with the extension of the contracts was associated with the costs used to represent the extended contracts. For the SWPA and WAPA contracts, recent escalations were used to replicate an estimate of the future increases. These increases were provided in four year cycles of approximately 14 percent for each cycle.

The current contract with Westar is based on KEPCo paying the average incremental Westar system cost. KEPCo would be provided any baseload energy from the Westar resources after fulfillment of the Westar native load requirements. As the available energy from these resources is used more by the load growth of Westar's native load, less energy is available from these low cost resources to be used by KEPCo. Therefore, the cost of the Westar contract would tend to reflect Westar marginal generation costs over time. For purposes of this study, this increase is based on an increasing amount of energy being provided by a combined cycle gas unit. To assess the variability of the Westar contract costs, sensitivity analyses were performed on Scenario X2A in an effort to better reflect how contract costs might increase. The sensitivity analyses scenarios are identified as Scenarios X2B, X2C, and X2D. Of the various contract extension scenarios considered, Scenario X2D is considered the most likely. Table III-1 presents further detail regarding the assumptions contained in the contract extension scenarios.

Table III-1
Definition of Resource Scenarios

Contract Extension Scenarios

Scenario X1 **Extend Contracts – No WC up-rate**

No Wolf Creek up-rate expenditures or capacity increase

WAPA, SWPA, Westar, Sunflower, KCPL contracts continue throughout study period

Demand and energy charges for each contract begin to escalate after current contract expiration dates

Contract escalation rates reflect historical cost increases only

Scenario X2A **Extend Contracts - With WC up-rate**

Wolf Creek secondary plant up-rate expenditures and capacity increase included

WAPA, SWPA, Westar, Sunflower, KCPL contracts continue throughout study period

Demand and energy charges for each contract begin to escalate after current contract expiration dates

Contract escalation rates reflect historical cost increases only

Scenario X2B **Extend Contracts @ 4.5 % Max Escalation - With WC up-rate**

Upper bound of probabilistic distribution on future contract escalation rates increased to 4.5%

Wolf Creek secondary plant up-rate expenditures and capacity increase included

WAPA, SWPA, Westar, Sunflower, KCPL contracts continue throughout study period

Demand and energy charges for each contract begin to escalate after current contract expiration dates

Scenario X2C **Extend Contracts @ 5.5 % Max Escalation - With WC up-rate**

Upper bound of probabilistic distribution on future contract escalation rates increased to 5.5%

Wolf Creek secondary plant up-rate expenditures and capacity increase included

WAPA, SWPA, Westar, Sunflower, KCPL contracts continue throughout study period

Demand and energy charges for each contract begin to escalate after current contract expiration dates

Scenario X2D **Extend Contracts @ 6.5 % Max Escalation - With WC up-rate**

Upper bound of probabilistic distribution on future contract escalation rates increased to 6.5%

Wolf Creek secondary plant up-rate expenditures and capacity increase included

WAPA, SWPA, Westar, Sunflower, KCPL contracts continue throughout study period

Demand and energy charges for each contract begin to escalate after current contract expiration dates

Partner / Own Scenarios

Table III-2 defines five scenarios that were developed to evaluate resource costs under the global assumptions that the Westar, Sunflower, and KCPL contracts would have expired or been terminated after 2009 and that KEPCo would either partner in or construct the required baseload, intermediate load and peaking resources necessary to serve its load. Additionally, it was assumed for each of these scenarios that the Wolf Creek uprate would be accomplished. The various Partner / Own scenarios are identified as:

- *Scenario A* – KEPCo to build all new combustion turbines (CTs) to meet all KEPCo system load and energy requirements not served by Wolf Creek, SWPA, WAPA, and the Sharpe engines.

- *Scenario B* – KEPCo to partner in a combined-cycle unit and KEPCo to build new combustion turbines to meet all system load and energy requirements not served by Wolf Creek, SWPA, WAPA, and the Sharpe engines.

- *Scenario C* – KEPCo to build a combination of high efficiency CTs and standard CTs to meet all system load and energy requirements not served by Wolf Creek, SWPA, WAPA, and the Sharpe engines.

- *Scenario D* – KEPCo to partner in a baseload coal unit and KEPCo to build new standard performance CTs to meet all system load and energy requirements not served by Wolf Creek, SWPA, WAPA, and the Sharpe engines. KEPCo's assumed share of the coal unit would be 100 MW.

- *Scenario E* – KEPCo to partner in a baseload coal unit and KEPCo to build new internal combustion engines (IC engines) to meet all system load and energy requirements not served by Wolf Creek, SWPA, WAPA, and the Sharpe engines. KEPCo's assumed share of the coal unit would be 100 MW.

Table III-2 provides further detail pertaining to these resource scenarios, including the number and size of the new generating units required to meet load. Also, it was assumed that each scenario would include power market purchases in the event that such market purchases were more economical than the operation of installed resources. As part of this study, Burns & McDonnell modeled and simulated the regional power supply market and developed future market clearing prices for use in the analysis. The projections are shown in Figure III-1.

Table III-2
Long Range Resource Plan
Definition of Resource Scenarios

Partner/Own Scenarios

Scenario A: **Build all New Combustion Turbines (CTs), with WC Uprate**

Westar, Sunflower, KCPL Contracts expire after 2009

Wolf Creek Uprate to 74 MW by 2009

Sharpe engines rated at 20MW

SWPA (100 MW) and WAPA (13.4 to 12.5 MW) hydro allocations though 2040

Build new standard CTs: **320 MW by 2010 (8 CTs @ 40 MW each)**

600 MW by 2040 (15 CTs @ 40 MW each)

Scenario B: **Partner in Combined Cycle Unit, New Combustion Turbines (CTs), WC Uprate**

Westar, Sunflower, KCPL Contracts expire after 2009

Wolf Creek Uprate to 74 MW by 2009

Sharpe engines rated at 20MW

SWPA (100 MW) and WAPA (13.4 to 12.5 MW) hydro allocations though 2040

Partner in new Combined Cycle (CC) Unit - 100 MW by 2010

Build new standard CTs : **240 MW by 2010 (6 CTs @ 40 MW each)**

480 MW by 2040 (12 CTs @ 40 MW each)

Scenario C: **Build High Efficiency CTs and standard Peaking CTs, WC Uprate**

Westar, Sunflower, KCPL Contracts expire after 2009

Wolf Creek Uprate to 74 MW by 2009

Sharpe engines rated at 20MW

SWPA (100 MW) and WAPA (13.4 to 12.5 MW) hydro allocations though 2040

Build new High Efficiency CT - 100 MW by 2010

Build new standard CTs: **240 MW by 2010 (6 CTs @ 40 MW each)**

480 MW by 2040 (12 CTs @ 40 MW each)

Scenario D: **Partner in Baseload Coal Unit, Add New CTs, WC Uprate**

Westar, Sunflower, KCPL Contracts expire after 2009

Wolf Creek Uprate to 74 MW by 2009

Sharpe engines rated at 20MW

SWPA (100 MW) and WAPA (13.4 to 12.5 MW) hydro allocations though 2040

Partner in Baseload Coal Unit - 100 MW by 2010

Build new standard CTs : **240 MW by 2010 (6 CTs @ 40 MW each)**

480 MW by 2040 (12 CTs @ 40 MW each)

Scenario E: **Partner in Baseload Coal Unit, New Internal Combustion (IC) Engines, WC Uprate**

Westar, Sunflower, KCPL Contracts expire after 2009

Wolf Creek Uprate to 74 MW by 2009

Sharpe engines rated at 20MW

SWPA (100 MW) and WAPA (13.4 to 12.5 MW) hydro allocations though 2040

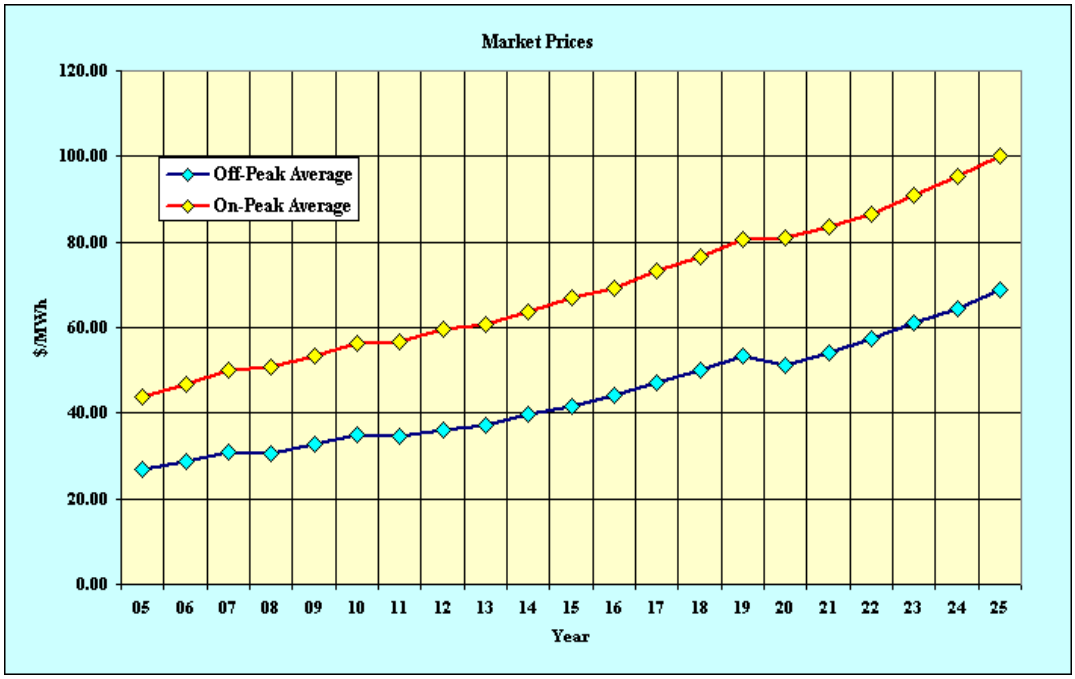
Partner in Baseload Coal Unit - 100 MW by 2010

Build new IC Engines: **208 MW by 2010 (104 engines @ 2 MW each)**

482 MW by 2040 (241 engines @ 2 MW each)

Note: ***All scenarios included Market Purchases as needed***

Figure III-1
Regional SPP Power Average Market Price Forecast



Partner / Own and Contract Extension Scenarios

As defined in Table III-3, Scenarios F and G were designed to evaluate combinations of contract extensions and the acquisition of new generating resources. Key features of Scenario F are as follows:

- The Sunflower and KCPL contracts would be extended according to current terms, and the Westar contract would be renegotiated as a partial requirements contract.
- An up rate at Wolf Creek would have been performed and SWPA, WAPA, and the Sharpe engines would be available to serve KEPCo load.
- KEPCo would partner in a baseload coal unit. The partnering arrangement would result in 50 MW of new baseload capacity.
- KEPCo would make power market purchases if such purchases were economically advantageous.

Key features of Scenario G are as follows:

- The Sunflower and KCPL contracts would be extended according to current terms, and the Westar contract would be renegotiated as a partial requirements contract.
- An uprate at Wolf Creek would have been performed and SWPA, WAPA, and the Sharpe engines would be available to serve load.
- KEPCo would partner in a baseload coal unit. The partnering arrangement would result in 50 MW of new baseload coal capacity.
- KEPCo would build ten new IC engines totaling 20 MW.
- KEPCo would make market purchases if such purchases were economically advantageous.

As defined in Table III-4, Scenarios H and I were designed to further evaluate combinations of contract extensions and the acquisition of new generating resources. Key features of Scenario H are as follows:

- The KCPL contract would be extended according to current terms.
- The Sunflower contract would be renegotiated as a partial requirements contract.
- The Westar contract would be renegotiated as a partial requirements contract.

- An uprate at Wolf Creek would have been performed and SWPA, WAPA, and the Sharpe engines would be available to serve KEPCo load throughout the planning period.

- KEPCo would partner in a baseload coal unit. The partnering arrangement would result in 100 MW of new baseload capacity.

- KEPCo would build ten new internal combustion (IC) engines, with each engine having a capacity of 2 MW.

- KEPCo would make power market purchases if such purchases were economically advantageous.

Key features of Scenario I are as follows:

- The KCPL and Sunflower contracts would be extended according to current terms.

- The Westar contract would be renegotiated as a market based partial requirements contract.

- An up rate at Wolf Creek would have been performed and SWPA, WAPA, and the Sharpe engines would be available to serve KEPCo load throughout the planning period.

- KEPCo would partner in a baseload coal unit. The partnering arrangement would result in 100 MW of new baseload capacity.

- KEPCo would build 21 new internal combustion (IC) engines, with each engine having a capacity of 2 MW.

- KEPCo would make power market purchases if such purchases were economically advantageous.

Table III-3
Definition of Resource Scenarios

Partner/Own & Contract Extension Scenarios

Scenario F: **Partner in Coal Unit, Extend Contracts as Required, with WC Uprate**

Sunflower and KCPL contracts extended according to current terms to meet future loads in those areas.

Wolf Creek Uprate to 74 MW by 2009

Sharpe engines rated at 20MW

SWPA (100 MW) and WAPA (13.4 to 12.5 MW) hydro allocations though 2040

Partner in Baseload Coal Unit - 50 MW by 2010

Coal energy to be used in Westar area.

Westar area supply contract renegotiated for partial requirements above available self-owned resources in the area:

- **Energy pricing equal to "On-Peak Market Energy" price as assumed in other cases.**
- **Monthly demand charge calculated based on capital costs of new combined cycle and combustion turbines, weighted 70%/30% CC/CT. Escalated at inflation.**
- **Demand charge applied to monthly peak demand in Westar area less the available capacity from Wolf Creek/coal unit/WAPA/SWPA/Sharpe.**
- **Fixed O&M charge also calculated based on cost for new combined cycles and combustion turbines, weighted 70%/30% CC/CT. Escalated at inflation.**

Scenario G: **Partner in Coal Unit, Extend Contracts, Add New IC Engines, with WC Uprate**

Sunflower and KCPL contracts extended according to current terms to meet future loads in those areas.

Wolf Creek Uprate to 74 MW by 2009

Sharpe engines rated at 20MW

SWPA (100 MW) and WAPA (13.4 to 12.5 MW) hydro allocations though 2040

Partner in Baseload Coal Unit - 50 MW by 2010

Coal energy to be used in Westar area.

Build new IC Engines: 20 MW by 2010 (10 engines @ 2 MW each)

Westar area supply contract renegotiated for partial requirements above available self-owned resources in the area:

- **Energy pricing equal to "On-Peak Market Energy" price as assumed in other cases.**
- **Monthly demand charge calculated based on capital costs of new combined cycle and combustion Turbines, weighted 70% - 30% CC/CT. Escalated at inflation.**
- **Demand charge applied to monthly peak demand in Westar area less the available capacity from Wolf Creek/coal unit/WAPA/SWlPA/Sharpe.**
- **Fixed O&M charge also calculated based on cost for new combined cycles and combustion turbines, weighted 70% - 30% CC/CT. Escalated at inflation.**

Note: All scenarios included Market Purchases as needed.

Table III-4
Definition of Resource Scenarios

Partner/Own & Contract Extension Scenarios

Scenario H: **Partner in Coal Unit, Extend Contracts as Required, Add New IC Engines, with WC Uprate**
Wolf Creek Uprate to 74 MW by 2009
Sharpe engines rated at 20MW
SWPA (100 MW) and WAPA (13.4 to 12.5 MW) hydro allocations though 2040
Partner in Baseload Coal Unit - 100 MW by 2010
Coal energy to be used in Westar area and for baseload requirements in Sunflower area.
Build new IC Engines:
KCPL contracts extended according to current terms to meet future loads in those areas.
Sunflower area supply contract renegotiated for partial requirements.
Westar area supply contract renegotiated for partial requirements above available self-owned resources in the area:

- **Energy pricing equal to "On-Peak Market Energy" price as assumed in other cases.**
- **Monthly demand charge calculated based on capital costs of new combined cycle and combustion turbines, weighted 70%/30% CC/CT. Escalated at inflation.**
- **Demand charge applied to monthly peak demand in Westar area less the available capacity from Wolf Creek/coal unit/WAPA/SWPA/Sharpe plus new IC Engines.**
- **Fixed O&M charge also calculated based on cost for new combined cycles and combustion turbines, weighted 70%/30% CC/CT. Escalated at inflation.**

Scenario I: **Partner in Coal Unit, Extend Contracts, Add New IC Engines, with WC Uprate**
Wolf Creek Uprate to 74 MW by 2009
Sharpe engines rated at 20MW
SWPA (100 MW) and WAPA (13.4 to 12.5 MW) hydro allocations though 2040
Partner in Baseload Coal Unit - 100 MW by 2010
Coal energy to be used in Westar area and for baseload requirements in Sunflower area.
Build new IC Engines:
Sunflower area power requirements supplied by new Baseload Coal Unit and IC Engines.
Westar area supply contract renegotiated for partial requirements above available self-owned resources in the area:

- **Energy pricing equal to "On-Peak Market Energy" price as assumed in other cases.**
- **Monthly demand charge calculated based on capital costs of new combined cycle and combustion turbines, weighted 70%/30% CC/CT. Escalated at inflation.**
- **Demand charge applied to monthly peak demand in Westar area less the available capacity from Wolf Creek/coal unit/WAPA/SWPA/Sharpe.**
- **Fixed O&M charge also calculated based on cost for new combined cycles and combustion turbines, weighted 70%/30% CC/CT. Escalated at inflation.**

Note: ***All scenarios included Market Purchases as needed***

Key Assumptions

Every forward-looking planning study contains a number of key variables such that the assumed future values of these variables have significant impact upon Study results. Listed below are key variables that were explicitly incorporated into the quantitative analysis performed in this Study. These variables are as follows:

- Natural gas price
- Coal price (assumed Powder River Basin, PRB coal would be used)
- Fuel oil No.2 price
- Electric power market prices
- Unit operating parameters and fixed and variable costs for generation technologies, including: coal, combined-cycle, simple-cycle combustion turbines, high efficiency combustion turbines, and internal combustion engines

Regarding these key variables, the specific assumptions used in this Study are presented in Table III-5 through III-6 and Figures III-1 and III-2. Noteworthy assumptions include:

- Natural gas prices are projected to remain high and increase throughout the planning period. By the year 2025, natural gas (including transportation) is projected to increase to approximately $10.00 per mmBtu.

- Coal prices are based on the assumption that PRB coal would be used as fuel for new baseload coal units. Coal prices are projected to increase throughout the planning period reaching approximately $1.60 per mmBtu by 2025.

- Fuel oil No.2 prices are projected to increase throughout the planning period though at a rate slightly less than that of natural gas. By the year 2025, fuel oil No.2 is projected to be $8.60 per mmBtu.

- Electric power market prices for on-peak and off-peak periods were projected for the planning period. By the year 2025, it is estimated that average on-peak prices could reach approximately $100.00 per MWh. By the same year, it is estimated that average off-peak market prices could reach $69.00 per MWh. It must be noted that considerable uncertainty currently exists regarding the long-term, steady-state operating conditions within the SPP regional transmission organization (RTO). Many operational issues remain to be worked out and thus any projections of long-term power market prices must be considered as relatively uncertain.

Estimates for new generating resources were developed using Burns & McDonnell's in house project pricing for coal and natural gas fired resources. Alternative resources such as wind, solar and other biomass fueled options were priced using data from public sources. The results of the screening of potential resource options are included in the Appendix.

Table III-5
Fuel Price Forecasts

Year	Henry Hub ($/MMBtu)	Gas Trans. ($/MMBtu)	Natural Gas Forecast ($/MMBtu)	PRB Coal, Minemouth ($/MMBtu)	PRB Coal Transportation ($/MMBtu)	Coal Forecast	Fuel Oil #2 ($/MMBtu)
2005	4.71	0.41	5.12	0.39	0.58	0.96	5.26
2010	5.60	0.46	6.06	0.44	0.65	1.10	5.95
2015	6.66	0.52	7.18	0.51	0.74	1.25	6.73
2020	7.92	0.59	8.51	0.58	0.84	1.42	7.61
2025	9.42	0.67	10.09	0.67	0.95	1.61	8.61
2030	11.20	0.76	11.96	0.77	1.07	1.83	9.75
2035	13.31	0.86	14.17	0.88	1.21	2.09	11.03
2040	15.83	0.97	16.80	1.01	1.37	2.38	12.48

Reference: DOE/EIA, NYMEX

Figure III-2
Fuel Price Forecasts

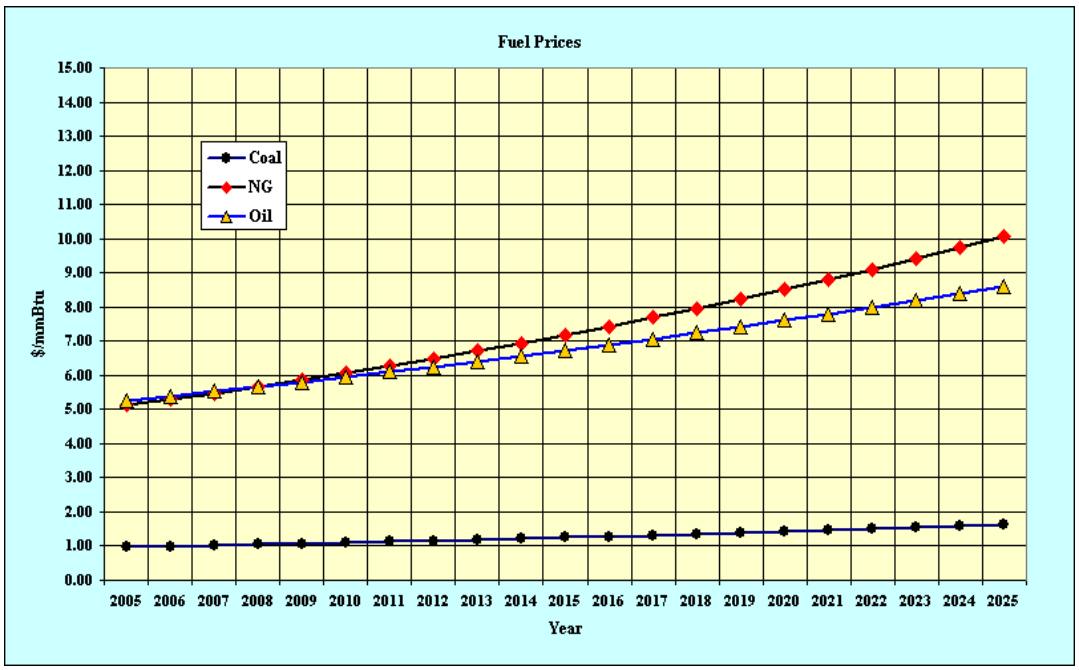


Table III-6
Regional Power Market Price Forecast

Year	Off-Peak Maximum Annual Prices $/MWh	Off-Peak Average Annual Prices $/MWh	On-Peak Maximum Annual Prices $/MWh	On-Peak Average Annual Prices $/MWh
2005	37.38	27.05	56.97	43.98
2010	44.84	35.06	71.01	56.20
2015	53.07	41.53	86.87	66.96
2020	64.87	51.26	115.33	80.81
2025	83.11	68.95	150.47	100.15
2030	98.66	82.84	183.73	118.12
2035	117.39	100.80	217.07	139.22
2040	139.17	119.51	257.33	165.06
2005-2025	4.08%	4.79%	4.98%	4.20%
2025-2040	3.50%	3.74%	3.64%	3.39%
2005-2040	3.83%	4.34%	4.40%	3.85%

Source: Henwood, EMSS Model

Regional Power Projects
Coal Projects

As part of this analysis, Burns & McDonnell researched available public data as well as internal company studies to identify potential regional baseload coal projects that may represent partnering opportunities for KEPCo. Table III-7 summarizes the projects identified. Based on information available at the time of the Phase I Study, the following points are noted:

- Sand Sage was reported to have the necessary permits to begin construction. This unit is being considered for the existing Holcomb Power Plant site. However, the unit is still seeking subscribers. If built, the unit would be close to various KEPCo members. The unit would represent a relatively low fuel price risk. Transmission represents an issue and would have to be studied in more detail. The success of this project meeting its announced on line date of 2008 is considered by Burns & McDonnell to be unlikely.

- Weston Bend 1 (subsequently referred to as Iatan Unit 2) is reported to be in the planning and permitting stage. This project is located on the Missouri River near Weston, Missouri. This project was still seeking subscribers. If built, the project would be close to various KEPCo high growth load centers. The project would represent a relatively low fuel price risk. Transmission represents an issue and would have to be studied in more detail.

- Atchison represented a possible alternative to Weston Bend 1. It is not anticipated that Great Plains Power would build both Weston Bend 1 and Atchison.

- Hugo 2, Choctow County, Oklahoma was reported to Burns & McDonnell by Western Farmers Electric Cooperative. This project received Board approval and is in the permitting stage. The project is essentially fully subscribed with Western Farmers and Brazos Electric. Given its location in southern Oklahoma, transmission represents a significant issue and would have to be studied in more detail.

- Nebraska City 2 was reported to be in the planning and permitting stage. This project was reported to be fully subscribed and was not considered further.

- NPPD “New Coal” was reported in the literature though it was not clear at what stage this project is in. This project probably represents the Whelan Plant being considered for an in service date of 2012. If built, the project would be relatively close to various KEPCo high growth load centers. If built, the project would represent a relatively low fuel price risk. Transmission represents an issue and would have to be studied in more detail.

- Council Bluffs Energy Center is under construction. This project is fully subscribed and was not considered further.

- Las Animas in Bent County, Colorado was reported in the literature though it was not clear at what stage the project is in. This project was still seeking subscribers. If built, the project would have to be delivered through an HVDC station into Kansas since it is located on the

western interconnection, in order to serve KEPCo members. The project would represent a relatively low fuel price risk. Transmission represents an issue since the majority of KEPCo's load is on the east side of the state and would have to be studied in more detail.

Table III-7
Regional Coal Projects

Baseload Coal Projects							Project Attributes			
Company Name	Plant Name	Plant City	Plant State	Plant County	Planned On-line Timing	Summer Capacity	Operational Likelihood	Available Capacity	On-line Timing	Fuel Price Risk
Sand Sage Power (Sunflower, DTE)	Sand Sage	Garden City	KS	Finney	2007	600	Permitting, EPC	YES	2009	LOW
Western Farmers Electric Cooperative	Hugo 2	Hugo	OK	Choctaw	2009	600	Board Approval	YES	2010	LOW
Westar	Westar has indicated the possibility of building a coal plant in Kansas.									
Great Plains Power, Inc	Weston Bend 1 OR Atchison	Weston	MO KS	Platte	2006 2010	700	Planning, Permitting	YES	2010 2010	LOW LOW
Nebraska Public Power Dist.	NPPD New Coal	Not Given	NE	N/A	2009	400			??	
Omaha Public Power Dist.	Nebraska City 2	Nebraska City	NE	Otoe	2009	600	Planning, Permitting, EPC	NO	2010	LOW
Lincoln Electric System & MidAmerican Energy Co.	Council Bluffs Energy Center	Council Bluffs	IA	Pottawattamie	2007	900	Under Construction	NO	2008	LOW

Note: Transmission constraints represent a potential issue with all resource plants studied.

Transmission matters to be analyzed in greater depth in Phase II.

Combined-Cycle Projects

Burns & McDonnell researched available public data as well as internal company studies to identify potential regional combined cycle projects that might represent partnering opportunities for KEPCo. Based on information available at the time, examples of combined-cycle projects with reasonable proximity to KEPCo load centers include:

- NPPD Combined-Cycle 230 MW, Gage County, NE
- Aries 516 MW, Cass County, MO
- Green County Energy Project 801 MW, Tulsa County, OK
- Oneta Generating Station 1,140 MW, Wagoner County, OK
- Redbud 1,200 MW, Oklahoma County, OK
- Chickasha 550 MW, Grady County, OK
- Kiamichi Energy Facility 1,126 MW, Pittsburg County, OK
- Smith Pocola Energy Project 600 MW, Le Flore County, OK

Owner Constructed Options

The cost to construct small base load power plants is at a disadvantage when compared to the economies of scale that are afforded to larger units. The economies of scale are available in the construction and, where the unit is constructed adjacent to an existing unit, potentially in the operations as well. Since KEPCo does not have any existing base load units, there are no sites under KEPCo control that might be potentials for a second unit.

One technology that may hold promise for small base load units is an integrated gasification combined cycle (IGCC) power plant. These units allow coal type fuels to be consumed in a process that cleans up the fuel prior to combustion as opposed to cleaning the exhaust stream from a coal burning plant. The gasification process produces syn gas which is then burned in a standard combustion turbine combined cycle plant. One advantage of a gasification process is its ability to reduce the carbon emissions from the facility.

The gasifiers for the units have been operated for several years in refineries and chemical production facilities. Eastman Chemicals has operated gasifiers for over twenty years and has availability results above 97 percent. The combustion turbines and combined cycle operations have high availability, proven over millions of operating hours.

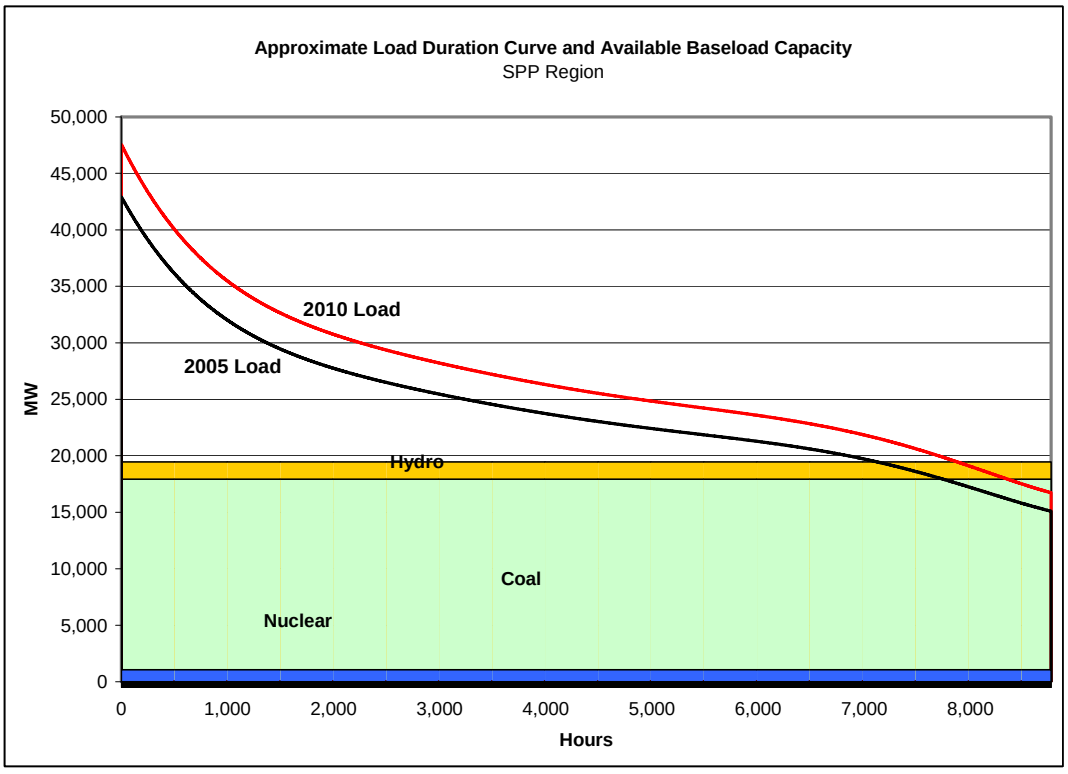
Kansas has a small gasifier operating at the Frontier Refinery in El Dorado. The refinery produces petroleum coke as a waste product and uses it as a feedstock for the gasifier. The output of the gasifier is used as the fuel supply for a 40MW combustion turbine. The process uses the Chevron/Texaco process which was recently acquired by General Electric. Capital cost estimates provided by GE for similar sized projects have not been attractive for a dedicated power project. However, should the capital cost come down on these facilities, it could be an interesting option for KEPCo to consider for the acquisition of a small coal facility.

Area Market

KEPCo serves load in the SPP market. This area is bordered on the north by the Mid-continent Area Power Pool (MAPP), on the east by the Midwest ISO, and on the southeast by the Southeastern Electric Reliability Council (SERC). The markets within and surrounding the SPP are moving to gas based resources as being the marginal unit.

According to the "2004 State of the Market Report, SPP Inc.," (Market Report) that was prepared by the Boston Pacific Company, Inc., who is the independent market monitor for the SPP, the SPP had a reserve margin of approximately 44 percent in 2004. Of the capacity operating in the SPP, almost 55 percent was natural gas fired. The load duration curve estimated for the SPP shown in Figure III-3 using North American Electric Reliability (NERC) reliability assessment data for the region, provides an indication that the energy available from base load resources in 2010 will be fully committed, moving all marginal energy to gas resources.

Figure III-3



Access to adjacent markets by certain SPP utilities is problematic for firm power supplies from outside the region. The Market Report indicated that the "Major regions of congestion during 2004 occurred westward and southward out of eastern Kansas and southward along the eastern portion of the border between Oklahoma and Texas near the edge of the ERCOT region." Even within the SPP, there are major constraints between certain control areas. KEPCo is operating with load served in the former Aquila control area through a transmission agreement with the SPP that lacks long term firm commitment.

The resources bid in the Midwest ISO market in recent power supply request for proposals managed by Burns & McDonnell have been gas based units. Firm transmission access from the Midwest ISO market to the Westar area has been represented as problematic in past KEPCo requests for power supply proposals managed by KEPCo.

The areas surrounding the KEPCo service territory have shown increased interest in coal based capacity additions. As further discussed in Part IV, there are numerous regional coal plants being considered. The on-line date for these units is planned for the 2010 to 2012 time frame and is dependent upon the successful identification of suitable partners committed to constructing the units, as they are all anticipated to have multiple participants.

The addition of the coal capacity is located primarily along the Missouri River, north of Kansas City and south of North Dakota. The ability to move additional firm bilateral contract capacity to the eastern markets is dependent on the construction of additional transmission facilities to the east. Burns & McDonnell anticipates that there will be an excess of coal energy on the market for the early part of the next decade should all of the coal plants planned be constructed. This may have an effect of reducing energy prices on the non-firm wholesale market for the area north of central Missouri and provide some benefit for the marginal price of energy in this area. Market projections used in this study are based on the addition of combined cycle facilities as the basis for bids produced in the area market.

Another factor which may have a potential to mitigate the pricing in the KEPCo region is the significant wind power potential held in western Kansas. Currently, there are several large wind farms being considered for the region. However, lack of transmission capacity is preventing the farms from begin realized. Kansas has recently created the Kansas Transmission Line Authority to act as a last resort option for funding transmission projects. If these farms are developed, they too should aid in wholesale market competition for non-firm energy.

* * * * *

Part IV

Resource Plan Evaluation

Overview

This section of the Report addresses the economic analyses and the risk analyses that were performed on the various resource plans defined in Part III of this report.

Economic Analysis

The resource scenarios were analyzed using a monthly dispatch model. The model used the economic dispatch of the resources to determine the amount of energy from each resource that would be used during the month. The monthly energy needs and peak loading were used to determine the dispatch. The model for the Long Range Plan were based on a spreadsheet model that accurately represented the various fixed costs associated with the supplier contracts. The assessment was performed on an incremental cost basis. Therefore, any cost projections indicated in the scenario analysis are net of the KEPCo costs that are common between plans.

Table IV-1 presents a summary of estimated costs for each of the resource scenarios evaluated. The costs presented in Table IV-1 represent the deterministic cost estimates for each scenario and were derived through traditional production cost simulations of each scenario. Also presented in Table IV-1 are the relative costs indices of each scenario compared to the least cost scenario.

A comparison of resource plans that did include a Wolf Creek uprate to those that did not indicated that it would be slightly more economically advantageous to uprate Wolf Creek to 74 MW with a total net addition of approximately 5MW to KEPCo. Total NPV costs without a Wolf Creek uprate were estimated to be approximately 1 percent greater than total NPV costs with a Wolf Creek uprate.

The analysis indicated that scenarios which included partnering in a new baseload coal unit (Scenarios D, E, F, G, H, I) proved to be less costly then those scenarios (Scenarios X2D, A, B, C) that did not include partnering in a baseload coal unit. As measured by the NPV of total scenario cost, Scenario H was determined to be the least costly resource option for meeting KEPCo's future load and energy requirements. Scenario H included partnering in a 100 MW baseload coal unit, building ten 2 MW IC engines, extending the KCPL contract, and renegotiating the Sunflower and Westar contracts to partial requirements.

As measured by the NPV of total scenario cost, Scenario E was determined to be the second ranked resource option. Scenario E included partnering in a 100 MW baseload coal unit. Scenario E differed from Scenario H in that Scenario E called for the building of a greater number of IC engines. Scenario E also assumed that the Westar, Sunflower and KCPL contracts

would expire after 2009. As shown in Table IV-1, the 35-year NPV for Scenario E was within 1% of the 35-year NPV for Scenario H, thus making these two scenarios essentially equivalent.

As measured by the NPV of total scenario cost, Scenario I was determined to be the third cost ranked resource option. Scenario I differed from Scenario H in that Scenario I called for a greater number of IC engines to be built. Scenario I also assumed that the Sunflower area power requirements would be supplied by new a baseload coal unit and also by IC engines. In contrast, Scenario H assumed that the Sunflower area supply contract would be renegotiated for partial requirements. As shown in Table IV-1, the 35-year NPV for Scenario I was within 4% of the 35-year NPV for Scenario H.

As shown in Table IV-1, Scenarios X2D and Scenarios A, B, and C were all within 4% of each other. These results reflect Burns & McDonnell's expectation it is likely that as Westar's native load increases, less and less cheaper power would be available for KEPCo and that Westar's future costs would increasingly reflect the marginal cost of new combined-cycle or CT units.

Table IV-2 provides further cost detail for resource scenarios A through I. Presented therein are the estimated fixed and variable costs for each scenario. Generally, those scenarios that had relatively higher variable costs proved to be the same scenarios that produced higher overall NPV values. In terms of average total costs, Scenario H resulted in costs that ranged from approximately $30.42 per MWh in 2006 to $48.06 per MWh by 2025. Scenario E resulted in costs that ranged from $30.42 per MWH in 2006 to $49.03 per MWh by 2025. Finally, Scenario I resulted in costs that ranged from $30.42 per MWH in 2006 to $50.96 per MWh by 2025.

Table IV-1
Summary of Costs by Resource Scenario
(Deterministic Cost Results)

	Resource Scenario Sorted by Costs	Deterministic Cost Estimates 35-Year NPV 2005 $x1000	Relative Costs Index
H	Partner Coal (100) + IC Engines, Contracts (PR)	$709,676	1.000
E	Partner Coal (100) + IC Engines	$710,726	1.001
I	Partner Coal (100) + IC Engines, Contracts (PR)	$736,524	1.038
D	Partner Coal (100) + CTs	$748,840	1.055
G	Partner Coal (50) + IC Engines, Contracts (PR)	$756,125	1.065
F	Partner Coal (50) + Contracts (PR)	$768,516	1.083
X2D	Extend Contracts @ 6.5% Max Escalation	$813,063	1.146
C	High Efficiency CTs + Peaking CTs (NG)	$816,897	1.151
A	All New CTs (NG)	$831,575	1.172
B	Combined-Cycle + CTs (NG)	$842,977	1.188

Note: **All resource plans include the Wolf Creek uprate to 74 MW by 2009**

Table IV-2
Cost Components by Resource Scenario
(Deterministic Cost Results)

		Period	Scenario A	Scenario B	Scenario C	Scenario D	Scenario E	Scenario F	Scenario G	Scenario H	Scenario I
35-Year NPV	2005 $x1000		$831,575	$842,977	$816,897	$748,840	$710,726	$768,516	$756,125	$709,676	$736,524
Energy / Variable Costs	$x1000	2006-2040	$3,420,851	$3,514,841	$3,330,322	$2,209,586	$2,209,586	$2,879,207	$2,787,746	$2,211,987	$2,455,902
Demand / Fixed Costs	$x1000	2006-2040	$1,441,091	$1,411,107	$1,358,737	$1,829,644	$1,650,195	$1,547,372	$1,511,971	$1,667,016	$1,616,005
Total Variable & Fixed Costs	$x1000	2006-2040	$4,865,542	$4,929,549	$4,692,660	$4,042,831	$3,863,382	$4,430,180	$4,303,317	$3,882,603	$4,075,509
Energy / Variable Costs	$ / mWh	2006-2040	$46.16	$47.42	$44.93	$29.81	$29.81	$39.17	$37.92	$30.08	$33.42
Demand / Fixed Costs	$ / mWh	2006-2040	$19.44	$19.04	$18.33	$24.69	$22.27	$21.05	$20.57	$22.67	$21.99
Total Variable & Fixed Costs	$ / mWh	2006-2040	$65.65	$66.51	$63.32	$54.55	$52.13	$60.26	$58.54	$52.81	$55.46
			Total Average Cost								
			$/mWh	$/mWh	$/mWh	$/mWh	$/mWh	$/mWh	$/mWh	$/mWh	$/mWh
		2006	$30.42	$30.42	$30.42	$30.42	$30.42	$30.42	$30.42	$30.42	$30.42
		2010	$33.79	$34.95	$34.00	$32.36	$29.96	$31.55	$34.52	$35.68	$36.61
		2015	$41.05	$41.16	$40.05	$37.52	$35.03	$37.63	$36.81	$34.56	$36.22
		2020	$49.12	$50.44	$48.07	$43.15	$40.67	$45.85	$44.56	$40.20	$42.48
		2025	$61.77	$62.67	$60.59	$51.11	$49.03	$56.60	$54.67	$48.06	$50.96
		2030	$75.50	$75.05	$72.37	$62.27	$58.86	$69.97	$67.58	$59.00	$62.81
		2035	$93.52	$96.04	$89.99	$74.57	$71.98	$86.28	$83.39	$73.42	$77.81
		2040	$113.25	$114.37	$107.00	$88.41	$86.81	$105.60	$102.03	$90.91	$96.12

Risk Analysis

A probabilistic risk model was constructed whereby probability distributions for the cost drivers were used to estimate the probability distribution of the NPV of each scenario's total costs. This analysis was undertaken as a companion analysis to the deterministic analysis discussed previously. The dispatch model constructed for the Long Range Plan used spreadsheet software as a basis. The use of a spreadsheet based program allowed use of an add on probabilistic software module to create a variety of futures for the scenarios. This allowed rapid assessment of the various scenarios using the distribution profiles of the cost of various assumptions.

Table IV-3 and Figures IV-1, IV-2 and IV-3 present estimated costs for each scenario based on a probabilistic risk assessment of key cost drivers, including capital costs, fuel prices and inflation rates. When reviewing these figures, a curve farther to the left, with a narrow distribution is more favorable than a curve further to the right with a wider distribution of net present values. The probability distributions for the input variables are provided on the accompanying CD in the dispatch models. Burns & McDonnell believes that this probabilistic approach represented a concise way to judge the risks associated with each possible course of action. The results of this risk assessment can be summarized as follows:

- A comparison of Table IV-1 and Table IV-3 shows that the probabilistic risk assessment resulted in the same relative cost ranking of the resource scenarios studied as was produced by the deterministic approach. Those scenarios that include partnering in a coal project had lower "most likely" NPV costs than those scenarios that did not include such a baseload partnering strategy.

- As determined by the probabilistic risk assessment, Scenario H again proved to be the least costly strategy.

- As measured by the "cost spread" of the NPV probability distributions, those scenarios that included partnering in a baseload coal resource represented strategies that had lower "downside" cost risk than those strategies that did not include partnering in a coal unit. The relative "Risk Index" ranged from 1.00 for Scenario H to 2.06 for Scenario B, with a higher number indicative of increased risk that the scenario costs would exceed the projected values.

- Figure IV-4 presents graphically the probabilistic cost results for Scenarios A, B, C, D, E, F, G, H, and I. As shown in this figure, the mean of the expected NPV values of Scenarios H, E, and I, all of which include a coal partnering option, was less than the expected means of the NPV values of Scenarios A, B, and C which do not include a coal partnering option. Also, as can be seen, the cost spreads, or "upside" cost exposures for Scenarios A, B, and C were determined to be considerably greater than the "upside" cost exposures for Scenarios H, E, and I.

- Figure IV-2 provides a comparison of the contract extension scenario X2D with Scenarios A, B, and C. Scenarios A, B, and C can be regarded as representative of the future marginal

cost of generation. As can be see, the most likely contract extension scenario, Scenario X2D moves toward these marginal generation costs and exhibits similar "upside" cost exposure.

- Figure IV-3 provides a comparison of the contract extension Scenario X2D with Scenarios H, E, and I. Scenarios H, E, and I all include partnering in a coal resource project. As can be see, the most likely contract extension scenario, Scenario X2D, produced a higher expected value of NPV than Scenario H, E, or I. Also, it can be seen that the "upside" cost exposure for Scenario X2D, as seen by the spread of its probability distribution curve, was considerably greater than either Scenarios H, E, or I, all of which had relatively tight spreads in their probability distribution curves.

Table IV-3
Summary of Costs by Resource Scenario
(Probabilistic Results)

			Probabilistic Cost Estimates Expected Value (A)		"Downside" Cost Exposure 25% Chance that Scenario Costs will Exceed NPV$ Values Listed Below (B)	Cost "Spread" (B) - (A)	Risk Index
Scenarios by Order of Evaluation			35-Year NPV 2005 $x1000		35-Year NPV 2005 $x1000	35-Year NPV 2005 $x1000	
X2A	Extend Contracts @ Historical Escalation With WC Uprate		$735,432		$758,136	$22,704	0.90
X2B	Extend Contracts @ 4.5% Max Escalation - With WC Uprate		$761,590		$790,681	$29,091	1.16
X2C	Extend Contracts @ 5.5% Max Escalation - With WC Uprate		$787,836		$827,806	$39,970	1.59
X2D	Extend Contracts @ 6.5% Max Escalation - With WC Uprate		$818,083		$872,946	$54,863	2.19
A	All New CTs, WC Uprate		$846,156		$898,196	$52,040	2.07
B	Combined-Cycle (100 MW) + CTs, WC Uprate		$849,132		$900,752	$51,620	2.06
C	High Efficiency CTs + Peaking CTs, WC Uprate		$821,941		$871,743	$49,802	1.98
D	Partner Coal (100 MW) + CTs, WC Uprate		$749,237		$777,956	$28,719	1.14
E	Partner Coal (100 MW) + IC Engines, WC Uprate		$711,982		$738,176	$26,194	1.04
F	Partner Coal (50 MW) + Contracts, WC Uprate		$763,392		$807,966	$44,574	1.78
G	Partner Coal (50 MW)) + IC Engines, Contracts, WC Uprate		$758,729		$790,281	$31,552	1.26
H	Partner Coal (100 MW) + Contracts, WC Uprate		$709,676		$734,770	$25,094	1.00
I	Partner Coal (100 MW) + IC Engines, Contracts, WC Uprate		$736,524		$766,092	$29,568	1.18
Scenario Costs Sorted by (A)				**Relative**		**Cost "Spread"**	**Risk**

		(A)	Costs	(B)	(B) - (A)	Index
H	Partner Coal (100) + Contracts, WC Uprate	$709,676	1.000	$734,770	$25,094	1.000
E	Partner Coal + IC Engines, WC Uprate	$711,982	1.003	$738,176	$26,194	1.044
I	Partner Coal (100) + IC Engines, Contracts, WC Uprate	$736,524	1.038	$766,092	$29,568	1.178
D	Partner Coal + CTs, WC Uprate	$749,237	1.056	$777,956	$28,719	1.144
G	Partner Coal (50) + IC Engines, Contracts, WC Uprate	$758,729	1.069	$790,281	$31,552	1.257
F	Partner Coal (50) + Contracts, WC Uprate	$763,392	1.076	$807,966	$44,574	1.776
X2D	Extend Contracts @ 6.5% Max Escalation - With WC Uprate	$818,083	1.153	$872,946	$54,863	2.186
C	High Efficiency CTs + Peaking CTs, WC Uprate	$821,941	1.158	$871,743	$49,802	1.985
A	All New CTs, WC Uprate	$846,156	1.192	$898,196	$52,040	2.074
B	Combined-Cycle + CTs, WC Uprate	$849,132	1.197	$900,752	$51,620	2.057

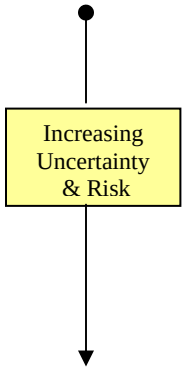


Figure IV-1
Risk Analysis Cost profiles
(Scenarios A, B, C, D, E, F, G, H, I)

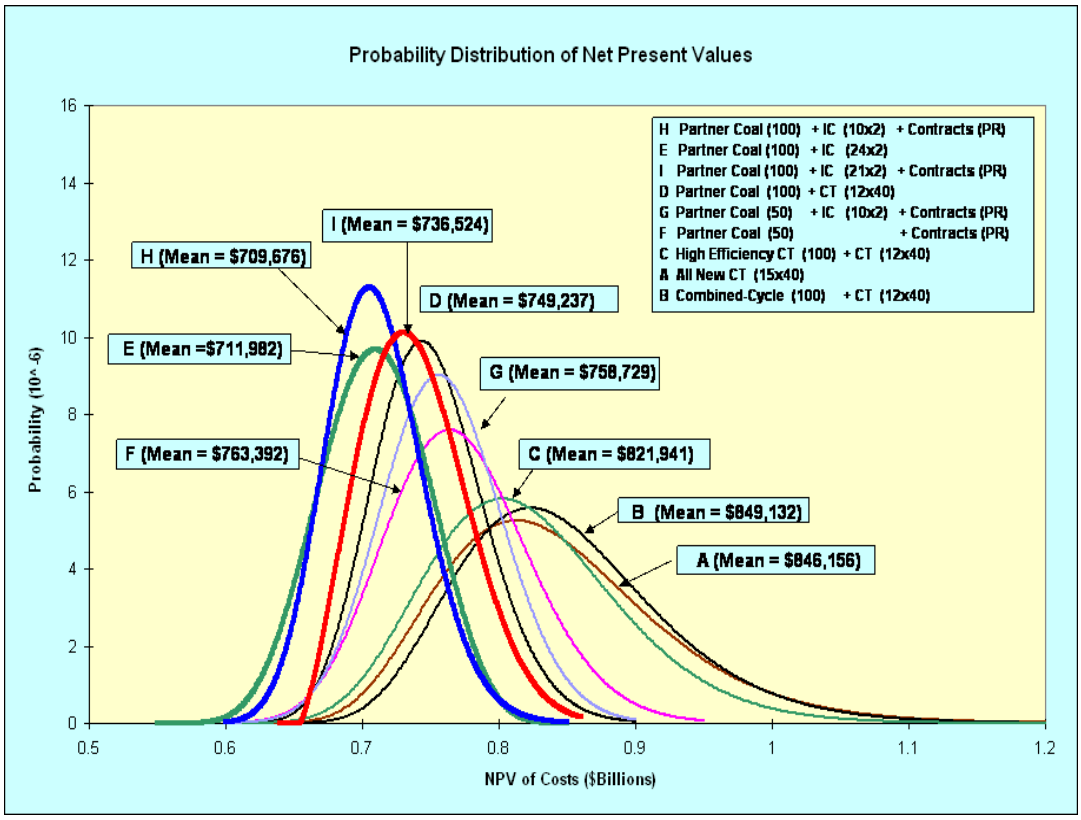


Figure IV-2
Likely Contract Extension vs.
Marginal Resource Cost
(Scenario X2D vs. A, B, C)

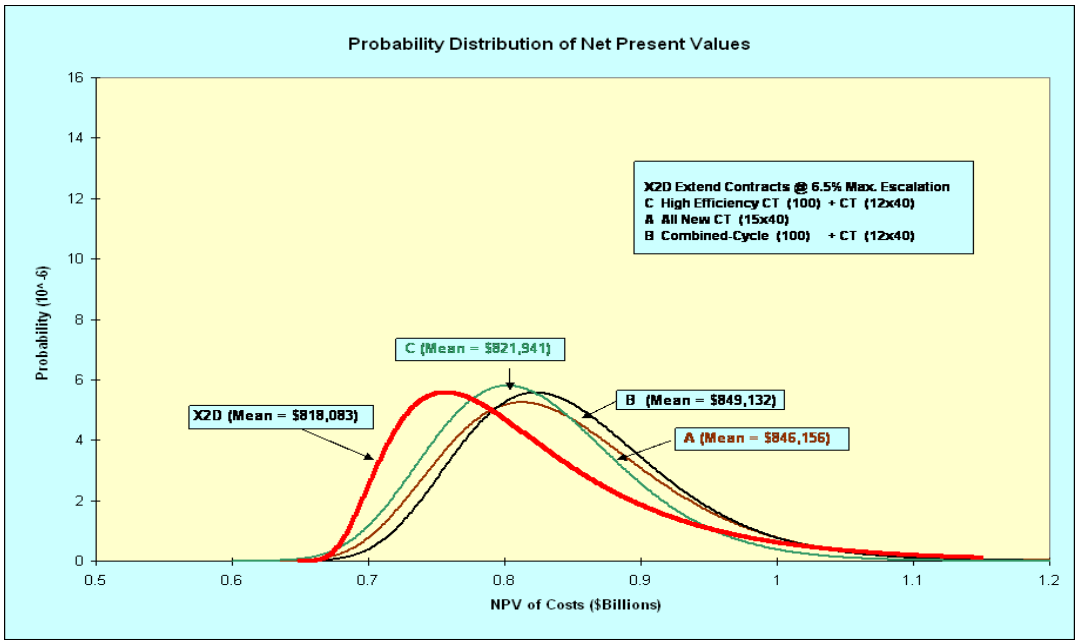
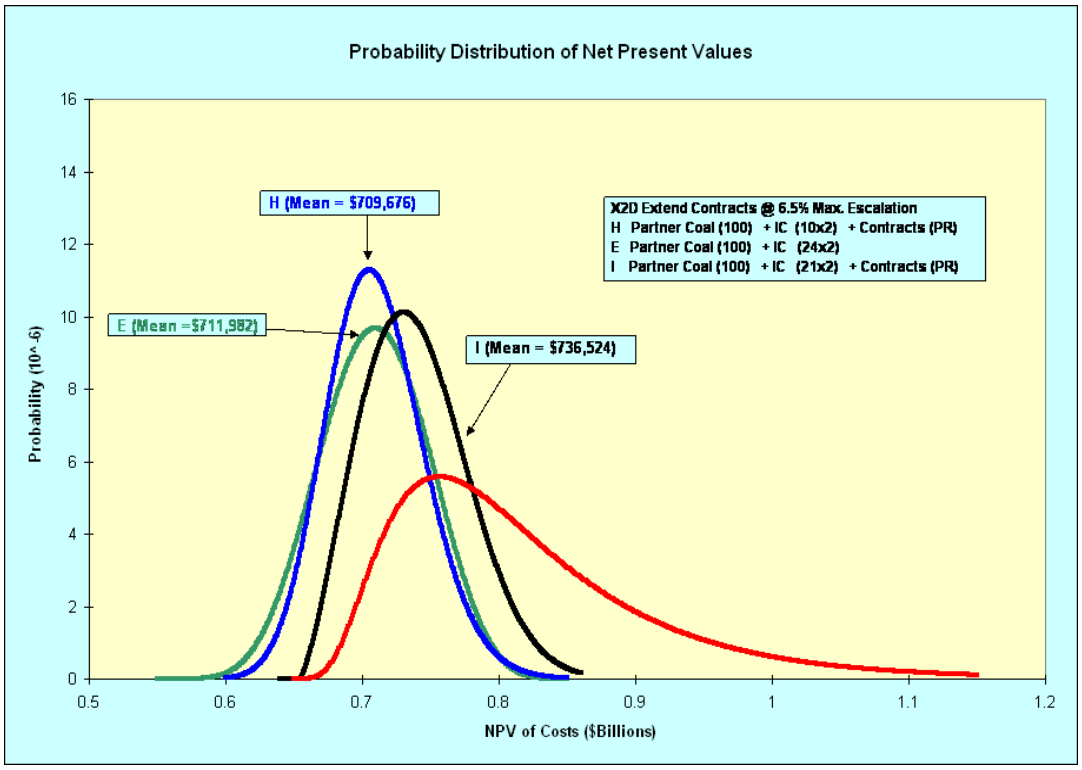


Figure IV-3
Least Cost Plans vs. Contract Extensions



CONCLUSIONS AND RECOMMENDATIONS

Based on the analyses performed and reflective of the information that was available to Burns & McDonnell at the time the analysis was performed, the following conclusions and recommendations are offered for KEPCo consideration.

Conclusions

Based on the assumptions used and the analysis performed above for the Long Range Planning Study, Burns & McDonnell offers the following conclusions:

1. A comparison of resource plans that did or did not include a Wolf Creek uprate indicated that it would be economically advantageous to uprate Wolf Creek to 74 MW. Total NPV costs without a Wolf Creek uprate were estimated to be approximately 1 percent greater than total NPV costs with a Wolf Creek uprate.

2. All scenarios that included partnering in a new baseload coal unit (Scenarios D, E, F, G, H, I) proved to be less costly then those scenarios (Scenarios X2D, A, B, C) that did not include partnering in a baseload coal unit.

3. As measured by the NPV of total scenario cost, Scenario H was determined to be the least costly resource option for meeting KEPCo's future load and energy requirements. Scenario H included partnering in a 100 MW baseload coal unit, building ten 2 MW IC engines, extending the KCPL contract, and renegotiating the Sunflower and Westar contracts to partial requirements.

4. The probabilistic risk assessment resulted in the same relative cost ranking of the resource scenarios studied as was produced by the deterministic approach. Those scenarios that include partnering in a coal project had lower "most likely" NPV costs than those scenarios that did not include such a baseload partnering strategy.

5. As determined by the probabilistic risk assessment, Scenario H again proved to be the least costly strategy.

6. As measured by the "cost spread" of the NPV probability distributions, those scenarios that included partnering in a baseload coal resource represented strategies that had lower "downside" cost risk than those strategies that did not include partnering in a coal unit.

Recommendations

Based on the study performed for this Long Range Resource Plan, Burns & McDonnell offers the following recommendations for KEPCo's consideration in the development of a resource plan strategy for the long term. Burns & McDonnell is of the opinion that:

1. KEPCo should pursue the Wolf Creek uprate

2. KEPCo should continue discussion with current suppliers using the above analysis as a guide to terms for renegotiating the existing contracts,

3. KEPCo should enter into definitive discussions with developers of area coal plants for specific terms, in-service schedules, etc.

4. Based on coal participation options, KEPCo should assess the benefits of smaller, staggered amounts of baseload capacity to be brought into the resource mix.

5. Based on the development of area markets, the contract terms available for purchase power contracts and the growth of the KEPCo system, KEPCo should reassess the value of adding small peaking units to replace a portion of the fixed capacity cost of the contracts. Since these units can be brought on line within approximately 24 months of deciding to move ahead, assessment of these units should be ongoing as market conditions change.

6. KEPCo should continuously update key assumptions to reflect latest cost and market conditions and improvements in the transmission capacity.

* * * * *

Part V

Construction Work Plan Analysis

The analyses performed in Parts II through IV constitute an evaluation of several long range resource scenarios which may be of benefit to KEPCo. Through the deterministic and probabilistic review, the analyses identified the use of coal energy as a low cost option in meeting future KEPCo load requirements when compared to the assumptions used for ongoing purchases from the market.

This part of the report provides the analyses required for development of a Generation Construction Work Plan to meet the requirements of the Rural Utilities Service (RUS) 7CFR1710 Subpart F. Information received on specific regional coal projects in which KEPCo could potentially invest are discussed. Also, the process and results of a Request for Power Supply proposals are included.

Potential Base Load Resource Options

The analysis performed in Part IV indicated that the addition of 100MW of base load energy to the KEPCo system, used in conjunction with additional peaking resources and market based partial requirements contracts, would be beneficial compared to other alternatives. The acquisition of the 100MW could be scheduled in amount and date acquired to take advantage of potential investment in multiple projects. The investment in multiple projects would also allow reduced risk since the capacity would be spread across multiple units.

Two reliability considerations are of major importance with the acquisition of new capacity. The first is the expected success of the project being developed to come on line in the time frame being considered. The delay of the project can expose a utility to increasing energy costs from its alternate sources, diminishing and delaying the benefits the project was to provide. The value lost from the delay in benefits cannot be made up when the unit finally comes on line. Therefore, it is important that projects selected have a high degree of potential success. Since KEPCo is not large enough to drive a project, it will have to select projects which are far along in the development process and have a high likely hood of being constructed on the time line considered. Due to the difficulties many base load projects have in the permitting process, success of project development can be a major concern in having the energy available when needed.

The second risk is to spread the “shaft” risk over multiple units. Utilities are exposed to increasing costs to replace energy due to outages of base load capacity. Should the outage occur at peak times, these replacement energy costs can be significant. Therefore, utilities are becoming more concerned with the size of any single unit in relation to the amount of replacement energy needed and the potential sources for the replacement energy. For KEPCo, the replacement energy would likely come from the spot market. In general, spreading the

energy needs over multiple unit shafts will help reduce the exposure to increased replacement energy costs during an outage.

The Midwest area has several coal unit projects which are in various stages of development. Numerous projects were identified in Part III. Of the projects identified, the following projects were considered as being most likely for consideration of KEPCo participation:

- Iatan Unit 2 being developed by KCPL
- Nearman Unit 2 being developed by Kansas City, Kansas Board of Public Utilities
- Hugo Unit 2 being developed by Western Farmers
- Sand Sage (Second unit at the Holcomb Plant) being developed by Sunflower Electric

A request for information letter was developed and mailed to the above utilities in order to ascertain the status of the projects and details about the financial aspects of acquiring capacity in the units.

In addition to these projects, consideration was also given to the development of a small integrated gasification combined cycle project in KEPCo's service territory.

Iatan Unit 2

The Iatan Unit 2 is a second unit pulverized coal unit being developed by KCPL. The plant is located just across the Missouri River from Kansas near Weston, Missouri. The unit is being sized to approximately 850MW. Participants in the plant include KCPL, Missouri Joint Municipal Electric Utility Commission, and Aquila. The project has filed for the necessary permits to allow construction of the resource. In addition, the project is moving through the regulatory approval process in Kansas and Missouri. The state of Kansas issued its stipulation order on April 27, 2005 approving the KCPL resource plan, of which Iatan 2 is a part. Missouri has provided similar approval to the resource plan in July 2005. (See Appendix __.)

A part of the KCPL resource plan includes the acquisition of 100MW of wind power with a potential for a second 100MW acquisition. The development of wind in Kansas requires the addition of transmission facilities to deliver the wind to utilities to the east, such as KCPL. There may be some potential to use participation by KEPCo in the Iatan project in the minimization of the transmission system development due to the counter flow nature of the wind from the west and the Iatan energy from the east.

KCPL provided information for evaluation purposes, including estimated financial parameters for capital, fuel, fixed and variable operations and maintenance. KCPL is scheduling the unit for an in service date of 2010.

Transmission studies for the project have been filed with the Southwest Power Pool for the KCPL portion of the capacity. KEPCo has filed for studies with the SPP on a 50W portion of the facility.

The Iatan 2 unit was considered as a likely option for consideration as a base load resource due to its development status. Discussions with KCPL indicated that there was an opportunity for KEPCo to acquire a 50 to 100MW portion of the facility. Subsequent discussions with KCPL have limited KEPCo's participation to a 30MW level.

Nearman 2

The Kansas City, Kansas Board of Public Utilities has been considering the addition of a second coal-fired unit at their Nearman site. The site would support the addition of an approximately 250 to 400MW unit. The unit would be a pulverized coal facility using western coal. Discussions were held with KCKBPU to determine the current status of the project and its anticipated schedule.

The unit is still under investigation by KCKBPU. No definitive schedule has been established for development of the unit. The analysis of the facility is currently in the feasibility stage and no development engineering has been started on the facility. Permitting and transmission studies for the facility have not been started. Due to the status of the facility, there are more attractive alternatives for the near term unit. However, the unit could be considered for a potential future amount of base load energy.

Hugo Unit 2

Western Farmers and Brazos Electric are developing a coal-fired unit on an existing site in Hugo, Oklahoma. The unit is a 750MW pulverized coal facility, using western coal. The unit is in the advanced stages of development. Prevention of Significant Deterioration (PSD) permitting has been started. The selection of an EIS third party contractor to perform the EIS is underway. It is expected that the permits will be issued in early 2006.

Due to the location of the Hugo station with regard to KEPCo's service territory, transmission delivery is considered to be a significant problem for KEPCo participation in this unit. Therefore, the unit was not considered as a realistic candidate.

Sand Sage

The Sand Sage unit is being developed by Sunflower Electric Cooperative and DTE Energy. It is proposed as a second unit to the Holcomb site. The unit has its necessary permits, water rights and other approvals necessary for construction. The permits were first received in the fall of 2002 and have been extended to allow construction to begin as late as December 2005.

A financial proposal was received from Sand Sage Power, LLC to provide a fifteen year contract for power from the facility. The offer was structured as a power purchase agreement. However, under the proposal, KEPCo would be charged as if it was an owner in the facility. Therefore, the charges would be cost based during the term of the agreement.

The Sand Sage unit would be located on the site of the existing Holcomb unit located near Holcomb, Kansas. Consideration has been given to selling the capacity from the unit into the electric market in the western interconnects. This approach would require the unit output to be electrically tied to the western interconnect with an HVDC connection to the eastern interconnect (where KEPCo is located.

There is currently no commitment for the majority of the output from the Sand Sage facility to any purchaser. Without the output committed to entities that are able to finance their purchase, it is difficult to provide any definitive in service date for the unit. Sand Sage Power LLC has indicated that an in service date of 2008 is projected. However, the construction time for the unit is estimated to be 43 months. Therefore, it is doubtful that the unit will be constructed on that schedule. Based on the unit's location and its access to markets, it is not considered probable that the unit will be subscribed to allow construction and connection to the eastern interconnects in the near term. The unit may be considered for future capacity needs should it be able to deliver into the eastern interconnect.

Recently, Tri State G&T, located in Denver, Colorado, announced that they were going to construct two 600MW units at the Holcomb site. These units well be tied directly to the western interconnect and not be able to sell energy into the eastern interconnect. Therefore, these units are of no potential benefit to KEPCo.

Existing Coal Unit

Westar offered KEPCo the opportunity to purchase up to 60MW from the Existing Coal Unit. The Existing Coal Unit is a coal fired facility located in St. Mary's, Kansas, just west of Topeka. There are three units with a total nominal net rating of approximately 2400MW. The 60MW would be spread across three of the units, with essentially 20MW coming from each of three shafts. This would provide improved reliability when compared to a project where more capacity was taken from a single shaft. The Existing Coal Unit units were brought on line in 1978, 1979 and 1983. This makes the newest unit at the site 22 years old.

Small Integrated Gasification Combined Cycle

The interest in IGCC plants is increasing as more stringent environmental requirements are placed on new coal facilities. There is an existing nominal 40MW project operating in the Frontier Refinery in El Dorado, Kansas. The unit operates on petroleum coke waste that is produced by the refinery. The coke is gasified to produce synthetic gas which is then burned in a 40MW combustion turbine to produce power for the refinery. Discussions with the refinery indicated that the operation was reliable and was able to be operated with the existing refinery staff. Refinery personnel indicated that there was sufficient petroleum coke to support an additional gasifier train. The location of the refinery, just east of Wichita, is in KEPCo's service territory and would be a good location for generation to serve KEPCo.

The refinery project was constructed and modified over time to remove some of the operational problems. Therefore, capital cost estimates were not easily taken from what the refinery unit

was built for versus what a new project would cost. Capital cost estimates were obtained from General Electric, who purchased the Chevron/Texaco gasifier technology. Preliminary estimates for a small gasifier were in the thousands of dollars per kW. The capital cost from General Electric was too great for the low cost fuel and operations and maintenance from the refinery to offset. Due to the high capital cost estimates, no further assessment of this option was considered.

Although this technology may not be economically attractive at the current time, the ability to sequester carbon and other advantages to emissions clean up may make it more attractive in the future. Ongoing discussions with the refinery may uncover another approach to constructing the unit that would reduce the construction cost to a more reasonable level.

Peaking and Intermediate Options

The analysis in Part IV indicates a need for peaking options and that owner built engines were the lower cost alternative. Although engine sets were shown to be the lower cost option, continual comparison to market capacity should be made prior to the installation of engines. In many wholesale markets, the value of capacity has declined to the point that it is much lower cost to acquire such capacity from the market. This is particularly true in the markets such as the Midwest ISO and SERC where combustion turbines have been installed beyond what is required to have adequate reserve margins. The current reserve margin in the SPP would tend to support low capacity values in the region also.

The value of the engines lies in reducing the fixed costs of purchase power contracts and the ability to schedule low cost non-firm energy against the facilities. The current projections of coal plant development may support this type of arrangement. If the area utilities construct significant coal based capacity to compete in the market, then KEPCo could see installation of the engine sets or other lower cost capacity options as a way to reduce its average energy cost.

The acquisition of this type of capacity has a much shorter time frame than base load capacity. Siting and permitting is much easier. These types of units could be installed in 24 months. Therefore, it is necessary for KEPCo to monitor the capacity market and its load forecast to determine when additional capacity should come from units constructed by KEPCo versus being acquired from the market.

Request for Power Supply Proposals

In order to comply with the Rural Utilities Services' requirements, a request for power supply proposals (RFP) was developed. The RFP requested base load and peaking capacity and energy options in minimum 25MW amounts for terms of 15 years minimum.

Development

The RFP was developed to allow a variety of options to be proposed. These would include contract and ownership type offers. The RFP required delivery of the capacity and energy to the KEPCo service territory connections with the control area providers, Westar, KCPL and Aquila.

The SPP is gaining regional transmission operator status. However, the market will still operate as a traditional wholesale market. It is not known when or if the market will move towards operation under the standard market design type of market.

Process

The RFP was posted on a project web site where prospective bidders could download it. The website was included in the ads placed in Power Marketer's Week and MegaWatt Daily. The ads were placed in the publications for one week between October 28, 2004 and November 2, 2004. Copies of the RFP and ad are included in Appendix D. In addition to the advertisements, the RFP was emailed directly to 64 firms that were either a utility, developer or power marketer.

Results

There were four notices of intent to bid received. However, there were no subsequent proposals received. Inquiries made to the prospective bidders revealed several concerns. Several prospective bidders were concerned about the inability to have transmission capacity to deliver the capacity and energy. The lack of transmission capacity had been evaluated on previous bids and it was found that firm transmission was unavailable with the existing system.

Also, the bidders were unsure about the upcoming Midwest ISO market modifications expected to take effect on March 1, 2005 (actually took effect on April 1, 2005) and how they would affect the long term value of capacity and energy. Concern was also expressed about the recent RFP issued by KEPCo for short term supply with no purchases taken from the market.

After the inquiries, several proposers indicated that they would be interested in submitting a proposal after the fact. However, no proposals were received from these solicitations either. The results of this RFP indicate the lack of a robust wholesale power market in the SPP area and Kansas in particular due to its transmission limitations and other market uncertainties. These results indicate the vulnerability of KEPCo to being a captive customer without the ability to have control over a portion of its capacity needs through acquisition of resources.

Current Power Supply Contracts

Due to the results of the RFP, the options for KEPCo reduced down to owner built and contract extensions with the existing suppliers. Assumptions used for the Long Range Plan were reviewed and updated where possible for use in the Generation Construction Work Plan.

KCPL

KEPCo serves approximately 15MW in the KCPL control area through a firm capacity and energy contract with KCPL. The contract is extended through filing with the FERC and it is expected that this contract will continue through the study period. Escalation of the contract pricing is assumed at the 2.5 percent rate used in the Long Range Plan.

SUNFLOWER
KEPCo has a firm power wholesale contract with Sunflower G&T which provides service to approximately 40MW of load in the Sunflower control area. This contract is an evergreen type of contract and is expected to be continued to provide the capacity and energy for the load served in the Sunflower area. This contract is expected to continue through the study period with escalation of the contract pricing occurring at the 2.5 percent rate used in the Long Range Plan.

WESTAR
KEPCo has an all requirements contract with Westar that provides for the loads within the Westar control areas and the load previously served by others in the Aquila and Empire control areas. This load totals approximately 360MW. The contract provides for the scheduling and dispatch of the resources owned by KEPCo, such as Wolf Creek and Sharpe Engines and the Western Area Power Administration and Southwestern Power Administration contracts. This contract is set to expire in 2008, but can be extended with agreement between the parties. KEPCo and Westar are currently in negotiations on any revised terms of the contract to determine the projected costs to KEPCo.

KEPCo has entered into negotiations with Westar on the terms of the contract extension. These talks are in the preliminary stage and do not have definitive terms offered by Westar to be used in this analysis. The assumptions developed in the Long Range Plan were carried forward in this analysis.

WESTERN AREA AND SOUTHWESTERN POWER ADMINISTRATIONS
KEPCo has wholesale power contracts with the Western and Southwestern Power Administrations. These contracts provide firm peaking and as available supplemental power from hydro-electric power facilities marketed by the two agencies. Contracts are limited in the amount of energy that can be dispatched from the capacity. The amount of supplemental energy available in any year varies due to water availability in the hydro facilities. The energy from these contracts is utilized primarily in the Westar and Sunflower areas.

These contracts are expected to be available through the study period. Escalation of the contracts is estimated to occur on a four year cycle at a rate of 14 percent for the cycle as used in the Long Range Plan.

Refined Base Load Analysis

Based on the discussions with potential suppliers, the only valid base load options considered for KEPCo were the acquisition of capacity from the Iatan 2 project or the Existing Coal Unit. A financial comparison of the two options was made to determine the bus bar cost of each project. The Iatan Unit 2 project would require a borrowing to acquire the capital for investment in the project, whereas the Existing Coal Unit purchase would be through a life of unit power purchase agreement.

The pricing information for Iatan 2 was provided by KCPL. The information provided was reviewed by Burns & McDonnell to reflect adjustments for financing, uncertainties and other factors considered necessary to reflect expected costs from the project. Since the Existing Coal Unit offer was a purchase, no adjustments were necessary. The basic cost information for the two facilities is summarized in Table V-1, which provides a levelized bus bar cost analysis of the two options. KCPL had initially considered that 50MW would be available from the unit, however, this was subsequently revised to 30MW.

Table V-1
Bus Bar Comparison of Iatan 2 and Existing Coal Unit Options
Economic Parameters for the Base Load Options (First yr of operation)

	Iatan 2	Jeffrey
Financed cost ($/kW)	Confidential	Confidential
Annual Cost ($/kW-yr)	Confidential	Confidential
Fixed O&M ($/kW-yr)	Confidential	Confidential
Variable O&M ($/MWh)	Confidential	Confidential
Fuel ($/MWh)	Confidential	Confidential
25 yr levelized bus cost	Confidential	Confidential

NOTE: Levelized cost at an 80% capacity factor, 6% interest and discount rate.

The Iatan Unit 2 option includes approximately $1,000,000 of property tax to Platte County Missouri which could potentially be reduced through negotiations. However, the entire amount is included in the above Fixed O&M numbers.

The above analysis is net of the SPP OATT costs for delivery of the energy to KEPCo. The SPP OATT cost will be essentially the same for either option, since the network service rate will be used for either option. Therefore it is anticipated that delivered energy costs will increase by an equivalent amount for either option. The analysis of the two options indicated that the Existing Coal Unit pricing was less attractive than the Iatan Unit 2. This was primarily due to the cost of fuel from the Existing Coal Unit plant.

The analysis for the Long Range Plan identified a level of 100MW of coal energy to be of benefit in reducing the long range costs of KEPCo, coupled with moving the contracts to partial requirements contracts using a combination of on and off peak market energy. Due to the lack of response from the RFP for power supply and a competitive wholesale market in the SPP area served by KEPCo, the existing contracts were retained for use in the model. Analysis of various combinations of the Iatan and Existing Coal Unit proposals were reviewed. Since the Iatan offer had the lower bus bar cost analysis, it was assumed that the entire 30MW would be taken as a portion of the 100MW identified in the Phase I assessment. Scenarios were developed with zero,

30, 45, and 60MW of Existing Coal Unit to determine the advantages of various levels of Existing Coal Unit in the supply mix.

Hourly production cost analysis was performed to review the impact on variable costs. The KEPCo system was modeled as the three control areas of Sunflower, Westar and KCPL. The load was allocated among the areas. Resources for the Sunflower area were the Sunflower contract and 4.4MW of the WAPA peaking contract. Resources for the KCPL area were the KCPL contract. The balance of the Sharpe and Wolf Creek resources and WAPA, SWPA and Westar contracts were used to meet load within the Westar area. The results of this analysis with the various amounts of Existing Coal Unit blended in with the Iatan showed no benefits in the variable costs. Therefore, the acquisition of Existing Coal Unit capacity with the current assumptions for the Westar, KCPL and Sunflower contracts is not considered beneficial and only the Iatan amount was considered further..

Although the RUS prefers the use of hourly production cost modeling in the support of Generation Construction Work Plans, due to the complexity of modeling the various fixed and variable aspects of the Westar, Sunflower and KCPL contracts, the spreadsheet models from the Long Range Plan were determined by Burns & McDonnell to be better suited to identify the total incremental costs of the system with the Iatan purchase included. Results from the dispatch of the hourly model were compared with the dispatch used in the spreadsheet model. The dispatch in the spreadsheet model was determined to be reasonably consistent with that of the hourly model for use in this analysis and the spreadsheet model was used for this CWP.

The comparison of the Iatan purchase was made to the contract extension Case X2 from the Long Range Plan. The following sensitivities were performed:

1. Westar energy costs were escalated at 2.5 and 6.5 percent, the ranges considered in the Long Rang Plan
2. Iatan fuel costs were increased by 20 percent from the base level.
3. Iatan construction costs were increased by 20 percent from the base level
4. Iatan financing interest rates were increased by 1 percent from the base interest rate.
5. The KEPCo base forecast rate of growth was reduced in half to reflect a low load growth scenario.

The net present value results of the analyses are summarized in Table V-2. The summary outputs from the models are provided in Appendix E. The models are indexed on the accompanying CD.

Table V-2
Comparison of Iatan 30MW Cases
With the Extension of Existing Contracts
($000's)

	Load Forecast	Base	Interest Rate	Construction Cost	Iatan Fuel
Westar @ 6.5%					
Without Iatan	$755,958	$884,486	$884,486	$884,486	$884,486
With Iatan	$728,450	$856,554	$859,230	$858,317	$859,517
Difference	**$27,508**	**$27,932**	**$25,255**	**$26,169**	**$24,969**
Westar @ 2.5%					
Without Iatan	$651,409	$737,483	$737,483	$737,483	$737,483
With Iatan	$658,684	$744,745	$747,455	$746,541	$747,741
Difference	**($7,275)**	**($7,262)**	**($9,972)**	**($9,058)**	**($10,258)**

The billings from Westar received during the 2005 summer have indicated an energy cost for 2005 greater than that considered in the above analysis. The analysis provided in Table ES-5 was updated with the recent Westar contract energy costs from January 2005 to date. These revised numbers were used as the base Westar energy values and escalated at the same rates of escalation as above. The net present values from this assessment are summarized in Table ES-6.

Table V-3
Comparison of Iatan 30MW Cases
With the Extension of Existing Contracts
With Revised Westar Energy Costs
($000's)

	Load Forecast	Base	Interest Rate	Construction Cost	Iatan Fuel
Westar @ 6.5%					
Without Iatan	$856,757	$1,018,591	$1,018,591	$1,018,591	$1,018,591
With Iatan	$798,240	$959,322	$962,013	$961,099	$962,299
Difference	**$58,517**	**$59,268**	**$56,578**	**$57,491**	**$56,291**
Westar @ 2.5%					
Without Iatan	$722,776	$825,565	$825,565	$825,565	$825,565
With Iatan	$712,591	$814,717	$817,426	$816,512	$817,712
Difference	**$10,185**	**$10,849**	**$8,139**	**$9,053**	**$7,853**

The analysis indicates that the projections on the Westar energy costs have a significant impact on the variance of the cases. The results of the analysis indicate that the Iatan project can operate as a hedge against escalation of the Westar purchase contract energy pricing.

Part VI

Iatan 2 Project Development

This part of the report discusses the current status and the expected activities for development of the Iatan 2 project. The following paragraphs provide a brief description of the activities. KCPL is in the process of moving the project forward through state regulatory reviews and state and federal permitting processes. Certain information about the project is considered confidential at this point. As the project moves forward, additional information will be made public. Following is a description of the project from the available information.

General

The proposed Iatan Unit 2 project is being developed by KCPL. KCPL operates the Iatan 1 unit at the proposed site for the Iatan 2 unit. The site is located adjacent to the Missouri River near Weston, Missouri. The Iatan 1 facility is a joint owned facility operated and maintained by KCPL. The owners in Iatan 1 are KCPL, Aquila and Empire District Electric. Iatan Unit 1 is a 670MW (net) pulverized coal unit operating on Powder River Basin coal. Iatan Unit 1 is interconnected to the area transmission grid via 345kV transmission lines into Missouri and Kansas. Unit 2 is proposed to be sited adjacent to the existing Unit 1 and take advantage of common facilities to the degree possible. KCPL is expected to perform the operation and maintenance of Unit 2. Unit 2 will be rated approximately 850MW (net) and operate on Powder River Basin coal. It is proposed that Unit 2 be a supercritical unit and include emission control equipment standard for new coal facilities. The unit has a projected on-line date of 2010.

Prospective Participants

The prospective participants in Unit 2 and the expected participation levels are:

- KCPL 500MW
- Empire District Electric up to 200MW
- Aquila up to 200MW
- Missouri Municipals 100MW

KEPCO has discussed the participation with KCPL in the unit. The initial amount sought by KEPCO was 50MW. However, KCPL has indicated that only 30MW of participation can be offered at this time.

Regulatory Status

Three of the four existing participants are regulated investor owned utilities. The primary regulators who are involved in the acceptance of the project for issuance of a Certificate of Convenience and Necessity CCN are the Missouri Public Service Commission (MPSC) and the Kansas Corporation Commission (KCC). The investor owned utilities are in the midst of filings with the MPSC and the KCC for the CCN and various rate treatments associated with approval to enter into the project.

The project has filed for the necessary permits to allow construction of the resource. In addition, the investor owned utilities in the project are moving through the regulatory approval process in Kansas and Missouri. The state of Kansas issued its stipulation order on August 5, 2005 approving the Iatan Unit 2 construction by KCPL and a rate increase of up to 20 percent. Missouri has provided approval to the KCPL resource plan in July 2005, of which Iatan Unit 2 is a major component. (See Appendix C).

The Missouri Joint Municipal Electric Utility Commission (MJMEUC) is a joint action agency for several Missouri municipal utilities. The MJMEUC manages various power supply sources for its members. Participation in Unit 2 would provide an additional resource. The MJMEUC is not regulated by the MPSC, but has to get the approval of its members to participate in Unit 2. There are several large municipal electric utilities in Missouri, including Columbia and Independence considering participation in the unit.

Development activities require participants to fund certain efforts in ratio to their expected participation. KEPCO has been provided a letter of intent to participate in the joint venture. Funding would be required from KEPCO upon the acceptance of the letter of intent and declaration that they desire to participate in the Unit 2.

Contracting Method

KCPL is considering a variety of contracting approaches to the construction of the unit. Under this approach, multiple contracts would be developed and administered by an engineering design firm, which is yet to be determined. Other contracting approaches include the multiple prime approach and the single contractor engineer, procure, construct (EPC) approach. The selection of the approach to be used is anticipated to be completed in the fourth quarter of 2005.

Technical Parameters

General

The conceptual design for the plant has been performed and ongoing engineering in support of permitting is being provided. Although detailed design of the unit has not commenced, there have been several design conditions determined. The following information is provided on a preliminary basis and is subject to change as the detailed design proceeds.

The plant elevation is 790 feet above mean sea level. Equipment and design of the facility will be suitable for the elevation, temperature and humidity for the location.

The project will be a supercritical unit operating at a pressure of 3690 psi with main steam and reheat temperatures of 1050^{o} F. The unit will burn sub-bituminous coal from the Powder River Basin in Wyoming and Montana. The new and clean heat rate for the unit is expected to be 9,050 Btu/kWh. The maximum degradation as indicated in the permit applications is expected to be 5 percent over the life of the unit. Typical average degradations for operations are expected to be 2.5 percent.

The unit is being developed for high availability. The unit will have a maintenance schedule set up for an eighteen month cycle for planned maintenance.

Structural

The plant will be designed with an enclosed boiler. Alignment with existing conveyors and other structures will be coordinated during the initial design. The units will share a common control room.

The plant will be designed for the following seismic requirements:

- Seismic Design Category IIB.
- Seismic factor, IE = 1.25
- Spectral Response Acceleration at Short Period: SDS = 0.13
- Spectral Response Acceleration at 1-Second Period: SD1 = 0.10

Wind design will be in accordance with the International Building Code (IBC) and meet the following:

- Basic Wind Speed (3-second gust) = 90mph
- Exposure = C
- Wind Factor, I_w = 1.15

Water System

Raw water supply for the existing Unit 1 is from wells located on the site. Cooling water is from the Missouri River and is used in a once through process for Unit 1. Additional raw water for Unit 2 will be provided through new collector wells adjacent to the Missouri River. Due to restrictions on use of the once through process on new generating units, the Unit 2 will use a cooling tower and will take the cooling water from the new collector wells. Raw water will be treated in a softening process prior to use on the site.

Preliminary water balance analysis for the Unit 2 indicate that approximately 7,400gpm of water will be taken from the wells for use in the unit. The majority of the water, approximately 7,000gpm, will be used in the cooling process. The balance of the raw water will be used in a variety of other plant functions.

The facility is designed to be a zero liquid discharge facility. Water treatment for cooling tower blowdown will be provided by a reverse osmosis (RO) system. A brine concentrator and crystallizer will also treat the rejects from the RO system. Water from the treatment systems will be returned for use in the cooling tower process. Existing wastewater treatment systems will be used for sanitary waste water.

Fuel Supply

The fuel for the facility will be low sulfur coal supplied from the coal basins in Montana and Wyoming. The design fuel selected for the facility is an 8,200 Btu/pound fuel with 0.7 percent sulfur. KCPL will provide fuel acquisition management for the participants. They will provide for the contracting for the supply and delivery of the fuel.

The fuel delivery system for the existing unit will be modified to allow use of 150 car trains for the coal deliveries. New rail car positioner equipment will be installed to accommodate the longer trains. The existing rotary car dumper is adequate for the longer trains. Additional coal storage facilities will be constructed to increase the long term storage capacity at the site. The Unit 2 fuel usage is estimated at approximately 9000 to 10000 tons of coal per day. This will require a train per day minimum to maintain fuel at the facility for both units considering typical capacity factors for the units.

The facility currently has connections to a single rail hauler, Burlington Northern. There have been options explored to allow connection to the Union Pacific as well to increase the competition for fuel deliveries. The current pricing of the coal does not warrant the completion of this connection at this time, however, future fuel pricing may require consideration of this option.

Geotechnical Investigation

A subsurface investigation of the planned site for location of the Unit 2 project will be performed prior to final design. Information from the existing station construction has been used to estimate the foundation requirements. No unusual requirements were determined to be necessary for the foundations for Unit 1.

Site Survey

KCPL owns the 3,221-acre parcel of land of which approximately 250 acres will be used for the Unit 2. Land use immediately surrounding the site, which is primarily agricultural, has experienced few changes since the construction of Unit 1. The site is located in Platte County, which is zoned. According to the Platte County Zoning Administrator, the Iatan Site is zoned for industrial use, and most of the land surrounding the site is zoned agricultural. Construction and operation of the Unit 2 Project on the Iatan Site is consistent with Platte County's zoning ordinance.

Electrical Interconnection

Unit 2 project will interconnect to the SPP transmission system through the existing Iatan 345 kV substation. The 345 kV Iatan station connects to the 345 kV line to Stranger Creek in Kansas and the St. Joseph substation in Missouri. Both terminals are interconnected to several 345kV and lower voltage lines. By expanding the substation capacity at the Iatan Unit 1 facility, the new unit could tie into the existing transmission system without the construction of a new transmission line corridor.

The SPP's "Expedited System Impact Study for Generation Interconnection Request" ("System Impact Study") dated April 27, 2004, determined that under normal fault events, addition of the Unit 2 project would not cause system instability. Under extreme disturbance fault events, however, system instability could occur. To provide redundant systems to assure network stability under extreme fault contingencies, the SPP study recommends a new 345 kV transmission line between the Iatan substation and the Nashua substations (the Iatan-Nashua 345 kV circuit) and other network upgrades. The network upgrades also will include expansion of the Iatan 345 kV bus and installation of six new 345 kV circuit breakers. The SPP is in the early stages of the routing process, and no transmission line corridor alternatives have been determined. Moreover, the SPP has not determined which utility(s) will be responsible for constructing the new transmission line.

KEPCO has filed the transmission interconnect study with the Southwest Power Pool (SPP). The SPP is performing several studies for transmission upgrades in Kansas. The transmission analysis being performed by the SPP to date is included in Appendix F. Based on the initial Study, the necessary upgrades for delivery of the power on a firm basis to KEPCO control areas could cost approximately $3 million to $22 million depending on other area participates. Revision of the 50 MW to 30 MW from Iatan may also reduce the cost.

The potential exists for a variety of capacity swap arrangements between KCPL and KEPCo to minimize any transmission investment. KCPL and KEPCo are joint owners in the Wolf Creek Power Plant located near Burlington, Kansas. The plant is located within the control area of Westar. Therefore, KEPCo may consider working with KCPL to allow the 50 MW for KEPCo to actually be taken from the Wolf Creek plant and KCPL to take the 50 MW from the Iatan Unit 2, which is in KCPL's control area. Other possibilities may exist for swapping of potential wind capacity that may need to be delivered from western Kansas to Missouri.

Emission Controls

The unit will utilize a variety of technologies for control of emissions. The following emission controls are included:

- Proper combustion controls to minimize CO
- Low NOx burners and selective catalytic reduction for NOx controls
- SO2 control with wet scrubber technology
- Pulse Jet fabric filter for particulate control
- Future activated carbon or other sorbent injection for mercury controls, if required.

The wet scrubber for the unit is planned to operate with a removal efficiency of 95 percent or higher. The process will use limestone as the reagent. This process also allows the potential sale of gypsum and fly ash from the facility. In addition, this process improves the reduction of mercury from the unit.

Noise abatement is not considered necessary beyond the reductions provided with the standard noise enclosures and silencing equipment.

Permitting

The construction and operation of the new coal fired unit and all supporting equipment will require the acquisition of a variety of permits and approvals from local, state, and federal agencies. The proposed project will require the following permits or authorizations:

- PSD Air permit
- Title IV Acid Rain Permit
- Modification to Existing Title V Operating Permit
- NPDES Construction Storm Water Pollution Permit Plan
- NPDES storm water and wastewater discharge permits
- Spill Prevention Control and Countermeasures (SPCC) Plan
- Facility Response Plan
- Solid Waste Disposal Area Permits
- Section 404 Permit – Clean Air Act
- Section 10 Permit – Rivers and Harbors Act
- Section 106 – National Historic Preservation Act
- Local Issues

Due to the 30MW purchase from the nominal 850MW unit, the acquisition would be below the RUS threshold where any environmental reports would need to be prepared specifically for the RUS. The following paragraphs discuss each of these items as they would apply to a coal fired unit at the Iatan Station site and the status of any filings.

PSD Air Permit

The PSD program requires an air quality analysis for each regulated pollutant that a proposed major source emits at levels greater than the significant emissions level. The purpose of the air quality analysis is to demonstrate, through the use of air quality dispersion models and background ambient data that allowable emission increases from the proposed source, combined with emissions from other sources, will not cause or contribute to violations of any Missouri Ambient Air Quality Standards or NAAQS.

The Unit 2 project's estimated emissions are being considered in a draft air quality permit application being prepared for filing with the Missouri Department of Natural Resources (MDNR). If the emission of any pollutant increase resulting from the Project is at a level that is greater than the PSD significance level, the Unit 2 project will be subject to PSD for that pollutant. If any of the emission increases are greater than the PSD Significant Emission Rate ("SER"), the Unit 2 project qualifies as a major pollutant source. To assess pollutant-specific impacts, the maximum predicted impact for each air pollutant is added to the respective background ambient air concentration to determine worst-case concentrations. These worst-case concentrations are then compared to NAAQS. Five of the six criteria pollutants evaluated for the

Project exceeded the SER and, in the absence of the reasons provided below, would be subject to full PSD review including Best Available Control Technology ("BACT") and air quality analysis.

In this instance, to reduce the environmental impact of the Unit 2 project, KCPL will retrofit Iatan Unit 1 with certain additional environmental control upgrades. Specifically, Iatan Unit 1 will be retrofitted to include an SCR system for NO_x control and a FGD system for SO_2 control. In addition, fabric filters will be installed on both plants to limit PM_{10} particulate emissions. Once these environmental control upgrades are in place, the Unit 2 project and the upgraded Iatan Unit 1 collectively will exceed the SER for only three of the six criteria pollutants—CO, PM_{10} and VOC. The entire Iatan facility's reduced annual emission will result in less SO_2 and NO_x than Iatan Unit 1 currently emits. Moreover, the Unit 2 project will also be in compliance with EPA's new mercury emission requirements.

The emissions of CO, PM_{10} and VOC exceed the SER and are therefore subject to PSD permitting. Accordingly, air quality and BACT analyses were performed for those pollutants. A control technology and/or emission limit for each emission unit was proposed that corresponds to that achievable through the application of specific production processes or control techniques while taking into account energy, environmental, and economic impacts.

According to the MDNR, there are general provisions that must be attained in order to comply with the PSD regulations in the state of Missouri. As a major stationary source, the Project is subject to the provision of the PSD program outlined in 10 CSR § 10-6.060.
There are five steps in a proposed BACT evaluation:

- Identify potentially applicable control technologies
- Eliminate technically infeasible control technologies
- Rank the remaining control technologies based upon emission reduction potential
- Evaluate the ranked controls based on energy, environmental, and/or economic considerations
- Select BACT

KCPL has completed the required PSD permit application. The permit application was submitted to the MDNR in the summer of 2005. It is anticipated that the MDNR will issue a Draft PSD permit in the fourth quarter of 2005.

Title IV Acid Rain Permit

The Acid Rain Program found in 40 CFR applies to utility units. A utility unit is defined as a unit owned or operated by a utility that serves as generator in any state that produces electricity for sale. The proposed unit meets this definition and is subject to the Acid Rain Program. The Acid Rain Program requires numerous pollutant monitors in addition to possession of SO_2 credits for each ton of SO_2 emitted. An Acid Rain Program permit application for the Unit 2 project will be submitted to EPA twenty four to thirty months prior to operations commencing.

Title V Operating Permit

The addition of the new Unit 2 project will require an amendment to the site's existing Title V operating permit. The Title V permit requires the codification of all federally enforceable air requirements at the Iatan Generating Station.

NPDES Construction Storm Water Pollution Prevention Plan

A construction Storm Water Pollution Prevention Plan must be submitted any time a proposed project will disturb more than 5 acres of land. This permit is required before construction begins at the site. This permit also requires the site to develop and maintain a Storm Water Pollution Prevention Plan (SWPPP). The SWPPP includes best management practices to control the discharge of sediment-laden runoff. The SWPPP should be completed within 180 days of the start of construction.

NPDES Operation Permits

The site's existing NPDES discharge permit will need to be amended to authorize the additional stormwater discharge from the proposed project. This permit must be received prior to initial discharge. This permit will be amended and submitted to the MDNR about twelve months prior to operations.

Spill Prevention Control and Countermeasures Plan

The Spill Prevention Control and Countermeasures (SPCC) Plan is required by the Oil Pollution Act. The SPCC Plan is required when a site stores 660 gallons of oil in a single container, or 1,300 gallons in a group of containers. This plan must be in place before any oil is taken onsite. This plan is required to be sealed by a professional engineer. The Iatan Generating Station has an existing SPCC Plan that will need to be revised prior to operating any new equipment.

Solid Waste Disposal Area Permits

Coal combustion by-product material generated during the electricity production will be disposed of in an on-site utility waste landfill designed and constructed in accordance with the Missouri solid waste regulations and as approved by the Solid Waste Management Program ("SWMP") of the MDNR. Permits are required from the MDNR for the construction and operation of the disposal area. The construction permit should be completed by September 2007 and the operational permit by October 2008.

Section 404 Permit (Clean Water Act)

Wetlands of the U.S. are protected by federal law under Section 404 of the Clean Water Act of 1977, which requires that a permit be issued by the USACE in order to fill or build in a wetland and also Executive Order 11990 – The Protection of Wetlands, which states that the destruction, loss, or degradation of wetlands should be minimized, to preserve and enhance the natural and beneficial values of wetlands. The Unit 2 project will impact approximately 20 acres of wetlands. KCPL submitted the Section 404 permit application to USACE in June 2005.

Section 10 Permit (Rivers and Harbors Act)

The Section 10 permit regulates construction of all structures impacting functioning of navigable waterways, such as an outfall or intake structure. KCPL will submit the Section 10 permit application to USACE in August 2005.

Section 106 – National Historic Preservation Act

A Phase I intensive archaeological survey reported three sites and one isolated find within the Unit 2 project area. One site was eligible for the NRHP as a historic district. Because of this determination by the Missouri Historical Preservation Program, KCPL, SHPO, and the USACE negotiated a Memorandum of Agreement ("MOA") addressing the archaeological and architectural investigations of the A. Nower Homestead (Nower Historic District), formerly referred to as "the Nower Farmstead. KCPL and SHPO have executed the MOA. The USACE has stated that it will execute the MOA when it issues the 404 permit. The MOA specified the measures to be implemented to evaluate the impacts to the Nower Historic District (which have been completed) and specified the measures required for mitigation (not implemented).

Local Issues

While the above information discusses the significant state and federal permits and authorizations that will be required for the construction and operation of the proposed project, there may be local city or county requirements that will need to be addressed. These requirements may include noise ordinances, construction permits, and water-use rights.

Site Layout

A site layout is provided at the end of this part.

Schedule

The necessary regulatory approvals from the Kansas Corporation Commission and Missouri Public Service Commission have been received by KCPL for its resource expansion plan, of which, the Iatan Unit 2 is a major component. The permitting for the project has begun and is expected to be complete during early 2006. With these approvals and permits, the unit construction can begin. Once construction has started, it is expected that it will take approximately 45 months for the plant to be declared commercial. Operation is currently planned for summer of 2010.

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Part VII

Financial Forecast

(Confidential)

Part VIII

Conclusions and Recommendations

Three Year Generation Construction Work Plan

Conclusions

Based on the analysis of loads and resources and the responses to the RFP, KEPCo will continue to be dependent on area utilities to provide capacity and energy to serve its load. Without acquisition of additional baseload resources, KEPCo's cost of power will continue to be on the margin of the utilities' cost of power. For those utilities, such as Westar, this means an increasing proportion of energy being provided by natural gas. The analysis prepared herein has indicated that by blending in additional coal based resources, KEPCo can reduce its exposure to projected energy costs. The most attractive baseload option, based on the assumptions used in the analysis, is the Iatan Unit 2. KEPCo can participate in this project with a nominal 30MW allocation. The project is scheduled to be commercial in 2010. Participation in this project will require obtaining funds for the equity purchase.

Beyond the decision for the participation in the Iatan Unit 2, the option of obtaining up to 60MW of the Existing Coal Unit was not shown to provide benefits at the current time with the assumptions used in the analysis for the extension of the Westar and other supplier contracts.

Additional issues that KEPCo should pursue include the upgrade to the Wolf Creek generating station to acquire the estimated 4MW of capacity. This project has been delayed by the other participants. Should it be reinitiated with similar terms as assessed in the Phase I analysis, KEPCo should participate in the project.

As mentioned above, the lack of a robust wholesale market in the KEPCo area will require KEPCo to continue to take power from the area utilities. For the Westar contract, the average cost of energy from the contract is based on the amount of energy taken under the contract versus the fixed and variable costs of the contract. KEPCo should continue to evaluate the value of installing peaking capacity in the Westar service area versus the costs of the Westar contract and area non-firm energy market to determine if KEPCo owned peaking capacity could reduce the overall costs of KEPCo's intermediate and peaking energy.

Three Year Generation Work Plan

Based on the analysis developed for this study, review of the market surrounding the KEPCo service areas and other factors affecting the power industry, Burns & McDonnell is of the opinion that KEPCo should:

1. Consider the impact of the acquisition of the Iatan project and other operating costs on member wholesale rates.

2. If the wholesale rate impacts are acceptable, pursue the acquisition of the 30MW of the Iatan Unit 2 capacity offered by KCPL.

3. Obtain the necessary financing to allow participation in the project.

4. Proceed with the negotiations of the various agreements to become a participant in the project.

5. Finalize the transmission service arrangements for the delivery of the power from the project

6. Complete negotiations with the control area service providers for the extension of the existing contracts and for the scheduling and integration of the output of the Iatan capacity to serve the KEPCo load.

7. Pursue the upgrade to the Wolf Creek generating station.

8. Based on the terms resulting from the extension of the Westar contract, compare the value of peaking facilities constructed by KEPCo to offset capacity and energy provided by Westar and determine if continued acquisition of the Iatan purchase is still attractive.

********End********