City of Independence, Missouri
Power & Light Department

2011
Master Plan Study
Update

November 2011

Sega Project No. 11-0083

ENGINEERING & TECHNICAL SERVICES

2011 Master Plan Study Update

Prepared for:

Independence Power & Light Department
21500 East Truman Road
Independence, Missouri 64051

FINAL REPORT

Prepared by:
Sega Inc.
16041 Foster
Overland Park, KS 66085
(913) 681-2881
www.segainc.com

State of Missouri Certificate of Authority No. 1009

TABLE OF CONTENTS

APPENDICES

GLOSSARY

GLOSSARY

ACI: Activated Carbon Injection

AECI: Associated Electric Cooperative, Inc.

BACT: Best Available Control Technology

BART: Best Available Retrofit Technology

BTA: Best Technology Available

Btu/kWh: British Thermal Unit Per Kilowatt-Hour

CAIR: Clean Air Interstate Rule

CATR: Clean Air Transport Rule

CEMS: Continuous Emissions Monitoring System

CFB: Circulating Fluidized Bed

City: City of Independence, Missouri

CO: Carbon Monoxide

CO_2: Carbon Dioxide

CSAPR: Cross-State Air Pollution Rule

CTG: Combustion Turbine Generator

DOE: United States Department of Energy

Dogwood: Dogwood Energy Center

DSI: Dry Sorbent Injection

EGU: Electric Generating Units

EIA: United States Department of Energy's Energy Information Administration

EIS: Energy Imbalance Services

EPA: United States Environmental Protection Agency

ESP: Electrostatic Precipitator

F: Fahrenheit

FF: Fabric Filter

FGD: Flue Gas Desulfurization

FIP: Federal Implementation Plans

GE: General Electric

GHG: Green House Gas

HAP: Hazardous Air Pollutants

HCl: Hydrogen Chloride

Hg: Mercury

HHV: Net Heat Rate

HRSG: Heat Recovery Steam Generators

Iatan 2: Iatan Generating Station, Unit 2

IGCC: Integrated Gasification Combined Cycle

IPL: City of Independence - Power & Light Department

KCP&L: Kansas City Power & Light Company

KCP&L-GMO: Kansas City Power & Light Company - Greater Missouri Operations (formerly Aquila, Inc. - Missouri Public Service)

kV: Kilovolt

kW: Kilowatt.

LNB: Low NO_x Burner

LTC: Load Tap Changer

LTP: Long Term Parts

MACT: Maximum Achievable Control Technology

MDNR: Missouri Department of Natural Resources

MGD: Million Gallons Per Day

MJMEUC: Missouri Joint Municipal Electric Utility Commission

MMBtu: Million British Thermal Unit

MPUA: Missouri Public Utility Alliance

MVA: Mega-Volt-Amp

MVAr: Mega-Volt-Amp-Reactive

MW: Megawatt

MWh: Megawatt-Hours

NAAQS: National Ambient Air Quality Standards

NAES: North American Energy Services

NC2: Nebraska City Generating Station, Unit 2

NPDES: National Pollutant Discharge Elimination System

NPV: Net Present Value

NO_2: Nitrogen Dioxide

NO_x: Nitrogen Oxide

NSPS: New Source Performance Standards

NSR: New Source Review

O_2: Oxygen

O&M: Operation and Maintenance

OEM: Original Equipment Manufacturer

OFA: Over-Fired Air

OPPD: Omaha Public Power District

PM: Particulate Matter

PPB: Parts Per Billion

PSD: Prevention of Significant Deterioration

PSIG: Pounds Per Square Inch Gage

RCT: Regenerative Combustion Turbine

RICE: Reciprocating Internal Combustion Engines

Sawvel: Sawvel and Associates

SCR: Selective Catalytic Reduction

Sega: Sega Inc.

SIP: State Implementation Plan

Smoky Hills II: Smoky Hills Wind Project II, LLC

SNCR: Selective Non-Catalytic Reduction

SNPR: Supplemental Notice of Proposed Rulemaking

SO_2: Sulfur Dioxide

SPP: Southwest Power Pool

TPY: Tons Per Year

μg/m3: Micrograms Per Cubic Meter

VOC: Volatile Organic Compounds

INDEX OF TABLES AND FIGURES

INDEX OF TABLES AND FIGURES

TABLES

FIGURES

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

Sega Inc. (Sega) prepared this 2011 Master Plan Study Update Report for the City of Independence, Missouri Power and Light Department (IPL). This is a continuation of the Master Plan effort that was initiated with the Phase 1 - Initial Assessment completed in December 2007 and the Phase 2 - Focused Analysis completed in July 2009. The Phase 2 Report presented the results of detailed analyses of the recommendations from the Phase 1 - Initial Assessment and provided IPL a recommended plan of action for energy efficiency efforts, transmission system improvements, and power supply resource plans. This 2011 Master Plan Study Update focuses on the power supply resource plans. This Section summarizes the results of the updated study.

STATUS OF PHASE 2 RECOMMENDATIONS

Sega recommended several items in the Phase 2 - Focused Analysis report for implementation by IPL. Two of those recommendations were for energy efficiency efforts and transmission system improvements. Both recommendations are provided in italics with their status below:

1. *IPL should implement/continue the following energy efficiency programs:*

   a. *Residential Lighting Program.*

   b. *Residential Air Conditioning and Heat Pump Rebates.*

   c. *Energy Star New Home Program.*

   d. *Low Income Weatherization Program.*

   e. *Commercial/Industrial Efficiency Program.*

   Status: IPL has implemented each of these energy efficiency programs and monitors their results.

2. *IPL should implement the transmission system improvements identified in the Phase 1 report, including constructing a new 161-kV transmission line from Substation M to Substation A at Blue Valley, and the installation of 161-kV and 69-kV capacitor banks at several substations.*

   Status: IPL has constructed the 161-kV transmission line from Substation A to Substation M and has installed several other related transmission and substation improvements. Two capacitor banks are being designed for installation at IPL substations that will increase IPL's net import capability.

The other recommendations from the Phase 2 Report dealt with power supply resource plans which are specifically addressed in this updated Study.

CHANGES SINCE PHASE 2

Significant changes affecting power supplies have occurred since the Phase 2 Master Plan Study was prepared in 2009. Each has a potential impact on IPL's long-term power supply:

1. The national recession on the local and regional economy has resulted in declining loads and energy consumption at IPL as well as neighboring utilities for the past three years.

2. IPL finalized participation in two new state-of-the-art coal-fired generating units. The Omaha Public Power District (OPPD) Nebraska City Generating Station Unit 2 (NC2) and the Kansas City Power & Light Company (KCP&L) Iatan Generating Station Unit 2 (Iatan 2) projects were successfully completed in 2009 and 2010, respectively, providing IPL with a total of 106 MW of base load generation beyond the 20-year power supply planning horizon.

3. From 2007 through 2010, as these units were being completed, approximately 100 new coal-fired generating units in various stages of planning and permitting were indefinitely delayed or canceled.

4. Natural gas prices have decreased and have been less volatile as technically proven reserves of shale gas significantly increased domestic supply capability at the same time that domestic usage decreased from the national economic recession.

5. Increasingly more stringent environmental regulations have significantly affected the permitting requirements for all existing and new fossil-fueled generating units.

6. The Phase 2 Master Plan Study was based on the regenerative combustion turbine (RCT) at the Blue Valley Plant returning to service January 1, 2010. IPL's current plans do not include restoring this unit to active service.

7. IPL and other municipal utilities were recently given the opportunity to participate in ownership of the Dogwood Energy Center, a 650 MW natural gas-fired combined cycle generating plant in Pleasant Hill, Missouri. The Dogwood facility has been in operation for 10 years and is owned by Kelson Energy. This Study specifically evaluated IPL's potential ownership participation in Dogwood.

NEW ENVIRONMENTAL REGULATION IMPACTS

Since Sega prepared the Phase 2 Master Plan Study in 2009, the United States Environmental Protection Agency (EPA) has made significant revisions to the environmental regulations governing power plant emissions, particularly for coal-fired electric generating units.

Summary of Major Environmental Regulations

Following is a brief overview of the new environmental regulations affecting IPL generation planning for this study.

1. ***Cross-State Air Pollution Rule (CSAPR):*** Effective on January 1, 2012, CSAPR requires 27 states to reduce power plant emissions that contribute to ozone and fine particle pollution in other states. CSAPR applies to new and existing electric generating units greater than 25 MW. Reductions in annual sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions are required through annual allowances limitations. Blue Valley 3 is the only IPL operating unit affected by CSAPR. The Blue Valley RCT unit would also need to comply with CSAPR if it was returned to service. Affected units must either install pollution control systems or purchase allowances from limited trading markets. Certain facets of CSPAR are not yet final.

2. ***Utility Boiler Maximum Achievable Control Technology (UMACT)***: EPA plans to finalize this rule by the end of 2011 with an expected compliance date in 2015. UMACT only applies to new and existing steam electric generating units that are larger than 25 MW. UMACT establishes emission rate limits for hazardous air pollutants (HAPs), including mercury

(Hg), particulate matter (PM), and hydrogen chloride (HCl). Blue Valley 3 is the only IPL unit affected by UMACT. Affected utilities are required to retrofit pollution control systems to meet emission rate limits by 2015.

3. ***Industrial Boiler MACT (IB MACT):*** This regulation is similar to UMACT, except IB MACT applies to new and existing coal-fired electric generating units 25 MW and smaller, requiring emission rate reductions for HAPs, including PM, HCl, Hg, carbon monoxide (CO), and dioxin/furan emissions. EPA has announced its intent to issue a final rule by April 30, 2012 that would require compliance by April 30, 2015. IB MACT will have significant impacts on four IPL units: Missouri City 1 and 2 and Blue Valley 1 and 2.

4. ***National Ambient Air Quality Standards (NAAQS) and Ozone-Nonattainment:*** EPA recently proposed reductions in the acceptable levels of pollutants in ambient air that will trigger mandatory reductions in emissions from electric generating units in the future. However, the measures required for compliance with CSPAR, UMACT, and IB MACT for coal firing would have already addressed most of these issues. NAAQS and Ozone Nonattainment compliance measures will apply to all IPL electric generating units. Expected compliance date is at the end of 2017.

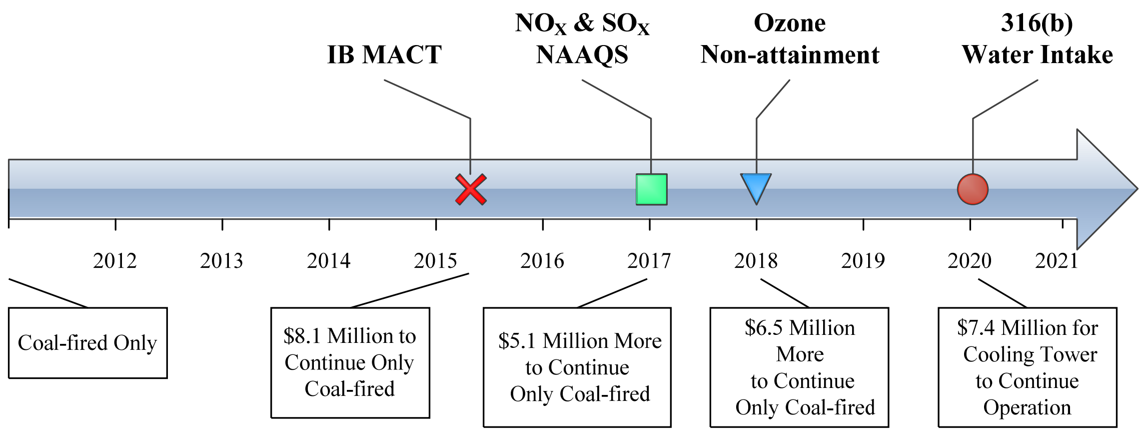
5. ***Clean Water Act Section 316(b):*** EPA has proposed revisions to its rules for implementing the Clean Water Act to minimize the impacts on aquatic organisms from the withdrawal of water from lakes and rivers from once-through cooling water intake structures. Missouri City Units 1 and 2 are the only IPL units that would be affected by these revisions which are not anticipated to require compliance until 2020.

Sega identified corrective measures for each IPL coal-fired generating unit to comply with these newly enacted and/or proposed EPA regulations. After considering compliance strategies for each unit, the costs and schedules for the recommended compliance measures were utilized to develop power supply plans for this Study. Timelines were prepared for each IPL coal-fired unit to summarize the cost and schedule impact of compliance with applicable regulations.

Missouri City Plant

As shown in Figure ES- 1, continued operation of Missouri City 1 and 2 on coal is projected to require a total capital expenditure of $27.1 million (in 2011 dollars) through 2020 for compliance with newly enacted and/or proposed EPA regulations.

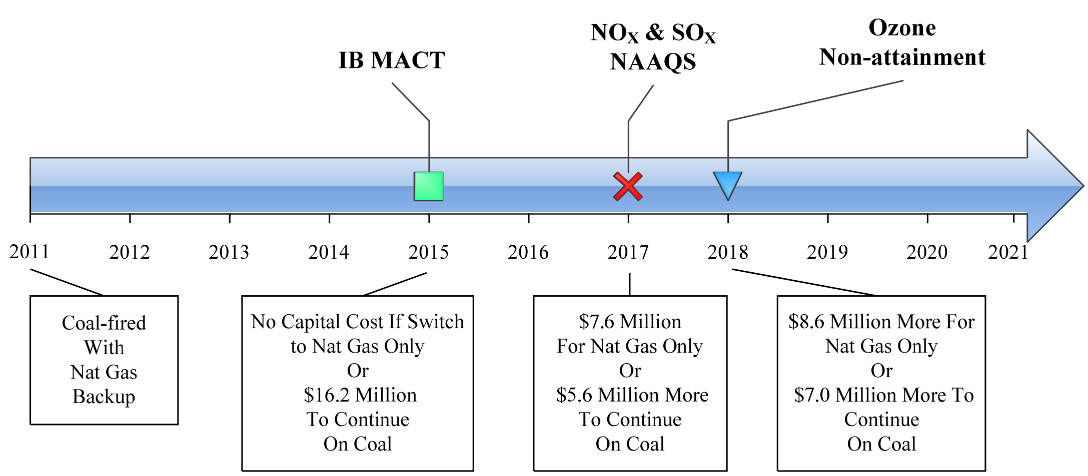
Figure ES-1
Impact of Environmental Regulations on Missouri City Units 1 and 2



Blue Valley Units 1 and 2

Continued operation of Blue Valley 1 and 2 on coal is projected to require a total capital expenditure of $28.8 million (in 2011 dollars) through 2018 for compliance with newly enacted and/or proposed EPA regulations. If Blue Valley Units 1 and 2 were to switch to natural gas in 2015, the projected capital expenditure would drop to $16.2 million (in 2011 dollars). Figure ES-2 illustrates these expenditures on a time line.

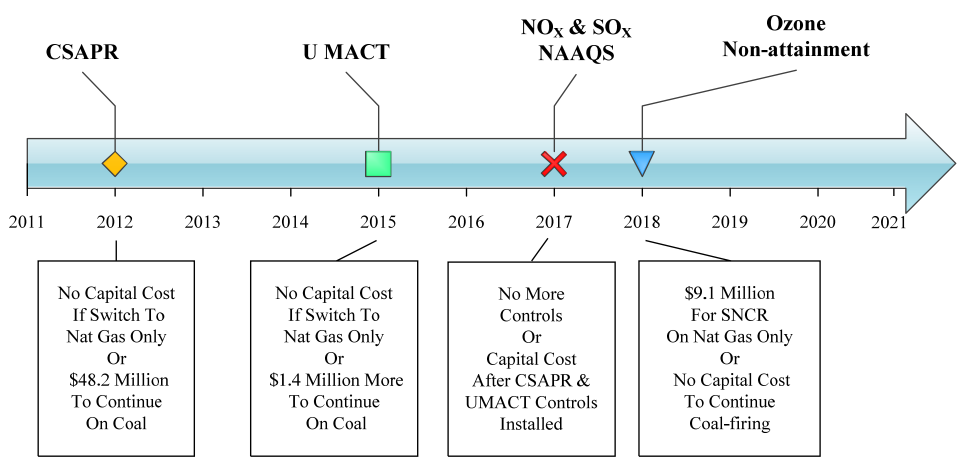
Figure ES-2
Impact of Environmental Regulations on Blue Valley Units 1 and 2



Blue Valley Unit 3

Capital costs for compliance with newly enacted and/or proposed EPA regulations for coal-firing at Blue Valley Unit 3 are projected to total $49.6 million (in 2011 dollars) through 2018. If Blue Valley Unit 3 is switched to natural gas at the start of 2012, the total projected capital cost for compliance with newly enacted and/or proposed EPA regulations would be reduced to $9.1 million (in 2011 dollars).

Figure ES-3
Impact of Environmental Regulations on Blue Valley Unit 3



RESOURCE NEEDS

Based on the anticipated impacts of newly enacted and/or proposed EPA regulations for each IPL unit and assessment of their condition with their manufacturers' replacement recommendations, Sega compiled a recommended replacement schedule for IPL's generating units. Table ES-1 provides this unit replacement schedule, which became the basis for development of the updated power supply plans evaluated in this Study.

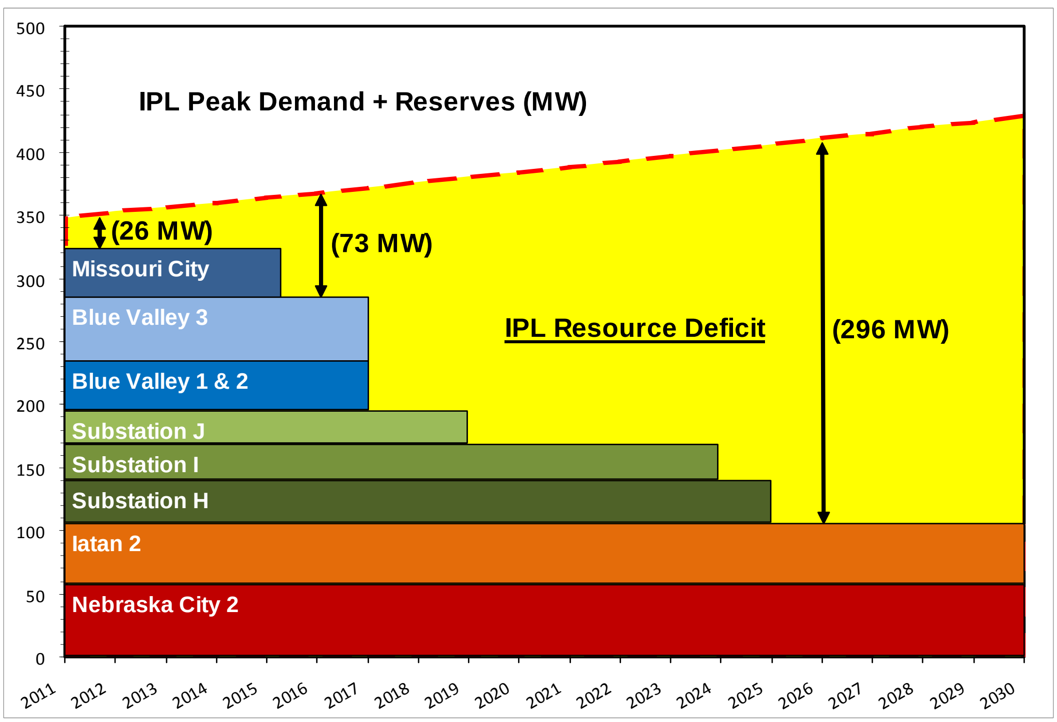
Table ES-1
Recommended Generating Unit Replacement Schedule

Units	End of Calendar Year
Missouri City Units 1 and 2 (1)	2015
Blue Valley Units 1, 2, and 3	2016
Combustion Turbines J-1 and J-2	2018
Combustion Turbines I-3 and I-4	2023
Combustion Turbines H-5 and H-6	2024

(1) April 30, 2015

The results of IPL's updated load forecast were reviewed and combined with the unit replacement schedule to develop resource needs as shown in Figure ES-4.

Figure ES-4
IPL Resource Needs 2011 - 2030



Based on the load forecast and projected operation of IPL's existing generating resources and committed power supply resources, a capacity shortfall of approximately 26 MW is expected in 2012, increasing to 73 MW in 2015 to eventually 293 MW in 2026.

POWER SUPPLY PLANS

Two of the five power supply plans that were developed in Phase 2 for meeting the City's resource needs over the 20-year planning period and three new power supply plans were evaluated in this study.

Case A: Purchase Capacity and Energy from the Market

Case A involves purchasing all future capacity and energy needs form the market. This case was previously developed in Phase 2 for evaluating the cost of not participating in, or constructing, any new generating units and relying solely on the market for future capacity and energy needs.

Case B: Construct Coal Generation

IPL would construct a 180 MW coal-fired circulating fluidized bed steam generating plant that would commence operations in 2020. IPL would construct this size unit to achieve economies of scale, but would sell 105 MW to others in a joint-ownership type arrangement and retain 75 MW to serve its native load. Additional resource needs would be satisfied with construction of gas-fired combustion turbines.

Case C: Purchase Portions of Dogwood Combined Cycle Plant

Case C involved purchasing an ownership interest from the Dogwood combined cycle plant. Natural gas-fired combined cycle generating plants are more efficient than coal-fired plants and produce fewer emissions. The Dogwood Energy Center is 650-MW, natural gas-fired facility located in Pleasant Hill, Missouri that is owned by Kelson Energy. This plant has been in service for 10 years and has an expected remaining life of approximately 25 more years. Additional future resource needs would be satisfied with construction of gas-fired generation.

ECONOMIC ANALYSIS

Economic analysis utilizing production cost modeling determined that Case C (Dogwood) is the lowest cost plan when compared to Case A and Case B. Several sensitivity analyses were performed on the Dogwood ownership option, including the amount of capacity (50, 75, and 100 MW) and the year that such purchase would be made (2012 and 2014). The plan that included a 50 MW of Dogwood in 2012 with an additional 50 MW of Dogwood in 2014 resulted in the lowest cost option.

However, the difference in total NPV cost between the lowest cost sensitivity case and the highest cost sensitivity case for the Dogwood purchase options is less than 2 percent and, thus, essentially equal. The results of the sensitivity cases indicate that purchasing a portion of Dogwood in 2012, 2014, or some portion in 2012 and more in 2014 are nearly equal in total NPV cost from 2012 through 2030.

OTHER PLANNING CONSIDERATIONS

While the cost of power supply resources and how that cost compares to other alternative power supply resources is usually of great importance, other important factors include resource diversity, fuel diversity, and diversity of vested interests of business partners. The Dogwood facility can be a beneficial power supply resource if it can provide benefits when considering all of these factors.

Cost of Project

The ownership purchase price coupled with tax-exempt municipal financing is considerably less expensive than other resource alternatives, such as purchasing capacity and energy from other utilities. The ownership purchase price of Dogwood is approximately one half of the cost of building new gas-fired peaking generation. At purchase capacities of 50 MW, 75 MW, and 100 MW, the present value of total annual power supply costs over a 20-year planning period are nearly the same. Purchasing 100 MW would have a greater impact initially on electric costs than the 50 MW and 75 MW purchase level and on revenue requirements because 100 MW is not needed by the system initially.

Resource Diversity

Resource diversity is important to prevent reliance on one single resource or one fuel. IPL has purchased power agreements for approximately 50 MW of capacity and energy each in the NC2 and Iatan 2 projects. This capacity increment is approximately 13 percent of the IPL peak demand and is approximately equal to the reserve margin IPL must maintain in the Southwest Power Pool (13.67 percent of peak demand). Therefore, 50 MW in one generating unit is a good fit for the IPL system as this capacity is approximately equal to the capacity reserve margin requirement.

Fuel Diversity

Fuel diversity is another important consideration since dependence on a single fuel should be avoided. Recent EPA regulation changes have caused natural gas to be a favorable fuel for electric generation. Currently, IPL relies mostly on coal generation and very little on natural gas. In calendar year 2010, IPL's energy supply was comprised of the following: 89 percent from coal-fired generation (IPL Blue Valley and Missouri City units, Montrose, Iatan 2, and Nebraska City 2); 4 percent from renewable generation (Smoky Hills II wind generation); less than 1 percent from IPL gas and oil-fired generation; and the remaining 6 percent from short-term spot market purchases.

Purchasing an ownership interest in the Dogwood facility increases IPL's fuel diversity by adding additional natural gas generation.

Business Partner Diversity

The Dogwood facility would add another set of business partners to the IPL resource fleet. On one hand, more partners can cause greater administration, but on the other hand this can provide more diversity. Both Iatan 2 and Nebraska City 2 involve different sets of business partners.

Industry Practice

Many municipal electric utilities and joint-action agencies participate in joint projects with multiple business partners as a matter of necessity to achieve economies of scale. Many try to spread their risks to avoid relying on too much capacity from one generating unit shaft. An ownership interest in the Dogwood facility in combination with the purchases from Iatan 2 and Nebraska City 2 are in line with this practice.

Environmental Considerations

In addition to burning natural gas, the Dogwood facility has environmental control equipment in place to reduce emissions. The plant's NO_X emissions are below 4 ppm and it is also a zero liquid discharge facility. It may also be possible to further reduce NO_X emissions in the future without capital cost by increasing the catalyst reagent injection rate. Efficient, natural gas-fired combined cycle plants, such as the Dogwood Energy Center, produce fewer greenhouse gas (GHG) emissions per MWh than do comparably sized coal-fired units. If GHG emissions become restricted by regulations as has already been discussed on the national level, Dogwood will be less affected than a similar sized coal-fired unit. Therefore, the Dogwood plant is in a good position to deal with existing and future environmental regulations.

<u>Additional Dogwood Planning Considerations</u>

The Dogwood Energy Center proposal is economically favorable to IPL because its ownership purchase price coupled with tax-exempt municipal financing is very competitive with the market price of capacity in SPP and when compared to the cost of constructing new generators. The cost of energy from Dogwood is favorable compared to on-peak market electric energy prices (during the summer months).

Sega concludes that up to 75 MW of capacity from Dogwood is a reasonable and prudent amount to pursue to balance the economic, environmental, and risk considerations.

DISCLAIMER

This update Report was prepared for the sole use of Sega's client, IPL, and for the limited purposes stated within the Report. The observations, conclusions, and recommendations contained herein attributed to Sega, constitute the opinions of Sega. Sega relied upon statements, information, documents, and opinions provided by IPL staff and/or others in the preparation of this report. Sega has assumed they are accurate, and makes no assurances, representations, or warranties and takes no responsibility whatsoever regarding their accuracy. Sega grants no certifications and gives no assurances, except as explicitly stated herein.

CONCLUSIONS

Based on the analyses in this report, Sega concludes the following:

1. Based on the load forecast and projected operation of IPL's existing generating resources and committed power supply resources, a capacity shortfall of approximately 26 MW is expected in 2012, increasing to 73 MW in 2015.

2. Purchasing up to 75 MW of Dogwood increases the fuel diversity of the IPL system by adding natural gas generation to IPL's power supply portfolio.

3. The lowest cost power supply plan based on the current analysis is to purchase 50 MW of the Dogwood Energy Center combined cycle plant in 2012, purchase an additional 0 to 50 MW of Dogwood in 2014, and construct peaking capacity generation to meet future capacity requirements.

4. Purchasing up to 75 MW of Dogwood would follow the resource diversity that IPL began by purchasing approximately 50 MW of NC2 and 50 MW of Iatan 2.

RECOMMENDED ACTIONS

Based on the analyses in this report, Sega recommends the following actions:

1. IPL should purchase 50 MW of the Dogwood Energy Center in 2012 to satisfy the 26 MW projected capacity shortfall in 2012.

2. IPL should purchase up to 25 MW of the Dogwood Energy Center in 2014 (in addition to the 50 MW in 2012) because the projected capacity shortfall of the IPL system increases to 73 MW in 2015.

3. If financing options available to IPL do not appear favorable for incrementally purchasing portions of Dogwood in 2012 and 2014, IPL should pursue purchasing up to 75 MW of Dogwood in 2012.

4. As existing IPL units are retired, on-system generating capacity should be constructed to meet future capacity requirements.

5. IPL should remain flexible with respect to the size and timing of peaking capacity additions as circumstances assumed in this Report could change between the time of this Report and when generating units are constructed.

6. IPL should continue the planning process and continue monitoring environmental and regulatory developments as well as monitoring new opportunities for participation in joint projects.

SECTION 1

INTRODUCTION

INTRODUCTION

INTRODUCTION

This Report is an update to the second phase of the Master Plan Study (Phase 2 - Focused Analysis) for the period 2009 through 2028 prepared for the Power and Light Department (IPL) of the City of Independence, Missouri (City). The Phase 2 - Focused Analysis report was completed June 2009. This Report is part of IPL's effort to develop a power supply resource plan as part of its on-going planning process. This Report updates the Master Plan Study for changes that have occurred since the completion of Phase 2 such as economic conditions, new developments in environmental regulations, etc. In addition, Kelson Energy has offered IPL the opportunity to participate in a share of the ownership of the Dogwood Energy Center (Dogwood) in nearby Pleasant Hill, Missouri, a 10-year old, 600 MW-class, natural gas-fired combined cycle generating plant. This Report evaluates three levels of participation in Dogwood: 50 MW, 75 MW, and 100 MW.

BACKGROUND

IPL is a municipally owned electric utility serving the residents and businesses located within the City of Independence, Missouri. IPL is an administrative Department of the City, reporting to the City Manager and, ultimately, the City Council. An appointed Public Utility Advisory Board advises the City Council on certain utility matters. Dating back to its founding bond election in April 1901, now 110 years later, IPL serves more than 56,000 customers with a peak demand of about 315 megawatts (MW).

CHANGES

Several significant changes affecting power supplies have occurred since the Phase 2 Master Plan Study report was submitted in 2009. They are appropriate to list here because each has a bearing on IPL's long-term power supply plan.

1. The national recession on the local and regional economy has resulted in declining loads and energy consumption at IPL as well as neighboring utilities for the past three years.

2. IPL finalized participation in two new state-of-the-art coal-fired generating units. The Omaha Public Power District (OPPD) Nebraska City Generating Station Unit 2 (NC2) and the Kansas City Power & Light Company (KCP&L) Iatan Generating Station Unit 2 (Iatan 2) projects were successfully completed in 2009 and 2010, respectively, providing IPL with a total of 106 MW of base load generation beyond the 20-year power supply planning horizon.

3. From 2007 through 2010, as these units were being completed, approximately 100 new coal-fired generating units in various stages of planning and permitting were indefinitely delayed or canceled.

4. Natural gas prices have decreased and have been less volatile as technically proven reserves of shale gas significantly increased domestic supply capability at the same time that domestic usage decreased from the national economic recession.

5. Increasingly more stringent environmental regulations have significantly affected the permitting requirements for all existing and new fossil-fueled generating units.

6. The Phase 2 Master Plan Study was based on the regenerative combustion turbine (RCT) at the Blue Valley Plant returning to service January 1, 2010. IPL's current plans do not include restoring this unit to active service.

7. IPL and other municipal utilities were recently given the opportunity to participate in ownership of the Dogwood Energy Center, a 650 MW natural gas-fired combined cycle generating plant in Pleasant Hill, Missouri. The Dogwood facility has been in operation for 10 years and is owned by Kelson Energy. This Study specifically evaluated IPL's potential ownership participation in Dogwood.

GENERAL

IPL retained Sega, Inc. (Sega) to prepare a detailed economic analysis and evaluation of select power supply options that were evaluated in Phase 2 and some new power supply options that have become available since the Phase 2 report was completed.

With the prior knowledge and approval of IPL, Sega utilized a subconsultant that specializes in particular areas of this study together with Sega staff to prepare this analysis. Sawvel and Associates, Inc. (Sawvel) determined an appropriate resource energy mix, developed alternate power supply plans, and performed an economic analysis of the power supply plans. Wherever the term "Sega" is used in this Report, it is intended to include collectively Sega and Sawvel in their combined efforts on behalf of IPL.

SUMMARY OF PHASE 2 RECOMMENDATIONS

Sega recommended several IPL actions in the Phase 2 - Focused Analysis report. Sega's recommendations are provided in italics and the status of each activity is noted below each recommendation.

1. *IPL should implement/continue the following energy efficiency programs:*

    a. *Residential Lighting Program.*

    b. *Residential Air Conditioning and Heat Pump Rebates.*

    c. *Energy Star New Home Program.*

    d. *Low Income Weatherization Program.*

    e. *Commercial/Industrial Efficiency Program.*

    <u>Status</u>: IPL has implemented each of these energy efficiency programs and monitors their results.

2. *IPL should implement the transmission system improvements identified in the Phase 1 report, including constructing a new 161-kV transmission line from Substation M to Substation A at Blue Valley, and the installation of 161-kV and 69-kV capacitor banks at several substations.*

    <u>Status</u>: IPL has constructed the 161-kV transmission line from Substation A to Substation M and has installed several other related transmission and substation improvements. Two capacitor banks are being designed for installation at IPL substations that will increase IPL's net import capability.

3. *IPL should continue its consideration of renewable resources as those resources become economically feasible. Wind turbine generation and landfill gas generation are potential renewable energy resources that IPL should continue exploring.*

   Status: No new renewable resources have been added since IPL entered into an agreement for the purchase of 15 MW of capacity from the Smoky Hills Wind Project II, LLC in 2008. However, since that time, IPL staff has continued to explore additional renewable resources and holds on-going discussions with potential new wind power, solar, and biomass generation developers.

4. *IPL should plan to replace Missouri City Units 1 and 2 in 2014 and Blue Valley Units 1, 2, and 3 in 2017.*

   Status: This 2011 Master Plan Study Update specifically addresses this item. The planned replacement dates may change as a result of this Report.

5. *As indicated by the economic analysis, IPL should pursue participation in generating units owned by others. If such participation becomes available and is economical, IPL should pursue this option before making a significant investment in construction of its own unit(s).*

   Status: This 2011 Master Plan Study Update specifically addresses this item with evaluations for IPL's potential participation in the Dogwood facility.

6. *IPL should develop an implementation plan to determine critical path items related to constructing its own coal-fired baseload plant as well as its own gas-fired baseload plant.*

   Status: Increasingly more restrictive environmental regulations have caused greater permitting uncertainty for coal plant construction. Because of this uncertainty and the availability of participation in Dogwood, IPL commissioned this 2011 Master Plan Study Update to identify and evaluate potential alternatives for its long-term power supply needs.

7. *Future CO_2 emission costs and the price of natural gas may have an impact on the decision to construct coal-fired generation. Thus, IPL should monitor CO_2 legislation and gas prices to determine, in conjunction with the critical path items as determined pursuant to Recommendation No. 7, if constructing its own coal-fired generation is more economically favorable than constructing gas-fired combined cycle generation.*

Status: Efforts to pass Federal CO_2 emissions laws, such as "Cap and Trade" have failed to pass in the United States Congress. Although the United States Environmental Protection Agency (EPA) has instituted new Green House Gas (GHG) permitting and reporting measures for utilities, widespread CO_2 emissions allowance trading has not commenced.

Natural gas prices have dropped and have remained relatively flat since 2008. The United States Department of Energy's Energy Information Administration (EIA) reported that the annual average well head price of natural gas dropped from $7.97 per thousand cubic feet in 2008 to $3.66 in 2009, rebounding to $4.16 for 2010. The average natural gas price reflected in the spot market for this region (as reported by the New York Mercantile Exchange for Henry Hub, Texas) for July 2011 was $4.43, down from a 12-month high of $4.80 during June 2010. The continuing economic recession has resulted in decreased demand for natural gas. Meanwhile, shale gas development has increased U.S. natural gas supplies. However, concerns about fracking technology could impact the gas recovery and production rates. Natural gas pricing volatility could return if the economy rebounds and electric utilities are forced to turn to natural gas as the only choice for schedulable generation because of environmental regulatory requirements.

IPL continuously monitors pending environmental regulations, CO_2 legislation, and natural gas prices as an integral part of the planning process.

8. *IPL should plan for replacement of Combustion Turbines J-1 and J-2 in 2019; I-3 and I-4 in 2023; and H-5 and H-6 in 2025.*

   Status: This 2011 Master Plan Study Update specifically addresses this item with evaluation of potential alternative power plans.

9. *To replace its existing generation and to meet future peaking generation needs, IPL should place in service combustion turbines in 2012, 2014, 2019, 2023, and 2027. IPL should remain flexible with respect to the size and timing of combustion turbine additions as circumstances assumed in this report could change between the time of this report and when generating units are constructed.*

   Status: This 2011 Master Plan Study Update specifically addresses this item with evaluation of potential alternative power plans.

APPROACH

Sega's approach to this Report began with an initial coordination meeting with IPL management and staff. The Phase 2 report was the starting point of this update effort. Input parameters were developed using information in response to a data request. After the input parameters were created, a production simulation model for the period 2011 through 2030 was developed for this Study.

The following power supply plans for meeting the City's projected load forecast were evaluated:

1. Case A: Purchase Capacity and Energy Needs from the Market.
2. Case B: Self-Build Coal-Fired Baseload Generation and Combustion Turbines.
3. Case C: Purchase Ownership in Dogwood Combined Cycle Plant and Construct Peaking Combustion Turbines.

Several tasks were completed to evaluate the power supply plan cases.

Task 1 - Evaluate Resource Energy Mix

A load forecast developed by IPL was reviewed and tables and graphs were prepared to evaluate the resource energy mix of the IPL system in several future years. Baseload, intermediate, and peaking needs in excess of existing and committed resources were identified for each year.

Task 2 - Resource Planning

Power supply planning cases were developed to evaluate power supply resource options identified in the scope of work. Two power supply plans evaluated in the Phase 2 Master Plan were updated to reflect changes in assumptions since 2009 and evaluated in this Report. Three new power supply plans were prepared for this Report to evaluate purchasing ownership of a portion of Dogwood.

Task 3 - Environmental Compliance Strategy and Cost

Sega prepared an environmental compliance strategy and estimated the costs to implement that strategy as presented in Section 3 - Environmental Considerations. The results were then considered in development of the resource plans, including the potential for fuel switching, costs to install pollution control equipment, and retirement dates for IPL's existing resources. Appendix A provides an overview of current and proposed future environmental regulations that are expected to impact electric utility planning.

Task 4 - Screen Power Supply Resource Alternatives

A screening analysis was prepared to compare the total cost of each resource alternative at various capacity factors. The results were used to determine what resource alternatives should be considered baseload, intermediate, or peaking.

Task 5 - Power Supply Analysis

A production simulation model was used to evaluate power supply plans for the IPL system. Variable costs for each resource such as fuel costs, emission costs, and variable operation and maintenance costs were modeled in the production simulation model. Annual power supply costs from each plan were compared using a present value of annual costs analysis on a total current year dollar basis. Initial production model results were utilized to determine reasonable capacity purchase levels for Dogwood.

The results of each of these tasks are summarized in the following sections of this Report. Section 2 - Existing System provides an updated summary of the IPL electric system and generating resources. Section 3 - Environmental Considerations provides a discussion of the impacts of environmental regulations on existing IPL generation resources and the potential costs and strategies for compliance. A related, more detailed explanation of applicable environmental regulations is provided for reference in Appendix A. Section 4 - Resource Energy Mix summarizes an analysis of a resource energy mix to meet IPL's capacity and energy needs and to determine the relative needs for different categories of generating resources: base load, peaking, and intermediate. Section 5 - Power Supply Alternatives summarizes the resource alternatives that were identified for supplying IPL's projected future capacity and energy requirements. Section 6 - Power Supply Plans describes the multiple power supply plans that were developed during this study to meet IPL's needs. Section 7 - Economic Analysis of Power Supply Plans summarizes the economic analysis of five fundamental IPL power supply plans. Finally, Section 8 - Conclusions and Recommendations provides the results of this study in Sega's recommendations for IPL.

SECTION 2

EXISTING SYSTEM

EXISTING SYSTEM

This Section describes the existing power supply resources and transmission system of IPL. Power supply resources include existing and committed purchase power arrangements.

EXISTING GENERATING UNITS

IPL owns 12 generating units with a total rated capacity of 288 MW as shown in Table 2-1.

Table 2-1
Existing IPL Generation

Unit	Year of Initial Operation	Type	Fuel	SPP Capacity Rating (Net MW)	Normal Operating Capability (Net MW)
Blue Valley 1	1958	Steam	Coal/Gas/Oil	21	20
Blue Valley 2	1958	Steam	Coal/Gas/Oil	21	20
Blue Valley 3	1965	Steam	Coal/Gas/Oil	51	50
Missouri City 1(1)	1955	Steam	Coal	19	19
Missouri City 2(1)	1955	Steam	Coal	19	19
RCT(2)	1976	CT	Gas/Oil	50	45
Sub J1	1968	CT	Oil	15	13
Sub J2	1968	CT	Oil	15	13
Sub I3	1972	CT	Oil	19	16
Sub I4	1972	CT	Oil	19	16
Sub H5	1972	CT	Gas/Oil	19	16
Sub H6	1974	CT	Gas/Oil	20	17
Total Installed Generation				288	264

(1) Acquired by IPL in 1979

(2) Not in operation as of the date of this Report.

IPL currently supplements this mix of internal generating resources with long-term baseload purchase power arrangements and economy energy purchases when economically desirable.

Blue Valley Station

The Blue Valley Station includes three coal-fired steam units. These units are used to generate base load and intermediate load energy.

Blue Valley Units 1 and 2 were placed in service in 1958 and are pulverized coal-fired units with capacity ratings of 21 MW net each. They are non-reheat units with boilers designed for operation at 850 pounds per square inch gage (psig) and 900 degrees F main steam conditions.

Unit 3 is the largest pulverized coal-fired steam unit at the Blue Valley Station. This unit was placed in service by IPL in 1965 and is the newest coal unit in the system. Blue Valley Unit 3 is a non-reheat coal-fired steam electric generator operating at 1,250 psig and 950 degrees F with a capacity rating of 51 MW net.

Missouri City Station

The Missouri City Station includes two coal-fired steam units that were originally installed in 1955 and are the oldest generators in the system. IPL purchased this plant from Northwest Electric Cooperative in 1979 and placed it back in service in 1982. Missouri City Units 1 and 2 are non-reheat pulverized coal-fired steam-electric generators rated at 19 MW net each. The boilers produce main steam at 850 psig and 900 degrees F to drive the steam turbine generators. The Missouri City Station is located outside of the IPL service territory near Missouri City in Clay County between Highway 210 and the Missouri River. For the past 15 years, the Missouri City Station has been operated as a seasonal supply resource, operating in baseload mode during the summer peak load period.

Combustion Turbines

IPL owns and operates six GE Frame 5 combustion turbines at three substations on its system. Two units are located at each of Substations H, I, and J. The total rated capacity from these units is 107 MW. The four units located at Substations I and J (68 MW) are oil-fired only. Two combustion turbines at Substation H totaling 39 MW are fueled with either natural gas or oil. All six units have black-start capability. Each of these combustion turbines is connected to the distribution voltage side of its substation at 13.2 kV.

In addition, IPL owns a 50 MW General Electric (GE) Model 7B regenerative combustion turbine (RCT) which is located at the Blue Valley Station. This natural gas and oil-fired unit is currently out of service. For the purposes of this Study, it is assumed that the unit has been retired.

EXISTING PURCHASE POWER ARRANGEMENTS

IPL has entered into two unit power purchase agreements to replace the KCP&L Montrose agreement that ended on May 31, 2011. These agreements are with Omaha Public Power District (OPPD) for capacity and energy from Nebraska City Generating Station, Unit 2 (NC2) and with Missouri Joint Municipal Electric Utility Commission (MJMEUC) for capacity and energy from KCP&L's Iatan Generating Station, Unit 2 (Iatan 2).

Nebraska City Generating Station, Unit 2 Purchase

The NC2 purchase is for an 8.33 percent share (net 56 MW) of the nominal 663 MW coal-fired steam plant owned by OPPD. NC2 began commercial operation May 2009. This cost-based purchase agreement is for the life of the unit and is expected to provide baseload energy to IPL beyond the term of this study. IPL has reserved firm transmission service from the Southwest Power Pool (SPP) to deliver 57 MW of capacity and energy from NC2 to IPL.

Iatan Generating Station, Unit 2 Purchase

The second baseload unit power purchase agreement is with the MJMEUC for 50 percent of MJMEUC's share of KCP&L's 850 MW Iatan 2 coal-fired steam plant. MJMEUC acquired an 11.76 percent (initially 100 MW) undivided ownership interest in the unit and sold 50 percent of their share to IPL under a cost-based purchase power agreement. Iatan 2 began commercial operation in December 2010. This purchase agreement is tied to the life of the unit and is expected to provide baseload energy to IPL beyond the term of this Study. IPL has secured 50 MW of long-term, firm transmission service from SPP for the delivery of energy generated at Iatan 2.

Smoky Hills II Wind Power Purchase

IPL entered into an agreement with Smoky Hills Wind Project II, LLC (Smoky Hills II) to purchase 15 MW of capacity and energy from the project beginning in December 2008 and ending in December 2028. Smoky Hills II is located approximately 20 miles west of Salina, Kansas. This purchase is expected to provide intermittent renewable energy estimated at 61,101 MWh annually and approximately 2 MW of accredited capacity under SPP criteria.

SYSTEM OPERATION AND DISPATCH

The power supply system is dispatched by IPL operating staff. Currently, the normal order of economic dispatch is to first schedule energy from Blue Valley Units 1 and 2 and Missouri City Station. Blue Valley Unit 3 is the last steam unit dispatched due to the SO_2 emission costs associated specifically with this unit. Combustion turbines are dispatched if they are less costly than market energy purchases. The Missouri City steam units are used primarily during the five-month summer season.

INTERCONNECTIONS AND TRANSMISSION SYSTEM

The IPL transmission system currently includes approximately 27 miles of 161-kV transmission lines and 46 miles of 69-kV transmission lines. The distribution system is served by 12, 69/13.2-kV substations. All of these distribution substations are served by at least two 69-kV lines and all include two transformers to step down to distribution voltages. Substation F is served entirely by KCP&L from two 69-kV lines with 69-kV switches to select one of the two lines. Six of the distribution substation transformers also serve as generator step-up transformers for the combustion turbines at Substations H, I, and J. The combustion turbines are directly connected to the 13.2-kV bus for power injection into the 13.2-kV distribution system. Three 10 mega-volt-amp-reactive (MVAr) capacitor banks provide reactive compensation on the 69-kV buses at Substations M, N, and H.

IPL is interconnected at 161-kV with KCP&L, Kansas City Power & Light - Greater Missouri Operations Company (KCP&L-GMO, formerly Aquila's Missouri Public Service Company that was acquired by KCP&L in 2008), and Associated Electric Cooperative, Inc. (AECI). There are also several smaller 69-kV interconnections with KCP&L. The Missouri City power plant is interconnected to AECI at 13.8-kV at the plant substation. IPL serves the KCP&L Blue Mills Distribution Substation from the 161-kV transmission line between Substation A and Eckles Road Substation. The IPL interconnections and delivery points are summarized in Table 2-2.

There are three, 161/69-kV substations in the IPL system, including substations M, N, and A. A new 161-kV transmission line now connects Substations A and M. The 161-kV interconnection at Substation M consists of a 112 mega-volt-amp (MVA) capacity 161/69-kV transformer connected to two 161-kV transmission lines that extends to the KCP&L Hawthorn Power Plant substation and to Substation A. Substation N consists of a 112 MVA, 161/69-kV transformer connected to a 161-kV line that extends to the KCP&L Blue Valley Substation. Substation A at the Blue Valley Power Plant consists of two 112 MVA, 161/69-kV transformers connected to a 161-kV line that extends to the KCP&L-GMO Sibley Power Plant, with intermediate connections at the KCP&L Blue Mills Substation and the IPL Eckles Road Substation. IPL is interconnected with AECI at the

Eckles Road Substation and with KCP&L-GMO at the Sibley Power Plant. All 161/69-kV transformers include load tap changers (LTC) for control of the 69-kV bus voltage.

Table 2-2
Interconnections and Delivery Points

COMPONENTS	Interconnecting Utility	Interconnect Voltage (kV)
Interconnections		
Substation N to KCP&L's Blue Valley Substation	KCP&L	161
Substation M to Hawthorn Station	KCP&L	161
Substation E to Hawthorn Station	KCP&L	69
Substation H to Hawthorn Station and to Liberty Substation	KCP&L	69
Substation A to Lake City Substation	KCP&L	69
Eckles Road Substation to Sibley Station	KCP&L-GMO	161
Substation N to Blue Ridge Substation	KCP&L-GMO	69
Eckles Road Switching Substation to Missouri City and Pittsville	AECI	161
Missouri City Generators to Missouri City Substation	AECI	13.8
Delivery Points		
Blue Mills Substation (Served by IPL Substation A - Eckles Road Line)	KCP&L	161
Substation F (Served from KCP&L Hawthorn - Substation H Line)	KCP&L	69

IPL's capability to import power from outside its system is approximately 280 MW. Two capacitor banks planned for installation at IPL substations in 2012 will increase the net import capability to 314 MW.

SECTION 3

ENVIRONMENTAL CONSIDERATIONS

ENVIRONMENTAL CONSIDERATIONS

INTRODUCTION

Since the Phase 2 Master Plan Study was prepared in 2009, several significant revisions have been made to Federal environmental regulations for electric generating units. An overview of the specific United States EPA regulations is provided in Appendix A as a reference for the environmental regulatory discussions in this document. The purpose of this Section is to outline the various corrective measures that are now anticipated to be required for the IPL generating units to comply with the emissions requirements of newly enacted and/or proposed EPA regulations applicable to the units and how each will be affected. After considering potential compliance options for the units, the costs and schedules of recommended screening scenarios for power supply screening analysis are discussed later in this Section.

OVERVIEW OF ENVIRONMENTAL REGULATIONS IMPACTING MASTER PLANNING

Certain environmental regulations (current and potential future) impact Master Planning for IPL. This Section also provides a general overview of the applicability and timing of requirements to the existing IPL resources. Environmental regulations which have been found to impact the Master Planning are in the area of air quality and cooling water intake. Although there are solid waste and water quality regulations with environmental compliance requirements applicable to the existing and future generation equipment, these have been found to not have an impact on the Master Planning process. Air quality regulations and compliance requirements have been found to have a substantial impact on the Master Planning evaluation of the scenarios considered.

Air quality and cooling water regulations and compliance requirements addressed in this overview include:

1. Cross-State Air Pollution Rule (CSAPR).
2. Regional Haze Rule.
3. Utility Boiler Maximum Achievable Control Technology (MACT).
4. Industrial/Commercial/Institutional Boiler Maximum Achievable Control Technology (MACT).
5. Combustion Turbine Generator (CTG) Maximum Achievable Control Technology (MACT).
6. Ozone Non-Attainment Area/New Ozone National Ambient Air Quality Standards (NAAQS).
7. New Sulfur Dioxide (SO_2) National Ambient Air Quality Standards (NAAQS).
8. New Nitrogen Dioxide (NO_2) National Ambient Air Quality Standards (NAAQS).
9. Particulate Matter$_{2.5}$ ($PM_{2.5}$) National Ambient Air Quality Standards (NAAQS).
10. New Source Performance Standards (NSPS).
11. New Source Review (NSR).
12. Clean Water Act Cooling Water Intake 316(b) Rule.

The applicability of these environmental regulations and rules to the specific IPL generating units is in the following Sections.

IMPACT OF REGULATIONS ON IPL UNITS

The pertinent details of the potential impacts of the applicable environmental regulations on each of the IPL generating units are discussed below. This formed the underlying basis for development of the screening options presented later in this Report. The approximate capital cost anticipated for compliance options with these regulations are summarized in Table 3-1 and are referenced in the Sections below.

Table 3-1
Summary of Capital Costs Required to Comply with Environmental Regulations

Regulation & Implementation Year	Regulated Air Constituents	Blue Valley				Missouri City Units 1 & 2	Combustion Turbines
		Units 1 & 2		Unit 3			
		Coal	Gas	Coal	Gas		
CSAPR 2012	SO_2, NO_x	NA	NA	$48.1 (1, 2, 5, 6, 7, 10)	$0.0 (6)	NA	NA
IB MACT 2015	PM, HCl, Hg, CO, dioxin/furans	$16.2 (3, 4, 8, 9, 10, 13)	$0.0	NA	NA	$8.1 (3, 4, 8, 9, 11, 13)	NA
Utility MACT 2015	PM, HCl/ SO_2, Hg	NA	NA	$1.4 (4)	$0.0	NA	NA
NAAQS - SO_2 2017	SO_2	$0.0	$0.0	$0.0	$0.0	$0.0	NA
NAAQS - NO_x 2017	NO_x	$5.6 (2)	$7.6 (1, 2)	$0.0	$0.0	$5.1 (1, 2)	$15.3 (14)
NAAQS - Ozone 2018	NO_x	$7.0 (7)	$8.6 (7)	$0.0	$9.1	$6.5 (7)	$0.0
316(b) Intake 2020	NA	NA	NA	NA	NA	$7.4 (15)	NA
Total Capital Costs		**$28.8**	**$16.2**	**$49.5**	**$9.1**	**$27.1**	**$15.3**

Control Technology Codes:

1. Low NO_x burners
2. Over-fired air
3. Dry sorbent injection
4. Activated carbon injection
5. Semi-dry FGD
6. Limited operating hours
7. Selective non-catalytic reduction
8. Certified emissions monitor
9. Combustion control
10. Fabric filter conversion/addition
11. Fabric filter upgrade
12. ESP rebuild
13. Good combustion practices
14. Water injection
15. Cooling tower

NOTES:

1. NA - Rule not applicable.
2. Each individual cost shown is for compliance with only for the rule/year indicated. Total compliance cost for an indicated year is determined by also adding in all applicable costs for previous years which were required to allow the source to continue operation.
3. All values stated in 2011 dollars.

Blue Valley Unit 3

Cross-State Air Pollution Rule

The Cross-State Air Pollution Rule (CSAPR), which takes effect January 1, 2012, places limitations on the amount of nitrogen oxides (NO_X) and sulfur dioxide (SO_2) emissions from generating facilities over 25 MW in size. Options for meeting the NO_X and SO_2 emission limits include installing emission reduction systems, limiting the operating hours of the unit, purchasing emission allowances, and/or switching from coal to natural gas.

Based on recent natural gas test burns, IPL believes that the NO_X emission rate will be reduced significantly if the unit burns natural gas as compared to coal. Therefore, Blue Valley Unit 3 could be operated on natural gas up to its CSAPR NO_X allowance allocation tonnage without installing new emissions reduction measures. This would limit annual full-load equivalent hours to less than approximately 4,000 hours per year in 2012 and thereafter, or up to 8,000 annual hours at a 50 percent annual capacity factor (which is closer to this unit's historical capacity factor). SO_2 emissions would be reduced to near zero and would not be a limitation on hours of operation.

For continued coal-fired operation of Blue Valley Unit 3, an expenditure of approximately $48.1 million in 2011 dollars for SO_2 and NO_X emission reduction equipment would be required in addition to limiting annual full-load equivalent hours to less than approximately 1,200 hours per year, or 2,400 annual hours at a 50 percent annual capacity factor. The emission reduction equipment would include low NO_X burners (LNB), over-fired air (OFA), and selective non-catalytic reduction (SNCR) for NO_X reduction; a semi-dry flue gas desulfurization (FGD) system and the addition of a fabric filter (FF) or conversion of the existing electrostatic precipitator (ESP) would be necessary for SO_2 reduction. Although compliance with CSAPR begins in 2011, installation of this equipment is not feasible until the end of 2013. Blue Valley Unit 3 would still have to operate on natural gas (less than 4,000 hours per year) prior to scheduling and completing the control installation.

Utility Boiler MACT

The proposed Utility Boiler Maximum Achievable Control Technology (Utility MACT) is anticipated to require compliance by 2015 for controlling coal-fired emissions of hazardous air pollutants (HAPs), including particulate matter (PM), hydrogen chloride (HCl), and mercury (Hg) for units equal to or greater than 25 MW in size. Utility MACT is based on specific emission rates, rather than annual cumulative tons of emissions. As a result, limiting operating hours or acquiring pollutant allowances are not permitted. Full compliance with Utility MACT would be achieved with Blue Valley Unit 3 firing only natural gas with no additional capital expenditure.

For continued coal-fired operation of Blue Valley Unit 3, compliance with Utility MACT would require the semi-dry FGD system and fabric filter measures indicated above for addressing CSAPR plus activated carbon injection (ACI). The total capital cost for addition of these controls to comply with Utility MACT (in its proposed form) in 2015 for burning coal in Blue Valley Unit 3 is projected to be $1.4 million in 2011 dollars. This is in addition to the $48.1 million which would have been spent previously to comply with CSAPR. However, if the compliance measures indicated above for addressing CSAPR for firing coal were already installed (which also include NO_x reduction measures), the addition of just ACI is estimated to cost approximately $1.4 million in 2011 dollars and would require a shorter two-week outage for installation.

SO_2 and NO_2 NAAQS

The recently promulgated National Ambient Air Quality Standards (NAAQS) for SO_2 and for nitrogen dioxide (NO_2) would impact Blue Valley Unit 3 coal-fired operation by 2017. However, the measures required to be implemented in prior years for compliance with CSAPR and/or Utility Boiler MACT on coal would already have addressed these issues: A semi-dry FGD and fabric filter for SO_2-NAAQS and LNB/OFA/SNCR for NO_x. Additional emission controls would not be anticipated for SO_2-NAAQS and NO_2 NAAQS under the natural gas firing compliance scenario for Blue Valley Unit 3.

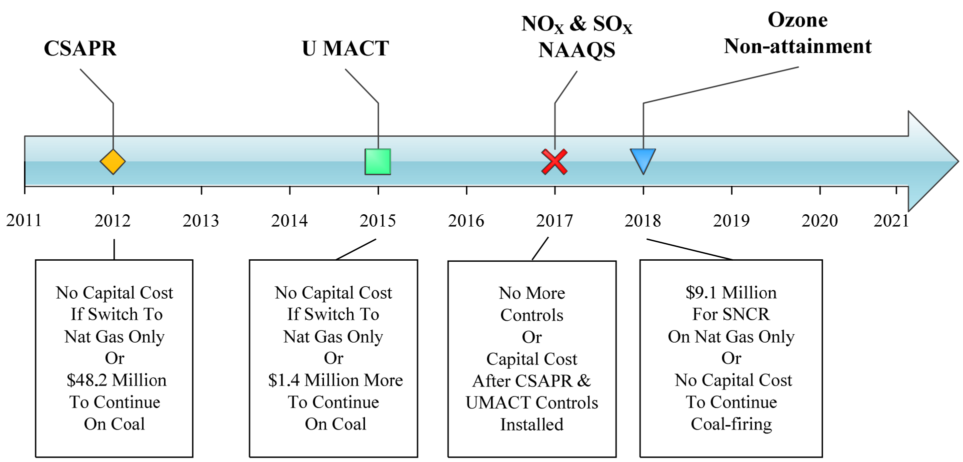
Ozone Non-Attainment Area/New Ozone NAAQS

Ozone non-attainment is expected to require NO_X reduction measures in 2018 for both coal-fired and natural gas-fired operation of Blue Valley Unit 3. Compliance measures would include LNB/OFA and SNCR for the coal-fired scenario, but these measures would most likely have been installed previously for compliance with CSAPR for continued operation on coal. SNCR would likely be required for the natural gas-fired scenario by 2018 at an estimated cost of $9.1 million in 2011 dollars.

Summary

A timeline of regulatory compliance and associated costs for Blue Valley Unit 3 is shown in Figure 3-1.

Figure 3-1
Impact of Environmental Regulations on Blue Valley Unit 3



If Blue Valley Unit 3 is limited to firing only natural gas beginning in 2012, no capital cost expenditures would be required until 2018 when $9.1 million (2011 dollars) would be required for SNCR installation for the ozone non-attainment area compliance. Annual operation would be limited to less than 4,000 hours of equivalent full load (or 8,000 hours at 50 percent capacity factor) on natural gas.

However, continued coal-firing at Blue Valley Unit 3 is projected to require a capital expenditure of $48.1 million in 2011 dollars for LNB, OFA, semi-dry FGD, SNCR, and FF to comply with CSAPR. An additional $1.4 million in 2011 dollars would be required for installation of ACI by 2015 (assuming the fabric filter installed is designed for additional ACI-loading capability) for compliance with Utility Boiler MACT for coal firing. Gas firing would be required in 2012 and 2013 in the interim if the emission control measures for coal firing were to be procured and installed.

Blue Valley Units 1 and 2

CSAPR and Utility Boiler MACT are not applicable to units that are 25 MW or less in capacity and, therefore, do not apply to Blue Valley Units 1 and 2.

The Industrial Boiler Maximum Achievable Control Technology (IB MACT) regulation (in its current March 21, 2011 form) is anticipated to require modifications to Blue Valley Units 1 and 2 by 2015 based on the rule reconsideration timeline EPA issued on June 24, 2011 for reducing PM, HCl, Hg, carbon monoxide (CO), and dioxin/furan emissions. Alternatively, Blue Valley Units 1 and 2 could switch to firing only natural gas fuel to comply with IB MACT without modifications.

For continued coal-fired operation of Blue Valley Units 1 and 2, an expenditure of $16.2 million in 2011 dollars would be required by 2015. Improved combustion controls, dry sorbent injection (DSI), ACI, and the addition of a fabric filter or conversion of the existing ESP to a fabric filter would be necessary. Again, if Blue Valley Units 1 and 2 were to be operated solely on natural gas, these measures would not be required.

The recently promulgated NAAQS for SO_2 and for NO_2 would impact Blue Valley Units 1 and 2 coal-fired operations by 2017. However, the measures required to be implemented in prior years for compliance with Industrial Boiler MACT would already have addressed the SO_2 issue. The NO_2-NAAQS would require the addition of OFA at a cost of approximately

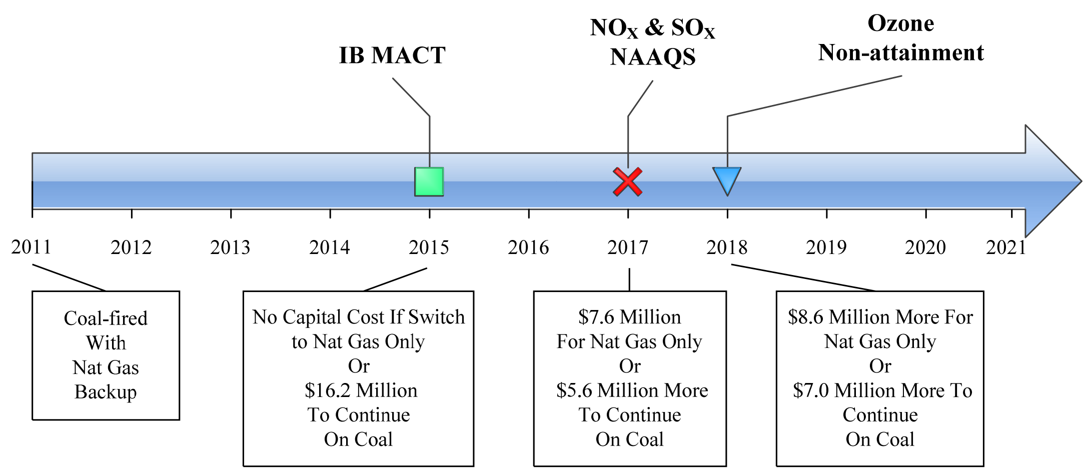
$5.6 million. Likewise SO_2-NAAQS would not affect Blue Valley Units 1 and 2 natural gas-fired operations; however, NO_2-NAAQS would require installation of LNB/OFA for gas firing. These gas-fired NO_X reduction measures would cost approximately $7.6 million.

Finally, ozone non-attainment is expected to require NO_X reduction measures in 2018 for both coal-fired and natural gas-fired operation of Blue Valley Units 1 and 2. Compliance measures would include LNB/OFA and SNCR, but the LNB/OFA would have been installed previously for compliance with NO_X-NAAQS. The additional cost of SNCR would be approximately $7.0 million in 2011 dollars for coal operation or $8.6 million in 2011 dollars for natural gas operation

Summary

A timeline of regulatory compliance and associated costs for Blue Valley Units 1 and 2 is shown in Figure 3-2.

Figure 3-2
Impact of Environmental Regulations on Blue Valley Units 1 and 2



If Blue Valley Units 1 and 2 are limited to firing only natural gas by 2015, and LNB, OFA, and SNCR are installed by 2018, the total estimated capital cost would be $16.2 million in 2011 dollars. However, for continued coal-firing at Blue Valley Units 1 and 2 starting in 2015, a capital expenditure of $16.2 million in 2011 dollars will be required for DSI, ACI, and fabric filter by year 2015, an additional $5.6 million in 2011 dollars will be required for installation of LNB/OFA by 2017, and an additional $7.0 million in 2011 dollars will be required for installation of SNCR by 2018.

Missouri City Units 1 and 2

The IB MACT regulation is anticipated to require modifications to Missouri City Units 1 and 2 by 2015 for reducing PM, HCl, Hg, CO, and dioxin/furan emissions. These units are coal fired and switching to natural gas fuel is not an available option.

For continued coal-fired operation of Missouri City Units 1 and 2, an expenditure of $8.1 million in 2011 dollars would be required by 2015. Improved combustion controls, DSI, ACI, and upgrades to the existing fabric filter would be necessary.

The SO_2-NAAQS and NO_2-NAAQS regulations would also impact Missouri City Units 1 and 2 by 2017. As at Blue Valley Units 1 and 2, the measures required to be implemented in prior years for compliance with IB MACT would already have addressed the SO_2 issue. However, the NO_2-NAAQS regulation would require the addition of LNB/OFA at a cost of approximately $5.1 million in 2011 dollars.

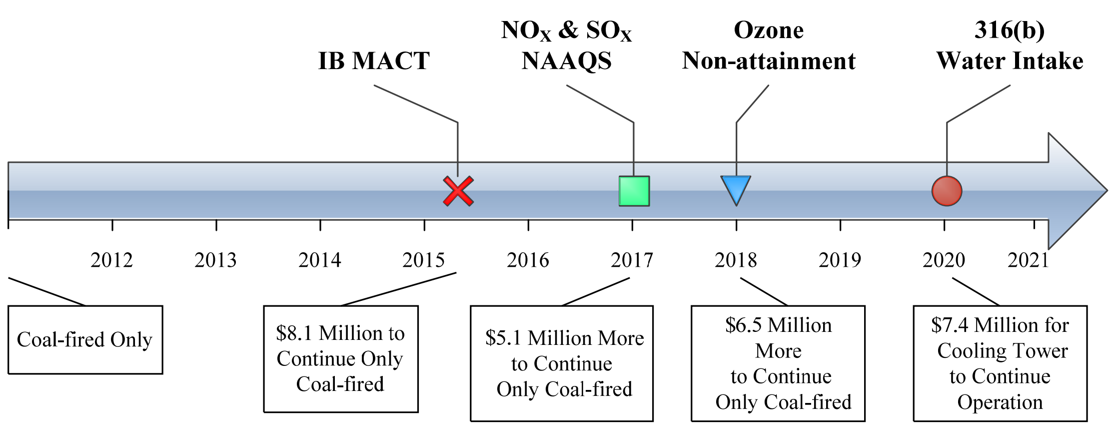
Ozone non-attainment is expected to require NO_x reduction measures in 2018. Compliance measures would include LNB/OFA and SNCR, but the LNB/OFA would have been installed previously for compliance with NO_2-NAAQS. The additional cost of the SNCR would be $6.5 million for coal operation in 2011 dollars.

EPA has also proposed revisions to Section 316(b) of the Clean Water Act, regulating the location, design, construction, and capacity of once-through cooling water intake structures for the best technology available for minimizing environmental impacts to aquatic organisms from the withdrawal of cooling water from lakes and rivers. Missouri City Units 1 and 2 are the only IPL units affected by the revisions to 316(b), which are scheduled to require compliance by 2020. Sega briefly reviewed the requirements for retrofitting the existing Missouri City Units 1 and 2 water intake on the Missouri River and believes that conversion to a closed-loop evaporative cooling tower system would be less costly (approximately $7.4 million in 2011 dollars) than reconstructing the circulating water intake and screens to the new Section 316(b) requirements (roughly $12 to $15 million in 2011 dollars).

Summary

A timeline of regulatory compliance and associated costs for Missouri City Units 1 and 2 is shown in Figure 3-3. For continued operation at Missouri City Units 1 and 2, a capital expenditure of $8.1 million in 2011 dollars will be required for DSI, ACI, and FF by 2015, an additional $5.1 million in 2011 dollars will be required for installation of LNB/OFA by 2017, and an additional $6.5 million in 2011 dollars will be required for installation of SNCR by 2018. Continued operation of Missouri City Units 1 and 2 in 2020 would also require installation of a closed-loop evaporative cooling system at a projected cost of $7.4 million in 2011 dollars.

Figure 3-3
Impact of Environmental Regulations on Missouri City Units 1 and 2



Combustion Turbines

The IPL GE Frame 5 combustion turbines are installed in pairs at the J, I, and H Substations. J-1, J-2, I-3, and I-4 combustion turbines are oil-fired, while H-5 and H-6 are natural gas-fired and have oil-firing capability. None of these combustion turbines exceeds 25 MW of capacity, so the CSAPR regulation is not applicable to them. The Combustion Turbine Generator MACT would not apply to these units unless modifications are made that would trigger applicability. A triggering modification is any physical change or change in the method of operation which results in an increase in emissions and cannot be considered exempt, such as routine maintenance, repair, or replacement. The SO_2-NAAQS is not expected to impact these units because of the ultra low sulfur content of the fuel/oil they burn.

As with the other IPL units, the new NO_2-NAAQS and the ozone non-attainment area regulations are expected to impact these combustion turbines by 2017 and 2018 and are expected to require NO_x reduction measures in 2017. Water injection would reduce NO_x emissions to 42 ppmvd at 15 percent oxygen (O_2) on natural gas and 65 ppmvd at 15 percent O_2 on distillate. The cost per combustion turbine is estimated to be $2.55 million in 2011 dollars for the installation of combustion turbine original equipment manufacturer (OEM) injection equipment, demineralized water storage tanks, and forwarding pump skids. Sega presumed that demineralized water would be trucked from the Blue Valley Power Station and IPL would rent truck-mounted reverse osmosis equipment to place at each unit during peak demand seasons in order to minimize capital expense.

ENVIRONMENTAL COMPLIANCE STRATEGY

The power supply plans options evaluated later in this Report were based on a prudent environmental compliance strategy to limit major capital costs while operating the IPL units for their remaining useful lives in compliance with new environmental regulations.

The strategy for each unit is summarized as follows. The dates indicated are approximations and are dependant in many cases on final rule development by regulatory agencies.

Missouri City Units 1 and 2

Continue coal fired operation of the Missouri City Plant until April 30, 2015 (IB MACT). Then, replace these 60-year old units with 38-MW of capacity from other resources.

Blue Valley Units 1 and 2

Continue coal firing these units until April 30, 2015 (IB MACT), then switch to natural gas-fired operations until December 31, 2016 (NO_2 and SO_x NAAQS). Replace the 42-MW rated capacity of these two units with other resources after 58 years of operation.

Blue Valley Unit 3

Limit operation of this unit to no more than approximately 4,000 hours of equivalent full-load operation per year (or 8,000 annual hours at a 50 percent annual capacity factor) firing only natural gas beginning on January 1, 2012 (CSAPR). IPL should replace the 50 MW capacity of this unit with other resources after 51 years of operation on December 31, 2016 (NO_2 and SO_2 NAAQS).

SECTION 4

RESOURCE ENERGY MIX

RESOURCE ENERGY MIX

This Section summarizes an analysis of a resource energy mix to meet IPL's capacity and energy needs. The resource energy mix was used to estimate baseload, intermediate, peaking, and planning reserve margin needs of the IPL system. The approach to estimating resource needs was to first develop a "load duration curve" graph from the IPL load forecast. The graph is used to estimate the amounts of capacity needed for each category of resources.

LOAD FORECAST

IPL prepared annual and monthly projections of system energy requirements and system peak demand and annual projections of the number of customers for their budget and planning activities. These annual projections are based on historical analyses of growth trends and anticipated significant load additions or reductions in the IPL service area, including adjustments since 2009 resulting from the economic recession, as well as the impacts of energy efficiency programs. Table 4-1 provides IPL's projection of the impacts of energy efficiency programs for the study period.

Table 4-1
IPL Projected Energy Efficiency Impacts

Year	Peak Demand (MW)	Energy (MWh)		Year	Peak Demand (MW)	Energy (MWh)
2011	0.67	3,401		2021	3.08	15,798
2012	0.92	4,699		2022	3.23	16,449
2013	1.19	6,082		2023	3.38	17,101
2014	1.45	7,465		2024	3.46	17,610
2015	1.71	8,838		2025	3.53	18,115
2016	1.97	10,213		2026	3.61	18,623
2017	2.23	11,587		2027	3.69	19,126
2018	2.46	12,773		2028	3.76	19,631
2019	2.69	13,961		2029	3.84	20,130
2020	2.92	15,145		2030	3.91	20,626

Table 4-2 provides the IPL load forecast through the year 2030, including the impacts of energy efficiency programs.

Table 4-2
IPL Load Forecast with Energy Efficiency Programs

Year	Peak Demand (MW)	Growth Rate (%)	Energy Requirement (MWh)	Growth Rate (%)	Annual Load Factor (%)	Growth Rate (%)
2002	294.4	-	1,109,883	-	43.0	-
2003	314.9	7.0	1,103,321	(0.59)	40.0	(7.06)
2004	289.7	(8.0)	1,097,040	(0.57)	43.2	8.08
2005	296.2	2.2	1,154,561	5.24	44.5	2.93
2006	314.5	6.2	1,149,693	(0.42)	41.7	(6.22)
2007	320.5	1.9	1,182,873	2.89	42.1	0.96
2008	298.5	(6.9)	1,165,442	(1.47)	44.6	5.79
2009	291.3	(2.4)	1,123,111	(3.63)	44.0	(1.25)
2010	299.5	2.8	994,871	(11.42)	37.9	(13.86)
Historical [2]						
Projected [1,3]						
2011	305.6	2.0	1,153,596	15.95	43.1	13.65
2012	310.3	1.5	1,181,549	2.42	43.5	0.89
2013	313.6	1.1	1,201,557	1.69	43.7	0.61
2014	317.2	1.1	1,221,747	1.68	44.0	0.55
2015	320.7	1.1	1,242,129	1.67	44.2	0.55
2016	324.1	1.1	1,262,691	1.66	44.5	0.58
2017	327.7	1.1	1,283,434	1.64	44.7	0.55
2018	331.3	1.1	1,304,549	1.65	44.9	0.52
2019	335.0	1.1	1,325,842	1.63	45.2	0.52
2020	338.6	1.1	1,347,322	1.62	45.4	0.55
2021	342.3	1.1	1,369,515	1.65	45.7	0.53
2022	346.2	1.1	1,391,890	1.63	45.9	0.50
2023	349.8	1.1	1,414,447	1.62	46.2	0.56
2024	353.7	1.1	1,437,330	1.62	46.4	0.49
2025	357.7	1.1	1,460,397	1.60	46.6	0.49
2026	361.6	1.1	1,483,644	1.59	46.8	0.49
2027	365.5	1.1	1,507,078	1.58	47.1	0.49
2028	369.5	1.1	1,530,691	1.57	47.3	0.49
2029	373.5	1.1	1,554,491	1.55	47.5	0.49
2030	377.5	1.1	1,578,477	1.54	47.7	0.49

(1) 2011 through 2030 projections prepared by IPL.
(2) Actual historical data 2002 through 2010.
(3) Projections are weather normalized.

RESOURCE ENERGY MIX

The "load duration curve" is used to estimate the amounts of capacity needed for each category of resources. Figure 4-1 shows the load duration curve for the IPL system in 2011. Existing resources were plotted on each graph according to their resource type. For example, NC2 is at the bottom of the graph because it is a baseload resource, the Substation J CTs are at the top of the graph because they are peaking units and the Blue Valley units are in the middle of the graph because they operate as a baseload/intermediate resource.

Baseload

This category of energy resources generally has high capital costs and relatively low operating costs. Baseload resources normally operate 75 percent to 90 percent of the hours in a year to provide power at relatively low total costs and typically include such technologies as coal-fired steam plants (NC2 and Iatan 2, for example), nuclear plants, and integrated gasification combined cycle (IGCC) plants. Baseload capacity needs were estimated using a capacity factor of approximately 95 percent.

Peaking

These are generating units that provide energy for short durations at the time of peak demand or as backup for baseload resources. Peaking resources typically have lower installation costs than baseload resources, but use more expensive fuels (natural gas or distillate). Internal combustion engines and combustion turbines are the most common peaking units. Utility-sized combustion turbines are available in discrete capacities ranging from 25 MW to nearly 200 MW each. Internal combustion generator sets are not commonly used in the U.S. in sizes above 8 MW each. Combustion turbines, similar to those currently used by IPL, are a reasonable peaking resource for the IPL system based on the projected peaking resource need and the total IPL capacity responsibility.

Similarly sized aeroderivative combustion turbines and medium-speed reciprocating internal combustion engines (RICE) that operate with more flexibility and are more efficient are also available for future peaking resources.

Intermediate

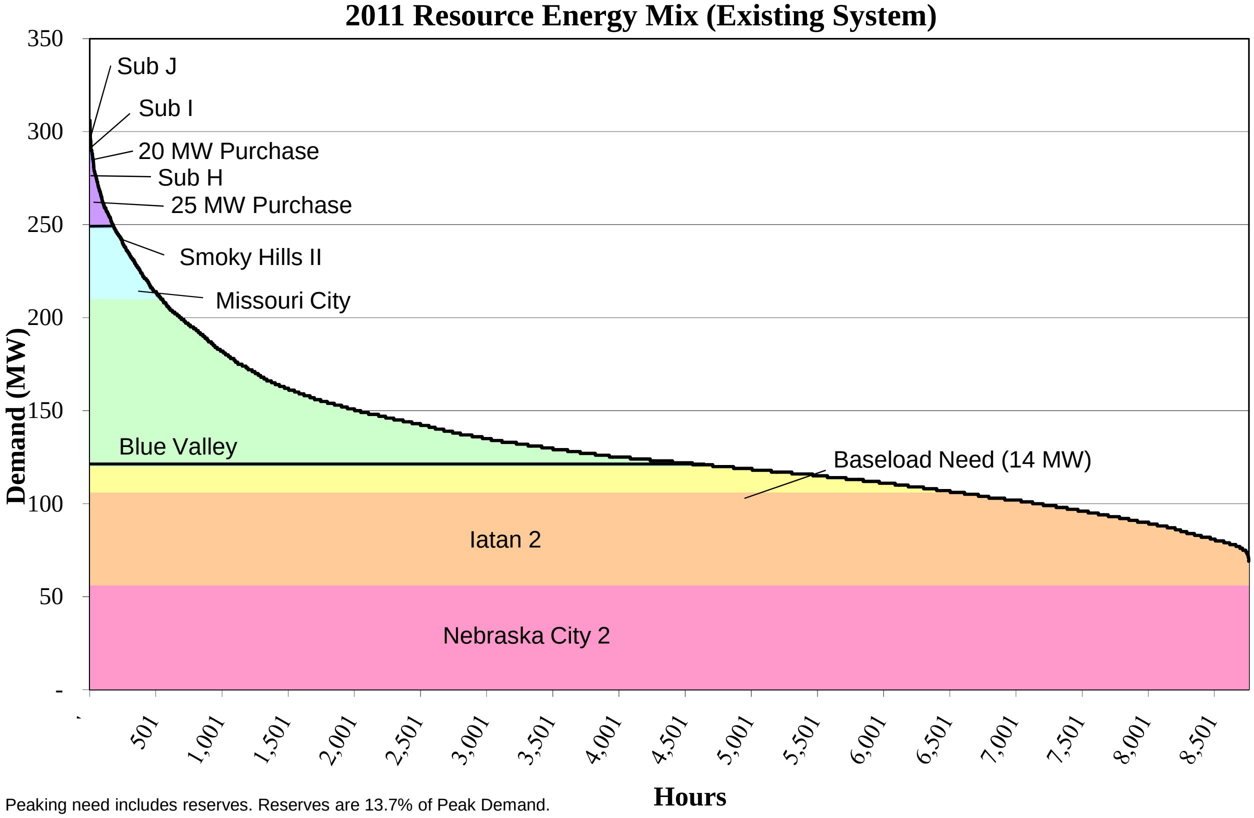
Between baseload and peaking resources, intermediate units serve less sharply defined loads, depending on the duration of loads at different times of the year. Typically, they are more expensive to build than peaking resources, but less costly than baseload resources. Usually burning relatively expensive fuels (natural gas, and/or distillate fuel oil), intermediate plants are typically more efficient than peaking units. Combustion turbines in combined cycle configuration are commonly used as intermediate resources. Combined cycle plants capture otherwise wasted exhaust energy from combustion turbines in heat recovery steam generators (HRSGs) to produce steam to drive a turbine generator. Recovering the waste heat from combustion turbines raises the efficiency of combined cycle plants above the efficiency of combustion turbines in simple cycle configuration. The more efficient aeroderivative combustion turbines and medium-speed RICE units may be run as intermediate resources. Similarly, highly efficient gas-fired combined cycle plants may be called upon for base load requirements.

Analysis

As mentioned previously, Figure 4-1 shows the 2011 load duration curve for the IPL system. The 2011 total baseload need of the IPL system is estimated at 120 MW. The 2011 baseload need after taking into account NC2 (56 MW) and Iatan 2 (50 MW) is 14 MW.

The 2011 total intermediate need of the IPL system is estimated at approximately 110 MW. Blue Valley, Missouri City, and Smoky Hills II combined are 133 MW, thus, IPL has approximately 20 MW of surplus intermediate capacity in 2011. Currently, the Blue Valley and Missouri City units are used to satisfy any shortfall of the baseload units. The 2011 total peaking need, including reserves (13.7 percent of the system peak), is estimated at approximately 118 MW. Total IPL peaking resources (SUB H, SUB I, SUB J) in 2011 are 91 MW. IPL also purchased 20 MW of capacity and associated energy from the MJMEUC and 25 MW of capacity and associated energy from Westar for Summer 2011. With these additional purchases, IPL has sufficient resources for the projected 2011 peak demand, including reserves, totaling 347 MW.

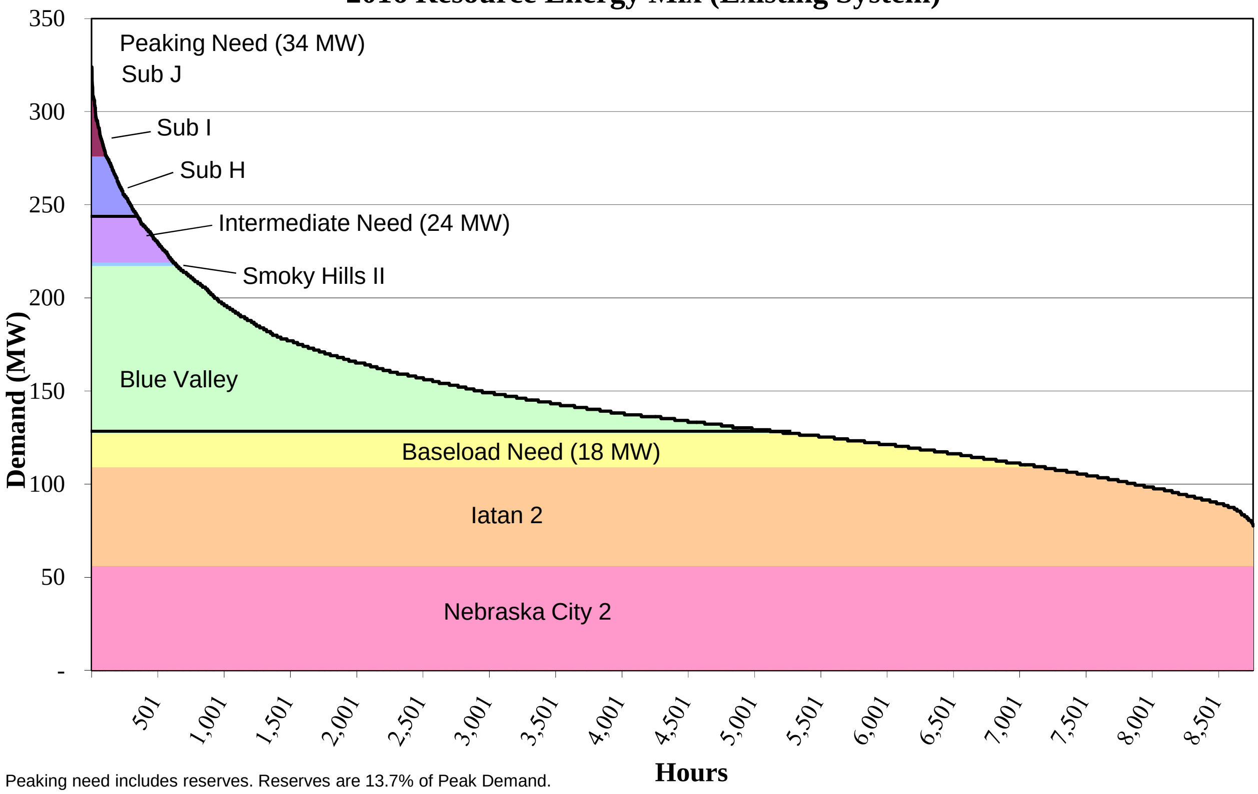
Figure 4-1
2011 Resource Energy Mix (Existing System)



Peaking need includes reserves. Reserves are 13.7% of Peak Demand.

Figure 4-2 shows the 2016 resource energy mix for the IPL system. The estimated baseload need increases to 18 MW in 2016. The estimated intermediate need becomes a 24 MW deficit in 2016. The estimated peaking need increases to 34 MW in 2016.

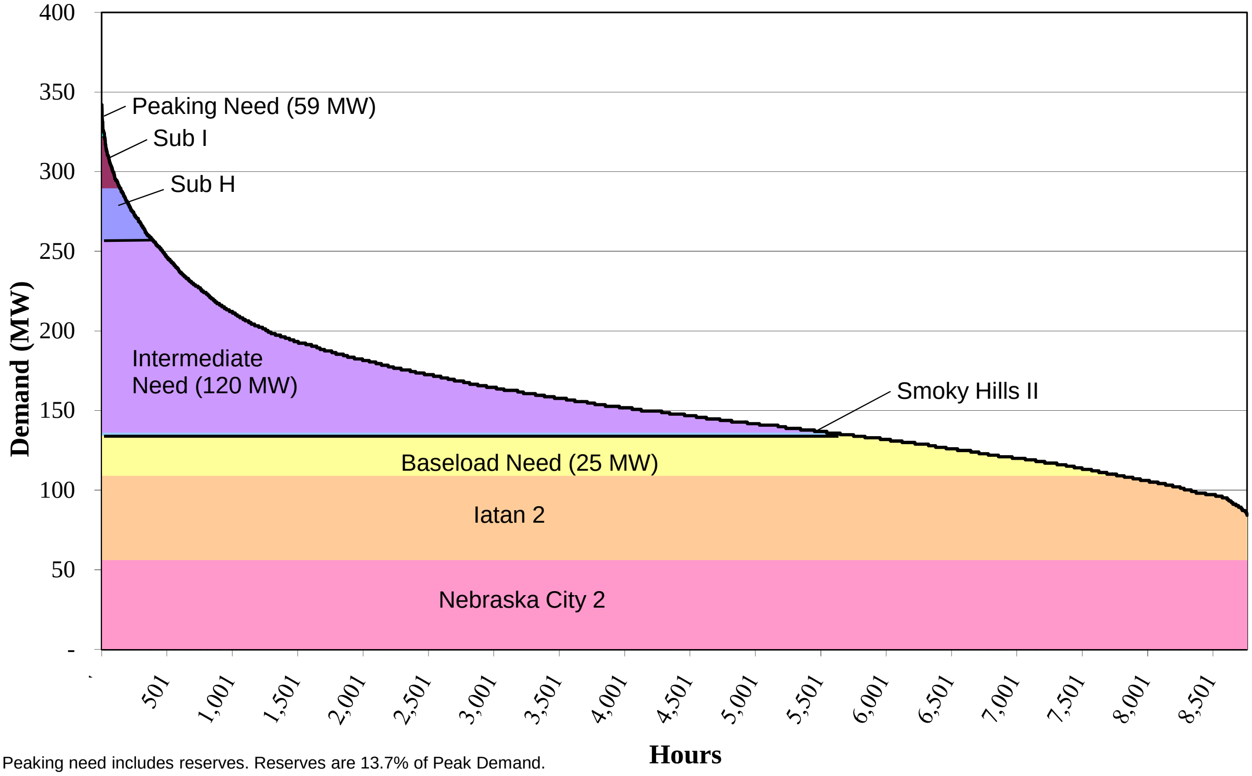
Figure 4-2
2016 Resource Energy Mix (Existing System)



Peaking need includes reserves. Reserves are 13.7% of Peak Demand.

Figure 4-3 shows the 2021 resource energy mix for the IPL system. The estimated baseload need increases from 18 MW in 2016 to 25 MW in 2021. The estimated intermediate need increases from 24 MW in 2016 to 120 MW in 2021 because the Blue Valley Plant is no longer in operation. The estimated peaking need increases from 34 MW in 2016 to 59 MW in 2021.

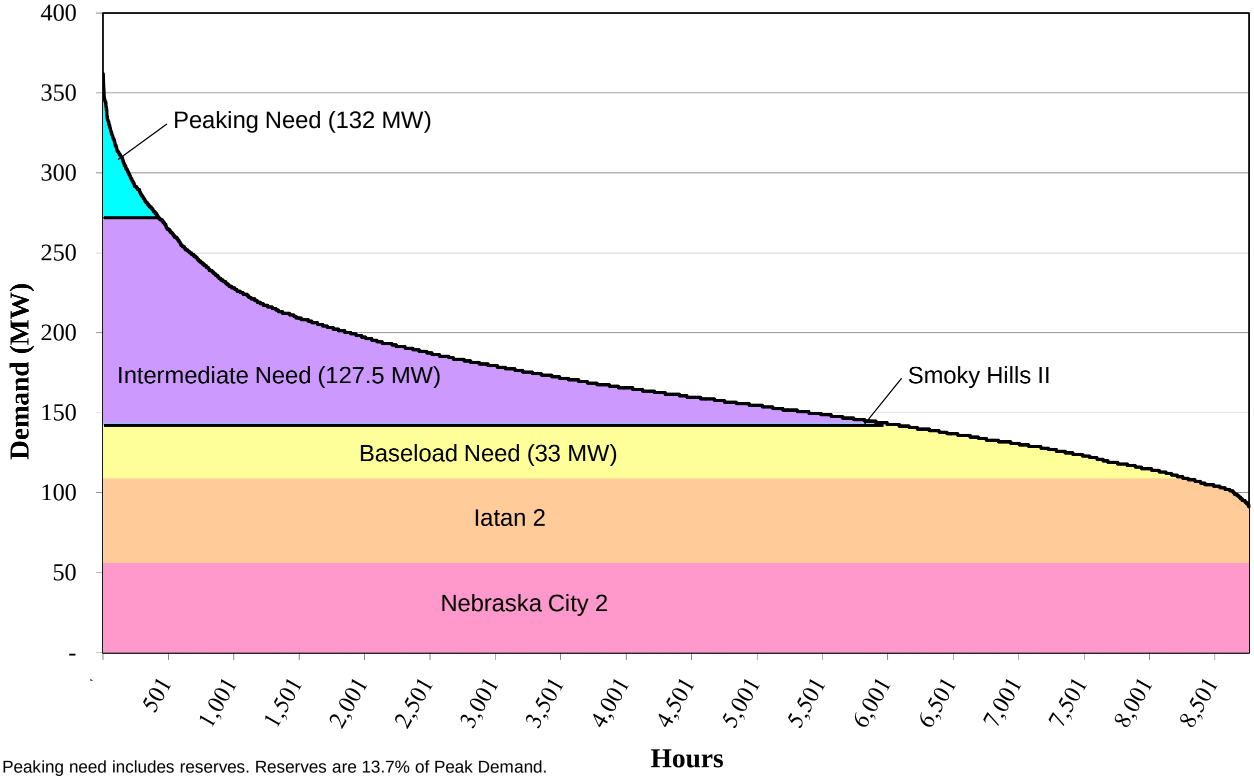
Figure 4-3
2021 Resource Energy Mix (Existing System)



Peaking need includes reserves. Reserves are 13.7% of Peak Demand.

Figure 4-4 shows the 2026 resource energy mix for the IPL system. The estimated baseload need increases from 25 MW in 2021 to 33 MW in 2026. The estimated intermediate need increases from 120 MW in 2021 to 127.5 MW in 2026. The estimated peaking need increases from 59 MW in 2021 to 132 MW in 2026.

Figure 4-4
2026 Resource Energy Mix (Existing System)



Peaking need includes reserves. Reserves are 13.7% of Peak Demand.

In summary, it was concluded that additional baseload, intermediate, and peaking resources are needed to meet future IPL resource needs and should be further evaluated on an economic basis. The baseload need is 33 MW by 2026, the intermediate need is 127.5 MW by 2026, and the peaking need is 132 MW by 2026.

SECTION 5

POWER SUPPLY ALTERNATIVES

POWER SUPPLY ALTERNATIVES

This Section describes power supply resource alternatives to supply projected future capacity and energy requirements. These alternatives include several self-build generating technologies. The potential impacts of environmental regulations are discussed with respect to these power supply alternatives.

PARTICIPATION OPTIONS

Due to increasingly more stringent environmental regulations, few, if any, coal-fired baseload generating units are being planned or constructed at this time. Therefore, the participation options available to IPL are limited to existing units for the time being. One such option that has become available is the Dogwood Energy Center, a 600 MW-class natural gas combined cycle plant located in nearby Pleasant Hill, Missouri.

Dogwood Energy Center

Sega performed a due diligence review of the Dogwood Energy Center (Dogwood) during 2010 for the Missouri Public Utility Alliance (MPUA). For the purposes of this IPL Master Plan Study Update, Sega discussed with IPL the results of the review we previously prepared for MPUA with Kelson Energy and the Dogwood plant staff and reviewed updated information for the intervening period.

Background

Dogwood was originally developed by Aquila Merchant in 1999 and constructed by Black & Veatch using an EPC contract approach. The plant was placed into commercial operation in two phases: first as a peaking facility during the summer of 2001 and then as a combined cycle plant on February 27, 2002. The plant consists of two Siemens Westinghouse Model 501FD2 (recently upgraded to 501FD3) natural gas-fired combustion turbine generators that each exhaust into their own Toshiba heat recovery steam generators (HRSGs) which produce steam to drive a steam turbine generator. The plant was originally named MEP Pleasant Hill, LLC, and was owned by Aquila Merchant and Calpine. In 2004, Aquila Merchant sold its share to Calpine. Kelson Energy acquired the plant in January 2007 out of bankruptcy through a competitive bidding procedure and renamed it the Dogwood Energy Center.

Calpine operated and maintained the plant from its commissioning until the sale of the plant to Kelson Energy in 2007. Since that time, North American Energy Services (NAES) has been the operator under a contract to Kelson Energy that was just renewed in 2010. Dogwood has a long-term parts (LTP) and service agreement with Siemens Energy, the original equipment manufacturer of the combustion turbine generators. Combustion turbine starts are monitored and utilized to determine planned maintenance outages under the LTP, which is currently expected to remain in effect through 2017 on the present operating basis.

Westar was the energy manager for Dogwood through 2010, making sales into the SPP energy imbalance market and on a bilateral basis under an energy management agreement. Westar schedules and dispatches the plant through an EIS dispatch signal that is followed when the plant is participating in the EIS market. Dogwood has primarily operated in summer cycling mode since commissioning, but has run on a very limited basis during winter.

Summary Findings

Sega's initial study during 2010 for MPUA gauged the basic design and configuration of the plant and reviewed the overall condition of the plant's equipment and systems based on operating and maintenance documentation, interviews of Kelson Energy and NAES staff, and observations made during a facility walk-down. Certain project agreements with the potential to affect plant capacity and energy were also reviewed, along with an SPP interconnection study. Sega previously performed a limited review and was not involved in nor included, economic evaluations.

After upgrades to both combustion turbines, recent capability tests indicate that the net plant capacity during summer at SPP rating conditions is approximately 610 MW, which is consistent with Sega's expectations. Plant capacity factor has held steady while equivalent availability and starting reliability have improved over the last four years.

Sega reviewed the potential impact on Dogwood of NO_X emission allocations under the EPA's new Cross-State Air Pollution Rule (CSAPR) that becomes effective on January 1, 2012. EPA issued separate annual allowances for each of the gas turbines in the Dogwood plant. Unit 1 will be allocated 33 annual NO_X allowances in 2012 and thereafter, and 23 ozone season NO_X allowances in 2012 and thereafter. Unit 2 will be allocated 30 annual NO_X allowances in 2012 and thereafter, and 18 ozone season NO_X allowances in 2012 and thereafter. Assuming that the future NO_X emission rate for both units is 3.8 ppm (just below the current Dogwood Title V Operating Permit limit of 4.0 ppm), the facility could operate for up to approximately 1,937 hours of equivalent full-load operation before the total facility's NO_X emissions allocation would be consumed. Thus, Dogwood will be limited to an approximate 22 percent annual capacity factor without purchasing additional allowances or reducing NO_X emission below the 3.8 ppm level assumed. Using the ozone season allocation for the applicable May to September time period, Dogwood operations will be limited to approximately a 34 percent seasonal capacity factor during these months. Further analysis of the installation details and performance history of Dogwood will be necessary to determine if NO_X emission rates can be further reduced; however, EPA has allocated enough NO_X allowances for Dogwood to continue operations as it has historically been run at around an annual capacity factor of 22 percent or less.

Sega concluded that Dogwood is a typical representation of a combined cycle plant configured with the addition of supplemental HRSG firing capacity, combustion turbine inlet air evaporative cooling, and combustion turbine steam power augmentation. The overall plant design is consistent with other similar plants of this type, size, vintage, and intended service. The overall condition of the equipment and systems in the facility was found to be appropriate for a plant of this age after an approximate decade of operation. Maintenance of the facility appeared to be consistent with accepted utility practices. Sega previously reported to MPUA that the facility's operational history and performance statistics have fluctuated, but steadily improved under the management of the present ownership and are expected to continue to improve and compare favorably with industry averages for combined cycle plants of similar size. Based upon information for the interim period made available for this IPL 2011 Master Plan Update, Sega's conclusions are unchanged. Based upon our review, Sega is not aware of any items or issues that would cause us to recommend against IPL's purchase of a portion of this facility.

SELF-BUILD OPTIONS

Sega developed the probable cost of constructing and operating generating resources that may be available to IPL. The capacities of generating units considered to be reasonable for the IPL system are described in more detail in this Section. Sega has included probable costs for a range of capacities that would likely be needed for IPL. The economic analysis section addresses the economic feasibility of resource alternatives in more detail.

Combustion Turbines

Two types of combustion turbines are commonly available for power generation: heavy-duty frame and aeroderivative. Frame-type combustion turbines were developed from steam turbine designs beginning in the 1950s. Aeroderivative gas turbines were developed later from modified aircraft engines that are smaller and generally more efficient and flexible than heavy-duty frame units. All of IPL's gas turbines are heavy-duty frame machines that have served the City well. However, modern aeroderivative gas turbines may better fit IPL's future needs because they have more flexible operating capabilities (more frequent starts and stops and short run times). All combustion turbines are modular designs that are available only in discrete size ranges. Most heavy-duty frame gas turbines manufactured today are larger units that would not fit IPL since most are 80 MW to 180 MW in size and can only be operated to about 60 percent load because of air permit emission limitations. Aeroderivative combustion turbines are smaller capacity units (50 MW or less) that can be operated at outputs of 15 MW or less. Aeroderivative combustion turbines better fit IPL's load profile and probable future needs than do heavy-duty frame type machines.

Natural gas-fired combustion turbines are a proven resource, are generally efficient; have relatively low capital costs; and emit less CO_2 than coal-fired baseload generation. Natural gas is generally a higher cost fuel and has historically experienced significant price volatility. Thus, if there are delays in the construction of baseload plants in the U.S., the demand for natural gas could increase substantially, and potentially cause natural gas prices to increase further.

<u>RICE Generators</u>

Reciprocating internal combustion engine (RICE) generating sets have been developed that compete with combustion turbines. Similar to diesel engines, but with spark ignitions, medium-speed RICE sets manufactured by Wärtsilä and others now have comparable efficiency, somewhat greater operating flexibility, and capital costs competitive with combustion turbines. In particular, Wärtsilä has begun offering a nominal 18 MW, natural gas-fired RICE set with a net heat rate (HHV) of approximately 8,000 Btu/kWh. The construction cost (without financing and owner's costs) was estimated at approximately $24 million or $1,333 per kW (2011 dollars) for one such unit. These engine generator sets are comparable in capacity to IPL's six GE Frame 5 combustion turbines, but are nearly twice as efficient and operate more efficiently at reduced loads. At the point at which IPL decides to add peaking capacity addition, a detailed comparison and analysis between aeroderivative combustion turbines and RICE sets should be conducted to determine the most appropriate technology at that time.

<u>Combined Cycle</u>

Combined cycle plants can be constructed in multiples of combustion turbine sizes to fit IPL's resource needs, bridging the gap between baseload and peaking. Combustion turbines can be installed as simple cycle peakers and later converted into a combined cycle plant by retrofitting the HRSGs and steam cycle equipment. Electric output is increased without much additional fuel expense when converting to combined cycle, greatly increasing efficiency above simple cycle units. Exhaust arrangements that allow the combustion turbines to bypass their HRSG can provide for flexible simple cycle operation when necessary, while obtaining the higher efficiency of combined cycle arrangement when appropriate. Combined cycle plants' greater efficiencies are better suited for intermediate and limited baseload applications than are simple cycle units. Thus, combined cycle was considered a reasonable resource alternative.

NEW GENERATING UNIT CAPITAL COST

Capital costs were estimated for new generating units included in the power supply plans. Costs were estimated by using ThermoFlow® software and were supplemented with electronic spreadsheet models. The primary cost-estimating effort was completed in Phase 1 of the Master Plan. Sega developed cost estimates based on industry experience, knowledge of other projects, vendor quotes for some major equipment, and information provided by Thermoflow® software. Estimated capital costs for coal-fired generating facilities, combustion turbines, and combined cycle plants developed in Phase 1 were increased by 25 percent to reflect recent increases in the cost of material and labor to update capital costs for Phase 2 (from 2007 to 2009). The increase was based on discussions with vendors, experience with other projects under or near construction, published cost reports on other projects, and periodic Thermoflow® software updates.

However, there has been significant material and labor cost uncertainty since that time. During July 2008, Synapse Energy Economics stated that cost increases had been driven by worldwide competition for power plant design and construction resources, commodities, equipment, and manufacturing capacity, and that there was little reason to expect that the worldwide competition would end any time in the foreseeable future. Since then, the industry has felt the impacts of the on-going recession and recent worldwide financial crisis on the costs of power plant equipment and construction. Most recently, the market for coal-fired power plant equipment and construction has collapsed as increasingly more stringent environmental regulation combined with reduced loads during the overall economic recession halted the construction of new units. However, the costs for special high-alloy materials used in most combustion turbines have increased. While many domestic power plant projects have been canceled or deferred, international projects, particularly in China and oil-producing countries, continue to dominate new power plant developments.

Therefore, Sega elected to conservatively maintain the 25 percent cost escalation figure for 2007 to 2009, with more moderate cost increases for combustion turbine-based plants and limited cost reductions for solid fueled plants through 2011.

Table 5-1 provides a summary of the updated capital costs for self-build generating resources used in the generating technology screening analysis.

Table 5-1
Summary of Self-Build Capital Costs

Unit	Total Financial Requirement ($)	Total Financial Requirement ($/kW)
180 MW CFB	657,819,024	3,655
115 MW CC	199,069,284	1,731
36 MW CT	52,386,654	1,455

Each generating unit type and its total financial requirement are summarized below. The total financial requirement includes the capital cost of a plant, interest during construction, and financing costs.

<u>180 MW CFB Coal-Fired Plant</u>

The total financial requirement is estimated at approximately $658 million, or $3,655 per kW, (2011 dollars) for this project. The full-load net plant heat rate was projected at 9,860 Btu/kWh. This project would require approximately eight years for permitting and installation. It would be of a size that could be sited on the IPL system. IPL would build, operate, and maintain the plant, but would likely sell some of the capacity from the plant to others.

115 MW Combined Cycle Gas-Fired Plant

The total financial requirement was estimated at approximately $199 million, or $1,731 per kW, (2011 dollars) for this plant. Net plant heat rate at full load was projected at 7,900 Btu/kWh. Five years would be required to complete this plant from start of permitting through commissioning. This particular plant design is based on two aeroderivative combustion turbines with heat recovery steam generators that produce steam to drive a steam turbine. The plant could be operated partially as one or two simple cycle combustion turbines as well as in combined cycle mode. The combustion turbines could be run on distillate oil as a backup fuel. These units would be installed on the IPL system and could also be equipped for black-start capability in a similar fashion to the existing IPL combustion turbines.

36 MW Simple Cycle Combustion Turbines

This plant is one combustion turbine module of the selected combined cycle plant. It was selected because its size fits well within the IPL resource needs and because it could be installed in pairs and, subsequently, converted to the combined cycle plant configuration. The estimated simple cycle installation of the 36 MW aeroderivative combustion turbine is approximately $52.4 million, or $1,455 per kW, (2011 dollars). The standard planning schedule recommended for permitting, procuring, installing, and commissioning such a plant is two years. The net plant heat rate of this combustion turbine is projected at 10,250 Btu/kWh at full load. These units would be installed on the IPL system.

Renewable Resources

The State of Missouri adopted a Renewable Energy Standard that applies to any electrical corporation in the State of Missouri. However, this Standard does not apply to Municipal Electric Utilities and to Rural Electric Cooperatives. This Master Plan includes renewable resources in amounts that would be consistent with the Missouri Renewable Energy Standard. The amounts of renewable energy resources indicated in the Standard are as follows:

1. No less than 2 percent of sales for calendar years 2011 through 2013.
2. No less than 5 percent of sales for calendar years 2014 through 2017.
3. No less than 10 percent of sales for calendar years 2018 through 2020.
4. No less than 15 percent of sales for calendar years 2021 and after.

At least 2 percent of the requirement should be from solar energy. Energy can be from owned or purchased resources in Missouri and outside of the State.

GENERATING TECHNOLOGY SCREENING ANALYSIS

Tables 5-2 through 5-4 provide a screening analysis of the generating technologies presented in this Section. This analysis provides a comparison of the total cost of each generating technology at several annual capacity factors for 2014, 2020, and 2026. Debt service for each year assumes a 2014 commercial operation date.

The Dogwood facility was the lowest cost alternative at nearly every capacity factor in each year. The Dogwood facility is expected to operate at a capacity factor between 10 and 20 percent annually. The following paragraph compares the estimated total cost of Dogwood to that of the next lowest cost alternative at a 15 percent annual capacity factor.

In 2014, the estimated total cost of Dogwood at a 15 percent capacity factor is 107.72/MWh. The next lowest cost alternative in 2014 at a 15 percent capacity factor is the Wärtsilä unit at $148.55/MWh. In 2020, the estimated total cost of Dogwood at a 15 percent capacity factor is $122.53/MWh. The next lowest cost alternative in 2020 at a 15 percent capacity factor is the Wärtsilä unit at $169.10/MWh. In 2026, the estimated total cost of Dogwood at a 15 percent capacity factor is $138.64/MWh. The next lowest cost alternative in 2026 at a 15 percent capacity factor is the Wärtsilä unit at $195.10/MWh.

Table 5-2
2014 Generating Unit Screening Analysis

Description	LM6000	CFB	Super-critical PC	Wartsila (EST)	LM6000 2-on-1 CC	Dogwood
Unit Statistics						
Generation Type (1)	CT	ST	ST	RICE	CC	CC
Fuel Type (2)	NG	Coal	Coal	NG	NG	NG
Net Capacity (MW)	36	180	600	9	115	100
Heat Rate (Btu/kWh)	10,250	9,860	9,590	8,575	7,900	7,400
Installed Cost ($000)	58,928	712,738	1,776,812	12,986	223,926	76,612
($/kW)	1,637	3,960	2,961	1,396	1,947	766
Fixed O&M ($000)	927	18,146	36,872	335	4,701	2,546
($/kW-mo)	2.15	8.40	5.12	3.00	3.41	2.12
Debt Service ($000)	3,958	51,038	127,149	869	15,043	6,059
($/kW-mo)	9.16	23.63	17.66	7.79	10.90	5.05
Total Fixed Costs ($000)	4,885	69,183	164,022	1,204	19,743	8,606
($/kW-mo)	11.31	32.03	22.78	10.79	14.31	7.17
Variable Operating Expenses ($/MWh)						
Fuel Price ($/MMBtu)	5.42	1.84	1.84	5.42	5.42	5.42
($/MWh)	55.56	18.14	17.65	46.48	42.82	40.11
Variable O&M (3)	3.95	7.24	7.90	3.57	5.26	2.12
Total Variable Cost ($/MWh)	59.50	25.38	25.54	50.05	48.08	42.23

	Total Cost ($/MWh)					
Capacity Factor (%)	**LM6000**	**CFB**	**Super-critical PC**	**Wartsila (EST)**	**LM6000 2-on-1 CC**	**Dogwood**
5	369.33	902.90	649.67	345.57	440.05	238.70
15	162.78	317.89	233.59	148.55	178.74	107.72
40	98.23	135.07	103.56	86.99	97.08	66.79
60	85.32	98.51	77.55	74.67	80.75	58.60
85	77.73	77.00	62.25	67.43	71.14	53.79
95	75.81	71.57	58.39	65.60	68.71	52.57

(1) CT = Combustion Turbine, CC = Combined Cycle , RICE = Reciprocating Internal Combustion Engine, ST = Steam

(2) NG = Natural Gas

(3) Dogwood generation assumed to be 50% combustion turbines and 50% steam. Variable O&M assumed to be $3.00/MWh for combustion turbines and $1.00/MWh for steam, with a weighted average variable O&M of $2.00/MWh in 2012 for Dogwood.

= Lowest Cost Alternative

Table 5-3
2020 Generating Unit Screening Analysis

Description	LM6000	CFB	Super-critical PC	Wartsila (EST)	LM6000 2-on-1 CC	Dogwood
Unit Statistics						
Generation Type [1]	CT	ST	ST	RICE	CC	CC
Fuel Type [2]	NG	Coal	Coal	NG	NG	NG
Net Capacity (MW)	36	180	600	9	115	100
Heat Rate (Btu/kWh)	10,250	9,860	9,590	8,575	7,900	7,400
Installed Cost ($000)	58,928	712,738	1,776,812	12,986	223,926	76,612
($/kW)	1,637	3,960	2,961	1,396	1,947	766
Fixed O&M ($000)	1,173	22,960	46,655	424	5,948	3,040
($/kW-mo)	2.72	10.63	6.48	3.80	4.31	2.53
Debt Service ($000)	3,958	45,453	113,299	869	15,043	6,059
($/kW-mo)	9.16	21.04	15.74	7.79	10.90	5.05
Total Fixed Costs ($000)	5,131	68,413	159,954	1,293	20,990	9,100
($/kW-mo)	11.88	31.67	22.22	11.58	15.21	7.58
Variable Operating Expenses ($/MWh)						
Fuel Price ($/MMBtu)	6.86	2.33	2.33	6.86	6.86	6.86
($/MWh)	70.29	22.96	22.33	58.81	54.18	50.75
Variable O&M [3]	5.00	9.16	9.99	4.52	6.66	2.53
Total Variable Cost ($/MWh)	75.29	32.11	32.32	63.32	60.84	53.28

	Total Cost ($/MWh)					
Capacity Factor (%)	**LM6000**	**CFB**	**Super-critical PC**	**Wartsila (EST)**	**LM6000 2-on-1 CC**	**Dogwood**
5	400.72	899.85	640.97	380.65	477.56	261.04
15	183.77	321.36	235.20	169.10	199.75	122.53
40	115.97	140.58	108.40	102.99	112.93	79.25
60	102.41	104.43	83.04	89.77	95.57	70.60
85	94.43	83.16	68.12	81.99	85.35	65.50
95	92.42	77.78	64.35	80.02	82.77	64.22

(1) CT = Combustion Turbine, CC = Combined Cycle , RICE = Reciprocating Internal Combustion Engine, ST = Steam

(2) NG = Natural Gas

(3) Dogwood generation assumed to be 50% combustion turbines and 50% steam. Variable O&M assumed to be $3.00/MWh for combustion turbines and $1.00/MWh for steam, with a weighted average variable O&M of $2.00/MWh in 2012 for Dogwood.

= Lowest Cost Alternative

Table 5-4
2026 Generating Unit Screening Analysis

Description	LM6000	CFB	Super-critical PC	Wartsila (EST)	LM6000 2-on-1 CC	Dogwood
Unit Statistics						
Generation Type [1]	CT	ST	ST	RICE	CC	CC
Fuel Type [2]	NG	Coal	Coal	NG	NG	NG
Net Capacity (MW)	36	180	600	9	115	100
Heat Rate (Btu/kWh)	10,250	9,860	9,590	8,575	7,900	7,400
Installed Cost ($000)	58,928	712,738	1,776,812	12,986	223,926	76,612
($/kW)	1,637	3,960	2,961	1,396	1,947	766
Fixed O&M ($000)	1,485	29,052	59,034	536	7,526	3,322
($/kW-mo)	3.44	13.45	8.20	4.80	5.45	2.77
Debt Service ($000)	3,958	45,453	113,299	869	15,043	6,059
($/kW-mo)	9.16	21.04	15.74	7.79	10.90	5.05
Total Fixed Costs ($000)	5,443	74,504	172,333	1,405	22,569	9,382
($/kW-mo)	12.60	34.49	23.94	12.59	16.35	7.82
Variable Operating Expenses ($/MWh)						
Fuel Price ($/MMBtu)	8.68	2.95	2.95	8.68	8.68	8.68
($/MWh)	88.95	29.05	28.25	74.41	68.55	64.21
Variable O&M [3]	6.32	11.59	12.64	5.71	8.43	3.03
Total Variable Cost ($/MWh)	95.27	40.63	40.89	80.12	76.98	67.24

	Total Cost ($/MWh)					
Capacity Factor (%)	**LM6000**	**CFB**	**Super-critical PC**	**Wartsila (EST)**	**LM6000 2-on-1 CC**	**Dogwood**
5	440.44	985.64	696.65	425.05	525.04	281.43
15	210.32	355.64	259.48	195.10	226.33	138.64
40	138.41	158.76	122.86	123.24	132.99	94.01
60	124.03	119.38	95.54	108.87	114.32	85.09
85	115.57	96.22	79.47	100.41	103.34	79.84
95	113.43	90.37	75.41	98.28	100.56	78.51

[1] CT = Combustion Turbine, CC = Combined Cycle , RICE = Reciprocating Internal Combustion Engine, ST = Steam

[2] NG = Natural Gas

[3] Dogwood generation assumed to be 50% combustion turbines and 50% steam. Variable O&M assumed to be $3.00/MWh for combustion turbines and $1.00/MWh for steam, with a weighted average variable O&M of $2.00/MWh in 2012 for Dogwood.

= Lowest Cost Alternative

SECTION 6

POWER SUPPLY PLANS

POWER SUPPLY PLANS

Power supply plans (cases) were developed and evaluated over the 20-year planning period using production cost simulation modeling. Two of these plans were evaluated in the Phase 2 study and three were added for evaluation in this Report.

GENERATING UNIT REPLACEMENT SCHEDULE

The cases were developed around the unit replacement planning schedule shown in Table 6-1. The schedule was developed by assessing the condition of the units and reviewing manufacturers' replacement recommendations, while evaluating the impacts of anitcipated environmental regulations.

Table 6-1
Generating Unit Replacement Schedule

Units	End of Calendar Year
Missouri City Units 1 and 2[(1)]	2015
Blue Valley Units 1, 2, and 3	2016
Combustion Turbines J-1 and J-2	2018
Combustion Turbines I-3 and I-4	2023
Combustion Turbines H-5 and H-6	2024

(1) April 30, 2015

Missouri City

The Missouri City Plant was planned to be replaced January 1, 2014 in the Phase 2 Master Plan Report. The Missouri City Plant replacement date has been moved to April 30, 2015 to coincide with the expected Industrial Boiler MACT regulation compliance date.

Blue Valley

In Phase 2 of the Master Plan Report, Blue Valley Units 1, 2, and 3 would continue to be operated until their replacement at the end of 2016. This has not changed from what was planned in Phase 2. The operating plan for these units has changed. In Phase 2, these units were planned to operate on coal through the end of 2016. Now, Units 1 and 2 are planned to be converted to natural gas operation by April 30, 2015 to comply with expected Industrial Boiler MACT regulation and Unit 3 is planned to be switched to natural gas operation on January 1, 2012 to comply with CSAPR regulation. As described in Section 3 - Environmental Considerations, no capital investment will be required to operate the Blue Valley units on natural gas. Market price projections, further described in Section 7 - Economic Analysis of Power Supply Plans, indicate the economic dispatch order of the Blue Valley units would not be changed after switching to natural gas operation.

Combustion Turbines

The H, I, and J combustion turbines would each be replaced after 50 years of service as shown in Table 6-1. This has not changed from what was assumed in the Phase 2 Master Plan Report.

DESCRIPTION OF POWER SUPPLY PLANS

As mentioned previously, there are five fundamental power supply plans (cases) labeled A, B, C-1, C-2, and C-3. Case A involves purchasing all future capacity and energy needs from the market. This case was developed to evaluate the cost of not participating in, or constructing, any new generating units and relying solely on the market for future capacity and energy needs. This case was evaluated in the Phase 2 Master Plan Report.

Case B involves IPL constructing a 180 MW circulating fluidized bed coal-fired generating unit on or near the IPL electric transmission system and selling 105 MW to another entity (75 MW IPL share). Combustion turbines (36 MW each) were added as needed to meet future capacity needs. This was the recommended power supply plan in the Phase 2 Master Plan Report. Changes in environmental regulations and public sentiment towards coal-fired generation have caused uncertainty as to the ability to execute this plan. This plan was evaluated for comparative purposes.

Cases C-1, C-2, and C-3 involve purchasing 50, 75, and 100 MW of the Dogwood Energy Center in 2014. Combustion turbines were added as needed to meet future capacity needs. The purpose of these cases is to evaluate the economic feasibility of purchasing an ownership share in the Dogwood Energy Center. Dogwood was not considered as a resource alternative in the Phase 2 Master Plan Report because it was not offered as a long-term purchase opportunity at that time.

Table 6-2 provides a brief description of the power supply cases that were evaluated in this study effort. These cases are described in more detail in this Section. All of these plans include renewable energy resources in the future consistent with the Missouri Renewable Energy Standard.

Table 6-2
Power Supply Planning Cases[(1)]
City of Independence, Missouri

Case Name	Name	Description
Case A - Market Purchase	Purchase Future Capacity and Energy Needs from the Market	No Generation Additions
Case B - Construct Coal Generation	Construct 180 MW Coal-fired CFB (75 MW IPL), Seven 36 MW Combustion Turbines	72 MW CT-2015 72 MW CT-2017 Construct 180 MW CFB (75 MW IPL Share)-2020 36 MW CT-2023 36 MW CT-2025 36 MW CT-2029
Case C-1 - 50 MW Dogwood	Purchase 50 MW of Dogwood and Construct Seven 36 MW Combustion Turbines	50 MW Dogwood-2014 36 MW CT-2014 72 MW CT-2017 36 MW CT-2019 72 MW CT-2023 36 MW CT-2025
Case C-2 - 75 MW Dogwood	Purchase 75 MW of Dogwood and Construct Seven 36 MW Combustion Turbines	75 MW Dogwood-2014 108 MW CT-2017 36 MW CT-2019 36 MW CT-2023 36 MW CT-2025 36 MW CT-2029
Case C-3 - 100 MW Dogwood	Purchase 100 MW of Dogwood and Construct Six 36 MW Combustion Turbines	100 MW Dogwood-2014 72 MW CT-2017 36 MW CT-2019 36 MW CT-2023 36 MW CT-2025 36 MW CT-2027

(1) All plans include renewable capacity equal to 15% of IPL's peak demand by 2021.

Case A: Purchase Capacity and Energy from the Market

Case A involves purchasing all capacity and energy requirements in excess of existing resources from the market. Table 6-3 - Capacity Plan A compares annual peak requirements to total available capacity under Plan A.

Table 6-3
Capacity Plan A:
Existing System
Purchase Capacity and Energy from the Market
Independence Power and Light
(MW)

Description	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Projected Annual Peak Demand	306	310	314	317	321	324	328	331	335	339	342	346	350	354	358	362	366	370	373	377
Planning Reserve (1)	42	43	43	43	44	44	45	45	46	46	47	47	48	48	49	50	50	51	51	52
System Capacity Responsibility	347	353	357	361	365	369	373	377	381	385	389	394	398	402	407	411	416	420	425	429
Missouri City Steam 1 & 2	38	38	38	38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Blue Valley Steam 1 & 2	40	40	40	40	40	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Blue Valley Steam 3	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Baseload/Intermediate Resources	128	128	128	128	90	90	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Blue Valley RCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Substation H	33	33	33	33	33	33	33	33	33	33	33	33	33	33	-	-	-	-	-	-
Substation I	32	32	32	32	32	32	32	32	32	32	32	32	-	-	-	-	-	-	-	-
Substation J	26	26	26	26	26	26	26	26	-	-	-	-	-	-	-	-	-	-	-	-
Peaking Resources	91	91	91	91	91	91	91	91	65	65	65	65	33	33	-	-	-	-	-	-
Total Generating Resources	**219**	**219**	**219**	**219**	**181**	**181**	**91**	**91**	**65**	**65**	**65**	**65**	**33**	**33**	**-**	**-**	**-**	**-**	**-**	**-**
KCPL (Montrose)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPPD (Nebraska City #2)	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56
MJMEUC (Iatan #2)	50	50	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
Smoky Hills II (2)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	-	-
Total Purchases	108	108	111	111	111	111	111	111	111	111	111	111	111	111	111	111	111	111	109	109
Total Existing and Committed Resources	**327**	**327**	**330**	**330**	**292**	**292**	**202**	**202**	**176**	**176**	**176**	**176**	**144**	**144**	**111**	**111**	**111**	**111**	**109**	**109**
Planned Generation																				
Intermediate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combustion Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal-Fired Steam	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned Generating Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned Purchase Power																				
Intermediate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Peaking (3)	20	26	27	31	73	77	171	172	202	206	208	212	248	252	290	294	298	303	309	313
Baseload	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewables (4)	-	-	-	-	-	-	-	3	3	3	6	6	6	6	6	6	6	7	7	7
Planned Purchases	20	26	27	31	73	77	171	175	205	209	213	218	254	258	296	300	305	309	316	320
Total Planned Capacity	20	26	27	31	73	77	171	175	205	209	213	218	254	258	296	300	305	309	316	320
Total Capacity Resources	**347**	**353**	**357**	**361**	**365**	**369**	**373**	**377**	**381**	**385**	**389**	**394**	**398**	**402**	**407**	**411**	**416**	**420**	**425**	**429**
Capacity Surplus/(Deficit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Footnotes:

(1) 13.7% of Peak Demand

(2) SPP accredited capacity is estimated at approximately 2 MW (15 MW full rated capacity)

(3) Estimated capacity need to meet System Capacity Responsibility.

(4) Future wind generation of 2%, 5%, 10%, and 15% of the peak demand minus Smoky Hills II, in 2011, 2014, 2018 and 2021 respectively.
Accredited capacity is estimated at approximately 20% of installed project capacity.
Added to meet possible renewable portfolio standards for the State of Missouri in the future.

Case B: Construct Coal-Fired Baseload Generation

Case B involves constructing a 180 MW coal-fired generating unit on or near the IPL electric transmission system and constructing seven 36 MW combustion turbines. Table 6-4 - Capacity Plan B compares annual peak requirements to total available capacity under Plan B.

1. Combustion turbines installed in:
    a. 2015 - Two.
    b. 2017 - Two.
    c. 2023 - One.
    d. 2025 - One.
    e. 2029 - One.
2. IPL would build, operate, and maintain a nominal 180 MW coal-fired circulating fluidized bed steam electric plant to commence operation in 2020. IPL would construct this size unit to achieve economies of scale, but would sell 105 MW to others in a joint-ownership type arrangement and retain 75 MW to serve its native load.

Table 6-4
Capacity Plan B:

Construct 180 MW Coal-Fired Generator in 2020
and Install Combustion Turbines in 2015, 2017, 2023, 2025 and 2029
Independence Power and Light
(MW)

Description	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Projected Annual Peak Demand	306	310	314	317	321	324	328	331	335	339	342	346	350	354	358	362	366	370	373	377
Planning Reserve (1)	42	43	43	43	44	44	45	45	46	46	47	47	48	48	49	50	50	51	51	52
System Capacity Responsibility	347	353	357	361	365	369	373	377	381	385	389	394	398	402	407	411	416	420	425	429
Missouri City Steam 1 & 2	38	38	38	38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Blue Valley Steam 1 & 2	40	40	40	40	40	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Blue Valley Steam 3	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Baseload/Intermediate Resources	128	128	128	128	90	90	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Blue Valley RCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Substation H	33	33	33	33	33	33	33	33	33	33	33	33	33	33	-	-	-	-	-	-
Substation I	32	32	32	32	32	32	32	32	32	32	32	32	-	-	-	-	-	-	-	-
Substation J	26	26	26	26	26	26	26	26	-	-	-	-	-	-	-	-	-	-	-	-
Peaking Resources	91	91	91	91	91	91	91	91	65	65	65	65	33	33	-	-	-	-	-	-
Total Generating Resources	**219**	**219**	**219**	**219**	**181**	**181**	**91**	**91**	**65**	**65**	**65**	**65**	**33**	**33**	**-**	**-**	**-**	**-**	**-**	**-**
KCPL (Montrose)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPPD (Nebraska City #2)	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56
MJMEUC (Iatan #2)	50	50	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
Smoky Hills II (2)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	-	-
Total Purchases	108	108	111	111	111	111	111	111	111	111	111	111	111	111	111	111	111	111	109	109
Total Existing and Committed Resources	**327**	**327**	**330**	**330**	**292**	**292**	**202**	**202**	**176**	**176**	**176**	**176**	**144**	**144**	**111**	**111**	**111**	**111**	**109**	**109**
Planned Generation																				
Intermediate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combustion Turbine (3)	-	-	-	-	72	72	144	144	144	144	144	144	180	180	216	216	216	216	252	252
Coal-Fired Steam (4)	-	-	-	-	-	-	-	-	-	75	75	75	75	75	75	75	75	75	75	75
Planned Generating Capacity	-	-	-	-	72	72	144	144	144	219	219	219	255	255	291	291	291	291	327	327
Planned Purchase Power																				
Intermediate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Peaking (5)	20	26	27	31	1	5	27	28	58	-	-	-	-	-	-	3	7	12	-	-
Baseload	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewables (6)	-	-	-	-	-	-	-	3	3	3	6	6	6	6	6	6	6	7	7	7
Planned Purchases	20	26	27	31	1	5	27	31	61	3	6	6	6	6	6	9	14	18	7	7
Total Planned Capacity	20	26	27	31	73	77	171	175	205	222	225	225	261	261	297	300	305	309	334	334
Total Capacity Resources	**347**	**353**	**357**	**361**	**365**	**369**	**373**	**377**	**381**	**398**	**401**	**401**	**405**	**405**	**408**	**411**	**416**	**420**	**443**	**443**
Capacity Surplus/(Deficit)	-	-	-	-	-	-	-	-	-	13	11	7	7	3	1	-	-	-	18	14

Footnotes:

(1) 13.7% of Peak Demand `

(2) SPP accredited capacity is estimated at approximately 2 MW (15 MW rated capacity)

(3) 36 MW combustion turbines added to meet capacity needs.

(4) 180 MW total plant capacity, 75 MW IPL share, 105 MW for other participant(s).

(5) Estimated peaking capacity to supply remaining capacity after Planned Generation Coal-Fired Steam
and Planned Generation Combustion Turbines.

(6) Future wind generation of 2%, 5%, 10%, and 15% of the peak demand minus Smoky Hills II, in 2011, 2014, 2018 and 2021 respectively.
Accredited capacity is estimated at approximately 20% of installed project capacity.
Added to meet possible renewable portfolio standards for the State of Missouri in the future.

Case C-1: Purchase 50 MW of Dogwood

Case C-1 involves purchasing 50 MW of the Dogwood Energy Center and constructing seven combustion turbines. Table 6-5 - Capacity Plan C-1 compares annual peak requirements to total available capacity under Plan C-1.

1. IPL would purchase 50 MW of the Dogwood plant beginning January 1, 2014.

2. Combustion turbines installed in:

   a. 2015 - One.

   b. 2017 - Two.

   c. 2019 - One.

   d. 2023 - Two.

   e. 2025 - One.

Table 6-5
Capacity Plan C-1:
Purchase 50MW Dogwood in 2014 and Install Combustion Turbines in 2015, 2017, 2019, 2023 and 2025
Independence Power and Light
(MW)

Description	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Projected Annual Peak Demand	306	310	314	317	321	324	328	331	335	339	342	346	350	354	358	362	366	370	373	377
Planning Reserve [1]	42	43	43	43	44	44	45	45	46	46	47	47	48	48	49	50	50	51	51	52
System Capacity Responsibility	347	353	357	361	365	369	373	377	381	385	389	394	398	402	407	411	416	420	425	429
Missouri City Steam 1 & 2	38	38	38	38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Blue Valley Steam 1 & 2	40	40	40	40	40	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Blue Valley Steam 3	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Baseload/Intermediate Resources	128	128	128	128	90	90	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Blue Valley RCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Substation H	33	33	33	33	33	33	33	33	33	33	33	33	33	33	-	-	-	-	-	-
Substation I	32	32	32	32	32	32	32	32	32	32	32	32	-	-	-	-	-	-	-	-
Substation J	26	26	26	26	26	26	26	26	-	-	-	-	-	-	-	-	-	-	-	-
Peaking Resources	91	91	91	91	91	91	91	91	65	65	65	65	33	33	-	-	-	-	-	-
Total Generating Resources	**219**	**219**	**219**	**219**	**181**	**181**	**91**	**91**	**65**	**65**	**65**	**65**	**33**	**33**	**-**	**-**	**-**	**-**	**-**	**-**
KCPL (Montrose)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPPD (Nebraska City #2)	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56
MJMEUC (Iatan #2)	50	50	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
Smoky Hills II [2]	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	-	-
Dogwood	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Total Purchases	108	108	111	161	161	161	161	161	161	161	161	161	161	161	161	161	161	161	159	159
Total Existing and Committed Resources	**327**	**327**	**330**	**380**	**342**	**342**	**252**	**252**	**226**	**226**	**226**	**226**	**194**	**194**	**161**	**161**	**161**	**161**	**159**	**159**
Planned Generation																				
Intermediate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combustion Turbine [3]	-	-	-	-	36	36	108	108	144	144	144	144	216	216	252	252	252	252	252	252
Coal-Fired Steam	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned Generating Capacity	-	-	-	-	36	36	108	108	144	144	144	144	216	216	252	252	252	252	252	252
Planned Purchase Power																				
Intermediate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Peaking	20	26	27	-	-	-	13	14	8	12	14	18	-	-	-	-	-	1	7	11
Baseload	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewables [4]	-	-	-	-	-	-	-	3	3	3	6	6	6	6	6	6	6	7	7	7
Planned Purchases	20	26	27	-	-	-	13	17	11	15	19	24	6	6	6	6	6	7	14	18
Total Planned Capacity	20	26	27	-	36	36	121	125	155	159	163	168	222	222	258	258	258	259	266	270
Total Capacity Resources	**347**	**353**	**357**	**380**	**378**	**378**	**373**	**377**	**381**	**385**	**389**	**394**	**416**	**416**	**419**	**419**	**419**	**420**	**425**	**429**
Capacity Surplus/(Deficit)																				
Total	(0)	-	-	19	13	9	-	(0)	-	-	-	-	18	14	12	8	4	-	-	-

Footnotes:

[1] 13.7% of Peak Demand `

[2] SPP accredited capacity is estimated at approximately 2 MW (15 MW full rated capacity)

[3] 36 MW combustion turbines added to meet capacity needs.

[4] Future wind generation of 2%, 5%, 10%, and 15% of the peak demand minus Smoky Hills II, in 2011, 2014, 2018 and 2021 respectively.
Accredited capacity is estimated at approximately 20% of installed project capacity.
Added to meet possible renewable portfolio standards for the State of Missouri in the future.

Case C-2: Purchase 75 MW of Dogwood

Case C-2 involves purchasing 75 MW of the Dogwood combined cycle plant and constructing seven combustion turbines. Table 6-6 - Capacity Plan C-2 compares annual peak requirements to total available capacity under Plan C-2.

1. IPL would purchase 75 MW of the Dogwood plant beginning January 1, 2014.
2. Combustion turbines installed in:
   a. 2017 - Three.
   b. 2019 - One.
   c. 2023 - One.
   d. 2025 - One.
   e. 2029 - One.

Table 6-6
Capacity Plan C-2:
Purchase 75MW Dogwood in 2014 and Install Combustion Turbines in 2017, 2019, 2023, 2025 and 2029
Independence Power and Light
(MW)

Description	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Projected Annual Peak Demand	306	310	314	317	321	324	328	331	335	339	342	346	350	354	358	362	366	370	373	377
Planning Reserve [1]	42	43	43	43	44	44	45	45	46	46	47	47	48	48	49	50	50	51	51	52
System Capacity Responsibility	347	353	357	361	365	369	373	377	381	385	389	394	398	402	407	411	416	420	425	429
Missouri City Steam 1 & 2	38	38	38	38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Blue Valley Steam 1 & 2	40	40	40	40	40	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Blue Valley Steam 3	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Baseload/Intermediate Resources	128	128	128	128	90	90	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Blue Valley RCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Substation H	33	33	33	33	33	33	33	33	33	33	33	33	33	33	-	-	-	-	-	-
Substation I	32	32	32	32	32	32	32	32	32	32	32	32	-	-	-	-	-	-	-	-
Substation J	26	26	26	26	26	26	26	26	-	-	-	-	-	-	-	-	-	-	-	-
Peaking Resources	91	91	91	91	91	91	91	91	65	65	65	65	33	33	-	-	-	-	-	-
Total Generating Resources	**219**	**219**	**219**	**219**	**181**	**181**	**91**	**91**	**65**	**65**	**65**	**65**	**33**	**33**	-	-	-	-	-	-
KCPL (Montrose)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPPD (Nebraska City #2)	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56
MJMEUC (Iatan #2)	50	50	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
Smoky Hills II [2]	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	-	-
Dogwood	-	-	-	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Total Purchases	108	108	111	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186	184	184
Total Existing and Committed Resources	**327**	**327**	**330**	**405**	**367**	**367**	**277**	**277**	**251**	**251**	**251**	**251**	**219**	**219**	**186**	**186**	**186**	**186**	**184**	**184**
Planned Generation																				
Intermediate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combustion Turbine [3]	-	-	-	-	-	-	108	108	144	144	144	144	180	180	216	216	216	216	252	252
Coal-Fired Steam	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned Generating Capacity	-	-	-	-	-	-	108	108	144	144	144	144	180	180	216	216	216	216	252	252
Planned Purchase Power																				
Intermediate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Peaking	20	26	27	-	-	2	-	-	-	-	-	-	-	-	-	3	7	12	-	-
Baseload	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewables [4]	-	-	-	-	-	-	-	3	3	3	6	6	6	6	6	6	6	7	7	7
Planned Purchases	20	26	27	-	-	2	-	3	3	3	6	6	6	6	6	9	14	18	7	7
Total Planned Capacity	20	26	27	-	-	2	108	111	147	147	150	150	186	186	222	225	230	234	259	259
Total Capacity Resources	**347**	**353**	**357**	**405**	**367**	**369**	**385**	**388**	**398**	**398**	**401**	**401**	**405**	**405**	**408**	**411**	**416**	**420**	**443**	**443**
Capacity Surplus/(Deficit)																				
Total	(0)	-	-	44	2	-	12	11	17	13	11	7	7	3	1	0	-	-	18	14

Footnotes:

(1) 13.7% of Peak Demand `

(2) SPP accredited capacity is estimated at approximately 2 MW (15 MW full rated capacity)

(3) 36 MW combustion turbines added to meet capacity needs.

(4) Future wind generation of 2%, 5%, 10%, and 15% of the peak demand minus Smoky Hills II, in 2011, 2014, 2018 and 2021 respectively.
Accredited capacity is estimated at approximately 20% of installed project capacity.
Added to meet possible renewable portfolio standards for the State of Missouri in the future.

Case C-3: Purchase 100 MW of Dogwood

Case C-3 involves purchasing 100 MW of the Dogwood combined cycle plant and constructing six combustion turbines. Table 6-7 - Capacity Plan C-3 compares annual peak requirements to total available capacity under Plan C-3.

1. IPL would purchase 100 MW of the Dogwood plant beginning January 1, 2014.

2. Combustion turbines installed in:

   a. 2017 - Two.

   b. 2019 - One.

   c. 2023 - One.

   d. 2025 - One.

   e. 2027 - One.

Table 6-7
Capacity Plan C-3:
Purchase 100MW Dogwood in 2014 and Install Combustion Turbines in 2017, 2019, 2023, 2025 and 2027
Independence Power and Light
(MW)

Description	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Projected Annual Peak Demand	306	310	314	317	321	324	328	331	335	339	342	346	350	354	358	362	366	370	373	377
Planning Reserve [1]	42	43	43	43	44	44	45	45	46	46	47	47	48	48	49	50	50	51	51	52
System Capacity Responsibility	347	353	357	361	365	369	373	377	381	385	389	394	398	402	407	411	416	420	425	429
Missouri City Steam 1 & 2	38	38	38	38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Blue Valley Steam 1 & 2	40	40	40	40	40	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Blue Valley Steam 3	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Baseload/Intermediate Resources	128	128	128	128	90	90	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Blue Valley RCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Substation H	33	33	33	33	33	33	33	33	33	33	33	33	33	33	-	-	-	-	-	-
Substation I	32	32	32	32	32	32	32	32	32	32	32	32	-	-	-	-	-	-	-	-
Substation J	26	26	26	26	26	26	26	26	-	-	-	-	-	-	-	-	-	-	-	-
Peaking Resources	91	91	91	91	91	91	91	91	65	65	65	65	33	33	-	-	-	-	-	-
Total Generating Resources	**219**	**219**	**219**	**219**	**181**	**181**	**91**	**91**	**65**	**65**	**65**	**65**	**33**	**33**	**-**	**-**	**-**	**-**	**-**	**-**
KCPL (Montrose)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPPD (Nebraska City #2)	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56
MJMEUC (Iatan #2)	50	50	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
Smoky Hills II [2]	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	-	-
Dogwood	-	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Total Purchases	108	108	111	211	211	211	211	211	211	211	211	211	211	211	211	211	211	211	209	209
Total Existing and Committed Resources	**327**	**327**	**330**	**430**	**392**	**392**	**302**	**302**	**276**	**276**	**276**	**276**	**244**	**244**	**211**	**211**	**211**	**211**	**209**	**209**
Planned Generation																				
Intermediate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combustion Turbine [3]	-	-	-	-	-	-	72	72	108	108	108	108	144	144	180	180	216	216	216	216
Coal-Fired Steam	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned Generating Capacity	-	-	-	-	-	-	72	72	108	108	108	108	144	144	180	180	216	216	216	216
Planned Purchase Power																				
Intermediate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Peaking	20	26	27	-	-	-	-	-	-	-	-	4	4	8	10	14	-	-	-	-
Baseload	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewables [4]	-	-	-	-	-	-	-	3	3	3	6	6	6	6	6	6	6	7	7	7
Planned Purchases	20	26	27	-	-	-	-	3	3	3	6	10	10	14	16	20	6	7	7	7
Total Planned Capacity	20	26	27	-	-	-	72	75	111	111	114	118	154	158	196	200	222	223	223	223
Total Capacity Resources	**347**	**353**	**357**	**430**	**392**	**392**	**374**	**377**	**387**	**387**	**390**	**394**	**398**	**402**	**407**	**411**	**433**	**434**	**432**	**432**
Capacity Surplus/(Deficit)																				
Total	(0)	-	-	69	27	23	1	0	6	2	0	-	-	-	-	0	18	13	7	3

Footnotes:

[1] 13.7% of Peak Demand `

[2] SPP accredited capacity is estimated at approximately 2 MW (15 MW full rated capacity)

[3] 36 MW combustion turbines added to meet capacity needs.

[4] Future wind generation of 2%, 5%, 10%, and 15% of the peak demand minus Smoky Hills II, in 2011, 2014, 2018 and 2021 respectively.
Accredited capacity is estimated at approximately 20% of installed project capacity.
Added to meet possible renewable portfolio standards for the State of Missouri in the future.

Summary

Case A relies heavily on the market capacity and energy market as there are no generation additions in Case A. Case B includes a 75 MW share of a coal-fired unit beginning in 2020. Nearly 150 MW of peaking capacity is needed before the coal unit is online and, thus, four 36 MW combustion turbines are installed by 2020 (144 MW). Cases C-1, C-2, and C-3 include varying amounts of purchases from Dogwood beginning in 2014. The more Dogwood that is purchased in 2014, the fewer combustion turbines are needed. The amount of Dogwood purchased also affects when combustion turbines are needed. With 50 MW of Dogwood, a combustion turbine is needed in 2015 to replace the Missouri City Plant. If 75 or 100 MW of Dogwood is purchased, new combustion turbines are not needed until 2017.

These plans are evaluated in Section 7 - Economic Analysis of Power Supply Plans.

SECTION 7

ECONOMIC ANALYSIS OF POWER SUPPLY PLANS

ECONOMIC ANALYSIS OF POWER SUPPLY PLANS

This Section summarizes the economic analysis of the five fundamental power supply plans identified in Section 6 - Power Supply Plans. This evaluation compared the net present value (NPV) of annual power supply costs for each of five cases described in Section 6 - Power Supply Plans. Power supply costs include fuel, fixed operation, and maintenance costs of new generating units, new capital costs (and related debt service), and purchase power costs of existing resources. Fixed operation and maintenance of existing resources are included, but not existing debt service, which is not an incremental power supply cost.

The power supply planning cases were evaluated using a production cost simulation software model, the P-Plus Corporation P-Month model. P-Month can implement realistic unit commitment and dispatch procedures, including scheduled maintenance, while recognizing generating unit minimum up and down times, ramp rates, and hourly spinning reserve requirements to determine the lowest reasonable total incremental power supply costs for the system.

This model simulates the chronological, hour-by-hour operation of a generation system by dispatching (mathematically allocating) the forecasted hourly kilowatt load among the generating units in operation. Unit commitment and dispatch levels are based on unit type, fuel costs, transmission losses, and emission costs. Units are dispatched by the model such that the overall fuel expense of the system is minimized. The model calculates the fuel consumed using the unit commitment and dispatch described above, based on the load carried by a unit and the unit's efficiency characteristics.

ECONOMIC AND FINANCIAL PARAMETERS

Several key economic and financial parameters were used in developing the cost of generating facilities and in evaluating power supply plans. These parameters are as follows:

1. Municipal Tax Exempt Finance Rate:
    a. Coal-Fired Unit/Combustion Turbines: 6 percent.
    b. Dogwood: 5 percent.
2. 35-year financing term for new coal-fired generating units.
3. 30-year financing term for new combined cycle and combustion turbines.
4. Discount Rate: 5 percent.
5. Short-Term Interest Rate: 3.75 percent.
6. General O&M Escalation Rate: 4 percent.
7. Renewals and Replacements for New Construction: 0.5 percent of initial investment for first 10 years and 0.6 percent thereafter.

The operating costs of each resource were modeled in the production simulation model. The costs for each resource are described in the following paragraphs. Much of the detailed production simulation inputs are located in Appendix B and are referred to in this Section.

Nebraska City Generating Station, Unit 2

Table B-1 - Projected Purchased Power Prices shows projected energy and capacity prices for Nebraska City Generating Station, Unit 2 (NC2). NC2 coal prices were estimated at $2.11 per million British Thermal Units (MMBtu) in 2011 based on recent estimates provided by OPPD and escalated 4 percent annually.

Iatan Generating Station, Unit 2

Table B-1 - Projected Purchased Power Prices shows projected energy and capacity prices for Iatan Generating Station, Unit 2 (Iatan 2). Iatan 2 coal prices were estimated at $1.77/MMBtu in 2010 and escalated 4 percent annually.

Fuel Price Assumptions

The prices for coal, natural gas, and oil were estimated in 2011 dollars and escalated annually. Coal prices for the Blue Valley and Missouri City plants are shown in Table B-2 and were estimated based on recent negotiations between coal suppliers and IPL staff. The price of coal for a new generating unit owned and operated by IPL was estimated at $2.18/MMBtu in 2011 and is shown in Tables B-2 and B-21. Coal prices were escalated 3 percent annually.

IPL developed a natural gas price forecast which was the basis for the price projection for 2011. Table B-2 shows the natural gas price at $5.16/MMBtu in 2011, including transportation. Natural gas prices were escalated 4 percent annually. IPL projected the fuel oil price at $21.47/MMBtu in 2011, including transportation, as shown in Table B-2. Fuel oil prices were escalated 4.5 percent annually. Fuel oil is used in IPL combustion turbine generators.

Electric Market Prices

Short-term spot market energy purchase and sales prices were projected for the Kansas/Missouri area in SPP. The on-peak market sales prices used in the economic analysis were estimated at approximately 80 percent of projected on-peak market purchase prices. Table B-3 shows projected average annual market energy purchase and sale prices for 2011 through 2030. 2011 on-peak and off-peak market energy purchase prices were estimated at $36.42/MWh and $21.56/MWh, respectively. The 2011 on-peak and off-peak market energy sales prices were estimated at $29.13 MWh and $21.56 MWh, respectively. Market prices were escalated at 4 percent annually.

Transmission costs were added to the market purchase prices for the production simulation. Transmission costs were estimated at $4.63/MWh in 2011 based on the Fiscal Year 2011 KCP&L-GMO transmission formula rate for hourly on-peak, point-to-point transmission service and escalated 4 percent annually.

New Generating Units

Table B-5 shows the fixed and variable operating costs and characteristics of new generating units used in the power supply plans. The construction period for new combustion turbines and combined cycle was estimated at two years. The construction period for new coal-fired generation was estimated at seven years.

ECONOMIC ANALYSIS

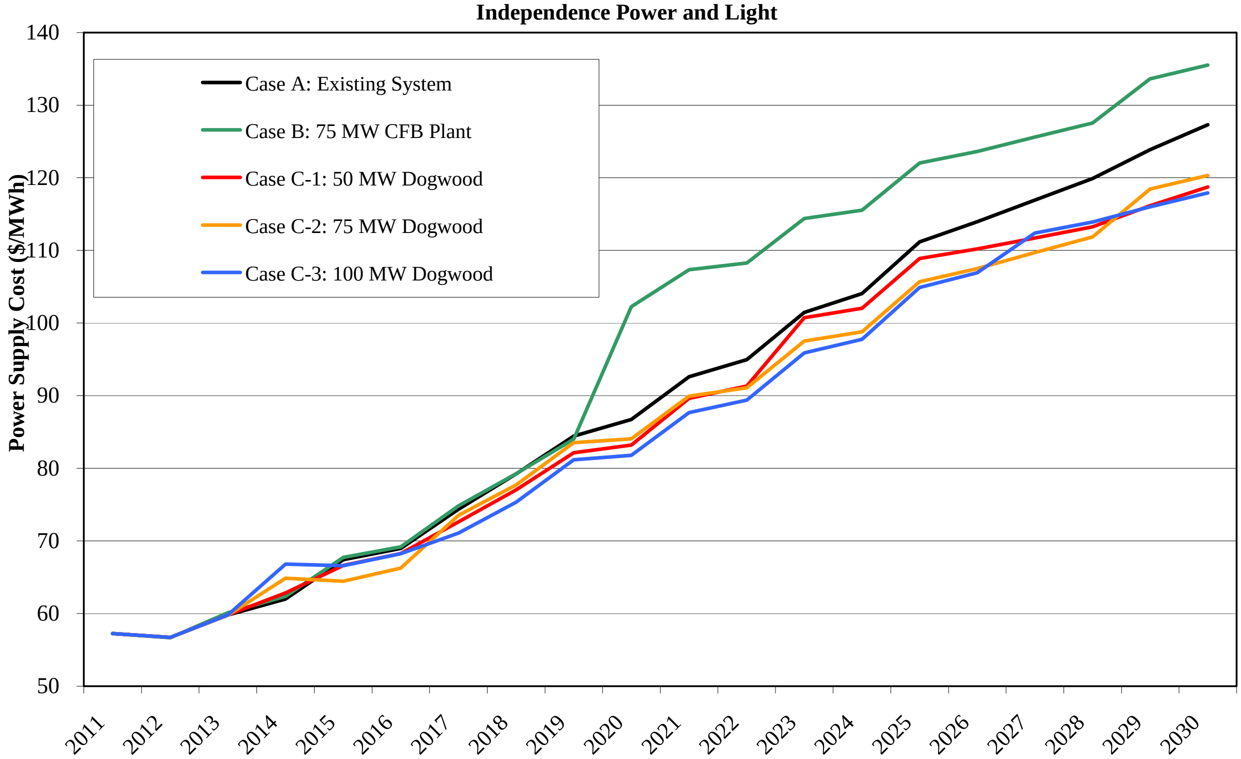
Table 7-1 summarizes the economic comparison results of the five power supply plan cases that were identified in Section 6 - Power Supply Plans. The five cases are shown on the table in alphabetical order. Figure 7-1 shows a graphical representation of the total annual incremental power supply costs of each case. The results of this analysis are explained in the following paragraphs.

Table 7-1
Comparison of Power Supply Plan Costs
City of Independence, Missouri

Case Name	2012 P. V. ($000)(1)	($/MWh)																			
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Case A	1,496,671	57.3	56.7	59.8	62.0	67.4	69.0	74.4	79.2	84.4	86.7	92.6	94.9	101.5	104.1	111.2	114.0	116.9	119.9	123.9	127.3
Case B	1,595,912	57.3	56.7	60.1	62.4	67.7	69.2	74.8	79.3	84.0	102.3	107.3	108.3	114.4	115.5	122.1	123.6	125.6	127.5	133.6	135.5
Case C-1	1,454,933	57.3	56.7	59.8	62.9	66.6	68.3	72.6	77.0	82.1	83.2	89.6	91.3	100.7	102.1	108.9	110.2	111.7	113.3	116.2	118.7
Case C-2	1,446,720	57.3	56.7	59.8	64.9	64.5	66.3	73.5	77.7	83.5	84.1	89.9	91.1	97.5	98.8	105.7	107.5	109.7	111.8	118.4	120.3
Case C-3	1,437,841	57.3	56.7	59.8	66.8	66.6	68.2	71.1	75.3	81.2	81.8	87.7	89.4	95.9	97.8	104.9	106.9	112.4	113.9	116.0	117.9

(1) Present Value (2012 through 2030) calculated using discount rate of 5.00%

Figure 7-1
Annual Power Supply Cost Comparison
Independence Power and Light



The lowest cost power supply plan is Case C-3, purchase 100 MW of the Dogwood Combined Cycle Plant, which is ranked first (lowest overall cost) out of the five alternatives evaluated. Case B, construct 180 MW coal-fired unit, was the highest cost case evaluated.

Case A involves purchasing future capacity and energy needs from the Market with no generation additions. Case A is ranked fourth with a present value of annual costs of $1,496,671,000 from 2012 through 2030. Case A is approximately 4 percent more expensive than Case C-3.

Case B involves IPL constructing a 180 MW CFB coal-fired unit, selling 105 MW of ownership in the unit to another entity, and constructing seven 36 MW combustion turbines. Case B is ranked fifth with a present value of $1,595,912,000 from 2012 through 2030. Case B is approximately 11 percent more expensive than Case C-3.

Case C-1 involves purchasing 50 MW of the Dogwood plant and building seven 36 MW combustion turbines. Case C-1 is ranked third at a present value of $1,454,933,000 from 2012 through 2030. Case C-1 is approximately 1.2 percent more costly than Case C-3.

Case C-2 involves purchasing 75 MW of the Dogwood plant and constructing seven 36 MW combustion turbines. Case C-2 is ranked second with a present value of $1,446,720,000 from 2012 through 2030. Case C-2 is approximately 0.6 percent more costly than Case C-3.

Case C-3 involves purchasing 100 MW of the Dogwood Plant and constructing six 36 MW combustion turbines. Case C-3 is the lowest cost plan with a present value of $1,437,841,000 from 2012 through 2030.

<u>Summary of Base Case Economic Analyses</u>

Case C-3, purchasing 100 MW from Dogwood in 2014 is the lowest reasonable cost option evaluated. However, Cases C-1 and C-2, 50 and 75 MW Dogwood, are only approximately 1 percent more costly and thus nearly equal. Thus, it is economical to purchase 50 to 100 MW of Dogwood.

DOGWOOD SENSITIVITY ANALYSES

IPL has indicated it may have the opportunity to not only purchase a share of Dogwood in 2012, 2013, or 2014, but also that a 50 MW share may be purchased in 2012 and then an additional amount purchased in 2013 or 2014. The purchase price of Dogwood increases daily from the January 1, 2012 offered price. The purchase price increases a fixed amount each day from January 1, 2012 through December 31, 2014. IPL needs approximately 25 MW of capacity in 2012 and 2013. Therefore, it could purchase 50 MW of Dogwood at the lowest price in 2012 and purchase additional Dogwood capacity in 2014 closer to when IPL needs additional capacity in 2015 when the Missouri City plant is no longer in operation.

This Section evaluates two sensitivities related to the timing of the Dogwood purchase. The first sensitivity (A) involves purchasing a share of Dogwood in 2012 (50, 75, and 100 MW). The second sensitivity (B) involves purchasing a 50 MW share of Dogwood in 2012 and an additional 0, 25, or 50 MW share of Dogwood in 2014. To accomplish this, a NPV analysis was prepared for the period 2012 through 2030 for both sensitivities. Annual debt service was estimated for 2012 and 2014 purchases of Dogwood using 18-year (2014) or 20-year (2012) amortization periods and a 5 percent interest rate.

2012 Dogwood Purchase

Table 7-2 summarizes the economic comparison of sensitivities. Figure 7-2 shows a graphical representation of the total annual incremental power supply costs of Cases C-1, C-2, C-3, and C-1A, C-2A, C-3A. Case C-1A involves purchasing 50 MW of Dogwood in 2012. Case C-1A is the highest cost sensitivity case evaluated with a total NPV cost of $1,450,149,000 from 2012 through 2030.

Table 7-2
Comparison of Power Supply Plan Costs
Dogwood Sensitivities A and B
City of Independence, Missouri

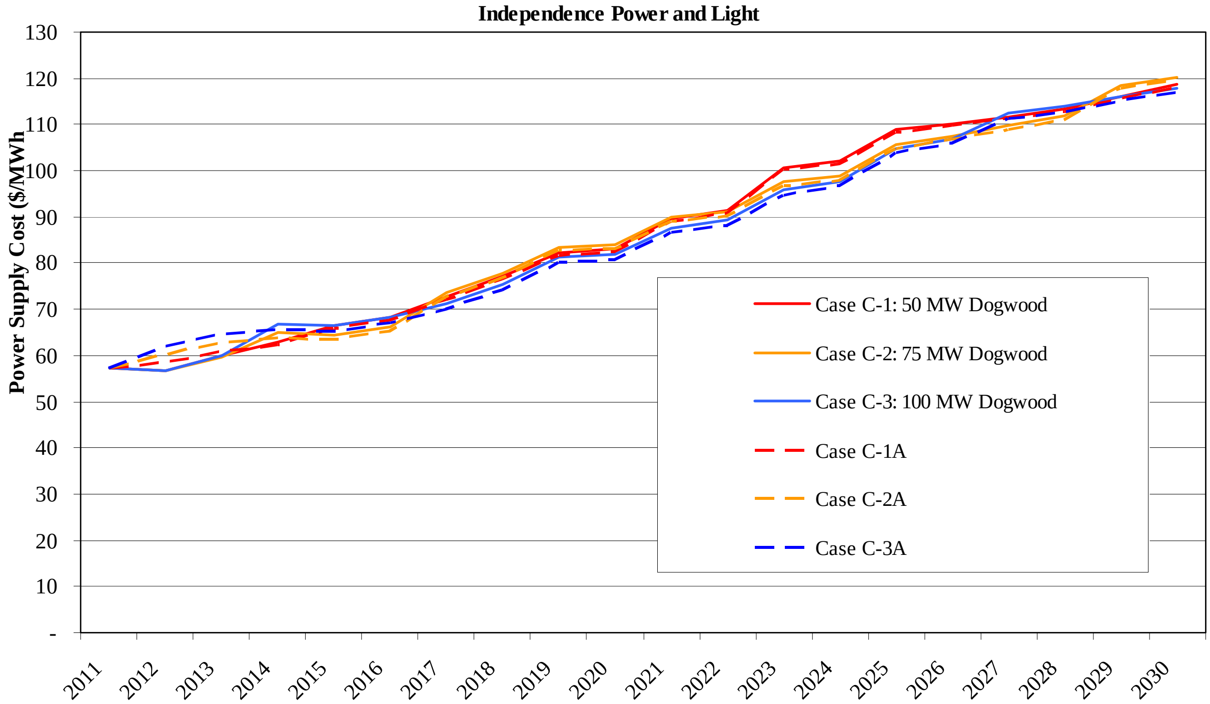
Case Name	2012 P. V. ($000)[1]	($/MWh)																			
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Case C-1	1,454,933	57.3	56.7	59.8	62.9	66.6	68.3	72.6	77.0	82.1	83.2	89.6	91.3	100.7	102.1	108.9	110.2	111.7	113.3	116.2	118.7
Case C-1A	1,450,149	57.3	58.4	61.0	62.2	66.0	67.7	72.0	76.5	81.6	82.6	89.1	90.8	100.2	101.5	108.4	109.7	111.2	112.8	115.7	118.3
Case C-1B	1,450,149	57.3	58.4	61.0	62.2	66.0	67.7	72.0	76.5	81.6	82.6	89.1	90.8	100.2	101.5	108.4	109.7	111.2	112.8	115.7	118.3
Case C-2	1,446,720	57.3	56.7	59.8	64.9	64.5	66.3	73.5	77.7	83.5	84.1	89.9	91.1	97.5	98.8	105.7	107.5	109.7	111.8	118.4	120.3
Case C-2A	1,442,337	57.3	60.3	62.8	63.9	63.6	65.4	72.6	76.8	82.7	83.2	89.1	90.3	96.7	98.0	104.9	106.7	108.9	111.1	117.7	119.6
Case C-2B	1,442,003	57.3	58.4	61.0	64.2	63.9	65.7	72.9	77.1	82.9	83.5	89.4	90.5	97.0	98.3	105.2	107.0	109.2	111.4	118.0	119.8
Case C-3	1,437,841	57.3	56.7	59.8	66.8	66.6	68.2	71.1	75.3	81.2	81.8	87.7	89.4	95.9	97.8	104.9	106.9	112.4	113.9	116.0	117.9
Case C-3A	1,433,732	57.3	62.1	64.7	65.6	65.4	67.1	69.9	74.2	80.0	80.7	86.6	88.3	94.8	96.7	103.9	105.9	111.4	112.9	115.1	117.0
Case C-3B	1,433,059	57.3	58.4	61.0	66.2	66.0	67.7	70.5	74.8	80.6	81.2	87.1	88.8	95.3	97.3	104.4	106.4	111.9	113.4	115.5	117.5

[1] Present Value (2012 through 2030) calculated using discount rate of 5.00%

Case C-2A involves purchasing 75 MW of Dogwood in 2012. Case C-2A is the fourth lowest cost sensitivity case evaluated with a total NPV cost of $1,442,337,000 from 2012 through 2030.

Case C-3A involves purchasing 100 MW of Dogwood in 2012. Case C-3A is the second lowest cost sensitivity case evaluated with a total NPV cost of $1,433,732,000 from 2012 through 2030.

Figure 7-2
Annual Power Supply Cost Comparison -
Sensitivity A (2012 Dogwood Purchase)



An important item to note about purchasing Dogwood in 2012 is the short-term impact on power supply costs in 2012 and 2013 when the IPL capacity need is approximately 25 MW. As shown in Table 7-2, purchasing 50, 75, and 100 MW of Dogwood in 2012 would cause an estimated increase in power supply costs for years 2012 and 2013 as compared to waiting to purchase in 2014. The estimated increased costs in these two years is offset by savings in later years due to the lower buy-in costs of Dogwood if purchased in 2012 as compared to purchasing in 2014.

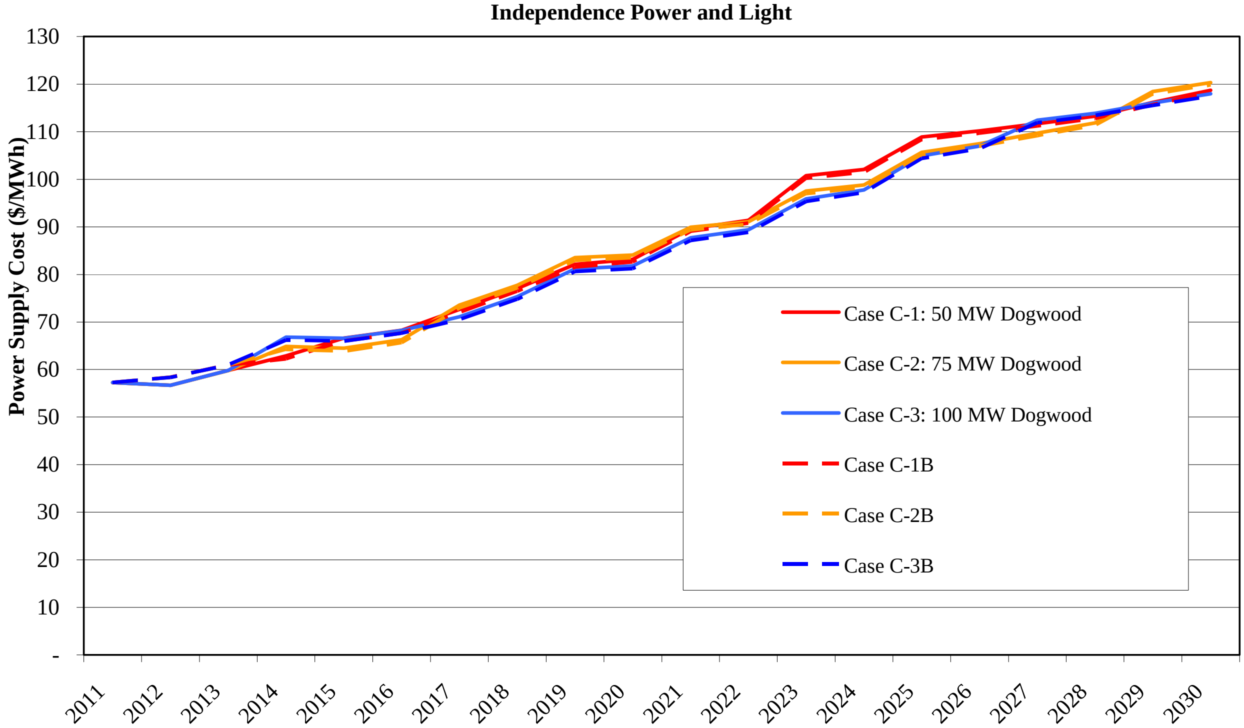
2012/2014 Stepped Dogwood Purchase

Figure 7-3 shows a graphical representation of the total annual incremental power supply costs of cases C-1, C-2, C-3, and C-1B, C-2B, C-3B. Case C-1B involves purchasing 50 MW of Dogwood in 2012. Case C-1B is identical to Case C-1A and, thus, is the highest cost sensitivity case evaluated.

Case C-2B involves purchasing 50 MW of Dogwood in 2012 and an additional 25 MW (75 MW total) of Dogwood in 2014. Case C-2B is the third lowest cost sensitivity case evaluated with a total NPV cost of $1,422,003,000 from 2012 through 2030.

Case C-3B involves purchasing 50 MW of Dogwood in 2012 and an additional 50 MW (100 MW total) of Dogwood in 2014. Case C-3B is the lowest cost sensitivity case evaluated with a total NPV cost of $1,433,059,000 from 2012 through 2030.

Figure 7-3
Annual Power Supply Cost Comparison -
Sensitivity B (2012/2014 Stepped Dogwood Purchase)
Independence Power and Light



Summary of Sensitivity Analyses

The difference in total NPV cost between the lowest cost sensitivity case, C-3B, and the highest cost sensitivity case, C-1A, is less than 2 percent and, thus, nearly equal. The lowest cost sensitivity case, Case C-3B, involves purchasing 50 MW of Dogwood in 2012 and an additional 50 MW of Dogwood in 2014. Case C-3B is less than approximately 1 percent lower in total NPV cost than the lowest cost base case, Case C-3, purchasing a 100 MW Dogwood in 2014. The results of the sensitivity cases indicate that purchasing Dogwood in 2012, 2014, or some in 2012 and some in 2014 are nearly equal in total NPV cost from 2012 through 2030.

However, the total NPV cost does not reflect the short-term impact on power supply costs, and, subsequently, electric rates. As mentioned previously, the power supply costs are projected to be more in 2012 and 2013 if the Dogwood purchase is made in 2012 versus 2014. Thus, although they are nearly equal in total NPV cost, purchasing 50 MW in 2012, then purchasing an additional 50 MW in 2014 would cause less of an increase in revenue requirements in 2012 and 2013, when no more than 50 MW of capacity is needed by the IPL system than purchasing 100 MW of Dogwood in 2012. These analyses do not include any sale of excess capacity. If IPL were able to sell its unneeded capacity in 2012 and 2013, the increase in revenue requirements could be lessened with this additional revenue stream.

DOGWOOD PLANNING CONSIDERATIONS

Several factors should be considered when planning power supply resources. The cost of power supply resources, and how that cost compares to other alternative power supply resources, is usually of great importance. Other important factors include resource diversity, fuel diversity, and diversity of vested interests of business partners.

The Dogwood Energy Center can be a beneficial power supply resource if it can provide benefits when considering the factors above.

Cost of Project

The Dogwood Energy Center is approximately 10 years old with a remaining life of approximately 25 years. The ownership purchase price coupled with tax-exempt municipal financing is currently considerably less expensive than other resource alternatives, such as purchasing capacity and energy from other utilities, and compared to constructing a new generating plant (combustion turbine, combined cycle, or reciprocating internal combustion engine). The ownership purchase price of Dogwood is approximately one half of the cost of building new gas-fired peaking generation. At purchase capacities of 50 MW, 75 MW, and 100 MW, the present value of total annual power supply costs over a 20-year planning period are nearly the same. Purchasing 100 MW would have a greater impact initially on electric costs than the 50 MW and 75 MW purchase level and, perhaps, also on revenue requirements because 100 MW is not needed by the system initially.

Resource Diversity

Resource diversity is important because one should not be reliant on only one resource or one fuel. IPL has purchased power agreements in the NC2 and Iatan 2 projects of approximately 50 MW each. This capacity level is approximately 13 percent of the IPL peak demand and is approximately equal to the reserve margin it must maintain in the Southwest Power Pool (13.67 percent of peak demand). Figure 7-4 shows the resource mix of the existing IPL system in 2020 with more than 50 percent of capacity coming from the market. Figures 7-5 through 7-7 show the resource mix of the IPL system with 50, 75, and 100 MW of Dogwood in 2020 with 3, 0, and 0 percent, respectively, of capacity needs purchased from the market.

Therefore, 50 MW in one generating unit is a good fit for the IPL system as this capacity is approximately equal to the capacity reserve margin.

Figure 7-4
2020 Capacity Resource Mix
Case A: Existing System

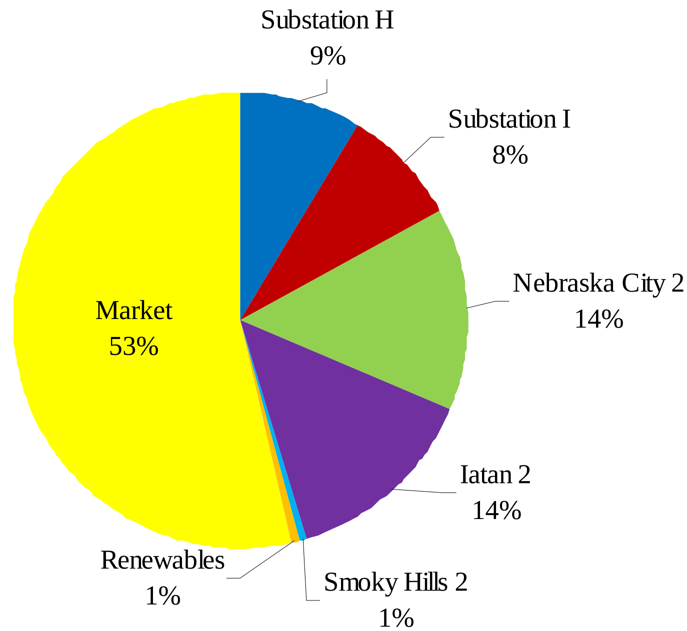


Figure 7-5
2020 Capacity Resource Mix
Case C-1: 50 MW Dogwood

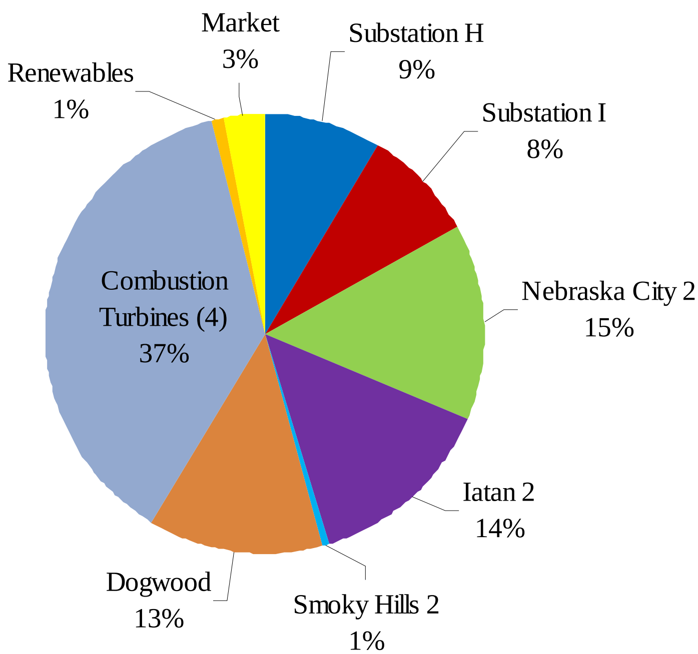


Figure 7-6
2020 Capacity Resource Mix
Case C-2: 75 MW Dogwood

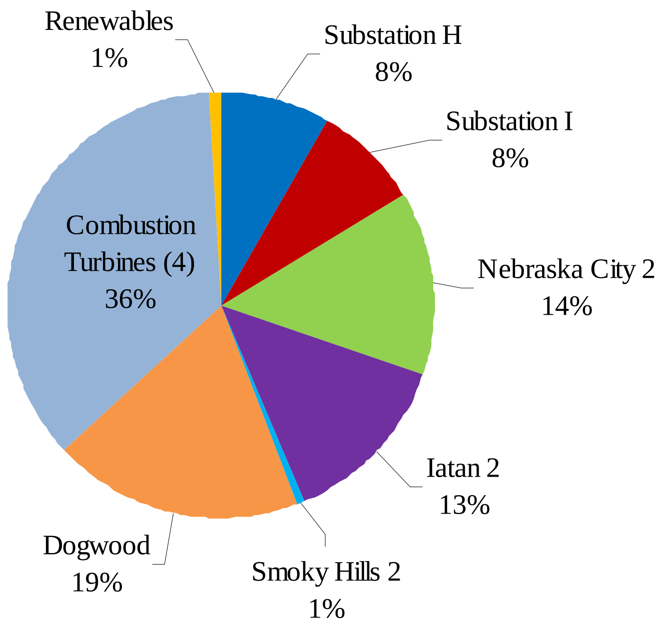
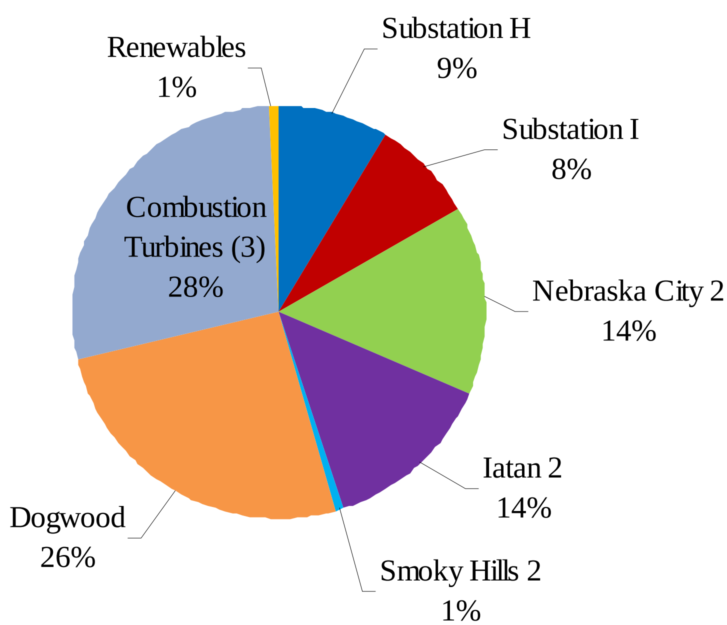


Figure 7-7
2020 Capacity Resource Mix
Case C-3: 100 MW Dogwood



Fuel Diversity

Fuel diversity is another important consideration. Dependence on a single fuel should be avoided. Recent EPA regulation changes have caused natural gas to be a favorable fuel for electric generation. Currently, IPL relies mostly on coal generation and very little on natural gas. Figure 7-8 shows the fuel mix of the existing IPL system in 2012 with 71 percent of the fuel mix coming from coal (IPL coal, Iatan 2, and NC2), 24 percent from purchase power or IPL natural gas generation and 5 percent from renewable resources (Smoky Hills II).

Figure 7-8
2012 Fuel Resource Mix
Case A: Existing System

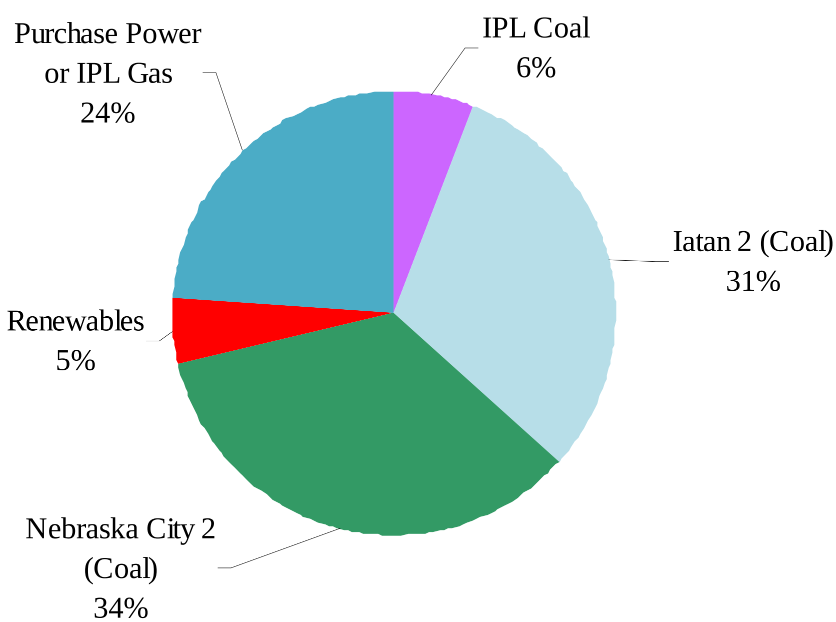
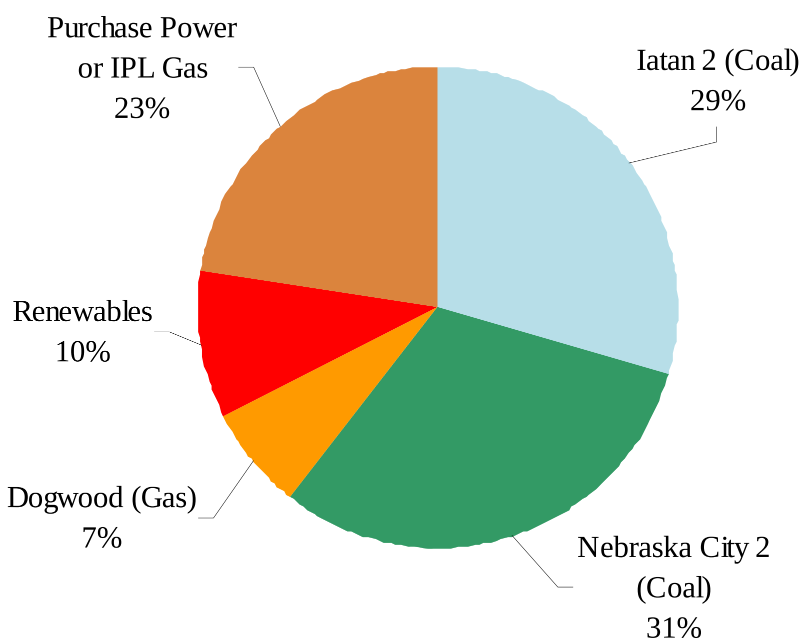


Figure 7-9 shows the fuel mix of the IPL system with 75 MW of Dogwood in 2020 with approximately 7 percent of the fuel mix from Dogwood natural gas generation, 60 percent from coal generation (Iatan 2 and NC2), 10 percent from renewables, and 23 percent from purchase power or IPL natural gas generation.

Market energy prices as of the date of this Report and historical operation of the Dogwood plant indicate that it would operate 10 to 15 percent of hours in a year (approximately equal to the on-peak hours in summer months). If on-peak market conditions were to change because of an increase in natural gas prices, it is expected that the dispatch cost of Dogwood would increase at a slower rate than the on-peak market price because of the efficiency of combined cycle plants such as Dogwood. The current inherent heat rate of generating units dispatching into the market is estimated to be 9,000 to 10,000 Btu/kWh, whereas the heat rate of Dogwood is approximately 7,400 Btu/kWh. Thus, even though the Dogwood Energy Center may not run often initially, it may run more often in the future and act as more of a hedge against increasing market energy prices.

Figure 7-9
2020 Fuel Resource Mix
Case C-2: 75 MW Dogwood



Purchasing an owenership interest in the Dogwood facility increases IPL's fuel diversity by adding additional natural gas generation. The Blue Valley and Missouri City power plants are projected to no longer be in operation by 2020, thereby decreasing IPL's reliance on coal-fired generation from approximately 71 percent in 2012 to 60 percent in 2020.

IPL is also projected to increase its renewable energy portfolio by 2020 and, thus, further increase its renewable generation from 5 percent in 2012 to 10 percent in 2020. As mentioned previously, Dogwood may further increase IPL's fuel diversity if market prices increase and cause Dogwood to be economically feasible to generate more hours of the year.

Business Partner Diversity

The Dogwood facility would add another set of business partners to the IPL resource fleet. On one hand, more partners can cause greater administration and on the other hand it can provide more diversity. Both Iatan 2 and NC2 involve different sets of business partners.

Industry Practice

Many municipal electric utilities and joint-action agencies participate in joint projects with multiple business partners as a matter of necessity to achieve economies of scale. Many try to spread their risks to avoid relying on too much capacity from one generating unit shaft. A capacity level of 75 MW is approximately 25 percent of IPL 2012 peak demand. This percentage will be reduced over time as IPL's load continues to grow.

Environmental Considerations

In addition to burning natural gas, the Dogwood plant has environmental control equipment in place to reduce emissions. The plant's NO_X emissions are below 4 ppm and it is also a zero liquid discharge facility. It may also be possible to further reduce NO_X emissions in the future without capital cost by increasing the catalyst reagent injection rate. Efficient, natural gas-fired combined cycle plants produce fewer greenhouse gas (GHG) emissions per MWh than do comparably-sized coal-fired units. If GHG emissions become restricted by regulations as has already been discussed on the national level, Dogwood will be less affected than a similar sized coal-fired unit. Therefore, the Dogwood plant is in a good position to deal with existing and future environmental regulations.

Additional Dogwood Planning Considerations

The Dogwood proposal is economically favorable to IPL because its ownership purchase price coupled with tax-exempt municipal financing is very competitive with the market price of capacity in SPP and when compared to the cost of constructing new generators. The cost of energy from Dogwood is favorable compared to on-peak market electric energy prices (during the summer months).

Sega concludes that up to 75 MW of capacity from Dogwood is a reasonable and prudent amount to pursue to balance the economic, environmental, and risk considerations.

SECTION 8

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS AND RECOMMENDATIONS

Based on the analyses in this report, Sega concludes the following:

1. Based on the load forecast and projected operation of IPL's existing generating resources and committed power supply resources, a capacity shortfall of approximately 26 MW is expected in 2012, increasing to 73 MW in 2015.

2. Purchasing up to 75 MW of Dogwood increases the fuel diversity of the IPL system by adding natural gas generation to IPL's power supply portfolio.

3. The lowest cost power supply plan based on the current analysis is to purchase 50 MW of the Dogwood Energy Center combined cycle plant in 2012, purchase an additional 0 to 50 MW of Dogwood in 2014, and construct peaking capacity generation to meet future capacity requirements.

4. Purchasing up to 75 MW of Dogwood would follow the resource diversity that IPL began by purchasing approximately 50 MW of NC2 and 50 MW of Iatan 2.

RECOMMENDED ACTIONS

Based on the analyses in this report, Sega recommends the following actions:

1. IPL should purchase 50 MW of the Dogwood Energy Center in 2012 to satisfy the 26 MW projected capacity shortfall in 2012.

2. IPL should purchase up to 25 MW of the Dogwood Energy Center in 2014 (in addition to the 50 MW in 2012) because the projected capacity shortfall of the IPL system increases to 73 MW in 2015.

3. If financing options available to IPL do not appear favorable for incrementally purchasing portions of Dogwood in 2012 and 2014, IPL should pursue purchasing up to 75 MW of Dogwood in 2012.

4. As existing IPL units are retired, on-system generating capacity should be constructed to meet future capacity requirements.

5. IPL should remain flexible with respect to the size and timing of peaking capacity additions as circumstances assumed in this Report could change between the time of this Report and when generating units are constructed.

6. IPL should continue the planning process and continue monitoring environmental and regulatory developments as well as monitoring new opportunities for participation in joint projects.

APPENDICES

APPENDIX A

ENVIRONMENTAL REGULATIONS

APPENDIX A:
ENVIRONMENTAL REGULATIONS

Certain environmental regulations (current and proposed future) impact Master Planning for IPL. This Appendix provides an overview of these regulations as a reference for this Master Planning study.

OVERVIEW OF ENVIRONMENTAL REGULATIONS IMPACTING MASTER PLANNING

Certain environmental regulations (current and potential future) impact Master Planning for IPL. This Section provides an overview of these regulations as a reference for the environmental regulatory discussions in this document. This Section also provides a general overview of the applicability and timing of requirements to the existing resources.

Environmental compliance requirements and related costs are inputs to the evaluation of remaining economic life portion of the existing generation equipment. Environmental compliance requirements and related costs also impact the cost of additional, future generation equipment. Environmental regulations which have been found to impact the Master Planning are in the area of air quality and cooling water intake. Although there are solid waste and water quality regulations with environmental compliance requirements applicable to the existing and future generation equipment, these have been found to not have a differential impact on the Master Planning process. Air quality regulations and compliance requirements have been found to have a substantial differential impact on the Master Planning evaluation of the scenarios considered.

Air quality and cooling water regulations and compliance requirements covered in this overview include:

1. Cross-State Air Pollution Rule (CSAPR).
2. Regional Haze Rule.

3. Utility Boiler Maximum Achievable Control Technology (MACT).
4. Industrial/Commercial/Institutional Boiler Maximum Achievable Control Technology (MACT).
5. Combustion Turbine Generator Maximum Achievable Control Technology (MACT).
6. Ozone Non-Attainment Area/New Ozone National Ambient Air Quality Standards (NAAQS).
7. New Sulfur Dioxide National Ambient Air Quality Standards (NAAQS).
8. New Nitrogen Dioxide National Ambient Air Quality Standards (NAAQS).
9. $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS).
10. New Source Performance Standards (NSPS).
11. New Source Review (NSR).
12. Cooling Water Intake 316(b) Rule.

Cross-State Air Pollution Rule (CSAPR)

On July 6, 2011, the EPA finalized a rule that helps States reduce air pollution and attain the 1997 ozone and fine particle and 2006 fine particle National Ambient Air Quality Standards (NAAQS). This rule, known as the Cross-State Air Pollution Rule (CSAPR), requires 27 States (including Missouri) to significantly improve air quality by reducing power plant emissions that cross State lines and contribute to ozone and fine particle pollution in other States. To speed implementation, EPA is adopting federal implementation plans (FIPs) for each of the States covered by this rule. EPA encourages States to replace these FIPs with State Implementation Plans (SIPs) starting as early as 2013.

Rule Background/Cap and Trade Basics

The CSAPR establishes a "cap and trade" system for SO_2 and NO_x based on EPA's proven Acid Rain Program. With the rule the EPA has "capped" the total regional SO_2 and NO_x

emissions sources subject to the rule will be allowed to emit. The emission “cap” for each emission source was determined by EPA based on past operational and emissions data on a State by State basis. The EPA will assign emission “allowances” for SO_2 and NO_x to each State (as State caps), and the States will allocate those allowances to sources (or other entities), which can trade them. As a result, sources are able to choose from many compliance alternatives, including installing pollution control equipment, switching fuels, or buying excess allowances from other sources that have reduced their emissions. Because each source must hold sufficient allowances to cover its emissions each year (and ozone season in some cases), the limited number of allowances available ensures required reductions are achieved. The flexibility of allowance trading creates financial incentives for electricity generators to look for new and low-cost ways to reduce emissions and improve the effectiveness of pollution control equipment.

This rule replaces EPA’s 2005 Clean Air Interstate Rule (CAIR). A December 2008 court decision kept the requirements of CAIR in place temporarily, but directed EPA to issue a new rule to implement Clean Air Act requirements concerning the transport of air pollution across State boundaries. This action responds to the court’s concerns. The CSAPR also replaces the previously EPA-proposed Clean Air Transport Rule (CATR) which would have required 31 States and the District of Columbia to significantly improve air quality by reducing power plant emissions that contribute to ozone and fine particle pollution in other States.

Basic Facts on Cross-State Air Pollution Rule (CSAPR)

The CSAPR impacts existing and new power plants in certain States. The emission sources impacted by the CSAPR are those individual power plant units with a generating capacity greater than 25 MW. The CSAPR specifically defines these as “electric generating units” (EGUs). EGUs are the same units specifically impacted by EPA’s Acid Rain Program and in the previous CAIR and CATR mentioned above as well as the proposed Utility Boiler MACT discussed below.

The CSAPR requires 23 States (including Missouri) to reduce annual SO_2 and NO_x emissions to help downwind areas attain the 24-hour and/or annual $PM_{2.5}$ NAAQS. Twenty (20) States (not including Missouri) are required in the final CSAPR to reduce ozone season NO_x emissions to help downwind areas attain the 1997 eight-hour ozone NAAQS. However, as noted below, EPA also issued a supplemental notice of proposed rulemaking to require six States (Iowa, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin) to make summertime NO_x reductions under the CSAPR ozone-season control program.

The final CSAPR divides the States required to reduce SO_2 into two groups. Both groups must reduce their SO_2 emissions beginning in 2012. Group 1 States (including Missouri) must make additional reductions in SO_2 emissions by 2014 in order to eliminate their significant contribution to air quality problems in downwind areas. SO_2 allowance trading between Group 1 and Group 2 States will not be allowed. Group 2 States include Alabama, Georgia, Kansas, Minnesota, Nebraska, South Carolina, and Texas.

In a separate, but related regulatory action, EPA also issued a supplemental notice of proposed rulemaking (SNPR) to require six states (Iowa, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin) to make seasonal NO_x reductions under the CSAPR ozone-season control program. (The ozone season runs from May 1 through September 30 of each year.) Five of those States (including Missouri) are already covered in the final rule for interstate fine particle pollution ($PM_{2.5}$). With the inclusion of these States, a total of 26 States would be required to reduce ozone-season NO_x emissions to assist in attaining the 1997 eight-hour ozone NAAQS. Finalizing this supplemental proposal would bring the total number of covered States under the CSAPR to 28. EPA issued a proposal instead of a final action for these States in order to provide additional opportunity for public comment on their linkages to downwind non-attainment and maintenance areas. EPA is proposing to finalize this proposal by the end of 2011.

Cross-State Air Pollution Rule (CSAPR) Timeline

Applicability and compliance with allowance limits initiate quickly, starting January 1, 2012 for SO_2 and annual NO_X and May 1, 2012 for ozone season NO_X. Additional SO_2 emission reductions in Group 1 States will be required in 2014. Sources are required to procure the amount of allowances necessary for compliance by March 1 of the following year for annual SO_2 and NO_X emissions, and by December 1 of the same year for seasonal NO_X. Emission allowances not used in one year can be banked for use in future years or traded.

Cross-State Air Pollution Rule (CSAPR) Allowances

The final rule allocates the following number of allowances to IPL Blue Valley Unit 3:

1. SO_2 Allocation for each of 2012 and 2013: 594 tons.
2. SO_2 Allocation for 2014 and each year thereafter: 457 tons.
3. NO_X Annual Allocation for each of 2012 and 2013: 147 tons.
4. NO_X Annual Allocation for 2014 and each year thereafter: 132 tons.
5. NO_X Ozone Season Allocation for each of 2012 and 2013: 77 tons (proposed in SNPR).
6. NO_X Ozone Season Allocation for 2014 and each year thereafter: 68 tons (proposed in SNPR).

Cross-State Air Pollution Rule (CSAPR) Impact on IPL

The only existing IPL generating units which are EGUs, and thus required to comply with CSAPR, are Blue Valley Unit 3 and the RCT at Blue Valley. The RCT is not listed in the CSAPR allocation table, but will be an affected unit and would need NO_X and SO_2 allowances to cover its emissions starting in 2012. Existing units not listed in the allocation table are eligible for “New Unit” set aside allocations. A new continuous emissions monitoring system (CEMS) to measure and track NO_X emission would also be required. (As noted elsewhere in this study, the RCT will not be repaired and will be considered retired. Therefore, the RCT is not impacted by CSAPR.) New generation equipment greater than 25 MW in capacity will also be affected. IPL will need to hold sufficient NO_X and SO_2 allowances to cover the annual emissions of these pollutants from the affected units. Compliance can be achieved by either receiving sufficient allowances from the State-operated cap and trade program, reduce emissions to levels less than the number of allowances held, or purchasing additional allowances to meet the annual emissions from the affected units. SO_2 allowance trading between Group 1 (including Missouri) and Group 2 States (including Kansas) will not be allowed. IPL would also need to hold sufficient ozone season allowances for Blue Valley Unit 3 operation if the SNPR requires Missouri (and five other States) to make summertime NO_X reductions under the CSAPR ozone-season control program.

Regional Haze Rule

The Regional Haze Rule requires the application of air quality controls on older power generating units built between 1962 and 1977 that have the potential to emit more than 250 tons per year of visibility-impairing pollution.

Basic Facts on Regional Haze

1. In 1990, Congress amended the Clean Air Act, providing additional emphasis on regional haze issues. Among other things, the 1990 Amendments required the EPA to work with several western States to establish a Commission to address visibility in the Grand Canyon National Park. The EPA established the Grand Canyon Visibility Transport Commission in 1991.

2. The EPA issued regulations to improve visibility, or visual air quality, in 156 national parks and wilderness areas across the country. These areas include many of our best-known and most-treasured natural areas, such as the Grand Canyon, Yosemite, Yellowstone, Mount Rainier, Shenandoah, the Great Smoky Mountains, Acadia, and the Everglades.

3. The regulations call for States to establish goals for improving visibility in national parks and wilderness areas and to develop long-term strategies for reducing emissions of air pollutants that cause visibility impairment.

Best Available Retrofit Technology (BART)

1. On June 15, 2005, the EPA finalized amendments to the July 1999 regional haze rule. These amendments apply to the provisions of the Regional Haze Rule that require emission controls known as best available retrofit technology (BART) for industrial facilities emitting air pollutants that reduce visibility by causing or contributing to regional haze.

2. The pollutants that reduce visibility include $PM_{2.5}$, and compounds which contribute to $PM_{2.5}$ formation, such as NO_x, SO_2, and under certain conditions volatile organic compounds and ammonia.

3. The BART requirements of the Regional Haze Rule apply to facilities built between 1962 and 1977 that have the potential to emit more than 250 tons a year of visibility-impairing pollution. Those facilities fall into 26 categories, including utility and industrial boilers, and large industrial plants such as pulp mills, refineries, and smelters. Many of these facilities have not been previously subject to federal pollution control requirements for these pollutants.

4. The June 15, 2005 amendments include guidelines, known as BART guidelines, for States to use in determining which facilities must install controls and the type of controls the facilities must use.

5. States must develop their implementation plans by December 2007. States will identify the facilities that will have to reduce emissions under BART and then set BART emissions limits for those facilities.

6. States must consider a number of factors when determining what facilities will be covered by BART, including:

    a. The cost of the controls.

    b. The impact of controls on energy usage or any non-air quality environmental impacts.

    c. The remaining useful life of the equipment to be controlled.

    d. Any existing pollution controls already in place.

    e. Visibility improvement that would result from controlling the emissions.

7. On March 10, 2005, the EPA issued the CAIR, requiring reductions in emissions of SO_2 and NO_x from EGUs in 28 eastern States and the District of Columbia. (In 2011, CAIR was replaced by CSAPR as discussed above.) When fully implemented, the CAIR would have reduced SO_2 emissions in these States by over 70 percent and NO_x emissions by over 60 percent from 2003 levels. The CAIR established an EPA-administered cap and trade program for EGUs in which States may participate as a means to meet these requirements. In the BART guidelines, the EPA presents the results of an analysis showing that controls for EGUs subject to CAIR will result in more visibility improvement in natural areas than BART would have provided. Therefore, States which adopted the CAIR cap and trade program for SO_2 and NO_x were allowed to apply CAIR controls as a substitute for controls required under BART because CAIR controls are "better than BART" for EGUs in the States subject to CAIR. Although not specifically stated in the rules, an assumption can be made that compliance with the new CSAPR requirements will similarly satisfy the BART control requirements of the Regional Haze Rule.

Utility Boiler Maximum Achievable Control Technology (MACT)

Basic Facts on Utility Boiler Maximum Achievable Control Technology (MACT)

On March 16, 2011, the EPA issued a proposed rule that would reduce and limit emissions of toxic air pollutants from power plants. These limits are defined as Maximum Achievable Control Technology (MACT). Specifically, the proposal would reduce emissions from new and existing coal- and oil-fired EGUs. EPA has committed to issuing the final rule by December 16, 2011. Compliance will be required three years after publication of the rule in the Federal Register, making this approximately the beginning of 2015.

1. The rule affects utility boilers greater than 25 MW in size (i.e., EGUs) located at a major source of HAPs.

   a. Major Source: Potential to emit 10 tons/year of one HAP or 25 tons/year of all HAPs combined. Emissions from the entire facility, including non-boiler or process heater sources, count toward major source status.

   b. Hazardous Air Pollutants: Boilers and process heaters emit HAPs such as arsenic, cadmium, chromium, hydrogen chloride, hydrogen fluoride, lead, manganese, mercury, and nickel.

2. For all existing and new coal-fired EGUs, the proposed MACT standards would establish numerical emission limits for mercury, PM (a surrogate for toxic non-mercury metals), and HCl (a surrogate for toxic acid gases).

3. The proposal would establish alternative MACT standards, including SO_2 (as an alternate to HCl), individual non-mercury metal air toxics (as an alternate to PM), and total non-mercury metal air toxics (as an alternate to PM) for certain subcategories of power plants.

4. The proposed MACT standards would establish work practices, instead of numerical emission limits, to limit emissions of organic air toxics, including dioxin/furan, from existing and new coal and oil-fired power plants. Because dioxins and furans form from inefficient combustion, the proposed work practice standards would require an annual performance test program for each EGU that would include inspection, adjustment, and/or maintenance and repairs to ensure optimal combustion.

The only existing IPL generating unit which is an EGU boiler, and thus required to comply with CSAPR, is Blue Valley Unit 3.

<u>Industrial/Commercial/Institutional Boiler MACT (IB MACT)</u>

Basic Facts on IB MACT

On July 30, 2007, the Court of Appeals for the District of Columbia Circuit issued its mandate in a case which vacated and remanded the EPA's September 2004 Boiler Rule for air toxics emissions control. A new final rule was issued by the EPA and published in the Federal Register March 21, 2011 and required compliance by March 21, 2014. This initial effective date was stayed by the EPA on May 16, 2011 to seek additional input and conduct additional analysis for reconsideration prior to re-issuing the final IB MACT and new effective date. On June 24, 2011, EPA announced their timeline for reconsideration of the IB MACT standards. This timeline states that EPA intends to sign a proposed rule by November 30, 2011 and sign a final rule by April 30, 2012. This delays the compliance date by over one year from March 21, 2014 to April or May of 2015 as a result of EPA's reconsideration process.

The following discussion is based on the March 21, 2011 version of the "final" rule. The new rule is more stringent than the rule vacated in 2007. The following describes the new rule for reference.

1. The rule affects boilers located at a major source of HAPs.
2. The rule does not apply to EGUs because EGUs are covered separately by the Utility Boiler MACT.
3. The rule sets MACT emission limits for particulate, mercury, hydrogen chloride, carbon monoxide, and dioxin/furan.

IPL has four existing operating units which are classified as industrial boilers under this rule.

Combustion Turbine Generator MACT (CTG MACT)

Basic Facts on CTG MACT

1. On August 29, 2003, the EPA issued requirements to reduce and limit toxic air emissions from stationary combustion turbines; these were amended August 18, 2004. These requirements apply to oil-fired turbines used at facilities such as power plants, chemical and manufacturing plants, and pipeline compressor stations. CTG MACT does not apply to natural gas-fired combustion turbines.
2. The final rule will reduce emissions of a number of toxic air pollutants such as formaldehyde, toluene, acetaldehyde, and benzene.
3. This rule limits the amount of air pollution that may be released from exhaust stacks of any new stationary combustion turbine (built after January 14, 2003). Existing turbines do not have to meet emission limitations. However, an existing CTG which burns oil can trigger the MACT limitations requirements if it undergoes a "modification". A triggering modification is any physical change or change in the method of operation which results in an increase in emissions and cannot be considered exempt, such as routine maintenance, repair, or replacement.

4. The Clean Air Act requires the EPA to identify air toxics controls based on the emissions levels achieved by the best-performing facilities. This baseline for controls is established differently for existing and new sources. In the case of stationary combustion turbines, there were not enough existing turbines with controls to establish a baseline level of control. Requiring these facilities to add controls required for new turbines is cost prohibitive.

5. New turbines must comply with this rule when they are brought online. These units have up to six months after the rule is final, or six months after startup, whichever is later, to demonstrate compliance with the new standards.

6. This rule requires certain types of stationary combustion turbines to reduce formaldehyde emissions to 91 parts per billion (ppb) or less. This applies to the following:

    a. Lean premix combustor turbines which burn distillate oil.

    b. Diffusion flame combustor turbines which burn distillate oil.

7. The EPA expects owners or operators of these turbines to install equipment known as "carbon monoxide catalytic oxidation systems". These systems not only reduce carbon monoxide emissions, they also reduce air toxic emissions such as formaldehyde, toluene, acetaldehyde, and benzene.

8. Facilities may use other means to reduce emissions and comply with the formaldehyde emissions limit of 91 parts per billion. If they choose to do so, they must petition the Administrator to establish parameters that determine continuous compliance.

Ozone Non-Attainment Area/New Ozone National Ambient Air Quality Standards (NAAQS)

Basic Facts on Ozone National Ambient Air Quality Standards (NAAQS)

1. The EPA issued an eight-hour ozone National Ambient Air Quality Standard (NAAQS) in July 1997. The eight-hour ozone standard was 0.08 parts per million (ppm), averaged over eight hours. Because of rounding, this standard was essentially 0.084 ppm in practice. This standard is based on the average of the highest values measured over the previous three years.

2. On April 30, 2004, the EPA published a final rule designating and classifying all areas in the United States for the NAAQS for eight-hour ozone.

3. In 2008, the EPA lowered the NAAQS for ozone to 0.075 ppm. The revision reflected new scientific evidence about ozone and its effects on people and public welfare.

4. Subsequent to 2008, the EPA proposed to further reduce the 2008 eight-hour average ozone NAAQS to an expected range of 0.060 to 0.070 ppm. This revised NAAQS would have been implemented prior to the next regularly scheduled date for review of the NAAQS in 2013. However, in September 2011, President Obama instructed the EPA to cancel plans to revise the 2008 NAAQS and proceed on the regularly scheduled course for reviewing the NAAQS in 2013.

Attainment Status and Affect on Air Emission Sources

After several years of being close to the NAAQS, the Kansas City area was classified as having "marginal" compliance with the 1997 NAAQS (0.084 ppm). As a result, both the State of Kansas and State of Missouri have SIPs with initial measures designed to reduce the rise in ozone levels and return the Kansas City area to full compliance status with the 1997 NAAQS for ozone. If the initial phase of measures were not effective or additional violations of the ozone NAAQS occurred over the next three years, a second phase of "contingency" measures of emissions reductions would be required. These contingency measures have been triggered. During the summer of 2007, the Kansas City area officially violated the 1997 NAAQS of 0.084 ppm for ozone. The highest ambient ozone concentration level reported during the 2005 through 2007 period was 0.087 ppm, which exceeded the 0.084 ppm 1997 NAAQS for ozone. The MDNR has required IPL to implement NO_X emissions reductions to comply with these contingency measures.

The EPA has not officially designated Kansas City a non-attainment area yet, pending their action on MDNR's recommendation for non-attainment area boundaries for the new, 0.075 ppm NAAQS issued in 2008. This delay in action has also been the result of EPA's proposed lowering of the 2008 NAAQS. As noted above, President Obama in September 2011 has cancelled EPA's proposed lowering of the 2008 NAAQS and to consider revising the 2008 NAAQS in 2013 according to the regular schedule. Therefore, the original process of finalizing the Kansas City nonattainment area classification for the 2008 NAAQS will continue and will result in the MDNR's development of a revised SIP for ozone attainment plans. The MDNR will have to develop emission control and offset rules for the Kansas City area. It is expected that Platte, Clay, and Jackson Counties in Missouri would be in the affected non-attainment area; therefore, all of the IPL generating units would be affected.

New Sulfur Dioxide National Ambient Air Quality Standards (NAAQS)

On June 2, 2010, EPA lowered the primary NAAQS for SO_2 and may impact IPL units.

Basic Facts on Sulfur Dioxide Air Quality Standard

1. EPA revised the primary SO_2 standard by establishing a new one-hour standard at a level of 75 parts per billion (ppb).

2. The Agency revoked the two existing primary standards of 140 ppb evaluated over 24 hours and 30 ppb evaluated over an entire year because they will not add additional public health protection given a one-hour standard at 75 ppb.

3. EPA did not revise the secondary SO_2 NAAQS set to protect public welfare (including effects on soil, water, visibility, wildlife, crops, vegetation, national monuments, and buildings).

4. A summary of the implementation timeline for the new NAAQS is below:

   a. June 2010: EPA established the new primary one-hour SO_2 standard of 75 ppb.

   b. June 2011: States must submit designation recommendations.

   c. February 2012: EPA notifies States if they intend to modify recommendations.

   d. June 2012: EPA finalizes initial area designations.

   e. June 2013: States must submit infrastructure SIPs for unclassifiable areas.

f. February 2014: States must submit attainment SIPs for non-attainment areas.

g. August 2017: Initial attainment date for all areas.

Attainment Status and Affect on Air Emission Sources

MDNR developed non-attainment designation recommendations for the EPA. These recommendations, based on historical monitoring data, include a proposed non-attainment area in Kansas City which is west of Interstate 435, east of the Kansas State line, south of the Missouri River and north of Interstate 70/670. Although the IPL generating units are not within this initially recommended non-attainment area, an individual unit will be impacted by this non-attainment area if dispersion modeling demonstrates that the unit has a significant contribution to the non-attainment area. The non-attainment area may also be adjusted in the future based on additional monitoring data collected or the results of dispersion modeling of SO_2 from the major sources in the Kansas City area. Given the relative size of the SO_2 emissions from the IPL units and the stringency of the new one-hour SO_2 NAAQS, an assumption is made that IPL's coal-fired units will be impacted by the new SO_2 NAAQS. The impact would include a reduction of SO_2 emission levels.

New Nitrogen Dioxide National Ambient Air Quality Standards (NAAQS)

On January 22, 2010, EPA strengthened the health-based NAAQS for nitrogen dioxide (NO_2).

Basic Facts on Nitrogen Dioxide Air Quality Standard

1. EPA set a new one-hour NO_2 standard at the level of 100 ppb. This level defines the maximum allowable concentration anywhere in an area.

2. In addition to establishing an averaging time and level, EPA also set a new "form" for the standard. The form is the air quality statistic used to determine if an area meets the standard. The form for the one-hour NO_2 standard is the three-year average of the 98th percentile of the annual distribution of daily maximum one-hour average concentrations.

3. EPA also retained, with no change, the current annual average NO_2 standard of 53 ppb.

4. To determine compliance with the new standard, EPA established new ambient air monitoring and reporting requirements for NO_2.

   a. In urban areas, monitors are required near major roads as well as in other locations where maximum concentrations are expected.

   b. Additional monitors are required in large urban areas to measure the highest concentrations of NO_2 that occur more broadly across communities.

   c. Working with the States, EPA will site a subset of monitors in locations to help protect communities that are susceptible and vulnerable to NO_2-related health effects.

5. Implementing the new NO_2 standard:

   a. EPA expects to identify or "designate" areas as attaining or not attaining the new standard by January 2012, within two years of establishing the new NO_2 standard. These designations will be based on the existing community-wide monitoring network. Areas with monitors recording violations of the new standards will be designated "non-attainment". EPA anticipates designating all other areas of the country "unclassifiable" to reflect the fact that there is insufficient data available to determine if those areas are meeting the revised NAAQS.

   b. Once the expanded network of NO_2 monitors is fully deployed and three years of air quality data have been collected, EPA intends to redesignate areas in 2016 or 2017, as appropriate, based on the air quality data from the new monitoring network.

Attainment Status and Affect on Air Emission Sources

MDNR has not yet recommended areas for non-attainment designation. Given the relative size of the NO_x emissions from the IPL units and the stringency of the new one-hour NO_2 NAAQS, an assumption is made that IPL's generating units will be impacted by the new NO_2 NAAQS. The impact would include a reduction of NO_x emission levels.

PM$_{2.5}$ National Ambient Air Quality Standards (NAAQS)

Basic Facts on PM$_{2.5}$ Standard

1. In July 1997, the EPA issued the NAAQS for Fine Particles (PM$_{2.5}$). The standards include an annual standard set at 15 micrograms per cubic meter (µg/m3), based on the three-year average of annual mean PM$_{2.5}$ concentrations and a 24-hour standard of 65 micrograms per cubic meter, based on the three-year average of the 98th percentile of 24-hour concentrations.

2. The EPA on September 21, 2006 strengthened the air quality standards for particle pollution. The final standards address two categories of particle pollution: PM$_{2.5}$, which are 2.5 micrometers in diameter and smaller; and "inhalable coarse particles" (PM$_{10}$) which are smaller than 10 micrometers.

3. The new 24-hour fine particle standard decreased from the 1997 level of 65 µg/m3 to 35 µg/m3, and retained the current annual fine particle standard at 15 µg/m3. The EPA also retained the existing national 24-hour PM$_{10}$ standard of 150 µg/m3.

4. The EPA has two primary standards for fine particles, an annual standard designed to protect against health effects caused by exposures ranging from days to years and a 24-hour standard designed to provide additional protection on days with high peak PM$_{2.5}$ concentrations.

24-Hour Standards

Primary

The EPA has substantially strengthened the primary 24-hour fine particle standard, lowering it from the current level of 65 µg/m3 to 35 µg/m3.

Secondary

The EPA has set the secondary standard at the same level as the primary standard (35 µg/m3).

Annual Standards

Primary

The EPA retained the primary annual standard at 15 μg/m3.

Secondary

The EPA has set the secondary standard at the same level as the primary standard (15 μg/m3).

The Clean Air Act requires EPA to designate areas as attainment (meeting the standards) or non-attainment (not meeting the standards) when the EPA sets a new standard or revises an existing standard.

Once an area is designated as non-attainment, the Clean Air Act requires the State to submit an implementation plan to EPA within three years.

Based on historical monitoring data, no areas of the Kansas City region are expected to be deemed non-attainment.

New Source Performance Standards (NSPS)

New Source Performance Standards (NSPS) apply only to new generation equipment or to equipment that is modified and has a resulting increase in the maximum hourly emission rate. The determination of whether a physical change to the equipment is a modification and thus subject to NSPS depends on factors such as relative cost, frequency of the change, and whether the change can be considered routine based on what is typical for the industry. Future physical changes to the existing generation equipment will need to undergo a determination of whether the change is a modification and, if so, whether the change results in an increase in the hourly emissions. If the change is a modification, the maximum operation could be limited such that there is not an increase in maximum hourly emissions.

Basic Facts on New Source Performance Standards (NSPS)

1. NSPS regulations specify emission limitations which apply to certain new equipment and to modifications of existing equipment. There is an NSPS for coal-fired boilers and there is an NSPS for combustion turbine generators.

2. NSPS limits apply to new equipment and to existing equipment that undergoes a modification that results in an increase in the maximum hourly emission rate measured in pounds per hour (lb/h).

3. NSPS limits for coal-fired steam generators typically require some form of air quality control equipment for NO_x, SO_2, PM, and mercury. The type of controls and performance applicable depends on site-specific conditions.

NSPS regulations were written by the EPA to require a specific level of emission control for a new source or for a modification to an existing source. The determination of whether the regulation applies is based on whether there is any increase in the maximum hourly emissions. NSPS can be avoided if the modification does not increase the maximum hourly emission rate (in pounds per hour). Thus, NSPS can be avoided if the future maximum operational level is limited to the past maximum operational level in the past five years. This may involve taking a voluntary limit of fuel firing rate or power output to the recent past maximum. As an alternative, emission control equipment can be added to limit the maximum hourly emissions, even if the future operational level increases above the past maximum.

New Source Review (NSR)

New Source Review (NSR) applies only to new generation equipment facilities or to facilities with equipment that is modified and the facility has a resulting "significant" increase in the annual emission rate. (Significant means 40 tons of NO_x or SO_2, 15 tons of PM_{10}, and 100 tons of CO, for example.) The determination of whether a physical change to the equipment is a modification, and thus subject to NSR, depends on factors such as relative cost, frequency of the change, and whether the change can be considered routine based on what is typical for the industry. Future physical changes to the existing generation equipment will need to undergo a determination of whether the change is a modification, and if so, whether the change results in a significant increase in the annual emissions. If the change is a modification, the maximum operation could be limited such that there is not a significant increase in annual emissions.

Basic Facts on New Source Review (NSR)

1. NSR regulations specify requirements to receive a permit to commence construction of the new equipment or modification. These requirements include the application of a stringent level of emission control known as Best Available Control Technology (BACT), detail air quality impact predictions, and an extended agency and public review period.

2. NSR is triggered when there is an increase of more than the significance levels of NO_X, SO_2, PM, CO, and/or VOC.

3. BACT for coal-fired steam generators requires air quality control equipment for NO_X, SO_2, PM, and mercury. The type of controls and performance applicable depends on site-specific conditions.

The EPA wrote NSR regulations in 1978. The goal of these regulations is to prevent the air quality in an area from degrading significantly when a new air pollutant emission source is built. The particular regulations that apply are also known as prevention of significant deterioration (PSD). PSD regulations must be followed for new major sources of air pollutants as well as major "modifications" to existing sources where there is an increase in air pollutants over the past emissions. A modification is defined in the regulations as any physical change to the source or any change in the method of operation. Of course, this includes a very wide range of plant changes. However, the regulations also exclude certain changes from being considered a modification. These exempted changes include "routine maintenance, repair, and replacement." In general, the determination of routine considers factors such as extent of modification, relative cost of work, how often it is performed, whether it is considered routine by the industry, and whether the courts have in the past considered the particular work not routine.

PSD requires a long approval process and forces the new source to use BACT. BACT includes the use of SCR, scrubbers, and baghouses. Even existing sources that undertake a modification and increase their emissions by a certain amount must go through this long approval process and use BACT.

PSD rules require that modifications at existing major sources must undergo permit review for each pollutant which is calculated to have a "significant emissions increase" as a result of the modification. According to the rules, an emissions increase is determined as the difference between the future projected actual emissions and the past baseline actual emissions. "Projected actual emissions" is defined as the maximum annual rate (tpy) that the source is projected to emit in any one of the five years after the source resumes regular operation after the modification. The projected emission rate considers the effect the modification will have on increasing or decreasing the hourly emissions and on projected utilization. According to the rules, the projected actual emissions exclude any emissions due to increased capacity utilization that could have been accommodated by the source prior to the modification and is unrelated to the modification. This increased utilization includes electricity demand growth.

"Baseline actual emissions" is defined as the actual emissions (in tpy) during any consecutive 24-month period selected by the Owner during the five- or 10-year period prior to start of the modification. (Five years for electric utility units greater than 25 MW, 10 years for other sources.)

Cooling Water Intake 316(b) Rule

Basic Facts on Cooling Water Intake 316(b) Rule

On March 28, 2011, as required by the Clean Water Act and pursuant to a settlement agreement, the EPA is proposing regulations for protection of fish and other aquatic organisms drawn each year into cooling water systems at large power plants and factories.

Comments on the rule are due by July 2011. The final rule must be signed by July 27, 2012 under the terms of a settlement agreement with an environmental organization. Compliance must be within eight years of the final rule, thus estimated to be 2020.

1. Section 316(b) of the Clean Water Act requires that National Pollutant Discharge Elimination System (NPDES) permits for facilities with cooling water intake structures ensure that the location, design, construction, and capacity of the structures reflect the best technology available (BTA) to minimize harmful impacts on the environment.

2. There are three components to the proposed regulation:

    a. First, existing facilities that withdraw at least 25 percent of their water from an adjacent waterbody exclusively for cooling purposes and have a design intake flow of greater than 2 million gallons per day (MGD) that would be subject to an upper limit on how many fish can be killed by being pinned against intake screens or other parts at the facility (impingement). These limits have both an annual average component and a monthly average component which would require periodic monitoring of impingement. The facility would determine which technology would be best suited to meeting this limit. Alternately, the facility could reduce their intake velocity to 0.5 feet per second. At this rate, most of the fish can swim away from the cooling water intake of the facility.

    b. Second, existing facilities will be assessed by permitting authorities as to the most appropriate means (site-specific controls), if any, would be required to reduce the number of aquatic organisms sucked into cooling water systems (entrainment). This determination is made by the permitting authorities and may include the use of close-cycle cooling. Bigger facilities that withdraw very large amounts of water (at least 125 million gallons per day) would be required to conduct studies to help their permitting authority determine the most appropriate method of controlling entrainment.

    c. Third, new units that add electrical generation capacity at an existing facility would be required to add technology that is equivalent to closed-cycle cooling (continually recycles and cools the water so that minimal water needs to be withdrawn from an adjacent waterbody). This can be done by incorporating a closed-cycle system into the design of the new unit or by making other design changes equivalent to the reductions associated with closed-cycle cooling. Closed-cycle cooling systems, often referred to as cooling towers or wet cooling, are the most effective at reducing entrainment.

The only IPL facility subject to this rule is the Missouri City Power Plant because it has once-through cooling with a cooling water intake structure on the Missouri River. If this facility must comply with this rule, the options are (by 2020) to replace the existing intake structure with a new structure with the anticipated impingement and entrainment controls or to replace the once-through cooling system with a cooling tower.

Summary of Impact

The regulations which have an impact on the Master Planning process are included in the summary matrix shown in Table A-1 at the end of this Appendix. A brief overview of each of the regulations included in the matrix is provided in the subsequent paragraphs. Regulations not shown either have no impact or do not have a substantial differential impact for this Master Plan Study report. The regulations are discussed in the chronological order in which they impact the IPL units. Note that the selection of compliance plans for earlier regulations will impact the selection of compliance plans for later regulations.

Cross-State Air Pollution Rule (CSAPR)

The existing IPL generating units which are EGUs are Blue Valley Unit 3 and the RCT at Blue Valley. As noted in this report, IPL has chosen not to repair the RCT at Blue Valley. Thus, the only IPL unit impacted by this program is Blue Valley Unit 3. This program has the earliest impact on IPL, requiring compliance in 2012. This unit will need to reduce NO_X and SO_2 emissions with controls, fuel switch, reduced operation, purchase allowances, or a combination of the above.

Utility Boiler Maximum Achievable Control Technology (MACT)

The only existing IPL generating unit impacted by this proposed rule is Blue Valley Unit 3. IPL will need to install new emissions reduction equipment on this unit in order to comply with the emission limitations imposed by the new regulation, burn only natural gas, or shut down. The appropriate compliance plan will be affected by the compliance plan selected for CSAPR because the same unit is affected. Compliance is required by early 2015.

Industrial Boiler Maximum Achievable Control Technology (IB MACT)

The existing IPL generating units impacted by this rule are Blue Valley Units 1 and 2 and Missouri City Units 1 and 2. IPL will need to install new emissions reduction equipment on these units in order to comply with the emission limitations imposed by the new regulations, burn only natural gas, or shut down. (Missouri City conversion to natural gas is not feasible.) Compliance is required by early 2015 under EPA's latest rule reconsideration timeline.

Ozone Non-Attainment Area/New Ozone National Ambient Air Quality Standards (NAAQS)

The contingency measures for Missouri have required Blue Valley to reduce NO_X emissions. IPL has chosen to reduce NO_X emissions either on Blue Valley Units 1 and 2 through the retrofit of low NO_X burners or Blue Valley Unit 3 through the firing of natural gas only. If ozone levels increase or the area is deemed non-attainment of the lower NAAQS issued in 2008, further NO_X reductions will likely be required. This could require IPL to add NO_X reduction equipment on all existing generating units by 2018.

SO_2 National Ambient Air Quality Standards (NAAQS)

The coal-fired IPL generating units may be found to cause or significantly contribute to a future non-attainment area for the lower SO_2 NAAQS issued in 2010. If this is the case, IPL could be required to reduce SO_2 emissions from the coal-fired generating units by adding emission reduction equipment on all existing coal-fired generating units by 2017 or burn natural gas only.

NO_2 National Ambient Air Quality Standards (NAAQS)

The IPL generating units may be found to cause or significantly contribute to a future non-attainment area for the lower NO_2 NAAQS issued in 2010. If this is the case, IPL could be required to reduce NO_x emissions from all generating units by adding emission reduction equipment on all existing generating units by 2018.

Cooling Water Intake 316(b) Rule

The only existing IPL generating units impacted by this proposed regulation are Missouri City Units 1 and 2. The anticipated technology to control impacts to aquatic life would be the replacement of the existing once-through cooling water system with a closed-cycle cooling system (a cooling tower) by 2020.

Table A-1
Summary of Future Regulatory Applicability

Regulation/ Assumed Year of Compliance	Regulated Air Constituents	Blue Valley Units 1 and 2 (Coal/Gas)	Blue Valley Unit 3 (Coal/Gas)	Missouri City Units 1 and 2 (Coal Only)	RCT (Gas/Oil)	Combustion Turbines (Gas/Oil)
CSAPR 2012 and 2014	SO_2, NO_x	Not Affected	Affected	Not Affected	Retired - Not Impacted	Not Affected
IB MACT 2015	PM, HCl, Hg, CO, dioxin, furans	Affected	Not Affected	Affected	Not Affected	Not Affected
Utility MACT 2015	PM, HCl/SO_2, Hg	Not Affected	Affected	Not Affected	Not Affected	Not Affected
NAAQS - SO_2 2017	SO_2	Affected	Affected	Affected	Retired - Not Impacted	Affected
NAAQS - NO_2 2017	NO_x	Affected	Affected	Affected	Retired - Not Impacted	Affected
NAAQS - Ozone 2018	NO_x	Affected	Affected	Affected	Retired - Not Impacted	Affected
316(b) Intake 2020	--	None	Not Affected	Affected	Not Affected	Not Affected

Notes:

1. Applicability indicated as "Affected" means that the regulation considers the unit is subject to the rule's requirements because of the unit's type/fuel/age/size.
2. Applicability indicated as "Not Affected" means that regulation does not consider the unit subject to the rule's requirements because of the unit's type/fuel/age/size.
3. Applicability indicated as "Retired - Not Impacted" means that although the unit is considered affected by the rule, the unit will be retired and is, therefore, not impacted.
4. Regulations not shown either have no impact or do not have a substantial differential impact for this Master Plan Study report.

APPENDIX B

PRODUCTION SIMULATION INPUTS

Table B-1
Projected Purchased Power Prices
City of Independence, Missouri

Year	KCPL Montrose[1]			Nebraska City 2[1]			Iatan 2[1]		
	Capacity Price ($/kW)	Energy Price ($/MWh)	Total ($/MWh)	Capacity Price ($/kW)	Energy Price ($/MWh)	Total ($/MWh)	Capacity Price ($/kW)	Energy Price ($/MWh)	Total ($/MWh)
2011	7.97	20.83	33.67	14.23	20.22	42.63	22.53	18.34	53.82
2012	-	-	-	14.23	18.85	41.26	23.29	19.06	55.74
2013	-	-	-	16.70	19.27	45.57	23.20	19.81	56.34
2014	-	-	-	16.53	20.59	46.62	23.58	20.60	57.74
2015	-	-	-	17.72	21.04	48.94	23.47	21.42	58.37
2016	-	-	-	18.01	21.68	50.04	23.65	22.27	59.51
2017	-	-	-	18.32	22.34	51.18	23.84	23.15	60.69
2018	-	-	-	18.63	23.01	52.35	24.03	24.07	61.91
2019	-	-	-	19.03	23.92	53.89	24.27	25.03	63.24
2020	-	-	-	19.45	24.87	55.50	24.52	26.02	64.62
2021	-	-	-	19.88	25.86	57.17	24.78	27.05	66.06
2022	-	-	-	20.33	26.88	58.90	25.05	28.12	67.56
2023	-	-	-	20.80	27.94	60.69	25.33	29.23	69.11
2024	-	-	-	21.28	29.05	62.56	25.62	30.39	70.72
2025	-	-	-	21.78	30.20	64.50	25.91	31.59	72.40
2026	-	-	-	22.30	31.39	66.51	26.22	32.84	74.14
2027	-	-	-	22.84	32.64	68.60	26.55	34.15	75.94
2028	-	-	-	23.40	33.93	70.77	26.88	35.50	77.82
2029	-	-	-	23.97	35.27	73.02	27.22	36.90	79.77
2030	-	-	-	24.57	36.67	75.36	27.58	38.37	81.80

(1) See Tables B-12 through B-14.

Table B-2
Fuel Price Projection[1]
($/MMBtu)
City of Independence, Missouri

Year	Blue Valley 1 & 2	Blue Valley 3	Missouri City 1 & 2	IPL PRB Coal	Natural Gas	Fuel Oil
2011	3.09	3.09	3.13	2.18	5.16	21.47
2012	3.14	3.14	3.20	2.27	5.42	22.20
2013	3.20	3.20	3.27	2.36	5.65	22.93
2014	3.29	3.29	-	2.46	5.87	23.96
2015	3.39	3.39	-	2.55	6.11	25.04
2016	3.50	3.50	-	2.66	6.35	26.17
2017	-	-	-	2.76	6.60	27.34
2018	-	-	-	2.87	6.87	28.57
2019	-	-	-	2.99	7.14	29.86
2020	-	-	-	3.11	7.43	31.20
2021	-	-	-	3.23	7.73	32.61
2022	-	-	-	3.36	8.04	34.07
2023	-	-	-	3.50	8.36	35.61
2024	-	-	-	3.64	8.69	37.21
2025	-	-	-	3.78	9.04	38.89
2026	-	-	-	3.93	9.40	40.63
2027	-	-	-	4.09	9.78	42.46
2028	-	-	-	4.25	10.17	44.37

[1] See Appendix Tables B-19 through B-23.

Table B-3
Projected Annual Market Price ($/MWh)
City of Independence, Missouri

Year	Purchase[1]		Sales[1]	
	On-Peak	Off-Peak	On-Peak	Off-Peak
2011	36.42	21.56	29.13	21.56
2012	38.89	22.05	31.11	22.05
2013	40.45	22.93	32.36	22.93
2014	42.06	23.85	33.65	23.85
2015	43.75	24.80	35.00	24.80
2016	45.50	25.79	36.40	25.79
2017	47.32	26.82	37.85	26.82
2018	49.21	27.90	39.37	27.90
2019	51.18	29.01	40.94	29.01
2020	53.22	30.17	42.58	30.17
2021	55.35	31.38	44.28	31.38
2022	57.57	32.63	46.05	32.63
2023	59.87	33.94	47.90	33.94
2024	62.26	35.30	49.81	35.30
2025	64.76	36.71	51.80	36.71
2026	67.35	38.18	53.88	38.18
2027	70.04	39.70	56.03	39.70
2028	72.84	41.29	58.27	41.29
2029	75.75	42.94	60.60	42.94
2030	78.78	44.66	63.03	44.66

[1] Estimated based on historical IPL market purchase and sales prices and the ratio of purchase prices to sales prices.

Table B-4
Emission Allowance
Price Forecast
City of Independence, Missouri
($/ton)

Year	SO_2[1]	NO_x	
		Annual[2]	Ozone
2011	5.00	180.00	25.00
2012	5.15	185.40	25.75
2013	5.30	190.96	26.52
2014	5.46	196.69	27.32
2015	5.63	202.59	28.14
2016	5.80	208.67	28.98
2017	5.97	214.93	29.85
2018	6.15	221.38	30.75
2019	6.33	228.02	31.67
2020	6.52	234.86	32.62
2021	6.72	241.90	33.60
2022	6.92	249.16	34.61
2023	7.13	256.64	35.64
2024	7.34	264.34	36.71
2025	7.56	272.27	37.81
2026	7.79	280.43	38.95
2027	8.02	288.85	40.12
2028	8.26	297.51	41.32
2029	8.51	306.44	42.56
2030	8.77	315.63	43.84

(1) Prices for 2011 from Cantor Fitzgerald Market Summary dated April 27,2011. Escalated 3% annually after 2011.

Table B-5
Key Production Simulation Inputs for Planned Generating Units
2014
City of Independence, Missouri

Generating Unit	Net Capacity (MW)		Expected/ Remaining Life (yrs)	Forced Outage Rate (%)	Fuel Type	Net Heat Rate (Btu/kWh)	Maintenance		Debt Service ($/kW-mo)[1]	Variable O&M ($/MWh)	Fixed O&M ($/kW-mo)	Renewals and Replacements ($/kW-mo)[2]	Emission Rates (lbs/MMBtu)			
	Max	Min					Begin	Days					SO_2	NO_x	CO_2	Hg
Dogwood CC	650	100	20	5	Gas	7,400	0	0	5.46	2.12	2.12	0.00	0	0	0	0
180 MW CFB	180	60	40	10	Coal	9,860	11/1	30	23.63	7.24	6.40	2.00	0.09	0.09	273	$3x10^{-6}$
36 MW LM6000 CT	36	18	35	5	Gas	10,250	10/1	30	0.00	3.95	1.54	0.61	-	0.009	110	-
115 MW LM6000 CC	115	58	35	5	Gas	7,900	4/1	30	11.79	5.26	2.63	0.77	-	0.009	110	-

(1) Based on debt service shown in Tables B-16 through B-18. De-escalated 4% annually for 2014$.

(2) Dogwood Renewals and Replacements assumed to be included in Fixed O&M provided by IPL.

Table B-6

Key Production Simulation Inputs for Existing and Committed Generating Units[1]

2011

City of Independence, Missouri

Input Category	Blue Valley Unit 1	Blue Valley Unit 2	Blue Valley Unit 3	Missouri City Unit 1	Missouri City Unit 2	Montrose Unit 1	Montrose Unit 2	Montrose Unit 3	Nebraska City Unit 2	Iatan Unit 2	Blue Valley RCT	Sub J Unit 1	Sub J Unit 2	Sub I Unit 3	Sub I Unit 4	Sub H Unit 5	Sub H Unit 6
Dependable Max Capacity	20	20	50	19	19	30	30	30	56	50	43	13	13	16	16	16	17
Peak Capacity	21	21	51	19	19	30	30	30	56	50	50	15	15	19	19	19	20
Min Capacity	8	8	20	5	5	10	10	10	26	30	20	1	1	1	1	5	5
FOR(%)	7	7	7	7	7	4	5	4	5	5	20	20	20	20	20	20	20
Dispatch Level	4	4	4	4	4	1	1	1	1	1	5	5	5	5	5	5	5
Fuel Burn Ratio(%)	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-
-Coal	98	98	98	99	99	100	100	100	100	100	-	-	-	-	-	-	-
-Gas	2	2	2	-	-	-	-	-	-	-	100	-	-	-	-	100	100
-Oil	-	-	-	1	1	-	-	-	-	-	-	100	100	100	100	-	-
Startup Fuel (type)	Gas	Gas	Gas	Oil	Oil	-	-	-	-	-	Gas	Oil	Oil	Oil	Oil	Gas	Gas
Startup Fuel (MMBtu/Start)	500	500	800	500	500	-	-	-	-	-	80	7	7	7	7	40	40
Heat Rate (Btu/kWh)	13,600	13,600	12,375	13,600	13,600	10,818	10,818	10,818	9,188	9,188	11,000	15,000	15,000	14,000	14,000	15,000	15,000
Ramp Rate (MW/hour)	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Minimum Down Time (hrs)	72	72	72	72	72	72	72	72	72	72	-	-	-	-	-	-	-
Minimum Up Time (hrs)	-	-	-	-	-	-	-	-	-	-	4	2	2	2	2	2	2
Losses (%)	-	-	-	-	-	2.6	2.6	2.6	4.8	2.6	-	-	-	-	-	-	-
Variable O&M ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2009	3.27	3.27	3.27	2.84	2.84	2.63	2.63	2.63	-	1.32	10.15	10.15	10.15	10.15	10.15	10.15	10.15
Escalation	4.0	4.0	4.0	4.0	4.0	4	4	4	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Fixed O&M ($/kW-mo)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2009	7.18	7.18	7.18	2.15	2.15	7.97	7.97	7.97	14.23	22.53	0.45	0.45	0.45	0.45	0.45	0.45	0.45
Escalation	4.0	4.0	4.0	4.0	4.0	-	-	-	1.7	1.40	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Emissions (lbs/MMBtu)																	
SO_2	5.00	5.00	5.00	5.00	5.00	0.82	0.82	0.82	0.095	0.09							
NOx	0.50	0.50	0.30	0.50	0.50	0.33	0.33	0.33	0.07	0.07	0.60	0.80	0.80	0.80	0.80	0.80	0.80
CO_2[2]	219	219	202	213	213	273	273	273	273	273	110	160	160	160	160	110	110
Hg	3×10^{-6}	3×10^{-6}	4×10^{-6}	2.5×10^{-6}	2.5×10^{-6}	6×10^{-6}	6×10^{-6}	6×10^{-6}	4×10^{-6}	4×10^{-6}							

[1] From Prosym Inputs provided by IPL May 5, 2008 and updates to inputs provided by IPL in an April 12, 2011 email titled "IPL Information Requested".

Table B-7
Key Production Simulation Inputs for Existing and Committed Generating Units[1]
2011
City of Independence, Missouri

Generating Unit	In Service Date	Retirement Date	Net Capacity [2] (MW)		Forced Outage Rate (%)	Fuel Type	Heat Rate Constant				Net Average Heat Rate (Btu/kWh)	Maintenance	
			Max	Min			A	B	C	D		Begin Date	# of Days
Blue Valley 1	1958	1/1/2017	21	8	7	Coal/Gas/ Oil	17.58920	12.27320	(0.04052)	0.00154	13,600	12/1	46
Blue Valley 2	1958	1/1/2017	21	8	7	Coal/Gas/ Oil	17.58920	12.27320	(0.04052)	0.00154	13,600	1/16	46
Blue Valley 3	1965	1/1/2017	51	20	7	Coal/Gas/ Oil	68.54620	8.34373	0.06112	(0.00033)	12,375	10/1	61
Missouri City 1	1955	1/1/2014	19	5	7	Coal	17.58920	12.27320	(0.04052)	0.00154	13,600	10/1	243
Missouri City 2	1955	1/1/2014	19	5	7	Coal	17.58920	12.27320	(0.04052)	0.00154	13,600	10/1	243
Total Steam	0	0	131	46	0	0	0.00000	0.00000	0.00000	0.00000	0	1/0	0
Blue Valley RCT	1976	1/1/2027	50	20	20	Gas/Oil	197.08400	7.48471	(0.02236)	0.00022	11,000	1/1	365
Sub J1	1968	1/1/2019	15	1	20	Oil	77.00020	9.81421	0.00001	0.00000	15,000		
Sub J2	1968	1/1/2019	15	1	20	Oil	77.00020	9.81421	0.00001	0.00000	15,000		
Sub I3	1972	1/1/2023	19	1	20	Oil	97.47710	5.59949	0.29305	(0.00537)	14,000		
Sub I4	1972	1/1/2023	19	1	20	Oil	97.47710	5.59949	0.29305	(0.00537)	14,000		
Sub H5	1972	1/1/2025	19	5	20	Gas/Oil	90.43010	10.55310	(0.04792)	0.00208	15,000		
Sub H6	1974	1/1/2025	20	5	20	Gas/Oil	90.43010	10.55310	(0.04792)	0.00208	15,000		
Total CT	0	0	157	34	0	0	0	0	0	0	0	0	0
Montrose Unit 1	0	6/1/2011	30	10	3.69	Coal	Use net average heat rate				10818	5/1	4
Montrose Unit 2	0	6/1/2011	30	10	4.50	Coal	Use net average heat rate				10818	1/17	50
Montrose Unit 3	0	6/1/2011	30	10	4.37	Coal	Use net average heat rate				10818	5/8	4
NC #2	2009	1/1/2049	56	26	5	Coal	Use net average heat rate				9188	3/1	31
Iatan #2	2010	1/1/2050	50	30	5	Coal	Use net average heat rate				9188	4/1	30
Total Purchase			196	86									
Total Capacity			484	166									

[1] From Prosym Inputs provided by IPL May 5, 2008.
[2] Peak Capacity with natural gas firing.

Table B-8
Blue Valley 1&2
Projected Fixed and Variable Operating Costs
City of Independence, Missouri

Year	Fixed Cost[1] ($/kW-mo)	Fuel Cost[2] ($/MMBtu)	Heat Rate (Btu/kWh)	Fuel Cost[3] ($/MWh)	Variable O&M ($/MWh)	Fuel + Var. O&M ($/MWh)
2011	7.18	3.12	13,600	42.46	3.27	45.73
2012	7.47	3.18	13,600	43.26	3.40	46.66
2013	7.77	3.24	13,600	44.07	3.54	47.60
2014	8.08	3.34	13,600	45.41	3.68	49.09
2015	8.40	3.44	13,600	46.79	3.83	50.62
2016	8.74	5.94	13,600	80.75	1.22	81.96

(1) 2011 from Table B-6, Key Production Simulation Inputs for Existing and Committed Generating Units. Escalated 4% annually. Primary fuel switched from coal to natural gas beginning April 1, 2015. Variable O&M while operating on natural gas assumed to be $1.00/MWh in 2011 escalating 4% annually.

(2) From Table B-20, Projected Blue Valley and Missouri City Fuel Prices.

(3) Net Heat Rate multiplied by Fuel Cost and divided by 1000.

Table B-9
Blue Valley 3
Projected Fixed and Variable Operating Costs
City of Independence, Missouri

Year	Fixed Cost ($/kW-mo)	Fuel Cost(1) ($/MMBtu)	Heat Rate (Btu/kWh)	Fuel Cost(2) ($/MWh)	Variable O&M ($/MWh)	Fuel + Var. O&M ($/MWh)
2011	7.18	3.12	12,375	38.64	3.27	41.91
2012	7.47	5.08	12,375	62.81	1.04	63.85
2013	7.77	5.28	12,375	65.32	1.08	66.40
2014	8.08	5.49	12,375	67.93	1.12	69.06
2015	8.40	5.71	12,375	70.65	1.17	71.82
2016	8.74	5.94	12,375	73.47	1.22	74.69

(1) 2011 from Table B-6, Key Production Simulation Inputs for Existing and Committed Generating Units. Escalated 4% annually. Primary fuel switched from coal to natural gas beginning January 1, 2012. Variable O&M while operating on natural gas assumed to be $1.00/MWh in 2011 escalating 4% annually.

(2) From Table B-20, Projected Blue Valley and Missouri City Fuel Prices.

(3) Net Heat Rate multiplied by Fuel Cost and divided by 1000.

Table B-10
Missouri City 1&2
Projected Fixed and Variable Operating Costs
City of Independence, Missouri

Year	Fixed Cost[1] ($/kW-mo)	Fuel Cost[2] ($/MMBtu)	Heat Rate (Btu/kWh)	Fuel Cost[3] ($/MWh)	Variable O&M[1] ($/MWh)	Fuel + Var. O&M ($/MWh)
2011	2.15	331.47	13,600	45.08	2.84	47.92
2012	2.24	339.30	13,600	46.14	2.95	49.10
2013	2.33	347.15	13,600	47.21	3.07	50.28
2014	2.42	358.03	13,600	48.69	3.19	51.89

(1) 2011 from Table B-6, Key Production Simulation Inputs for Existing and Committed Generating Units. Escalated 4% annually.

(2) Fuel Cost from Table B-20, Projected Blue Valley and Missouri City Fuel Prices.

(3) Net Heat Rate multiplied by Fuel Cost and divided by 1000.

Table B-11
Iatan #2
Projected Ownership and Operating Costs[1]
City of Independence, Missouri

Year	Debt Service ($/kW-mo)	Fixed O&M[2] ($/kW-mo)	XMSN Service [3] ($/kW-mo)	Renewals and Replacements[4] ($/kW-mo)	Total Fixed Cost[5] ($/kW-mo)	Fuel Costs ($/MWh)[2]	Variable O&M ($/MWh)[2]	XMSN Losses ($/MWh)[6]	Dispatch Cost[7] ($/MWh)
2011	16.71	3.34	1.28	1.20	22.53	16.23	1.32	0.80	18.34
2012	16.71	4.05	1.32	1.22	23.29	16.87	1.37	0.82	19.06
2013	16.71	3.90	1.36	1.23	23.20	17.55	1.42	0.84	19.81
2014	16.71	4.23	1.40	1.25	23.58	18.25	1.48	0.87	20.60
2015	16.71	4.05	1.44	1.27	23.47	18.98	1.54	0.90	21.42
2016	16.71	4.17	1.48	1.28	23.65	19.74	1.60	0.93	22.27
2017	16.71	4.30	1.53	1.30	23.84	20.53	1.66	0.96	23.15
2018	16.71	4.43	1.57	1.32	24.03	21.35	1.73	0.99	24.07
2019	16.71	4.61	1.62	1.34	24.27	22.21	1.80	1.02	25.03
2020	16.71	4.79	1.67	1.35	24.52	23.09	1.87	1.05	26.02
2021	16.71	4.98	1.72	1.37	24.78	24.02	1.95	1.08	27.05
2022	16.71	5.18	1.77	1.39	25.05	24.98	2.02	1.11	28.12
2023	16.71	5.39	1.82	1.41	25.33	25.98	2.11	1.15	29.23
2024	16.71	5.60	1.88	1.42	25.62	27.02	2.19	1.18	30.39
2025	16.71	5.83	1.94	1.44	25.91	28.10	2.28	1.22	31.59
2026	16.71	6.06	1.99	1.46	26.22	29.22	2.37	1.25	32.84
2027	16.71	6.30	2.05	1.48	26.55	30.39	2.46	1.29	34.15
2028	16.71	6.56	2.12	1.50	26.88	31.61	2.56	1.33	35.50
2029	16.71	6.82	2.18	1.52	27.22	32.87	2.66	1.37	36.90
2030	16.71	7.09	2.24	1.54	27.58	34.18	2.77	1.41	38.37

(1) From "Iatan II Cost Estimate" provided by IPL Staff April 12, 2011.

(2) See Table B-24. Escalated 4% annually.

(3) Escalated 3% annually.

(4) Escalated 1.3% annually after 2018.

(5) Sum of Debt Service, Fixed O&M, XMSN Service and Renewals and Replacements.

(6) Escalated 3% annually after 2018.

(7) Sum of Fuel Costs, Variable O&M and XMSN Losses.

Table B-12
Nebraska City #2
Projected Ownership and Operating Costs[1]
City of Independence, Missouri

Year	Debt Service ($/kW-mo)	Fixed O&M[2] ($/kW-mo)	XMSN Service [3] ($/kW-mo)	Renewals and Replacements[4] ($/kW-mo)	Total Fixed Cost[5] ($/kW-mo)	Fuel Costs ($/MWh)[2]	Variable O&M ($/MWh)[6]	XMSN Losses ($/MWh)[7]	Dispatch Cost[8] ($/MWh)
2011	7.11	5.06	1.36	0.71	14.23	19.41	-	0.81	20.22
2012	7.11	5.02	1.40	0.71	14.23	18.02	-	0.83	18.85
2013	7.11	5.57	3.32	0.71	16.70	18.42	-	0.85	19.27
2014	7.11	5.30	3.41	0.71	16.53	19.71	-	0.88	20.59
2015	7.11	6.38	3.52	0.71	17.72	20.13	-	0.91	21.04
2016	7.11	6.57	3.62	0.71	18.01	20.74	-	0.94	21.68
2017	7.11	6.77	3.73	0.71	18.32	21.37	-	0.97	22.34
2018	7.11	6.97	3.84	0.71	18.63	22.01	-	1.00	23.01
2019	7.11	7.25	3.96	0.72	19.03	22.89	-	1.03	23.92
2020	7.11	7.54	4.08	0.72	19.45	23.81	-	1.06	24.87
2021	7.11	7.84	4.20	0.73	19.88	24.76	-	1.09	25.86
2022	7.11	8.15	4.33	0.74	20.33	25.75	-	1.13	26.88
2023	7.11	8.48	4.46	0.75	20.80	26.78	-	1.16	27.94
2024	7.11	8.82	4.59	0.76	21.28	27.85	-	1.19	29.05
2025	7.11	9.17	4.73	0.77	21.78	28.97	-	1.23	30.20
2026	7.11	9.54	4.87	0.78	22.30	30.13	-	1.27	31.39
2027	7.11	9.92	5.01	0.79	22.84	31.33	-	1.30	32.64
2028	7.11	10.32	5.17	0.80	23.40	32.59	-	1.34	33.93
2029	7.11	10.73	5.32	0.81	23.97	33.89	-	1.38	35.27
2030	7.11	11.16	5.48	0.82	24.57	35.25	-	1.43	36.67

(1) From "NC2 Costs" provided by IPL Staff April 12, 2011.

(2) See Table B-25. Escalated 4% annually.

(3) Escalated 3% annually after 2018.

(4) Escalated 1.3% annually after 2018.

(5) Sum of Debt Service, Fixed O&M, XMSN Service and Renewals and Replacements.

(6) Included in Fuel Costs.

(7) Escalated 3% annually after 2018.

(8) Sum of Fuel Costs, Variable O&M and XMSN Losses.

Table B-13
KCPL Montrose
Operation and Maintenance Costs [1]
City of Independence, Missouri

Year	Fixed Cost ($/kW-mo)	Fuel ($/MWh)	Variable O&M ($/MWh)	Emission Cost ($/MWh)	Fuel + Var. O&M ($/MWh)
2011	7.97	18.00	2.83	-	20.83

[1] Information provided by IPL.

Table B-14
Dogwood Fuel and Variable
Operation and Maintenance Costs
Independence Power and Light

Year	Debt Service[(1)] ($/kW-mo)	Fixed O&M[(2)] ($/kW-mo)	Renewals & Repl. ($/kW-mo)	Demand Rate ($/kW-mo)	Fuel Cost[(3)] ($/MWh)	Variable O&M[(2)] ($/MWh)	Energy Rate ($/MWh)	Total Cost[(4)] ($/MWh)
2011	-	-		-	-	-	-	
2012				-			-	-
2013				-			-	-
2014	5.46	2.12	-	7.58	43.45	2.12	45.57	149.45
2015	5.46	2.19	-	7.65	45.19	2.19	47.37	152.13
2016	5.46	2.25	-	7.71	46.99	2.25	49.25	154.90
2017	5.46	2.32	-	7.78	48.87	2.32	51.19	157.77
2018	5.46	2.39	-	7.85	50.83	2.39	53.22	160.75
2019	5.46	2.46	-	7.92	52.86	2.46	55.32	163.83
2020	5.46	2.53	-	8.00	54.98	2.53	57.51	167.03
2021	5.46	2.61	-	8.07	57.18	2.61	59.79	170.35
2022	5.46	2.69	-	8.15	59.46	2.69	62.15	173.79
2023	5.46	2.77	-	8.23	61.84	2.77	64.61	177.35
2024	5.46	2.85	-	8.31	64.31	2.85	67.17	181.04
2025	5.46	2.94	-	8.40	66.89	2.94	69.82	184.87
2026	5.46	3.03	-	8.49	69.56	3.03	72.59	188.84
2027	5.46	3.12	-	8.58	72.35	3.12	75.46	192.96
2028	5.46	3.21	-	8.67	75.24	3.21	78.45	197.23
2029	5.46	3.31	-	8.77	78.25	3.31	81.55	201.65
2030	5.46	3.40	-	8.87	81.38	3.40	84.78	206.24

(1) From Table C-1 Dogwood Estimated Total Financial Requirement and Debt Service.

(2) From Dogwood Model Data for 2011 Master Plan Update received from IPL on April 15, 2011.
Escalated 3% annually.

(3) From Table B-26, Dogwood Fuel Characteristics.

(4) 10% capacity factor.

Table B-15
180MW Coal-Fired CFB Plant
Debt Service, Operation and Maintenance Costs
City of Independence, Missouri

Year	Debt Service [(1)] ($/kW-mo)	Fixed O&M [(2)] ($/kW-mo)	Renewals and Replacements ($/kW-mo)[(3)]	Total Fixed Charges ($/kW-mo)	Fuel [(4)] ($/MWh)	Variable O&M [(5)] ($/MWh)	Fuel + Var. Costs ($/MWh)
2020	29.90	8.10	2.17	40.17	30.65	9.16	39.81
2021	29.90	8.43	2.17	40.49	31.88	9.52	41.40
2022	29.90	8.76	2.17	40.83	33.15	9.91	43.06
2023	29.90	9.12	2.17	41.18	34.48	10.30	44.78
2024	29.90	9.48	2.17	41.54	35.86	10.71	46.57
2025	29.90	9.86	2.17	41.92	37.29	11.14	48.43
2026	29.90	10.25	2.17	42.32	38.78	11.59	50.37
2027	29.90	10.66	2.17	42.73	40.33	12.05	52.38
2028	29.90	11.09	2.17	43.15	41.95	12.53	54.48
2029	29.90	11.53	2.17	43.60	43.62	13.03	56.66
2030	29.90	11.99	2.60	44.49	45.37	13.56	58.93

(1) From Table C-3.
(2) Escalated 4% annually.
(3) 0.5% of Capital Investment ($5,202/kW) for first 10 years and 0.6% thereafter.
(4) From Table B-21.
(5) Escalated 4% annually.

Table B-16
115 MW LM6000 2-on-1 Combined Cycle
Debt Service, Operation and Maintenance Costs
City of Independence, Missouri

Year	Debt Service [(1)] ($/kW-mo)	Fixed O&M [(2)] ($/kW-mo)	Renewals and Replacements ($/kW-mo)[(3)]	Total Fixed Charges ($/kW-mo)	Fuel [(4)] ($/MWh)	Variable O&M [(5)] ($/MWh)	Fuel + Var. Costs ($/MWh)
2011							
2012							
2013							
2014							
2015							
2016	12.75	2.85	0.88	16.47	50.17	5.69	55.86
2017	12.75	2.96	0.88	16.59	52.18	5.92	58.10
2018	12.75	3.08	0.88	16.71	54.26	6.16	60.42
2019	12.75	3.20	0.88	16.83	56.43	6.40	62.84
2020	12.75	3.33	0.88	16.96	58.69	6.66	65.35
2021	12.75	3.46	0.88	17.09	61.04	6.93	67.97
2022	12.75	3.60	0.88	17.23	63.48	7.20	70.68
2023	12.75	3.75	0.88	17.37	66.02	7.49	73.51
2024	12.75	3.90	0.88	17.52	68.66	7.79	76.45
2025	12.75	4.05	0.88	17.68	71.41	8.10	79.51
2026	12.75	4.21	1.05	18.02	74.26	8.43	82.69
2027	12.75	4.38	1.05	18.19	77.23	8.76	86.00
2028	12.75	4.56	1.05	18.36	80.32	9.12	89.44

(1) See Table C-5.

(2) Escalated 4% annually.

(3) 0.5% of Capital Investment ($2106/kW) for first 10 years and 0.6% thereafter.

(4) See Table B-22.

(5) Escalated 4% annually.

Table B-17
36 MW LM6000 Combustion Turbine in 2014
Debt Service, Operation and Maintenance Costs
City of Independence, Missouri

Year	Debt Service (1) ($/kW-mo)	Fixed O&M (2) ($/kW-mo)	Renewals and Replacements ($/kW-mo)(3)	Total Fixed Charges ($/kW-mo)	Fuel (4) ($/MWh)	Variable O&M (5) ($/MWh)	Fuel + Var. Costs ($/MWh)
2014	10.31	1.54	0.71	12.56	54.77	3.95	58.71
2015	10.31	1.60	0.71	12.62	56.96	4.11	61.06
2016	10.31	1.67	0.71	12.68	59.24	4.27	63.51
2017	10.31	1.73	0.71	12.75	61.61	4.44	66.05
2018	10.31	1.80	0.71	12.82	64.07	4.62	68.69
2019	10.31	1.87	0.71	12.89	66.63	4.80	71.44
2020	10.31	1.95	0.71	12.96	69.30	5.00	74.29
2021	10.31	2.03	0.71	13.04	72.07	5.20	77.26
2022	10.31	2.11	0.71	13.12	74.95	5.40	80.36
2023	10.31	2.19	0.71	13.21	77.95	5.62	83.57
2024	10.31	2.28	0.85	13.44	81.07	5.84	86.91
2025	10.31	2.37	0.85	13.53	84.31	6.08	90.39
2026	10.31	2.47	0.85	13.62	87.68	6.32	94.00
2027	10.31	2.56	0.85	13.72	91.19	6.57	97.76
2028	10.31	2.67	0.85	13.82	94.84	6.84	101.68
2029	10.31	2.77	0.85	13.93	98.63	7.11	105.74
2030	10.31	2.88	0.85	14.04	102.58	7.39	109.97

(1) See Table C-7.
(2) Escalated 4% annually.
(2) Variable O&M costs consist of ash and lime disposal and chemical supply costs
(3) 0.5% of Capital Investment ($1637/kW) for first 10 years and 0.6% thereafter.
(4) See Table B-22.
(5) Escalated 4% annually.

Table B-18
Projected Annual Fuel Prices
City of Independence, Missouri

Year	Coal ($/MMBtu)[1]			Natural Gas ($/MMBtu)[2]	Oil ($/MMBtu)[3]
	Blue Valley 1&2	Blue Valley 3	Missouri City 1&2	12-Month Average	12-Month Average
2011	3.09	3.09	3.13	5.16	21.47
2012	3.14	3.14	3.20	5.42	22.20
2013	3.20	3.20	3.27	5.65	22.93
2014	3.29	3.29	3.37	5.87	23.96
2015	3.39	3.39	3.48	6.11	25.04
2016	3.50	3.50	3.58	6.35	26.17
2017	3.60	3.60	3.69	6.60	27.34
2018	3.71	3.71	3.80	6.87	28.57
2019	3.82	3.82	3.92	7.14	29.86
2020	3.94	3.94	4.04	7.43	31.20
2021	4.06	4.06	4.16	7.73	32.61
2022	4.18	4.18	4.29	8.04	34.07
2023	4.30	4.30	4.42	8.36	35.61
2024	4.43	4.43	4.55	8.69	37.21
2025	4.57	4.57	4.69	9.04	38.89
2026	4.71	4.71	4.83	9.40	40.63
2027	4.85	4.85	4.98	9.78	42.46
2028	4.99	4.99	5.13	10.17	44.37

[1] Provided by Robert Stillwell in a April 12, 2011 email titled "IPL Information Requested". Escalated 3% annually.

[2] From Table B-22, Projected Natural Gas Prices.

[3] From Table B-23, Projected Oil Prices.

Table B-19
Projected Blue Valley and Missouri City Fuel Prices
City of Independence, Missouri

Year	Blue Valley 1&2 Fuel (Cents/MMbtu)			Blue Valley 3 Fuel (Cents/MMbtu)			Missouri City 1&2 Fuel (Cents/MMbtu)		
	Coal	Gas	Weighted Average (1)	Coal	Gas	Weighted Average (1)	Coal	Oil	Weighted Average (2)
2011	302.47	9.76	312.23	302.47	9.76	312.23	310.00	21.47	331.47
2012	307.96	10.15	318.11		507.52	507.52	317.10	22.20	339.30
2013	313.46	10.56	324.01		527.82	527.82	324.22	22.93	347.15
2014	322.91	10.98	333.88		548.93	548.93	334.07	23.96	358.03
2015	332.64	11.42	344.06		570.89	570.89	344.21	25.04	369.25
2016		593.73	593.73		593.73	593.73			

(1) 98% Coal and 2% Gas

(2) 99% Coal and 1% Oil

Table B-20
Southern Powder River Basin Coal Price Forecast (Includes KC Switchyard) ($/MMBtu)
City of Independence, Missouri

Year	Delivered Price(1)(2)	Rail Car Fees(2)	Total Price(3)
2011	2.09	0.09	2.18
2012	2.17	0.10	2.27
2013	2.26	0.10	2.36
2014	2.35	0.11	2.46
2015	2.45	0.11	2.55
2016	2.54	0.11	2.66
2017	2.65	0.12	2.76
2018	2.75	0.12	2.87
2019	2.86	0.13	2.99
2020	2.98	0.13	3.11
2021	3.09	0.14	3.23
2022	3.22	0.14	3.36
2023	3.35	0.15	3.50
2024	3.48	0.16	3.64
2025	3.62	0.16	3.78
2026	3.76	0.17	3.93
2027	3.92	0.18	4.09
2028	4.07	0.18	4.25
2029	4.23	0.19	4.42
2030	4.40	0.20	4.60

(1) Based on recent Iatan 2 fuel price estimates. Increased to reflect the lack of economy of scale and increased cost of transportation through the KC Switchyard.

(2) Escalated 3% annually.

(3) Includes Rail Car Fees

Table B-21
Projected Natural Gas Prices
(1) (2) (3)

City of Independence, Missouri
($/MMBtu)

Year	Summer	Winter	Annual
2011	4.88	5.56	5.16
2012	5.08	5.90	5.42
2013	5.28	6.16	5.65
2014	5.49	6.41	5.87
2015	5.71	6.66	6.11
2016	5.94	6.93	6.35
2017	6.17	7.21	6.60
2018	6.42	7.49	6.87
2019	6.68	7.79	7.14
2020	6.95	8.11	7.43
2021	7.22	8.43	7.73
2022	7.51	8.77	8.04
2023	7.81	9.12	8.36
2024	8.13	9.48	8.69
2025	8.45	9.86	9.04
2026	8.79	10.26	9.40
2027	9.14	10.67	9.78
2028	9.51	11.09	10.17
2029	9.89	11.54	10.57
2030	10.28	12.00	11.00

(1) Pipeline price of natural gas based on future prices for Henry Hub minus $0.30/MMBtu (typical spread between Henry Hub index and Williams index). Delivered price of natural gas equals pipeline price plus estimated Seminole charges (19.75¢ per MCF plus 1.94% of Gas Price) plus MGE charges (34.37¢ per MCF in summer and 54.34¢ per MCF in winter).

(2) Escalated 4% annually.

(3) Summer Natural Gas Price is from April through October.

Table B-22
Projected Oil Prices [1] [2]
City of Independence, Missouri
($/MMBtu)

Year	Price
2011	21.47
2012	22.20
2013	22.93
2014	23.96
2015	25.04
2016	26.17
2017	27.34
2018	28.57
2019	29.86
2020	31.20
2021	32.61
2022	34.07
2023	35.61
2024	37.21
2025	38.89
2026	40.63
2027	42.46
2028	44.37
2029	46.37
2030	48.46

[1] Escalated 4.5% annually.

[2] Price of fuel oil based on NYMEX Futures for Heating Oil plus 20¢/gallon for estimated spread between NYMEX and cost delivered to IPL.

Table B-23
Iatan #2
Projected Annual Coal Price [1]
City of Independence, Missouri

Year	Fuel Cost ($/MWh)	Heat Rate (Btu/kWh)	Coal Price (cents/MMBtu)
2011	16.23	9,188	176.60
2012	16.87	9,188	183.66
2013	17.55	9,188	191.01
2014	18.25	9,188	198.65
2015	18.98	9,188	206.59
2016	19.74	9,188	214.86
2017	20.53	9,188	223.45
2018	21.35	9,188	232.39
2019	22.21	9,188	241.68
2020	23.09	9,188	251.35
2021	24.02	9,188	261.40
2022	24.98	9,188	271.86
2023	25.98	9,188	282.74
2024	27.02	9,188	294.05
2025	28.10	9,188	305.81
2026	29.22	9,188	318.04
2027	30.39	9,188	330.76
2028	31.61	9,188	343.99
2029	32.87	9,188	357.75
2030	34.18	9,188	372.06

[1] From "Iatan 2 Cost Estimate" provided by IPL Staff
April 12, 2011.

Table B-24
Nebraska City #2
Projected Annual Coal Price [1]
City of Independence, Missouri

Year	Fuel Cost ($/MWh)	Heat Rate (Btu/kWh)	Coal Price (cents/MMBtu)
2011	19.41	9,188	211.24
2012	18.02	9,188	196.10
2013	18.42	9,188	200.50
2014	19.71	9,188	214.47
2015	20.13	9,188	219.10
2016	20.74	9,188	225.76
2017	21.37	9,188	232.58
2018	22.01	9,188	239.60
2019	22.89	9,188	249.18
2020	23.81	9,188	259.15
2021	24.76	9,188	269.51
2022	25.75	9,188	280.29
2023	26.78	9,188	291.50
2024	27.85	9,188	303.16
2025	28.97	9,188	315.29
2026	30.13	9,188	327.90
2027	31.33	9,188	341.02
2028	32.59	9,188	354.66
2029	33.89	9,188	368.85
2030	35.25	9,188	383.60

[1] From "NC2 Costs" provided by IPL Staff April 12, 2011.

Table B-25
Dogwood Fuel Characteristics
Independence Power and Light

Year	Fuel Price[1] ($/MMBtu)	Net[2] Average Heat Rate (Btu/kWh)	Fuel Cost ($/MWh)
2012	5.42	7,400	40.10
2013	5.65	7,400	41.78
2014	5.87	7,400	43.45
2015	6.11	7,400	45.19
2016	6.35	7,400	46.99
2017	6.60	7,400	48.87
2018	6.87	7,400	50.83
2019	7.14	7,400	52.86
2020	7.43	7,400	54.98
2021	7.73	7,400	57.18
2022	8.04	7,400	59.46
2023	8.36	7,400	61.84
2024	8.69	7,400	64.31
2025	9.04	7,400	66.89
2026	9.40	7,400	69.56
2027	9.78	7,400	72.35
2028	10.17	7,400	75.24
2029	10.57	7,400	78.25
2030	11.00	7,400	81.38

(1)From Table B-22, Projected Natural Gas Prices

(2)Estimated from Dogwood Model Data for 2011 Master Plan Update received from IPL on April 15, 2011.

APPENDIX C

GENERATING UNIT CAPITAL COSTS AND DEBT SERVICE

Table C-1

Dogwood Estimated Total Financial Requirement and Debt Service

2014

Independence Power and Light

Description	($000)
Total Capital Cost	67,760
Debt Service Reserve Fund	6,554
Financing costs[(1)]	2,298
Total Financial Req't	76,612
($/kW)[(2)]	766
Annual Debt Service[(3)]	6,554
($/kW-mo.)[(2)(3)]	5.46

(1) 3.0% of total financial requirement.

(2) Rated capacity is 100 MW.

(3) 5.0% Long term interest rate,
18 year financing term.

Table C-2
Construction Drawdown for 180 MW Coal-Fired CFB Plant
(2014$)
City of Independence, Missouri

Description	2011 ($000)	2014 ($000)	% of Expenditures							Construction Drawdown Schedule							
			2011	2012	2013	2014	2015	2016	2017	2011	2012	2013	2014	2015	2016	2017	Total ($000)
Total Construction Cost[(1)(2)]	708,470	796,932	0.14%	2.12%	15.37%	34.11%	33.75%	10.10%	4.41%	1,116	16,895	122,489	271,834	268,965	80,490	35,145	796,932

(1) Estimated 2011 Construction Cost from New Generating Unit Capital Costs sheet prepared by SEGA received May 11, 2011.

(2) 4% annual escalation.

Table C-3
180 MW Coal-Fired CFB Plant Financing Costs
(2014$)
City of Independence, Missouri

Year	Accumulated Balance	Construction Drawdown	Interest Rate [1]	Annual Interest Cost	Drawdown and Interest
1	0	1,115,705	3.75%	41,839	1,157,544
2	1,157,544	16,894,967	3.75%	676,969	17,571,936
3	18,729,480	122,488,510	3.75%	5,295,675	127,784,184
4	146,513,665	271,833,641	3.75%	15,688,024	287,521,665
5	434,035,329	268,964,684	3.75%	26,362,501	295,327,185
6	729,362,514	80,490,172	3.75%	30,369,476	110,859,648
7	840,222,162	35,144,719	3.75%	32,826,258	67,970,977

Total Construction Drawdown	796,932,398
Interest During Construction	111,260,741
Financing costs [2]	28,088,448
Total Financial Requirements	936,281,587
($/kW)	5,202
Annual debt service [3]	64,578,954
Annual debt service ($/kW-mo.) [3]	29.90

(1) 3.75% Bond Anticipation Note (BAN) interest rate
(2) 3.0% of total financial requirements
(3) 6.00% Long term interest rate,
35 year financing term.

Table C-4
Construction Drawdown for 115 MW LM6000 2-on-1 Combined Cycle
City of Independence, Missouri

Description	2011 ($000)	2015 ($000)	% of Expenditures			Construction Drawdown Schedule		
			2015	2016		2015	2016	Total ($000)
Total Construction Cost[1][2]	190,000	222,273	50%	50%	100%	111,137	111,137	222,273

[1] Estimated 2011 Construction Cost from New Generating Unit Capital Costs sheet prepared by SEGA received May 11, 2011.

[2] Escalated 4% Annually

Table C-5
115 MW LM6000 2-on-1 Combined Cycle Financing Costs
(2016$)
City of Independence, Missouri

Year	Accumulated Balance	Construction Drawdown	Interest Rate [1]	Annual Interest Cost	Drawdown and Interest
1	0	111,136,563	3.75%	4,167,621	115,304,184
2	115,304,184	111,136,563	3.75%	8,491,528	119,628,091

Total Construction Drawdown	222,273,126
Interest During Construction	12,659,149
Financing costs [2]	7,265,947
Total Financial Requirements	242,198,222
($/kW)	2,106
Annual debt service [3]	17,595,437
Annual debt service ($/kW-mo.) [3]	12.75

[1] 3.75% Bond Anticipation Note (BAN) interest rate
[2] 3.0% of total financial requirements
[3] 6.0% Long term interest rate,
30 year financing term.

Table C-6
Construction Drawdown for 36 MW LM6000 Combustion Turbine
(2015$)
City of Independence, Missouri

Description	2011 ($000)	2014 ($000)	% of Expenditures 2013	% of Expenditures 2014	% of Expenditures	Construction Drawdown Schedule 2014	Construction Drawdown Schedule 2015	Construction Drawdown Schedule Total ($000)
Total Construction Cost[1][2]	50,000	56,243	50%	50%	100%	28,122	28,122	56,243

[1] Estimated 2011 Construction Cost from New Generating Unit Capital Costs sheet prepared by SEGA received May 11, 2011.

[2] Escalated 4% Annually

Table C-7
36 MW LM6000 Simple Cycle Combustion Turbine Financing Costs
(2015$)
City of Independence, Missouri

Year	Accumulated Balance	Construction Drawdown	Interest Rate (1)	Annual Interest Cost	Drawdown and Interest
1	0	28,121,600	3.75%	1,054,560	29,176,160
2	29,176,160	28,121,600	3.75%	2,148,666	30,270,266

Total Construction Drawdown	56,243,200
Interest During Construction	3,203,226
Financing costs (2)	1,838,549
Total Financial Requirements	61,284,975
($/kW)	1,702
Annual debt service (3)	4,452,287
Annual debt service ($/kW-mo.) (3)	10.31

(1) 3.75% Bond Anticipation Note (BAN) interest rate

(2) 3.0% of total financial requirements

(3) 6.0% Long term interest rate,
30 year financing term.