ELECTRIC COST OF SERVICE AND RATE DESIGN REPORT

Independence, MO

0703.003

May 29, 2015

Sawvel
AND ASSOCIATES
Consultants and Engineers

EXECUTIVE SUMMARY
2014-2015 ELECTRIC
COST OF SERVICE
AND
RATE DESIGN REPORT

Prepared for

CITY OF INDEPENDENCE, MISSOURI

POWER & LIGHT DEPARTMENT

May 29, 2015

Sawvel
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AND ASSOCIATES, INC.
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Mr. E. Leon Daggett
Power & Light Director
City of Independence, Missouri
Power & Light Department
21500 E. Truman Road
Independence, MO 64051-0519

RE: City of Independence, Missouri
Power & Light Department
2014-2015 Electric Cost of Service and Rate Design Report – Executive Summary

Dear Mr. Daggett:

We are pleased to present the Executive Summary of our report on the 2014-2015 Electric Cost of Service and Rate Design Study (Rate Study) for the City of Independence, Missouri (City). The purpose of the Rate Study is to evaluate the financial position of the City's Power & Light Department (IPL) for the five year projected period FY2015-16 through FY2019-20 and to provide the following:

- A rate plan for the projected period
- Goals and objectives for a rate design strategy
- A detailed cost of service analysis
- Proposed restructured and additional rates for implementation October 1, 2015

We appreciate the opportunity to provide consulting services to the City and IPL and look forward to discussing this report with you.

Sincerely,

Joseph A. Herz
Vice President

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FINAL
EXECUTIVE SUMMARY
2014-2015 ELECTRIC COST OF SERVICE AND RATE DESIGN REPORT
CITY OF INDEPENDENCE, MISSOURI POWER & LIGHT DEPARTMENT

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EXECUTIVE SUMMARY

INTRODUCTION

The City of Independence, Missouri (City) owns and operates, through its Power and Light Department (IPL), electric generation, transmission and distribution facilities to serve the electricity needs of its customers. Typical of similarly situated municipally owned electric systems, the City is facing the challenges of pursuing and implementing renewable energy options, transitioning to new base load resources that are more energy efficient but higher cost, and maintaining and improving an aging infrastructure, while providing low-cost, reliable electric service. These challenges also include compliance with new and changing environmental requirements and regulations affecting the future operation of IPL's resources and maintaining financial stability during a period of rising costs for fuel, equipment, and material.

The City retained Sawvel and Associates, Inc. (Sawvel) to prepare a 2014-2015 Electric Cost of Service and Rate Design Study (Rate Study) for IPL. The scope of services for this Rate Study was comprised of the following:

- Task 1 - Five Year Financial Forecast and Rate Design Strategy
  - Understanding overall financial requirements and needed base rate revenue adjustments, if any.
  - Developing a rate design strategy to meet identified goals and objectives.
- Task 2 - Customer Class Cost of Service Analysis
- Task 3 - Rate Design and Implementation of New Restructured Rates Effective October 1, 2015
  - Considering the impact of any restructured rates to IPL customers.
  - Developing new rates that address identified goals and objectives.
  - Comparing IPL's current and proposed rates to comparable rates of neighboring utilities.

The Rate Study report is comprised of the following:

- Section 1 – Introduction which provides the scope of services provided by Sawvel for this Rate Study.

- Section 2 – Rate Plan which provides the evaluation of IPL's financial position for the five year projected period FY2015-16 through FY2019-20 and provides the goals and objectives for rate design strategy and recommendations for a rate plan.
- Section 3 – Class Cost of Service Analysis which provides the detailed class cost of service analysis.
- Section 4 – Rate Design which provides a proposed rate schedule of restructured and new rates to meet IPL's revenue requirements and rate design strategy goals and objectives for implementation October 1, 2015.
- Section 5 – Bill Comparisons which provides a comparison of IPL's existing rates to proposed rates and neighboring utility rates.

The remaining sections of this Executive Summary provide a summary of Sawvel's (1) findings regarding IPL's financial position and cost of service analysis, and (2) recommendations regarding changes to IPL's rates to meet recommended goals and objectives.

FINDINGS ON IPL FINANCIAL POSITION

By developing a rate plan, the City is exercising control of its future to maintain financial integrity and a favorable credit rating. As part of the rate plan, IPL developed a Pro Forma spreadsheet that provides historical and projected revenues and revenue requirements of the electric utility as well as a net income statement, cash flow analysis and electric fund balances. From Sawvel's experience, and our observations and analyses of the information provided by IPL, the IPL Pro Forma projections provide a reasonable basis for development of the electric rate plan.

Sawvel's findings on IPL's financial position as shown in the Pro Forma are listed below:

1. Currently, IPL's depreciation expense (a non-cash item used to calculate net income) is more than the debt service principal payments included in IPL's cash flow calculation which results in negative net income. Projecting negative net income is generally not viewed favorably by the financial community. Negative net income is an indicator that a utility is not re-investing in its electric system and is borrowing, rather than cash funding, capital improvements and is retiring debt at a slower pace than the utility's plant is being depreciated.

2. IPL currently has an unrestricted cash fund balance that should be reduced by cash funding a portion of their capital improvement program that would otherwise have been funded by debt and reducing rates. In order to determine the amount of the unrestricted

cash fund balance to use toward funding capital improvements and reducing rates, it is important for IPL to have an unrestricted cash fund balance policy with a cash balance target. Sawvel developed such a policy for IPL that results in the targeted unrestricted cash fund balance to be maintained by IPL to be approximately $23 to $25 million.

3. In order to achieve positive net income and positive cash flow by the end of the projected period, IPL's Pro Forma showed the funding of capital improvements with available unrestricted cash and no base rate increases until October 1, 2017. Table ES-1 shows the projected operating results from the IPL Pro Forma for the period FY2015-16 through FY2019-20. These operating results for IPL show total revenues, total revenue requirements, the ending operating fund balance, cash flow analysis, net income statement results, and total customer sales in GWh as well as future overall base rate revenue increases.

Table ES-1
Projected Operating Results - IPL Pro Forma Summary with Projected Base Rate Increases ($000)
Independence Power & Light

Description	Fiscal Year Ending June 30				
	2016	**2017**	**2018**	**2019**	**2020**
Revenue from Base Rates	131,115	134,166	138,691	143,905	149,536
Revenue from PCA-1	0	1,164	2,760	3,407	3,952
Revenue from REC-1	340	1,057	1,070	1,084	394
Other	12,270	12,378	12,490	12,606	12,729
Total Revenues	**143,725**	**148,765**	**155,011**	**161,002**	**166,611**
Power Supply Expenses	64,476	65,710	66,142	67,578	69,498
Other O&M Expenses	43,710	48,606	51,292	54,260	57,324
Debt Service	8,924	8,983	9,163	9,972	11,695
Recurring Routine Adds & Replace	7,000	7,210	7,426	7,649	7,879
Major Cap Impr - Cash Funded	17,393	7,714	6,116	6,095	4,235
Other	13,800	14,283	14,871	15,447	15,980
Total Revenue Requirements	**155,303**	**152,506**	**155,010**	**161,001**	**166,611**
Balance - Net Cash Flow	**(11,578)**	**(3,741)**	**1**	**1**	**0**
Ending Operating Fund Balance	**27,241**	**23,500**	**23,501**	**23,502**	**23,502**
Major Cap Impr - Debt Funded	0	765	2,285	9,895	10,060
Net Income	**(6,403)**	**(3,088)**	**(1,052)**	**(1,002)**	**218**
Customer Sales GWh	1,055	1,059	1,062	1,065	1,069
Projected Base Rate Increase	0.0%	0.0%	3.3%	3.3%	3.3%

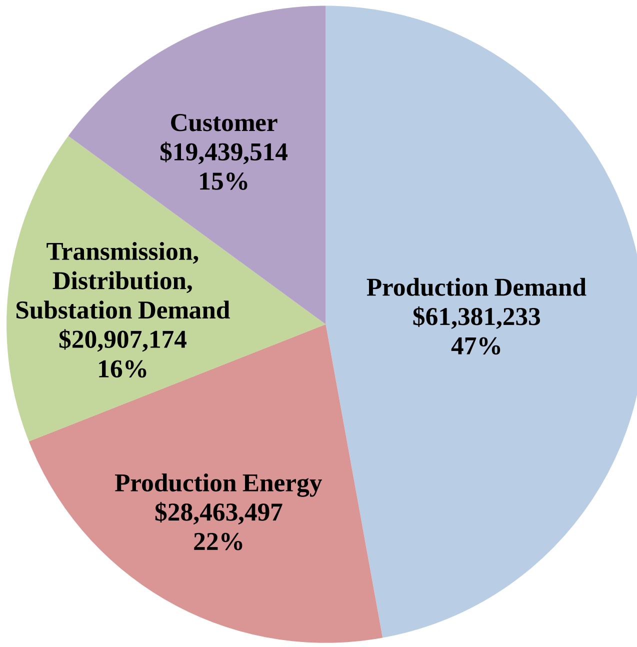
Based on the review of IPL's financial position, it was determined that the proposed restructured rates, when fully implemented, could result in a $3 million annual reduction of revenues from the commercial and industrial customers. As described later in this report, this revenue reduction is consistent with the cost of service analysis and would position IPL's higher load factor customers to be more competitive with neighboring utility rates. It was also determined that the proposed restructured customer charges for the residential and general service customers could be phased in to mitigate the impact to low use customers of replacing the minimum charge with a customer charge. This phase in would result in a $4.1 million reduction in residential and general service revenues in FY 2015-16 and a $0.8 million reduction in residential and general service revenues in FY 2016-17. Table ES-1 is based on these revenue reductions and shows that IPL can maintain financial integrity with these revenue reductions.

FINDINGS ON COST OF SERVICE ANALYSIS

IPL provides full-requirements electric service to residential and non-residential rate class customers under a number of electric rate schedules. A class cost of service study is an analytical process of assigning a proportionate share of the cost of owning, operating and maintaining an electric utility system to the rate classes of customers it serves.

In a cost of service analysis, the cost of owning, operating and maintaining an electric utility system is called test year revenue requirements. Graph ES-1 illustrates the breakdown of IPL's test year revenue requirements by function. As shown in Graph ES-1, IPL's power supply costs (shown as Production Demand and Production Energy) represents 70% of IPL's total cost of serving its customers.

Graph ES-1
Functionalization of Test Year
Revenue Requirements



Since Sawvel's 2008 rate study for IPL, the most significant change in IPL's power supply resource mix has been its purchased power capacity. IPL was purchasing 90 MW of capacity and energy from Kansas City Power & Light (KCPL) from KCPL's Montrose station. The Montrose purchase expired May 31, 2011. IPL planned for the expiration of the Montrose purchase by arranging for two baseload capacity and energy purchases from new coal-fired generating units - 55 MW from Omaha Public Power District (OPPD) from OPPD's Nebraska City #2 unit and 50 MW from the Missouri Joint Municipal Electric Utility Commission (MJMEUC) from MJMEUC's ownership share of KCPL's Iatan #2 unit. The Nebraska City #2 unit began commercial operation May 2009 and the Iatan #2 unit began commercial operation in June 2010. In addition, IPL purchased a 12.3% ownership share (75 MW) of the Dogwood plant - a 610 MW natural gas-fired combined cycle plant. IPL is also purchasing 15 MW of renewable energy from the Smoky Hills II Wind Farm and recently executed a 20 MW purchase power agreement for the purchase of wind energy out of the Marshall Wind Farm. Each of these resources are managed and staffed by the project managers responsible for the operation of each of these generation projects. Each of these resources are participating in SPP's integrated market and are dispatched by SPP.

Class cost of service studies are used for the following purposes:

- To allocate costs to different classes of customers based on how each customer group causes costs to be incurred.
- To provide a guide to determine how costs will be recovered from customers within each customer class.
- To calculate the costs of different types of services provided to different types of customers.
- To provide information to utility management to evaluate costs by customer class.

Table ES-2 summarizes the revenue distribution by rate class at current rates with the results of the cost of service analysis for each rate class.

Table ES-2
Comparison of Revenue Distribution ($)
Existing Rates vs Cost of Service
Adjusted Test Year 2014
Independence Power & Light

Rate Class	Existing Rate Revenue	Cost of Service	Difference ($)	Difference (%)
Residential	72,394,233	75,229,696	2,835,463	3.9
General Service	5,950,211	7,114,798	1,164,588	19.6
Large General Service	50,120,198	44,369,272	(5,750,926)	(11.5)
Large Power	4,726,777	3,477,653	(1,249,124)	(26.4)
Total Excluding Lighting/Signals	**133,191,419**	**130,191,419**	**(3,000,000)**	**(2.3)**

The following can be observed from Table ES-2 regarding existing rate class revenue:

1. Revenues from the Residential class are less than cost of service.
2. Revenues from the General Service class are less than cost of service.
3. Revenues from the Large General Service class are more than cost of service.
4. Revenues from the Large Power class are more than cost of service.

RECOMMENDED RATE CHANGES

IPL's serves approximately 56,510 metered customers under 21 rate schedule customer designations. In addition, IPL has rate schedules for City traffic signals, private outdoor lighting service and public street lighting service. IPL's current rate structures for its customer classes are dated and no longer consistent with that of its neighboring utilities. Several of these customer designations were developed in the past to promote various types of end use (i.e., electric water heaters, electric space heating equipment, etc.). This can result, however, in similar types of service being provided to consumers at different rates unless monitored and verified by IPL for facilities and equipment installed and used behind the meter.

Another characteristic of IPL current base rates is that the rate schedules contain numerous energy and demand blocks. The current base rates also do not have separate customer charges, but instead have various minimum bill provisions and higher initial rate block prices to represent built-in customer charges. The current trend in the electric industry is to use monthly customer charges in rate schedules and to reduce the number of rate blocks within each rate schedule.

The purpose of the customer charge rate component is to collect the customer-related costs of providing electric service. The utility incurs cost to serve customers even for those that use little to no electricity and a customer charge provides the mechanism to collect these costs from customers. A consultant recently retained by the City to conduct an evaluation of potential renewable energy options and programs recommended IPL review the current rate structure to eliminate or reduce rate subsidization issues before deploying any renewable energy programs. For example, a customer charge reduces the subsidization of solar PV customers by customers not participating in such a program because of the solar PV customers' reduced electricity usage from IPL. Customer related costs are currently recovered through electricity usage charges; under the proposed restructured rates, a customer charge will be implemented to recover IPL's customer related costs from all customers regardless of electricity usage.

Customer-related costs are those costs that vary based on the number and type of customers served by the electric system. These costs typically include the following:

1. A portion of the utility's Distribution System Operation and Maintenance Costs.
2. The cost of connecting the customer to the utility's distribution system, and the cost of installing metering equipment to measure the customer's electricity usage.
3. The cost associated with the customer meter reading, billing and accounting functions, and the administration of the rates, collection of payments, etc.

Customer-related distribution costs include a portion of the operating and maintenance cost of distributing power at primary (13 kV) and secondary (below 4 kV) voltages to customers such as poles, transformers and tree trimming. Metering costs include the installation and maintenance cost of meters and the monthly labor cost to read customer meters. Customer-related billing and accounting costs include costs associated with the monthly preparation and processing of customer bills and utility revenue accounting.

The cost of service analysis quantified IPL's customer related costs for each of the customer classes. For example, analysis indicated a cost of service customer charge for the residential rate class of $23.96 per month. The recommended residential customer charge is $14.50 per month, or 60% of IPL's residential customer related costs. The difference between IPL's cost of $23.96 and the recommended rate of $14.50 per month is essentially rolled into, and recovered from, the residential energy charge. As discussed later, it is recommended the proposed residential customer charge be phased-in to lessen the customer bill impact for lower energy use residential customers while moving towards cost of service based rates. The comparison of the recommended IPL customer charge is compared with the customer charges of neighboring utilities in tables described later in this report.

Goals and Objectives

Based on discussions between IPL and Sawvel, the following goals and objectives were established for IPL's rate design strategy:

- Move rates toward cost of service
- Reduce subsidization by high load factor customers to move toward rate competitiveness
- Eliminate the requirement for end use provisions to receive incentive rates
- Consolidate rate schedules whenever appropriate
- Make rate structure changes by replacing minimums with customer charges and reducing the number of block rates
- Develop seasonal rates for all rate classes that provide incentives for increased winter usage.
- Develop and restructure rates to become more rate competitive with the neighboring utilities of Kansas City Power & Light, Kansas City Power & Light – GMO, and the Board of Public Utilities – Kansas City, Kansas.
- Develop a high load factor rate for large customers.

- Develop a partial requirements rate and related agreements for customers that may choose to install on-site generation to supply a portion of the customer's electricity requirements
- Develop a community solar tariff
- Develop Schedule REC -1 Regulatory and Environmental Compliance Rider to recover regulatory and environmental costs not included in IPL's base rates or Schedule PCA-1 that are difficult to predict and not in control of IPL.
- Develop Schedule PCA-1 Power Cost Adjustment incorporating the following:
    - Develop a stable, predictable forward-looking adjustment factor rather than a monthly calculation.
    - Remove recovery of purchase power demand cost and transmission charges
    - Reset the base cost to the current level of power supply fuel and energy cost and set the rider to zero
    - Provide for a review the Schedule PCA-1 calculation and make projections for the periods beginning February and August.

As of October 1, 2016, the recommended proposed restructured schedule of rates would reduce revenues by approximately $3 million per year (2.3%) and will impact the revenue from each rate class. Table ES-3 summarizes the revenue distribution by rate class at current rates with the recommended revenue by rate class using rates effective October 1, 2016.

Table ES-3
Comparison of Revenue Distribution ($)
Existing Rates vs Proposed Restructured Rates
Adjusted Test Year 2014
Independence Power & Light

Rate Class	Existing Rate Revenue[1]	Proposed Revenue	Difference ($)	Difference (%)
Residential	73,576,524	73,974,611	398,087	0.5
General Service	6,060,329	6,399,955	339,626	5.6
Large General Service	50,849,669	47,483,258	(3,366,411)	(6.6)
Large Power	5,327,618	4,879,985	(447,633)	(8.4)
Total Excluding Lighting/Signals	**135,814,140**	**132,737,809**	**(3,076,331)**	**(2.3)**

[1] Adjusted to reflect March 2014 through February 2015 average FCA.

Sawvel developed a recommended proposed restructured schedule of rates to be effective October 1, 2015 that includes a phase in of the customer charge to residential and general service customers through October 1, 2016. If implemented, the recommended proposed restructured schedule of rates would reduce retail revenues by approximately $7.9 million ($4.9 million for the phase-in of customer charges plus the $3 million as described in Table ES-3) for the 12 months from October 1, 2015 through September 30, 2016. Table ES-4 provides the Revenue Reduction for Phase-In of Residential and General Service Customer Charges.

Table ES-4
Revenue Reduction for Phase In of Residential and General Service Customer Charges ($)
Independence Power & Light

Description	FY 2015 - 2016			FY 2016 - 2017	Total
	October 1, 2015 - April 30, 2016	May 1, 2016 - June 30, 2016	Subtotal	July 1, 2016 - September 30, 2016	
Residential Revenue Reduction	3,414,243	513,420	3,927,663	770,130	4,697,793
General Service Revenue Reduction	135,786	19,398	155,184	29,097	184,281
Total Revenue Reduction	3,550,029	532,818	4,082,847	799,227	4,882,074

The following paragraphs provide a description of the proposed restructured Schedule of Rates:

Residential

IPL's current residential rate tariffs consist of five different rate applications depending on the customer's electrical equipment:

- Standard Residential (RS-3) for those customers that have no qualifying electrical space heating or electrical water heating equipment.
- Residential with Water Heating (RSWH) for those customers that have qualifying electrical water heating.
- Residential with Space Heating (RSSH) for those customers that have qualifying electrical space heating equipment.
- Residential with Water Heating and Space Heating (RSSHW) for those customers that have both qualifying electrical water heating and space heating.
- All Electric Residential (RS-4) for those customers that have all electrical equipment for all needs and have no natural gas service to their facility.

The proposed Residential rate schedule consolidates these five existing residential rate codes (RS-3, RSWH, RSSH, RSSHW, RS-4) into two new rates: RS-1 (General Use) and RSSH-1 (grandfathered space heating). Those existing customers that have qualifying electric space heating equipment currently being billed under the RSSH, RSSHW or RS-4 rate codes will receive a discounted rate to minimize the rate impact of the new proposed rates. The space heating rate is not available to new customers or new service locations. The proposed RS-1 rate schedule was developed so as to continue to encourage electric space heating. The energy rate blocks were simplified from ten (3 on-peak, 7 off-peak) to four (1 on-peak, 3 off-peak).

In addition, a customer charge of $14.50 per month is recommended to replace the existing minimum bill provision. As previously discussed, customer charges are needed for recovery of IPL's fixed costs to serve customers and to prevent customer subsidization issues, especially with customers that have installed behind the meter generation. To lessen the impact of full implementation of the $14.50 monthly customer charge, especially on low usage residential customers, it is recommended that the monthly customer charge be phased in as follows:

October 1, 2015	$5.00
May 1, 2016	$9.50
October 1, 2016	$14.50

General Service

IPL's current general service rate tariffs consist of:

- General Service (GS-1)
- Churches and Hospitals (CH-1)
- Churches and Hospitals – All Electric (CH-AL)

The proposed new rate tariff consolidates these three rate codes under one rate tariff, General Service (GS-1). To recognize that churches are normally weekend, off-peak users and to continue prior practice, the energy rate for all kWh for churches and hospitals was discounted. The energy rate blocks were simplified from five (non-seasonal) to three (1 on-peak, 2 off-peak) blocks with implementation of seasonal rates.

In addition, a customer charge of $16.00 per month is recommended to replace the existing minimum bill provision. To lessen the impact of full implementation of the $16.00 monthly customer charge, especially on low usage general service customers, it is recommended that the monthly customer charge be phased in as follows:

October 1, 2015	$10.00
May 1, 2016	$13.00
October 1, 2016	$16.00

Large General Service

IPL's current large general service rate classes consist of:

- Large General Service (LGS-1)
- Large General Service – Primary Voltage (LGSPV)
- Total Electric General Service (TEGS)
- Schools (EDU-1)
- All Electric Schools (EDU-AL)
- Sewer Pumping (SP-1)

The proposed Large General Service rate schedule is a consolidation of these existing rate codes. The proposed LGS-1 rate schedule also includes a customer charge of $50.00 per month and the three demand blocks were simplified into one on-peak and one off-peak. The existing customers currently being billed under TEGS and EDU-1 and EDU-AL will be grandfathered on the new LGS-1 rate schedule with a discount to minimize rate impact on these customers.

Large Power

The proposed Large Power rate schedule (LP-1) is a consolidation of the existing LP-2 (Large Power) and SCIS-1 (Special Contract Large Industrial) rate schedules. This schedule includes a customer charge of $500.00 per month and consolidates eight energy blocks and three demand blocks into one energy block and one demand block. One of the rate design goals is to incentivize high load factor loads. To accomplish that goal, this schedule was designed with a low energy charge and high demand charge in an effort to favor high load factor customers and attract new large power high load factor customers.

General Service Space Heating (Frozen GSSH-1)

The existing GSSH-1 (General Service Space Heating) rate schedule requires customers to have a separate meter to measure the heating load in their facility. In consideration that these customers made an initial investment in electrical design and wiring to have this separate meter, this rate schedule is proposed to be frozen. This schedule will not be available to new customers or new service locations. If an existing GSSH-1 service location changes customers, the new customer would be served under the appropriate GS-1 or LGS-1 rate schedule.

Large Power (Frozen LP-2)

The existing LP-2 (Large Power) rate schedule was frozen to allow existing LP-2 customers (currently there are 3 customers are on the LP-2 rate) the option of remaining on the LP-2 rates to take advantage of the current Economic Development Rider (Schedule EDR-5). The existing

LP-2 energy rates were increased to reflect the amount of power supply costs that were rolled into proposed base rates under the new Power Cost Adjustment Rider described below. This schedule will not be available to new customers or new service locations and customers that move to the proposed LP-1 rate will not be able to return to the LP-2 rate.

Special Contract Large Interruptible Industrial (Frozen SCIS-1)

The existing SCIS-1 (Special Contract Large Interruptible Industrial) rate schedule was frozen to allow existing SCIS-1 customers (currently there are 2 customers on the SCIS-1 rate) the option of remaining on the SCIS-1 rates and to take advantage of the Economic Development Rider. The existing SCIS-1 energy rates were increased to reflect the amount of power supply costs that were rolled into proposed base rates. This schedule will not be available to new customers or new service locations and customers that move to the proposed LP-1 rate will not be able to return to the SCIS-1 rate.

Power Cost Adjustment Schedule PCA-1

The purpose of IPL's existing Schedule FA-1 Power Supply Fuel-Energy Cost Adjustment is to pass through to customers the difference between IPL's actual power supply costs and the power supply costs included in, or built into, the base rates. This calculation is done on a monthly basis. Now that a restructuring of IPL's base rates is being studied, it is appropriate to design any such restructured base rates to recover the current level of power supply costs and set the cost adjustment mechanism to zero.

The proposed Power Cost Adjustment Schedule PCA-1 is designed to be a stable, predictable forward-looking adjustment factor rather than a monthly calculation. The proposed Schedule PCA-1 recovers only fuel and energy costs going forward above or below the level of fuel and energy costs included in the proposed base rates. Based on IPL's power supply cost projection, the cost base for fuel and energy costs included in the proposed base rates is $0.0236/kWh.

IPL shall review the proposed Schedule PCA-1 calculation and shall make projections for the periods beginning February and August. Following such proposed Schedule PCA-1 review and calculation, the Power & Light Director shall direct the proposed Schedule PCA-1 to be applied, as deemed necessary to accomplish recovery of IPL's fuel and energy related costs in a timely manner.

Regulatory and Environmental Compliance Rider Schedule REC-1

As an owner of electric generation, transmission and distribution facilities, the City may be subject to future government mandates or environmental compliance costs that are not recovered through its existing rates or riders. The proposed Regulatory and Environmental Compliance

Rider Schedule REC-1 provides for the recovery of such unfunded mandated governmental and environmental compliance costs.

The calculation of Schedule REC-1 shall be determined prior to the beginning of the fiscal year and applied to customer bills beginning July 1 each year. Actual costs incurred will be used for reconciliation of any over or under recovery of governmental mandates or environmental compliance costs not included in base rates. The Schedule REC-1 monthly charge is estimated to initially be $0.66 per month.

Community Solar

A Community Solar Program provides customers the opportunity to purchase energy from solar without impacting the structure of their houses and without the utility financing the development of a potentially costly project. This program allows the projects to be financed through a power purchase agreement (PPA) with the developer and passes the cost directly to the customers participating in the program.

As of the date of this report, IPL staff was still finalizing a PPA and other technical aspects for potential project development and had not made a recommendation to the City Manager and City Council for their ultimate approval to move forward with a solar farm. Nevertheless, Sawvel has developed a Community Solar Rider that could be used as a model if the City moves forward with the solar farm.

Sawvel reviewed several community solar programs of other utilities and recommends a rider similar to the City of Springfield, Missouri. The proposed Community Solar Rider provides the option for customers to purchase from a utility scale solar farm in 1 kW blocks and receive solar Renewable Energy Credits applicable to their share of the output of the solar farm. The customer would pay an additional charge per kWh of allocated solar farm output in addition to the charges for service under the applicable IPL electric rate schedule. The charge for solar farm output is reflective of the difference in cost of the solar farm output and the IPL total system power supply costs included in proposed base rates. The charge will adjust coincident with the Power Cost Adjustment Rider. As IPL's total system power supply costs increase, the solar charge would decrease and vice versa. This prevents other customers who choose not to buy solar from subsidizing the customers that do. The customers who buy from the solar farm benefit from the economies of scale of a utility scale solar farm.

Partial Requirements Rate

Sawvel developed a Partial Requirements Rate, and related Partial Requirements Electric Service Agreement and Interconnection Agreement, for customers that install generation behind the meter on their site. Customers with on-site generation will look to the City to provide that portion of their electric service requirements that is not provided by the customer's on-site generation (i.e., partial requirements service rather than full requirements service). The purpose of the Partial Requirements Rate is to recover IPL's cost of serving such customers so other customers don't subsidize the Partial Requirements customers.

BILL COMPARISONS

Bill comparisons were prepared for each rate class to compare bills using proposed rates to the proposed or estimated rates of neighboring utilities. The neighboring utilities included Kansas City Power and Light (KCPL), Kansas City Power and Light - Greater Missouri Operations (GMO or Old Aquila), and Kansas City, Kansas Board of Public Utilities (BPU). Tables ES-5 through ES-14 show the bill comparisons by season, if applicable, for each Sawvel proposed restructured rate schedule. All neighboring utility rates in the following tables are based on rates proposed or estimated. Kansas City Power and Light has filed for a rate increase of 15.9% that, if approved, could go into effect as soon as September 30, 2015. A financial rating agency has reported BPU's rates are estimated to increase 5% in 2015 and 2016. GMO – Old Aquila is expected to make a rate filing in early 2016. KCPL's proposed 15.9% increase was used for purposes of estimating GMO – Old Aquila's rates.

Residential

Table ES-5 shows the results of comparing the phased in proposed restructured rates for IPL to IPL's existing rates for a typical use residential customer using 1,100 kWh per month during the on-peak (summer) season and 700 kWh per month during the off peak season (winter). Table ES-6 shows the results of comparing the phased in proposed restructured rates for IPL to IPL existing rates for a low use residential customer using 400 kWh per month during the on-peak (summer) season and 400 kWh per month during the off peak season (winter).

Tables ES-7 and ES-8 show the results of comparing the completely phased in proposed restructured rates for IPL to the proposed or estimated future rates for IPL's neighboring utilities for both the typical use residential customer and the low use residential customer.

General Service

Table ES-9 shows the results of comparing the phased in proposed restructured rates for IPL to IPL's existing rates for a typical use general service customer using 800 kWh per month during the on-peak (summer) season and 800 kWh per month during the off peak season (winter).

Table ES-10 shows the results of comparing the completely phased in proposed restructured rates for IPL to the proposed or estimated future rates for IPL's neighboring utilities for the typical use general service customer.

Table ES-5

Residential Rate Monthly Bill Comparison - IPL Existing vs IPL Proposed Restructured - Typical Use Customer

	Winter 700 kWh	Summer 1,100 kWh						
IPL Existing (1)								
Energy Charge	$95.32	$167.58						
	700 kWh	1,100 kWh	700 kWh	1,100 kWh	Difference from IPL Existing			
	Winter effective Oct 1 2015	Summer effective May 1 2016	Winter effective Oct 1 2016	Summer effective May 1 2017	Winter effective Oct 1 2015	Summer effective May 1 2016	Winter effective Oct 1 2016	Summer effective May 1 2017
IPL Proposed Restructured								
Customer Charge	$5.00	$9.50	$14.50	$14.50				
Energy Charge	$86.80	$154.00	$86.80	$154.00	-8.9%	-8.1%	-8.9%	-8.1%
Schedule REC	$0.66	$0.66	$0.66	$0.66				
Total	$92.46	$164.16	$101.96	$169.16	-3.0%	-2.0%	7.0%	0.9%
Difference IPL Proposed Restructured less Existing	($2.86)	($3.42)	$6.64	$1.58				

(1) IPL currently has a minimum charge with no usage of $4.14.

Table ES-6

Residential Rate Monthly Bill Comparison - IPL Existing vs IPL Proposed Restructured - Low Use Customer

	Winter 400 kWh	Summer 400 kWh						
IPL Existing (1)								
Energy Charge	$52.45	$62.75						
	400 kWh	400 kWh	400 kWh	700 kWh	Difference from IPL Existing			
	Winter effective Oct 1 2015	Summer effective May 1 2016	Winter effective Oct 1 2016	Summer effective May 1 2017	Winter effective Oct 1 2015	Summer effective May 1 2016	Winter effective Oct 1 2016	Summer effective May 1 2017
IPL Proposed Restructured								
Customer Charge	$5.00	$9.50	$14.50	$14.50				
Energy Charge	$53.20	$56.00	$53.20	$56.00	1.4%	-10.8%	1.4%	-10.8%
Schedule REC	$0.66	$0.66	$0.66	$0.66				
Total	$58.86	$66.16	$68.36	$71.16	12.2%	5.4%	30.3%	13.4%
Difference IPL Proposed Restructured less Existing	$6.41	$3.41	$15.91	$8.41				

(1) IPL currently has a minimum charge with no usage of $4.14.

Table ES-7
Residential Rate Comparison - IPL Proposed Restructured vs Neighboring Utilities Estimated Future (Customer Charge $14.50/month effective October 1, 2016) - Typical Use Customer

	Summer 1,100 kWh	Winter 700 kWh	Difference from IPL Proposed Restructured Summer	Difference from IPL Proposed Restructured Winter
IPL Proposed Restructured				
Customer Charge	$14.50	$14.50		
Energy Charge	$154.00	$86.80		
Schedule REC	$0.66	$0.66		
Total	$169.16	$101.96		
KCPL Proposed (1)				
Customer Charge	$25.00	$25.00	72.4%	72.4%
Energy Charge	160.55	84.78	4.3%	-2.3%
Environmental Charges				
Total	$185.55	$109.78	9.7%	7.7%
Difference IPL Proposed Restructured less KCPL	($16.39)	($7.82)		
Old Aquila Estimated (2)				
Customer Charge	$12.09	$12.09	-16.6%	-16.6%
Energy Charge	170.31	102.54	10.6%	18.1%
Environmental Charges				
Total	$182.40	$114.63	7.8%	12.4%
Difference IPL Proposed Restructured less Old Aquila	($13.24)	($12.67)		
KCK BPU Estimated (3)				
Customer Charge	$17.60	$17.60	21.4%	21.4%
Energy Charge	125.37	80.71	-18.6%	-7.0%
Environmental Charges	$3.34	$2.13	406.7%	222.4%
Total	$146.31	$100.43	-13.5%	-1.5%
Difference IPL Proposed Restructured less KCK BPU	$22.85	$1.53		

(1) KCPL proposed rate increase of 15.9% pending before Missouri Public Service Commission.
(2) Old Aquila expected to file for rate increase in early 2016. Assumed 15.9% increase to match KCPL increase.
(3) Rating agency reports KCK BPU estimated to increase rates 5% in 2015 and 2016.

Table ES-8
Residential Rate Comparison - IPL Proposed Restructured vs Neighboring Utilities
Estimated Future (Customer Charge $14.50/month effective
October 1, 2016) - Low Use Customer

	Summer 400 kWh	Winter 400 kWh	Difference from IPL Proposed	
			Summer	Winter
IPL Proposed Restructured				
Customer Charge	$14.50	$14.50		
Energy Charge	$56.00	$53.20		
Schedule REC	$0.66	$0.66		
Total	$71.16	$68.36		
KCPL Proposed (1)				
Customer Charge	$25.00	$25.00	72.4%	72.4%
Energy Charge	59.97	46.88	7.1%	-11.9%
Environmental Charges				
Total	$84.97	$71.88	19.4%	5.2%
Difference IPL Proposed Restructured less KCPL	($13.81)	($3.52)		
Old Aquila Estimated (2)				
Customer Charge	$12.09	$12.09	-16.6%	-16.6%
Energy Charge	61.67	61.67	10.1%	15.9%
Environmental Charges				
Total	$73.76	$73.76	3.7%	7.9%
Difference IPL Proposed Restructured less Old Aquila	($2.60)	($5.40)		
KCK BPU Estimated (3)				
Customer Charge	$17.60	$17.60	21.4%	21.4%
Energy Charge	$55.09	47.04	-1.6%	-11.6%
Environmental Charges	$1.22	$1.22	84.2%	84.2%
Total	$73.91	$65.86	3.9%	-3.7%
Difference IPL Proposed Restructured less KCK BPU	($2.75)	$2.50		

(1) KCPL proposed rate increase of 15.9% pending before Missouri Public Service Commission.
(2) Old Aquila expected to file for rate increase in early 2016. Assumed 15.9% increase to match KCPL increase.
(3) Rating agency reports KCK BPU estimated to increase rates 5% in 2015 and 2016.

Table ES-9

General Service Rate Monthly Bill Comparison - IPL Existing vs IPL Proposed Restructured - Typical Use Customer

	Winter 800 kWh	Summer 800 kWh
IPL Existing (1)		
Energy Charge	$141.81	$141.81

	800 kWh Winter effective Oct 1 2015	800 kWh Summer effective May 1 2016	800 kWh Winter effective Oct 1 2016	800 kWh Summer effective May 1 2017	Difference from IPL Existing: Winter effective Oct 1 2015	Difference from IPL Existing: Summer effective May 1 2016	Difference from IPL Existing: Winter effective Oct 1 2016	Difference from IPL Existing: Summer effective May 1 2017
IPL Proposed Restructured								
Customer Charge	$10.00	$13.00	$16.00	$16.00				
Energy Charge	$122.80	$136.00	$122.80	$136.00	-13.4%	-4.1%	-13.4%	-4.1%
Schedule REC	$0.66	$0.66	$0.66	$0.66				
Total	$133.46	$149.66	$139.46	$152.66	-5.9%	5.5%	-1.7%	7.7%
Restructured less Existing	($8.35)	$7.85	($2.35)	$10.85				

(1) IPL currently has a minimum charge with no usage of $4.08 for single phase and $17.58 for three phase or $11.95 per kW for customers with demand of 10kW or more.

Table ES-10

General Service Rate Monthly Bill Comparison - IPL Proposed Restructured vs Neighboring Utilities Estimated Future (Customer Charge $16.00/month effective October 1, 2016) - Typical Use Customer

	Summer 800 kWh	Winter 800 kWh	Difference from IPL Proposed Restructured Summer	Difference from IPL Proposed Restructured Winter
IPL Proposed Restructured				
Customer Charge	$16.00	$16.00		
Energy Charge	$136.00	$122.80		
Schedule REC	$0.66	$0.66		
Total	$152.66	$139.46		
KCPL Proposed (1)				
Customer Charge	$19.06	$19.06	19.1%	19.1%
Energy Charge	$151.59	$118.19	11.5%	-3.8%
Environmental Charges				
Total	$170.65	$137.25	11.8%	-1.6%
Difference IPL Proposed Restructured less KCPL	($17.99)	$2.21		
Old Aquila Estimated (2)				
Customer Charge	$19.92	$19.92	24.5%	24.5%
Energy Charge	$141.39	$106.34	4.0%	-13.4%
Environmental Charges				
Total	$161.31	$126.26	5.7%	-9.5%
Difference IPL Proposed Restructured less Old Aquila	($8.65)	$13.20		
KCK BPU Estimated (3)				
Customer Charge	$33.00	$33.00	106.3%	106.3%
Energy Charge	$133.04	$122.29	-2.2%	-0.4%
Environmental Charges	$2.43	$2.43	268.5%	268.5%
Total	$168.47	$157.72	10.4%	13.1%
Difference IPL Proposed Restructured less KCK BPU	($15.81)	($18.26)		

(1) KCPL proposed rate increase of 15.9% pending before Missouri Public Service Commission.
(2) Old Aquila expected to file for rate increase in early 2016. Assumed 15.9% increase to match KCPL increase.
(3) Rating agency reports KCK BPU estimated to increase rates 5% in 2015 and 2016.

Large General Service

Table ES-11 shows the results of comparing the proposed restructured rates for IPL to IPL's existing rates for a representative large general service customer using 16,425 kWh and 50 kW per month during the on-peak (summer) season and 16,425 kWh and 50 kW per month during the off peak season (winter). Table ES-12 shows the results of comparing the proposed restructured rates for IPL to the proposed or estimated future rates for IPL's neighboring utilities for the representative large general service customer.

Large Power

Table ES-13 shows the results of comparing the proposed restructured rates for IPL to IPL's existing rates for a representative large power customer using 912,500 kWh and 2,500 kW per month during the on-peak (summer) season and 912,500 kWh and 2,500 kW per month during the off peak season (winter). Table ES-14 shows the results of comparing the proposed restructured rates for IPL to the proposed or estimated future rates for IPL's neighboring utilities for a representative large power customer.

Table ES-11
Large General Service Rate Monthly Bill Comparison - IPL Existing vs IPL Proposed Restructured (Customer Charge $50.00/month effective October 1, 2015) - Representative Customer

	Summer 16,425 kWh 50 kW	Winter 16,425 kWh 50 kW	Difference from IPL Existing	
			Summer	Winter
IPL Existing (1)				
Energy Charge	$1,845.30	$1,845.30		
Demand Charge	$392.00	$392.00		
Total	$2,237.30	$2,237.30		
IPL Proposed Restructured				
Customer Charge	$50.00	$50.00		
Energy Charge	$1,846.13	$1,599.75	0.0%	-13.3%
Demand Charge	$350.00	$250.00	-10.7%	-36.2%
Schedule REC	$0.66	$0.66		
Total	$2,246.79	$1,900.41	0.4%	-15.1%
Difference Proposed IPL Restructuring less Existing	$9.48	($336.89)		

(1) IPL currently has a minimum charge with no usage of $6.31 per kW of highest demand during last 12 months.

Table ES-12

Large General Service Rate Monthly Bill Comparison - IPL Proposed Restructured vs Neighboring Utilities Estimated Future (Customer Charge $50.00/month effective October 1, 2015) - Representative Customer

	Summer 16,425 kWh 50 kW	Winter 16,425 kWh 50 kW	Difference from IPL Proposed Restructured	
			Summer	Winter
IPL Proposed Restructured				
Customer Charge	$50.00	$50.00		
Energy Charge	$1,846.13	$1,599.75		
Demand Charge	$350.00	$250.00		
Schedule REC	$0.66	$0.66		
Total	$2,246.79	$1,900.41		
KCPL Proposed (1)				
Customer Charge	$55.35	$55.35	10.7%	10.7%
Energy Charge	$1,793.35	$1,485.17	-2.9%	-7.2%
Demand Charge	$400.14	$296.79	14.3%	18.7%
Environmental Charges				
Total	$2,248.84	$1,837.31	0.1%	-3.3%
Difference IPL Proposed Restructured less KCPL	($2.06)	$63.10		
Old Aquila Estimated (2)				
Customer Charge	$20.00	$20.00	-60.0%	-60.0%
Energy Charge	$2,051.08	$1,734.29	11.1%	8.4%
Demand Charge	$294.97	$186.89	-15.7%	-25.2%
Environmental Charges				
Total	$2,366.05	$1,941.18	5.3%	2.1%
Difference IPL Proposed Restructured less Old Aquila	($119.26)	($40.77)		
KCK BPU Estimated (3)				
Customer Charge	$33.00	$33.00	-34.0%	-34.0%
Energy Charge	$1,694.41	$1,467.68	-8.2%	-8.3%
Demand Charge	$655.50	$655.50	87.3%	162.2%
Environmental Charges	$50.93	$50.93		
Total	$2,433.84	$2,207.11	8.3%	16.1%
Difference IPL Proposed Restructured less KCK BPU	($187.06)	($306.70)		

(1) KCPL proposed rate increase of 15.9% pending before Missouri Public Service Commission.

(2) Old Aquila expected to file for rate increase in early 2016. Assumed 15.9% increase to match KCPL increase.

(3) Rating agency reports KCK BPU estimated to increase rates 5% in 2015 and 2016.

Table ES-13
Large Power Rate Monthly Bill Comparison - IPL Existing vs IPL Proposed Restructured (Customer Charge $500.00/month effective October 1, 2015) - Representative Customer

	Summer 912,500 kWh 2,500 kW	Winter 912,500 kWh 2,500 kW	Difference from IPL Existing	
			Summer	Winter
IPL Existing (1)				
Energy Charge	$90,289.48	$90,289.48		
Demand Charge	$10,110.00	$10,110.00		
Total	$100,399.48	$100,399.48		
IPL Proposed Restructured				
Customer Charge	$500.00	$500.00		
Energy Charge	$35,131.25	$35,131.25	-61.1%	-61.1%
Demand Charge	$46,250.00	$46,250.00	357.5%	357.5%
Schedule REC	$0.66	$0.66		
Total	$81,881.91	$81,881.91	-18.4%	-18.4%
Difference Proposed IPL Restructuring less Existing	($18,517.57)	($18,517.57)		

(1) IPL currently has a minimum charge with no usage of $4.83/kW of the highest demand in the prior 12 months.

Table ES-14
Large Power Rate Comparison - IPL Proposed Restructured vs Neighboring Utilities Estimated Future
(Customer Charge $500.00/month effective October 1, 2015) - Representative Customer

	Summer 912,500 kWh 2,500 kW	Winter 912,500 kWh 2,500 kW	Difference from IPL Proposed Restructured	
			Summer	Winter
IPL Proposed Restructured				
Customer Charge	$500.00	$500.00		
Energy Charge	$35,131.25	$35,131.25		
Demand Charge	$46,250.00	$46,250.00		
Schedule REC	$0.66	$0.66		
Total	$81,881.91	$81,881.91		
KCPL Proposed (1)				
Customer Charge	$1,001.15	$1,001.15	100.2%	100.2%
Energy Charge	$87,196.56	$74,588.00	148.2%	112.3%
Demand Charge	$23,320.00	$15,760.00	-49.6%	-65.9%
Environmental Charges				
Total	$111,517.71	$91,349.15	36.2%	11.6%
Difference IPL Proposed Restructured less KCPL	($29,635.80)	($9,467.24)		
Old Aquila Estimated (2)				
Customer Charge	$207.47	$207.47	-58.5%	-58.5%
Energy Charge	$82,553.80	$60,335.77	135.0%	71.7%
Demand Charge	$23,614.63	$9,850.05	-48.9%	-78.7%
Environmental Charges				
Total	$106,375.90	$70,393.30	29.9%	-14.0%
Difference IPL Proposed Restructured less Old Aquila	($24,493.99)	$11,488.61		
KCK BPU Estimated (3)				
Customer Charge	$154.00	$154.00	-84.6%	-84.6%
Energy Charge	$80,381.73	$71,126.34	128.8%	102.5%
Demand Charge	$30,387.50	$30,387.50	-34.3%	-34.3%
Environmental Charges	$2,774.00	$2,774.00		
Total	$113,697.23	$104,441.84	38.9%	27.6%
Difference IPL Proposed Restructured less KCK BPU	($31,815.32)	($22,559.93)		

(1) KCPL proposed rate increase of 15.9% pending before Missouri Public Service Commission.
(2) Old Aquila expected to file for rate increase in early 2016. Assumed 15.9% increase to match KCPL increase.
(3) Rating agency reports KCK BPU estimated to increase rates 5% in 2015 and 2016.

RECOMMENDATIONS

Based on the IPL Pro Forma and the rate design goals and objectives, Sawvel makes the following recommendations:

1. Restructure rates in the manner described above to be effective October 1, 2015 that results in a reduction of $7.9 million in revenues for the 12 month period from October 1, 2015 through September 30, 2016 and $3 million annual reduction in revenues thereafter.

2. Implement the proposed Power Cost Adjustment Schedule PCA-1 and Regulatory and Environmental Compliance Schedule REC-1.

3. Implement the Unrestricted Cash Fund Balance Policy.

4. Defer implementation of additional base rate revenue increases at this time pending the completion of the following:
    a. Final FERC determination of net SPP Transmission revenues and expenses to be realized by IPL
    b. Review of IPL's depreciation rates and implementation of any changes to these depreciation rates and IPL's depreciation expense
    c. Finalize major capital improvements including transmission and substation projects based on projected load growth

After completion of the above, IPL should update its Pro Forma and revise the rate plan as needed to ensure the unrestricted cash fund policy is being met in the future and to generate positive net income.

2014-2015 ELECTRIC COST OF SERVICE AND RATE DESIGN REPORT

Prepared for

CITY OF INDEPENDENCE, MISSOURI
POWER & LIGHT DEPARTMENT

May 29, 2015

Sawvel AND ASSOCIATES
Consultants and Engineers

Sawvel
AND ASSOCIATES, INC.
Consultants and Engineers

May 29, 2015

Mr. E. Leon Daggett
Power & Light Director
City of Independence, Missouri
Power & Light Department
21500 E. Truman Road
Independence, MO 64051-0519

RE: City of Independence, Missouri
Power & Light Department
2014-2015 Electric Cost of Service and Rate Design Report

Dear Mr. Daggett:

We are pleased to present our report on the 2014-2015 Electric Cost of Service and Rate Design Study (Rate Study) for the City of Independence, Missouri (City). The purpose of the Rate Study is to evaluate the financial position of the City's Power & Light Department (IPL) for the five year projected period FY2015-16 through FY2019-20 and to provide the following:

- A rate plan for the projected period
- Goals and objectives for a rate design strategy
- A detailed cost of service analysis
- Proposed restructured and additional rates for implementation October 1, 2015

We appreciate the opportunity to provide consulting services to the City and IPL and look forward to discussing this report with you.

Sincerely,

Joseph A. Herz
Vice President

100 East Main Cross Street ■ Suite 300 ■ Findlay, OH 45840-4889
Phone: 419-422-4812 ■ Email: sawvel@sawvel.com ■ Fax: 419-423-5076

2014-2015 Electric Cost of Service and Rate Design Report
City of Independence, Missouri Power & Light Department

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Table G-4 Schedule 9 - Capital Improvement Budget Projection

SECTION 1 - INTRODUCTION

The City of Independence, Missouri (City) owns and operates, through its Power and Light Department (IPL), electric generation, transmission and distribution facilities to serve the electricity needs of its customers. Typical of similarly situated municipally owned electric systems, the City is facing the challenges of pursuing and implementing renewable energy options, transitioning to new base load resources that are more energy efficient but higher cost, and maintaining and improving an aging infrastructure, while providing low-cost, reliable electric service. These challenges also include compliance with new and changing environmental requirements and regulations affecting the future operation of IPL's resources and maintaining financial stability during a period of rising costs for fuel, equipment, and material.

The City retained Sawvel and Associates, Inc. (Sawvel) to prepare a 2014-2015 Electric Cost of Service and Rate Design Study (Rate Study) for IPL.

The scope of services for this Rate Study was comprised of the following:

- Task 1 - Five Year Financial Forecast and Rate Design Strategy
  - Understanding overall financial requirements and needed base rate revenue adjustments, if any
  - Developing a rate design strategy to meet identified goals and objectives
- Task 2 - Customer Class Cost of Service Analysis
- Task 3 - Rate Design and Implementation of New Restructured Rates Effective October 1, 2015
  - Considering the impact of any restructured rates to IPL customers
  - Developing new rates that address identified goals and objectives
  - Comparing IPL's current and proposed rates to comparable rates of neighboring utilities

REVIEW OF THE 2008 ELECTRIC COST OF SERVICE AND RATE PLAN

In 2008, a five-year rate plan that was developed and implemented by IPL that consisted of the following:

- An increase of revenues up to the level needed to recover costs and build the unrestricted cash fund balance.

- A revised fuel-energy cost adjustment that provided for a transition through significant changes in IPL's power supply resources and a corresponding change in IPL's cost structure (i.e., a shift from older less efficient coal-fired resources with relatively high energy and low demand cost, to a newer, fuel-efficient diverse mix of resources resulting in lower energy, but higher demand costs).
- A decision to defer rate structure changes and movement toward cost of service until a later date. At the time of the 2008 Rate Plan, it was decided not to compound the impact of five years of annual rate increases with the added impact and complexity of restructuring retail rates.

The 2008 Rate Plan accomplished the intended goals in a manner that provided predictability for IPL's base rates over the five-year period ending FY2011-12. The annual base rate revenue increases generated the revenue necessary to meet IPL's revenue requirements. Because of the revised fuel-energy cost adjustment, IPL remained whole through the power supply resource transition during the five-year rate plan period.

As noted in the 2008 Electric Cost of Service and Rate Plan, to successfully manage a municipal electric utility requires one to take on the following responsibilities:

- Maintain your assets
- Be a pro active planner – maintain big picture perspective
- Maximize resources available to you as a utility owner
- Communicate with customers, advisory boards, councils, financial community, etc.
- Establish flexible, competitive rates that provide for financial integrity and bond ordinance compliance
- Provide electric service in the lowest reasonable cost manner consistent with a highly reliable system
- Be responsible stewards of the environment

2014-2015 Rate Study Report Overview

The remainder of this Report of the Rate Study is comprised of the following:

- Section 2 – Rate Plan. This section provides the evaluation of IPL's financial position for the five year projected period FY2015-16 through FY2019-20 and provides the goals and objectives for rate design strategy and recommendations for a rate plan.

- Section 3 – Class Cost of Service Analysis. This section provides the detailed class cost of service analysis.
- Section 4 – Rate Design. This section provides a proposed rate schedule of restructured and new rates to meet IPL's revenue requirements and rate design strategy goals and objectives for implementation October 1, 2015.
- Section 5 – Bill Comparisons. This section provides a comparison of IPL's existing rates to proposed rates and neighboring utility rates.
- Section 6 – Recommendations. This section provides Sawvel's recommendations.

SECTION 2 – RATE PLAN

KEY ELEMENTS IN DEVELOPING A RATE PLAN

By developing a rate plan, the City is exercising control of its future to maintain financial integrity and a favorable credit rating. Under municipal utility ownership, the City, through IPL, is in control of, and is responsible for, each of the following items:

- Projecting existing and potential customers' electric needs in IPL's service area and calculating revenues from IPL's rates that include **recovering all power supply related costs, recovering unfunded mandated regulatory and environmental costs, and offering renewable energy options to IPL customers**
- Preparing a power supply plan that takes into consideration improvements in efficiency, the projected cost of power supply resources, and **the market value of those power supply resources including transmission** now and in the future in an environmentally responsible and cost effective manner
- Preparing a plan of infrastructure capital improvements to maintain a safe and reliable electric system and **the funding of capital improvements**
- Projecting the revenue requirements (cost of service) of the electric system, including operation and maintenance costs, capital improvements, debt service and **fund balances to meet targets**, and comparing those requirements to the revenues from IPL's rates
- Determining the timing and magnitude of future rate changes that provide compliance with City charter and bond covenant requirements and sound financial guidelines including **maintaining positive net income and cash flow**

The following paragraphs describe IPL's understanding of key elements (in **bold** type above) in developing a rate plan.

Maintaining Positive Net Income and Cash Flow

Currently, IPL's depreciation expense (a non-cash item used to calculate net income) is more than the debt service principal payments included in IPL's cash flow calculation which results in negative net income.

The City's bond indenture for IPL borrowings sets certain minimum cash flow requirements. For example, one of the requirements is that revenues available after payment of expenses to operate, maintain and repair the electric system are to exceed debt service requirements by a certain minimum amount (referred to as debt service coverage).

Projecting negative net income is generally not viewed favorably by the financial community. Negative net income is an indicator that a utility is not re-investing in its electric system and is borrowing, rather than cash funding, capital improvements and is retiring debt at a slower pace than the utility's plant is being depreciated. For these reasons, setting rates to generate positive net income and utilizing available cash to fund capital improvements is a good fiscal policy.

Developing a Fund Balance Policy and Target

It is important for IPL to have an unrestricted cash fund balance policy with a cash balance target. The financial community often considers in its rating analyses whether an unrestricted cash fund policy is in place, and the level of such fund balances. This is important in ratings provided by the credit rating agencies which have a direct impact on the cost to borrow funds.

Sawvel developed the proposed policy for establishing the unrestricted cash fund balance to be maintained for IPL. This proposed policy and the worksheet that calculates the target fund balance is provided in Appendix A.

The proposed policy addresses the methodology for calculating targeted unrestricted cash fund balances, and other policy matters such as to the actions to be taken if fund balances fall below targeted amounts. The establishment of unrestricted cash fund balance requirements is the sum of the following four factors:

- 11.0% of annual fuel and purchased power energy costs
- 12.5% of annual O&M Expenses (cash basis) less annual fuel and purchased power
- 50.0% of the sum of the current budget year and the next year's recurring routine system additions and cash funded capital improvements and expenditures
- $2,000,000 for emergency contingency reserves

As shown in the Appendix A worksheet, the targeted unrestricted cash fund balance to be maintained by IPL is proposed to be approximately $23 to $25 million. Currently, the unrestricted cash fund balance is estimated to be over $38 million at the end of FY2014-15 which includes the settlement amount reached in the RCT lawsuit in FY2013-14.

Funding Capital Improvements

As described above, the targeted unrestricted cash fund balance to be maintained by IPL is proposed to be approximately $23 to $25 million. The way to reduce the unrestricted cash fund balance to the target level is to cash fund a portion of their capital improvement program that would otherwise have been funded by debt.

Table 2-1 shows IPL's capital improvement program for the budget year FY2014-15 and the projected period FY2015-16 through FY2019-2020. This table also shows the resulting funding mechanisms from the IPL Pro Forma that will reduce the unrestricted cash fund balance to the proposed target level by year end FY2016-17. The IPL Pro Forma is discussed later in this section.

Table 2-1
Capital Improvements and Funding Mechanisms - IPL Pro Forma Summary ($000)
Independence Power & Light

Description	Fiscal Year Ending June 30						Total
	2015	2016	2017	2018	2019	2020	
Capital Improvements							
Production Plant	1,025	6,700	3,531	0	0	0	11,256
Transm & Distrib Plant	5,164	7,658	4,448	8,251	15,990	14,295	55,806
General Plant	3,871	3,036	500	150	0	0	7,557
Total	**10,060**	**17,394**	**8,479**	**8,401**	**15,990**	**14,295**	**74,619**
Funding Mechanism							
Existing Bond Funds	3,207	0	0	0	0	0	3,207
New Bond Funds	0	0	765	2,285	9,895	10,060	23,005
Schedule REC-1	88	1,450	471	0	0	0	2,009
Funded by Operations (Cash)	6,766	15,943	7,243	6,116	6,095	4,235	46,398
Total	**10,061**	**17,393**	**8,479**	**8,401**	**15,990**	**14,295**	**74,619**

Continuing to debt fund most of the projected capital projects (including deferral of principal payments) rather than utilizing available cash flows will likely increase the challenge of IPL's rates to be cost-competitive with neighboring utilities in the future.

Developing the Power Cost Adjustment Schedule PCA-1

The purpose of IPL's existing Schedule FA-1 Power Supply Fuel-Energy Cost Adjustment is to pass through to customers the difference between IPL's actual power supply costs and the power supply costs included in, or built into, the base rates. This calculation is done on a monthly basis.

Now that a restructuring of IPL's base rates is being studied, it is appropriate to design any such restructured base rates to recover the current level of power supply costs and set the cost adjustment mechanism to zero.

The proposed Power Cost Adjustment Schedule PCA-1 is designed to be a stable, predictable forward-looking adjustment factor rather than a monthly calculation. The proposed Schedule PCA-1 recovers only fuel and energy costs going forward above or below the level of fuel and energy costs included in the proposed base rates. Based on IPL's power supply cost projection, the cost base for fuel and energy costs included in the proposed base rates is $0.0236/kWh.

The methodology of the proposed Schedule PCA-1 involves the sum of the following five factors expressed in dollars:

- FOB cost of fuel used at IPL's generating stations
- Cost of purchased energy
- Less energy sales transaction revenue
- Payment in Lieu of Taxes (PILOT) adjustment
- Reconciliation of over recovery or under recovery from prior periods already adjusted for PILOT

The sum of the five factors listed above is then divided by the energy sales (kWh) to those IPL customers subject to proposed Schedule PCA-1. The cost base for fuel and energy costs already in the proposed base rates of $0.0236/kWh is then subtracted to determine the level of proposed Schedule PCA-1.

All IPL customers are subject to proposed Schedule PCA-1 except private outdoor lighting and public street lighting.

IPL shall review the proposed Schedule PCA-1 calculation and shall make projections for the periods beginning February and August. Following such proposed Schedule PCA-1 review and calculation, the Power & Light Director shall direct the proposed Schedule PCA-1 to be applied, as deemed necessary to accomplish recovery of IPL's fuel and energy related costs in a timely manner.

The proposed Schedule PCA-1 and the worksheets that calculate the level of the proposed Schedule PCA-1 revenues for the projected period FY2015-16 through FY2019-2020 are provided in Appendix C.

Developing the Regulatory and Environmental Compliance Rider Schedule REC-1

As an owner of electric generation, transmission and distribution facilities, the City may be subject to future unknown government mandates or environmental compliance costs that are not recovered through its existing rates or riders. The proposed Regulatory and Environmental Compliance Rider Schedule REC-1 provides for the recovery of such unfunded mandated governmental and environmental compliance costs.

The methodology of the proposed Schedule REC-1 involves the sum of the following three factors expressed in dollars:

- All IPL expenditures for operating, capital improvements, investments and related debt service principal and interest payments that are paid or payable to parties, other than IPL employees, which are associated with IPL's compliance with environmental and regulatory mandates that are not included or recovered through IPL's rate schedules. These expenditures shall be credited to reflect proceeds received from insurance carriers or other entities for amounts that represent reimbursement for such regulatory or environmental expenditures
- PILOT adjustment
- Reconciliation of over recovery or under recovery from prior periods already adjusted for PILOT

The sum of the three factors listed above is then divided by the number of IPL retail customer billings for the time period that are subject to proposed Schedule REC-1. This rider is calculated as a monthly charge per customer.

Current projections of regulatory and environmental costs that would apply to the proposed Schedule REC-1 are as follows:

MO City Ash Pond Closure	$1,000,000	over 3 years
MO City Plant Retirement Costs	$ 921,000	over 3 years
MO City Settling Basin	$ 608,895	over 10 years at 5%interest
Annual On-going Regulatory and Environmental Expenses	$ 230,000	escalated annually at 5%

The calculation of Schedule REC-1 shall be determined prior to the beginning of the fiscal year and applied to customer bills beginning July 1 each year. Actual costs incurred will be used for reconciliation of any over or under recovery of governmental mandates or environmental compliance costs not included in base rates.

The proposed Schedule REC-1 and the worksheet that calculates the level of proposed Schedule REC-1 revenues based on projections for the period beginning October 1, 2015 through June 30, 2016 and thereafter FY2016-17 through FY 2019-20 are provided in Appendix D. Based on these projections, the Schedule REC-1 monthly charge is estimated to initially be $0.66 per month.

Renewable Energy Options for IPL Customers

City Resolution 5933 Section 3 states:

"That the City Manager is hereby authorized and directed to develop and present to the City Council a study to evaluate potential incentives and sustainable programs which can be provided to customers for the use of renewable energy options."

The City retained Burns & McDonnell (BMcD) to prepare a preliminary report entitled "Renewable Energy Options Evaluation" dated November 25, 2014 in response to the City's Resolution 5933 Section 3. In this report, BMcD evaluated and discussed existing incentive programs for the use of renewable energy options with utility companies implementing those programs and identified five recommendations for IPL.

The five recommendations and Sawvel comments regarding these five recommendations are provided as follows:

Utility Purchased Efficiency Program: As an example, the LED Buy-Down Program offered by CPS Energy discussed in this Study, provides benefits to both the utility and customers with no long term contracts or obligations between entities. In this program, the utility buys equipment in bulk at a reduced price and directly sells the material to customers interested in purchasing. However, these programs are generally used to reduce load which is the revenue source of the utility. In the instance of the LED Program, assuming the 200,000 LED lights are installed, they provide a load reduction of approximately 9,900 kW per hour of operation. The revenue lost from this program is approximately $1,300 for every hour all light bulbs are used (assuming a cost per kWh of $0.13).

Sawvel Comment: This recommendation would be considered and implemented by IPL and will not be part of the rate design study.

Community Solar Program: A Community Solar Program provides customers the opportunity to purchase energy from solar without impacting the structure of their houses and without the utility financing the development of a potentially costly project. This program allows the projects to be financed through a power purchase agreement (PPA) with the developer and passes the cost directly to the customers participating in the program. This program also provides the benefit of having one interconnection location compared to sporadic rooftop residential solar which allows utilities to better manage the stability of inconsistencies with the solar energy produced.

Additionally, this program is becoming widely popular with other utilities in Missouri as well as Austin Energy and CPS Energy which have both stated they are currently developing these programs.

Sawvel Comment: As of the date of this report, IPL staff was still finalizing a PPA and other technical aspects for potential project development and had not made a recommendation to the City Manager and City Council for their ultimate approval to move forward with a solar farm. Nevertheless, this Rate Study provides a proposed Community Solar Rider that could be used as a model if the City moves forward with the solar farm. The proposed Community Solar Rider is discussed later in this report.

Energy Efficiency Loan Program: Although IPL currently has an Energy Efficiency Loan Program (HELP), BMcD recommends further review and potentially refining the program based upon the recommendations provided by Columbia Water & Light (CW&L). From CW&L's experience with their program, BMcD recommended that IPL include enough protection to the utility in case the customer does not pay the loan. One example is to incorporate a clause in the loan agreement which gives the utility the authority to turn off the power to the customer if the customer does not pay the loan.

Sawvel Comment: This recommendation would be considered and implemented by IPL and will not be part of the rate design study.

Program Marketing: From communications with several utilities, the most common challenge in implementing their programs was marketing. Most utilities recommended increasing marketing efforts to better promote and make customers aware of what programs are available to them and increase participation. Therefore, it is recommended that IPL look at ways to increase marketing efforts related to their existing programs plus any new programs that are put in place.

Sawvel Comment: This recommendation would be considered and implemented by IPL and will not be part of the rate design study.

Rate Review: It is recommended that IPL review their current rate structure to eliminate or reduce any rate subsidization issues. Deploying programs prior to a rate structure review could result in program costs being subsidized by customers not participating in programs.

Sawvel Comment: This recommendation is considered as part of the rate design goals and objectives for the Rate Study and is discussed later in this report.

Southwest Power Pool (SPP) Transmission Revenues

On April 8, 2015, the City signed the Southwest Power Pool (SPP) Membership Agreement as a "transmission-owner" member. As a transmission owner member, the City designated its transmission facilities to the SPP for operation and administrative control. In addition, the City executed SPP's Network Integration Transmission Service (NITS) agreement whereby the City would begin taking NITS service beginning on June 1, 2015 replacing the City's current point-to-point transmission service arrangements.

Under this new structure, the City will pay for transmission service for all of the energy requirements of IPL customers (including any energy that is produced by IPL generation). This service will be provided under the NITS agreement which is Attachment F of the SPP Tariff.

In return for turning over functional control of IPL transmission facilities to SPP, SPP will pay the City for use of the transmission system by the City and by other entities utilizing the SPP transmission system which now would include the City's facilities. The amount of revenue received is based on the City's cost to own, maintain and operate the transmission system (i.e., revenue requirements). An engineering consulting firm (NewGen Strategies & Solutions) was hired by IPL to calculate the annual transmission system revenue requirements and they have estimated it to be approximately $7.2 million. If this figure is approved after a formal review process, the City would receive $7.2 million in revenues from SPP.

On April 13, 2015, SPP submitted to the Federal Energy Regulatory Commission (FERC) tariff revisions to implement a stated annual transmission revenue requirement for the City to be included in KCPL's pricing zone under the Tariff and requested an effective date of June 1, 2015.

FERC, who regulates the transmission and wholesale sales of electricity in interstate commerce, will need to approve the membership change and the revenue requirement calculation. The FERC process will provide a forum where other entities (other SPP members) can comment on and contest the filing. Therefore, the resulting revenues and costs of these changes will be determined through the FERC approval process.

IPL PRO FORMA WITH RATE INCREASES

IPL developed the IPL Pro Forma internally which provides historical information, budget year fiscal year (ending June 30) FY2014-15, and a five year projected period FY2015-16 through FY2019-20 of IPL's revenues and revenue requirements. The Pro Forma also includes a cash flow analysis and a net income statement.

Table 2-2 shows the historical operating results for the period FY2010-11through FY2013-14. These operating results for IPL show total revenues, total revenue requirements, the ending operating fund balance, cash flow analysis, net income statement results, and total customer sales in GWh (thousands of MWh).

Table 2-2
Historical Operating Results -IPL Pro Forma Summary ($000)
Independence Power & Light

Description	Fiscal Year Ending June 30			
	2011	**2012**	**2013**	**2014**
Revenue from Base Rates	106,811	111,334	111,534	110,581
Revenue from FA-1	14,757	24,472	21,623	23,953
Other	6,809	5,563	6,324	13,250
Total Revenues	**128,377**	**141,369**	**139,481**	**147,784**
Power Supply Expenses	65,655	70,742	65,090	67,347
Other O&M Expenses	33,285	36,290	33,757	38,080
Debt Service	5,699	7,065	10,071	10,853
Recurring Routine Adds & Replace	8,723	2,651	3,972	6,385
Major Cap Impr - Cash Funded	0	0	0	2,026
Other	12,404	13,146	13,392	13,368
Total Revenue Requirements	**125,766**	**129,894**	**126,282**	**138,059**
Balance - Net Cash Flow	**2,611**	**11,475**	**13,199**	**9,725**
Ending Operating Fund Balance	**8,877**	**20,352**	**33,551**	**43,276**
Major Cap Impr - Debt Funded	549	47,736	20,000	0
Net Income	**(617)**	**1,807**	**(2,821)**	**339**
Customer Sales GWh	1,090	1,069	1,044	1,030

Some important items to note from the information in Table 2-2 are as follows:

- Customer sales in GWh slightly decreased during the period
- Total revenues (including Schedule FA-1 revenues and the RCT settlement amount shown in FY2013-14) increased at a greater rate than total revenue requirements (including power supply expenses) during the period causing the ending operating fund balance to increase throughout the period
- Net income was positive in some years and negative in other years
- Cash flow was positive in all years

Since October 2014, Sawvel and IPL have discussed and reviewed the assumptions used in developing the IPL Pro Forma based on the key elements in developing a rate plan as described earlier in this section. Based on the review of IPL's financial position, it was determined that the proposed restructured rates, when fully implemented, could result in a $3 million annual reduction of revenues from commercial and industrial customers. As described later n this report, this revenue reduction is consistent with the cost of service analysis and would position IPL's higher load factor customers to be more competitive with neighboring utility rates. It was also determined that the proposed restructured customer charges for the residential and general service customers could be phased in to mitigate the impact to low use customers of replacing the minimum charge with a customer charge. This phase in would result in $4.1 million reduction in residential and general service revenues in FY 2015-16 and a $0.8 million reduction in residential and general service revenues in FY 2016-17.

Table 2-3 shows the projected operating results from the IPL Pro Forma for the period FY2014-15 through FY2019-20. These operating results for IPL show total revenues, total revenue requirements, the ending operating fund balance, cash flow analysis, net income statement results, and total customer sales in GWh as well as future overall base rate revenue increases.

Table 2-3
Projected Operating Results - IPL Pro Forma Summary with Projected Rate Increases ($000)
Independence Power & Light

Description	Fiscal Year Ending June 30					
	2015	**2016**	**2017**	**2018**	**2019**	**2020**
Revenue from Base Rates	106,383	131,115	134,166	138,691	143,905	149,536
Revenue from FA-1 / PCA-1	27,146	0	1,164	2,760	3,407	3,952
Revenue from REC-1	0	340	1,057	1,070	1,084	394
Other	4,430	12,270	12,378	12,490	12,606	12,729
Total Revenues	**137,959**	**143,725**	**148,765**	**155,011**	**161,002**	**166,611**
Power Supply Expenses	65,460	64,476	65,710	66,142	67,578	69,498
Other O&M Expenses	40,576	43,710	48,606	51,292	54,260	57,324
Debt Service	8,925	8,924	8,983	9,163	9,972	11,695
Recurring Routine Adds & Replace	7,227	7,000	7,210	7,426	7,649	7,879
Major Cap Impr - Cash Funded	6,854	17,393	7,714	6,116	6,095	4,235
Other	13,371	13,800	14,283	14,871	15,447	15,980
Total Revenue Requirements	**142,413**	**155,303**	**152,506**	**155,010**	**161,001**	**166,611**
Balance - Net Cash Flow	**(4,454)**	**(11,578)**	**(3,741)**	**1**	**1**	**0**
Ending Operating Fund Balance	**38,819**	**27,241**	**23,500**	**23,501**	**23,502**	**23,502**
Major Cap Impr - Debt Funded	0	0	765	2,285	9,895	10,060
Net Income	**(10,726)**	**(6,403)**	**(3,088)**	**(1,052)**	**(1,002)**	**218**
Customer Sales GWh	1,089	1,055	1,059	1,062	1,065	1,069
Projected Base Rate Increase		0.0%	0.0%	3.3%	3.3%	3.3%

Some important items to note from the information in Table 2-3 are as follows:

- Customer sales in GWh slightly decreasing from FY 2014-2015 to FY 2015-16 then slightly increasing beginning in FY2015-16 throughout the projected period.
- Base rate increases that are projected to be needed are shown.
- Total revenues increased at a lesser rate than total revenue requirements (including power supply expenses and cash funding major capital improvements) during the period FY 2014-15 through FY 2016-17. As a result, the ending operating fund balance decreased to the target level of $23 million by year end FY 2016-17. Thereafter, revenues are adjusted when needed to maintain the ending operating fund balance at the target level throughout the projected period.
- Net income is projected to become positive by FY2019-20.
- Cash flow is projected to become positive by FY2019-20.

The IPL Pro Forma includes the following detail:

- Load forecast of energy sales to IPL customers
- Revenues from sales to IPL customers assuming restructured base rates and estimated base rate revenue increases when needed
- Schedule PCA-1 revenues that recover fuel and energy costs not included in the assumed restructured base rates
- Schedule REC-1 revenues that recover the costs of unfunded mandated regulatory and environmental costs identified by IPL not included in the assumed restructured rates or Schedule PCA-1
- Other revenues including Wholesale Interchange revenue and Wholesale Border Customer revenue
- Power supply dispatch costs developed by IPL and based on the load forecast of energy sales to IPL customers plus losses and unaccounted for energy
- Other operating and maintenance expenses including non-fuel operating and maintenance, transmission (less wheeling), distribution, customer account, customer information, and administrative and general
- Payroll, PILOT and property taxes
- Depreciation expense
- Debt service
- Bond rate covenant requirements calculation for meeting the minimum of 1.10

- No inventory adjustments are included in the IPL Pro Forma. At this time, IPL does not know of any inventory adjustments for the projected period FY2015-16 through FY2019-20
- Capital Improvement Program by project
- Electric Fund balance target

From Sawvel's experience, and our observations and analyses of the information provided by IPL, the IPL Pro Forma projections provide a reasonable basis for development of the electric rate plan. The key elements of the IPL Pro Forma are listed below.

- Development of Schedule PCA-1 to recover projected fuel and energy costs not included in base rates and setting the adjustment to zero beginning October 1, 2015.
- Addition of Schedule REC-1 beginning October 1, 2015 to recover the unfunded mandated environmental and regulatory costs identified by IPL not included in base rates or Schedule PCA-1.
- Addition of SPP Transmission Service Revenues of $7.237 million annually beginning October 1, 2015.
- Reduction of revenues from base rates by approximately $7.9 million for the 12 months from October 1, 2015 through September 30, 2016 and $3 million annually thereafter.
- Achievement of the unrestricted cash fund policy target of $23.5 million by the end of FY2016-17.
- Funding of capital improvements with unrestricted cash rather than debt throughout the projected period FY2015-16 through FY 2019-20.
- Achievement of positive net income and positive cash flow by the end of FY2017-18.Projected base rate revenue increases of 3.3% beginning October 1 in 2017, 2018 and 2019, respectively

The summary tables from the IPL Pro Forma are shown in Appendix G.

GOALS AND OBJECTIVES FOR IPL'S RATE DESIGN STRATEGY

Based on discussions between IPL and Sawvel, the goals and objectives for IPL's rate design strategy are:

- Move rates toward cost of service
- Reduce subsidization by high load factor customers to move toward rate competitiveness

- Eliminate the requirement for end use provisions to receive incentive rates
- Consolidate rate schedules whenever appropriate
- Make rate structure changes by replacing minimums with customer charges and reducing the number of block rates
- Develop seasonal rates for all rate classes that provide incentives for increased winter usage.
- Develop and restructure rates to become more rate competitive with the neighboring utilities of Kansas City Power & Light, Kansas City Power & Light – GMO, and the Board of Public Utilities – Kansas City, Kansas
- Develop Schedule PCA-1 Power Cost Adjustment incorporating the following:
    - Develop a stable, predictable forward-looking adjustment factor rather than a monthly calculation
    - Remove recovery of purchase power demand cost and transmission charges
    - Reset the base cost to the current level of power supply fuel and energy cost and set the adjustment factor to zero
    - Provide for a review the Schedule PCA-1 calculation and make projections for the periods beginning February and August.
- Develop Schedule REC -1 Regulatory and Environmental Compliance Rider to recover regulatory and environmental costs not included in IPL's base rates or Schedule PCA-1 that are difficult to predict and not in control of IPL.
- Develop a partial requirements rate and related agreements for customers that may choose to install on-site generation to supply a portion of the customer's electricity requirements
- Develop a community solar tariff

IPL'S RATE PLAN

IPL's rate plan was developed based on the key elements in developing a rate plan, the IPL Pro Forma and the goals and objectives for a rate design strategy as discussed above. The rate plan is comprised of the following two-phase approach:

- Phase 1 - Develop new rates and rate structures based on IPL's goals and objectives for a rate design strategy to become effective October 1, 2015.

- Phase 2 - Adjust base rate revenues to generate a positive net income. Based on the IPL Pro Forma, three (3) annual 3.3% per year overall revenue increases beginning October 1, 2017, 2018 and 2019, respectively, are needed to generate a positive net income by the end of the projected period.

At this time, there is a level of uncertainty regarding the amount of base rate revenue increases needed to generate a positive net income. Therefore, it is recommended that IPL defer the second phase of the rate plan at this time. These uncertainties are comprised of the following:

- The net amount of IPL's transmission-related revenues and expenses to be realized when implemented and finalized by SPP and FERC
- Depreciation rates used for IPL
- Major capital improvements including transmission and substation projects based on projected load growth
- Restructuring existing debt

The following paragraphs provide further discussion of these uncertainties and what IPL can do to mitigate their impact on the IPL Rate Plan:

Southwest Power Pool (SPP) Transmission

The net revenue to be realized by IPL as a transmission owner in SPP is uncertain until the FERC acts on the filing. The outcome could have significant impact on the rate plan's future revenue adjustments.

Depreciation Study

Depreciation expense is a non-cash expense item that is used in determining net income. The depreciation rates used by IPL to determine depreciation expense have not been reviewed or updated for some time. We recommend that IPL conduct a depreciation study to determine the appropriate depreciation rates and expenses that should now be applicable to IPL's plant in service. It is important for purposes of determining net income that the appropriate depreciation rates and depreciation expenses are being used.

Capital Improvements and Load Growth

The lack of load growth in recent years is having a negative impact on achieving positive net income especially under the current IPL rate structure which is heavily based on energy use charges. Restructuring the rates to include a customer charge and demand charges and reducing reliance on energy usage charges will mitigate the negative impact on achieving positive net income.

Rate restructuring will also help for future load growth by positioning IPL with rates that are more competitive with neighboring utilities than the current rate structure. Also, the addition of restructured rates that incentivizes high load factor loads will assist with attracting customers to locate or expand facilities in the IPL service area.

Regarding the funding of future capital improvements, a reasonable target for IPL's debt equity ratio should be 60% debt and 40% equity. Reductions in future capital improvements will allow for funding a greater portion of capital improvements from cash and reduce borrowings.

Debt Restructuring

The structuring of IPL's principal and interest payments does not line up with the IPL Pro Forma projections or IPL's net income statement. IPL requested the City's Finance Department to investigate possible opportunities for the cost effective restructuring of IPL's debt. It was determined that the earliest call date on the electric system debt is the year 2020. Much of this debt is advance refundable with tax-exempt debt, meaning the City could issue tax-exempt bonds to put money in escrow today to pay interest on the bonds until the call date, and call the bonds at the call date. However, the negative arbitrage on that escrow overwhelms any savings that lower interest rates would generate, causing present value savings on all three outstanding electric system bond issues to be negative. Therefore, it doesn't appear that restructuring the debt can occur for several more years.

SAWVEL COMMENTS AND RECOMMENDATIONS

Based on the IPL Pro Forma and the rate design goals and objectives described in this section of the report, Sawvel makes the following recommendations:

1. Restructure rates in the manner described above to be effective October 1, 2015 through October 1, 2016 that results in a $7.9 million reduction in revenues for the 12 month period from October 1, 2015 through September 30, 2016 and $3 million annual reduction in revenues thereafter as set forth in Appendix F.

2. Implement the proposed Power Cost Adjustment Schedule PCA-1 and Regulatory and Environmental Compliance Schedule REC-1 described above as set forth in Appendix F and detailed in Appendices C and D.

3. Implement the Unrestricted Cash Fund Balance Policy as set forth in Appendix A.

4. Defer implementation of additional base rate revenue increases at this time pending the completion of the following:
    a. Final FERC determination of net SPP Transmission revenues and expenses to be realized by IPL
    b. Review of IPL's depreciation rates and implementation of any changes to these depreciation rates and IPL's depreciation expenses
    c. Finalize major capital improvements including transmission and substation projects based on projected load growth

After completion of the above, IPL should update its Pro Forma and revise the rate plan as needed to ensure the unrestricted cash fund policy is being met in the future and to generate positive net income.

SECTION 3 - CLASS COST OF SERVICE ANALYSIS

INTRODUCTION

A class cost of service study is an analytical process of assigning a proportionate share of the cost of owning, operating and maintaining an electric utility system to the classes of customers it serves. IPL provides full-requirements electric service to residential, non-residential and lighting customers under a number of electric rate schedules. Customer classes used for cost of service analysis are summarized in Table 3-1.

Table 3-1
Customer Classes for Cost of Service
Fiscal Year 2014
Independence Power & Light

Customer Class	Number Of Customers	Energy Sales (MWh)	Current Rate Revenue ($)
Residential	51,342	518,923	72,394,233
General Service	3,233	36,964	5,950,211
Large General Service	1,828	416,431	50,120,198
Large Power	5	51,429	4,726,777
Total Excluding Lighting/Signals	**56,409**	**1,023,746**	**133,191,419**

Class cost of service studies are used for the following purposes:

- To allocate costs to different classes of customers based on how each customer group causes costs to be incurred.
- To determine how costs will be recovered from customers within each customer class.
- To calculate the costs of different types of services provided to different types of customers.
- To provide information to utility management to evaluate costs and incentive programs by customer class.

A cost of service analysis is prepared for a specific test period, usually one year, and is referred to as the "test year". The class cost of service analysis involves development of the utility's revenue requirements for the test year and defining the customer groups for which the utility's cost of serving is to be calculated. Test year revenue requirements are allocated to various customer groups in a fashion that reflects the cost of providing service to each customer group. The cost allocation process consists of three major parts: functionalization of costs, classification of costs, and allocation of costs among customer groups. Upon completion of the cost allocation process, results of the cost of service analysis are summarized and the cost of serving each customer group is compared with test year revenues from each customer group.

The spreadsheet model used for the cost of service analysis is included as Appendix B.

TEST YEAR SELECTION AND PRO FORMA ADJUSTMENTS

Generally, electric rates are designed for a number of years and are typically developed using the most current actual or projected cost and sales information for a selected time period. The test period used for cost of service analysis is normally 12 months in length and is referred to as the test year. Normally the test year includes projected cost and sales data for the time rates are likely to remain in effect.

Test Year FY2014

The most current actual costs and sales information available was FY2014 (July 2013 through June 2014) from the IPL Pro Forma. Therefore, FY2014 was selected as the test year for cost of service analysis. However, several capital improvement project expenditures and cost increases are projected to occur after FY2014. As a result, pro forma adjustments of actual FY2014 test year revenues and expenditures are necessary for such test year FY2014 costs to be representative of projected costs through FY2019.

Pro Forma Adjustments (Revenue Requirements)

Pro forma adjustments were made to actual FY2014 revenue requirements to recognize certain decreases in debt service, and adjustments to reflect future capital improvements and Miscellaneous Other Revenue. Test year pro forma adjustments are shown in Table COS-10 in Appendix B. Pro forma adjustments were made to revenue requirements so that there was a decrease in total rate revenue of $3,000,000 from FY2014 to Cost of Service rate revenue.

Pro Forma Adjustments (FY2014 Retail Revenue)

Pro forma adjustments were made to actual FY2014 customer retail revenue to recognize certain rate changes and economic development credits that began during or after the conclusion of FY2014. The first adjustment was a decrease in revenue from the new EDU-1 and EDUAL rate classes to reflect the new rate schedule for those customers identified as schools that went into effect after FY2014. The second adjustment was to reflect a full fiscal year of economic development rider discount (Schedule EDR-5) for a large customer that is expected to take advantage of such rider.

COST ALLOCATION PROCESS

Once test year selections for the cost of service analysis have been designated, revenue requirements are allocated to each customer class to reflect the cost of providing service to that customer class. The three steps of the cost allocation process are functionalization, classification and allocation of revenue requirements. Each step of the cost allocation process is described below.

Functionalization

Functionalization is the process whereby costs incurred by the utility to provide service are categorized by service function. Service functions are power supply, transmission, distribution, customer service and facilities, and miscellaneous. The power supply function includes costs associated with power generation and purchased power. The transmission function includes costs associated with bulk power delivery from points of interconnection with other utilities and with internal power supply resources to the distribution system. Costs associated with delivery of power to customers, except those served from the IPL transmission system, are included in the distribution function. Meter reading and customer service functions such as billing and accounting are included in the customer service and facilities function.

IPL accounting reports record some costs by the function for which they were incurred. Thus, some costs used in the cost of service analysis were already grouped by service function. However, other costs are recorded as joint costs or common costs that relate to more than one service function. Joint costs occur when provision of one service function is a byproduct of another service function. Common costs are incurred for support and management of the utility system, such as administrative and general expenses, insurance, etc., and are common to a number of service functions. These joint and common costs cannot be directly assigned to a particular service function and must be distributed among service functions on a basis that best reflects cost causation principles. The basis for assignment of joint and common costs in the cost of service analysis included use of labor and wage ratios (for assignment of joint or common labor-related costs), plant ratios, or by detailed analysis of particular costs to determine cost-causation or mutually beneficial relationships.

Classification

The next step in the cost allocation procedure is classification of functionalized costs. The classification process recognizes that costs are incurred for a number of purposes: to meet customer peak demands (demand-related costs), to provide energy (energy-related costs), and connecting and billing customers (customer-related costs). The classification process groups costs by the purpose for which they were incurred. Details of the functionalization and classification of test year FY2014 costs are provided in Tables COS-1, COS-2, COS-3, COS-4 and COS-5 in Appendix B.

Cost-causative characteristics of each of the above functionalized and classified cost components are described below.

Power Supply – IPL acquires and dispatches generation and purchased power resources to meet customer demand and energy needs. Energy-related costs such as fuel, purchased power energy charges and variable expenses of municipal generating facilities vary with customer energy (kWh) sales. These energy-related costs are assigned to customer classes in the cost of service analysis on the basis of test year energy sales. Power supply demand-related costs are incurred to meet the maximum load (referred to as coincident peak demand) of all customers. Electric System power supply resources are described in the Power Supply Resources section of this report.

Transmission – Transmission facilities move power to distribution system load centers and are designed to meet the coincident peak demand imposed on power supply resources. Accordingly, functionalized transmission line and transmission interconnection substation costs are classified as demand-related costs.

Distribution – Distribution facilities deliver power from 161 kV and 69 kV transmission substations to customer service locations in the IPL service area. The distribution system facilities required are primarily a function of the voltage level of service (i.e., primary vs. secondary), and the size and number of customers. Distribution facilities, from both an operational and planning perspective, are constructed to meet localized area loads and customers. Localized area load is used to size distribution equipment at primary and secondary service levels to meet customer maximum demands, referred to as non-coincident peak demand.

Further classification of voltage level (primary vs. secondary) distribution costs into demand and customer components was made using the minimum size method. This method assumes the distribution system can be built to serve the minimum loading requirement of the customers. The minimum size method involves determining the minimum transformer and conductor size currently installed by the utility. The minimum size method classifies costs associated with these facilities as customer-related because such facilities would be installed by IPL to stand ready to provide electricity, even if the customer doesn't use any power or energy. All costs of distribution facilities installed in excess of the minimum size are to serve non-coincident customer peak demands and are therefore classified as demand-related.

Services and Meters – The costs of installing, operating and maintaining customer services and meters are classified as customer-related costs. Services include costs of overhead and underground conductors leading from the distribution system last pole or manhole to the point of connection with the customer's wiring. Meter costs include demand, energy and reactive metering equipment.

Billing and Accounting – Billing and accounting costs include the cost of reading meters, preparing customer billings, managing customer accounts and related reporting. This function also includes the cost of providing information, advertising and promotion of IPL services. The cost of this service function is classified as customer-related.

Allocation of Revenue Requirements

Allocation factors are used to allocate functionalized and classified costs to each customer class in the cost of service analysis. Allocation factors for each cost component were developed based on energy sales by customer class, kW-demand (coincident peak demand and non-coincident peak demand) by customer class, number of customers and direct assignment. The development of allocation factors is described below. Allocation factors by customer class are applied to cost components to determine the cost of serving each customer class. Details of the allocation of test year FY2014 costs are provided in Table COS-6 in Appendix B.

DEVELOPMENT OF ALLOCATION FACTORS

The cost of service analysis allocates costs to each customer class based on its particular requirements for service. Each functionalized and classified cost component described above is allocated to the customer classes in a different manner. The development of each of the energy, demand and customer allocation categories is described below.

Energy

Energy-related costs are allocated to each customer class based on kWh-energy of each class. Metered energy usage is the basis for the information. Development of the energy allocation factor takes into account the difference in losses incurred for service at different voltage levels as shown in Table 3-2.

Table 3-2
Energy Sales, Losses and Requirement (MWh)
Fiscal Year 2014
Independence Power & Light

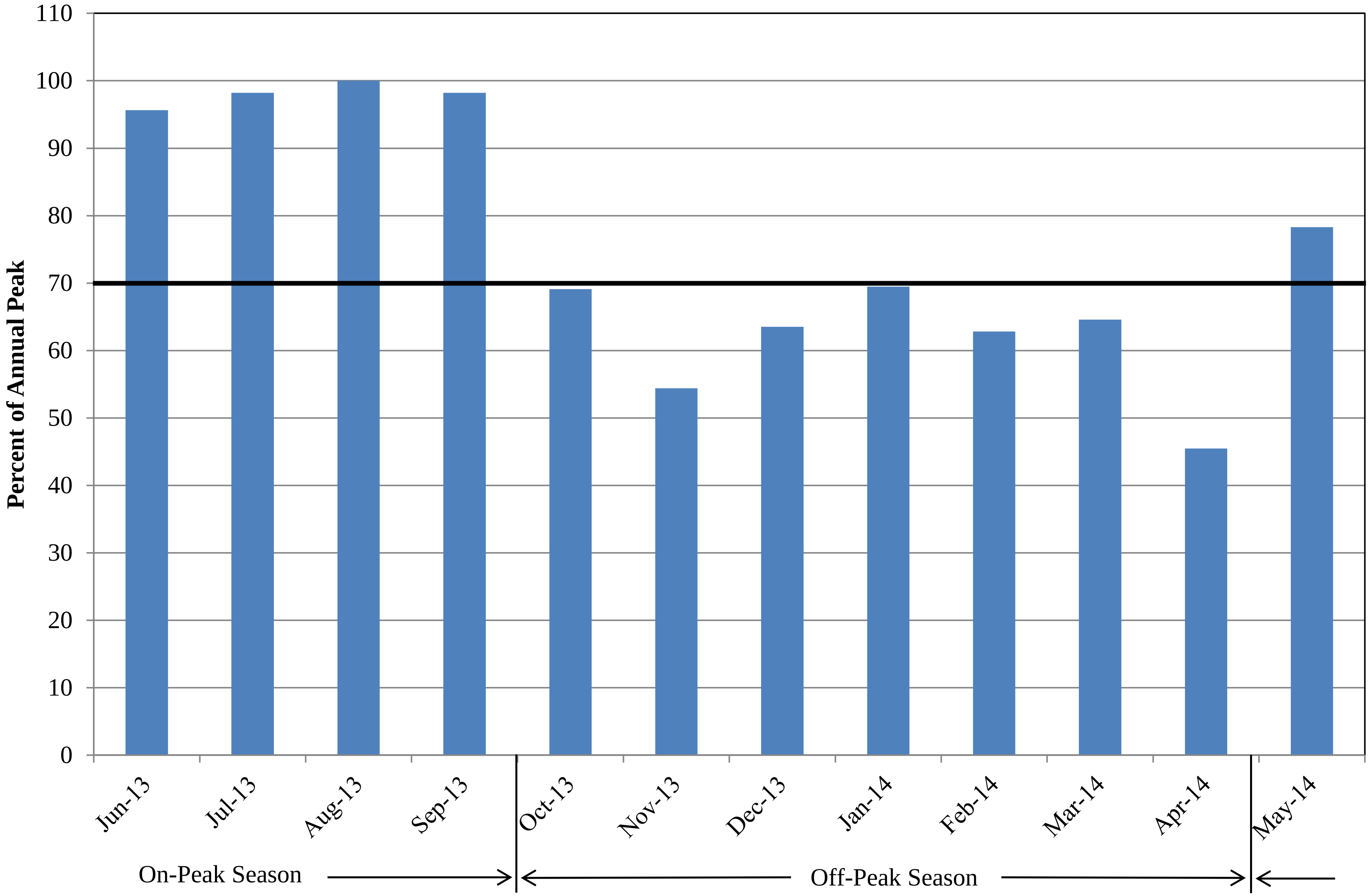
Customer Class	Metered Energy Sales	Losses	Energy Requirement at Source	(%)
Residential	518,923	23,717	542,640	50.7
General Service	36,964	1,689	38,653	3.6
Large General Service	416,431	18,850	435,281	40.7
Large Power	51,429	1,296	52,725	4.9
Total Excluding Lighting/Signals	**1,023,746**	**45,553**	**1,069,299**	**100.0**

Coincident Peak Demand

IPL is a summer-peaking utility. Therefore, to meet coincident peak demands during peak hours of the summer months, IPL has acquired power supply resources and installed transmission facilities designed to meet the summer coincident peak demands of its customers for power supply and transmission service functions.

Graph 3-1 illustrates monthly coincident peak demands for the test year. As shown by Graph 3-1, the May through September coincident peak demands are within approximately 70 percent of the annual maximum electric system coincident peak demand. The development of a coincident peak demand allocation factor for each customer class is based on that customer class' contribution to coincident peak demand during the 5-month period May through September. The use of this coincident peak demand allocation methodology, referred to as 5-CP, links cost incurrence and the cost causer for allocation of demand related costs of power supply and transmission service functions.

Graph 3-1
IPL Monthly Coincident Peak Demand



Development of the coincident peak demand allocation factor for each customer class using the 5-CP methodology is summarized in Table 3-3. The coincident peak demand of each customer class was determined by first determining the non-coincident peak demand of each customer class. An analysis was conducted to estimate the diversity between each customer class' non-coincident peak and its contribution to the coincident peak demand. The relationship between each customer class' non-coincident peak demand and its coincident peak demand is referred to as its coincident factor. The coincident factor of each customer class was estimated by Sawvel using a range of information.

For residential, Sawvel obtained simulated residential hourly load information representative of the Kansas City area from the Open Energy Information website (en.openei.org) that was developed using the Building America House Simulation Protocols developed by the U.S. Department of Energy National Renewable Energy Laboratory. This hourly load profile was used to determine the percent of residential non-coincident peak demand that occurs during the five IPL summer coincident peaks. These results were verified by consulting a neighboring utility regarding the load factors of their residential customers and comparing to the simulated results.

For Large General Service and Total Electric General Service, Sawvel used the actual 5 CP coincidence factors of those IPL Large General Service and Total Electric General Service customers that hourly demand data was provided by IPL. Sawvel analyzed the hourly metered load data for those customers to develop estimates for the rest of the class. Sawvel used monthly non-coincident peak demands for Education, Churches and Hospitals adjusted by their corresponding Bary Curve factors to estimate their 5 CP coincident demands. Actual hourly demands for all of the Large Power customers were obtained from IPL and used to determine their actual 5 CP coincident demands.

Non-Coincident Peak Demand

Table 3-3 provides non-coincident and coincident peak demands of each customer class used in the cost of service analysis.

Table 3-3
Coincident and Non-Coincident Peak Demands (kW)
Fiscal Year 2014
Independence Power & Light

Rate Class	Non-Coincident Demand	(%)	5-Month Average Coincident Demand[1]	(%)
Residential	179,884	55.8	143,167	55.9
General Service	18,532	5.7	12,402	4.8
Large General Service	114,674	35.5	94,217	36.8
Large Power	9,507	2.9	6,412	2.5
Total Excluding Lighting/Signals	**322,596**	**100.0**	**256,199**	**100.0**

[1] May through September.

Residential non-coincident peak demands were estimated using load factors of 33.61% and 38.61% for general use and space heating residential customers, respectively. General Service non-coincident peak demands were estimated assuming 200 hours of monthly use representative of 8 hours of weekday operation resulting in a load factor of 27.4%. LGS-1, LGSSH-1, EDU-1, EDU-AE, CH-1, CH-AE, LGSPV, TEGS, LP-2 and SCISF non-coincident peak demands were estimated using actual FY2014 billing data. Sewer Pumping (SP-1) non-coincident peak demand was estimated using a load factor of 21.5%.

Customer

Allocation of customer-related cost is based on number of customers by class of service with weighting factors. Weighting factors reflect differences in characteristics between customer classes and are used to give cost causative recognition for such differences. Weighting factors utilized to derive customer allocation factors are summarized in Table 3-4.

Table 3-4

Customer Cost Allocation Factors
Fiscal Year 2014
(%)
Independence Power & Light

Customer Class	Meters	Services	Billing & Accounting
Residential	75.56	75.56	75.56
General Service	10.46	10.46	10.46
Large General Service	13.72	13.72	13.72
Large Power	0.26	0.26	0.26
Total Excluding Lighting/Signals	**100.00**	**100.00**	**100.00**

SUMMARY OF COST OF SERVICE RESULTS

Cost of service analysis results are provided in Table COS-7 in Appendix B. This table shows the cost to serve each customer class including customer, demand and energy components in dollars and unit costs. A comparison of revenue under existing rates and cost of service rates is presented in Table COS-8 in Appendix B.

Table 3-5 summarizes the revenue distribution by rate class at current rates with the cost of service results for each rate class. A comparison of existing rates to cost of service rates is provided in Table COS-9 in Appendix B. The Test Year FY 2014 revenue requirements with a $3,000,000 rate decrease are provided in Table COS-10 in Appendix B.

Table 3-5
Comparison of Revenue Distribution ($)
Existing Rates vs Cost of Service
Adjusted Test Year 2014
Independence Power & Light

Rate Class	Existing Rate Revenue	Cost of Service	Difference ($)	Difference (%)
Residential	72,394,233	75,229,696	2,835,463	3.9
General Service	5,950,211	7,114,798	1,164,588	19.6
Large General Service	50,120,198	44,369,272	(5,750,926)	(11.5)
Large Power	4,726,777	3,477,653	(1,249,124)	(26.4)
Total Excluding Lighting/Signals	**133,191,419**	**130,191,419**	**(3,000,000)**	**(2.3)**

The following can be observed from Table 3-5 regarding existing rate class revenue:

1. Revenues from the Residential class are less than cost of service.
2. Revenues from the General Service class are less than cost of service.
3. Revenues from the Large General Service class are more than cost of service.
4. Revenues from the Large Power class are more than cost of service.

LIGHTING CUSTOMERS

Sawvel performed a cost analysis of IPL street lighting using data provided by IPL. The provided data included the following:

1. Total Cost (Varies by Light/Pole Type)
2. Energy Use (Varies by Light)
3. Estimated Lifespan (40 years)
4. Operation and Maintenance Costs ($10 per light per year)

The estimated annual fixed cost of each light type was calculated by amortizing the total cost over 40 years using a 5 percent rate of return. The result was added to the annual operation and maintenance cost and then divided by 12 to get a monthly facilities charge. The monthly energy cost was determined using the Schedule LP-1 energy rate of $0.0385/kWh grossed up for 2 percent distribution system losses for an energy rate of $0.0393/kWh. The cost analysis for LED

Public Street Lighting for each rate code is shown in Table 3-6. The analysis indicated monthly rates ranging between $1.71 to $24.54 per month depending on the type of street light fixture.

Using the results of the cost analysis and the number of LED street lights would result in an annual cost of approximately $491,000 and is sufficient to collect the estimated annual cost of owning, operating and maintaining the LED street lights on the IPL system.

IPL is in the process of selecting and finalizing the private outdoor lighting LED options. Thus, a cost analysis was not performed for LED private outdoor lighting and no changes were made on the existing private outdoor lighting rate schedule.

Table 3-6
LED Street Lighting Cost Analysis
Independence Power & Light

Rate Analysis	FR-1	FR-2	B-1	B-2	B-3	B-4	B-5	B-6	B-7	B-8	B-9	B-10	B-11	B-12	B-13	B-14	B-15	B-16	C-1	C-2	C-3
Expected Life	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Rate of Return	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%
Levelized Return	3.328%	3.328%	3.328%	3.328%	3.328%	3.328%	3.328%	3.328%	3.328%	3.328%	3.328%	3.328%	3.328%	3.328%	3.328%	3.328%	3.328%	3.328%	3.328%	3.328%	3.328%
O&M	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Equipment																					
Pole			487.16	487.16	487.16	487.16	509.00	509.00	509.00	509.00	1,489.70	1,489.70	1,690.62	1,690.62	616.00	616.00	509.00	1,489.70	0.00	275.54	487.16
Mastarms			50.93	56.47	101.86	112.94	165.00	165.00	330.00	330.00	308.03	308.03	616.06	616.06	158.00	79.00	165.00	308.03	50.93	50.93	50.93
Breakaway Base				166.79		166.79		166.79		166.79		289.00		289.00							0.00
Foundation			205.01	205.01	205.01	205.01	205.01	205.01	205.01	205.01	205.01	205.01	205.01	205.01	205.01	205.01	205.01	205.01			205.01
Luminaires											674.00	674.00	1,348.00	1,348.00	904.00	452.00		674.00			0.00
Lamps	345.83	345.83	345.83	345.83	345.83	345.83	345.83	345.83	345.83	345.83	274.00	274.00	274.00	274.00	254.00	254.00	345.83	274.00	345.83	345.83	345.83
Total Cost	345.83	345.83	1,088.93	1,261.26	1,139.86	1,317.73	1,224.84	1,391.63	1,389.84	1,556.63	2,950.74	3,239.74	4,133.69	4,422.69	2,137.01	1,606.01	1,224.84	2,950.74	396.76	672.30	1,088.93
Department Financed ($/mo.)																					
O&M			10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Depreciation			27.22	31.53	28.50	32.94	30.62	34.79	34.75	38.92	73.77	80.99	103.34	110.57	53.43	40.15	30.62	73.77	9.92	16.81	27.22
Return			36.24	41.97	37.93	43.85	40.76	46.31	46.25	51.80	98.20	107.81	137.56	147.18	71.12	53.45	40.76	98.20	13.20	22.37	36.24
Subtotal			73.46	83.50	76.43	86.79	81.38	91.10	91.00	100.72	181.97	198.80	250.90	267.75	134.55	103.60	81.38	181.97	33.12	49.18	73.46
PILOT			7.34	8.34	7.63	8.67	8.13	9.10	9.09	10.06	18.17	19.85	25.06	26.74	13.44	10.35	8.13	18.17	3.31	4.91	7.34
Total Cost			80.80	91.84	84.06	95.46	89.51	100.20	100.09	110.78	200.14	218.65	275.96	294.49	147.99	113.95	89.51	200.14	36.43	54.09	80.80
Dept. Fin. Monthly Rate ($/mo.)			**6.73**	**7.65**	**7.01**	**7.96**	**7.46**	**8.35**	**8.34**	**9.23**	**16.68**	**18.22**	**23.00**	**24.54**	**12.33**	**9.50**	**7.46**	**16.68**	**3.04**	**4.51**	**6.73**
Customer Financed ($/mo.)																					
O&M	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Depreciation	8.65	8.65	27.22	31.53	28.50	32.94	30.62	34.79	34.75	38.92	73.77	80.99	103.34	110.57	53.43	40.15	30.62	73.77	9.92	16.81	27.22
Return	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	18.65	18.65	37.22	41.53	38.50	42.94	40.62	44.79	44.75	48.92	83.77	90.99	113.34	120.57	63.43	50.15	40.62	83.77	19.92	26.81	37.22
PILOT	1.86	1.86	3.72	4.15	3.84	4.29	4.06	4.47	4.47	4.89	8.37	9.09	11.32	12.04	6.33	5.01	4.06	8.37	1.99	2.68	3.72
Total Cost	20.51	20.51	40.94	45.68	42.34	47.23	44.68	49.26	49.22	53.81	92.14	100.08	124.66	132.61	69.76	55.16	44.68	92.14	21.91	29.49	40.94
Cust. Fin. Monthly Rate ($/mo.)	**1.71**	**1.71**	**3.41**	**3.81**	**3.53**	**3.94**	**3.72**	**4.11**	**4.10**	**4.48**	**7.68**	**8.34**	**10.39**	**11.05**	**5.81**	**4.60**	**3.72**	**7.68**	**1.83**	**2.46**	**3.41**

SECTION 4 - RATE DESIGN

IPL serves approximately 56,510 metered customers under 21 rate schedule customer designations. In addition, IPL has rate schedules for City traffic signals, private outdoor lighting service and public street lighting service. IPL's current rate structures for its customer classes are dated and no longer consistent with that of its neighboring utilities. Several of these customer designations were developed in the past to promote various types of end use (i.e. electric water heaters, electric space heating equipment, etc.). This can result, however, in similar types of service being provided to consumers at different rates unless monitored and verified by IPL for facilities and equipment installed and used behind the meter.

Another characteristic of IPL current base rates is that the rate schedules contain numerous energy and demand blocks. The current base rates also do not have separate customer charges, but instead have various minimum bill provisions and higher initial rate block prices to represent built-in customer charges. The current trend in the electric industry is to use monthly customer charges in rate schedules and to reduce the number of rate blocks within each rate schedule.

The purpose of the customer charge rate component is to collect the customer-related costs of providing electric service. The utility incurs cost to customers even for those that use little to no electricity and a customer charge provides the mechanism to collect these costs from customer. A consultant recently retained by the City to conduct an evaluation of potential renewable energy options and programs recommended IPL review the current rate structure to eliminate or reduce rate subsidization issues before deploying any renewable energy programs. For example, a customer charge reduces the subsidization of solar PV customers by customers not participating in such a program because of the solar PV customers' reduced electricity usage from IPL. Customer related costs are currently recovered through electricity usage charges; under the proposed restructured rates, a customer charge will be implemented to recover IPL's customer related costs from all customers regardless of electricity usage.

Customer-related costs are those costs that vary based on the number and type of customers served by the electric system. These costs typically include the following:

1. A portion of the utility's Distribution System Operation and Maintenance Costs.
2. The cost of connecting the customer to the utility's distribution system, and the cost of installing metering equipment to measure the customer's electricity usage.
3. The cost associated with the customer meter reading, billing and accounting functions, and the administrative of the rates, collection of payments, etc.

Customer-related distribution costs include a portion of the operating and maintenance cost of distributing power at primary (13 kV) and secondary (below 4 kV) voltages to customers such as poles, transformers and tree trimming. Metering costs include the installation and maintenance cost of meters and the monthly labor cost to read customer meters. Customer-related billing and accounting costs include costs associated with the monthly preparation and processing of customer bills and utility revenue accounting.

The cost of service analysis quantified IPL's customer related costs for each of the customer classes. For example, analysis indicated a cost of service customer charge for the residential rate class of $23.96 per month. The recommended residential customer charge is $14.50 per month, or 60% of IPL's residential customer related costs. The difference between IPL's cost of $23.96 and the recommended rate of $14.50 per month is essentially rolled into, and recovered from, the residential energy charge. As discussed later, it is recommended the proposed residential customer charge be phased-in to lessen the customer bill impact for lower energy use residential customers while moving towards cost of service based rates. The comparison of the recommended IPL customer charge is compared with the customer charges of neighboring utilities in tables described later in this report.

GOALS AND OBJECTIVES FOR IPL'S RATE DESIGN STRATEGY

Based on discussions between IPL and Sawvel, the following goals and objectives were established for IPL's rate design strategy:

- Move rates toward cost of service
- Reduce subsidization by high load factor customers to move toward rate competitiveness
- Eliminate the requirement for end use provisions to receive incentive rates
- Consolidate rate schedules whenever appropriate
- Make rate structure changes by replacing minimums with customer charges and reducing the number of block rates
- Develop seasonal rates for all rate classes that provide incentives for increased winter usage
- Develop and restructure rates to become more rate competitive with the neighboring utilities of Kansas City Power & Light, Kansas City Power & Light – GMO, and the Board of Public Utilities – Kansas City, Kansas
- Develop a high load factor rate for large customers

- Develop a partial requirements rate and related agreements for customers that may choose to install on-site generation to supply a portion of the customer's electricity requirements
- Develop a community solar tariff
- Develop Schedule REC -1 Regulatory and Environmental Compliance Rider to recover regulatory and environmental costs not included in IPL's base rates or Schedule PCA-1 that are difficult to predict and not in control of IPL
- Develop Schedule PCA-1 Power Cost Adjustment incorporating the following:
    - Develop a stable, predictable forward-looking adjustment factor rather than a monthly calculation
    - Remove recovery of purchase power demand cost and transmission charges
    - Reset the base cost to the current level of power supply fuel and energy cost and set the adjustment factor to zero
    - Provide for a review the Schedule PCA-1 calculation and make projections for the periods beginning February and August

Table 4-1 and Table 4-2 provide a summary of the proposed consolidation of the existing rate schedules.

Table 4-1
Proposed Consolidation of Existing Schedule of Rates by Rate Code
Independence Power & Light

Existing Schedule of Rates and Customer Classifications	Schedule Designation	Average No. of Customers [1]	Residential: Standard	Residential: Discount For Electric Heat [Grand-fathered]	General Service: Standard, Add Seasonal Rates	General Service: Discount For Churches and Hospitals	Large General Service: Standard, Add Seasonal Rates	Large General Service: Discounts For Schools	Large General Service: Discounts For Total Electric [Grand-Fathered]	Large General Service: Discounts For Primary Service	Large Power: Standard	Large Power: Adjustments For Secondary Service	Large Power: Adjustments For Transmission Service	Space Heating: GS Electric Heat [FROZEN]	Space Heating: LGS Electric Heat [FROZEN]	Special Contract Interruptible [FROZEN]
Residential																
Residential Service - Standard	RS-3	43,408	RS-3													
Residential Electric Water Heating	RSWH	857	RSWH													
Residential Electric Space Heating	RSSH	1,987	RSSH	RSSH												
Residential Electric Space-Heating & Water Heating	RSSHW	108	RSSHW	RSSHW												
Residential All Electric Home Service	RS-4	4,983	RS-4	RS-4												
Commercial & Industrial																
General Service																
General Service - Standard	GS-1	3,009			GS-1											
General Service Electric Space Heating [2]	GSSH-1	10												GSSH-1		
Churches, and Hospitals	CH-1	210			CH-1	CH-1										
Churches, and Hospitals All Electric	CHAL	4			CHAL	CHAL										
Large General Service																
Large General Service	LGS-1	1,618					LGS-1									
Large General Service Electric Space Heating [2]	LGSSH	15													LGSSH	
Large General Service Primary Voltage	LGSPV	6					LGSPV			LGSPV						
Schools	EDU-1	67					EDU-1	EDU-1								
Schools All Electric	EDUAL	7					EDUAL	EDUAL								
Sewer Pumping	SP-1	6					SP-1									
Total Electric General Service	TEGS	110					TEGS									
Large Power																
Large Power Service	LP-2	3									LP-2					
Large Power Service - Secondary Voltage		0									LPSVS	LPSVS				
Large Power Service - Transmission Voltage	LPTVS	0									LPTVS		LPTVS			
Special Contract Large Interruptible Industrial Service	SCIS-1	0														SCIS-1
Combined, Interruptible & Firm	SCISF	2														SCISF
Lighting																
City Traffic Signals	TRS-2	64														
Private Outdoor Lighting Service	PL-3	1,718														
Public Street Lighting Service [3]	PSL-2FR PSL-3CF PSL-3DF LED	12,045														
Adders and Riders																
Power Supply Fuel-Energy Cost Adjustment	FA-1	Revised														
Economic Development Rider	EDR-5	Unchanged														
Regulatory and Environmental Compliance Rider	REC-1	New														
Customer-Generator Net Metering Contract Service Rider	NM-1	Unchanged														

[1] Test year July 2013 through June 2014.
[2] Separately metered space heating use only applied during seven month winter season.
[3] Number of lamp fixtures.

Table 4-2
Proposed Consolidation of Existing Schedule of Rates by Number of Customers
Independence Power & Light

			Residential		General Service		Large General Service				Large Power			Space Heating		
				Discount For		Discount For		Discounts For				Adjustments For		GS	LGS	
Existing Schedule of Rates and Customer Classifications	Schedule Designation	Average No. of Customers (1)	Standard	Electric Heat [Grand-fathered]	Standard, Add Seasonal Rates	Churches and Hospitals	Standard, Add Seasonal Rates	Schools	Total Electric [Grand-Fathered]	Primary Service	Standard	Secondary Service	Transmission Service	Electric Heat [FROZEN]	Electric Heat [FROZEN]	Special Contract Interruptible [FROZEN]
Residential																
Residential Service - Standard	RS-3	43,408	43,408													
Residential Electric Water Heating	RSWH	857	857													
Residential Electric Space Heating	RSSH	1,987	1,987	1,987												
Residential Electric Space-Heating & Water Heating	RSSHW	108	108	108												
Residential All Electric Home Service	RS-4	4,983	4,983	4,983												
Commercial & Industrial																
General Service																
General Service - Standard	GS-1	3,009			3,009											
General Service Electric Space Heating (2)	GSSH-1	10												10		
Churches, and Hospitals	CH-1	210			210	210										
Churches, and Hospitals All Electric	CHAL	4			4	4										
Large General Service																
Large General Service	LGS-1	1,618					1,618									
Large General Service Electric Space Heating (2)	LGSSH	15													15	
Large General Service Primary Voltage	LGSPV	6					6			6						
Schools	EDU-1	67					67	67								
Schools All Electric	EDUAL	7					7	7								
Sewer Pumping	SP-1	6					6									
Total Electric General Service	TEGS	110					110		110							
Large Power																
Large Power Service	LP-2	3									3					
Large Power Service - Secondary Voltage		0									0	0				
Large Power Service - Transmission Voltage	LPTVS	0									0		0			
Special Contract Large Interruptible Industrial Service	SCIS-1	0														0
Combined, Interruptible & Firm	SCISF	2														2
Lighting																
City Traffic Signals	TRS-2	64														
Private Outdoor Lighting Service	PL-3	1,718														
Public Street Lighting Service (3)	PSL-2FR PSL-3CF PSL-3DF LED	12,045														
Adders and Riders																
Power Supply Fuel-Energy Cost Adjustment	FA-1	Revised														
Economic Development Rider	EDR-5	Unchanged														
Regulatory and Environmental Compliance Rider	REC-1	New														
Customer-Generator Net Metering Contract Service Rider	NM-1	Unchanged														

(1) Test year July 2013 through June 2014.
(2) Separately metered space heating use only applied during seven month winter season.
(3) Number of lamp fixtures.

PROPOSED SCHEDULE OF RATES

The proposed Schedule of Rates is provided in Appendix G.

As of October 1, 2016, the recommended proposed restructured schedule of rates would reduce revenues by approximately $3 million per year (2.3%) and will impact the revenue from each rate class. Table 4-3 summarizes the revenue distribution by rate class at current rates with the recommended revenue by rate class using rates effective October 1, 2016.

Table 4-3
Comparison of Revenue Distribution ($)
Existing Rates vs Proposed Restructured Rates
Adjusted Test Year 2014
Independence Power & Light

Rate Class	Existing Rate Revenue(1)	Proposed Revenue	Difference ($)	Difference (%)
Residential	73,576,524	73,974,611	398,087	0.5
General Service	6,060,329	6,399,955	339,626	5.6
Large General Service	50,849,669	47,483,258	(3,366,411)	(6.6)
Large Power	5,327,618	4,879,985	(447,633)	(8.4)
Total Excluding Lighting/Signals	**135,814,140**	**132,737,809**	**(3,076,331)**	**(2.3)**

(1) Adjusted to reflect March 2014 through February 2015 average FCA.

Sawvel developed a recommended proposed restructured schedule of rates to be effective October 1, 2015 that includes a phase in of the customer charge to residential and general service customers through October 1, 2016. If implemented, the recommended proposed restructured schedule of rates would reduce retail revenues by approximately $7.9 million ($4.9 million for the phase-in of customer charges plus the $3 million as described in Table 4-3) for the 12 months from October 1, 2015 through September 30, 2016. Table 4-4 provides the Revenue Reduction for Phase-In of Residential and General Service Customer Charges.

Table 4-4
Revenue Reduction for Phase In of Residential and General Service Customer Charges ($)
Independence Power & Light

Description	FY 2015 - 2016 October 1, 2015 - April 30, 2016	FY 2015 - 2016 May 1, 2016 - June 30, 2016	FY 2015 - 2016 Subtotal	FY 2016 - 2017 July 1, 2016 - September 30, 2016	Total
Residential Revenue Reduction	3,414,243	513,420	3,927,663	770,130	4,697,793
General Service Revenue Reduction	135,786	19,398	155,184	29,097	184,281
Total Revenue Reduction	3,550,029	532,818	4,082,847	799,227	4,882,074

The following paragraphs provide a description of the proposed restructured Schedule of Rates:

Residential

IPL's current residential rate tariffs consist of five different rate applications depending on the customer's electrical equipment:

- Standard Residential (RS-3) for those customers that have no qualifying electrical space heating or electrical water heating equipment.
- Residential with Water Heating (RSWH) for those customers that have qualifying electrical water heating.
- Residential with Space Heating (RSSH) for those customers that have qualifying electrical space heating equipment.
- Residential with Water Heating and Space Heating (RSSHW) for those customers that have both qualifying electrical water heating and space heating.
- All Electric Residential (RS-4) for those customers that have all electrical equipment for all needs and have no natural gas service to their facility.

The proposed Residential rate schedule consolidates these five existing residential rate codes (RS-3, RSWH, RSSH, RSSHW, RS-4) into two new rates: RS-1 (General Use) and RSSH-1 (grandfathered space heating). Those existing customers that have qualifying electric space heating equipment currently being billed under the RSSH, RSSHW or RS-4 rate codes will receive a discounted rate to minimize the rate impact of the new proposed rates. The space heating rate is not available to new customers or new service locations. The proposed RS-1 rate schedule was developed so as to continue to encourage electric space heating. The energy rate blocks were simplified from ten (3 on-peak, 7 off-peak) to four (1 on-peak, 3 off-peak).

In addition, a customer charge of $14.50 per month is recommended to replace the existing minimum bill provision. As previously discussed, customer charges are needed for recovery of IPL's fixed costs to serve customers and to prevent customer subsidization issues, especially with customers that have installed behind the meter generation. To lessen the impact of full implementation of the $14.50 monthly customer charge, especially on low usage residential customers, it is recommended that the monthly customer charge be phased in as follows:

October 1, 2015	$5.00
May 1, 2016	$9.50
October 1, 2016	$14.50

General Service

IPL's current general service rate tariffs consist of:

- General Service (GS-1)
- Churches and Hospitals (CH-1)
- Churches and Hospitals – All Electric (CH-AL)

The proposed new rate tariff consolidates these three rate codes under one rate tariff, General Service (GS-1). To recognize that churches are normally weekend, off-peak users and to continue prior practice, the energy rate for all kWh for churches and hospitals was discounted. The energy rate blocks were simplified from five (non-seasonal) to three (1 on-peak, 2 off-peak) blocks with implementation of seasonal rates.

In addition, a customer charge of $16.00 per month is recommended to replace the existing minimum bill provision. To lessen the impact of full implementation of the $16.00 monthly customer charge, especially on low usage general service customers, it is recommended that the monthly customer charge be phased in as follows:

October 1, 2015	$10.00
May 1, 2016	$13.00
October 1, 2016	$16.00

Large General Service

IPL's current large general service rate classes consist of:

- Large General Service (LGS-1)
- Large General Service – Primary Voltage (LGSPV)
- Total Electric General Service (TEGS)

- Schools (EDU-1)
- All Electric Schools (EDU-AL)
- Sewer Pumping (SP-1)

The proposed Large General Service rate schedule is a consolidation of these existing rate codes. The proposed LGS-1 rate schedule also includes a customer charge of $50.00 per month and the three demand blocks were simplified into one on-peak and one off-peak. The existing customers currently being billed under TEGS and EDU-1 and EDU-AL will be grandfathered on the new LGS-1 rate schedule with a discount to minimize rate impact on these customers.

Large Power

The proposed Large Power rate schedule is a consolidation of the existing LP-2 (Large Power) and SCIS-1 (Special Contract Large Industrial) rate schedules. This schedule includes a customer charge of $500.00 per month and consolidates eight energy blocks and three demand blocks into one energy block and one demand block. One of the rate design goals is to incentivize high load factor loads. To accomplish that goal, this schedule was designed with a low energy charge and high demand charge in an effort to favor high load factor customers and attract new large power high load factor customers.

General Service Space Heating (Frozen GSSH-1)

The existing GSSH-1 (General Service Space Heating) rate schedule requires customers to have a separate meter to measure the heating load in their facility. In consideration that these customers made an initial investment in electrical design and wiring to have this separate meter, this rate schedule is proposed to be frozen. This schedule will not be available to new customers or new service locations. If an existing GSSH-1 service location changes customers, the new customer would be served under the appropriate GS-1 or LGS-1 rate schedule.

Large Power (Frozen LP-2)

The existing LP-2 (Large Power) rate schedule was frozen to allow existing LP-2 customers (currently there are 3 customers are on the LP-2 rate) the option of remaining on the LP-2 rates to take advantage of the current Economic Development Rider (Schedule EDR-5). The existing LP-2 energy rates were increased to reflect the amount of power supply costs that were rolled into proposed base rates under the new Power Cost Adjustment Rider described below. This schedule will not be available to new customers or new service locations and customers that move to the proposed LP-1 rate will not be able to return to the LP-2 rate.

Special Contract Large Interruptible Industrial (Frozen SCIS-1)

The existing SCIS-1 (Special Contract Large Interruptible Industrial) rate schedule was frozen to allow existing SCIS-1 customers (currently there are 2 customers on the SCIS-1 rate) the option of remaining on the SCIS-1 rates and to take advantage of the Economic Development Rider. The existing SCIS-1 energy rates were increased to reflect the amount of power supply costs that were rolled into proposed base rates. This schedule will not be available to new customers or new service locations and customers that move to the proposed LP-1 rate will not be able to return to the SCIS-1 rate.

Power Cost Adjustment Schedule PCA-1

The purpose of IPL's existing Schedule FA-1 Power Supply Fuel-Energy Cost Adjustment is to pass through to customers the difference between IPL's actual power supply costs and the power supply costs included in, or built into, the base rates. This calculation is done on a monthly basis. Now that a restructuring of IPL's base rates is being studied, it is appropriate to design any such restructured base rates to recover the current level of power supply costs and set the cost adjustment mechanism to zero.

The proposed Power Cost Adjustment Schedule PCA-1 is designed to be a stable, predictable forward-looking adjustment factor rather than a monthly calculation. The proposed Schedule PCA-1 recovers only fuel and energy costs going forward above or below the level of fuel and energy costs included in the proposed base rates. Based on IPL's power supply cost projection, the cost base for fuel and energy costs included in the proposed base rates is $0.0236/kWh.

IPL shall review the proposed Schedule PCA-1 calculation and shall make projections for the periods beginning February and August. Following such proposed Schedule PCA-1 review and calculation, the Power & Light Director shall direct the proposed Schedule PCA-1 to be applied, as deemed necessary to accomplish recovery of IPL's fuel and energy related costs in a timely manner.

Regulatory and Environmental Compliance Rider Schedule REC-1

As an owner of electric generation, transmission and distribution facilities, the City may be subject to future government mandates or environmental compliance costs that are not recovered through its existing rates or riders. The proposed Regulatory and Environmental Compliance Rider Schedule REC-1 provides for the recovery of such unfunded mandated governmental and environmental compliance costs.

The calculation of Schedule REC-1 shall be determined prior to the beginning of the fiscal year and applied to customer bills beginning July 1 each year. Actual costs incurred will be used for reconciliation of any over or under recovery of governmental mandates or environmental compliance costs not included in base rates. The Schedule REC-1 monthly charge is estimated to initially be $0.66 per month.

Community Solar

A Community Solar Program provides customers the opportunity to purchase energy from solar without impacting the structure of their houses and without the utility financing the development of a potentially costly project. This program allows the projects to be financed through a power purchase agreement (PPA) with the developer and passes the cost directly to the customers participating in the program.

As of the date of this report, IPL staff was still finalizing a PPA and other technical aspects for potential project development and had not made a recommendation to the City Manager and City Council for their ultimate approval to move forward with a solar farm. Nevertheless, Sawvel has developed a Community Solar Rider that could be used as a model if the City moves forward with the solar farm.

Sawvel reviewed several community solar programs of other utilities and recommends a rider similar to the City of Springfield, Missouri. The proposed Community Solar Rider provides the option for customers to purchase from a utility scale solar farm in 1 kW blocks and receive solar Renewable Energy Credits applicable to their share of the output of the solar farm. The customer would pay an additional charge per kWh of allocated solar farm output in addition to the charges for service under the applicable IPL electric rate schedule. The charge for solar farm output is reflective of the difference in cost of the solar farm output and the IPL total system power supply costs included in proposed base rates. The charge will adjust coincident with the Power Cost Adjustment Rider. As IPL's total system power supply costs increase, the solar charge would decrease and vice versa. This prevents other customers who choose not to buy solar from subsidizing the customers that do. The customers who buy from the solar farm benefit from the economies of scale of a utility scale solar farm.

PARTIAL REQUIREMENTS RATE

Sawvel developed a Partial Requirements Rate, and related Partial Requirements Electric Service Agreement and Interconnection Agreement, for customers that install generation behind the meter on their site. The purpose of the Partial Requirements Rate is to recover IPL's cost of serving such customers, and that other customers do not subsidize the Partial Requirements customers.

Customers with on-site generation will look to the City to provide that portion of their electric service requirements that is not provided by the customer's on-site generation (i.e., partial requirements service rather than full requirements service). Specifically, partial requirements service to a customer with on-site generation will consist of the following services provided by the City's electric utility:

- Partial Requirements Service – to supplement the electricity generated by the customer's on-site generation to supply the balance of electricity needed by the customer to meet its total requirements. The customer specifies, by agreement, the "up-to" amount of Partial Requirements Service it desires from the utility while the customer's on-site generation is operational.
- Back-Up Services – to back-up the customer's on-site generation when the customer's generation is experiencing a full or partial outage. Some outages are planned, such as for maintenance, and other outages are unscheduled, often caused by equipment failure. Back-Up Services are two-fold. The first involves the amount of capability the customer desires from the utility to "stand-by" to back-up the customer's generation in the event of a full or partial outage of the customer's on-site generation. The customer specifies, by agreement, the amount of Back-Up Service stand-by capability it desires from the utility. The second is the provision of back-up service during an outage.
- Excess Power – for electricity provided by the utility that is in excess of the amount of Partial Requirements Service, and Back-Up Service that the customer has contracted for, by agreement, with the utility.

Each of these partial requirements services are explained below as well as the basis for the charges to be developed for each of these services.

As indicated above, a customer with on-site generation will be required to specify a contract demand for the amount of Partial Requirements Service, and a contract demand for the amount of Back-Up Service to be provided by the utility. Also, the customer will need to execute an Interconnection Agreement that sets forth the standards and requirements by the customer while installing and operating its on-site generation in order to not adversely affect the safe and reliable operation of the City's electric system.

The Partial Requirements Rate Schedule, and the associated Partial Requirements Service Agreement and Interconnection Agreement, will not be required of, or applicable to, customers with on-site generation that is used only for emergency purposes during utility outages. Customers with on-site emergency generation purchase all of their power and energy requirements from the utility except during electric system outages. Customers with on-site emergency generation are considered full-requirements customers rather than partial requirements customers.

Partial Requirements Service

Partial Requirements Service is the electricity provided to the customer that is in addition to its self-generation, and is needed to cover the balance of the customer's total electricity requirements not provided by its on-site generation. The customer will contract for a specific up-to amount of Partial Requirements Power that the City agrees to have available for delivery to the customer as Partial Requirements Service. The basis for the Partial Requirements Power demand rate will be the comparable large customer demand rate derived from the Appendix B cost of service analysis.

Back-Up Service

Back-Up Service is electric service used to back-up the customer's on-site generating facility during outages of the customer's on-site generation. Under the Partial Requirements Electric Service Agreement, the customer can contract for a specific amount of Back-Up Power Service, not to exceed the output capability of the customer's on-site generation, that the City agrees to have available for delivery. The customer's electricity demand usage, that exceeds its Partial Requirements Power contract demand, will be billed as Back-Up Power, up to the Back-Up Power contract demand.

Billing for Back-Up Service is comprised of two charges:

- Back-Up Facilities Charge – a monthly charge applied to the Back-Up contract demand
- Daily Back-Up Power Charge – applied to the highest 30-minute demand of Back-Up Service provided each day

Back-Up Service charges were derived from the Large Power cost of service results. The Back-Up Facilities Charge represents the transmission component of the cost of service demand rate, plus 15% of demand-related power supply component of the cost of service demand rate. The 15% of demand-related power supply component is representative of the City's power supply planning reserve margin, and is used to reasonably approximate costs associated with the City's electric system backing up the customer's on-site generating facility. Planning reserve margins are necessary to account for regional planning reserve requirements, load forecast errors, and other resource planning uncertainties.

The Daily Back-Up Power Charge is calculated as a per day demand rate and is developed to capture the difference between the Partial Requirements Power Charge and the Back-Up Facilities Charge (other than during scheduled maintenance periods as discussed below). In order to arrive at the Daily Back-Up Power Charge, an analysis was performed of the Large Power customers' daily demands during the test year and compared to the Large Power customers' monthly peak demands for the same period. The results of the analysis were used to develop the

Daily Back-Up Power Charge to recover the full monthly difference between the Partial Requirements Power Charge and the Back-Up Facilities Charge.

By using the industry-accepted partial requirements rate-making approach described above, the Partial Requirements Rate Schedule results in charges that will recover the full cost of service if the customer did not self-generate. In other words, the combination of Back-Up Facilities Charges and the Daily Back-Up Power Charges will equal the Large Power cost of service demand rates.

Maintenance Power Service

Maintenance Power Service is electric service during periods when the customer's generating facility is not operating because of scheduled maintenance to the customer's generating equipment. Under the new Partial Requirements Rate Schedule, the customer will submit a proposed maintenance schedule to the City. The customer's maintenance schedule will be submitted by September of each year. The Partial Requirements Electric Service Agreement will provide for coordination of maintenance scheduling through an Operating Committee provided for in the Agreement.

The customer will submit a maintenance schedule for the 18-month period beginning January 1 of the following year. The City will provide Maintenance Power during scheduled maintenance periods, not to exceed the customer's Back-Up Power contract demand, for a maximum of 30 days per calendar year. The customer can receive Maintenance Power during scheduled maintenance periods of one continuous 30-day period or two continuous 15-day periods. Should circumstances warrant, the City may cancel a scheduled maintenance outage with seven days' notice prior to the start of a customer's scheduled maintenance outage.

The Daily Maintenance Power Charge is a daily demand rate applied to the maximum 30-minute demand during schedule maintenance periods. The Daily Maintenance Power Charge is one-half of the Daily Back-Up Power Charge

Excess Power Service

Excess Power Service is power supplied by the City to serve the customer's electricity needs that exceed the levels of the customer's contract demands for Partial Requirements Power and Back-Up Power. The Excess Power Charge is two times the Partial Requirements Power demand charge.

Table 4-5 provides a summary of the Partial Requirements service charges based on cost of service results.

Table 4-5
Partial Requirements Service Charges
Independence Power & Light

Description	Basis For Charge	COS Rate
Customer Service Charge ($/month)	Large Power Customer Service Charge	634.75
Partial Requirements Rate ($/kW-month)	Large Power Demand Charge	18.97
Back-Up Facilities Charge ($/kW-month) applied to Back-Up Power contracted for demand	Demand Related Costs (IPL distribution, substations, transmission and interconnections plus 15% power supply)	4.07
Daily Back-Up Power Charge ($/kW-day)	Difference between Partial Requirements Power Charge and Back-Up Facilities Charge	0.64
Excess Power Charge ($/kW-month)	Twice the Partial Requirements Power Charge	37.94
Partial Requirements & Back-Up Energy Charge ($/kWh)	Large Power Energy Charge	0.02729
Daily Maintenance Service Charge ($/kW-day)	One-half of Daily Back-Up Power Charge	0.32

The Partial Requirements Service Agreement and Interconnection Agreement are provided in Appendix E.

SECTION 5 – BILL COMPARISONS

Bill comparisons were prepared for each rate class to compare bills using proposed rates to the proposed or estimated rates of neighboring utilities. The neighboring utilities included Kansas City Power and Light (KCPL), Kansas City Power and Light - Greater Missouri Operations (GMO or Old Aquila), and Kansas City, Kansas Board of Public Utilities (BPU). Tables 5-1 through 5-10 show the bill comparisons by season, if applicable, for each Sawvel proposed restructured rate schedule. All neighboring utility rates in the following tables are based on rates proposed or estimated. Kansas City Power and Light has filed for a rate increase of 15.9% that, if approved, could go into effect as soon as September 30, 2015. A financial rating agency has reported BPU's rates are estimated to increase 5% in 2015 and 2016. GMO – Old Aquila is expected to make a rate filing in early 2016. KCPL's proposed 15.9% increase was used for purposes of estimating GMO – Old Aquila's rates.

Residential

Table 5-1 shows the results of comparing the phased in proposed restructured rates for IPL to IPL's existing rates for a typical use residential customer using 1,100 kWh per month during the on-peak (summer) season and 700 kWh per month during the off peak season (winter). Table 5-2 shows the results of comparing the phased in proposed restructured rates for IPL to IPL existing rates for a low use residential customer using 400 kWh per month during the on-peak (summer) season and 400 kWh per month during the off peak season (winter).

Tables 5-3 and 5-4 show the results of comparing the completely phased in proposed restructured rates for IPL to the proposed or estimated future rates for IPL's neighboring utilities for both the typical use residential customer and the low use residential customer.

General Service

Table 5-5 shows the results of comparing the phased in proposed restructured rates for IPL to IPL's existing rates for a typical use general service customer using 800 kWh per month during the on-peak (summer) season and 800 kWh per month during the off peak season (winter).

Table 5-6 shows the results of comparing the completely phased in proposed restructured rates for IPL to the proposed or estimated future rates for IPL's neighboring utilities for the typical use general service customer.

Table 5-1

Residential Rate Monthly Bill Comparison - IPL Existing vs IPL Proposed Restructured - Typical Use Customer

	Winter 700 kWh	Summer 1,100 kWh
IPL Existing (1)		
Energy Charge	$95.32	$167.58

	700 kWh Winter effective Oct 1 2015	1,100 kWh Summer effective May 1 2016	700 kWh Winter effective Oct 1 2016	1,100 kWh Summer effective May 1 2017	Difference from IPL Existing: Winter effective Oct 1 2015	Summer effective May 1 2016	Winter effective Oct 1 2016	Summer effective May 1 2017
IPL Proposed Restructured								
Customer Charge	$5.00	$9.50	$14.50	$14.50				
Energy Charge	$86.80	$154.00	$86.80	$154.00	-8.9%	-8.1%	-8.9%	-8.1%
Schedule REC	$0.66	$0.66	$0.66	$0.66				
Total	$92.46	$164.16	$101.96	$169.16	-3.0%	-2.0%	7.0%	0.9%
Difference IPL Proposed Restructured less Existing	($2.86)	($3.42)	$6.64	$1.58				

(1) IPL currently has a minimum charge with no usage of $4.14.

Table 5-2
Residential Rate Monthly Bill Comparison - IPL Existing vs IPL Proposed Restructured - Low Use Customer

	Winter 400 kWh	Summer 400 kWh
IPL Existing (1)		
Energy Charge	$52.45	$62.75

	400 kWh Winter effective Oct 1 2015	400 kWh Summer effective May 1 2016	400 kWh Winter effective Oct 1 2016	700 kWh Summer effective May 1 2017	Difference from IPL Existing Winter effective Oct 1 2015	Summer effective May 1 2016	Winter effective Oct 1 2016	Summer effective May 1 2017
IPL Proposed Restructured								
Customer Charge	$5.00	$9.50	$14.50	$14.50				
Energy Charge	$53.20	$56.00	$53.20	$56.00	1.4%	-10.8%	1.4%	-10.8%
Schedule REC	$0.66	$0.66	$0.66	$0.66				
Total	$58.86	$66.16	$68.36	$71.16	12.2%	5.4%	30.3%	13.4%
Difference IPL Proposed Restructured less Existing	$6.41	$3.41	$15.91	$8.41				

(1) IPL currently has a minimum charge with no usage of $4.14.

Table 5-3
Residential Rate Comparison - IPL Proposed Restructured vs Neighboring Utilities Estimated Future (Customer Charge $14.50/month effective October 1, 2016) - Typical Use Customer

	Summer 1,100 kWh	Winter 700 kWh	Difference from IPL Proposed Restructured Summer	Difference from IPL Proposed Restructured Winter
IPL Proposed Restructured				
Customer Charge	$14.50	$14.50		
Energy Charge	$154.00	$86.80		
Schedule REC	$0.66	$0.66		
Total	$169.16	$101.96		
KCPL Proposed (1)				
Customer Charge	$25.00	$25.00	72.4%	72.4%
Energy Charge	160.55	84.78	4.3%	-2.3%
Environmental Charges				
Total	$185.55	$109.78	9.7%	7.7%
Difference IPL Proposed Restructured less KCPL	($16.39)	($7.82)		
Old Aquila Estimated (2)				
Customer Charge	$12.09	$12.09	-16.6%	-16.6%
Energy Charge	170.31	102.54	10.6%	18.1%
Environmental Charges				
Total	$182.40	$114.63	7.8%	12.4%
Difference IPL Proposed Restructured less Old Aquila	($13.24)	($12.67)		
KCK BPU Estimated (3)				
Customer Charge	$17.60	$17.60	21.4%	21.4%
Energy Charge	125.37	80.71	-18.6%	-7.0%
Environmental Charges	$3.34	$2.13	406.7%	222.4%
Total	$146.31	$100.43	-13.5%	-1.5%
Difference IPL Proposed Restructured less KCK BPU	$22.85	$1.53		

(1) KCPL proposed rate increase of 15.9% pending before Missouri Public Service Commission.
(2) Old Aquila expected to file for rate increase in early 2016. Assumed 15.9% increase to match KCPL increase.
(3) Rating agency reports KCK BPU estimated to increase rates 5% in 2015 and 2016.

Table 5-4
Residential Rate Comparison - IPL Proposed Restructured vs Neighboring Utilities
Estimated Future (Customer Charge $14.50/month effective
October 1, 2016) - Low Use Customer

	Summer 400 kWh	Winter 400 kWh	Difference from IPL Proposed	
			Summer	Winter
IPL Proposed Restructured				
Customer Charge	$14.50	$14.50		
Energy Charge	$56.00	$53.20		
Schedule REC	$0.66	$0.66		
Total	$71.16	$68.36		
KCPL Proposed (1)				
Customer Charge	$25.00	$25.00	72.4%	72.4%
Energy Charge	59.97	46.88	7.1%	-11.9%
Environmental Charges				
Total	$84.97	$71.88	19.4%	5.2%
Difference IPL Proposed Restructured less KCPL	($13.81)	($3.52)		
Old Aquila Estimated (2)				
Customer Charge	$12.09	$12.09	-16.6%	-16.6%
Energy Charge	61.67	61.67	10.1%	15.9%
Environmental Charges				
Total	$73.76	$73.76	3.7%	7.9%
Difference IPL Proposed Restructured less Old Aquila	($2.60)	($5.40)		
KCK BPU Estimated (3)				
Customer Charge	$17.60	$17.60	21.4%	21.4%
Energy Charge	$55.09	47.04	-1.6%	-11.6%
Environmental Charges	$1.22	$1.22	84.2%	84.2%
Total	$73.91	$65.86	3.9%	-3.7%
Difference IPL Proposed Restructured less KCK BPU	($2.75)	$2.50		

(1) KCPL proposed rate increase of 15.9% pending before Missouri Public Service Commission.
(2) Old Aquila expected to file for rate increase in early 2016. Assumed 15.9% increase to match KCPL increase.
(3) Rating agency reports KCK BPU estimated to increase rates 5% in 2015 and 2016.

Table 5-5
General Service Rate Monthly Bill Comparison - IPL Existing vs IPL Proposed Restructured - Typical Use Customer

	Winter 800 kWh	Summer 800 kWh						
IPL Existing (1)								
Energy Charge	$141.81	$141.81						
					Difference from IPL Existing			
	800 kWh Winter effective Oct 1 2015	800 kWh Summer effective May 1 2016	800 kWh Winter effective Oct 1 2016	800 kWh Summer effective May 1 2017	Winter effective Oct 1 2015	Summer effective May 1 2016	Winter effective Oct 1 2016	Summer effective May 1 2017
IPL Proposed Restructured								
Customer Charge	$10.00	$13.00	$16.00	$16.00				
Energy Charge	$122.80	$136.00	$122.80	$136.00	-13.4%	-4.1%	-13.4%	-4.1%
Schedule REC	$0.66	$0.66	$0.66	$0.66				
Total	$133.46	$149.66	$139.46	$152.66	-5.9%	5.5%	-1.7%	7.7%
Restructured less Existing	($8.35)	$7.85	($2.35)	$10.85				

(1) IPL currently has a minimum charge with no usage of $4.08 for single phase and $17.58 for three phase or $11.95 per kW for customers with demand of 10kW or more.

Table 5-6

General Service Rate Monthly Bill Comparison - IPL Proposed Restructured vs Neighboring Utilities Estimated Future (Customer Charge $16.00/month effective October 1, 2016) - Typical Use Customer

	Summer 800 kWh	Winter 800 kWh	Difference from IPL Proposed Restructured Summer	Difference from IPL Proposed Restructured Winter
IPL Proposed Restructured				
Customer Charge	$16.00	$16.00		
Energy Charge	$136.00	$122.80		
Schedule REC	$0.66	$0.66		
Total	$152.66	$139.46		
KCPL Proposed (1)				
Customer Charge	$19.06	$19.06	19.1%	19.1%
Energy Charge	$151.59	$118.19	11.5%	-3.8%
Environmental Charges				
Total	$170.65	$137.25	11.8%	-1.6%
Difference IPL Proposed Restructured less KCPL	($17.99)	$2.21		
Old Aquila Estimated (2)				
Customer Charge	$19.92	$19.92	24.5%	24.5%
Energy Charge	$141.39	$106.34	4.0%	-13.4%
Environmental Charges				
Total	$161.31	$126.26	5.7%	-9.5%
Difference IPL Proposed Restructured less Old Aquila	($8.65)	$13.20		
KCK BPU Estimated (3)				
Customer Charge	$33.00	$33.00	106.3%	106.3%
Energy Charge	$133.04	$122.29	-2.2%	-0.4%
Environmental Charges	$2.43	$2.43	268.5%	268.5%
Total	$168.47	$157.72	10.4%	13.1%
Difference IPL Proposed Restructured less KCK BPU	($15.81)	($18.26)		

(1) KCPL proposed rate increase of 15.9% pending before Missouri Public Service Commission.
(2) Old Aquila expected to file for rate increase in early 2016. Assumed 15.9% increase to match KCPL increase.
(3) Rating agency reports KCK BPU estimated to increase rates 5% in 2015 and 2016.

Large General Service

Table 5-7 shows the results of comparing the proposed restructured rates for IPL to IPL's existing rates for a representative large general service customer using 16,425 kWh and 50 kW per month during the on-peak (summer) season and 16,425 kWh and 50 kW per month during the off peak season (winter). Table 5-8 shows the results of comparing the proposed restructured rates for IPL to the proposed or estimated future rates for IPL's neighboring utilities for the representative large general service customer.

Large Power

Table 5-9 shows the results of comparing the proposed restructured rates for IPL to IPL's existing rates for a representative large power customer using 912,500 kWh and 2,500 kW per month during the on-peak (summer) season and 912,500 kWh and 2,500 kW per month during the off peak season (winter). Table 5-10 shows the results of comparing the proposed restructured rates for IPL to the proposed or estimated future rates for IPL's neighboring utilities for a representative large power customer.

Table 5-7
Large General Service Rate Monthly Bill Comparison - IPL Existing vs IPL Proposed Restructured (Customer Charge $50.00/month effective October 1, 2015) - Representative Customer

	Summer 16,425 kWh 50 kW	Winter 16,425 kWh 50 kW	Difference from IPL Existing	
			Summer	Winter
IPL Existing (1)				
Energy Charge	$1,845.30	$1,845.30		
Demand Charge	$392.00	$392.00		
Total	$2,237.30	$2,237.30		
IPL Proposed Restructured				
Customer Charge	$50.00	$50.00		
Energy Charge	$1,846.13	$1,599.75	0.0%	-13.3%
Demand Charge	$350.00	$250.00	-10.7%	-36.2%
Schedule REC	$0.66	$0.66		
Total	$2,246.79	$1,900.41	0.4%	-15.1%
Difference Proposed IPL Restructuring less Existing	$9.48	($336.89)		

(1) IPL currently has a minimum charge with no usage of $6.31 per kW of highest demand during last 12 months.

Table 5-8

Large General Service Rate Monthly Bill Comparison - IPL Proposed Restructured vs Neighboring Utilities Estimated Future (Customer Charge $50.00/month effective October 1, 2015) - Representative Customer

	Summer 16,425 kWh 50 kW	Winter 16,425 kWh 50 kW	Difference from IPL Proposed Restructured	
			Summer	Winter
IPL Proposed Restructured				
Customer Charge	$50.00	$50.00		
Energy Charge	$1,846.13	$1,599.75		
Demand Charge	$350.00	$250.00		
Schedule REC	$0.66	$0.66		
Total	$2,246.79	$1,900.41		
KCPL Proposed (1)				
Customer Charge	$55.35	$55.35	10.7%	10.7%
Energy Charge	$1,896.49	$1,552.21	2.7%	-3.0%
Demand Charge	$400.14	$296.79	14.3%	18.7%
Environmental Charges				
Total	$2,351.99	$1,904.36	4.7%	0.2%
Difference IPL Proposed Restructured less KCPL	($105.20)	($3.95)		
Old Aquila Estimated (2)				
Customer Charge	$20.00	$20.00	-60.0%	-60.0%
Energy Charge	$2,051.08	$1,734.29	11.1%	8.4%
Demand Charge	$294.97	$186.89	-15.7%	-25.2%
Environmental Charges				
Total	$2,366.05	$1,941.18	5.3%	2.1%
Difference IPL Proposed Restructured less Old Aquila	($119.26)	($40.77)		
KCK BPU Estimated (3)				
Customer Charge	$33.00	$33.00	-34.0%	-34.0%
Energy Charge	$1,694.41	$1,467.68	-8.2%	-8.3%
Demand Charge	$655.50	$655.50	87.3%	162.2%
Environmental Charges	$50.93	$50.93		
Total	$2,433.84	$2,207.11	8.3%	16.1%
Difference IPL Proposed Restructured less KCK BPU	($187.06)	($306.70)		

(1) KCPL proposed rate increase of 15.9% pending before Missouri Public Service Commission.

(2) Old Aquila expected to file for rate increase in early 2016. Assumed 15.9% increase to match KCPL increase.

(3) Rating agency reports KCK BPU estimated to increase rates 5% in 2015 and 2016.

Table 5-9
Large Power Rate Monthly Bill Comparison - IPL Existing vs IPL Proposed Restructured (Customer Charge $500.00/month effective October 1, 2015) - Representative Customer

	Summer 912,500 kWh 2,500 kW	Winter 912,500 kWh 2,500 kW	Difference from IPL Existing	
			Summer	Winter
IPL Existing (1)				
Energy Charge	$90,289.48	$90,289.48		
Demand Charge	$10,110.00	$10,110.00		
Total	$100,399.48	$100,399.48		
IPL Proposed Restructured				
Customer Charge	$500.00	$500.00		
Energy Charge	$35,131.25	$35,131.25	-61.1%	-61.1%
Demand Charge	$46,250.00	$46,250.00	357.5%	357.5%
Schedule REC	$0.66	$0.66		
Total	$81,881.91	$81,881.91	-18.4%	-18.4%
Difference Proposed IPL Restructuring less Existing	($18,517.57)	($18,517.57)		

(1) IPL currently has a minimum charge with no usage of $4.83/kW of the highest demand in the prior 12 months.

Table 5-10

Large Power Rate Comparison - IPL Proposed Restructured vs Neighboring Utilities Estimated Future (Customer Charge $500.00/month effective October 1, 2015) - Representative Customer

	Summer 912,500 kWh 2,500 kW	Winter 912,500 kWh 2,500 kW	Difference from IPL Proposed Restructured	
			Summer	Winter
IPL Proposed Restructured				
Customer Charge	$500.00	$500.00		
Energy Charge	$35,131.25	$35,131.25		
Demand Charge	$46,250.00	$46,250.00		
Schedule REC	$0.66	$0.66		
Total	$81,881.91	$81,881.91		
KCPL Proposed (1)				
Customer Charge	$1,001.15	$1,001.15	100.2%	100.2%
Energy Charge	$87,196.56	$74,588.00	148.2%	112.3%
Demand Charge	$23,320.00	$15,760.00	-49.6%	-65.9%
Environmental Charges				
Total	$111,517.71	$91,349.15	36.2%	11.6%
Difference IPL Proposed Restructured less KCPL	($29,635.80)	($9,467.24)		
Old Aquila Estimated (2)				
Customer Charge	$207.47	$207.47	-58.5%	-58.5%
Energy Charge	$82,553.80	$60,335.77	135.0%	71.7%
Demand Charge	$23,614.63	$9,850.05	-48.9%	-78.7%
Environmental Charges				
Total	$106,375.90	$70,393.30	29.9%	-14.0%
Difference IPL Proposed Restructured less Old Aquila	($24,493.99)	$11,488.61		
KCK BPU Estimated (3)				
Customer Charge	$154.00	$154.00	-84.6%	-84.6%
Energy Charge	$80,381.73	$71,126.34	128.8%	102.5%
Demand Charge	$30,387.50	$30,387.50	-34.3%	-34.3%
Environmental Charges	$2,774.00	$2,774.00		
Total	$113,697.23	$104,441.84	38.9%	27.6%
Difference IPL Proposed Restructured less KCK BPU	($31,815.32)	($22,559.93)		

(1) KCPL proposed rate increase of 15.9% pending before Missouri Public Service Commission.

(2) Old Aquila expected to file for rate increase in early 2016. Assumed 15.9% increase to match KCPL increase.

(3) Rating agency reports KCK BPU estimated to increase rates 5% in 2015 and 2016.

SECTION 6 – RECOMMENDATIONS

Based on the IPL Pro Forma and the rate design goals and objectives, Sawvel makes the following recommendations:

1. Restructure rates in the manner described above to be effective October 1, 2015 that results in a reduction of $7.9 million in revenues for the 12 month period from October 1, 2015 through September 30, 2016 and $3 million annual reduction in revenues thereafter.

2. Implement the proposed Power Cost Adjustment Schedule PCA-1 and Regulatory and Environmental Compliance Schedule REC-1.

3. Implement the Unrestricted Cash Fund Balance Policy.

4. Defer implementation of additional base rate revenue increases at this time pending the completion of the following:
    a. Final FERC determination of net SPP Transmission revenues and expenses to be realized by IPL
    b. Review of IPL's depreciation rates and implementation of any changes to these depreciation rates and IPL's depreciation expense
    c. Finalize major capital improvements including transmission and substation projects based on projected load growth

After completion of the above, IPL should update its Pro Forma and revise the rate plan as needed to ensure the unrestricted cash fund policy is being met in the future and to generate positive net income.

APPENDIX A

PROPOSED FUND BALANCE POLICY AND TARGET WORKSHEET

Independence Power & Light

<u>Operating Fund Balance (Unrestricted Cash) Policy</u>

The purpose of the Operating Fund Balance (Unrestricted Cash) Policy is to maintain an adequate amount of unrestricted cash reserves to protect Independence Power & Light (IPL)'s ability to provide reliable electric service during periods of power supply cost uncertainties, reductions in sales due to weather or a sluggish economy, volatile energy prices, and rising capital improvement costs while maintaining stable rates. It is important for IPL to maintain the financial flexibility to smooth rate increases and stagger rate adjustments for customers of the electric utility. Rating agencies often examine the electric system's fund balance when considering the overall economic health and credit quality of IPL and the City of Independence, Missouri (the City).

This Operating Fund Balance (Unrestricted Cash) Policy addresses the unrestricted cash fund balance requirements for IPL. IPL may hold more money than the established unrestricted cash reserve guidelines based on an assessment of uncertainties and other financial policies such as:

- Financial risk facing the electric system
- Rate setting policies
- Variability in power supply costs
- Debt policies
- Future capital improvements needed by the electric system

The adequacy of the Operating Fund Balance (Unrestricted Cash) Policy guidelines may be reviewed each year, and if appropriate, revised guidelines may be adopted. The unrestricted cash reserve calculation shall be updated every year with the budget process and the updating of IPL's Pro Forma. Any changes in expenses, debt and capital improvements will impact the unrestricted cash fund balance requirements.

<u>Methodology</u>:

The methodology used to calculate unrestricted cash fund balance requirements for IPL is based on certain assumptions related to fuel and purchased power energy costs, other O&M expenses (cash basis - excluding depreciation), recurring routine system additions, cash funded capital improvement expenditures, and large unexpected emergency expenditures. The establishment of unrestricted cash fund balance requirements is the sum of the following four factors:

- 11.0% of annual fuel and purchased power energy costs.
- 12.5% of annual O&M expenses (cash basis) less annual fuel and purchased power energy costs.

- 50.0% of the sum of the current budget year and the next year's recurring routine system additions and cash funded capital improvements and expenditures.

- $2,000,000 for emergency contingency reserves.

The above methodology attempts to quantify the amount of unrestricted cash IPL should keep in reserve. The above unrestricted cash reserve calculation considers IPL's requirement "in total" and is not intended to represent the limit of unrestricted cash reserves that can be used for events occurring in each individual category.

Other Policy Matters:

a. If certain events occur that result in IPL's unrestricted cash reserves falling below the above unrestricted cash reserve levels, the City Council shall take action to restore the unrestricted cash reserves to the above required levels over not more than the subsequent five years. These actions may include a combination of a number of options, including:

    1. Rate Adjustments
    2. Cost Reductions
    3. Issuance of bonds to fund capital improvement programs
    4. Modification of the assumptions used to determine the unrestricted cash reserve levels

b. The City shall maintain Debt Service Reserves for IPL according to the requirements as outlined in the bonding documents at any time that bonds are issued for capital projects and for which the debt service shall be paid from the revenues of IPL.

c. Any unrestricted cash fund balance in excess of the amounts set forth above shall be available for transfer into a designated rate stabilization fund, or for funding capital improvements that otherwise would be funded by debt. The actual amount of transfer into a designated rate stabilization fund shall be determined by the IPL Director in concurrence with the City Manager and upon approval by City Council. Any funding of capital improvement expenditures pursuant to this provision shall be excluded from the above unrestricted cash reserve calculation. Due diligence shall be taken to leave sufficient funds available to cover anticipated expenditures at the beginning of the following fiscal year.

d. Unrestricted cash fund balance shall be available for use in acquisition of equipment and capital projects as outlined in the five year IPL Pro Forma. Funds may also be made available for use during unanticipated emergencies and disasters.

Adopted by the Governing Body of the City of Independence, Missouri
____________________, 201[4].

Table A-1 Worksheet - Calculation of Operating Fund Balance (Unrestricted Cash) Target

Independence Power & Light

Line No.	Description	FY2014-15	FY2015-16	FY2016-17	FY2017-18	FY2018-19	FY2019-20	
1	**Fuel and Purchased Power Energy Costs**	$ 26,592,000	$ 24,052,000	$ 25,388,000	$ 26,914,000	$ 27,640,000	$ 28,401,000	
2	Starting Point - No. of Days	45						
3	Reduction for Fuel-Energy Cost Adjustment							
4	Reconciles Cost Incurred with Billings to Customer (insert -2 days)	(2)						
5	Is forward looking, and can anticipate changes (insert -3 days)	(3)						
6	No. of Days	40						
7	Percent	11.0%						
8	Fund Balance Target for Fuel and Purch Power Costs	$ 2,914,192	$ 2,635,836	$ 2,782,247	$ 2,949,479	$ 3,029,041	$ 3,112,438	
9	**Other O&M Expenses**	$ 79,444,000	$ 84,134,000	$ 88,928,000	$ 90,520,000	$ 94,198,000	$ 98,421,000	
10	Starting Point - No. of Months	1.50						
11	Add if IPL Electric Rates:							
12	Do Not Have Demand Charges to Com/Ind Customers (insert 2 mo.)	-						
13	Have Seasonal/Inverted Rates (insert 1 mo.)	-						
14	No. of Months	1.50						
15	Percent	12.5%						
16	Fund Balance Target for Other Operating Expenditures	$ 9,930,500	$ 10,516,750	$ 11,116,000	$ 11,315,000	$ 11,774,750	$ 12,302,625	
17	**Capital-Related Expenditures (Not Debt Funded)**							
18	Recurring Routine System Additions (not debt funded)	$ 7,000,000	$ 7,000,000	$ 7,210,000	$ 7,426,000	$ 7,649,000	$ 7,879,000	$ 8,000,000
19	Capital Improvement Expenditures - Cash Funded	$ 6,854,000	$ 17,393,000	$ 7,714,000	$ 6,116,000	$ 6,095,000	$ 4,235,000	$ 5,000,000
20	Capital Expenditures Used To Reduce Operating Fund Balance	$ (6,854,000)	$ (17,393,000)	$ (7,714,000)	$ (6,116,000)	$ (6,095,000)	$ (4,235,000)	$ (5,000,000)
21	Total Capital-Related Expenditures (Not Debt Funded)	$ 7,000,000	$ 7,000,000	$ 7,210,000	$ 7,426,000	$ 7,649,000	$ 7,879,000	$ 8,000,000
22	Starting Point - 50% of Current Year plus Subsequent Year	$ 7,000,000	$ 7,105,000	$ 7,318,000	$ 7,537,500	$ 7,764,000	$ 7,939,500	
23	**Emergency Fund Allowance**							
24	Insurance Deductible	$ -						
25	Largest Piece of Equipment (example - substation transformer)	$ -						
26	Judgement - Amount of Emergency Funds to Have Available	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 2,000,000	
27	**Fund Balance Target**	$ 21,844,692	$ 22,257,586	$ 23,216,247	$ 23,801,979	$ 24,567,791	$ 25,354,563	
28	Operating Fund Balance - Unrestricted Cash from IPL Pro Forma	$38,819,000	$27,241,000	$23,500,000	$23,501,000	$23,504,000	$23,503,000	

APPENDIX B
COST OF SERVICE RESULTS

Table B-1
Cost of Service - Functionalization/Classification
Summary Allocation Factor Table
($)
Independence Power & Light

Line		Source/	Total System	Production		Transmission	Substation	Distribution							Billing/
								Primary		Secondary					
No	Description	Factor	($)	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Lighting	Service	Meters	Accounting
1	Net Production Plant		223,022,074	223,022,074	0	0	0	0	0	0	0	0	0	0	0
2	Net Production Plant Factor	**P100**	100.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	Purchased Power		47,942,732	25,148,667	22,794,065	0	0	0	0	0	0	0	0	0	0
4	Purchased Power Factor	**P200**	100.0%	52%	48%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	Primary Classification														
6	Primary Classification Factor	**D100**	100.0%	0.0%	0.0%	0.0%	0.0%	45.0%	55.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
7	Secondary Classification														
8	Secondary Classification Factor	**D200**	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	35.0%	65.0%	0.0%	0.0%	0.0%	0.0%
9	Net Distribution Classification		1.00	0.00	0.00	0.00	0.00	0.35	0.42	0.08	0.15	0.00	0.00	0.00	0.00
10	Net Distribution Classification Factor	**D300**	100.0%	0.0%	0.0%	0.0%	0.0%	34.7%	42.4%	8.1%	15.0%	0.0%	0.0%	0.0%	0.0%
11	T&D Classification		180,013,630	0	1	40,707,154	25,040,680	23,616,201	28,864,246	15,903,844	29,535,710	0	7,727,880	8,617,914	0
12	T&D Classification Factor	**D400**	100.0%	0.0%	0.0%	22.6%	13.9%	13.1%	16.0%	8.8%	16.4%	0.0%	4.3%	4.8%	0.0%
13	Net PT&D		403,035,705	223,022,074	1	40,707,154	25,040,680	23,616,201	28,864,246	15,903,844	29,535,710	0	7,727,880	8,617,914	0
14	Net PT&D Factor	**N_PTD**	100.0%	55.3%	0.0%	10.1%	6.2%	5.9%	7.2%	3.9%	7.3%	0.0%	1.9%	2.1%	0.0%
27	Labor Factor	**L**	100.0%	45.0%	0.0%	11.1%	6.8%	6.4%	7.9%	4.3%	8.0%	0.0%	2.1%	8.3%	0.0%
28	Other Factor	**O**	100.0%	43.2%	0.0%	9.9%	6.1%	5.7%	7.0%	3.9%	7.2%	0.0%	1.9%	15.1%	0.0%

Table B-2
Cost of Service - Functionalization/Classification
Summary Operating Expenses
($)
Independence Power & Light

Description	Source Factor	Total System Test Year FY14 ($)	Production		Transmission	Substation	Distribution				Lighting	Service	Meters	Billing/ Accounting	Direct Assign.
							Primary		Secondary						
			Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer					
O&M Expenses															
Purchased Power		47,942,732	25,148,667	22,794,065	0	0	0	0	0	0	0	0	0	0	0
Fuel		5,527,924	0	5,527,924	0	0	0	0	0	0	0	0	0	0	0
Load Control		2,465,159	2,465,159	0	0	0	0	0	0	0	0	0	0	0	0
Border Customer		79,794	41,857	37,938	0	0	0	0	0	0	0	0	0	0	0
Production O&M		11,079,654	11,079,654	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - Wheeling		6,175,999	0	0	6,175,999	0	0	0	0	0	0	0	0	0	0
Transmission Less Wheeling		1,468,278	0	0	1,468,278	0	0	0	0	0	0	0	0	0	0
Distribution O&M		11,409,556	0	0	0	0	3,953,411	4,831,947	918,469	1,705,729	0	0	0	0	0
Customer Accts, Service and Info		3,868,172	0	0	0	0	0	0	0	0	0	0	3,868,172	0	0
Administrative & General		17,762,528	7,988,211	0	1,970,713	1,212,268	1,143,307	1,397,375	769,936	1,429,882	0	374,122	1,476,715	0	0
Payroll Taxes		1,300,868	585,030	0	144,328	88,782	83,732	102,339	56,388	104,720	0	27,399	108,150	0	0
Depreciation Charged to O&M Expense		(643,381)	(356,018)	(0)	(64,982)	(39,973)	(37,699)	(46,077)	(25,388)	(47,149)	0	(12,336)	(13,757)	0	0
Unbilled Revenue		40,387	22,348	0	4,079	2,509	2,367	2,892	1,594	2,960	0	774	864	0	0
Other Post Retirement Benefits (Non-Cash)		(2,239,013)	(1,006,935)	(0)	(248,414)	(152,810)	(144,117)	(176,143)	(97,052)	(180,240)	0	(47,159)	(186,144)	0	0
Fuel, SO2 & Mat. Inv. Adjustments		(1,063,654)	0	(1,063,654)	0	0	0	0	0	0	0	0	0	0	0
Total O&M		105,175,004	45,967,973	27,296,273	9,450,001	1,110,777	5,001,000	6,112,333	1,623,946	3,015,900	0	342,800	5,253,999	0	0
Debt Service															
Existing Bonds	**N_PTD**	8,921,057	4,936,517	0	901,039	554,267	522,737	638,900	352,026	653,763	0	171,054	190,755	0	0
New Bonds	**N_PTD**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Debt Service		8,921,057	4,936,517	0	901,039	554,267	522,737	638,900	352,026	653,763	0	171,054	190,755	0	0
Capital Improvements															
Capital Improvements	**N_PTD**	8,008,000	4,431,272	0	808,819	497,538	469,235	573,510	315,997	586,851	0	153,547	171,231	0	0
Routine Additions	**N_PTD**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deprec. To Elim Neg Net Inc	**N_PTD**	3,113,659	1,722,960	0	314,484	193,452	182,447	222,991	122,865	228,179	0	59,702	66,578	0	0
Transfers (999)	**N_PTD**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital Improvements		11,121,659	6,154,232	0	1,123,303	690,991	651,683	796,501	438,862	815,030	0	213,249	237,809	0	0
Revenue Credits															
Other Operating Income		(7,625,054)	(1,427,574)	(1,558,800)	(3,300,460)	(184,826)	(174,312)	(213,048)	(117,387)	(218,004)	0	(57,040)	(373,604)	0	0
Other Income		(750,000)	(415,017)	(0)	(75,751)	(46,598)	(43,947)	(53,713)	(29,595)	(54,962)	0	(14,381)	(16,037)	0	0
Total Revenue Credits		(8,375,054)	(1,842,591)	(1,558,800)	(3,376,211)	(231,423)	(218,258)	(266,760)	(146,982)	(272,966)	0	(71,420)	(389,641)	0	0
Subtotal - Before PILOT		116,842,665	55,216,132	25,737,473	8,098,132	2,124,611	5,957,160	7,280,974	2,267,853	4,211,727	0	655,683	5,292,921	0	0
Payment in Lieu of Taxes															
Gross Receipts Tax	**9.08**	12,513,736	5,703,040	2,726,025	1,146,777	235,820	617,224	754,385	241,500	448,500	0	72,777	567,688	0	0
Property and Other		835,018	462,062	0	84,338	51,880	48,929	59,802	32,950	61,193	0	16,011	17,855	0	0
Total PILOT		13,348,754	6,165,102	2,726,025	1,231,115	287,700	666,153	814,187	274,450	509,692	0	88,788	585,543	0	0
Total COS		130,191,419	61,381,233	28,463,497	9,329,247	2,412,311	6,623,313	8,095,161	2,542,303	4,721,419	0	744,471	5,878,464	0	0

Table B-3

Cost of Service - Functionalization/Classification

Operating Expenses

($)

Independence Power & Light

Description	Source Factor	Total System Test Year FY14 ($)[1]	Production		Transmission	Substation	Distribution				Lighting	Service	Meters	Billing/ Accounting
							Primary		Secondary					
			Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer				
Operating Expenses														
Purchased Power	**P200**	47,942,732	25,148,667	22,794,065	0	0	0	0	0	0	0	0	0	0
Fuel	**D/A**	5,527,924	0	5,527,924	0	0	0	0	0	0	0	0	0	0
Load Control	**P100**	2,465,159	2,465,159	0	0	0	0	0	0	0	0	0	0	0
Border Customer	**P200**	79,794	41,857	37,938	0	0	0	0	0	0	0	0	0	0
Production O&M	**P100**	11,079,654	11,079,654	0	0	0	0	0	0	0	0	0	0	0
Transmission - Wheeling	**D/A**	6,175,999	0	0	6,175,999	0	0	0	0	0	0	0	0	0
Transmission Less Wheeling	**D/A**	1,468,278	0	0	1,468,278	0	0	0	0	0	0	0	0	0
Distribution O&M	**D300**	11,409,556	0	0	0	0	3,953,411	4,831,947	918,469	1,705,729	0	0	0	0
Customer Accts, Service and Info	**D/A**	3,868,172	0	0	0	0	0	0	0	0	0	0	3,868,172	0
Administrative and General	**L**	17,762,528	7,988,211	0	1,970,713	1,212,268	1,143,307	1,397,375	769,936	1,429,882	0	374,122	1,476,715	0
Total O&M		**107,779,797**	**46,723,548**	**28,359,927**	**9,614,990**	**1,212,268**	**5,096,718**	**6,229,322**	**1,688,405**	**3,135,610**	**0**	**374,122**	**5,344,887**	**0**
Payroll Taxes	**L**	1,300,868	585,030	0	144,328	88,782	83,732	102,339	56,388	104,720	0	27,399	108,150	0
Depreciation Charged to O&M Expense	**N_PTD**	(643,381)	(356,018)	(0)	(64,982)	(39,973)	(37,699)	(46,077)	(25,388)	(47,149)	0	(12,336)	(13,757)	0
Unbilled Revenue	**N_PTD**	40,387	22,348	0	4,079	2,509	2,367	2,892	1,594	2,960	0	774	864	0
Other Post Retirement Benefits (Non-Cash)	**L**	(2,239,013)	(1,006,935)	(0)	(248,414)	(152,810)	(144,117)	(176,143)	(97,052)	(180,240)	0	(47,159)	(186,144)	0
Fuel, SO2 & Mat. Inv. Adjustments	**D/A**	(1,063,654)	0	(1,063,654)	0	0	0	0	0	0	0	0	0	0
Total O&M (Cash Flow)		**105,175,004**	**45,967,973**	**27,296,273**	**9,450,001**	**1,110,777**	**5,001,000**	**6,112,333**	**1,623,946**	**3,015,900**	**0**	**342,800**	**5,253,999**	**0**
Payment in Lieu of Taxes														
Gross Receipts Tax @ 9.08%	**O**	12,513,736	5,408,322	0	1,239,068	762,203	718,843	878,586	484,090	899,025	0	235,226	1,888,373	0
Property and Other	**N_PTD**	835,018	462,062	0	84,338	51,880	48,929	59,802	32,950	61,193	0	16,011	17,855	0
Total Payment in Lieu of Taxes		13,348,754	5,870,384	0	1,323,406	814,082	767,772	938,388	517,040	960,218	0	251,236	1,906,228	0
Revenue Credits														
Wholesale Sales to Border Cust.	**P100**	(150,000)	(150,000)	0	0	0	0	0	0	0	0	0	0	0
Wholesale Sales to Interchanges	**D/A**	(1,558,800)	0	(1,558,800)	0	0	0	0	0	0	0	0	0	0
Other Operating Revenues	**O**	(1,935,400)	(836,462)	(0)	(191,637)	(117,884)	(111,178)	(135,884)	(74,870)	(139,045)	0	(36,380)	(292,060)	0
Proposed Revenue Reduction	**D/A**	(3,000,000)	0	0	(3,000,000)	0	0	0	0	0	0	0	0	0
Private Outdoor Lighting Revenue	**L**	(392,595)	(176,559)	(0)	(43,558)	(26,794)	(25,270)	(30,885)	(17,017)	(31,604)	0	(8,269)	(32,639)	0
Public Street Lighting Revenue	**L**	(510,003)	(229,360)	(0)	(56,584)	(34,807)	(32,827)	(40,122)	(22,107)	(41,055)	0	(10,742)	(42,400)	0
Traffic Signal Revenue	**L**	(78,256)	(35,193)	(0)	(8,682)	(5,341)	(5,037)	(6,156)	(3,392)	(6,300)	0	(1,648)	(6,506)	0
Total Other Operating Income		(7,625,054)	(1,427,574)	(1,558,800)	(3,300,460)	(184,826)	(174,312)	(213,048)	(117,387)	(218,004)	0	(57,040)	(373,604)	0
Interest on Invested Funds	**N_PTD**	0	0	0	0	0	0	0	0	0	0	0	0	0
Miscellaneous[2]	**N_PTD**	(750,000)	(415,017)	(0)	(75,751)	(46,598)	(43,947)	(53,713)	(29,595)	(54,962)	0	(14,381)	(16,037)	0
Total Other Income		(750,000)	(415,017)	(0)	(75,751)	(46,598)	(43,947)	(53,713)	(29,595)	(54,962)	0	(14,381)	(16,037)	0
Total Revenue Credits		(8,375,054)	(1,842,591)	(1,558,800)	(3,376,211)	(231,423)	(218,258)	(266,760)	(146,982)	(272,966)	0	(71,420)	(389,641)	0
Total		110,148,703	49,995,766	25,737,473	7,397,196	1,693,436	5,550,513	6,783,961	1,994,005	3,703,152	0	522,616	6,770,586	0

[1] From "IPL Pro Forma Budget - 2014 Rate Study (v10b)" provided by City Staff.

Table B-4
Cost of Service - Functionalization/Classification
Net Plant Investment as of June 30, 2014
Independence Power & Light

Description	Source Factor	Total System Test Year FY2014 ($)[1]	Production Demand	Production Energy	Transmission Demand	Substation Demand	Distribution Primary Demand	Distribution Primary Customer	Distribution Secondary Demand	Distribution Secondary Customer	Lighting	Service	Meters	Billing/ Acct'g
Net Intangible														
	D/A		0	0	0	0	0	0	0	0	0	0	0	0
Net Production Plant														
Steam Production														
Land and Land Rights	D/A	369,959	369,959	0	0	0	0	0	0	0	0	0	0	0
Structures & Improvements	D/A	13,081,611	13,081,611	0	0	0	0	0	0	0	0	0	0	0
Boiler Plant Equipment	D/A	83,102,641	83,102,641	0	0	0	0	0	0	0	0	0	0	0
Turbogenerator Units	D/A	35,008,106	35,008,106	0	0	0	0	0	0	0	0	0	0	0
Accessory Electric Equipment	D/A	7,167,054	7,167,054	0	0	0	0	0	0	0	0	0	0	0
Miscellaneous Equipment	D/A	1,114,471	1,114,471	0	0	0	0	0	0	0	0	0	0	0
Total Steam Production		139,843,842	139,843,842	0	0	0	0	0	0	0	0	0	0	0
Other Production Plant														
Land and Land Rights	D/A	30,458	30,458	0	0	0	0	0	0	0	0	0	0	0
Structures & Improvements	D/A	4,306,954	4,306,954	0	0	0	0	0	0	0	0	0	0	0
Fuel-Holders-Accessories	D/A	1,951,305	1,951,305	0	0	0	0	0	0	0	0	0	0	0
Prime Movers	D/A	21,646,769	21,646,769	0	0	0	0	0	0	0	0	0	0	0
Generators	D/A	50,187,533	50,187,533	0	0	0	0	0	0	0	0	0	0	0
Accessory Electric Equipment	D/A	5,008,509	5,008,509	0	0	0	0	0	0	0	0	0	0	0
Miscellaneous Equipment	D/A	46,704	46,704	0	0	0	0	0	0	0	0	0	0	0
Total Other Production		83,178,233	83,178,233	0	0	0	0	0	0	0	0	0	0	0
Total Net Production		223,022,074	223,022,074	0	0	0	0	0	0	0	0	0	0	0
Net Transmission Plant														
Land and Land Rights	D/A	1,779,023		0	1,779,023	0	0	0	0	0	0	0	0	0
Structures & Improvements	D/A	4,891,863		0	4,891,863	0	0	0	0	0	0	0	0	0
Station Equipment	D/A	14,301,404		0	14,301,404	0	0	0	0	0	0	0	0	0
Tower and Fixtures	D/A	3,426,975		1	3,426,975	0	0	0	0	0	0	0	0	0
Poles and Fixtures	D/A	8,676,066		0	8,676,066	0	0	0	0	0	0	0	0	0
Overhead Conductors-Devices	D/A	4,434,117		0	4,434,117	0	0	0	0	0	0	0	0	0
Underground Conduit	D/A	423,503		0	423,503	0	0	0	0	0	0	0	0	0
Underground Conductors-Devices	D/A	2,774,203		0	2,774,203	0	0	0	0	0	0	0	0	0
Total Net Transmission		40,707,154	0	1	40,707,154	0	0	0	0	0	0	0	0	0
Net Distribution Plant														
Land and Land Rights	D/A	692,536	0	0	0	692,536	0	0	0	0	0	0	0	0
Structures & Improvements	D/A	1,715,261	0	0	0	1,715,261	0	0	0	0	0	0	0	0
Station Equipment	D/A	22,632,883	0	0	0	22,632,883	0	0	0	0	0	0	0	0
Poles, Towers, & Fixtures	D300	14,336,417	0	0	0	0	4,967,568	6,071,472	1,154,082	2,143,294	0	0	0	0
Overhead Conductors & Devices	D300	14,976,232	0	0	0	0	5,189,264	6,342,434	1,205,587	2,238,947	0	0	0	0
Underground Conduit	D300	12,515,387	0	0	0	0	4,336,582	5,300,267	1,007,489	1,871,050	0	0	0	0
Underground Conductors & Device	D300	26,328,389	0	0	0	0	9,122,787	11,150,073	2,119,435	3,936,094	0	0	0	0
Line Transformers	D200	29,763,577	0	0	0	0	0	0	10,417,252	19,346,325	0	0	0	0
Services	D/A	7,727,880	0	0	0	0	0	0	0	0	0	7,727,880	0	0
Meters	D/A	8,617,914	0	0	0	0	0	0	0	0	0	0	8,617,914	0
Public Street Lighting	D/A	16,080,274	0	0	0	0	0	0	0	0	16,080,274	0	0	0
Total Net Distribution		155,386,749	0	0	0	25,040,680	23,616,201	28,864,246	15,903,844	29,535,710	16,080,274	7,727,880	8,617,914	0
Net General Plant														
Land and Land Rights	L	1,000,152	449,791	0	110,965	68,259	64,376	78,682	43,353	80,512	0	21,066	83,149	0
Structures & Improvements	L	7,497,448	3,371,772	0	831,825	511,691	482,582	589,823	324,985	603,544	0	157,914	623,312	0
Office Furniture & Fixtures	L	359,970	161,887	0	39,938	24,567	23,170	28,319	15,603	28,978	0	7,582	29,927	0
Computer Equipment	L	5,637,781	2,535,438	0	625,499	384,771	362,883	443,523	244,376	453,841	0	118,745	468,705	0
Transportation Equipment	L	9,696,991	4,360,957	0	1,075,860	661,806	624,159	762,860	420,327	780,607	0	204,242	806,174	0
Stores Equipment	L	83,997	37,775	0	9,319	5,733	5,407	6,608	3,641	6,762	0	1,769	6,983	0
Tools, Shop & Garage Equipment	L	1,074,144	483,067	0	119,174	73,309	69,139	84,503	46,560	86,468	0	22,624	89,301	0
Laboratory Equipment	L	222,133	99,898	0	24,645	15,160	14,298	17,475	9,629	17,882	0	4,679	18,467	0
Power Operated Equipment	L	12,981	5,838	0	1,440	886	836	1,021	563	1,045	0	273	1,079	0
Communication Equipment	L	345,591	155,420	0	38,343	23,586	22,244	27,188	14,980	27,820	0	7,279	28,731	0
Miscellaneous Equipment	L	106,665	47,970	0	11,834	7,280	6,866	8,391	4,624	8,587	0	2,247	8,868	0
Other Tangible Property	L	180,526	81,187	0	20,029	12,321	11,620	14,202	7,825	14,532	0	3,802	15,008	0
Fiber Optic	L	3,913,609	1,760,039	0	434,206	267,098	251,904	307,883	169,640	315,045	0	82,430	325,364	0
Total Net General		30,131,987	13,551,038	0	3,343,077	2,056,467	1,939,482	2,370,478	1,306,104	2,425,622	0	634,652	2,505,068	0
Net Plant Investment		449,247,965	236,573,112	1	44,050,231	27,097,147	25,555,683	31,234,723	17,209,948	31,961,332	16,080,274	8,362,532	11,122,982	0

[1] From file "21. Monthly Balances Plant in Service 2013-14" provided by City Staff.

Table B-5
Cost of Service - Functionalization/Classification
Summary of Operating Expenses (Excluding Fuel and Purchase Power)
Independence Power & Light

Description	Source Factor	Total System ($)	Production Demand	Production Energy	Transmission Demand	Substation Demand	Distribution Primary Demand	Distribution Primary Customer	Distribution Secondary Demand	Distribution Secondary Customer	Lighting	Service	Meters	Billing/ Accounting
Salaries & Wages														
Production O & M	**P100**	8,674,030	8,674,030	0	0	0	0	0	0	0	0	0	0	0
Customer Service	**D/A**	1,037,521	0	0	0	0	0	0	0	0	0	0	1,037,521	0
Transmission & Distribution	**D400**	9,515,325	0	0	2,151,736	1,323,623	1,248,327	1,525,733	840,660	1,561,226	0	408,487	455,534	0
	D/A	0	0	0	0	0	0	0	0	0	0	0	0	0
A & G Expenses	**O**	1,555,329	672,199	0	154,003	94,734	89,345	109,199	60,167	111,740	0	29,236	234,705	0
Total Salaries & Wages		20,782,205	9,346,229	0	2,305,739	1,418,357	1,337,672	1,634,932	900,827	1,672,965	0	437,723	1,727,760	0
Ratio Factor "L"		100.0%	45.0%	0.0%	11.1%	6.8%	6.4%	7.9%	4.3%	8.0%	0.0%	2.1%	8.3%	0.0%
Operating Expenses														
Production O & M	**P100**	9,414,848	9,414,848	0	0	0	0	0	0	0	0	0	0	0
Customer Service	**D/A**	2,830,651	0	0	0	0	0	0	0	0	0	0	2,830,651	0
Transmission & Distribution	**D400**	9,538,507	0	0	2,156,978	1,326,848	1,251,368	1,529,450	842,708	1,565,029	0	409,483	456,643	0
	D/A	0	0	0	0	0	0	0	0	0	0	0	0	0
Other A&G		0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses		21,784,006	9,414,848	0	2,156,978	1,326,848	1,251,368	1,529,450	842,708	1,565,029	0	409,483	3,287,294	0
Ratio Factor "O"		100.0%	43.2%	0.0%	9.9%	6.1%	5.7%	7.0%	3.9%	7.2%	0.0%	1.9%	15.1%	0.0%

Table B-6
Cost of Service - Development of Allocation Factors by Rate Class
Independence Power & Light

Description	Factor	Total	Residential						General Service	Large General Service									Total Elec. Gen. Service	Large Power	Private Outdoor	Street	Traffic Signals
										Secondary Voltage													
			(RS-3)	(RSWH)	(RSSHW)	(RSSH)	(RS-4)	Total	(GS-1 & GSSH-1)	(LGS-1 & LGSSH-1)	(SP-1)	(EDU-1)	(EDU-AE)	(CH-1)	(CH-AE)	Subtotal	Primary (LGSPV)	Total	(TEGS)	(LP-2 & SCISF)	Lighting	Lights	(TRS-1)
Allocation Factor Input Data																							
Energy Related MWh																							
Energy Sales [1]	99%	1,023,746	412,222	10,224	2,295	22,966	71,216	518,923	26,239	311,685	2,312	26,936	4,736	10,425	299	356,394	8,888	365,282	61,873	51,429	0	0	0
Primary Distribution Losses [2]	1.50%	15,407	6,204	154	35	346	1,072	7,810	395	4,691	35	405	71	157	5	5,364	134	5,497	931	774	0	0	0
Secondary Distribution Losses [2]	2.00%	19,559	8,369	208	47	466	1,446	10,535	533	6,328	47	547	96	212	6	7,235	0	7,416	1,256	0	0	0	0
Energy at Substation		1,058,712	426,795	10,585	2,376	23,778	73,733	537,267	27,167	322,704	2,394	27,888	4,904	10,794	310	368,993	9,022	378,195	64,060	52,203	0	0	0
Transmission Losses [3]	1.00%	10,587	4,268	106	24	238	737	5,373	272	3,227	24	279	49	108	3	3,690	90	3,782	641	522	0	0	0
Energy at Source	99%	1,069,299	431,063	10,691	2,400	24,016	74,471	542,640	27,439	325,931	2,418	28,167	4,953	10,902	313	372,683	9,112	381,795	64,701	52,725	0	0	0
Total Losses	4.45	45,553	18,840	467	105	1,050	3,255	23,717	1,199	14,245	106	1,231	216	476	14	16,289	224	16,513	2,828	1,296	0	0	0
Energy @ Source Factor	**K300**	100%	40.31%	1.00%	0.22%	2.25%	6.96%	50.75%	2.57%	30.48%	0.23%	2.63%	0.46%	1.02%	0.03%	34.85%	0.85%	35.71%	6.05%	4.93%	0.00%	0.00%	0.00%
Non-Coincident Load Factor [4]		37.84%	33.61%	33.61%	38.61%	38.61%	38.61%	34.44%	27.40%	44.90%	21.50%	28.93%	22.45%	17.87%	26.30%	40.56%	45.74%	40.67%	50.52%	63.31%	50.00%	50.00%	100.00%
Demand Related kW (incl. losses)																							
Noncoincident Class Peak Demand [5]	**NCP**	322,596	146,422	3,631	710	7,101	22,020	179,884	11,432	82,862	1,284	11,114	2,518	6,964	136	104,878	2,274	107,152	14,621	9,507	0	0	0
Noncoincident Class Peak Demand Factor	**K200**	100%	45.39%	1.13%	0.22%	2.20%	6.83%	55.76%	3.54%	25.69%	0.40%	3.45%	0.78%	2.16%	0.04%	32.51%	0.70%	33.22%	4.53%	2.95%	0.00%	0.00%	0.00%
Noncoincident Class Peak Demand [5]		310,815	146,422	3,631	710	7,101	22,020	179,884	11,432	82,862	1,284	11,114	2,518	6,964	136	104,878	0	104,878	14,621	0	0	0	0
Noncoincident Class Peak Demand Factor	**K202**	100%	47.11%	1.17%	0.23%	2.28%	7.08%	57.87%	3.68%	26.66%	0.41%	3.58%	0.81%	2.24%	0.04%	33.74%	0.00%	33.74%	4.70%	0.00%	0.00%	0.00%	0.00%
Coincident Demand at Source [6]	272,353	272,324	127,000	3,150	616	6,159	19,099	156,024	9,372	72,360	959	7,465	886	4,605	76	86,351	1,986	88,337	12,305	6,286	0	0	0
Coincident Demand Load Factor [7]	***1CP***	44.82%	38.75%	38.75%	44.51%	44.51%	44.51%	39.70%	33.42%	51.42%	28.79%	43.07%	63.81%	27.02%	47.18%	49.27%	52.38%	49.34%	60.02%	95.76%	0.00%	0.00%	100.00%
Coincident Demand at Source Factor	**K204a**	100%	46.64%	1.16%	0.23%	2.26%	7.01%	57.29%	3.44%	26.57%	0.35%	2.74%	0.33%	1.69%	0.03%	31.71%	0.73%	32.44%	4.52%	2.31%	0.00%	0.00%	0.00%
Coincident Demand at Source [6]	256,207	256,199	116,535	2,890	565	5,652	17,525	143,167	7,684	67,235	1,178	8,591	1,014	4,642	76	82,737	2,113	84,849	14,086	6,412	0	0	0
Coincident Demand Load Factor [7]	***5CP***	47.65%	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.04%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Coincident Demand at Source Factor	**K204**	100%	45.49%	1.13%	0.22%	2.21%	6.84%	55.88%	3.00%	26.24%	0.46%	3.35%	0.40%	1.81%	0.03%	32.29%	0.82%	33.12%	5.50%	2.50%	0.00%	0.00%	0.00%
Average & Excess Demand (kW)																							
Average Demand [8]		122,066	49,208	1,220	274	2,742	8,501	61,945	3,132	37,207	276	3,215	565	1,244	36	42,544	1,040	44	7,386	6,019	0	0	0
Class Excess Demand [9]		150,258	77,792	1,929	342	3,418	10,598	94,079	6,240	35,154	683	4,250	321	3,361	40	43,808	946	44,753	4,919	267	0	0	0
Average & Excess Demand [10]		132,046	59,327	1,471	298	2,981	9,243	73,320	4,232	36,480	420	3,581	479	1,994	37	42,991	1,007	43,998	6,513	3,983	0	0	0
Average & Excess Demand Factor	**K206**	100%	44.93%	1.11%	0.23%	2.26%	7.00%	55.53%	3.21%	27.63%	0.32%	2.71%	0.36%	1.51%	0.03%	32.56%	0.76%	33.32%	4.93%	3.02%	0.00%	0.00%	0.00%
Consumer Related																							
Average Number Of Consumers		56,409	43,408	857	108	1,987	4,983	51,342	3,019	1,633	6	67	7	210	4	1,927	6	1,933	110	5	0	0	0
Primary Line Weighting Factor			1.000	1.000	1.000	1.000	1.000		2.000	5.000	5.000	3.000	3.000	3.000	3.000		35.000		5.000	35.000	0.000	0.000	1.000
Weighted Number Of Consumers		67,371	43,408	857	108	1,987	4,983	51,342	6,038	8,163	30	201	21	630	12	9,057	210	9,267	549	175	0	0	0
Primary Line Factor	**K402**	100%	64.43%	1.27%	0.16%	2.95%	7.40%	76.21%	8.96%	12.12%	0.04%	0.30%	0.03%	0.94%	0.02%	13.44%	0.31%	13.75%	0.81%	0.26%	0.00%	0.00%	0.00%

Table B-6

Cost of Service - Development of Allocation Factors by Rate Class

Independence Power & Light

Description	Factor	Total	Residential (RS-3)	Residential (RSWH)	Residential (RSSHW)	Residential (RSSH)	Residential (RS-4)	Residential Total	General Service (GS-1 & GSSH-1)	Large General Service Secondary Voltage (LGS-1 & LGSSH-1)	Large General Service Secondary Voltage (SP-1)	Large General Service Secondary Voltage (EDU-1)	Large General Service Secondary Voltage (EDU-AE)	Large General Service Secondary Voltage (CH-1)	Large General Service Secondary Voltage (CH-AE)	Large General Service Secondary Voltage Subtotal	Large General Service Primary (LGSPV)	Large General Service Total	Total Elec. Gen. Service (TEGS)	Large Power (LP-2 & SCISF)	Private Outdoor Lighting	Street Lights	Traffic Signals (TRS-1)
Secondary Weighting Factor			1.000	1.000	1.000	1.000	1.000		2.000	5.000	5.000	5.000	5.000	5.000	5.000		0.000		5.000	0.000	0.500	0.200	1.000
Weighted Number Of Consumers		67,562	43,408	857	108	1,987	4,983	51,342	6,038	8,163	30	335	35	1,050	20	9,633	0	9,633	549	0	0	0	0
Secondary Line Factor	**K404**	100%	64.25%	1.27%	0.16%	2.94%	7.38%	75.99%	8.94%	12.08%	0.04%	0.50%	0.05%	1.55%	0.03%	14.26%	0.00%	14.26%	0.81%	0.00%	0.00%	0.00%	0.00%
Meter Weighting Factor			1.000	1.000	1.000	1.000	1.000		2.000	5.000	5.000	5.000	5.000	5.000	5.000		35.000		5.000	35.000	0.000	0.000	1.000
Weighted Number Of Consumers		67,947	43,408	857	108	1,987	4,983	51,342	6,038	8,163	30	335	35	1,050	20	9,633	210	9,843	549	175	0	0	0
Meter Factor	**K406**	100%	63.89%	1.26%	0.16%	2.92%	7.33%	75.56%	8.89%	12.01%	0.04%	0.49%	0.05%	1.55%	0.03%	14.18%	0.31%	14.49%	0.81%	0.26%	0.00%	0.00%	0.00%
Service Weighting Factor			1.000	1.000	1.000	1.000	1.000		2.000	5.000	5.000	5.000	5.000	5.000	5.000		35.000		5.000	35.000	0.000	0.000	1.000
Weighted Number Of Consumers		67,947	43,408	857	108	1,987	4,983	51,342	6,038	8,163	30	335	35	1,050	20	9,633	210	9,843	549	175	0	0	0
Service Factor	**K410**	100%	63.89%	1.26%	0.16%	2.92%	7.33%	75.56%	8.89%	12.01%	0.04%	0.49%	0.05%	1.55%	0.03%	14.18%	0.31%	14.49%	0.81%	0.26%	0.00%	0.00%	0.00%
Consumer Account Weighting Factor			1.000	1.000	1.000	1.000	1.000		2.000	5.000	5.000	5.000	5.000	5.000	5.000		35.000		5.000	35.000	0.500	0.200	1.000
Weighted Number Of Consumers		67,947	43,408	857	108	1,987	4,983	51,342	6,038	8,163	30	335	35	1,050	20	9,633	210	9,843	549	175	0	0	0
Consumer Account Factor	**K408**	100%	63.89%	1.26%	0.16%	2.92%	7.33%	75.56%	8.89%	12.01%	0.04%	0.49%	0.05%	1.55%	0.03%	14.18%	0.31%	14.49%	0.81%	0.26%	0.00%	0.00%	0.00%

(1) Actual July 2013 through June 2014.

(2) Distribution loses estimated at approximately 5.63% from 1989 Cost of Service Study.

(3) Transmission losses estimated at approximately 2.2088% from 1989 Cost of Service Study.

(4) Formula for Demand related customers is Energy at Source divided by Noncoincident class peak divided by 8760.

(5) Demand related actual class peak demand. Formula for non-demand customers is Energy at Source divided by 8760 divided by Noncoincident load factor.

(6) Noncoincident class peak multiplied by Bary's curve factor.

(7) Energy at Source divided by Non-Coincident Demand divided by 8760.

(8) Energy at Source divided by 8760.

(9) Noncoincident Class Peak minus Average Demand.

(10) Average Demand multiplied by Average System Load Factor plus Class Excess Demand multiplied by 1 minus Average System Load Factor.

Table B-7
Allocation of Cost of Service Expense
Independence Power & Light

				Residential						General Service	Large General Service													
											Secondary Voltage													
Ref.	Description	Allocation Factor	Total	(RS-3)	(RSWH)	(RSSHW)	(RSSH)	(RS-4)	Total	(GS-1 & GSSH-1)	(LGS-1 & LGSSH-1)	(SP-1)	(EDU-1)	(EDU-AE)	(CH-1)	(CH-AE)	Subtotal	Primary (LGSPV)	Total	Total Electric GS (TEGS)	Large Power (LP-2 & SCISF)	Private Outdoor Lighting(1)	Street Lights(1)	Traffic Signals (TRS-1)(1)
Cost of Service Allocation		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	Production Demand	K204	61,381,233	27,920,013	692,445	135,314	1,354,060	4,198,784	34,300,616	1,840,936	16,108,466	282,208	2,058,319	242,994	1,112,190	18,215	19,822,392	506,225	20,328,616	3,374,754	1,536,310	-	-	-
2	Production Energy	K300	28,463,497	11,474,383	284,577	63,884	639,275	1,982,319	14,444,438	730,385	8,675,898	64,356	749,774	131,836	290,189	8,332	9,920,385	242,552	10,162,936	1,722,264	1,403,473	-	-	-
3	Transmission Demand	K204	9,329,247	4,243,523	105,244	20,566	205,802	638,167	5,213,302	279,801	2,448,303	42,892	312,841	36,932	169,040	2,769	3,012,777	76,940	3,089,718	512,924	233,502	-	-	-
4	Substation Demand	K200	2,412,311	1,094,915	27,155	5,306	53,101	164,660	1,345,138	85,483	619,626	9,599	83,112	18,832	52,076	1,016	784,261	17,005	801,265	109,333	71,091	-	-	-
5	Distribution Primary Demand	K200	6,623,313	3,006,232	74,558	14,570	145,796	452,096	3,693,250	234,706	1,701,263	26,356	228,194	51,706	142,981	2,789	2,153,290	46,688	2,199,978	300,188	195,191	-	-	-
6	Distribution Primary Customer	K402	8,095,161	5,215,862	102,915	12,937	238,764	598,718	6,169,197	725,555	980,790	3,605	24,152	2,523	75,700	1,442	1,088,212	25,233	1,113,445	65,937	21,028	-	-	-
7	Distribution Secondary Demand	K202	2,542,303	1,197,654	29,703	5,804	58,084	180,111	1,471,356	93,505	677,767	10,500	90,910	20,599	56,962	1,111	857,850	-	857,850	119,592	-	-	-	-
8	Distribution Secondary Customer	K404	4,721,419	3,033,498	59,855	7,524	138,863	348,209	3,587,948	421,976	570,419	2,096	23,411	2,446	73,377	1,398	673,147	-	673,147	38,348	-	-	-	-
9	Street Lighting	K412	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Service	K410	744,471	475,610	9,384	1,180	21,772	54,594	562,540	66,160	89,434	329	3,670	383	11,504	219	105,540	2,301	107,841	6,012	1,917	-	-	-
11	Meters	K406	5,878,464	3,755,495	74,101	9,315	171,914	431,085	4,441,909	522,410	706,183	2,595	28,983	3,028	90,841	1,730	833,361	18,168	851,529	47,475	15,140	-	-	-
12	Billing & Accounting	K408	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Total Cost of Service		130,191,419	61,417,186	1,459,936	276,400	3,027,431	9,048,742	75,229,696	5,000,917	32,578,149	444,536	3,603,366	511,281	2,074,861	39,021	39,251,214	935,112	40,186,326	6,296,828	3,477,653	-	-	-
14	$ per kWh		0.12717	0.14899	0.14280	0.12043	0.13182	0.12706	0.14497	0.19059	0.10452	0.19227	0.13378	0.10795	0.19902	0.13037	0.11013	0.10521	0.11001	0.10177	0.06762	#DIV/0!	#DIV/0!	#DIV/0!
Cost Classification Summary																								
15	Customer Cost		19,439,514	12,480,465	246,255	30,956	571,313	1,432,606	14,761,595	1,736,100	2,346,826	8,625	80,216	8,381	251,422	4,789	2,695,470	45,702	2,741,172	157,773	38,085	-	-	-
16	Demand Cost		82,288,407	37,462,338	929,105	181,561	1,816,843	5,633,817	46,023,663	2,534,432	21,555,425	371,555	2,773,376	371,063	1,533,250	25,900	26,604,670	646,858	27,251,528	4,416,791	2,036,094	-	-	-
17	Energy Cost		28,463,497	11,474,383	284,577	63,884	639,275	1,982,319	14,444,438	730,385	8,675,898	64,356	749,774	131,836	290,189	8,332	9,912,053	242,552	10,154,605	1,722,264	1,403,473	-	-	-
18	Direct Cost		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Total		130,191,419	61,417,186	1,459,936	276,400	3,027,431	9,048,742	75,229,696	5,000,917	32,578,149	444,536	3,603,366	511,281	2,074,861	39,021	2,519,398	935,112	40,147,305	6,296,828	3,477,653	-	-	-
Customer Statistics																								
20	Average Number of Customers		56,409	43,408	857	108	1,987	4,983	51,342	3,019	1,633	6	67	7	210	4		6		110	5	-	-	-
21	Billing Demand (MW)		322,596								77,424							1,937		13,694	8,944	-	-	-
22	Billing Energy (MWh)		1,023,746	412,222	10,224	2,295	22,966	71,216	518,923	26,239	311,685	2,312	26,936	4,736	10,425	299		8,888		61,873	51,429	-	-	-
Cost of Service Rate																								
22	Customer ($/Month)		28.72	23.96	23.96	23.96	23.96	23.96	23.96	47.92	119.80	119.80	99.77	99.77	99.77	99.77		634.75		119.80	634.75	#DIV/0!	#DIV/0!	#DIV/0!
23	Demand ($/kW-Month)		21.26	-	-	-	-	-	-	-	23.20	-	-	-	-	-		27.83		26.88	18.97	-	-	#DIV/0!
24	Energy ($/kWh)		0.02780	0.11871	0.11871	0.10694	0.10694	0.10694	0.11653	0.12442	0.02784	0.18854	0.13080	0.10618	0.17491	0.11437		0.02729		0.02784	0.02729	#DIV/0!	#DIV/0!	#DIV/0!
Total ($/kWh)			0.12717	0.14899	0.14280	0.12043	0.13182	0.12706	0.14497	0.19059	0.10452	0.19227	0.13378	0.10795	0.19902	0.13037		0.10521		0.10177	0.06762	#DIV/0!	#DIV/0!	#DIV/0!

(1) A separate cost analysis was performed for lighting and signals. The resulting cost from this analysis was credited in the test year revenue requirements as a revenue credit.

Table B-8
Comparison of Revenues from Existing Rates to Cost of Service ($)

Independence Power & Light

Rate Class	Showcase Power and Light Statements				Cost of Service	Cost of Service Minus Existing	
	Sales (MWh)	Existing Rate Revenue ($)					
		Base Rate [1]	FCA	Total		($)	(%) [2]
Residential							
(RS-3)	412,222	50,196,507	9,614,075	59,810,582	61,417,186	1,606,604	2.69
(RSWH)	10,224	1,127,236	239,695	1,366,931	1,459,936	93,005	6.80
(RSSHW)	2,295	205,561	54,242	259,803	276,400	16,597	6.39
(RSSH)	22,966	2,368,068	540,193	2,908,261	3,027,431	119,170	4.10
(RS-4)	71,216	6,356,050	1,692,606	8,048,656	9,048,742	1,000,086	12.43
Total Residential	518,923	60,253,422	12,140,811	72,394,233	75,229,696	2,835,463	3.92
General Service							
(GS-1 & GSSH-1)	26,239	3,911,833	615,477	4,527,310	5,000,917	473,607	10.46
(LGS-1 & LGSSH-1)	311,685	31,892,066	7,283,443	39,175,509	32,578,149	(6,597,360)	(16.84)
(SP-1)	2,312	241,037	54,452	295,489	444,536	149,047	50.44
(EDU-1)	26,936	2,569,590	619,677	3,189,267	3,603,366	414,099	12.98
(EDUAL)	4,736	325,373	107,082	432,455	511,281	78,826	18.23
(CH-1)	10,425	1,148,795	241,354	1,390,149	2,074,861	684,712	49.25
(CHAL)	299	26,158	6,594	32,752	39,021	6,269	19.14
(TEGS)	61,873	4,552,610	1,453,507	6,006,117	6,296,828	290,711	4.84
(LGSPV)	8,888	813,465	207,896	1,021,361	935,112	(86,249)	(8.44)
Total General Service	453,395	45,480,927	10,589,481	56,070,409	51,484,071	(4,586,338)	(8.18)
Large Power							
(LP-2 & SCISF)	51,429	3,525,084	1,201,693	4,726,777	3,477,653	(1,249,124)	(26.43)
Total Large Power	51,429	3,525,084	1,201,693	4,726,777	3,477,653	(1,249,124)	(26.43)
Total System Subtotal	1,023,746	109,259,433	23,931,985	133,191,419	130,191,419	(3,000,000)	(2.25)
EDR Discounts		(425,603)	(150,635)	(576,237)	(423,958)	152,280	(26.43)
Total System w EDR	1,023,746	108,833,830	23,781,351	132,615,181	129,767,461	(2,847,720)	(2.15)

(1) Actual FY2014 with Adjustments for new school rates (EDU-1 and EDUAL) and Burd & Fletcher EDR Discount (LP-2 & SCISF)

(2) Percent increase/(decrease) in Revenue compared to Existing Revenue.

Table B-9
Comparison of Existing Rates to Cost of Service Rates
Independence Power & Light

Description	Existing Rates	Cost of Service Rates
Residential Service (RS-3)		
Customer Charge ($/Month)		23.96
Energy Charge ($/kWh)		0.11871
On-Peak Season (5 Mo. May-Sep)		
First 30 kWh	0.15200	
Next 70 kWh	0.09740	
All over 100 kWh	0.09240	
Off-Peak Season (7 mo. Oct-Apr)		
First 30 kWh	0.15200	
Next 70 kWh	0.09740	
Next 200 kWh	0.09240	
Next 300 kWh	0.08370	
All over 600 kWh	0.07840	
Residential Service Water Heaters (RSWH)		
Customer Charge ($/Month)		23.96
Energy Charge ($/kWh)		0.11871
After first 150 kWh, next 300 kWh	0.06130	
Residential Service Space and Water Heaters (RSSHW)		
Customer Charge ($/Month)		23.96
Energy Charge ($/kWh)		0.10694
All over 900 kWh	0.04350	
Residential Service Space Heaters (RSSH)		
Customer Charge ($/Month)		23.96
Energy Charge ($/kWh)		0.10694
All over 600 kWh	0.04350	
Residential All Electric Home Service (RS-4)		
Customer Charge ($/Month)		23.96
Energy Charge ($/kWh)		0.10694
On-Peak Season (5 Mo. May-Sep)		
First 500 kWh	0.09050	
All over 500 kWh	0.08050	
Off-Peak Season (7 mo. Oct-Apr)		
First 500 kWh	0.09050	
Next 400 kWh	0.06890	
All over 900 kWh	0.04350	

Table B-9

Comparison of Existing Rates to Cost of Service Rates

Independence Power & Light

Description	Existing Rates	Cost of Service Rates
General Service (GS-1)		
Customer Charge ($/Month)		47.92
Energy Charge ($/kWh)		0.12442
First 16 kWh	0.03070	
Next 84 kWh	0.15220	
Next 100 kWh	0.12200	
Next 600 kWh	0.10390	
All over 800 kWh	0.10040	
Large General Service (LGS-1)		
Customer Charge ($/Month)		119.80
Demand Charge ($/kW-Month)		23.20
First 50 kW	5.92	
Next 100 kW	4.76	
All over 150 kW	3.54	
Energy Charge ($/kWh)		0.02784
First 100 hours use times kW billing demand	0.07200	
Next 200 hours use times kW billing demand	0.06230	
Next 100 hours use times kW bill demand	0.05000	
All over 400 hours use times KW billing demand	0.04620	
Sewer Pumping (SP-1)		
Customer Charge ($/Month)		119.80
Energy Charge ($/kWh)	0.07460	0.18854
Schools (EDU-1)		
Customer Charge ($/Month)		99.77
Energy Charge ($/kWh)		0.13080
Energy Charge (EDU-AL) ($/kWh)		0.10618
On-Peak Season (5 Mo. May-Sep)		
First 100 kWh	0.15100	
Next 300 kWh	0.09170	
All over 400 kWh	0.08320	
Off-Peak Season (7 mo. Oct-Apr)		
First 100 kWh	0.15100	
Next 300 kWh	0.09170	
Next 3600 kWh	0.08320	
All over 4,000 kWh	0.07470	
All Electric Service all over 10,000 kWh	0.04880	

Table B-9
Comparison of Existing Rates to Cost of Service Rates
Independence Power & Light

Description	Existing Rates	Cost of Service Rates
Churches and Hospitals (CH-1)		
Customer Charge ($/Month)		99.77
Energy Charge ($/kWh)		0.17491
Energy Charge (CH-AL) ($/kWh)		0.11437
On-Peak Season (5 Mo. May-Sep)		
First 100 kWh	0.15100	
Next 300 kWh	0.09170	
All over 400 kWh	0.08320	
Off-Peak Season (7 mo. Oct-Apr)		
First 100 kWh	0.15100	
Next 300 kWh	0.09170	
Next 3600 kWh	0.08320	
All over 4,000 kWh	0.07470	
All Electric Service all over 10,000 kWh	0.04880	
Large General Service Secondary/Primary Voltage (LGSSPV)		
Customer Charge ($/Month)		634.75
Demand Charge ($/kW-Month)		27.83
First 50 kW	5.92	
Next 100 kW	4.76	
All over 150 kW	3.54	
Energy Charge ($/kWh)		0.02729
First 100 hours use times kW billing demand	0.07200	
Next 200 hours use times kW billing demand	0.06230	
Next 100 hours use times kW bill demand	0.05000	
All over 400 hours use times KW billing demand	0.04620	

Table B-9
Comparison of Existing Rates to Cost of Service Rates
Independence Power & Light

Description	Existing Rates	Cost of Service Rates
Total Electric General Service (TEGS)		
Customer Charge ($/Month)		119.80
Demand Charge ($/kW-Month)		26.88
First 150 kW	4.80	
Next 850 kW	3.40	
Next 1,000 kW	3.03	
All over 2,000 kW	2.78	
Energy Charge ($/kWh)		0.02784
Rate A Energy used with first 1400 kW		
First 75 hours use times kW billing demand	0.06050	
Next 225 hours use times kW billing demand	0.05520	
Next 100 hours use times kW billing demand	0.04630	
All over 400 hours use times kW billing demand	0.04280	
Rate B Energy used with all over 1,400 kW		
First 75 hours use times kW billing demand	0.05770	
Next 225 hours use times kW billing demand	0.05260	
Next 100 hours use times kW billing demand	0.04520	
All over 400 hours use times kW billing demand	0.04280	
Large Power Service (LP-2)		
Customer Charge ($/Month)		634.75
Demand charge ($/kW)		18.97
first 500 kW	4.30	
next 500 kW	3.64	
all over 1,000 kW	2.44	
Energy Charge ($/kWh)		0.02729
Rate A Energy used with first 1800 kW		
First150 hours use times kW billing demand	0.05900	
Next 200 hours use times kW billing demand	0.05360	
Next 100 hours use times kW billing demand	0.04620	
All over 450 hours use times kW billing demand	0.04240	
Rate B Energy Used over 1800 kW		
First 150 hours use times kW billing demand	0.54200	
Next 200 hours use times kW billing demand	0.04820	
Next 100 hours use times kW billing demand	0.03930	
All over 450 hours use times kW billing demand	0.03610	

Table B-10
Test Year Revenue Requirements - 0% Increase
Independence Power and Light

Description	**FY14TY Actual**	**Pro Forma Adjustments**	**FY14TY w/ Pro Forma Adjustments**
OPERATING EXPENSE			
Purchased Power - Demand	25,148,667	-	25,148,667
Purchased Power - Energy	22,794,065	-	22,794,065
Fuel	5,527,924	-	5,527,924
Load Control	2,465,159	-	2,465,159
Border Customer	79,794	-	79,794
Production O&M	11,331,814	(252,160)	11,079,654
Transmission - Wheeling	6,175,999	-	6,175,999
Transmission Less Wheeling	1,468,278	-	1,468,278
Distribution O&M	11,409,556	-	11,409,556
Customer Accts, Service and Info	3,868,172	-	3,868,172
Administrative and General	17,762,528	-	17,762,528
Total O&M	**108,031,957**	**(252,160)**	**107,779,797**
Payroll Taxes	1,300,868	-	1,300,868
Depreciation Charged to O&M Expense	(643,381)	-	(643,381)
Unbilled Revenue	40,387	-	40,387
Other Post Retirement Benefits (Non-Cash)	(2,239,013)	-	(2,239,013)
Fuel, SO2 & Material Inventory Adjustments	(1,063,654)	-	(1,063,654)
Total O&M (Cash Flow)	**105,427,164**	**(252,160)**	**105,175,004**
Payment in Lieu of Taxes			
Gross Receipts Tax @ 9.08%	12,533,077	(19,341)	12,513,736
Property and Other	835,018	-	835,018
Total Payment in Lieu of Taxes	13,368,095	(19,341)	13,348,754
Debt Service			
Existing	10,853,078	(1,932,021)	8,921,057
New	-	-	-
Total Debt Service	10,853,078	(1,932,021)	8,921,057
Capital Improvements			
Capital Improvements	2,026,388	5,981,612	8,008,000
Routine Additions	6,385,058	(6,385,058)	-
Depreciation to Eliminate Neg. Net Income	-	3,113,659	3,113,659
Transfers (999)		-	-
Total Capital Improvements	8,411,446	2,710,213	11,121,659
Revenue Credits			
Wholesale Sales to Border Customers	(166,473)	16,473	(150,000)
Wholesale Sales to Interchanges	(2,087,725)	528,925	(1,558,800)
Other Operating Revenue	(2,025,995)	90,595	(1,935,400)
Proposed Revenue Reduction	-	(3,000,000)	(3,000,000)
Private Outdoor Lighting Revenue	(392,595)		(392,595)
Public Street Lights Revenue	(510,003)		(510,003)
Traffic Signal Revenue	(78,256)		(78,256)
Total Revenue Credits	(5,261,047)	(2,364,007)	(7,625,054)
Other Revenue			
Interest on Invested Funds	(29,439)	29,439	-
Miscellaneous	(8,940,088)	8,190,088	(750,000)
Total Revenue Credits	(8,969,527)	8,219,527	(750,000)
Total Revenue Requirements	**123,829,208**	**6,362,210**	**130,191,419**

APPENDIX C

PROPOSED POWER COST ADJUSTMENT – SCHEDULE PCA-1 AND WORKSHEETS

Table C-1 Proposed Schedule PCA-1 For Year 2015/16 from ProForma V17b
Independence Power & Light
(All Amounts in $ Except Where Noted)

Line No.	Description	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Total		
1	Power Supply Related Cost ($)															
2	B - FOB Cost of Fuel Used at IPL's Generating Stations (1)															
3	Blue Valley Steam	223,823	239,602	173,811	148,897	161,042	193,952	198,376	176,211	166,900	144,628	178,208	209,550	2,215,000	2,215,000	Sch 3B Ln 16
4	Missouri City	37,388	40,024	29,034	24,872	26,901	32,398	33,137	29,435	27,879	24,159	29,768	35,004	370,000	370,000	Sch 3B Ln 17
5	Gas Turbines	101	108	78	67	73	88	90	80	75	65	80	95	1,000	1,000	Sch 3B Ln 18
6	Dogwood Fuel	339,321	363,244	263,502	225,731	244,145	294,037	300,743	267,141	253,025	219,260	270,169	317,683	3,358,000	3,358,000	Sch 3B Ln 20
7	Dogwood Variable	0	0	0	0	0	0	0	0	0	0	0	0	0		
8	Inventory Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0		
9	subtotal	600,633	642,978	466,425	399,567	432,161	520,475	532,346	472,867	447,879	388,112	478,226	562,332	5,944,000	5,944,000	
10	C - Cost of Purchased Energy (2)															
11	OPPD	623,874	667,857	484,473	415,028	448,883	540,614	552,944	491,164	465,210	403,130	496,731	584,091	6,174,000	6,174,000	Sch 3B Ln 22
12	MJMEUC	618,619	662,232	480,393	411,533	445,102	536,061	548,287	487,028	461,292	399,735	492,547	579,171	6,122,000	6,122,000	Sch 3B Ln 23
13	ENEL - Smoky Hills	263,333	281,898	204,493	175,180	189,470	228,189	233,394	207,317	196,362	170,158	209,666	246,540	2,606,000	2,606,000	Sch 3B Ln 24
14	Other Purchases	323,962	346,801	251,575	215,513	233,093	280,727	287,130	255,049	241,572	209,335	257,940	303,303	3,206,000	3,206,000	Sch 3B Ln 25
15	SPP IM Costs	0	0	0	0	0	0	0	0	0	0	0	0	0		
16	SPP IM TCR Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0		
17	Tenaska Power Services	0	0	0	0	0	0	0	0	0	0	0	0	0		
18	SPP EIS True Up	0	0	0	0	0	0	0	0	0	0	0	0	0		
19	Dogwood True Up	0	0	0	0	0	0	0	0	0	0	0	0	0		
20	Net Metering Customers	0	0	0	0	0	0	0	0	0	0	0	0	0		
21																
22	subtotal	1,829,788	1,958,789	1,420,933	1,217,254	1,316,548	1,585,591	1,621,755	1,440,558	1,364,435	1,182,359	1,456,884	1,713,106	18,108,000	18,108,000	
23	D - Energy Sales Transactions (3)															
24	SPP IM Sales	0	0	0	0	0	0	0	0	0	0	0	0	0		
25	SPP IM Sales TCR	0	0	0	0	0	0	0	0	0	0	0	0	0		
26	Other Sales	151,573	162,259	117,705	100,833	109,058	131,345	134,340	119,331	113,025	97,942	120,683	141,907	1,500,000	1,500,000	Sch 1 Ln 24
27																
28	subtotal	151,573	162,259	117,705	100,833	109,058	131,345	134,340	119,331	113,025	97,942	120,683	141,907	1,500,000	1,500,000	
29	B + C - D	2,278,847	2,439,508	1,769,654	1,515,988	1,639,651	1,974,721	2,019,760	1,794,094	1,699,289	1,472,529	1,814,427	2,133,531	22,552,000	22,552,000	
30	E - PILOT Adjustment on B + C - D	227,584	243,629	176,732	151,399	163,749	197,211	201,709	179,173	169,705	147,059	181,203	213,071	2,252,223	2,252,223	
31	subtotal	2,506,431	2,683,137	1,946,385	1,667,387	1,803,400	2,171,932	2,221,470	1,973,267	1,868,994	1,619,587	1,995,631	2,346,602	24,804,223	24,804,223	
32	F - Reconciliation From Previous Year Already Adjusted for PILOT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
33	Total	$2,506,431	$2,683,137	$1,946,385	$1,667,387	$1,803,400	$2,171,932	$2,221,470	$1,973,267	$1,868,994	$1,619,587	$1,995,631	$2,346,602	$24,804,223	$24,804,223	
34	G - Energy Sales (kWh) Subject to Schedule PCA-1	106,569,163	114,082,366	82,756,961	70,894,439	76,677,454	92,346,840	94,453,087	83,899,930	79,466,405	68,862,075	84,850,791	99,773,488	1,054,633,000	1,054,633,000	Sch 1 Ln 5 - Unbilled
35	**SUMMARY OF POWER SUPPLY RELATED COST**															
36	To be recovered	$2,506,431	$2,683,137	$1,946,385	$1,667,387	$1,803,400	$2,171,932	$2,221,470	$1,973,267	$1,868,994	$1,619,587	$1,995,631	$2,346,602	24,804,223		
37	Recovered through base rates	2,515,032	2,692,344	1,953,064	1,673,109	1,809,588	2,179,385	2,229,093	1,980,038	1,875,407	1,625,145	2,002,479	2,354,654	24,889,339		
38	Recovered through PCA-1	0	0	0	0	0	0	0	0	0	0	0	0	0		
39																
40	Reconciliation - R Over/(Under) Recovery															
41	Within month	8,601	9,207	6,679	5,722	6,188	7,453	7,623	6,771	6,413	5,558	6,848	8,052			
42	Cumulative amount starting Jul 1 2015	8,601	17,808	24,487	30,209	36,397	43,850	51,473	58,244	64,657	70,215	77,063	85,115	85,115		
43	Power Cost per kWh sold ($/kWh)	0.02352	0.02352	0.02352	0.02352	0.02352	0.02352	0.02352	0.02352	0.02352	0.02352	0.02352	0.02352	0.02352		
44	Power Cost Recovered in Rates ($/kWh)															
45	Base Rate - B	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023519	
46	PCA-1 Applied Within Period	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000		
47	Total Recovered in Rates	0.02360	0.02360	0.02360	0.02360	0.02360	0.02360	0.02360	0.02360	0.02360	0.02360	0.02360	0.02360	0.02360		

Negative "Within month - Cumulative amount" means under recovery of power costs in rates.
Positive "Within month - Cumulative amount" means over recovery of power costs in rates.

Table C-2 Proposed Schedule PCA-1 Revised For Year 2016/17 ProForma V17b
Independence Power & Light
(All Amounts in $ Except Where Noted)

Line No.	Description	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Total		
1	Power Supply Related Cost ($)															
2	B - FOB Cost of Fuel Used at IPL's Generating Stations (1)															
3	Blue Valley Steam	46,684	49,976	36,253	31,057	33,590	40,454	41,377	36,754	34,812	30,166	37,170	43,707	462,000	462,000	Sch 3B Ln 16
4	Missouri City	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Sch 3B Ln 17
5	Gas Turbines	303	325	235	202	218	263	269	239	226	196	241	284	3,000	3,000	Sch 3B Ln 18
6	Dogwood Fuel	448,353	479,962	348,171	298,264	322,594	388,517	397,378	352,980	334,327	289,713	356,980	419,762	4,437,000	4,437,000	Sch 3B Ln 20
7	Dogwood Variable	0	0	0	0	0	0	0	0	0	0	0	0	0		
8	Inventory Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0		
9	subtotal	495,340	530,262	384,660	329,522	356,402	429,234	439,024	389,972	369,365	320,075	394,392	463,753	4,902,000	4,902,000	
10	C - Cost of Purchased Energy (2)															
11	OPPD	625,592	669,696	485,807	416,171	450,119	542,103	554,467	492,517	466,491	404,240	498,099	585,699	6,191,000	6,191,000	Sch 3B Ln 22
12	MJMEUC	631,048	675,538	490,045	419,801	454,045	546,831	559,303	496,813	470,560	407,766	502,443	590,808	6,245,000	6,245,000	Sch 3B Ln 23
13	ENEL - Smoky Hills	263,636	282,222	204,728	175,382	189,688	228,452	233,662	207,556	196,588	170,354	209,908	246,824	2,609,000	2,609,000	Sch 3B Ln 24
14	Other Purchases	549,805	588,567	426,955	365,754	395,590	476,430	487,297	432,852	409,978	355,269	437,757	514,745	5,441,000	5,441,000	Sch 3B Ln 25
15	SPP IM Costs	0	0	0	0	0	0	0	0	0	0	0	0	0		
16	SPP IM TCR Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0		
17	Tenaska Power Services	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Sch 3A Ln 45
18	SPP EIS True Up	0	0	0	0	0	0	0	0	0	0	0	0	0		
19	Dogwood True Up	0	0	0	0	0	0	0	0	0	0	0	0	0		
20	Net Metering Customers	0	0	0	0	0	0	0	0	0	0	0	0	0		
21																
22	subtotal	2,070,081	2,216,023	1,607,535	1,377,108	1,489,442	1,793,816	1,834,729	1,629,737	1,543,616	1,337,630	1,648,207	1,938,077	20,486,000	20,486,000	
23	D - Energy Sales Transactions (3)															
24	SPP IM Sales	159,152	170,372	123,590	105,875	114,511	137,912	141,057	125,297	118,676	102,839	126,717	149,003	1,575,000	1,575,000	Sch 1 Ln 24
25	SPP IM Sales TCR	0	0	0	0	0	0	0	0	0	0	0	0	0		
26	Other Sales	0	0	0	0	0	0	0	0	0	0	0	0	0		
27																
28	subtotal	159,152	170,372	123,590	105,875	114,511	137,912	141,057	125,297	118,676	102,839	126,717	149,003	1,575,000	1,575,000	
29	B + C - D	2,406,270	2,575,914	1,868,604	1,600,755	1,731,332	2,085,138	2,132,696	1,894,412	1,794,305	1,554,866	1,915,882	2,252,827	23,813,000	23,813,000	
30	E - PILOT Adjustment on B + C - D	240,309	257,251	186,614	159,864	172,905	208,239	212,988	189,191	179,194	155,281	191,335	224,985	2,378,157	2,378,157	
31	subtotal	2,646,579	2,833,165	2,055,218	1,760,619	1,904,237	2,293,377	2,345,684	2,083,603	1,973,499	1,710,147	2,107,217	2,477,813	26,191,157	26,191,157	
32	F - Reconciliation From Previous Year Already Adjusted for PILOT	(7,093)	(7,093)	(7,093)	(7,093)	(7,093)	(7,093)	(7,093)	(7,093)	(7,093)	(7,093)	(7,093)	(7,093)	(85,115)	0	
33	Total	$2,639,486	$2,826,072	$2,048,125	$1,753,527	$1,897,144	$2,286,284	$2,338,591	$2,076,510	$1,966,406	$1,703,054	$2,100,124	$2,470,720	$26,106,042	$26,191,157	
34	G - Energy Sales (kWh) Subject to Schedule PCA-1	106,913,436	114,450,910	83,024,308	71,123,464	76,925,161	92,645,167	94,758,218	84,170,970	79,723,122	69,084,534	85,124,902	100,095,807	1,058,040,000	1,058,040,000	Sch 1 Ln 5 - Unbilled
35	**SUMMARY OF POWER SUPPLY RELATED COST**															
36	To be recovered	$2,639,486	$2,826,072	$2,048,125	$1,753,527	$1,897,144	$2,286,284	$2,338,591	$2,076,510	$1,966,406	$1,703,054	$2,100,124	$2,470,720	26,106,042		
37	Recovered through base rates	2,523,157	2,701,041	1,959,374	1,678,514	1,815,434	2,186,426	2,236,294	1,986,435	1,881,466	1,630,395	2,008,948	2,362,261	24,969,744		
38	Recovered through PCA-1	117,605	125,896	91,327	78,236	84,618	101,910	104,234	92,588	87,695	75,993	93,637	110,105	1,163,844		
39																
40	Reconciliation - R Over/(Under) Recovery															
41	Within month	1,276	866	2,576	3,223	2,907	2,052	1,937	2,513	2,755	3,334	2,461	1,647			
42	Cumulative amount starting Jul 1 2016	1,276	2,141	4,717	7,940	10,847	12,899	14,836	17,349	20,104	23,438	25,900	27,546	27,546		
43	Power Cost per kWh sold ($/kWh)	0.02469	0.02469	0.02467	0.02465	0.02466	0.02468	0.02468	0.02467	0.02467	0.02465	0.02467	0.02468	0.02467		
44	Power Cost Recovered in Rates ($/kWh)															
45	Base Rate - B	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.024674	
46	PCA-1 Applied Within Period	0.001100	0.001100	0.001100	0.001100	0.001100	0.001100	0.001100	0.001100	0.001100	0.001100	0.001100	0.001100	0.001100		
47	Total Recovered in Rates	0.02470	0.02470	0.02470	0.02470	0.02470	0.02470	0.02470	0.02470	0.02470	0.02470	0.02470	0.02470	0.02470		

Negative "Within month - Cumulative amount" means under recovery of power costs in rates.
Positive "Within month - Cumulative amount" means over recovery of power costs in rates.

Table C-3 Proposed Schedule PCA-1 Revised For Year 2017/18 ProForma V17b
Independence Power & Light
(All Amounts in $ Except Where Noted)

Line No.	Description	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Total		
1	Power Supply Related Cost ($)															
2	B - FOB Cost of Fuel Used at IPL's Generating Stations (1)															
3	Blue Valley Steam	57,598	61,658	44,728	38,316	41,442	49,911	51,049	45,346	42,949	37,218	45,860	53,925	570,000	570,000	Sch 3B Ln 16
4	Missouri City	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Sch 3B Ln 17
5	Gas Turbines	101	108	78	67	73	88	90	80	75	65	80	95	1,000	1,000	Sch 3B Ln 18
6	Dogwood Fuel	506,759	542,485	393,527	337,118	364,617	439,128	449,144	398,962	377,879	327,454	403,483	474,444	5,015,000	5,015,000	Sch 3B Ln 20
7	Dogwood Variable	0	0	0	0	0	0	0	0	0	0	0	0	0		
8	Inventory Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0		
9	subtotal	564,457	604,252	438,333	375,502	406,132	489,127	500,283	444,387	420,904	364,737	449,423	528,463	5,586,000	5,586,000	
10	C - Cost of Purchased Energy (2)															
11	OPPD	694,810	743,795	539,559	462,218	499,922	602,083	615,816	547,011	518,105	448,967	553,210	650,504	6,876,000	6,876,000	Sch 3B Ln 22
12	MJMEUC	555,161	594,300	431,114	369,317	399,443	481,071	492,043	437,068	413,972	358,730	442,021	519,760	5,494,000	5,494,000	Sch 3B Ln 23
13	ENEL - Smoky Hills	262,524	281,032	203,865	174,643	188,888	227,489	232,677	206,680	195,759	169,636	209,023	245,784	2,598,000	2,598,000	Sch 3B Ln 24
14	Other Purchases	642,669	687,978	499,069	427,531	462,406	556,901	569,603	505,961	479,225	415,275	511,696	601,687	6,360,000	6,360,000	Sch 3B Ln 25
15	SPP IM Costs	0	0	0	0	0	0	0	0	0	0	0	0	0		
16	SPP IM TCR Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0		
17	Tenaska Power Services	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Sch 3A Ln 45
18	SPP EIS True Up	0	0	0	0	0	0	0	0	0	0	0	0	0		
19	Dogwood True Up	0	0	0	0	0	0	0	0	0	0	0	0	0		
20	Net Metering Customers	0	0	0	0	0	0	0	0	0	0	0	0	0		
21																
22	subtotal	2,155,164	2,307,105	1,673,606	1,433,709	1,550,660	1,867,544	1,910,139	1,696,721	1,607,061	1,392,608	1,715,950	2,017,734	21,328,000	21,328,000	
23	D - Energy Sales Transactions (3)															
24	SPP IM Sales	167,134	178,917	129,789	111,185	120,255	144,829	148,132	131,582	124,629	107,998	133,073	156,477	1,654,000	1,654,000	Sch 1 Ln 24
25	SPP IM Sales TCR	0	0	0	0	0	0	0	0	0	0	0	0	0		
26	Other Sales	0	0	0	0	0	0	0	0	0	0	0	0	0		
27																
28	subtotal	167,134	178,917	129,789	111,185	120,255	144,829	148,132	131,582	124,629	107,998	133,073	156,477	1,654,000	1,654,000	
29	B + C - D	2,552,487	2,732,439	1,982,150	1,698,025	1,836,537	2,211,842	2,262,289	2,009,526	1,903,336	1,649,347	2,032,300	2,389,721	25,260,000	25,260,000	
30	E - PILOT Adjustment on B + C - D	254,912	272,883	197,953	169,578	183,411	220,892	225,930	200,687	190,082	164,717	202,962	238,657	2,522,666	2,522,666	
31	subtotal	2,807,399	3,005,323	2,180,103	1,867,604	2,019,948	2,432,734	2,488,220	2,210,213	2,093,419	1,814,064	2,235,262	2,628,377	27,782,666	27,782,666	
32	F - Reconciliation From Previous Year Already Adjusted for PILOT	(2,296)	(2,296)	(2,296)	(2,296)	(2,296)	(2,296)	(2,296)	(2,296)	(2,296)	(2,296)	(2,296)	(2,296)	(27,546)	0	
33	Total	$2,805,103	$3,003,027	$2,177,808	$1,865,308	$2,017,653	$2,430,438	$2,485,924	$2,207,918	$2,091,123	$1,811,769	$2,232,967	$2,626,082	$27,755,120	$27,782,666	
34	G - Energy Sales (kWh) Subject to Schedule PCA-1	107,251,848	114,813,180	83,287,104	71,348,590	77,168,651	92,938,416	95,058,155	84,437,395	79,975,468	69,303,206	85,394,347	100,412,639	1,061,389,000	1,061,389,000	Sch 1 Ln 5 - Unbilled
35	**SUMMARY OF POWER SUPPLY RELATED COST**															
36	To be recovered	$2,805,103	$3,003,027	$2,177,808	$1,865,308	$2,017,653	$2,430,438	$2,485,924	$2,207,918	$2,091,123	$1,811,769	$2,232,967	$2,626,082	27,755,120		
37	Recovered through base rates	2,531,144	2,709,591	1,965,576	1,683,827	1,821,180	2,193,347	2,243,372	1,992,723	1,887,421	1,635,556	2,015,307	2,369,738	25,048,780		
38	Recovered through PCA-1	278,855	298,514	216,546	185,506	200,638	241,640	247,151	219,537	207,936	180,188	222,025	261,073	2,759,611		
39																
40	Reconciliation - R Over/(Under) Recovery															
41	Within month	4,895	5,078	4,314	4,025	4,166	4,548	4,600	4,342	4,234	3,975	4,365	4,729			
42	Cumulative amount starting Jul 1 2016	4,895	9,973	14,288	18,312	22,478	27,027	31,626	35,968	40,202	44,177	48,543	53,272	53,272		
43	Power Cost per kWh sold ($/kWh)	0.02615	0.02616	0.02615	0.02614	0.02615	0.02615	0.02615	0.02615	0.02615	0.02614	0.02615	0.02615	0.02615		
44	Power Cost Recovered in Rates ($/kWh)															
45	Base Rate - B	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.026150	
46	PCA-1 Applied Within Period	0.002600	0.002600	0.002600	0.002600	0.002600	0.002600	0.002600	0.002600	0.002600	0.002600	0.002600	0.002600	0.002600		
47	Total Recovered in Rates	0.02620	0.02620	0.02620	0.02620	0.02620	0.02620	0.02620	0.02620	0.02620	0.02620	0.02620	0.02620	0.02620		

Negative "Within month - Cumulative amount" means under recovery of power costs in rates.
Positive "Within month - Cumulative amount" means over recovery of power costs in rates.

Table C-4 Proposed Schedule PCA-1 Revised For Year 2018/19 ProForma V17b
Independence Power & Light
(All Amounts in $ Except Where Noted)

Line No.	Description	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Total		
1	Power Supply Related Cost ($)															
2	B - FOB Cost of Fuel Used at IPL's Generating Stations (1)															
3	Blue Valley Steam	59,012	63,173	45,826	39,258	42,460	51,137	52,303	46,459	44,004	38,132	46,986	55,249	584,000	584,000	Sch 3B Ln 16
4	Missouri City	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Sch 3B Ln 17
5	Gas Turbines	707	757	549	471	509	613	627	557	527	457	563	662	7,000	7,000	Sch 3B Ln 18
6	Dogwood Fuel	510,497	546,488	396,430	339,605	367,307	442,368	452,458	401,905	380,667	329,869	406,460	477,944	5,052,000	5,052,000	Sch 3B Ln 20
7	Dogwood Variable	0	0	0	0	0	0	0	0	0	0	0	0	0		
8	Inventory Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0		
9	subtotal	570,217	610,418	442,806	379,333	410,276	494,118	505,388	448,921	425,199	368,459	454,009	533,856	5,643,000	5,643,000	
10	C - Cost of Purchased Energy (2)															
11	OPPD	650,248	696,091	504,954	432,573	467,859	563,468	576,320	511,928	484,876	420,172	517,730	608,783	6,435,000	6,435,000	Sch 3B Ln 22
12	MJMEUC	787,269	842,773	611,359	523,726	566,447	682,203	697,763	619,803	587,050	508,712	626,827	737,067	7,791,000	7,791,000	Sch 3B Ln 23
13	ENEL - Smoky Hills	262,827	281,357	204,100	174,844	189,107	227,751	232,946	206,919	195,985	169,832	209,264	246,067	2,601,000	2,601,000	Sch 3B Ln 24
14	Other Purchases	522,320	559,144	405,611	347,470	375,814	452,613	462,936	411,213	389,483	337,509	415,873	489,013	5,169,000	5,169,000	Sch 3B Ln 25
15	SPP IM Costs	0	0	0	0	0	0	0	0	0	0	0	0	0		
16	SPP IM TCR Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0		
17	Tenaska Power Services	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Sch 3A Ln 45
18	SPP EIS True Up	0	0	0	0	0	0	0	0	0	0	0	0	0		
19	Dogwood True Up	0	0	0	0	0	0	0	0	0	0	0	0	0		
20	Net Metering Customers	0	0	0	0	0	0	0	0	0	0	0	0	0		
21																
22	subtotal	2,222,664	2,379,364	1,726,024	1,478,613	1,599,227	1,926,036	1,969,965	1,749,863	1,657,395	1,436,225	1,769,694	2,080,930	21,996,000	21,996,000	
23	D - Energy Sales Transactions (3)															
24	SPP IM Sales	175,420	187,788	136,224	116,697	126,216	152,009	155,476	138,105	130,807	113,352	139,670	164,234	1,736,000	1,736,000	Sch 1 Ln 24
25	SPP IM Sales TCR	0	0	0	0	0	0	0	0	0	0	0	0	0		
26	Other Sales	0	0	0	0	0	0	0	0	0	0	0	0	0		
27																
28	subtotal	175,420	187,788	136,224	116,697	126,216	152,009	155,476	138,105	130,807	113,352	139,670	164,234	1,736,000	1,736,000	
29	B + C - D	2,617,461	2,801,994	2,032,606	1,741,249	1,883,287	2,268,145	2,319,876	2,060,679	1,951,786	1,691,332	2,084,033	2,450,552	25,903,000	25,903,000	
30	E - PILOT Adjustment on B + C - D	261,401	279,830	202,992	173,895	188,080	226,515	231,681	205,796	194,921	168,910	208,128	244,732	2,586,881	2,586,881	
31	subtotal	2,878,862	3,081,824	2,235,599	1,915,144	2,071,367	2,494,660	2,551,558	2,266,475	2,146,707	1,860,242	2,292,161	2,695,283	28,489,881	28,489,881	
32	F - Reconciliation From Previous Year Already Adjusted for PILOT	(4,439)	(4,439)	(4,439)	(4,439)	(4,439)	(4,439)	(4,439)	(4,439)	(4,439)	(4,439)	(4,439)	(4,439)	(53,272)	0	
33	Total	$2,874,423	$3,077,384	$2,231,159	$1,910,705	$2,066,927	$2,490,220	$2,547,119	$2,262,035	$2,142,268	$1,855,802	$2,287,722	$2,690,844	$28,436,609	$28,489,881	
34	G - Energy Sales (kWh) Subject to Schedule PCA-1	107,590,866	115,176,099	83,550,371	71,574,120	77,412,578	93,232,190	95,358,630	84,704,297	80,228,267	69,522,271	85,664,275	100,730,038	1,064,744,000	1,064,744,000	Sch 1 Ln 5 - Unbilled
35	**SUMMARY OF POWER SUPPLY RELATED COST**															
36	To be recovered	$2,874,423	$3,077,384	$2,231,159	$1,910,705	$2,066,927	$2,490,220	$2,547,119	$2,262,035	$2,142,268	$1,855,802	$2,287,722	$2,690,844	28,436,609		
37	Recovered through base rates	2,539,144	2,718,156	1,971,789	1,689,149	1,826,937	2,200,280	2,250,464	1,999,021	1,893,387	1,640,726	2,021,677	2,377,229	25,127,958		
38	Recovered through PCA-1	344,291	368,564	267,361	229,037	247,720	298,343	305,148	271,054	256,730	222,471	274,126	322,336	3,407,181		
39																
40	Reconciliation - R Over/(Under) Recovery															
41	Within month	9,013	9,335	7,991	7,482	7,730	8,402	8,493	8,040	7,850	7,394	8,081	8,721			
42	Cumulative amount starting Jul 1 2016	9,013	18,348	26,338	33,820	41,550	49,952	58,445	66,484	74,334	81,728	89,809	98,530	98,530		
43	Power Cost per kWh sold ($/kWh)	0.02672	0.02672	0.02670	0.02670	0.02670	0.02671	0.02671	0.02671	0.02670	0.02669	0.02671	0.02671	0.02671		
44	Power Cost Recovered in Rates ($/kWh)															
45	Base Rate - B	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.026707	
46	PCA-1 Applied Within Period	0.003200	0.003200	0.003200	0.003200	0.003200	0.003200	0.003200	0.003200	0.003200	0.003200	0.003200	0.003200	0.003200		
47	Total Recovered in Rates	0.02680	0.02680	0.02680	0.02680	0.02680	0.02680	0.02680	0.02680	0.02680	0.02680	0.02680	0.02680	0.02680		

Negative "Within month - Cumulative amount" means under recovery of power costs in rates.
Positive "Within month - Cumulative amount" means over recovery of power costs in rates.

Table C - 5 Proposed Schedule PCA-1 Revised For Year 2019/20 ProForma V17b
Independence Power & Light
(All Amounts in $ Except Where Noted)

Line No.	Description	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Total		
1	Power Supply Related Cost ($)															
2	B - FOB Cost of Fuel Used at IPL's Generating Stations (1)															
3	Blue Valley Steam	49,817	53,329	38,686	33,140	35,844	43,169	44,153	39,220	37,147	32,190	39,664	46,640	493,000	493,000	Sch 3B Ln 16
4	Missouri City	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Sch 3B Ln 17
5	Gas Turbines	303	325	235	202	218	263	269	239	226	196	241	284	3,000	3,000	Sch 3B Ln 18
6	Dogwood Fuel	520,097	556,764	403,885	345,991	374,214	450,687	460,966	409,463	387,826	336,072	414,103	486,932	5,147,000	5,147,000	Sch 3B Ln 20
7	Dogwood Variable	0	0	0	0	0	0	0	0	0	0	0	0	0		
8	Inventory Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0		
9	subtotal	570,217	610,418	442,806	379,333	410,276	494,118	505,388	448,921	425,199	368,459	454,009	533,856	5,643,000	5,643,000	
10	C - Cost of Purchased Energy (2)															
11	OPPD	734,320	786,090	570,241	488,502	528,350	636,320	650,834	578,117	547,567	474,497	584,669	687,494	7,267,000	7,267,000	Sch 3B Ln 22
12	MJMEUC	849,616	909,515	659,775	565,202	611,307	736,230	753,022	668,887	633,541	548,999	676,468	795,438	8,408,000	8,408,000	Sch 3B Ln 23
13	ENEL - Smoky Hills	264,141	282,763	205,120	175,718	190,052	228,890	234,110	207,953	196,964	170,681	210,310	247,297	2,614,000	2,614,000	Sch 3B Ln 24
14	Other Purchases	451,687	483,531	350,761	300,482	324,993	391,407	400,334	355,605	336,814	291,868	359,635	422,884	4,470,000	4,470,000	Sch 3B Ln 25
15	SPP IM Costs	0	0	0	0	0	0	0	0	0	0	0	0	0		
16	SPP IM TCR Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0		
17	Tenaska Power Services	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Sch 3A Ln 45
18	SPP EIS True Up	0	0	0	0	0	0	0	0	0	0	0	0	0		
19	Dogwood True Up	0	0	0	0	0	0	0	0	0	0	0	0	0		
20	Net Metering Customers	0	0	0	0	0	0	0	0	0	0	0	0	0		
21																
22	subtotal	2,299,765	2,461,900	1,785,897	1,529,903	1,654,701	1,992,847	2,038,299	1,810,562	1,714,887	1,486,045	1,831,082	2,153,114	22,759,000	22,759,000	
23	D - Energy Sales Transactions (3)															
24	SPP IM Sales	184,212	197,199	143,051	122,546	132,542	159,627	163,268	145,026	137,363	119,032	146,670	172,465	1,823,000	1,823,000	Sch 1 Ln 24
25	SPP IM Sales TCR	0	0	0	0	0	0	0	0	0	0	0	0	0		
26	Other Sales	0	0	0	0	0	0	0	0	0	0	0	0	0		
27																
28	subtotal	184,212	197,199	143,051	122,546	132,542	159,627	163,268	145,026	137,363	119,032	146,670	172,465	1,823,000	1,823,000	
29	B + C - D	2,685,770	2,875,119	2,085,652	1,786,691	1,932,435	2,327,337	2,380,419	2,114,457	2,002,723	1,735,471	2,138,421	2,514,505	26,579,000	26,579,000	
30	E - PILOT Adjustment on B + C - D	268,223	287,132	208,290	178,433	192,988	232,427	237,728	211,167	200,008	173,318	213,560	251,119	2,654,392	2,654,392	
31	subtotal	2,953,993	3,162,251	2,293,942	1,965,124	2,125,424	2,559,764	2,618,147	2,325,624	2,202,731	1,908,789	2,351,981	2,765,623	29,233,392	29,233,392	
32	F - Reconciliation From Previous Year Already Adjusted for PILOT	(8,211)	(8,211)	(8,211)	(8,211)	(8,211)	(8,211)	(8,211)	(8,211)	(8,211)	(8,211)	(8,211)	(8,211)	(98,530)	0	
33	Total	$2,945,782	$3,154,040	$2,285,731	$1,956,913	$2,117,213	$2,551,553	$2,609,936	$2,317,413	$2,194,520	$1,900,578	$2,343,770	$2,757,412	$29,134,862	$29,233,392	
34	G - Energy Sales (kWh) Subject to Schedule PCA-1	107,940,797	115,550,701	83,822,112	71,806,909	77,664,356	93,535,420	95,668,776	84,979,792	80,489,203	69,748,387	85,942,891	101,057,655	1,068,207,000	1,068,207,000	Sch 1 Ln 5 - Unbilled
35	**SUMMARY OF POWER SUPPLY RELATED COST**															
36	To be recovered	$2,945,782	$3,154,040	$2,285,731	$1,956,913	$2,117,213	$2,551,553	$2,609,936	$2,317,413	$2,194,520	$1,900,578	$2,343,770	$2,757,412	29,134,862		
37	Recovered through base rates	2,547,403	2,726,997	1,978,202	1,694,643	1,832,879	2,207,436	2,257,783	2,005,523	1,899,545	1,646,062	2,028,252	2,384,961	25,209,685		
38	Recovered through PCA-1	399,381	427,538	310,142	265,686	287,358	346,081	353,974	314,425	297,810	258,069	317,989	373,913	3,952,366		
39																
40	Reconciliation - R Over/(Under) Recovery															
41	Within month	1,002	494	2,613	3,415	3,024	1,964	1,822	2,535	2,835	3,553	2,471	1,462			
42	Cumulative amount starting Jul 1 2016	1,002	1,496	4,108	7,524	10,547	12,511	14,333	16,868	19,704	23,256	25,727	27,189	27,189		
43	Power Cost per kWh sold ($/kWh)	0.02729	0.02730	0.02727	0.02725	0.02726	0.02728	0.02728	0.02727	0.02726	0.02725	0.02727	0.02729	0.02727		
44	Power Cost Recovered in Rates ($/kWh)															
45	Base Rate - B	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.023600	0.027275	
46	PCA-1 Applied Within Period	0.003700	0.003700	0.003700	0.003700	0.003700	0.003700	0.003700	0.003700	0.003700	0.003700	0.003700	0.003700	0.003700		
47	Total Recovered in Rates	0.02730	0.02730	0.02730	0.02730	0.02730	0.02730	0.02730	0.02730	0.02730	0.02730	0.02730	0.02730	0.02730		

Negative "Within month - Cumulative amount" means under recovery of power costs in rates.
Positive "Within month - Cumulative amount" means over recovery of power costs in rates.

APPENDIX D

PROPOSED REGULATORY AND ENVIRONMENTAL COMPLIANCE RIDER – SCHEDULE REC-1 AND WORKSHEET

Table D-1 Regulatory & Environmental Compliance Rider (Schedule REC-1) Calculation of Rate ($ except where noted)

Independence Power &Light

	Description	Regulatory Body				Projected FY 2015/16	Projected FY 2016/17	Projected FY 2017/18	Projected FY 2018/19	Projected FY 2019/20
	Annual Regulatory & Environmental Expenses									
	Permit Fees (EIQ)	MoDNR				125,000	131,250	137,813	144,703	151,938
	Annual Stack Testing	MoDNR / EPA				13,000	13,650	14,333	15,049	15,802
	Blue Valley NPDES Water Sampling	MoDNR				5,000	5,250	5,513	5,788	6,078
	Underground tank inspection - Shirley	MoDNR				43,000	45,150	47,408	49,778	52,267
	Mo City Ash Pond Groundwater Monitoring/Reporting	MoDNR				44,000	46,200	48,510	50,936	53,482
	Subtotal					230,000	241,500	253,575	266,254	279,566
	Capital Expenditures and Amortized Costs									
	Description		Total Capital Cost	Term	Interest	Annual Projected Cost FY 2015/16	Annual Projected Cost FY 2016/17	Annual Projected Cost FY 2017/18	Annual Projected Cost FY 2018/19	Annual Projected Cost FY 2019/20
	Mo City Settling Basin (Installed in 2014/15)	MoDNR	608,895	10	5.00%	78,855	78,855	78,855	78,855	78,855
	Mo City Ash Pond Closure (to be installed in 2016/17)	MoDNR	1,000,000	3	0.00%	-	333,333	333,333	333,333	0
	Mo Retirement Costs (to be installed in 2016/17)	MoDNR	921,000	3	0.00%	-	307,000	307,000	307,000	0
	Subtotal					78,855	719,188	719,188	719,188	78,855
B	Regulatory & Environmental Compliance Costs					308,855	960,688	972,763	985,442	358,421
C	Adjustment of PILOT (= B / (1 - 0.0908))					339,699	1,056,630	1,069,911	1,083,856	394,216
D	Reconciliation Adjustment for Prior Fiscal Year					0	0	0	0	0
E	Annual Number of Retail Customer Billings					511,047	684,803	688,227	691,668	695,126
A	Regulatory & Environmental Rider Rate ($/cust/mo.)					0.66	1.54	1.55	1.57	0.57
	Effective Date					Oct 1 2015	July 1 2016	July 1 2017	July 1 2018	July 1 2019

APPENDIX E

PROPOSED PARTIAL REQUIREMENTS RATE SCHEDULE, SERVICE AGREEMENT AND INTERCONNECTION AGREEMENT

Partial Requirements Electric Service Agreement
Between
Independence Power & Light Department
and
[Customer]

This Partial Requirements Electric Service Agreement ("Agreement"), entered into on this ____ day of ___________, 2015, is by and between the Independence Power & Light Department ("Department"), a Missouri municipal corporation, _______________ ("Customer"), each sometimes referred to herein as "Party" or collectively as "Parties."

WHEREAS, the Department is a provider of electric energy and power to retail electric customers; and

WHEREAS, Customer plans to install, own and operate Customer-Owned Generation that supplies a portion of its Facility's electric requirements; and

WHEREAS, Customer desires to purchase from the Department under this Agreement, Partial Requirements Electric Service to meet the electric requirements of its Facility, net of any such requirements satisfied by said Customer-Owned Generation; and

WHEREAS, the Department desires to be the exclusive provider of such Partial Requirements Electric Service to Customer's Facility;

NOW, THEREFORE, the Parties hereto agree as follows:

Article I. Definitions

The following terms, when used herein with initial capitalization, whether singular or plural, shall have the meanings specified in this Article I:

"Agreement" means this Partial Requirements Electric Service Agreement and any renewals thereof or amendments thereto.

"Back-Up Contract Demand" means the specified Demand in kilowatts ("kW") of Back-Up Power that the Customer contracts with the Department to supply and which the Department agrees to have available for delivery to the Customer in excess of which the Department is under no obligation to supply. The Back-Up Contract Demand shall be established by agreement between the Customer and the Department. The Back-Up Contract Demand shall not exceed the total output capacity of the Customer-Owned Generation facilities.

"Back-Up Power" means electric power expressed in kW and associated energy expressed in kilowatt-hours ("kWh") to meet the agreed-upon Back-Up Contract Demand portion of Customer's electric load requirements. Back-Up Power shall be billed in accordance with the Electric Rate Schedule.

"Billing Demand" means the Demand in kW for the fifteen (15) minute period of Customer's greatest use during the Billing Period, determined to the nearest kW, as shown by or computed from Department meter readings at the Point of Delivery.

"Billing Period" means the period of approximately thirty (30) days between regular successive meter readings.

"Customer-Owned Generation" means the Customer's planned installation of on-site, operable generating equipment associated with the Facility. The Customer-Owned Generation consists of a __________________________ generator, with a nameplate rating of _______ kW, located at the Facility.

"Demand" means the maximum rate in kW at which electric energy is generated, transferred, or used. Demand measurements are calculated based on integrated average usage over consecutive fifteen (15) minute periods of time, unless specified otherwise in the applicable Electric Rate Schedule.

"Electric Rules and Regulations" means the Department's currently effective electric service policies, standards and requirements as may be in effect from time to time and filed with the City Clerk of Independence.

"Electric Rate Schedule" means the Department's currently effective Electric Rate Schedule PR-1, Partial Requirements Service, as the same may be amended or superseded from time to time.

"Excess Power" is the Customer's kW of Billing Demand in excess of Customer's Total Contract Demand. The Excess Power kW for the Billing Period shall be the kW for the fifteen (15) minute period of the Customer's greatest use of Excess Power during the Billing Period. Excess Power shall equal the Customer's Billing Demand minus the Total Contract Demand but shall not be less than zero. Excess Power shall be billed in accordance with the Electric Rate Schedule.

"Facility" means the Customer's facilities to which the Department shall provide electric power and energy, served from Customer's _______________ Substation located at _________________, and includes the Customer-Owned Generation.

"Maintenance Power" means electric power expressed in kW and associated energy expressed in kWh made available by the Department to Customer during scheduled Customer-Owned Generation maintenance periods to replace Back-Up Power. Maintenance Power shall not exceed the Back-Up Contract Demand.

"Interconnection Agreement" shall mean the Transmission System Generator Interconnection Agreement between the Parties. Department and Customer must execute a Generator Interconnection Agreement as a condition of this Agreement.

"Interconnection Standards" shall mean all provisions, forms and related documents described in collective parts of the Department's Customer-Owned Generator Interconnection Standards or successor document.

"Point of Delivery" means the point of delivery for all Partial Requirements, Back-Up and Maintenance Power delivered to Customer, and shall be at the Department's point of metering used for billing purposes.

"Partial Requirements Contract Demand" is the specified Demand in kW of Partial Requirements Power that the Customer contracts with the Department to supply and which the Department agrees to have available for delivery to the Customer in excess of which the Department is under no obligation to supply. The Partial Requirements Contract Demand shall be established by agreement between the Customer and Department.

"Partial Requirements Power" means electric power expressed in kW and associated energy expressed in kWh to meet the agreed-upon Partial Requirements Contract Demand portion of Customer's electric load requirements. Partial Requirements Power shall be billed in accordance with the Electric Rate Schedule.

"Total Contract Demand" is the sum of Partial Requirements Contract Demand and Back-Up Contract Demand. Total Contract Demand is the maximum Demand that the Department agrees to supply and have available for delivery to Customer.

Article II. Term and Termination

Section 2.01 Term

This Agreement shall be effective upon execution by both parties, and shall remain in full force and effect for an Initial Period of five (5) years from the Effective Date. Thereafter, this Agreement shall continue in full force and effect for successive periods of one (1) year. Either Party may terminate this Agreement at the end of the Initial Period or any succeeding period of one (1) year upon delivery of written notice by the terminating Party not less than twelve (12) months prior to the end of the Initial Period or of any succeeding period; provided, however, this Agreement shall remain effective so long as Customer receives partial requirements electric service from the Department, unless superseded by a replacement agreement.

Article III. Delivery of Partial Requirements, Back-Up and Maintenance Power

Section 3.01 Partial Requirements, Back-Up and Maintenance Power Requirements

The Customer shall purchase from the Department all of the Partial Requirements, Back-Up and Maintenance Power requirements at its Facility served under this Agreement and use such electric power in a manner that shall not be harmful to the Department electric system and facilities owned or operated by or on behalf of the Department.

Section 3.02 Electric Rate Schedule

All electric power service provided to the Customer under this Agreement shall be provided under the rates, terms and conditions of the Department's Electric Rate Schedule ("Schedule PR-1") and Electric Rules and Regulations. The Customer contracts the following amounts of service to be provided by the Department:

Partial Requirements Contract Demand - ____________ kW

Back-Up Contract Demand - _____________ kW

Section 3.03 Scope of Deliveries

The Department shall deliver such amounts of Partial Requirement, Back-Up and Maintenance Power and Energy to the Point of Delivery as Customer requires to meet its Facility load up to the Total Contract Demand, and the Department may deliver additional amounts of power and energy necessary to meet Customer's Excess Power requirements, subject to the provisions of Article VI. At no time shall the Department be obligated to deliver power and energy in excess of the Customer's Total Contract Demand to the Facility.

Section 3.04 Changes to Partial Requirements and Back-Up Contract Demand

Upon receipt of Customer's written request for deliveries of power and energy that exceed Customer's existing Partial Requirements Contract Demand or Back-Up Contract Demand, the Department shall attempt to supply such additional power and energy under terms and conditions acceptable to both Parties. Within fifteen (15) days of receipt of Customer's request, the Department shall advise the Customer in writing whether additional power and energy is or can be made available and the terms on which it can be made available. If the Department and Customer agree in writing that the Department shall provide Customer with power and energy in excess of Customer's Partial Requirements Contract Demand or Back-Up Contract Demand commitments, the amount of agreed deliveries shall become the Customer's new Partial Requirements Contract Demand or Back-Up Contract Demand, amending and superseding the Partial Requirements Contract Demand or Back-Up Contract Demand specified in this Agreement.

Customer may reduce Partial Requirements Contract Demand or Back-Up Contract Demand only by mutual agreement with the Department.

Section 3.05 Commencement of Deliveries

The Department shall make initial deliveries as soon as practicable after the effective date of this Agreement.

Section 3.06 Delivery Voltage

The Department shall deliver power and energy at the Point of Delivery in the form of three-phase, alternating current at a nominal frequency of 60 Hertz, and at a nominal voltage of 13,200 volts (13.2 kV) or 69,000 volts (69 kV).

Section 3.07 Resale of Power

Customer shall not resell any electric power and energy delivered under this Agreement to any other person or entity.

Article IV. Billing, Prices and Payment for Power and Energy

Section 4.01 Billing

All billing statements for service under this Agreement shall show the amount due for the type and quantity of power and energy purchased or delivered and the associated charges in accordance with the Electric Rate Schedule and any charges permitted or required under applicable Electric Rules and Regulations. The sum of which shall establish the total amount due from Customer for the Billing Period.

Section 4.02 Payments

All bills shall be paid by the date specified on the bill, and late charges shall be imposed upon any delinquent amounts. Customer may make payments by check, EDI or wire transfer to an account designated by the Department. The Customer account number must be included with each payment. If Customer disputes any portion of Customer's bill, Customer shall pay the total bill and shall designate the disputed portion. The Department shall decide the dispute within sixty (60) days after Customer's notice of dispute. [Any refund the Department determines Customer is due shall bear interest at the then effective prime rate as quoted in The Wall Street Journal. – refund and discuss with IPL; what is the current practice and policy regarding refunds?]

Section 4.03 Deposits

The Department may request deposits from the Customer to the extent permitted under the Electric Rules and Regulations and the Electric Rate Schedule. In the event of a default by Customer in any of its obligations under this Agreement, Interconnection Agreement, Interconnection Standards, Electric Rules and Regulations, or Electric Rate Schedule, the Department may exercise any or all of its rights and remedies under this Agreement, Interconnection Agreement, Interconnection Standards, Electric Rules and Regulations, or Electric Rate Schedule and under any applicable laws, rules and regulations with respect to any such deposits.

Article V. Metering

Section 5.01 Metering Equipment

The Department shall provide, maintain and test meters and metering equipment required for billing purposes as specified in the Electric Rate Schedule and Electric Rules and Regulations at the current metering point in the Customer's Point of Delivery.

Section 5.02 Telecommunications Facilities

Customer shall provide a dedicated telephone line or other Department-approved dedicated telecommunications data access for meter interrogation. Customer shall provide the dedicated telecommunications access without charge to the Department.

Article VI. Operational Constraints

Section 6.01 Notification

Customer shall notify the Department prior to increasing its consumption of electric power and energy in a manner that would exceed the normal operating limits of the Department electric system, and Customer shall provide sufficient time for the Department to accommodate such increased loads. Customer shall also notify the Department prior to any significant change in load characteristics or installation of devices (such as large power factor correction capacitors, large rectifiers, large variable/adjustable speed drives, etc.) that could impact operation of the Department electric system, other electric customers, or Customer's interaction with the Department electric system.

Section 6.02 Normal Operating Conditions

Customer shall purchase from the Department all of the Partial Requirements, Back-Up and Maintenance Power requirements for its Facility served under this Agreement and shall use such electric power in a manner that shall not be harmful to the Department's electric system, other electric customers and facilities owned or operated by or on behalf of the Department. Customer shall comply with all Department Electric Rules and Regulations and Interconnection Standards. Customer accepts and shall adhere to the Department's normal operating conditions as provided in the Interconnection Standards and Interconnection Agreement. All measurement of current and voltage under this Article VI shall be taken at the Point of Delivery.

Section 6.03 Reactive Requirements

Customer shall control and limit the flow of reactive power so as to maintain power factor in accordance with the applicable Electric Rate Schedule. The Customer's Billing Demand shall be increased in accordance with the applicable Electric Rate Schedule for power factor outside the required range.

Section 6.04 Voltage Fluctuation and Flicker

In order to receive electric service from the Department, Customer shall continuously comply with Department voltage fluctuation and flicker requirements, and with the operating criteria set forth in the Department's Interconnection Standards.

Section 6.05 Harmonic Distortion

Customer shall operate the Facility in such a manner so that harmonic distortion and notching falls within the harmonic distortion requirements of the Interconnection Standards.

Section 6.06 Current Imbalance

Customer shall design and operate its Facility and Customer-Owned Generation in a manner such that Facility steady-state load currents are reasonably balanced between each phase with respect to load and shall not cause electricity to back feed onto the Department electric system. The Department will not provide compensation for or return to the Customer any electricity that back feeds from the Customer onto the Department electric system.

Section 6.07 Remediation

In the event that the Customer's operations fall outside of the requirements of the Interconnection Standards and this Agreement, or adversely affect operation of the Department electric system, or other electric customers, the Department shall give written notice of the corrective action required, and Customer shall have fourteen (14) days to discuss the Department requirements. After such fourteen (14) day period, the Department shall give Customer its final determination of the required corrective action. Although the Department will discuss corrective action with the Customer, final determination of corrective action required shall be made by the Department based on compliance with Department Electric Rules and Regulations and Interconnection Standards.

Should Customer fail to take corrective action required by the Department within thirty (30) days after written notice from the Department or fail to pursue completion of such corrective action with diligence, the Department may perform such services or supply and install such equipment as it deems necessary to provide corrective action, whereupon Customer shall compensate the Department for all sums expended, all materials utilized, and all services contracted or performed, by paying a sum equal to 110% of all costs, expenses, material, and labor charges incurred by the Department, including internal material and labor charges and standard overhead costs. Customer shall pay such sums within fifteen (15) days after the Department has mailed an itemized statement of its charges therefore. If Customer desires to operate outside of these limits, Customer shall pay for studies done by the Department to determine the impact on other electric customers and whether the proposed operation is acceptable to the Department.

Provided, should the Department at any time reasonably determine that Customer's operations pose a threat to the safety of Department employees or the public, pose an imminent threat to the integrity of the Department electric system, or may materially interfere with the performance of Department service obligations, the Department shall attempt to provide notice to Customer that Customer must change its operations. If Customer fails to take corrective action on a timely basis, or if notice cannot be provided by the Department to Customer prior to the time when corrective action must occur, the Department may perform such work and/or take such corrective action that is necessary, including disconnection, without additional notice to Customer and without subjecting itself to any liability, provided the Department acted reasonably. If the Department performed the work and/or corrective action, as soon as practicable thereafter, the Department will advise Customer in writing of the work performed or the action taken and will endeavor to arrange for the accommodation of Customer's operations, subject to the terms of this Agreement, Electric Rules and Regulations, Interconnection Standards, and all other applicable rules or regulations. Customer shall be responsible for paying the Department, upon demand, for all reasonable costs incurred by the Department for all work, action, and accommodation performed by the Department that is consistent with the terms of this paragraph.

Article VII. Joint Operating Committee

The Parties shall form a Joint Operating Committee consisting of representatives of each Party. The Joint Operating Committee shall meet at least four times per year to discuss the operation, maintenance, inspection, testing and planning relating to any of the services provided under this Agreement. The activities of the Joint Operating Committee shall include, but not be limited to:

a. Providing liaison between the Parties at the management level on all matters pertaining to this Agreement.
b. Developing, maintaining, reviewing and updating as appropriate specific operating rules and procedures to support billing procedures and decisions regarding the operation of the Customer-Owned Generation facilities.
c. Keeping each Party advised of the need for additional facilities affecting the Department's delivery of services to be provided under this Agreement.
d. Developing operations and communications procedures for the efficient and effective utilization and scheduling of resources and services under this Agreement, including procedures for interruptions in the event of emergency conditions affecting the availability of services to be provided under this Agreement.
e. Annually, the Customer shall provide the Department with an updated five- (5-) year forecast of its electric demand and energy requirements and an estimate of what portion of Customer's electric requirements the Customer estimates will be served using its Customer-Owned Generation facilities.
f. Reviewing, discussing and, when possible, resolving disputes between the Parties arising under this Agreement.

The Parties' representatives shall be responsible persons connected with day-to-day operations of the respective Party. Such representatives shall be fully authorized to discuss all matters relating to operations under this Agreement and matters that are not specifically provided for herein. For the purpose of inspection of equipment and reading of meters, checking of records, and all other pertinent matters, said representatives and their authorized alternates shall have the right of entry at reasonable hours to all property hereto used in connection with the performance of this Agreement.

Article VIII. Integration; Amendment

This Agreement contains the entire agreement of the Parties with respect to the subject matter, and replaces and supersedes in entirety all prior agreements between the parties related to the same subject matter. Except pursuant to Article IX and Article XI Section 11.02 below, this

Agreement may be modified only by a subsequent written amendment or agreement executed by both Parties.

Article IX. Jurisdiction of Regulatory Authorities

The Electric Rate Schedule, Interconnection Standards and Electric Rules and Regulations are incorporated herein and by reference made a part hereof. Customer acknowledges that it is familiar with the Electric Rate Schedule, Interconnection Standards and Electric Rules and Regulations and agrees to abide by the same and all amendments and changes thereto. In the event that any state, federal, or municipal authority determines that any provision of this Agreement conflicts with or is in violation of the Electric Rate Schedule, Interconnection Standards or Electric Rules and Regulations, amends or supersedes the Electric Rate Schedule, Interconnection Standards or Electric Rules and Regulations, or issues any rules, regulations, or orders which require the Department to alter or amend any of the provisions of this Agreement or to terminate or curtail delivery of power and energy to Customer, this Agreement automatically shall be amended to comply with such determination, amendment, rule, regulation or order, and the Department shall not be liable to Customer for damages or losses of any kind whatsoever which Customer may sustain as a result of such determination, amendment, rule, regulation or order, including consequential damages.

Article X. Assignment

Customer’s rights and obligations under this Agreement may not be assigned without the Department’s consent except in connection with a sale, assignment, lease or transfer of Customer’s interest in its Facility, or real or personal property related thereto subject to (1) such successor’s qualification as a customer under Department policies, Electric Rules and Regulations, Interconnection Standards and the Electric Rate Schedule; and (2) the written agreement of such successor to be bound by this Agreement, Electric Rules and Regulations, Interconnection Standards and Electric Rate Schedule, and to assume the obligations of Customer from the date of assignment. The Department may condition such assignment upon posting a deposit as permitted under the Electric Rules and Regulations and Electric Rate Schedule. If the Department consents to any such sale, assignment, lease or transfer, Customer shall remain liable for any liabilities and obligations under this Agreement, Interconnection Standards, Electric Rules and Regulations and Electric Rate Schedule through the date of assignment.

Article XI. Information

Furnishing Information

Upon request, Customer shall submit its year-end financial statements to the Department, certified to be true and correct and in accordance with GAAP. Customer shall submit such additional information as the Department may reasonably request from time to time in furtherance of the purposes of this Agreement.

Accuracy of Information

Customer represents that all information it has furnished or will furnish to the Department in connection with this Agreement is accurate and complete in all material respects. Customer also represents that Customer has not omitted and will not knowingly omit any fact in connection with the information to be furnished under this Agreement, which materially and adversely affects the business, operations, property or condition of the Facility or the obligations of the Department under this Agreement. Should the Department base its willingness to enter into any portion of this Agreement or any decision with respect to credit, deposits or any other material matter, using inaccurate information furnished by Customer, the Department shall have the right to revoke its decision with respect to such matter and modify this Agreement and/or its decision to reflect the determination which the Department would have made had the Department received accurate information.

Article XII. Remedies; Waiver

Either Party may exercise any or all of its rights and remedies under this Agreement, Electric Rate Schedule, Interconnection Standards, Electric Rules and Regulations and any applicable laws, rules and regulations. The Department's liability for any action arising out of its activities relating to this Agreement or Department electric utility service shall be limited to repair or replacement of any non-operating or defective portion of Department electric facilities. Under no circumstances shall the Department be liable for any economic losses, costs or damages, including but not limited to special, indirect, incidental, consequential, punitive, or exemplary damages. No provision of this Agreement, Electric Rate Schedule, Interconnection Standards or Electric Rules and Regulations shall be deemed to have been waived unless such waiver is in writing signed by the waiving Party. No failure by any Party to insist upon the strict performance of any provision of this Agreement, Electric Rate Schedule, Interconnection Standards, Electric Rules and Regulations or to exercise any right or remedy consequent upon a breach thereof shall constitute a waiver of any such breach of such provision or of any other provision. No waiver of any provision of this Agreement, Electric Rate Schedule, Interconnection Standards or Electric Rules and Regulations shall be deemed a waiver of any other provision of this Agreement, Electric Rate Schedule, Interconnection Standards, Electric Rules and Regulations or a waiver of such provision with respect to any subsequent breach, unless expressly provided in writing.

Article XIII. Attorneys' Fees

In any suit or action arising out of or related to this Agreement involving a claim, counterclaim or cross-claim made by either Party against the other Party, the substantially prevailing Party shall be entitled to recover the costs and fees (including, without limitation, reasonable attorneys' fees, the fees and costs of experts and consultants, copying, courier and telecommunication costs, and deposition costs and all other costs of discovery) incurred by such substantially prevailing Party in such suit or action, including, without limitation, any post-trial or appellate proceeding, or in the collection or enforcement of any judgment or award entered or made in such suit or action.

Article XIV. Setoff

If Customer should default under any of its obligations under this Agreement, the Department shall be entitled, at its option and in its discretion without notice to Customer, to (a) setoff amounts due and owing to the Department by Customer under this Agreement, against any amounts due and owing by the Department or any of its affiliates, to the Customer or any of its affiliates, under any agreements, instruments or undertakings between the Department or any of its affiliates, and Customer or any of its affiliates and/or (b) withhold payment of any amount due Customer or its affiliates by the Department or its affiliates—such amount to be determined by the Department, in the Department's reasonable discretion, as sufficient to cover Customer's unliquidated obligations, once liquidated, to the extent that Customer's obligations under this Agreement are not yet liquidated. The remedy provided for in this Article XIV shall be (a) without prejudice to and in addition to any right of setoff, combination of accounts, lien or other right to which the Department is at any time otherwise entitled (whether by operation of law, contract or otherwise); and (b) exercisable against any trustee in bankruptcy, debtor in possession, assignee for the benefit of creditors, receiver, or execution, judgment or attachment creditor, notwithstanding the fact that such right of setoff shall not have been exercised by the Department prior to such default.

Article XV. Governing Law; Jurisdiction; Venue

All provisions of this Agreement and the rights and obligations of the parties hereto shall in all cases be governed by and construed in accordance with the laws of the State of Missouri applicable to contracts executed in and to be wholly performed in Missouri by persons domiciled in the State of Missouri. Each Party hereto agrees that any suit, action or proceeding seeking to enforce any provision of, or based on any matter arising out of or in connection with this Agreement or the transactions contemplated hereby or thereby, may only be brought before the state courts of the State of Missouri or federal courts located within the State of Missouri and each Party hereby consents to the exclusive jurisdiction of such forums (and of the appellate courts therefrom) in any such suit, action or proceeding. Furthermore, each Party hereto waives, to the extent permitted by law, any objection which it may now or hereafter have to the laying of the venue of any such suit, action or proceeding in any such forum or that any such suit, action or proceeding which is brought in any such forum has been brought in any inconvenient forum. If for any reason, service of process cannot be found in the State of Missouri, process in any such suit, action or proceeding may be served on a Party anywhere in the world, whether within or without the jurisdiction of any such forum.

Article XVI. Waiver of Jury Trial

To the fullest extent permitted by law, each of the Parties hereto waives any right it may have to a trial by jury in respect of litigation directly or indirectly arising out of, under or in connection with this Agreement. Each Party further waives any right to consolidate any action in which a jury trial has been waived with any other action in which a jury trial cannot be or has not been waived.

Article. XVII. Headings

The descriptive headings contained in this Agreement are included for reference only and shall not affect in any way the meaning or interpretation of this Agreement.

Article XVIII. Communications and Notice

Customer’s contact at the Department for all matters regarding this Agreement is:

____
____
____
____
____
____

Any legal notice required to be given hereunder by one Party to the other Party shall be sent by hand delivery, by courier service, or by registered or certified mail, return receipt requested, to the other Party hereto at its address hereafter set forth.

If to the Department: ____
____
____
____
____

If to the Customer: ____
____
____
____

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by persons duly authorized as of the date first above written.

Customer	**Independence Power & Light Department**
By:______________________________	By:______________________________
Name:____________________________	Name:____________________________
Title:_____________________________	Title:_____________________________

Draft

Independence Power & Light Department

GENERATOR INTERCONNECTION AGREEMENT

October 1, 2015

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Attachment 6 –Description of System Upgrades and Estimate of System Upgrade Costs

Transmission System Generator Interconnection Agreement

This Generator Interconnection Agreement ("Agreement") is made and entered into this ________ day of ________________, 20__, by the Independence Power & Light Department ("Department") and ___________________ ____ ("Interconnection Customer") each hereinafter sometimes referred to individually as "Party" or to collectively as the "Parties."

Department Information

Power & Light Director
Independence Power & Light Department
21500 East Truman Road
Independence, MO 64051
816/325-7437 Fax: _________________ Email: ________________________

Interconnection Customer Information

Interconnection Customer: ____
Attention: ____
Address: ____
City: ______________________________ State: ______________ Zip: ______
Phone: ________________ Fax: _________________ Email: ____________________

In consideration of the mutual covenants set forth herein, the Parties agree as follows:

Article 1. Scope and Limitations of Agreement

1.1 This Agreement shall be used for all requests for interconnection to the Distribution or Transmission System.

1.2 This Agreement governs the terms and conditions under which the Interconnection Customer's Generating Facility or Facilities will interconnect with and operate in parallel with the Distribution or Transmission System.

1.3 This Agreement does not constitute an agreement to purchase or deliver the Interconnection Customer's power. The purchase or delivery of power and other services that the Interconnection Customer may desire is subject to separate negotiation with the Department and is not included in this Interconnection Agreement.

1.4 Nothing in this Agreement is intended to affect any other agreement between the Department and the Interconnection Customer.

1.5 Responsibilities of the Parties

1.5.1 The Parties shall perform all obligations of this Agreement in accordance with all Applicable Laws and Regulations, Operating Requirements, and Prudent Utility Practice.

1.5.2 The Interconnection Customer shall construct, interconnect, operate and maintain its Generating Facility and construct, operate, and maintain its Interconnection Facilities in accordance with applicable manufacturer's recommended maintenance schedules, and in accordance with this Agreement and Prudent Utility Practice.

1.5.3 The Department shall construct, operate, and maintain its Distribution, Transmission System and Interconnection Facilities in accordance with this Agreement, and with Prudent Utility Practice.

1.5.4 The Interconnection Customer agrees to construct its facilities or systems in accordance with applicable specifications that meet or exceed those provided by the National Electrical Safety Code, the American National Standards Institute, IEEE, Underwriter's Laboratories, Department Interconnection Standards and Operating Requirements in effect at the time of construction, and other applicable national, state, and local codes and standards. The Interconnection Customer agrees to design, install, maintain, and operate its Generating Facility so as to reasonably minimize the likelihood of a disturbance adversely affecting or impairing the Department Transmission and Distribution Systems, Affected Systems, and other electric customers.

1.5.5 Each Party shall operate, maintain, repair, and inspect, and shall be fully responsible for the facilities that it now or subsequently may own unless otherwise specified in the Attachments to this Agreement. Each Party shall be responsible for the safe installation, operation, maintenance, repair and condition of their respective lines and appurtenances on their respective sides of the point of change of ownership. The Department and the Interconnection Customer, as appropriate, shall provide Interconnection Facilities that adequately protect the Department's Transmission and Distribution System, personnel, and other persons and electric customers from damage and injury. The allocation of responsibility for the design, installation, operation, maintenance and ownership of

Interconnection Facilities shall be delineated in the Attachments to this Agreement.

1.5.6 The Department shall coordinate with all Affected Systems to support the interconnection.

1.6 Parallel Operation Obligations

Once the Generating Facility has been authorized to interconnect and to commence parallel operation, the Interconnection Customer shall abide by all rules and procedures pertaining to the parallel operation of the Generating Facility including, but not limited to; 1) the rules and procedures concerning the operation of generation set forth in the Department Interconnection Standards and the applicable Electric Rate Schedule and; 2) Operating Requirements set forth in Attachment 5 of this Agreement.

1.7 Metering

The Interconnection Customer shall be responsible for the Department's reasonable and necessary cost for the purchase, installation, operation, maintenance, testing, repair, and replacement of metering and data acquisition equipment specified in Attachments 2 and 3 of this Agreement. Metering shall be accomplished by use of a Department approved electric meter or meters. Specific metering shall be at the Department's discretion. The Interconnection Customer shall supply, at no expense to the Department, a suitable location for the meter(s) and associated equipment.

1.8 Reactive Power

1.8.1 The Interconnection Customer shall design its Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Department has established different requirements that apply to all similarly situated generators on a comparable basis.

1.9 Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 or the body of this Agreement.

Article 2. Inspection, Testing, Authorization, and Right of Access

2.1 Equipment Testing and Inspection

2.1.1 The Interconnection Customer shall test and inspect its Generating Facility and Interconnection Facilities prior to interconnection. The Interconnection Customer shall notify the Department of such activities no fewer than five Business Days (or as may be agreed to by the Parties) prior to such testing and inspection. Testing and inspection shall occur on a Business Day. The Interconnection Customer shall provide the Department reasonable opportunity to inspect the Generating Facility and Interconnection Facilities prior to interconnection and to witness initial testing and commissioning of the Generating Facility. The Interconnection Customer shall provide the Department a written test report when such testing and inspection is completed.

2.1.2 The Department shall provide the Interconnection Customer written acknowledgment that it has received the Interconnection Customer's written test report. Such written acknowledgment shall not be deemed to be or construed as any representation, assurance, guarantee, or warranty by the Department of the safety, durability, suitability, or reliability of the Generating Facility or any associated control, protective, and safety devices owned or controlled by the Interconnection Customer or the quality of power produced by the Generating Facility.

2.2 Authorization Required Prior to Parallel Operation

2.2.1 The Department shall use Reasonable Efforts to list applicable parallel operation requirements in Attachment 5 of this Agreement. Additionally, the Department shall notify the Interconnection Customer of any changes to these requirements as soon as practicable.

2.2.2 The Interconnection Customer shall not interconnect or operate its Generating Facility in parallel with the Transmission or Distribution System without prior written authorization of the Department. The Department will provide such authorization once the Department receives notification that the Interconnection Customer has complied with all applicable Interconnection Standards and parallel operation requirements.

2.3 Right of Access

2.3.1 Upon reasonable notice, the Department may send a representative to the premises of the Interconnection Customer at or immediately before the time the Generating Facility first produces energy to inspect the interconnection, and observe the commissioning of the Generating Facility (including any required testing), startup, and operation for a period of up to three Business Days after initial start-up of the unit. In addition, the Interconnection Customer shall notify the Department at least five Business Days prior to conducting any on-site verification testing of the Generating Facility.

2.3.2 Following the initial inspection process described above, at reasonable hours, and upon reasonable notice, or at any time without notice in the event of an emergency or hazardous condition, the Department shall have access to the Interconnection Customer's premises for any reasonable purpose in connection with the performance of the obligations imposed on it by this Agreement or if necessary to meet its service obligations to its customers.

2.3.3 Each Party shall be responsible for its own costs associated with following this Article.

Article 3. Effective Date, Term, Termination, and Disconnection

3.1 Effective Date

This Agreement shall become effective upon execution by the Parties.

3.2 Term of Agreement

This Agreement shall become effective on the Effective Date and shall remain in effect for an initial term of ten (10) years from the Effective Date and shall automatically renew for successive one-year periods thereafter, unless terminated in accordance with Article 3.3 of this Agreement.

3.3 Termination

3.3.1 The Interconnection Customer may terminate this Agreement at any time by giving the Department at least sixty (60) days' prior written notice stating

Interconnection Customer's intent to terminate the Agreement at the expiration of such notice period.

3.3.2 The Department may terminate the Agreement at any time following Interconnection Customer's failure to generate energy from its Generation Facility in parallel with the Transmission System by the later of two (2) years from the date of execution of the Interconnection Agreement or twelve (12) months after completion of the interconnection provided for by the Agreement;

3.3.3 Either Party may terminate this Agreement after Default pursuant to Article 6.4.

3.3.4 Upon termination of this Agreement, the Generating Facility shall be permanently disconnected from the Transmission and Distribution System. All costs required to effect such disconnection shall be borne by the Interconnection Customer.

3.3.5 Termination of this Agreement shall not relieve either Party of its liabilities and obligations owed or continuing at the time of termination.

3.3.6 This provisions of this Article shall survive termination or expiration of this Agreement.

3.4 Temporary Disconnection

Temporary disconnection shall continue only for so long as reasonably necessary under Prudent Utility Practice.

3.4.1 Emergency Conditions -- "Emergency Condition" shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of the Department, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, the Distribution System, the Department's Interconnection Facilities or Transmission Systems of others to which the Transmission System is directly connected; or (3) that, in the case of the Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or the Interconnection Customer's Interconnection Facilities. Under Emergency Conditions, the Department may immediately suspend interconnection service and temporarily disconnect the Generating Facility. The Department shall notify the Interconnection Customer promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Interconnection Customer's operation of the Generating Facility. The Interconnection Customer shall notify the Department promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Transmission and Distribution Systems or any Affected Systems. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of both Parties' facilities and operations, its anticipated duration, and the necessary corrective action.

3.4.2 Routine Maintenance, Construction, and Repair

The Department may interrupt interconnection service or curtail the output of the Generating Facility and temporarily disconnect the Generating Facility from the Transmission and Distribution Systems when necessary for routine maintenance, construction, and repairs on the Transmission and Distribution Systems. The Department shall provide the Interconnection Customer with five Business Days' notice prior to such interruption. The Department shall use Reasonable Efforts to coordinate such reduction or temporary disconnection with the Interconnection Customer.

3.4.3 Forced Outages

During any forced outage, the Department may suspend interconnection service to effect immediate repairs on the Transmission and Distribution Systems. The Department shall use Reasonable Efforts to provide the Interconnection Customer with prior notice.

3.4.4 Adverse Operating Effects

The Department shall notify the Interconnection Customer as soon as practicable if, based on Prudent Utility Practice, operation of the Generating Facility may cause disruption or deterioration of service to other customers served from the Transmission and Distribution systems, or if operating the Generating Facility could cause damage to Affected Systems. Supporting documentation used to reach the decision to disconnect shall be provided to the Interconnection Customer upon request. If, after notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time, the Department may disconnect the Generating Facility. The Department shall provide the Interconnection Customer with five Business Days' notice of such disconnection, unless the provisions of Article 3.4.1 apply.

3.4.5 Modification of the Generating Facility

The Interconnection Customer must receive written authorization from the Department before making any change to the Generating Facility that may have a material impact on the safety or reliability of the Transmission and Distribution Systems. Such authorization shall not be unreasonably withheld. Modifications shall be done in accordance with Prudent Utility Practice. If the Interconnection Customer makes such modification without the Department's prior written authorization, the Department shall have the right to temporarily disconnect the Generating Facility.

3.4.6 Reconnection

The Parties shall cooperate with each other to restore the Generating Facility, Interconnection Facilities, and the Transmission and Distribution Systems to their normal operating state as soon as reasonably practicable following a temporary disconnection.

Article 4. Cost Responsibility for Interconnection Facilities and Distribution Upgrades

4.1 Interconnection Facilities

4.1.1 The Interconnection Customer shall pay for the cost of the Interconnection Facilities itemized in Attachment 2 of this Agreement. The Department shall provide an estimated cost, including overheads, for the purchase and construction of its Interconnection Facilities and provide a detailed itemization of such costs. At the Department's sole discretion, costs associated with Interconnection Facilities may be shared with other entities that may benefit from such facilities.

4.1.2 The Interconnection Customer shall be responsible for all expenses, including overheads, associated with (1) owning, operating, maintaining, repairing, and replacing its own Interconnection Facilities, and (2) operating, maintaining, repairing, and replacing the Department's Interconnection Facilities.

4.2 Distribution System Upgrades

The Department shall not be obligated to make upgrades or improvements to its Transmission and Distribution Systems to accommodate the Interconnection Customer's Generating Facility. Where System Upgrades are required prior to interconnection of the Generating Facility, the Department will provide the Interconnection Customer with an estimated schedule and the Interconnection Customer's estimated cost for such System Upgrades. The Department shall design, procure, construct, install, and own any Transmission and Distribution System Upgrades described in Attachment 6 of this Agreement. The actual cost of the Distribution System Upgrades, including overheads, shall be directly assigned to the Interconnection Customer.

Article 5. Billing, Payment, Milestones, and Financial Security

5.1 Billing and Payment Procedures and Final Accounting

5.1.1 The Department shall estimate the costs, including overheads, for the design, engineering, procurement, construction and inspection costs of Interconnection Facilities and System Upgrades and provide a detailed itemization of such costs in Attachment 6. Prior to commencement of System Upgrades that are required to allow interconnection of the Generation Facility, Interconnection Customer shall deposit with the Department an amount equal to the estimated cost of said System Upgrades.

5.1.2 Within ninety (90) days of completing the construction and installation of the Department's Interconnection Facilities and/or System Upgrades described in Attachment 6 to this Agreement, the Department shall provide the Interconnection Customer with a final accounting report of any difference between the Interconnection Customer's actual cost of such facilities or System Upgrades, and the amount deposited by Interconnection Customer with the Department for such facilities or System Upgrades. If the Interconnection Customer's cost responsibility exceeds its deposited amount, the Department shall invoice the Interconnection Customer for the amount due and the Interconnection Customer shall make payment to the Department within 30 calendar days. If the Interconnection Customer's deposited amount exceeds actual costs under this Agreement, the Department shall refund to the Interconnection Customer an amount equal to the difference within 30 calendar days of the final accounting report.

Article 6. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default

6.1 Assignment

This Agreement may be assigned by either Party upon 90 Business Days prior written notice and opportunity to object by the other Party; provided that:

6.1.1 Either Party may assign this Agreement without the consent of the other Party to any affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement, provided that the Interconnection Customer promptly notifies the Department of any such assignment;

6.1.2 The Interconnection Customer shall have the right to assign this Agreement, without the consent of the Department, for collateral security purposes to aid in providing financing for the Generating Facility, provided that the Interconnection Customer promptly notifies the Department of any such assignment.

6.1.3 Any attempted assignment that violates this Article or impacts the Department's tax-exempt status is void and ineffective. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. An assignee is responsible for meeting the same financial, credit, and insurance obligations as the Interconnection Customer. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

6.2 Limitation of Liability and Indemnification

Interconnection Customer agrees to assume all liability for and shall indemnify the Department for any claims, losses, costs, and expenses of any kind or character to the extent that they result from the design, construction, operation or maintenance of its Generation Facility. Such indemnity shall include, but is not limited to, financial responsibility for: (a) the Department's monetary losses; (b) reasonable costs and expenses of defending an action or claim made by a third party; (c) damages related to the death or injury of a third party; (d) damages to the property of the Department; (e) damages to the property of a third party; (f) damages for the disruption of the business of a third party. This paragraph does not create a liability on the part of the Interconnection

Customer to the Department or a third party, but requires indemnification where such liability exists. The limitations of liability provided in this paragraph do not apply in cases of gross negligence or intentional wrongdoing.

6.3 Force Majeure

6.3.1 As used in this Article, a Force Majeure Event shall mean "any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing."

6.3.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event (Affected Party) shall promptly notify the other Party, either in writing or via the telephone, of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance. The Affected Party shall keep the other Party informed on a continuing basis of developments relating to the Force Majeure Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of Reasonable Efforts. The Affected Party will use Reasonable Efforts to resume its performance as soon as possible.

6.4 Default

6.4.1 No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of a Force Majeure Event as defined in this Agreement or the result of an act or omission of the other Party. Upon a Default, the non-defaulting Party shall give written notice of such Default to the defaulting Party. Except as provided in Article 6.4.2, the defaulting Party shall have 60 calendar days from receipt of the Default notice within which to cure such Default; provided however, if such Default is not capable of cure within 60 calendar days, the defaulting Party shall commence such cure within 20 calendar days after notice and continuously and diligently complete such cure within six months from receipt of the Default notice; and, if cured within such time, the Default specified in such notice shall cease to exist.

6.4.2 If a Default is not cured as provided in this Article, or if a Default is not capable of being cured within the period provided for herein, the non-defaulting Party shall have the right to terminate this Agreement by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this Agreement, to recover from the defaulting Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this Article will survive termination of this Agreement.

Article 7. Insurance

7.1 The Interconnection Customer shall, at its own expense, maintain in force general liability insurance without any exclusion for liabilities related to the interconnection undertaken pursuant to this Agreement. The amount of such insurance shall be sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made. The Interconnection Customer shall obtain additional insurance only if necessary as a function of owning and operating a generating facility. Such insurance shall be obtained from an insurance provider authorized to do business in the State of Missouri. Certification that such insurance is in effect shall be provided upon request of the Department, except that the Interconnection Customer shall show proof of insurance to the Department no later than ten (10) Business Days prior to the Generating Facility's anticipated commercial operation date.

7.2 The Department agrees to maintain general liability insurance or self-insurance consistent with the Department's commercial practice. Such insurance or self-insurance shall not exclude coverage for the Department's liabilities undertaken pursuant to this Agreement.

7.3 The Parties further agree to notify each other whenever an accident or incident occurs resulting in any injuries or damages that are included within the scope of coverage of such insurance, whether or not such coverage is sought.

Article 8. Confidentiality

8.1 Confidential Information shall mean any confidential and/or proprietary information provided by one Party to the other Party that is clearly marked or otherwise designated "Confidential."

8.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party), or necessary to be divulged in an action to enforce this Agreement. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under this Agreement, or to fulfill legal or regulatory requirements.

8.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.

Article 9. Taxes

9.1 The Parties agree to follow all applicable tax laws and regulations, consistent with FERC policy, Internal Revenue Service, and State of Missouri requirements.

9.2 Each Party shall cooperate with the other to maintain the other Party's tax status. Nothing in this Agreement is intended to adversely affect the Department's tax-exempt status.

Article 10. Miscellaneous

10.1 <u>Governing Law, Regulatory Authority, and Rules</u>
The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the State of Missouri, without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each

Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

10.2 Amendment

The Parties may amend this Agreement by a written instrument duly executed by both Parties.

10.3 No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

10.4 Waiver

10.4.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

10.4.2 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement.

10.5 Entire Agreement

This Agreement, including all Attachments, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

10.6 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

10.7 <u>No Partnership</u>

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

10.8 <u>Severability</u>

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

10.9 <u>Subcontractors</u>

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain liable to the other Party for the performance of such subcontractor.

10.9.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Department be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

10.9.2 The obligations under this Article will not be limited in any way by any limitation of subcontractor's insurance.

Article 11. Notices

11.1 General

Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person, delivered by recognized national currier service, or sent by first class mail, postage prepaid, to the person specified below:

If to the Interconnection Customer:

Interconnection Customer: ____
Attention: __________________________________
Address: ____
City: ________________________________ State:______________ Zip:_______
Phone: ________________ Fax: _________________

If to the Department:

Power & Light Director
Independence Power & Light Department
21500 East Truman Road
Independence, MO 64051
816/325-7437

11.2 Billing and Payment

Billings and payments shall be sent to the addresses set out below:

Interconnection Customer:

Interconnection Customer: ____
Attention: __________________________________
Address: ____
City: ________________________________ State:______________ Zip:_______
Phone: ________________ Fax: _________________

11.3 Alternative Forms of Notice

Any notice or request required or permitted to be given by either Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or e-mail to the telephone numbers and e-mail addresses set out below:

If to the Interconnection Customer:

Interconnection Customer: ____
Attention: ____________________________________
Address: ____
City: __________________________________ State:_______________ Zip:________
Phone: _________________ Fax: __________________

If to the Department:
Power & Light Director
Independence Power & Light Department
21500 East Truman Road
Independence, MO 64051
816/325-7437

11.4 Designated Operating Representative

The Parties may also designate operating representatives to conduct the communications which may be necessary or convenient for the administration of this Agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

Interconnection Customer's Operating Representative:

Interconnection Customer: ____
Attention: ____________________________________
Address: ____
City: __________________________________ State:_______________ Zip:________
Phone: _________________ Fax: __________________

Department's Operating Representative:

Power & Light Director
Independence Power & Light Department
21500 East Truman Road
Independence, MO 64051
816/325-7437

11.5 Changes to the Notice Information

Either Party may change this information by giving ten (10) Business Days written notice prior to the effective date of the change.

Article 12. Signatures

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

For the Department

Name: ____

Title: ____

Date: ___________________

For the Interconnection Customer

Name: ____

Title: ____

Date: ___________________

Attachment 1

Glossary of Terms

Affected System – An electric system other than the Transmission System that may be affected by the proposed interconnection.

Applicable Laws and Regulations – All duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority, including the ordinances of the City of Independence, Department Interconnection Standards, and Electric Utility Rules and Regulations.

Business Day – Monday through Friday, excluding Federal Holidays.

Default – The failure of a breaching Party to cure its breach under the Generator Interconnection Agreement.

Department – Independence Power & Light Department

Distribution System – The Department's facilities and equipment used to provide electric service to customers.

Distribution System Upgrades – Additions, modifications, and upgrades to the Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility. Distribution System Upgrades do not include Interconnection Facilities.

Generating Facility – The Interconnection Customer's device for the production of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Governmental Authority – Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, the Interconnection Provider, or any Affiliate thereof.

Interconnection Customer – Any entity that proposes to interconnect its Generating Facility with the Transmission System.

Interconnection Facilities – The Department's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission and Distribution Systems. Interconnection Facilities are sole use facilities and shall not include Transmission and Distribution Systems or Distribution System Upgrades.

Interconnection Request – The Interconnection Customer's request, in accordance with the Tariff, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Transmission and Distribution Systems.

Material Modification – A modification that has a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Operating Requirements – Any operating and technical requirements that may be applicable due to Regional Transmission Organization, Independent System Operator, control area, or the Department's requirements, including those set forth in the Transmission System Generator Interconnection Agreement and Department Interconnection Standards.

Party or Parties – The Department, Interconnection Customer or any combination of the above.

Point of Interconnection – The point where the Interconnection Facilities connect with the Transmission and Distribution Systems.

Prudent Utility Practice – Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Prudent Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Reasonable Efforts – With respect to an action required to be attempted or taken by a Party under the Transmission System Generator Interconnection Agreement, efforts that are timely and consistent with Prudent Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

System Upgrades – The required additions and modifications to the Transmission and Distribution Systems at or beyond the Point of Interconnection. Upgrades may be Upgrades or Distribution System Upgrades. System Upgrades do not include Interconnection Facilities.

Tariff –Tariff through which Interconnection Service is offered, and as amended or supplemented from time to time, or any successor tariff.

Transmission System – The facilities owned, controlled or operated by the Department that are used to provide transmission service to customers.

Transmission System Upgrades – Additions, modifications, and upgrades to the Transmission System required at or beyond the point at which the Generating Facility interconnects with the Transmission System to accommodate the interconnection of the Generating Facility with the Transmission System. Transmission System Upgrades do not include Distribution Upgrades.

Attachment 2

Description and Costs of the Generating Facility, Interconnection Facilities, and Metering Equipment

Equipment, including the Generating Facility, Interconnection Facilities, and metering equipment shall be itemized and identified as being owned by the Interconnection Customer, or the Department. The Department will provide an estimated itemized cost, including overheads, of its Interconnection Facilities and metering equipment.

Attachment 3

One-line Diagram Depicting the Generating Facility, Interconnection Facilities, Metering Equipment, and Upgrades

Attachment 4

Milestones

In-Service Date: ____________________

Project milestones and responsibility as agreed to by the Parties:

	Milestone/Date	Responsible Party
(1)	____	______________________
(2)	____	______________________
(3)	____	______________________
(4)	____	______________________
(5)	____	______________________
(6)	____	______________________
(7)	____	______________________
(8)	____	______________________
(9)	____	______________________
(10)	____	______________________

Attachment 5

Additional Operating Requirements for the Department's Transmission and Distribution Systems and Affected Systems Needed to Support the Interconnection Customer's Needs

The Department shall also provide requirements that must be met by the Interconnection Customer prior to interconnection and parallel operation of the Generating Facility with the Transmission and Distribution Systems.

Attachment 6

Description of System Upgrades and Estimate of System Upgrade Costs

The Department shall describe System Upgrades and provide an itemized estimate of the cost, including overheads, of the System Upgrades.

APPENDIX F
PROPOSED SCHEDULE OF RATES EFFECTIVE OCTOBER 1, 2015

INDEPENDENCE POWER & LIGHT DEPARTMENT
Independence, Missouri

Schedules of Rates

Title	Schedule Designation	Effective Date of Schedule	Page Number
Residential Service	RS-1	10/1/15	A-2
General Service	GS-1	10/1/15	A-4
Large General Service	LGS-1	10/1/15	A-6
Large Power Service	LP-1	10/1/15	A-9
Large Power Service (FROZEN)	LP-FR	10/1/15	A-12
General Service Electric Space Heating (FROZEN)	GSSH-FR	10/1/15	A-16
Private Outdoor Lighting Service	PL-1	10/1/15	A-18
Special Contract Large Interruptible Industrial Service (FROZEN)	SCIS-FR	10/1/15	A-21
City Traffic Signals	TRS-1	10/1/15	A-26
Power Cost Adjustment	PCA-1	10/1/15	A-28
Economic Development Rider (FROZEN)	EDR-FR	10/1/15	A-31
Public Street Lighting Service	PSL-1FR PSL-1CF PSL-1DF	10/1/15 10/1/15 10/1/15	A-35 A-37 A-39
Customer-Generator Net Metering Contract Service Rider	NM-1	10/1/15	A-41
Regulatory and Environmental Compliance Rider	REC-1	10/1/15	A-54
Partial Requirements Service	PR-1	10/1/15	A-56
Community Solar Rider	CSR-1	10/1/15	A-60

Passed by City Council by Ordinance No. _______ on the ____ day of ____________, 2015.

INDEPENDENCE POWER & LIGHT DEPARTMENT
Independence, Missouri

Schedule RS-1
Residential Service

AVAILABLE

Electric service is available under this schedule in the entire area served by the Department's existing secondary voltage distribution system.

APPLICABLE

To single family dwelling units supplied through one meter and individually metered apartments for all domestic uses.

CHARACTER OF SERVICE

Alternating current, 60 cycles; single phase 120 or 120/240 volts; three phase secondary voltages at the Department's option.

NET MONTHLY BILL

	Effective Oct. 1, 2015	Effective May 1, 2016	Effective Oct. 1, 2016
Customer Charge	$5.00	$9.50	$14.50

Energy Rates

Off-Peak Season

14.00¢	per kWh for the first 300 kWh
11.20¢	per kWh for the next 700 kWh
8.40¢	per kWh for all over 1,000 kWh

On-Peak Season

14.00¢ per kWh for all kWh

Minimum Monthly Bill

The Customer Charge.

GRANDFATHERED ELECTRIC HEAT CUSTOMERS

Customer accounts receiving electric service under the RSSH, RSSHW and RS-4 Rate Schedules immediately prior to the effective date of this Rate Schedule shall receive a discount of 1.50 cents per kWh off of the second and third Off-Peak Season energy block rates. This discount is not available to new customers, new service locations or service locations that change customers after the effective date of this schedule.

POWER COST ADJUSTMENT

See Schedule PCA-1.

REGULATORY AND ENVIRONMENTAL COMPLIANCE RIDER

See Schedule REC-1.

BILLING PERIODS

The "off-peak" season shall be for seven consecutive billing months with the first billing month commencing with meter reading cycle 1 occurring in October each year.

The "on-peak" season shall be the remaining five consecutive billing months.

PAYMENT

Monthly bills will be rendered NET, payable on or before the due date of the net monthly bill. The gross monthly bill, which is 105 percent of the net monthly bill, will be collected if monthly bill is not paid on or before due date.

PAYMENT IN LIEU OF TAXES TO CITY OF INDEPENDENCE

The net monthly bill rates of this service schedule include charges for the Department’s payment in lieu of taxes (PILOT) to the City’s General Fund as authorized by Section 3.17 of the City Charter. The Department’s PILOT payment to the City is equal to the amount of City taxes and fees charged on privately owned utilities, including the 9.08 percent franchise fee, applicable utility property taxes and sales taxes.

TERMS OF SERVICE

Service rendered under this schedule is subject to the Department's standard rules and regulations.

Schedule GS-1
General Service

AVAILABLE

Electric service is available under this schedule in the entire area served by the Department's existing secondary voltage distribution system.

APPLICABLE

To any customer for all power and energy uses at any one location where service of a single character is taken through one meter at one point of delivery for which no specific schedule is provided. This schedule is not applicable to resale or shared electric service.

CHARACTER OF SERVICE

Alternating current 60 cycles; single phase, 120 or 120/240 volts, three phase, 3 wire 240 or 480 volts; three phase, 4 wire 120/208 or 277/480 volts; three phase 4 wire 120/240 volts at the Department's option.

NET MONTHLY BILL

	Effective Oct. 1, 2015	Effective May 1, 2016	Effective Oct. 1, 2016
Customer Charge	$10.00	$13.00	$16.00

Energy Rates

Off-Peak Season

17.00¢ per kWh for the first 400 kWh
13.70¢ per kWh for all over 400 kWh

On-Peak Season

17.00¢ per kWh for all kWh

Minimum Monthly Bill

The Customer Charge. .

PROVISION FOR CHURCHES

This provision is available to publicly and privately endowed non-profit churches of generally recognized denominations. The On-Peak and Off-Peak energy rate for all energy is equal to 13.70 cents per kWh.

Schedule GS-1
General Service
(Continued)

POWER COST ADJUSTMENT

See Schedule PCA-1.

REGULATORY AND ENVIRONMENTAL COMPLIANCE RIDER

See Schedule REC-1.

PAYMENT

Monthly bills will be rendered NET, payable on or before the due date of the net monthly bill. The gross monthly bill, which is 105 percent of the net monthly bill, will be collected if monthly bill is not paid on or before due date.

PAYMENT IN LIEU OF TAXES TO CITY OF INDEPENDENCE

The net monthly bill rates of this service schedule include charges for the Department's payment in lieu of taxes (PILOT) to the City's General Fund as authorized by Section 3.17 of the City Charter. The Department's PILOT payment to the City is equal to the amount of City taxes and fees charged on privately owned utilities, including the 9.08 percent franchise fee, applicable utility property taxes and sales taxes.

TERMS OF SERVICE

Service rendered under this schedule is subject to the Department's standard rules and regulations.

Schedule LGS-1
Large General Service

AVAILABLE

Electric service is available under this schedule in the entire area served by the Department's existing secondary and primary voltage distribution systems.

APPLICABLE

To any customer for all power and energy uses at any one location where service of a single character is taken through one meter at one point of delivery. This schedule is not applicable to resale or shared electric service.

CHARACTER OF SERVICE

Secondary Voltages: Alternating current, 60 cycles; single phase, 120 or 120/240 volts; three phase, 3 wire, 240 or 480 volts; three phase, 4 wire, 120/208 or 277/480 volts, three phase, 4 wire, 120/240 volts at the Department's option.

Primary Voltages: Alternating current, 60 cycles, three phase, 13,200 volts or 4,160 volts at the Department's option.

NET MONTHLY BILL

Customer Charge $50.00

Demand Rates

On-Peak	Off-Peak	
$7.00	$5.00	per kW of billing demand

Energy Rates

On-Peak	Off-Peak	
12.50¢	11.00¢	per KWH of energy use resulting from the first 100 hours use times KW billing demand
11.00¢	9.50¢	per KWH of energy use resulting from the next 200 hours use times KW billing demand
8.50¢	7.00¢	per KWH of energy use resulting from the next 100 hours use times KW billing demand
6.50¢	4.50¢	per KWH of energy use resulting from all over 400 hours use times KW billing demand

Minimum Monthly Bill

The Customer Charge plus the Demand Charge.

Primary Voltage Discount

Where the Department renders electric service at 4,160 or 13,200 volts and the customer furnishes and maintains all transformation equipment, controlling and protective equipment and other facilities required to transform the delivery voltage to a utilization voltage, the net monthly rate shall be discounted 7.0 percent.

GRANDFATHERED TOTAL ELECTRIC CUSTOMERS

Customer accounts receiving electric service under the TEGS Rate Schedule immediately prior to the effective date of this Rate Schedule shall receive a discount of 1.00 cent per kWh on all energy charges except for the last Off-Peak Season energy block. The over 400 hours used Off-Peak Season energy block charge shall be 4.00 cents per kWh. This discount is not available to new customers, new service locations or service locations that change customers after the effective date of this schedule.

PROVISION FOR SCHOOLS

Publicly and privately endowed non-profit educational schools and colleges shall receive a discount of 1.00 cent per kWh off of the On-Peak Season energy charges and a discount of 0.5 cents per kWh off of the Off-Peak Season energy charges. All customers receiving electric service under the EDU-AL Rate Schedule immediately prior to the effective date of this Rate Schedule shall receive an additional discount of 5.00 cents per kWh off of the Off-Peak Season first block energy charge for all off-peak season kWh use.

POWER COST ADJUSTMENT

See Schedule PCA-1.

REGULATORY AND ENVIRONMENTAL COMPLIANCE RIDER

See Schedule REC-1.

BILLING DEMAND DETERMINATION

Secondary Voltage Service: The monthly billing demand shall be the maximum 30-minute measured kilowatt (KW) demand as adjusted for power factor during the month, but the minimum billing demand during any month shall not be less than 10 KW nor less than 80 percent of the highest adjusted measured demands established during the summer billing months of July, August and September for the latest twelve months ending with the current month. Monthly measured demands will be adjusted or corrected for power factor if customer's power factor is found by test to be less than 85 percent lagging. The measured demand corrected for power factor shall be determined by multiplying the maximum measured kilowatt demand during the month by 85 percent and dividing by the percentage power factor as determined. Fractional Billing demands will be rounded to the nearest whole kilowatt demand.

Primary Voltage Service: The monthly billing demand shall be the maximum 30-minute measured kilowatt (KW) demand as adjusted for power factor during the month, but the minimum billing demand during any month shall not be less than 75 KW nor less than 80 percent of the highest adjusted measured demand established during the summer billing months of July, August and September for the latest twelve months ending with the current month. Monthly measured demands will be adjusted or corrected for power factor if customer's power factor is found by test to be less than 85 percent lagging. The measured demand corrected for power factor shall be determined by multiplying the maximum measured kilowatt demand during the month by 85 percent and dividing by the percentage power factor as determined. Fractional billing demands will be rounded to the nearest whole kilowatt demand.

SECONDARY METERING OF PRIMARY VOLTAGE SERVICE

When the power and energy requirements of primary voltage customers are measured at the secondary voltage side of the customer's power transformer (at the Department's option) the recorded energy and demand shall be increased by 2.5 percent to account for losses through the transformer.

PAYMENT

Monthly bills will be rendered NET, payable on or before the due date of the net monthly bill. The gross monthly bill, which is 105 percent of the net monthly bill, will be collected if monthly bill is not paid on or before due date.

PAYMENT IN LIEU OF TAXES TO CITY OF INDEPENDENCE

The net monthly bill rates of this service schedule include charges for the Department’s payment in lieu of taxes (PILOT) to the City’s General Fund as authorized by Section 3.17 of the City Charter. The Department’s PILOT payment to the City is equal to the amount of City taxes and fees charged on privately owned utilities, including the 9.08 percent franchise fee, applicable utility property taxes and sales taxes.

TERMS OF SERVICE

Service rendered under this schedule is subject to the Department's standard rules and regulations.

Schedule LP-1
Large Power Service

AVAILABLE

Electric service is available under this schedule in the entire area served by the Department's existing 13,200 volt primary voltage distribution system and 69,000 volt transmission system.

APPLICABLE

To any customer with a monthly demand of 1,000 kW or greater for all demand and energy uses at any one location where service of a single character is taken through one meter at one point of delivery. This schedule is not applicable to resale or shared electric service.

CHARACTER OF SERVICE

Alternating current, 60 cycles, three phase, 13,200 volts primary distribution delivery or 69,000 volt transmission delivery.

NET MONTHLY BILL

Customer Charge $500.00

Demand Charge

$18.50 per kW for all billing demand

Energy Charge

3.85¢ per kWh of energy use

Minimum Monthly Bill

The Customer Charge plus Demand Charges.

TRANSMISSION VOLTAGE DISCOUNT

Where the Department renders electric service at 69,000 volts and the customer furnishes and maintains all transformation equipment, controlling and protective equipment and other facilities required to transform the delivery voltage to a utilization voltage, the demand charge of the net monthly rate shall be discounted $1.02 per kW of billing demand.

POWER COST ADJUSTMENT

See Schedule PCA-1.

Schedule LP-1
Large Power Service
(Continued)

REGULATORY AND ENVIRONMENTAL COMPLIANCE RIDER

See Schedule REC-1.

BILLING DEMAND DETERMINATION

Primary Voltage Service

The monthly billing demand shall be the maximum 30-minute measured kilowatt (kW) demand as adjusted for power factor during the month, but the minimum billing demand during any month shall not be less than 1,000 kW nor less than 80 percent of the highest adjusted measured demands established during the summer billing months of July, August and September for the latest twelve months ending with the current month. Monthly measured demands will be adjusted or corrected for power factor if customer's power factor is found by test to be less than 85 percent lagging. The measured demand corrected for power factor shall be determined by multiplying the maximum measured kilowatt demand during the month by 85 percent and dividing by the percentage power factor as determined. Fractional billing demands will be rounded to the nearest whole kilowatt demand.

Transmission Voltage Service

The monthly billing demand shall be the maximum 30-minute measured kilowatt (kW) demand as adjusted for power factor during the month, but the minimum billing demand during any month shall not be less than 3,000 kW nor less than 80 percent of the highest adjusted measured demands established during the summer billing months of July, August and September for the latest twelve months ending with the current month. Monthly measured demands will be adjusted or corrected for power factor if customer's power factor is found by test to be less than 85 percent lagging. The measured demand corrected for power factor shall be determined by multiplying the maximum measured kilowatt demand during the month by 85 percent and dividing by the percentage power factor as determined. Fractional billing demands will be rounded to the nearest whole kilowatt demand.

EXTRA FACILITIES TRANSFORMATION RENTAL CHARGES

Upon the customer’s written request for Extra Facilities Transformation Equipment at the time of new service application, and if mutually beneficial to the Department and the customer as determined by the Department, the Department at its sole option will provide and maintain Extra Facilities Transformation Equipment to the customer at an agreed upon location on customer’s property which converts the delivered 13.2 kV primary voltage service to a lower standard primary or secondary voltage. The monthly rental charge for Extra Facilities Transformation is in addition to the customer’s Net Monthly Bill Rate for electric service and shall be equal to 1.3 percent of the Department’s total investment in the Extra Facilities Transformation Equipment provided herein.

Schedule LP-1
Large Power Service
(Continued)

PAYMENT

Monthly billing will be rendered NET, payable on or before the due date of the net monthly bill. The gross monthly bill, which is 105 percent of the net monthly bill, will be collected if monthly bill is not paid on or before due date.

PAYMENT IN LIEU OF TAXES TO CITY OF INDEPENDENCE

The net monthly bill rates of this service schedule include charges for the Department's payment in lieu of taxes (PILOT) to the City's General Fund as authorized by Section 3.17 of the City Charter. The Department's PILOT payment to the City is equal to the amount of City taxes and fees charged on privately owned utilities, including the 9.08 percent franchise fee, applicable utility property taxes and sales taxes.

TERMS OF CONTRACT AND SERVICE

The customer shall execute the Department's standard form of contract for three years or more, designating therein the amount of power contracted for. The contract shall be automatically renewed annually after initial period until terminated by written notice from either party. Service rendered under this schedule is subject to the Department's standard rules and regulations.

Schedule LP-FR
Large Power Service
(FROZEN September 30, 2015)

AVAILABLE

Electric service is available under this schedule in the entire area served by the Department's existing 13,200 volt primary voltage distribution system and 69,000 volt transmission system. This schedule is available only to Customers' physical locations taking service under this schedule as of September 30, 2015 and who are served hereunder continuously thereafter. This schedule is not available to new customers, new service locations or service locations that have changed customers after the effective date of this schedule.

APPLICABLE

To any industrial customer for all power and energy uses at any one location where service of a single character is taken through one meter at one point of delivery. This schedule is not applicable to resale or shared electric service.

CHARACTER OF SERVICE

Alternating current, 60 cycles, three phase, 13,200 volts primary distribution delivery or 69,000 volt transmission delivery.

NET MONTHLY BILL

Rate

Demand Charge

$5.70	per KW for the first 500 KW of billing demand
$4.83	per KW for the next 500 KW of billing demand
$3.23	per KW for all additional KW of billing demand

Energy Charge

*Rate A (Applicable to energy used with first 1,800 KW of billing demand)

10.55¢	per KWH of energy use resulting from the first 150 hours use times KW billing demand
9.84¢	per KWH of energy use resulting from the next 200 hours use times KW billing demand
8.86¢	per KWH of energy use resulting from the next 100 hours use times KW billing demand
8.35¢	per KWH of energy use resulting from all over 450 hours use times KW billing demand

**Rate B (Applicable to energy used with all over 1,800 KW of billing demand)

9.93¢	per KWH of energy use resulting from the first 150 hours use times KW billing demand over 1,800 KW
9.12¢	per KWH of energy use resulting from the next 200 hours use times KW billing demand over 1,800 KW
7.94¢	per KWH of energy use resulting from the next 100 hours use times KW billing demand over 1,800 KW
7.53¢	per KWH of energy use resulting from all over 450 hours use times KW billing demand over 1,800 KW

Minimum Monthly Bill

The Demand and Energy Charges, but not less than the charge of $4.83 per KW of the highest adjusted measured demand established during the twelve months ending with current month. The minimum monthly bill will be adjusted to include any Extra Facilities Charge if applicable.

TOTAL METERED ENERGY TO BE BILLED AT ENERGY RATE "A" AND RATE "B"

Rate "A" applies only to Energy used with the first 1,800 KW of Billing Demand. When customer's Billing Demand is 1,800 KW or less, total Metered Energy is billed under Rate "A". When customer's Billing Demand is greater than 1,800 KW, total Energy to be billed under Rate "A" and Rate "B" is determined as follows:

*Rate "A" Total Energy KWH = 1,800 KW divided by Total Billing Demand (times) total Metered Energy; and

**Rate "B" Total Energy KWH = Total Metered Energy minus Rate "A" Total Energy KWH.

TRANSMISSION VOLTAGE DISCOUNT

Where the Department renders electric service at 69,000 volts and the customer furnishes and maintains all transformation equipment, controlling and protective equipment and other facilities required to transform the delivery voltage to a utilization voltage, the demand charge of the net monthly rate shall be discounted $1.02 per kW of billing demand.

POWER COST ADJUSTMENT

See Schedule PCA-1.

REGULATORY AND ENVIRONMENTAL COMPLIANCE RIDER

See Schedule REC-1.

BILLING DEMAND DETERMINATION

Primary Voltage Service

The monthly billing demand shall be the maximum 30-minute measured kilowatt (kW) demand as adjusted for power factor during the month, but the minimum billing demand during any month shall not be less than 1,000 kW nor less than 80 percent of the highest adjusted measured demands established during the summer billing months of July, August and September for the latest twelve months ending with the current month. Monthly measured demands will be adjusted or corrected for power factor if customer's power factor is found by test to be less than 85 percent lagging. The measured demand corrected for power factor shall be determined by multiplying the maximum measured kilowatt demand during the month by 85 percent and dividing by the percentage power factor as determined. Fractional billing demands will be rounded to the nearest whole kilowatt demand.

Transmission Voltage Service

The monthly billing demand shall be the maximum 30-minute measured kilowatt (kW) demand as adjusted for power factor during the month, but the minimum billing demand during any month shall not be less than 3,000 kW nor less than 80 percent of the highest adjusted measured demands established during the summer billing months of July, August and September for the latest twelve months ending with the current month. Monthly measured demands will be adjusted or corrected for power factor if customer's power factor is found by test to be less than 85 percent lagging. The measured demand corrected for power factor shall be determined by multiplying the maximum measured kilowatt demand during the month by 85 percent and dividing by the percentage power factor as determined. Fractional billing demands will be rounded to the nearest whole kilowatt demand.

EXTRA FACILITIES TRANSFORMATION RENTAL CHARGES

Upon the customer’s written request for Extra Facilities Transformation Equipment at the time of new service application, and if mutually beneficial to the Department and the customer as determined by the Department, the Department at its sole option will provide and maintain Extra Facilities Transformation Equipment to the customer at an agreed upon location on customer’s property which converts the delivered 13.2 kV primary voltage service to a lower standard primary or secondary voltage. The monthly rental charge for Extra Facilities Transformation is in addition to the customer’s Net Monthly Bill Rate for electric service and shall be equal to 1.3 percent of the Department’s total investment in the Extra Facilities Transformation Equipment provided herein.

Schedule LP-FR
Large Power Service
(FROZEN September 30, 2015)
(Continued)

PAYMENT

Monthly billing will be rendered NET, payable on or before the due date of the net monthly bill. The gross monthly bill, which is 105 percent of the net monthly bill, will be collected if monthly bill is not paid on or before due date.

PAYMENT IN LIEU OF TAXES TO CITY OF INDEPENDENCE

The net monthly bill rates of this service schedule include charges for the Department's payment in lieu of taxes (PILOT) to the City's General Fund as authorized by Section 3.17 of the City Charter. The Department's PILOT payment to the City is equal to the amount of City taxes and fees charged on privately owned utilities, including the 9.08 percent franchise fee, applicable utility property taxes and sales taxes.

TERMS OF CONTRACT AND SERVICE

The customer shall execute the Department's standard form of contract for three years or more, designating therein the amount of power contracted for. The contract shall be automatically renewed annually after initial period until terminated by written notice from either party. Service rendered under this schedule is subject to the Department's standard rules and regulations.

Schedule GSSH-FR
General Service Electric Space Heating
(FROZEN September 30, 2015)

AVAILABLE

Electric service is available under this schedule in the entire area served by the Department's existing secondary voltage distribution system. This schedule is available only to Customers' physical locations taking service under this schedule as of September 30, 2015 and who are served hereunder continuously thereafter. This schedule is not available to new customers, new service locations or service locations that have changed customers after the effective date of this schedule.

APPLICABLE

To any customer whose normal power and energy requirements are billed on Schedules GS-1 or LGS-1, supplied through one meter at one point of delivery for all power and energy used for qualifying electric space heating equipment. Space heating equipment shall be operated at 208 volts or more and be of a design approved by the Department.

Permanently installed equipment to cool the same area served by the electric space heating equipment may be connected to the space heating circuit, but will not be billed under this schedule during the on-peak months.

Application of this rate is limited to seven consecutive billing months with the first billing month starting with meter reading cycle 1 occurring in October of each year. The power (KW) and energy (KWH) used during the five month period not covered by this schedule shall be added to the consumption through the General Service meter and billed under the applicable General Service schedules.

CHARACTER OF SERVICE

Alternating current, 60 cycles, single or three phase, at secondary voltages as the Department may have available for the service required.

NET MONTHLY BILL

Rate

7.10¢ per kWh for all kWh used.

Minimum Monthly Bill

The Rate Charge, but not less than the charge of $0.89 per kW of billing demand.

Qualifying Electric Space Heating Equipment

Qualifying electric space heating equipment shall be permanently installed, thermostatically controlled and in normal use and shall include all types of electric space heating equipment of not less than 3 kW (except heat pumps) which are the sole source of comfort heating for room or rooms to be heated. Qualifying space heating equipment shall also include electric heat pumps or add-on electric heat pumps used with fossil fuel heating and other types of heating or solar heating systems of not less than 12,000 Btu nominal cooling capacity. The add-on heat pump shall be the sole source of space heating for the space to be heated during outdoor temperatures at or above the thermal heating capacity balance point of the heat pump.

Add-on heat pumps shall be properly sized for the cooling space to be cooled and shall include the necessary control equipment which automatically operates the heat pump as the sole source of space heating during outdoor temperatures at or above the thermal heating capacity balance point of the heat pump. The thermal heating capacity balance point is the outdoor temperature at which the heating requirements of the space to be heated exceed the heating capacity of the heat pump and, therefore, other heating systems must be used in order to satisfy the heating requirements of the space to be heated.

POWER COST ADJUSTMENT

See Schedule PCA-1.

REGULATORY AND ENVIRONMENTAL COMPLIANCE RIDER

See Schedule REC-1.

BILLING DEMAND DETERMINATION

The maximum 30-minute measured kilowatt demand during the month, but not less than 6 KW.

PAYMENT

Monthly bills will be rendered NET, payable on or before the due date of the net monthly bill. The gross monthly bill, which is 105 percent of the net monthly bill, will be collected if monthly bill is not paid on or before due date.

PAYMENT IN LIEU OF TAXES TO CITY OF INDEPENDENCE

The net monthly bill rates of this service schedule include charges for the Department’s payment in lieu of taxes (PILOT) to the City’s General Fund as authorized by Section 3.17 of the City Charter. The Department’s PILOT payment to the City is equal to the amount of City taxes and fees charged on privately owned utilities, including the 9.08 percent franchise fee, applicable utility property taxes and sales taxes.

TERMS OF SERVICE

Service rendered under this schedule is subject to the Department's standard rules and regulations.

Schedule PL-1
Private Outdoor Lighting Service

AVAILABLE

Electric service is available under this schedule in the entire area served by the Department's existing secondary voltage distribution system.

APPLICABLE

To any customer for the lighting of private outdoor areas. The Department shall furnish, install, and maintain all facilities required for service. Lamp fixtures and flood lights will be operated by a photo cell switch on a dusk to dawn basis.

CHARACTER OF SERVICE

Alternating current, 60 cycles, single or three phase at secondary voltages as the Department may have available for the required service.

NET MONTHLY BILL

Rate

A. When mercury vapor area light fixture is mounted on an existing wood distribution pole where secondary voltage exists (frozen, not available for newly installed lights, after the effective date of Schedule PL-1):

175 watt luminaire	$17.28
400 watt luminaire	$27.68

B. When high pressure sodium vapor area light fixture is mounted on an existing wood distribution pole where secondary voltage exists (frozen, not available for newly installed lights, after the effective date of Schedule PL-1):

70 watt luminaire	$14.08
150 watt luminaire	$17.54

C. When a high pressure sodium vapor flood light fixture is mounted on an existing wood pole where secondary voltage exists:

70 watt flood light	$14.58
250 watt flood light	$20.59
400 watt flood light	$24.38

D. When facilities beyond those provided for in Rate A, Rate B, and Rate C are required, a charge of 1.5 percent of the Department’s estimated investment in the additional facilities provided will be added to the Net Monthly Bill.

E. When high pressure sodium vapor luminaire fixture or high pressure sodium vapor flood light fixture cannot be mounted on an existing wood distribution pole, the monthly charge in addition to charges provided in Rate B and C for a standard 30 foot wood distribution pole (including secondary voltage conductor) will be:

$6.65 per pole

F. If customer requests the replacement of existing mercury vapor area light luminaires with high pressure sodium vapor area light luminaires the customer will be charged a $42.92 per luminaire cost of removal charge for each mercury vapor luminaire replaced by a high pressure sodium vapor luminaire.

PAYMENT

Monthly bills will be rendered NET, payable on or before the due date of the net monthly bill, the gross monthly bill, which is 105 percent of the net monthly bill, will be collected if monthly bill is not paid on or before due date.

PAYMENT IN LIEU OF TAXES TO CITY OF INDEPENDENCE

The net monthly bill rates of this service schedule include charges for the Department’s payment in lieu of taxes (PILOT) to the City’s General Fund as authorized by Section 3.17 of the City Charter. The Department’s PILOT payment to the City is equal to the amount of City taxes and fees charged on privately owned utilities, including the 9.08 percent franchise fee, applicable utility property taxes and sales taxes.

TERMS OF SERVICE

Service rendered under this schedule is subject to the Department's standard rules and regulations.

INDEPENDENCE POWER & LIGHT DEPARTMENT
Independence, Missouri

Schedule PL-1
Private Outdoor Lighting Service
(Continued)

Form of Customer Agreement

This agreement is entered into this _______ day of ____________, 20____, between Independence Power & Light Department (Department) and ____ (Customer).

1. Scope: The Department will supply, install and maintain on property located at ____, the hereinafter specified number of automatically controlled lighting fixtures and wood poles.

2. Installations and Rates:

No. of Installed	Type and Size	Monthly Rate Per Installed Unit	Total Monthly Charge
______	70 Watt Sodium Vapor* Area Light Fixture (Nominal 5,800 Lumens)	$14.08	$_______
______	150 Watt Sodium Vapor* Area Light Fixture (Nominal 16,000 Lumens)	$17.54	$_______
______	70 Watt Sodium Vapor* Flood Light Fixture (Nominal 5,800 Lumens)	$14.58	$_______
______	250 Watt Sodium Vapor* Flood Light Fixture (Nominal 29,000 Lumens)	$20.59	$_______
______	400 Watt Sodium Vapor* Flood Light Fixture (Nominal 47,500 Lumens)	$24.38	$_______
______	30 Foot Wood Pole	$6.65	$_______
______	Existing Wood Pole	N/C	________

* High Pressure Sodium Vapor Luminaries

3. Terms of Agreement: This agreement shall be binding on both parties for a period of one year. It is understood that this agreement will be extended beyond the initial agreement term on a month to month basis until cancelled by the customer. The terms and conditions of the Private Outdoor Lighting Schedule PL-1 and Electric Service Policies, Standards and Requirements are subject to change from time to time by the appropriate action of the City Council of Independence, Missouri.

______________________________ ______________________________
Independence Power & Light Department Customer

______________________________ ______________________________
Job Number Account Number

Schedule SCIS-FR
Special Contract Large Interruptible Industrial Service
(FROZEN September 30, 2015)

AVAILABLE

Special agreement interruptible electric service or combined interruptible and partial backup firm service is available under this schedule when customer makes written request and the Department determines that such requested electric service in specific customer application will be cost effective to the Department and its customers under the rates, terms and conditions of electric service interruption included in this rate schedule. This schedule is available only to Customers' physical locations taking service under this schedule as of September 30, 2015 and who are served hereunder continuously thereafter. This schedule is not available to new customers, new service locations or service locations that have changed customers after the effective date of this schedule.

Available to any single metered industrial customer for all power and energy uses. Service will be supplied from the Department's three phase 13 KV distribution system for contract interruptible loads of 1,000 kilowatts or more. This schedule is not applicable to resale or shared electric service.

TERM OF SERVICE

Agreements under this schedule shall be for a term of not less than eight years. Service after the eighth year shall be automatically renewable each year unless canceled by the Department or customer after 12 months prior written notice.

NET MONTHLY RATE FOR INTERRUPTIBLE SERVICE

Demand Charge

\$5,529	for the first 1,000 kW of billing demand.
\$5.27	per kW for all additional kW of billing demand.

Energy Charge

7.80¢	per kWh of metered energy use resulting from the first 480 hours use times kW billing demand.
7.05¢	per kWh of metered energy use for all over 480 hours use times kW billing demand.

Minimum Monthly Bill

The minimum monthly charge shall be the Interruptible Demand and Energy Charges, any Backup Firm Electric Service Rider provision charges and Extra Facility Charge if applicable.

POWER COST ADJUSTMENT

See Schedule PCA-1.

TERMS AND CONDITIONS OF ELECTRIC SERVICE INTERRUPTION

Electric service provided at this rate schedule is subject to 100 percent interruption upon demand of the Department during the Seasonal Interruption Periods prescribed herein. If customer purchases

Backup Firm Service in accordance with the Backup Firm Electric Rider Provision included in Schedule SCIS-1, then customer's electric service shall be curtailed to a load amount not to exceed the amount of contracted demand for Backup Firm Service.

Seasonal Interruption Periods

Summer Season: For a maximum daily period of each hour between 12:00 noon through 10:00 P.M. for the period extending from June 20th through September 10th of each year, exclusive of weekends and generally recognized holidays.

Winter Season: For a maximum daily period of each hour between 5:00 P.M. through 9:00 P.M. for the period extending from November 15th through March 15th of each year, exclusive of weekends and generally recognized holidays.

Notification Period of Electric Service Interruption

The Department's Load Dispatcher will notify the customer 24 hours in advance of each day's electric service hourly interruption period during the prescribed Seasonal Interruption Periods.

In case of emergencies as determined by the Department, electric service interruptions during the prescribed Seasonal Interruption Periods may be implemented at one-hour notice to the customer.

Implementation of Electric Service Interruption

The Department reserves the right to restrict or limit the terms of implemented interruption to lesser number of days or hours than allowed in this rate schedule based upon content of Specific Service Interruption Agreements between the Department and the customer.

Summer Season Period

The Department's implementation of electric service interruption during the Summer Season Period will be based upon the expectation that the maximum outdoor temperature is to exceed 98° F during the day in which electric service is to be interrupted. Each day's hourly period of interruption will be determined by the Department as dictated by the electric system load, available capacity, and cost of energy supply, but will not be greater than the maximum period of 12:00 Noon through 10:00 P.M. If Backup Firm Electric Service is provided at the terms and conditions of Backup Firm Electric Service Rider Provision and at the Department's sole discretion, customer may elect, if authorized by the Department, not to curtail or interrupt the load to level of Backup Firm Service contract demand and be billed at the additional energy charge authorized by said Rider Provision for all energy used during maximum daily interruption period of 12:00 Noon to 10:00 P.M.

Winter Season Period

The Department's implementation of electric service interruption during the Winter Season Period will be based upon the expectation that the maximum outdoor temperature is to be less than 5° F during the day in which electric service is to be interrupted. Each day's hourly period of interruption will be determined by the Department as dictated by the electric system load, available capacity and cost of energy supply, but will not be greater than the maximum period of 5:00 P.M. through 9:00 P.M. If Backup Firm Electric Service is provided at the terms and conditions of Backup Firm Electric Service Rider Provision and at the Department's sole discretion, customer may elect, if authorized by the Department, not to curtail or interrupt the load to level of Backup Firm Service contract demand and be billed at the additional energy charge authorized by said Rider Provision for <u>all energy used during maximum daily interruption period</u> of 5:00 P.M. to 9:00 P.M.

BACKUP FIRM ELECTRIC SERVICE RIDER PROVISION

Upon written request of the customer and the concurrence of the Department, backup firm electric service will be provided to the customer through the interruptible service meter for essential plant electric requirements during periods when electric service is interrupted.

Backup firm electric service shall be provided upon the following conditions:

1. Backup firm electric service is defined as the maximum 30-minute delivery of electric power measured in kilowatts that the customer may use during implemented electric service interruption periods. The maximum amount of firm electric power delivery shall be the contract demand for backup firm electric service delivery.

2. The customer shall nominate a contract demand for backup firm service and the amount of the nominated contract demand shall be the lesser of the amount determined from provision (a) or (b) stated as follows:

   (a) an amount not to exceed 40 percent of the customer's expected highest monthly metered demand for interruptible service during a consecutive 12 month period; or

   (b) an amount that results in an implemented total net load interruption (highest monthly metered demand minus nominated contract demand) of not less than 1,000 kilowatts.

3. If customer's actual highest measured 30 minute kilowatt demand during an actual implemented interruption period exceeds the nominated contract demand for two consecutive days, then the highest measured demand shall be the contract demand for a subsequent 12 month period.

Backup firm service shall be provided only on an annual basis each year and shall be billed at the following Net Monthly Rate charge in addition to the Net Monthly Rate charges for Interruptible Service:

Monthly Demand Charge

$5.54 per KW for all KW of annual contract firm service demand.

Monthly Energy Charge

5.50¢ per KWH additional energy charge for all KWH used during actual implemented periods of service interruption or authorized use during the maximum daily interruption periods.

EXTRA FACILITIES RENTAL CHARGES FOR INTERRUPTIBLE SERVICE

Upon the written request of the customer and the concurrence of the Department, the Department will provide and maintain Extra Facilities including a stepdown transformer facility from either 13,200 volts to another standard single character primary or secondary voltage and all necessary Utility auxiliary and protective equipment at an agreed upon location at the customer's property. The monthly rental charge for Extra Facilities, in addition to customer's monthly rate for electric service, shall be equal to 1.3 percent of the Department's total investment in the Extra Facilities provided herein. The Department's metering of the customer's service will be at the Department's option on either the high or low voltage side of stepdown transformer facility, but if metering is on the low voltage side of transformer, said metering will include a loss compensating device to measure the stepdown transformer winding losses.

MONTHLY BILLING DEMAND DETERMINATION FOR INTERRUPTIBLE SERVICE

Demand will be determined by demand instruments or at the Department's option by demand tests. The Billing Kilowatt Demand for any month shall be the highest kilowatt demand indicated in any 30-minute interval during that month as adjusted for power factor, but not less than 1000 Kilowatts.

During the billing months when customer's electric service is subject to interruption (the days of June 20 through September 10 and November 15 through March 15), 50 percent of the highest metered KW demand established during the Off-Peak Hours (10:00 P.M. through 7:00 A.M.) that is in excess of the highest metered demand established during On-Peak Hours (7:00 A.M. through 10:00 P.M.) will be excluded from the Off-Peak Hour highest demand.

The highest kilowatt demand adjusted for power factor shall be determined by multiplying the measured highest kilowatt demand times 95% and dividing by the percentage power factor determined.

PAYMENT

Monthly bills will be rendered NET, payable on or before the due date of the net monthly bill. The gross monthly bill, which is 105 percent of the net monthly bill including Backup Firm Electric Service Charges and Extra Facilities Rental Charge, will be collected if the monthly bill is not paid on or before due date.

PAYMENT IN LIEU OF TAXES TO CITY OF INDEPENDENCE

The net monthly bill rates of this service schedule include charges for the Department's payment in lieu of taxes (PILOT) to the City's General Fund as authorized by Section 3.17 of the City Charter.

The Department's PILOT payment to the City is equal to the amount of City taxes and fees charged on privately owned utilities, including the 9.08 percent franchise fee, applicable utility property taxes and sales taxes.

TERMS OF SERVICE

Service rendered under this schedule is subject to the Department's standard rules and regulations.

Schedule TRS-1
City Traffic Signal Service

AVAILABLE

Electric service is available under this schedule in the entire area served by the Department's existing secondary voltage distribution system.

APPLICABLE

To the City of Independence for standard traffic signal control service and special emergency vehicle traffic control service. The Department shall operate and maintain standard traffic signal control facilities, but the City of Independence shall own and finance the installation and replacement cost of standard traffic signal control facilities (excluding Extra Facilities) applicable to the Net Monthly Bill provision of this schedule. Special Emergency Vehicle Traffic Control (EVTC) Service, provided under the Signal Extra Facilities Charge provision of this schedule, shall be billed at either of: (a) equipment that is owned, installed, replaced and maintained by the Department and whose continuing equipment original investment cost is financed by the Department; or (b) equipment that is owned, installed, replaced and maintained by the Department but whose initial equipment original investment cost is financed by the City of Independence and whose replacement equipment investment cost is financed by the Department.

CHARACTER OF SERVICE

Alternating current, 60 cycles, single phase secondary voltages

NET MONTHLY BILL

Monthly Rate – Standard Traffic Signal Control Service

(A)	Signal Facility Charge	$89.27	per metered location or intersection
(B)	Power Use Energy Charge	9.03¢	per KWH for all energy used

SIGNAL EXTRA FACILITIES CHARGE

As authorized by the City of Independence Public Works Department or Finance Department, the Power & Light Department shall install, replace and maintain Signal Extra Facilities Equipment for providing Emergency Vehicle Traffic Control Service at both City of Independence-owned and State of Missouri-owned traffic signal control locations at the following applicable Net Monthly charges:

(a) For Extra Facilities EVTC equipment whose original and replacement cost investment is financed by the Department, the Extra Facility Net Monthly billing charges applicable to the City of Independence shall be equal to 1.2 percent times the Department's applicable billing month's total installed investment cost for the Extra Facilities Equipment located at all traffic signal control locations.

(b) For Extra Facilities EVTC equipment whose initial original cost investment is financed by the City of Independence, the Extra Facility Net Monthly billing charges applicable to the City of Independence shall be equal to 0.9 percent times the Department's applicable billing month's total installed investment cost for the Extra Facilities Equipment located at all traffic signal control locations. The investment cost of EVTC equipment replaced by the Department, which was originally financed by the City, shall be financed by the Department and billed under provision (b).

The Extra Facilities Charges applicable to EVTC equipment installed on traffic signal locations owned, operated and maintained by the State of Missouri, whose electric service is provided to the State of Missouri under the Department's applicable General Service rate schedule, shall be billed to the City of Independence under the appropriate Signal Extra Facilities Charge provision of this schedule.

POWER COST ADJUSTMENT

See Schedule PCA-1.

REGULATORY AND ENVIRONMENTAL COMPLIANCE RIDER

See Schedule REC-1.

PAYMENT

Monthly bills will be rendered NET, payable on or before the due date of the net monthly bill. The gross monthly bill, which is 105 percent of the net monthly bill, will be collected if the monthly bill is not paid on or before due date.

PAYMENT IN LIEU OF TAXES TO CITY OF INDEPENDENCE

The net monthly bill rates of this service schedule include charges for the Department's payment in lieu of taxes (PILOT) to the City's General Fund as authorized by Section 3.17 of the City Charter. The Department's PILOT payment to the City is equal to the amount of City taxes and fees charged on privately owned utilities, including the 9.08 percent franchise fee, applicable utility property taxes and sales taxes.

TERMS OF SERVICE

Service rendered under this schedule is subject to the Department's standard rules and regulations.

INDEPENDENCE POWER & LIGHT DEPARTMENT
Independence, Missouri

Schedule PCA-1
Power Cost Adjustment

APPLICABLE

The Power Cost Adjustment Schedule PCA-1 shall be applicable to the Department's Retail Rate Schedules except for Public Street Lighting Services.

PURPOSE OF ADJUSTMENT

The Power Cost Adjustment Rate is to compensate the Department for the changes in fuel and purchased power energy related costs including applicable taxes (adjusted for sale of energy to other Utilities and entities) that are not included in the energy rates per kilowatt-hour of the Department's Retail Rate Schedules.

ADJUSTMENT FORMULA CHARGE

When the Department's adjusted unit fuel and purchased power energy related costs for the adjustment period (adjusted for the purchase and sale of energy to other Utilities and entities) is less than or exceeds $0.0236 per kWh, the Net Monthly Bill shall be decreased or increased respectively by an energy adjustment charge per kWh applied to the customer’s energy usage.

APPLICATION OF ADJUSTMENT

The Department shall review the PCA-1 calculation and shall make projections for the periods beginning February and August. Following such PCA-1 review and calculation, the Power & Light Director shall direct the PCA-1 to be applied, as deemed necessary to accomplish recovery of the Department’s fuel and purchased power energy related costs in a timely manner.

Schedule PCA-1
Power Cost Adjustment
(Continued)

Power Cost Determination

The Power Cost Adjustment will be determined from the following formula:

$$A = \frac{\$(B + C - D + E + F)}{G} - \text{Base}$$

Where A = Power Cost Adjustment Rate, expressed as dollar per kWh rounded to the nearest four decimal places.

B = The FOB cost of fuel used at the Department's Generating Stations including storage and handling costs plus environmental costs incurred in order to comply with State and Federal environmental regulations including, but not limited to, cost of environmental emission allowance credit purchases, emission taxes, and FOB cost of certain energy-related environmental commodities used to limit emissions.

C = The energy-related portion of the cost of power purchased from other utilities or entities pursuant to purchased power agreements and the energy-related portion of the cost of power purchased under regional organized power markets including any transmission system energy losses and congestion costs.

D = The energy-related portion of the revenue from the sale of electric energy to other Utilities or entities pursuant to power sales agreements and the energy-related portion of the revenue of power sales under regional organized power markets including any transmission system energy losses and congestion costs.

E = Adjustment for the Department's payment in lieu of taxes (PILOT) to the City's General Fund associated with the recovery of the Department's fuel and purchased power energy related costs under this Schedule PCA-1 computed as the PILOT rate (9.08%) divided by one (1) minus the PILOT rate, multiplied by the sum of B and C, minus D.

F = Reconciliation of the cumulative over or under cost recovery of fuel and purchased power energy related costs from the previous twelve-month period. Such reconciliation will be added or subtracted, as applicable, on a twelve-month amortization basis to subsequent monthly fuel and purchased power energy related costs.

G = The net Kilowatt-hour energy sales to customers that Schedule PCA-1 is applicable for the time period for which the fuel and purchased power energy related costs are computed.

Base = $0.0236/kWh

PAYMENT IN LIEU OF TAXES TO CITY OF INDEPENDENCE

The net monthly formula charge of this service schedule includes charges for the Department's payment in lieu of taxes (PILOT) to the City's General Fund as authorized by Section 3.17 of the City Charter. The Department's PILOT payment to the City is equal to the amount of City taxes and fees charged on privately owned utilities, including the 9.08 percent franchise fee, applicable utility property taxes and sales taxes.

TERMS OF SERVICE

Service rendered under this schedule is subject to the Department's standard rules and regulations.

Schedule EDR-FR
Economic Development Rider
(FROZEN September 30, 2015)

PURPOSE

The purpose of this Economic Development Rider is to encourage industrial development in the Department's service territory. These activities will diversify the Department's customer base, create jobs and serve to improve the utilization efficiency of existing Department facilities.

AVAILABLE

Electric service under this Rider is only available to Customers' physical locations taking service under frozen schedules LP-FR and SCIS-FR as of September 30, 2015 and who are served hereunder continuously thereafter. This schedule is not available to new customers, new service locations or service locations that have changed customers after the effective date of this schedule.

For purposes of this Rider, an industrial customer is defined as any business that is primarily engaged in the manufacturing or processing of a product for sale or resale or any other similar industrial related activities as may be determined by the Department from time to time. This Rider is not applicable to any Customer who is directly engaged in the retail trade of rendering goods and services to the general public.

APPLICABLE

Upon the written request of the customer and acceptance by the Department, the provisions of this Rider will be applicable to following customers that meet the following qualifications:

(1) New industrial customers whose electrical load characteristics qualify under Applicability provisions (3)(a) and (4) of this Rider.

(2) Existing industrial customers who either (i) have load expansion whose electric load characteristics qualify under Applicability provisions (3)(b) and (4) of this Rider or (ii) make a capital investment in their existing facility equal to or greater than ten times their annual electrical billings for the last 12 months and whose electrical load characteristics qualify under Applicability provisions (3)(c) and (4) of this Rider.

(3) (a) The peak demand of the new customer is reasonably projected to be at least 200 KW within two years of the new customer first receiving service from the Department. (b) The incremental peak load expansion of an existing customer is reasonably projected to be at least 200 KW and not less than 20 percent of the combined existing load and incremental load expansion within two years of existing customer first receiving service for load expansion.

(c) For an existing customer that qualifies under the capital investment criteria, the peak demand of the customer's facility shall be at least 200 KW.

(4) The annual load factor of the new customer or incremental load expansion of an existing customer is reasonably projected to equal or exceed an annual load factor of 50% within two years of the new customer or incremental load expansion first receiving service from the Department. For an existing customer that qualifies under the capital investment criteria, the customer annual load factor shall equal or exceed 50%. The annual customer load factor shall be determined using the following relationship:

> Annual Energy (KWH) of the customer or load expansion DIVIDED BY 8760 (Hours in year) DIVIDED BY Customer Demand or Incremental Customer Demand Load Expansion, Coincident with Department's Peak Demand.

(5) If as determined by the Department, the actual new customer load or existing customer incremental expansion load fails to qualify under the terms of Applicability Provisions (3) and (4) at the end of the two-year projection period starting with the first month's application of the Incentive Discount Provisions, the Department shall terminate the further application of the Incentive Discount Provisions for the remaining years of the discount period.

(6) Unless otherwise expressed in writing, the Customer agrees that the Department shall be the sole source of electricity used at the facility and to purchase, during the five-year term of the Agreement, all of its electric power requirements from the Department.

(7) The base or existing demand of an existing customer load will be based on the average of the two highest monthly metered peak loads established during the most recent 24-month period prior to load expansion. The percent load expansion will be determined by dividing the projected incremental load expansion by the sum of the base demand (prior to load expansion) and the incremental load expansion.

(8) If incremental load expansion of an existing customer is separately metered (at the Customer's option with Department Agreement) then the separately metered incremental load expansion will be treated as a new customer for the purpose of administering the provisions of this Rider, including applicable billing provisions.

Written requests for service under this Rider shall be accompanied by sufficiently detailed information to enable the Department to determine whether the new customer or incremental load expansion or the amount of capital investment meet the above criteria including items (1), (2), (3), (4), (7) and (8). All written requests for service under this Rider will be considered by the Department; however, requests which do not conform to the purpose and availability of this Rider, as stated above, will not be approved.

INCENTIVE DISCOUNT PROVISIONS

Schedule EDR-FR
Economic Development Rider
(FROZEN September 30, 2015)
(Continued)

The billed amounts under this Rider shall be determined by reducing otherwise applicable billing charges, including fuel adjustment, associated with the applicable rate schedule, by the following percentage amounts:

	Schedule A Discount	Schedule B Discount
First Contract Year	35.0%	14.0%
Second Contract Year	30.0%	12.0%
Third Contract Year	25.0%	10.0%
Fourth Contract Year	20.0%	8.0%
Fifth Contract Year	10.0%	4.0%
Sixth Contract Year and thereafter	0.0%	0.0%

Schedule A Discount applies to (i) the entire load for new customers; (ii) the entire load for existing customers that qualify under the capital investment criteria; and (iii) for the expanded load of existing customers that qualify under the load expansion criteria and have a separate meter for the expansion load (discount applies only to the separate meter for the load expansion).

Schedule B Discount applies to existing customers that qualify under the load expansion criteria and the existing customer's entire load (existing load plus expansion load) is metered with a single meter.

All other billing, operational and related provisions of the aforementioned rate schedule shall remain in effect.

FORM OF AGREEMENT

This Agreement is entered into as of this ___ day of ______________, 20___, by and between Independence Power & Light Department (Department) and ____(Customer).

WITNESSETH:

Whereas, Department has on file with the City Clerk of Independence a certain Economic Development Rider Schedule EDR-5 (Rider), and;

Whereas, Customer has furnished sufficient information to the Department to demonstrate that its new electric load facilities or additional electric load expansion facilities or the amount of capital investment satisfies the Availability and Applicability provisions of Rider Schedule EDR-5, and;

Whereas, Customer wishes to take electric service from the Department, and the Department agrees to furnish electric service to the Customer under this Rider and pursuant to Rate Schedule ____________ of the Department,

The Department and Customer agree as follows:

1. Service to the Customer's Facilities shall be pursuant to the Rider Schedule EDR-5, and Rate Schedule ____________, and the Department's Electric Service Policies, Standards, and Requirements, as may be in effect from time to time and filed with the City Clerk of Independence.
2. Customer further acknowledges that this Agreement is not assignable voluntarily by Customer, but shall nevertheless insure to the benefit of and be binding upon the Customer's successors by operation of law.
3. Customer acknowledges that all information provided to the Department for the purpose of determining whether the Customer is eligible for service under the Rider shall be retained by the Department, and shall be subject to inspection and disclosure under Chapters 386 and 393, RSMo 1986, as amended from time to time. Should the Customer designate any of such information as proprietary or confidential, Department shall notify Customer of any request for inspection or disclosure.
4. Unless agreed upon in writing, the Customer agrees that the Department shall be the sole source of electricity used at the facility and to purchase, during the five-year (5) Incentive Discount Provision period of the Rider, all of its electric power requirements from the Department.
5. This Agreement shall be governed in all respects by the laws of the State of Missouri and City Charter and Ordinances of the City of Independence (regardless of conflict of laws provisions), and by the Electric Service Policies, Standards, and Requirements of the Department as they may exist from time to time.

In witness whereof, the parties have signed this Agreement as of the date first above written.

Independence Power & Light Department	________________________________ Customer
By ______________________________	By ______________________________

Schedule PSL-1FR
Public Street Lighting Service

AVAILABLE

Public Street Lighting Service is available in the entire area served by the Department's secondary voltage distribution system for street lighting pole/fixtures installed by the Department prior to the effective date of this rate schedule. No new or additional Public Street Lighting Service Fixtures will be served under this rate schedule after April 30, 1999.

APPLICABLE

To the City of Independence for all Public Street Lighting Service under which the street lighting pole/fixtures were originally installed by the Department prior to May 1, 1999. When existing street lighting pole/fixtures are replaced by the Department at the end of said facilities useful life as determined by the Department; said converted or replaced street lighting fixtures will be served under Rate Schedule PSL-1DF.

The Department will own, operate and maintain the Public Street Lighting System Facilities served under this Rate Schedule.

Lamp Fixtures will be operated on a dusk to dawn basis generally through photo cell control.

NET MONTHLY BILL

Monthly Rate

(A) Energy Charge for Electric Supply to Street Lighting System Circuits:

(a-1) All energy used by the Public Street Lighting Lamps served under this rate schedule — 3.93¢ per KWH

(B) Facilities Charge for Overhead or Underground Circuit Street Lighting Pole/Fixtures:

(b-1) Lamp Fixtures Mounted on Standard Steel, Wood, Concrete and Ornamental poles — $1.71 per lamp

DETERMINATION OF MONTHLY ENERGY USE

The monthly energy use of street lighting fixtures served under this rate schedule shall be the sum of the lamp fixture wattage adjusted for transformer ballast losses times the estimated monthly dusk to dawn hours in each calendar month. Annual dusk to dawn operating hours is approximately 4,000 hours per year.

PAYMENT

Monthly bills will be rendered NET, payable on or before due date of the Net Monthly Bill. The gross monthly bill, which is 105 percent of the net monthly bill, will be collected if the monthly bill is not paid on or before due date.

PAYMENT IN LIEU OF TAXES TO CITY OF INDEPENDENCE

The net monthly bill rates of this service schedule include charges for the Department's payment in lieu of taxes (PILOT) to the City's General Fund as authorized by Section 3.17 of the City Charter. The Department's PILOT payment to the City is equal to the amount of City taxes and fees charged on privately owned utilities, including the 9.08 percent franchise fee, applicable utility property taxes and sales taxes.

TERMS OF SERVICE

Service rendered under this schedule is subject to the Department's standard rules and regulations.

INDEPENDENCE POWER & LIGHT DEPARTMENT
Independence, Missouri

Schedule PSL-1CF
Public Street Lighting Service

AVAILABLE

Public Street Lighting Service is available in the entire area served by the Department's secondary voltage distribution system for street lighting pole/fixture facilities systems installed by the Department but financed by the customer on or after May 1, 1999.

APPLICABLE

To the City of Independence for Public Street Lighting Service under which the Department owns, operates and maintains all Public Street Lighting Facilities. Under this rate schedule, either the City or "Other Entity" requesting the installation of any new street lighting facilities, which have been authorized by the City (Public Works Department), shall finance the construction cost of said facilities through "Contribution-in-Aid-of-Construction" payment to the Department. The Department will replace any Public Street Lighting System Facilities served under this rate schedule at the end of said facilities useful life as determined by the Department that has been previously financed by a capital contribution-in-aid-of-construction to the Department.

Lamp fixtures will be operated on a dusk-to-dawn basis generally through photo cell control.

NET MONTHLY BILL

Rate Code	Description	Monthly Rate Per KWH or Per Pole
(A) Energy Charge for Electric Supply to Street Lighting System Circuits:		
(a-1)	All energy used by the Public Street Lighting Lamps served under this rate schedule	3.93¢/KWH
(B) Facilities Charge for Underground Circuit Street Lighting System Poles:		
(b-1)	Lamp Fixture Mounted on Standard Steel/Concrete Pole	$3.41
(b-2)	Lamp Fixture Mounted on Breakaway Base Standard Steel Pole	$3.81
(b-3)	Double Mastarm Lamp Fixture Mounted on Standard Steel/Concrete Pole	$3.53
(b-4)	Double Mastarm Lamp Fixture Mounted on Breakaway Base Standard Steel Pole	$3.94
(b-5)	Lamp Fixture Mounted on Contemporary Aluminum Pole	$3.72
(b-6)	Lamp Fixture Mounted on Breakaway Base Contemporary Aluminum Pole	$4.11
(b-7)	Double Mastarm Lamp Fixture Mounted on Contemporary Aluminum Pole	$4.10
(b-8)	Double Mastarm Lamp Fixture Mounted on Break. Base Contemp. Aluminum Pole	$4.48
(b-9)	Pendent Lamp Fixture Mounted on Standard Ornamental Pole	$7.68
(b-10)	Pendent Lamp Fixture Mounted on Breakaway Base Standard Ornamental Pole	$8.34
(b-11)	Double Pendent Lamp Fixture Mounted on Standard Ornamental Pole	$10.39
(b-12)	Double Pendent Lamp Fixture Mounted on Breakaway Base Standard Orn. Pole	$11.05
(b-13)	Double Lamp Fixture Mounted on Ornamental Metal Post Pole	$5.81
(b-14)	Lamp Fixture Mounted on Ornamental Metal Post Pole	$4.60
(b-15)	Lamp Fixture Mounted on Contemporary Aluminum Pole - RESIDENTIAL	$3.72
(b-16)	Pendant Lamp Fixture Mounted on Ornamental Pole - RESIDENTIAL	$7.68
(C) Facilities Charge for Overhead Circuit Street Lighting System Poles:		
(c-1)	Lamp Fixture Mounted on an Existing Power Distribution Wood Pole	$1.83
(c-2)	Lamp Fixture Mounted on Standard Wood Pole	$2.46
(c-3)	Lamp Fixture Mounted on Standard Steel/Concrete Pole	$3.41

CAPITAL CONTRIBUTION-IN-AID-OF-CONSTRUCTION PAYMENT TO DEPARTMENT

The contribution-in-aid-of-construction payment to the Department from either the City or “Other Entity” requesting the construction of any new underground circuit Public Street Lighting Facilities is due prior to the start of construction and shall be equal to the estimated installed cost of Public Street Lighting Facilities provided by the Department. The contribution-in-aid-of-construction shall equal the estimated cost of both labor and materials for luminaries, lamps, mastarms, street light poles, breakaway pole bases if applicable, electrical underground circuits including conduit and wire if applicable, overhead electrical circuits if applicable, photo control cell and other miscellaneous street lighting systems materials.

DETERMINATION OF MONTHLY ENERGY USE

The monthly energy use of the street lighting fixtures served under this rate schedule shall be the sum of the lamp fixture wattage adjusted for transformer ballast losses times the estimated dusk to dawn hours in each calendar month. Annual dusk to dawn operating hours is approximately 4,000 hours per year.

PAYMENT

Monthly bills will be rendered NET, payable on or before due date of the Net Monthly Bill. The gross monthly bill, which is 105 percent of the net monthly bill, will be collected if the monthly bill is not paid on or before due date.

PAYMENT IN LIEU OF TAXES TO CITY OF INDEPENDENCE

The net monthly bill rates of this service schedule include charges for the Department’s payment in lieu of taxes (PILOT) to the City’s General Fund as authorized by Section 3.17 of the City Charter. The Department’s PILOT payment to the City is equal to the amount of City taxes and fees charged on privately owned utilities, including the 9.08 percent franchise fee, applicable utility property taxes and sales taxes.

TERMS OF SERVICE

Service rendered under this schedule is subject to the Department’s standard rules and regulations.

INDEPENDENCE POWER & LIGHT DEPARTMENT
Independence, Missouri

Schedule PSL-1DF
Public Street Lighting Service

AVAILABLE

Public Street Lighting Service is available in the entire area served by the Department's secondary voltage distribution system for new or replaced street lighting pole/fixture facilities installed and financed by the Department on or after May 1, 1999.

APPLICABLE

To the City of Independence for Public Street Lighting Service under which the Department owns, finances, operates and maintains all Public Street Lighting System Facilities served under this Rate Schedule. Under this rate schedule, the construction cost of any new or replaced street lighting facilities installed by the Department, which have been authorized by the City (Public Works Department), shall be financed by the Department. The Department will replace all Public Street Lighting System Facilities served under this rate schedule at the end of said facilities useful life as determined by the Department.

This rate schedule shall also be applicable to street lighting fixtures that are converted or replaced on or after May 1, 1999 which are currently served under Rate Schedule PSL-1FR when street lighting pole/fixtures are replaced by the Department at end of said facilities useful life as determined by the Department.

Lamp Fixtures will be operated on a dusk-to-dawn basis generally through photo cell control.

NET MONTHLY BILL

Rate Code	Description	Monthly Rate Per KWH or Per Pole
(A) Energy Charge for Electric Supply to Street Lighting System Circuits:		
(a-1)	All energy used by the Public Street Lighting Lamps served under this rate schedule	3.93¢/KWH
(B) Facilities Charge for Underground Circuit Street Lighting System Poles:		
(b-1)	Lamp Fixture Mounted on Standard Steel/Concrete Pole	$6.73
(b-2)	Lamp Fixture Mounted on Breakaway Base Standard Steel Pole	$7.65
(b-3)	Double Mastarm Lamp Fixture Mounted on Standard Steel/Concrete Pole	$7.01
(b-4)	Double Mastarm Lamp Fixture Mounted on Breakaway Base Standard Steel Pole	$7.96
(b-5)	Lamp Fixture Mounted on Contemporary Aluminum Pole	$7.46
(b-6)	Lamp Fixture Mounted on Breakaway Base Contemporary Aluminum Pole	$8.35
(b-7)	Double Mastarm Lamp Fixture Mounted on Contemporary Aluminum Pole	$8.34
(b-8)	Double Mastarm Lamp Fixture Mounted on Break. Base Contemp. Aluminum Pole	$9.23
(b-9)	Pendent Lamp Fixture Mounted on Standard Ornamental Pole	$16.68
(b-10)	Pendent Lamp Fixture Mounted on Breakaway Base Standard Ornamental Pole	$18.22
(b-11)	Double Pendent Lamp Fixture Mounted on Standard Ornamental Pole	$23.00
(b-12)	Double Pendent Lamp Fixture Mounted on Breakaway Base Standard Orn. Pole	$24.54
(b-13)	Double Lamp Fixture Mounted on Ornamental Metal Post Pole	$12.33
(b-14)	Lamp Fixture Mounted on Ornamental Metal Post Pole	$9.50
(b-15)	Lamp Fixture Mounted on Contemporary Aluminum Pole - RESIDENTIAL	$7.46
(b-16)	Pendant Lamp Fixture Mounted on Ornamental Pole - RESIDENTIAL	$16.68
(C) Facilities Charge for Overhead Circuit Street Lighting System Poles:		
(c-1)	Lamp Fixture Mounted on an Existing Power Distribution Wood Pole	$3.04

Schedule PSL-1DF
Public Street Lighting Service
(Continued)

Rate Code	Description	Monthly Rate Per KWH or Per Pole
(c-2)	Lamp Fixture Mounted on Standard Wood Pole	$4.51
(c-3)	Lamp Fixture Mounted on Standard Steel/Concrete Pole	$6.73

DETERMINATION OF MONTHLY ENERGY USE

The monthly energy use of the street lighting fixtures served under this rate schedule shall be the sum of the lamp fixture wattage adjusted for transformer ballast losses times the estimated monthly dusk to dawn hours in each calendar month. Annual dusk to dawn operating hours is approximately 4,000 hours per year.

PAYMENT

Monthly bills will be rendered NET, payable on or before due date of the Net Monthly Bill. The gross monthly bill, which is 105 percent of the net monthly bill, will be collected if the monthly bill is not paid on or before due date.

PAYMENT IN LIEU OF TAXES TO CITY OF INDEPENDENCE

The net monthly bill rates of this service schedule include charges for the Department's payment in lieu of taxes (PILOT) to the City's General Fund as authorized by Section 3.17 of the City Charter. The Department's PILOT payment to the City is equal to the amount of City taxes and fees charged on privately owned utilities, including the 9.08 percent franchise fee, applicable utility property taxes and sales taxes.

TERMS OF SERVICE

Service rendered under this schedule is subject to the Department's standard rules and regulations.

INDEPENDENCE POWER & LIGHT DEPARTMENT
Independence, Missouri

Schedule NM-1
Customer-Generator Net Metering Contract Service Rider

AVAILABLE

Electric Service is available under this schedule in the entire area served by the Department's existing secondary and primary voltage distribution systems.

APPLICABLE

To any customer normally served under the Department's other customer class rate schedules that has a Qualifying Net Metering Unit, as defined below, which is connected for parallel operation with the Department's electric system as provided for in the Consumer Clean Energy Act (Missouri Revised Statutes, 386.) and the Missouri Public Service Commission Net Metering Rule (4CSR 240-20.065). Customer-generators served under this schedule shall be limited to a generator capacity size of not more than 100 kilowatts. Service under this schedule shall be provided to customer-generators on first come, first served basis until the total rated generating capacity of net metering systems (in kilowatts) equals five percent (5%) of the Department's previous year's system single-hour peak load (in kilowatts). However, in a given calendar year, the Department shall not be required to approve any application for interconnection if the total rated generating capacity (in kilowatts) of all applications for interconnection already approved to date by the Department in such calendar year equals or exceeds one percent (1%) of the Department's previous year's system single-hour peak load (in kilowatts). This schedule is not applicable to breakdown, standby or resale electric service.

QUALIFYING NET METERING UNIT

A "Qualifying Net Metering Unit" means an electric generator unit which:

- is owned or operated by the customer-generator;
- is produced from wind, solar thermal sources, hydroelectric sources, photovoltaic cells and panels, fuel cells using hydrogen;
- has an electrical generating system with a capacity of not more than one hundred kilowatts (100 KW);
- is located on premises that are owned, operated, leased or otherwise controlled by the customer-generator;
- is interconnected with and operated in parallel phase and in synchronization with the Department's distribution power supply system; and
- is intended primarily to offset part of all of the customer-generator's own electric power requirements.

CHARACTER OF SERVICE

Alternating current, 60 cycles; at supply voltages, single or three phase, that apply to the customer-generator under the Department's appropriate customer class rate schedules.

NET METERED ENERGY AMOUNT

The Department will install metering equipment capable of measuring bi-directional electric power flow separately as follows: (a) the electrical energy delivered by the Department to the customer-generator, and (b) the electrical energy delivered by the customer-generator to the Department.

INTERCONNECTION APPLICATION/AGREEMENT
FOR
NET METERING SYSTEMS
(Continued)

Such metering equipment shall be capable of metering both energy (in kilowatt-hours) and demand (in kilowatts), if necessary, to bill customer under the Department's appropriate customer class rate schedule. The "Net Metered Energy Amount" in kilowatt-hours is the difference between the amount of energy metered by provisions (a) and (b) above.

NET MONTHLY BILL

a) When the Net Metered Energy Amount for the billing month is from the Department to the customer-generator, such Net Metered Energy Amount (KWH) and metered demand (KW), if applicable, will be billed under the Net Monthly Bill provisions of Department's retail customer class rate schedule applicable to customer-generator specific class of service.

b) When the Net Metered Energy Amount for the billing month is from the customer-generator to the Department, the customer-generator shall be billed as follows:

- The appropriate minimum bill charges and demand charges, if applicable, that are included in the Department's retail customer class rate schedule applicable to the customer-generator specific class of service; and

- A credit dollar amount for the Net Metered Energy Amount (KWH) supplied by the customer-generator to the Department at the Department's average avoided power supply energy costs as detailed as follows:

1) On-Peak Season Period
   3.14¢ per KWH per Net Metered Energy Amount delivered to the Department's electric system.

2) Off-Peak Season Period
   2.97¢ per KWH per Net Metered Energy Amount delivered to the Department's electric system.

3) The On-Peak Season Period is for the five consecutive months from May through September. The Off-Peak Season Period is for the seven consecutive months from October through April.

4) The credit dollar amount for the net energy supplied by customer-generator to the Department's electric system will be itemized on the customer-generator electric bill for the current month's billing period.

5) The On-Peak Season and Off-Peak Season avoided cost energy rates per KWH included herein are effective for the 12-month period ending April 2015 and are based on the Department's average avoided seasonal power supply energy costs for the preceding 12 months ending April 2014.

EFFECTIVE AVERAGE AVOIDED COST RATES FOR EACH 12 MONTH PERIOD AFTER APRIL 30, 2005

Each year at the end of April, the Department will determine its average avoided power supply energy costs for the previous Off-Peak Season Period and On-Peak Season Period which will apply to customer-generators subsequent monthly billing periods after April 2005 in accordance with the following formula:

$$A = \frac{B + C}{(D + E) \times F \times G}$$

where:

A = Average adjusted Off-Peak Season Period or On-Peak Season Period power supply energy costs per kilowatt hour

B = FOB cost of fuel used at Department's Generating Stations including storage and handling costs for Off-Peak Season Period or On-Peak Season Period

C = The cost of purchased electric energy from other utilities less any demand or capacity charges, exclusive of border customers purchases, for Off-Peak Season Period or On-Peak Season Period

D = The net kilowatt-hour generation of the Department's generating plants for Off-Peak Season Period or On-Peak Season Period

E = The delivered kilowatt-hour purchased electric energy into Department's system from other utilities, exclusive of border customers purchases, for Off-Peak Season Period or On-Peak Season Period

F = System loss factor of 0.95

G = Department's gross receipts tax payment factor of 0.9092 payable to City of Independence

CUSTOMER-GENERATOR MONTHLY METER READING PERIODS

The Department will generally read customer-generator meters on the nearest working day at the end of each calendar month. The Off-Peak Season Period starts with the first meter reading at the end of October and continues for the next six end-of-month readings through the month of April. The On-Peak Season Period starts with the first meter reading at the end of May and continues for the next four end-of-month readings through the month of September.

SPECIAL CONDITIONS

- The customer-generator must execute the Interconnection Application/Agreement for Net Metering Systems with the Department which further details the terms and conditions of service under this Schedule NM-1.

- The customer-generator shall carry no less than one hundred thousand dollars ($100,000) of liability insurance that provides for coverage of all risk liability for personal injuries (including death) and damage to property arising out of or caused by customer-generator or the Qualifying Net Metering Unit. Insurance may be in the form of an existing insurance policy or an endorsement on an existing insurance policy. For systems ten kilowatts (10 kW) or less, no liability insurance is required.

- The customer-generator is responsible for all costs associated with its generating facility.

- The customer-generator is responsible for all costs related to any modifications to the Department's facilities that may be required by the Department such as additional meter installation costs and costs for upgraded service line capacity that may be required by the Department for purposes of safety or reliability, or both.

- The Qualifying Net Metering Unit shall meet all applicable installation, safety and performance standards by the National Electrical Safety Code, the National Electric Code, the Institute of Electrical and Electronics Engineers (IEEE), and Underwriters Laboratory (UL). These requirements include, but are not limited to UL 1741, IEEE 929-2000, and IEEE 1547.

- Electric service rendered under this schedule is subject to the Department's standard rules and regulations.

- This Schedule NM-1 shall remain in effect until terminated in accordance with Terms and Termination Rights under the Interconnection Application/Agreement for Net Metering Services or if terminated, replaced, or revised by City Council ordinance. In such case where this schedule is replaced or revised, the Customer-Generator will have the option to continue taking service under the new schedule or terminating such service.

Schedule NM-1
Customer-Generator Net Metering Contract Service Rider

INTERCONNECTION APPLICATION/AGREEMENT FOR NET METERING SYSTEMS

For Customers Applying for Interconnection

If you are interested in applying for interconnection to City of Independence, Missouri - Power & Light Department's ("Department") electrical system, you should first contact the Department and ask for information related to interconnection of parallel generation equipment to Department's system and you should understand this information before proceeding with this Application. If you wish to apply for interconnection to Department's electrical system, please complete sections A, B, C, and D, and attach the plans and specifications describing the net metering, parallel generation, and interconnection facilities (hereinafter collectively referred to as the "Customer-Generator's System") and submit them to the Department at:

Independence Power & Light Department
Attn: Power & Light Director
21500 E. Truman Rd.
P.O. Box 1019
Independence, MO 64051

You will be provided with an approval or denial of this Application within thirty (30) days of receipt by the Department for Customer-Generators of ten kilowatts (10 kW) or less and within ninety (90) days of receipt by the Department for Customer-Generators of greater than ten kilowatts (10 kW). If this Application is denied, you will be provided with the reason(s) for the denial. If this Application is approved and signed by both you and the Department, it shall become a binding contract and shall govern your relationship with the Department.

For Customers Who Have Received Approval of Customer-Generator System Plans and Specifications

After receiving approval of your Application, it will be necessary to construct the Customer-Generator System in compliance with the plans and specifications described in the Application, complete sections E and F of this Application, and forward this Application to the Department for review and completion of section G at:

Independence Power & Light Department
Attn: Power & Light Director
21500 E. Truman Rd.
P.O. Box 1019
Independence, MO 64051

Prior to the interconnection of the qualified generation unit to the Department's system, the Customer-Generator will furnish the Department a certification from a qualified professional electrician or engineer that the installation meets the plans and specificiation described in the Application. If the Application for interconnection is approved by the Department and the Customer-Generator does not complete the interconnection within one (1) year after receipt of notice of the approval, the approval shall expire and the Customer-Generator shall be responsible for filing a new application.

INTERCONNECTION APPLICATION/AGREEMENT
FOR
NET METERING SYSTEMS
(Continued)

The Department will complete the utility portion of section G and, upon receipt of a completed Application/Agreement form and payment of any applicable fees, schedule a date for interconnection of the Customer-Generator System to Department's electrical system within fifteen (15) days of receipt by the Department if electric service already exists to the premises, unless the Customer-Generator and the Department agree to a later date. Similarly, upon receipt of a completed Application/ Agreement form and payment of any applicable fees, if electric service does not exist to the premises, the Department will schedule a date for interconnection of the Customer-Generator System to Department's electrical system no later than fifteen (15) days after service is established to the premises, unless the Customer-Generator and the Department agree to a later date.

For Customers Who Are Assuming Ownership or Operational Control of an Existing Customer-Generator System

If no changes are being made to the existing Customer-Generator System, complete sections A, D and F of this Application/Agreement and forward to the Department at:

Independence Power & Light Department
Attn: Power & Light Director
21500 E. Truman Rd.
P.O. Box 1019
Independence, MO 64051

The Department will review the new Application/Agreement and shall approve such, within fifteen (15) days of receipt by the Department if the new Customer-Generator has satisfactorily completed Application/Agreement, and no changes are being proposed to the existing Customer-Generator System. There are no fees or charges for the Customer-Generator who is assuming ownership or operational control of an existing Customer-Generator System if no modifications are being proposed to that System.

A. CUSTOMER-GENERATOR'S INFORMATION

Name: ____

Mailing Address: ____

City: ____________________ State: ____________________ Zip Code: ________

Service/Street Address (if different from above): ______________________________

City: ____________________ State: ____________________ Zip Code: ________

Daytime Phone: ________________ Fax: ______________ E-Mail: ____________

Emergency Contact Phone: ____

INDEPENDENCE POWER & LIGHT DEPARTMENT
Independence, Missouri

Schedule NM-1
Customer-Generator Net Metering Contract Service Rider

INTERCONNECTION APPLICATION/AGREEMENT
FOR
NET METERING SYSTEMS
(Continued)

Department's Electric Utility Account No. from Utility Bill: ________________________________

B. CUSTOMER-GENERATOR'S SYSTEM INFORMATION

Manufacturer Name Plate Power Rating: _____________________ KW Voltage: ______volts

AC or DC (circle one)

System Type: Wind __ Fuel Cell __________ Solar Thermal ____________________________

Photovoltaic ____ Hydroelectric ____Other (describe) ___________________________________

Service/Street Address: ____

Inverter/Interconnection Equipment Manufacturer: _______________________________________

Inverter/Interconnection Equipment Model No.: ____

Inverter/Interconnection Equipment Location (describe): ___________________________________

____

____

Outdoor Manual/Utility Accessible & Lockable Disconnect Switch Location (describe): _________

____

____

Existing Electrical Service Capacity: _______Amperes Voltage: ________Volts

Service Character: Single Phase ______ Three Phase ______

Total capacity of existing Customer-Generator System (if applicable): ______ kW

System Plans, Specifications, and Wiring Diagram must be attached for a valid application.

C. INSTALLATION INFORMATION/HARDWARE AND INSTALLATION COMPLIANCE

Company Installing System: ____

Contact Person of Company Installing System: __________________ Phone No. ___________

Contractor's License No. (if applicable): ____

Approximate Installation Date: ____

Mailing Address: ____

City: _________________________ State: _________________________ Zip Code: _________

Daytime Phone: ___________________ Fax: __________________ E-Mail: ________________

INTERCONNECTION APPLICATION/AGREEMENT
FOR
NET METERING SYSTEMS
(Continued)

Person or Agency Who Will Inspect/Certify Installation: ________________________________

The Customer-Generator's proposed system hardware complies with all applicable National Electrical Safety Code (NESC), National Electric Code (NEC), Institute of Electrical and Electronics Engineers (IEEE) and Underwriters Laboratories (UL) requirements for electrical equipment and their installation. As applicable to System type, these requirements include, but are not limited to, UL 1741, and IEEE 1547. The proposed installation complies with all applicable local electrical codes and all safety requirements of the City of Independence and the Department. The proposed System has a lockable, visible AC disconnect device, accessible at all times to Department's personnel. The System is only required to include one lockable, visible disconnect device, accessible to the Department. If the interconnection equipment is equipped with a visible, lockable, and accessible disconnect, no redundant device is needed to meet this requirement.

The Customer-Generator's proposed System has functioning controls to prevent voltage flicker, DC injection, overvoltage, undervoltage, overfrequency, underfrequency, and overcurrent, and to provide for System synchronization to Department's electrical system. The proposed System does have an anti-islanding function that prevents the generator from continuing to supply power when Department's electric system is not energized or operating normally. If the proposed System is designed to provide uninterruptible power to critical loads, either through energy storage or back-up generation, the proposed System includes a parallel blocking scheme for this backup source that prevents any backflow of power to Department's electrical system when the electrical system is not energized or not operating normally.

Signed (Installer): ______________________________________ Date: __________________

Name (print): ____

D. ADDITIONAL TERMS AND CONDITIONS

In addition to abiding by Department's other applicable rules and regulations, the Customer-Generator understands and agrees to the following specific terms and conditions:

1. Operation/Disconnection
   If it appears to the Department, at any time, in the reasonable exercise of its judgment, that operation of the Customer-Generator's System is adversely affecting safety, power quality or reliability of Department's electrical system, the Department may immediately disconnect and lock-out the Customer-Generator's System from Department's electrical system. The Customer-Generator shall permit Department's employees and inspectors reasonable access to inspect, test, and examine the Customer-Generator's System.

2. Liability
   Liability insurance is not required for Customer-Generators of ten kilowatts (10 kW) or less. For generators greater than ten kilowatts (10 kW), the Customer-Generator agrees to carry no less than $100,000 of liability insurance that provides for coverage of all risk of liability for

personal injuries (including death) and damage to property arising out of or caused by the operation of the Customer-Generator's System. Insurance may be in the form of an existing policy or an endorsement on an existing policy. Customer-Generators, including those whose systems are ten kilowatts (10 kW) or less, may have legal liabilities not covered under their existing insurance policy in the event the Customer-Generator's negligence or other wrongful conduct causes personal injury (including death), damage to property, or other actions and claims.

3. Metering and Distribution Costs
A Customer-Generator's facility shall be equipped with sufficient metering equipment that can measure the net amount of electrical energy produced or consumed by the Customer-Generator. If the Customer-Generator's existing meter equipment does not meet these requirements or if it is necessary for the Department to install additional distribution equipment to accommodate the Customer-Generator's facility, the Customer-Generator shall reimburse the Department for the costs to purchase and install the necessary additional equipment. At the request of the Customer-Generator, such costs may be initially paid for by the Department, and any amount up to the total costs and a reasonable interest charge may be recovered from the Customer-Generator over the course of up to twelve (12) billing cycles. Any subsequent meter testing, maintenance, or meter equipment change necessitated by the Customer-Generator shall be paid for by the Customer-Generator.

4. Ownership of Renewable Energy Credits or Renewable Energy Certificates (RECs)
RECS created through the generation of electricity by the Customer-Owner are owned by the Customer-Generator until explicitly transferred to another entity. Nothing in the application/agreement gives the Department any preferential entitlement to the RECs generated by the Customer-Generator's system.

5. Energy Pricing and Billing
Customer-Generator shall be billed for electric service supplied by the Department and credited for net energy delivered by Customer-Generator to the Department's electric system in accordance with Independence Power & Light Department's Schedule NM-1.

6. Terms and Termination Rights
This Agreement becomes effective when signed by both the Customer-Generator and the Department, and shall continue in effect until terminated. After fulfillment of any applicable initial tariff or rate schedule term, the Customer-Generator may terminate this Agreement at any time by giving the Department at least thirty (30) days prior written notice. In such event, the Customer-Generator shall, no later than the date of termination of Agreement, completely disconnect the Customer-Operator's System from parallel operation with Department's system. Either party may terminate this Agreement by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of this Agreement, so long as the notice specifies the basis for termination, and there is an opportunity to cure the default. This Agreement may also be terminated at any time by mutual agreement of the Customer-Generator and the Department. This

Agreement may also be terminated, if there is a change in Missouri State statutes that is determined to be applicable to this contract and authorizes its termination.

7. Transfer of Ownership
If operational control of the Customer-Generator's System transfers to any other party than the Customer-Generator, a new Application/Agreement must be completed by the person or persons taking over operational control of the existing Customer-Generator System. The Department shall be notified no less than thirty (30) days before the Customer-Generator anticipates transfer of operational control of the Customer-Generator's System. The person or persons taking over operational control of Customer-Generator's System must file a new Application/Agreement, and must receive authorization from the Department, before the existing Customer-Generator System can remain interconnected with Department's electrical system. The new Application/Agreement will only need to be completed to the extent necessary to affirm that the new person or persons having operational control of the existing Customer-Generator System completely understand the provisions of this Application/Agreement and agree to them. If no changes are being made to the Customer-Generator's System, completing sections A, D and F of this Application/Agreement will satisfy this requirement. If no changes are being proposed to the Customer-Generator System, the Department will assess no charges or fees for this transfer. The Department will review the new Application/Agreement and shall approve such, within fifteen (15) days if the new Customer-Generator has satisfactorily completed the Application/Agreement, and no changes are being proposed to the existing Customer-Generator System. The Department will then complete section G and forward a copy of the completed Application/Agreement back to the new Customer-Generator, thereby notifying the new Customer-Generator that the new Customer-Generator is authorized to operate the existing Customer-Generator System in parallel with Department's electrical system. If any changes are planned to be made to the existing Customer-Generator System that in any way may degrade or significantly alter that System's output characteristics, then the Customer-Generator shall submit to the Department a new Application/Agreement for the entire Customer-Generator System and all portions of the Application/Agreement must be completed.

8. Testing Requirement
IEEE 1547 requires periodic testing of all interconnection related protective functions. The Customer-Generator must, at least once every year, conduct a test to confirm that the Customer-Generator's net metering unit automatically ceases to energize the output (interconnection equipment output voltage goes to zero) within two (2) seconds of being disconnected from Department's electrical system. Disconnecting the net metering unit from Department's electrical system at the visible disconnect switch and measuring the time required for the unit to cease to energize the output shall satisfy this test. The Customer-Generator shall maintain a record of the results of these tests and, upon request by the Department, shall provide a copy of the test results to the Department. If the Customer-Generator is unable to provide a copy of the test results upon request, the Department shall notify the Customer-Generator by mail that Customer-Generator has thirty (30) days from the

date the Customer-Generator receives the request to provide to the Department, the results of a test. If the Customer-Generator's equipment ever fails this test, the Customer-Generator shall immediately disconnect the Customer-Generator System from Department's system. If the Customer-Generator does not provide results of a test to the Department within thirty (30) days of receiving a request from the Department or the results of the test provided to the Department show that the Customer-Generator's net metering unit is not functioning correctly, the Department may immediately disconnect the Customer-Generator System from Department's system. The Customer-Generator System shall not be reconnected to Department's electrical system by the Customer-Generator until the Customer-Generator System is repaired and operating in a normal and safe manner.

I have read, understand, and accept the provisions of Section D, subsections 1 through 8 of this Application/Agreement.

Signed (Customer-Generator): ____________________________________ Date: ____________

E. ELECTRICAL INSPECTION

The Customer-Generator System referenced above satisfies all requirements noted in Section C.

Inspector Name (print): ____

Inspector Certification: I am a Licensed Engineer in Missouri ____ or I am a Licensed Electrician in Missouri ___ License No. ___________________

Signed (Inspector): ____ Date: __________

F. CUSTOMER-GENERATOR ACKNOWLEDGEMENT

I am aware of the Customer-Generator System installed on my premises and I have been given warranty information and/or an operational manual for that system. Also, I have been provided with a copy of Department's Rate Schedule NM-1 (Customer-Generator Net Metering Contract Service Rider) and interconnection requirements. I am familiar with the operation of the Customer-Generator System.

I agree to abide by the terms of this Application/Agreement and I agree to operate and maintain the Customer-Generator System in accordance with the manufacturers recommended practices as well as Department's interconnection standards. If, at any time and for any reason, I believe that the Customer-Generator System is operating in an unusual manner that may result in any disturbances on Department's electrical system, I shall disconnect the Customer-Generator System and not reconnect it to Department's electrical system until the Customer-Generator System is operating normally after repair or inspection. Further, I agree to notify the Department no less than thirty (30) days prior to modification of the components or design of the Customer-Generator System that in any way may degrade or significantly alter that System's output characteristics. I acknowledge that any such modifications will require submission of a new Application/Agreement to the Department.

INTERCONNECTION APPLICATION/AGREEMENT
FOR
NET METERING SYSTEMS
(Continued)

I agree not to operate the Customer-Generator System in parallel with Department's electrical system until this Application/Agreement has been approved by the Department.

Signed (Customer-Generator):____________________________________ Date: __________

G. UTILITY APPLICATION APPROVAL *(COMPLETED BY THE DEPARTMENT)*

The Department does not, by approval of this Application/Agreement, assume any responsibility or liability or damage to property or physical injury to persons due to malfunction of the Customer-Generator System or the Customer-Generator's negligence.

This Application is approved by the Department on this ______ day of _____________, 20____

Department's Representative Name (print): ____

Signed Department's Representative: ____

Schedule REC-1

Regulatory and Environmental Compliance Rider

APPLICABLE

The Regulatory and Environmental Compliance Rider Schedule REC-1 shall be applicable to the Department's Retail Rate Schedules.

PURPOSE OF RIDER

The Regulatory and Environmental Compliance Rider is to compensate the Department for annual expenditures for the Department to comply with regulatory and environmental regulations that are not otherwise recovered through the Department's Retail Rate Schedules including Schedule PCA-1.

RIDER FORMULA CHARGE

Billing for this Rider shall be included with the regular billings for electric service as a separate line item on the bill in an amount sufficient to compensate the Department for any dollar amount expended to meet any regulatory and/or environmental requirement not already recovered in the Department's Retail Rates Schedules. Billing for this Rider shall be a monthly charge per customer.

APPLICATION OF RIDER

The calculation of the Regulatory and Environmental Compliance Rider shall be determined prior to the beginning of the Department's fiscal year and applied to customer bills beginning July 1 as a monthly charge per customer for the fiscal year.

REGULATORY AND ENVIRONMENTAL COMPLIANCE RIDER CHARGE DETERMINATION

The amount of the Regulatory and Environmental Compliance Rider monthly charge per customer shall be calculated pursuant to the following formula:

$$A = \frac{\$(B + C + D)}{E}$$

Where A = Regulatory and Environmental Compliance Rider Rate, expressed as dollar per customer per month rounded to the nearest two (2) decimal places.

B = Regulatory and environmental compliance costs projected for the fiscal year that are to be recovered through this Schedule REC-1. Regulatory and environmental costs to be recovered include all Department expenditures for operating, capital improvements, investments and related debt service principal and interest payments that are paid or payable to parties, other than Department's employees, which are associated with the Department's compliance with environmental and regulatory mandates that are not included or recovered through the Department's Retail Rate Schedules. Regulatory and environmental costs shall be credited to reflect proceeds received from insurance carriers or other entities for amounts that represent reimbursement of costs associated with regulatory or environmental expenditures.

C = Adjustment for the Department's payment in lieu of taxes (PILOT) to the City's General Fund associated with the recovery of the Department's regulatory and environmental costs under this Schedule REC-1 computed as the PILOT rate (9.08%) divided one (1) minus the PILOT rate multiplied by B above.

D = Reconciliation adjustment for any prior over/under collection from prior periods.

E = The annual number of the Department's retail customer billings.

PAYMENT IN LIEU OF TAXES TO CITY OF INDEPENDENCE

The net monthly formula charge of this service schedule includes charges for the Department's payment in lieu of taxes (PILOT) to the City's General Fund as authorized by Section 3.17 of the City Charter. The Department's PILOT payment to the City is equal to the amount of City taxes and fees charged on privately owned utilities, including the 9.08 percent franchise fee, applicable utility property taxes and sales taxes.

TERMS OF SERVICE

Service rendered under this schedule is subject to the Department's standard rules and regulations.

Schedule PR-1
Partial Requirements Service

AVAILABLE

Electric service is available under this schedule in the entire area served by the Department's existing 13,200 volt primary distribution system or 69,000 volt transmission system.

APPLICABLE

This schedule is for Customers who would otherwise qualify for service under the LGS-1 or LP-1 rates schedule, obtain part of their usual or regular electric power requirements from self-generation, and who require Partial Requirements and Back-up or Maintenance Power for all demand and energy use at any one location where service of a single character is taken through one meter at one point of delivery. This schedule is not applicable to resale or shared electric service. Service under this schedule will be delivered to the Customer from the Department's interconnected 13,200 volt primary distribution system or 69,000 volt transmission system, where the Department determines there are facilities of adequate capacity available. If an extension of existing 13,200 volt or 69,000 volt lines and additional equipment will be required, the Customer will be responsible for such line extension costs, easements and additional equipment costs. Customers receiving service under this schedule will be required to enter into a Partial Requirements Electric Service Agreement and a Transmission System Generator Interconnection Agreement with the Department.

CHARACTER OF SERVICE

Alternating current, 60 cycles, three phase, 13,200 volt primary distribution delivery or 69,000 volt transmission delivery.

NET MONTHLY BILL

Customer Charge $630.00

Demand Charge

Partial Requirements Rate:	$18.90 per kW for all kW of Demand up to Customer's Partial Requirements Contract Demand.
Back-Up Facilities Rate:	$4.04 per kW for all kW of Customer's Back-up Contract Demand.
Daily Back-up Power Rate:	$0.63 per kW Day for the sum of all daily kW of Demand in excess of Customer's Partial Requirement Contract Demand, but not to exceed Customer's Back-up Contract Demand.

Schedule PR-1
Partial Requirements Service
(Continued)

Daily Maintenance Service Charge:	One half of the Daily Back-up Power Rate for the sum of all daily kW of Back-up Demand during Scheduled Maintenance.
Excess Power Charge:	$37.79 per kW for all kW of Demand in excess of the sum of Customer's Partial Requirements Contract Demand and Back-up Contract Demand.

Energy Charges

Partial Requirements and Back-up Energy Rate:	$0.02709 per kWh for all kWh.

Minimum Monthly Bill

The monthly Customer Charge, plus Demand Charges.

TRANSMISSION VOLTAGE DISCOUNT

Where the Department renders electric service at transmission voltage and the customer furnishes and maintains all transformation equipment, controlling and protective equipment and other facilities required to transform the delivery voltage to a utilization voltage, the demand charge of the net monthly rate shall be discounted $1.02 per kW of billing demand.

POWER COST ADJUSTMENT

See Schedule PCA-1.

REGULATORY AND ENVIRONMENTAL COMPLIANCE RIDER

See Schedule REC-1.

BILLING DEMAND DETERMINATION

The monthly billing demand shall be the maximum 30-minute measured kilowatt (KW) demand as adjusted for power factor during the month, but the minimum billing demand during any month shall not be less than 3,000 KW nor less than 80 percent of the highest adjusted measured demands established during the summer billing months of July, August and September for the twelve months ending with current month. Monthly measured demands will be adjusted or corrected for power factor if customer's power factor is found by test to be less than 85 percent lagging. The measured demand corrected for power factor shall be determined by multiplying the maximum measured kilowatt demand during the month by 85 percent and dividing by the percentage power factor as determined. Fractional billing demands will be rounded to the nearest whole kilowatt demand.

EXTRA FACILITIES TRANSFORMATION RENTAL CHARGES

Upon the customer's written request for Extra Facilities Transformation Equipment at the time of new service application, and if mutually beneficial to the Department and the customer as determined by the Department, the Department at its sole option will provide and maintain Extra Facilities Transformation Equipment to the customer at an agreed upon location on customer's property which converts the delivered 13.2 kV primary voltage service to a lower standard primary or secondary voltage. The monthly rental charge for Extra Facilities Transformation is in addition to the customer's Net Monthly Bill Rate for electric service and shall be equal to 1.3 percent of the Department's total investment in the Extra Facilities Transformation Equipment provided herein.

MAINTENANCE POWER

Maintenance Power is electric power and energy made available by the Department to Customer during scheduled Customer-Owned Generation maintenance periods to replace Back-Up Power. Maintenance Power shall not exceed the Back-Up Contract Demand.

Customer shall, six (6) months prior to Customer's initial receipt of service under this Schedule, submit to the Department, in writing, Customer's proposed maintenance schedule for each month of an eighteen (18) month period beginning with the date of Customer's initial receipt of service under this Schedule. Customer shall, prior to September 1 of each subsequent year, submit to the Department, in writing, Customer's proposed maintenance schedule for each month of an eighteen (18) month period beginning with January 1 of the following year. Said proposed schedules will not be deemed accepted by the Department until Customer receives written acceptance from the Department. The Department will endeavor to provide said written notification of acceptance, or modification of Customer's proposed schedule, within 60 days of receipt of Customer's proposed maintenance schedule. Maintenance shall be scheduled for a maximum of 30 days per year. These 30 days may be taken in either one continuous period, or two continuous 15 day periods. Should circumstances warrant, the Department may cancel a scheduled maintenance outage with seven (7) days' notice prior to the beginning of a scheduled maintenance outage of Customer's generation facility.

CONTRACT TERM

Service under this schedule is pursuant to a contract with the Customer that specifies various terms and conditions including the Customer's Partial Requirements Contract Demand and Back-up Contract Demand. Seasonal service is not available under this schedule.

FORCE MAJEURE

Neither the Department nor Customer shall be subject to any liability or damages due to the inability of the Department to serve the Customer's load due to lack of available power and energy or other conditions beyond the Department's control. In the event of natural disasters or acts of God such as earthquakes, floods, or severe storms, neither party shall be liable for damages due to lack of ability for operations which affect the other party economically. Should any of the foregoing occur, the minimum billing demands that would otherwise be applicable under this Schedule shall be waived and Customer will have no liability for service charges until such time as Customer is reasonably able to resume service.

PAYMENT

Monthly billing will be rendered NET, payable on or before the due date of the net monthly bill. The gross monthly bill, which is 105 percent of the net monthly bill, will be collected if monthly bill is not paid on or before due date.

PAYMENT IN LIEU OF TAXES TO CITY OF INDEPENDENCE

The net monthly bill rates of this service schedule include charges for the Department's payment in lieu of taxes (PILOT) to the City's General Fund as authorized by Section 3.17 of the City Charter. The Department's PILOT payment to the City is equal to the amount of City taxes and fees charged on privately owned utilities, including the 9.08 percent franchise fee, applicable utility property taxes and sales taxes.

TERMS OF CONTRACT AND SERVICE

The customer shall execute the Department's standard form of contract for three years or more, designating therein the amount of power contracted for. The contract shall be automatically renewed annually after initial period until terminated by written notice from either party. Service rendered under this schedule is subject to the Department's standard rules and regulations.

INDEPENDENCE POWER & LIGHT DEPARTMENT
Independence, Missouri

Schedule CSR-1
Community Solar Rider

AVAILABLE

This optional Community Solar Rider is available by special contract to all customers served in the Independence Power & Light Department service territory by special contract. This Rider is subject to the availability of energy from the IPL Solar Farm (ISF), and by programmatic limitations specified by the Department. Availability is subject to the Department's standard rules and regulations.

Charges under this Rider represent the additional cost of energy from the ISF beyond the prevailing energy costs from non-solar energy costs. The non-solar energy cost is included in the Department's electric rate schedules, and shall be in addition to charges for service under other applicable rates. In order to represent the fixed, long-term nature of the purchased energy contract, associated with the ISF, charges created by this Rider adjust coincident with the Power Cost Adjustment (PCA) to net to a fixed PCA adjustment of [$_________] per kWh of allocated energy from the ISF.

The Department shall transfer to the customer the Solar Renewable Energy Credits produced by the customer's allocated portion of energy from the ISF. Solar Renewable Energy Credits not transferred to the customer at the customer's request, will be retired.

A customer selecting this rate option agrees to continue service under this Rider for a period not less than two years. Termination of service, through the selection of the customer, prior to the end of the required minimum two year period will result in a termination fee of $100 to be applied to the customer's account.

APPLICABLE

The Community Solar Rider will provide the option to receive energy and Solar Renewable Energy sourced from the ISF. Energy amounts are variable each month, and are determined through a defined allocation of monthly production from the IPL Solar Farm, as reported by the Department using conventional energy accounting methods.

MONTHLY CHARGES

Energy Rate

Allocated Portion of Energy from IPL Solar Farm From Each 1 kW of Installed Capacity:

[__________¢] per kWh minus Power Cost Adjustment

APPENDIX G

FINAL IPL PRO FORMA TABLES

Table G-1
2014-15 Rate Study
IPL - Cash Flow Analysis
Includes Proposed Rate Adjustments
(in $000)

	Actual							Projected					
	2007/08	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**
Operating Revenues													
Sales Revenues	107,619	105,065	114,745	126,756	139,878	137,749	138,814	136,954	142,225	147,265	153,511	159,502	165,111
Other Income (Interest & Misc.)	1,314	2,266	1,815	1,621	1,491	1,731	8,970	1,005	1,500	1,500	1,500	1,500	1,500
Total Operating Cash Inflow	108,933	107,331	116,560	128,377	141,369	139,481	147,784	137,959	143,725	148,765	155,011	161,002	166,611
Operating Expenses (Cash Basis)													
O&M Expenses	86,627	88,090	89,844	98,940	107,032	98,847	105,427	106,036	108,186	114,316	117,434	121,838	126,822
Recurring Routine System Additions	6,001	5,842	6,606	8,723	2,651	3,972	6,385	7,227	7,000	7,210	7,426	7,649	7,879
PILOT - Gross Receipts	9,780	9,482	10,054	11,619	12,360	12,581	12,533	12,511	12,914	13,371	13,931	14,479	14,983
PILOT - Property Taxes	760	785	785	785	786	811	835	860	886	912	940	968	997
Total Operating Cash Outflow	103,167	104,199	107,289	120,068	122,829	116,212	125,180	126,634	128,986	135,809	139,731	144,933	150,681
Cash from Operations	5,766	3,132	9,271	8,309	18,540	23,268	22,603	11,324	14,739	12,956	15,280	16,069	15,929
Debt Service - Existing Bonds	2,767	3,312	4,394	5,699	7,065	10,071	10,853	8,925	8,924	8,921	8,918	8,918	9,838
Debt Service - New Bonds	0	0	0	0	0	0	0	0	0	62	245	1,054	1,857
Total Debt Service	2,767	3,312	4,394	5,699	7,065	10,071	10,853	8,925	8,924	8,983	9,163	9,972	11,695
Net Cash Flow Prior to Capital Improvements	**2,999**	**(180)**	**4,877**	**2,610**	**11,475**	**13,197**	**11,750**	**2,400**	**5,815**	**3,973**	**6,117**	**6,097**	**4,235**
Total Capital Improvement Expenditures - Cash Funded	6,001	2,961	0	0	0	0	2,026	6,854	17,393	7,714	6,116	6,095	4,235
Total Capital Improvement Expenditures - Bond Funded	0	0	27,251	23,596	47,736	20,000	0	0	0	765	2,285	9,895	10,060
Net Cash Flow	**(3,002)**	**(3,141)**	**4,877**	**2,610**	**11,475**	**13,197**	**9,724**	**(4,454)**	**(11,578)**	**(3,741)**	**1**	**2**	**(0)**
Operating Fund Balance (Unrestricted cash)	**4,657**	**1,391**	**6,268**	**8,877**	**20,352**	**33,549**	**43,273**	**38,819**	**27,241**	**23,500**	**23,501**	**23,504**	**23,503**

Table G-2
2014-15 Rate Study
IPL - Net Income Statement
Includes Proposed Rate Adjustments
(in $000)

	Actual							Projected					
	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Operating Revenues													
Sales Revenues	106,334	103,829	113,518	124,646	137,715	135,537	136,788	135,012	140,341	145,348	151,561	157,518	163,092
Other Operating Revenues	1,285	1,236	1,227	2,110	2,164	2,213	2,026	1,942	1,884	1,917	1,950	1,984	2,019
Total Operating Revenues	107,619	105,065	114,745	126,756	139,878	137,749	138,814	136,954	142,225	147,265	153,511	159,502	165,111
Operating Expenses (Net Income Basis)													
O&M Expenses	91,394	90,217	93,303	100,411	107,067	103,590	109,333	109,715	113,558	117,513	120,852	125,370	130,560
Depreciation & Amortization	10,571	11,434	11,662	13,133	15,766	17,989	18,775	20,060	17,361	14,741	15,055	15,487	13,775
PILOT - Gross Receipts	9,780	9,482	10,054	11,619	12,360	12,581	12,533	12,511	12,914	13,371	13,931	14,479	14,983
PILOT - Property Taxes	760	785	785	785	786	811	835	860	886	912	940	968	997
Total Operating Expenses	112,504	111,918	115,804	125,948	135,978	134,972	141,476	143,145	144,719	146,537	150,777	156,304	160,316
Operating Income	(4,885)	(6,853)	(1,059)	808	3,900	2,777	(2,662)	(6,191)	(2,494)	728	2,734	3,199	4,795
Non-Operating Income and Expenses													
Interest Income	1,044	278	27	146	12	40	29	50	750	750	750	750	750
Other Misc. & Extraordinary Income	270	1,988	1,788	1,476	1,479	1,691	8,940	955	750	750	750	750	750
Interest & Amortization	(959)	(1,425)	(2,454)	(3,045)	(3,584)	(7,330)	(5,968)	(5,540)	(5,409)	(5,316)	(5,286)	(5,701)	(6,077)
Net Non-Operating Income & Expenses	355	841	(639)	(1,424)	(2,093)	(5,599)	3,002	(4,535)	(3,909)	(3,816)	(3,786)	(4,201)	(4,577)
Net Income	**(4,530)**	**(6,011)**	**(1,698)**	**(617)**	**1,807**	**(2,821)**	**339**	**(10,726)**	**(6,403)**	**(3,088)**	**(1,052)**	**(1,002)**	**218**
Net Cash Flow	**(3,002)**	**(3,141)**	**4,877**	**2,610**	**11,475**	**13,197**	**9,724**	**(4,454)**	**(11,578)**	**(3,741)**	**1**	**2**	**(0)**
Detail of Revenues													
Base Rate Revenues	91,840	89,676	98,172	106,811	111,334	111,534	110,581	106,383	131,455	135,223	139,761	144,989	149,930
FCA Revenues	12,413	12,388	11,306	14,757	24,472	21,623	23,953	27,146	0	1,164	2,760	3,407	3,952
Total Retail Revenues	104,253	102,064	109,479	121,569	135,806	133,156	134,534	133,529	131,455	136,387	142,521	148,396	153,883
Wholesale Sales & Transmission Revenues	2,081	1,765	4,039	3,077	1,909	2,380	2,254	1,483	8,886	8,961	9,040	9,122	9,209
Total Sales Revenues	106,334	103,829	113,518	124,646	137,715	135,537	136,788	135,012	140,341	145,348	151,561	157,518	163,092
Other Operating Revenues	1,285	1,236	1,227	2,110	2,164	2,213	2,026	1,942	1,884	1,917	1,950	1,984	2,019
Total Operating Revenues	107,619	105,065	114,745	126,756	139,878	137,749	138,814	136,954	142,225	147,265	153,511	159,502	165,111

Table G-3
FIVE YEAR FINANCIAL FORECAST SUMMARY
for 2014-15 Rate Study
Includes Proposed Rate Adjustments

Line No.	Description	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014	Projected 2015	Projected 2016	Projected 2017	Projected 2018	Projected 2019	Projected 2020	5 Year Total	Reference Schedule No. & Column or Line No.
		$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	
1	**Operating Revenues**													
2	Retail Sales													
3	Existing Base Rate Schedule (FCA rebased in 2015/16)	98,172	106,811	111,334	111,534	110,581	106,383	131,115	134,166	135,647	136,250	137,059	674,238	Sch 1, Ln 13
4	Proposed Annual Rate Increase (Effective on October 1)								0.00%	3.30%	3.30%	3.30%		
5	Cumulative Proposed Rate Increase (Adjusted for Oct 1 date)								0.00%	2.24%	5.62%	9.10%		
6	Amount of Proposed Increase								0	3,044	7,655	12,477	23,176	
7	Fuel Cost Adjustment (Sch FA-1)	11,306	14,757	24,472	21,623	23,953	27,146	0	1,164	2,760	3,407	3,952	11,283	Sch 1, Ln 16
8	Regulatory & Environmental Rider (Sch RER-1)	0	0	0	0	0	0	340	1,057	1,070	1,084	394	3,944	Sch 1, Ln 23
9	Total Retail Sales Revenue	109,479	121,569	135,806	133,156	134,534	133,529	131,455	136,387	142,521	148,396	153,882	712,641	
10	Wholesale Sales to Border Customers	173	192	151	144	166	154	149	149	149	149	149	745	Sch 1, Ln 26
11	Wholesale Sales to Other Utilities/SPP Market	3,866	2,884	1,758	2,237	2,088	1,329	1,500	1,575	1,654	1,736	1,823	8,288	Sch 1, Ln 25
12	SPP Transmission Service Revenues	0	0	0	0	0	0	7,237	7,237	7,237	7,237	7,237	36,187	Sch 1, Ln 28
13	Other Operating Revenues	1,227	2,110	2,164	2,213	2,026	1,942	1,884	1,917	1,950	1,984	2,019	9,754	Sch 1, Ln 29
14	Total Operating Revenues	114,745	126,756	139,878	137,749	138,814	136,954	142,225	147,265	153,511	159,502	165,111	767,615	
15	Other Income													
16	Interest on Invested Funds	27	146	12	40	29	50	750	750	750	750	750	3,750	Projected
17	Miscellaneous (Includes Allow - Funds Used for Const)	1,788	1,476	1,479	1,691	8,940	955	750	750	750	750	750	3,750	Sch 2
18	Total Other Income	1,815	1,621	1,491	1,731	8,970	1,005	1,500	1,500	1,500	1,500	1,500	7,500	
19	Total Gross Revenues	116,560	128,377	141,369	139,481	147,784	137,959	143,725	148,765	155,011	161,002	166,611	775,115	
20	Total Average Retail Sales Rate includes FCA (Line 5 / 70)	104.34	111.47	127.03	127.54	130.58	132.36	124.59	128.91	134.22	139.31	143.99	134.24	
21	Percent Increase in Total Average Retail Sales Rate	11.82%	6.83%	13.96%	0.40%	2.39%	1.36%	-5.87%	3.46%	4.12%	3.79%	3.36%		
22	**Electric System Costs**													
23	Operating Expenses													
24	Operation & Maintenance Expense (O&M)	92,258	99,330	105,916	102,390	108,032	108,463	112,244	116,139	119,415	123,867	128,988	600,653	Sch 3, Ln 27
25	Payroll Taxes	1,045	1,081	1,150	1,200	1,301	1,251	1,314	1,374	1,437	1,503	1,572	7,200	Sch 3, Ln 28
26	Pilot and Other Taxes													
27	9.08% GR Tax (9.08% X (Line 9 - Line 45)	10,054	11,619	12,360	12,581	12,533	12,511	12,914	13,371	13,931	14,479	14,983	69,678	Calc.
28	Property Taxes	785	785	786	811	835	860	886	912	940	968	997	4,703	Sch 3, Ln 30
29	Total Pilot Taxes	10,839	12,404	13,145	13,393	13,368	13,371	13,800	14,283	14,871	15,447	15,980	74,381	
30	Plant Depreciation Expenses	11,662	13,133	15,766	17,989	18,775	20,060	17,361	14,741	15,055	15,487	13,775	76,418	Sch 3, Ln 32
31	**Total Operating Expenses (Line 21 + 22 + 26 + 27)**	115,804	125,948	135,978	134,972	141,476	143,145	144,719	146,537	150,777	156,304	160,316	758,652	
32	Operating Income -- Return (Line 9 - 28)	(1,059)	808	3,900	2,777	(2,662)	(6,191)	(2,494)	728	2,734	3,199	4,795	8,962	
33	Other Income Expenses													
34	Interest on Revenue Bonds, Existing	2,149	2,734	3,245	6,131	5,838	5,660	5,529	5,391	5,233	5,068	4,893	26,113	Sch 4, Ln 11
35	Interest on Revenue Bonds, Proposed	0	0	0	0	0	0	0	45	173	753	1,304	2,275	Sch 5, Ln 13
36	Amortization of Bond Sale Costs/Premiums/Losses (Non-Cash)	305	311	339	1,199	130	(120)	(120)	(120)	(120)	(120)	(120)	(600)	Sch 6, Ln 18
37	Total Other Income Expenses	2,454	3,045	3,584	7,330	5,968	5,540	5,409	5,316	5,286	5,701	6,077	27,788	
38	**Net Income (line 14 - 28 - 34)**	(1,698)	(617)	1,807	(2,821)	339	(10,726)	(6,403)	(3,088)	(1,052)	(1,002)	218	(11,326)	
39	Credit for Depreciation on Contributed Capital	327	391	460	466	486	500	505	510	515	520	525	2,573	
40	**Amount Transferred to Retained Earnings (Line 35 + 36)**	(1,370)	(225)	2,267	(2,355)	825	(10,226)	(5,898)	(2,578)	(537)	(483)	743	(8,753)	

Table G-3
FIVE YEAR FINANCIAL FORECAST SUMMARY
for 2014-15 Rate Study
Includes Proposed Rate Adjustments

Line No.	Description	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014	Projected 2015	Projected 2016	Projected 2017	Projected 2018	Projected 2019	Projected 2020	5 Year Total	Reference Schedule No. & Column or Line No.
		$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	
39	**Capital Financing of System Improvements**													
40	Source of Funds													
41	Contributions and Advances in Aid of Construction	1,262	938	(292)	97	52	(227)	0	0	0	0	0	0	Sch 7
42	Plant Depreciation Expense	11,662	13,133	15,766	17,989	18,775	20,060	17,361	14,741	15,055	15,487	13,775	76,418	= Line 28
43	Depreciation Charged to O&M Expense	505	538	572	579	643	648	668	689	709	730	750	3,546	Depr. Sch.
44	Amortization Bond Sale Loss and Issue Costs	305	311	339	1,199	130	(120)	(120)	(120)	(120)	(120)	(120)	(600)	= Line 34
45	Net Income	(1,698)	(617)	1,807	(2,821)	339	(10,726)	(6,403)	(3,088)	(1,052)	(1,002)	218	(11,326)	= Line 36
46	Proposed Bond Sales Amount	31,415	26,005	53,287	21,619	0	0	0	861	2,571	11,132	11,318	25,881	Sch 5, Ln 4
47	FEMA	0	0	0	0	0	0	0	0	0	0	0	0	Projected
48	Unbilled Revenue	0	1,840	(3,100)	1,535	(40)	(832)	0	9	85	47	95	236	Sch 1, Ln 22
49	Other Post Retirement Benefits (Non-cash)	1,726	1,726	2,382	2,375	2,239	2,267	2,380	2,499	2,624	2,755	2,893	13,151	Projected
50	Other and Insurance	0	0	0	0	0	0	0	0	0	0	0	0	-
51	Total Source of Funds	45,176	43,874	70,760	42,572	22,138	11,069	13,886	15,591	19,871	29,029	28,929	107,306	
52	**Cost of System Improvements**													
53	Recurring Routine Additions & Replacements	7,868	9,661	2,359	4,069	6,437	7,000	7,000	7,210	7,426	7,649	7,879	37,164	Sch 8
54	Major Capital Improvements Budget - Funded by Cash	0	0	0	0	2,026	6,854	17,393	7,714	6,116	6,095	4,235	41,553	Sch 9, Ln 53
55	Major Capital Improvements Budget - Funded by Bonds	27,251	23,596	47,736	20,000	0	0	0	765	2,285	9,895	10,060	23,005	Sch 9, Ln 52
56	Bond Principal Payments, Existing	2,245	2,965	3,820	3,940	5,015	3,265	3,395	3,530	3,685	3,850	4,945	19,405	Sch 4, Ln 17
57	Bond Principal Payments, Proposed	0	0	0	0	0	0	0	17	72	301	553	943	Sch 5, Ln 22
58	Bond Issuance Cost, Including Reserve Funds	4,164	2,409	5,551	1,619	0	0	0	96	286	1,237	1,258	2,876	Sch 5, Ln 2
59	Other (Additional Bond Payments)	0	0	0	0	0	0	0	0	0	0	0	0	-
60	Fuel, SO2 & Material Inventory Adjustments	(1,228)	2,633	(180)	(253)	(1,064)	(1,596)	(2,324)	0	0	0	0	(2,324)	Projected
61	Total Cost of System Improvements	40,300	41,264	59,285	29,375	12,415	15,523	25,464	19,332	19,870	29,027	28,929	122,622	
62	**Annual Uncommitted Funds Available (Line 48 - 58)**	4,877	2,610	11,475	13,197	9,724	(4,454)	(11,578)	(3,741)	1	2	(0)	(15,316)	
63	**Cumulative Uncommitted Funds Available, Year End**	6,268	8,878	20,352	33,549	43,273	38,819	27,241	23,500	23,502	23,504	23,503		
64	**Net Revenues Available For Debt Service Coverage**													
65	Prior to Pilot Taxes (Line 14 - 21 - 22)	23,257	27,966	34,302	35,891	38,451	28,244	30,167	31,252	34,160	35,633	36,051	167,262	
66	After Pilot Taxes (Line 62 - 26)	12,418	15,562	21,157	22,498	25,083	14,873	16,367	16,969	19,289	20,186	20,070	92,881	
67	Debt Principal & Interest Payments (Line 31 + 32 + 52 + 53)	4,394	5,699	7,065	10,071	10,853	8,925	8,924	8,983	9,163	9,972	11,695	48,736	
68	Debt Service Coverage Ratio													
69	Prior to Pilot Taxes (Line 64 / Line 62)	5.29	4.91	4.86	3.56	3.54	3.16	3.38	3.48	3.73	3.57	3.08	3.43	
70	After Pilot Taxes (Line 64 / Line 63)	2.83	2.73	2.99	2.23	2.31	1.67	1.83	1.89	2.11	2.02	1.72	1.91	
71	**Electric System Net Investment**	174,320	191,625	236,234	232,662	230,232	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
72	**% Operating Income to Net Rate Base Invest. (Line 29 / 68)**	-0.61%	0.42%	1.65%	1.19%									
73	**Total Retail Energy Sales (MWh)**	1,049,218	1,090,549	1,069,052	1,044,043	1,030,251	1,008,797	1,055,098	1,058,040	1,061,856	1,065,215	1,068,677	5,308,886	Sch 1, Ln 5
74	**Weather and Conservation Sales Adjustment (MWh)**	0	0	0	0	0	0	0	0	0	0	0	0	
75	**Adjusted Retail Energy Sales (MWh)**	1,049,218	1,090,549	1,069,052	1,044,043	1,030,251	1,008,797	1,055,098	1,058,040	1,061,856	1,065,215	1,068,677	5,308,886	-
76	**Cooling Degree Days**	1,135	1,634	1,747	1,524	1,416	1,249	1,413	1,413	1,413	1,413	1,413		Sch 1, Ln 2
77	**Year End Revenue Bond Outstanding Balance**													
78	**Existing Bonds**	33,850	64,530	114,625	131,795	126,780	123,515	120,120	116,590	112,905	109,055	104,110		Sch 5, Ln 26
79	**Proposed Bonds**	0	0	0	0	0	0	0	844	3,342	14,173	24,938		Sch 6, Ln 40
80	**Total Bonds Outstanding**	33,850	64,530	114,625	131,795	126,780	123,515	120,120	117,434	116,247	123,228	129,048		
81	**Percent of Net Plant Investment**	19.4%	33.7%	48.5%	56.6%	55.1%								
82	**Year End City Equity in Electric System**	171,479	172,768	174,730	169,352	170,582	159,856	153,454	150,366	149,314	148,312	148,531		
83	**Debt Ratio to Total Capitalization**	16.5%	27.2%	39.6%	43.8%	42.6%	43.6%	43.9%	43.9%	43.8%	45.4%	46.5%		

Table G-4
Schedule 9
IPL - Capital Improvements Budget Projection
(in $000)

		Project Number	Funding Source	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
	Production Improvements									
1	- Mo City New Settling Pond	70211309	RER	88	0	0	0	0	0	88
2	- Substation H, I & J Controls Replacement and Compliance	70210807	Rates	0	0	0	0	0	0	0
3	- Combustion Turbine CO2 Upgrades	70211303	Rates	147	0	0	0	0	0	147
4	- Substation H-5/H-6 Hot Gas Compressor Project	-	Rates	750	0	0	0	0	0	750
5	- Plant Miscellaneous Projects	70210824	Rates	0	550	0	0	0	0	550
6	- Combustion Turbine Generators Exciter Upgrades	-	Rates	0	600	0	0	0	0	600
7	- Production Facilities Improvements	70211103	Rates	0	50	0	0	0	0	50
8	- Substation H-5/H-6 Hot Gas Path/Generator Inspection	-	Rates	40	1,300	1,560	0	0	0	2,900
9	- BV 1&2 Turbine Inspection / Repair	-	Rates	0	2,000	0	0	0	0	2,000
10	- Combustion Turbine Controls Upgrade	-	Rates	0	750	0	0	0	0	750
11	- Mo City Ash Pond Closure	-	RER	0	950	50	0	0	0	1,000
12	- Mo City Plant Retirement Costs	-	RER	0	500	421	0	0	0	921
13	- BV 3 Turbine Inspection / Repair	-	Rates	0	0	1,500	0	0	0	1,500
14	Total Production Plant Improvements			1,025	6,700	3,531	0	0	0	11,256
	Transmission & Distribution Improvements									
15	- Substation F Rebuild	70211004	Rates	475	0	0	0	0	0	475
16	- LED Street Lighting Conversion Project	70211202	Rates	208	0	0	0	0	0	208
17	- 69-kV Sub F - Sugar Creek Jct. Transmission Line Project	70211305	Rates	61	0	0	0	0	0	61
18	- T&D System Improvements (Overhead)	70210815	Rates	80	0	0	0	0	0	80
19	- Redesign & Reroute Sub K Underground Dist. Feeders	70210815	Rates	0	0	0	0	0	0	0
20	- Reconductor 161-kV Line (Eckles to Sibley)	70211304	Rates	198	0	0	0	0	0	198
21	- Substation B Rebuild	70211201	Rates	1,869	0	0	0	0	0	1,869
22	- Substation J Facility Improvements	70201310	Rates	919	4,655	0	0	0	0	5,574
23	- Fiber Optic Network	70210828	Rates	50	818	264	264	0	0	1,396
24	- Eckles Rd Substation Breaker and Relay Replacements	70201403	Rates	899	0	0	0	0	0	899
25	- Substation Facilities/Equipment Improvements	70211106	Rates	395	260	260	260	260	0	1,435
26	- New Substation S in Southeastern Independence	70211306	Rates	0	400	495	1,800	4,125	0	6,820
27	- Substation L Switchgear Replacement	-	Rates	0	900	0	0	0	0	900
28	- 69 KV Transmission Line (Sub B to Sub C)	-	Rates	0	125	975	0	0	0	1,100
29	- Substation B & C Line Terminal Improvements	-	Rates	0	175	494	0	0	0	669
30	- Substation I Switchgear & Transformer Replacement	-	Rates	0	175	1,440	0	0	0	1,615
31	- Trans & Dist Facilities/Equipment Improvements	-	Rates	0	150	150	150	150	150	750
32	- Substation E Switchgear Replacement	-	Rates	0	0	120	885	0	0	1,005
33	- Substation K Switchgear & Transformer Replacement	-	Rates	0	0	50	1,050	0	0	1,100
34	- 69 KV Transmission Line Rebuild (Sub E to Sub F)	-	Rates	0	0	200	2,842	0	0	3,042
35	- 161 KV Transmission Line (New Sub A to Sub S)	-	Rates	0	0	0	100	2,600	0	2,700
36	- 161 KV Transmission Line (New Sub S to Lakewood)	-	Rates	0	0	0	200	4,600	0	4,800
37	- New 161-kV Transmission Line (Sub N to Sub R)	-	Rates	0	0	0	200	800	3,800	4,800
38	- New 161-kV Transmission Line (Sub R to KCPL's Lakewood)	-	Rates	0	0	0	100	430	2,070	2,600
39	- 161/69 -KV Substation R Improvements	-	Rates	0	0	0	400	675	2,625	3,700
40	- 161 kV Substation N Line Terminal	-	Rates	0	0	0	0	0	350	350
41	- 161 kV KCPL Lakewood Substation Modifications	-	Rates	0	0	0	0	0	2,300	2,300
42	- 161 kV Substation A Line Terminal	-	Rates	0	0	0	0	450	0	450
43	- New Substation T in Eastern Independence	-	Rates	0	0	0	0	400	0	400
44	- Distribution Feeders & Ties Sub S	-	Rates	0	0	0	0	1,500	3,000	4,500
45	- Centralized Database/Outage Management System	-	Rates	10	0	0	0	0	0	10
46	Total Transmission & Distribution Plant Improvements			5,164	7,658	4,448	8,251	15,990	14,295	55,806
	General Plant Improvements									
47	- IPL Property Security Project	70201405	Rates	68	300	300	150	0	0	818
48	- New Office Building	70201201	Rates	3,598	1,925	0	0	0	0	5,523
49	- Service Center Fuel and Washing System	70201404	Rates	185	0	0	0	0	0	185
50	- New Billing System	-	Rates	0	536	200	0	0	0	736
1	- Work Management/Dispatch System Upgrade	-	Rates	15	100	0	0	0	0	115
48	- Systems Operation Backup Facility	70211005	Rates	4	0	0	0	0	0	4
49	- Systems Operation UPS Systerm - Service Center	-	Rates	0	150	0	0	0	0	150
50	- Network Monitoring & Surveillance Equipment - Fiber	-	Rates	0	25	0	0	0	0	25
51	- New Metering System	-	Rates	0	0	0	0	0	0	0
52	Total General Plant Improvements			3,871	3,036	500	150	0	0	7,557
53	**Totals**			**10,061**	**17,393**	**8,479**	**8,401**	**15,990**	**14,295**	**74,619**
	Funding Mechanism									
54	Existing Bond Funds			3,207	0	0	0	0	0	3,207
55	New Bond Funds			0	0	765	2,285	9,895	10,060	23,005
56	Projects Funded Through RER Charge			88	1,450	471	0	0	0	2,009
57	Funded by Operations (Cash)			6,766	15,943	7,243	6,116	6,095	4,235	42,163
58	Totals			10,061	17,393	8,479	8,401	15,990	14,295	70,384
	Depreciation Calculation					23,500	23,501	23,504	23,503	Ending Fu
58	Assumes 30 year life									
59		FY	2014/15	168	335	335	335	335	335	
60		FY	2015/16		290	580	580	580	580	
61		FY	2016/17			141	283	283	283	
62		FY	2017/18				140	280	280	
63		FY	2018/19					267	533	
64		FY	2019/20						238	
64	Totals			168	625	1,056	1,338	1,744	2,011	