INDIANOLA MUNICIPAL UTILITIES

IMU

Electric • Network Services • Water

IMU Board of Trustees
October 12, 2015
City Hall Council Chambers
5:30 p.m.

Agenda

1. Roll Call

2. Public Comments

3. Consent

   A. Claims for October 5th, 2015

   B. Minutes for September 28th, 2015

   C. Electric Crew Chief Recommendation

4. Fiber Expansion Financial Feasibility, Michael Maloney, D.A. Davidson & Co.

5. Cost of Electric Service Study, John Krejewski, JK Energy Consulting

6. Set October 26, 2015 as the Date for a Public Hearing Setting Electric Rates

7. In-Kind Donation Request, Calamar Development

8. F-5 Passive Optical Network Equipment

9. Approval of Memo of Understanding with the Iowa Dept. of Administrative Services

10. Lineman Hiring Process

11. Other Business

12. Adjourn

IMU Regular Downstairs **3. A.**

Meeting Date: 10/12/2015

Information

Subject

Claims for October 5th, 2015

Information

Claims for October 5th, 2015 are attached for approval.

Financial Impact

N/A

Staff Recommendation

Simple motion to approve is in order.

Attachments

APPROVAL OF CLAIMS 10-05-15

Vendor Name	GL Account Number	Description	Invoice Date	Net Invoice Amount
WATER OPERATING FUND				
ACCO UNLIMITED CORP.	600-8110-65010	LIQUID CHLORINATING	09/22/2015	1,401.64
CIRCLE B CASHWAY	600-8120-63100	GR4' DIAMOND BLADE - WELL #9	09/24/2015	9.65
CIRCLE B CASHWAY	600-8120-63100	PORTLAND CEMENT - WELL #9	09/25/2015	14.25
CITY OF INDIANOLA - UTILITY	600-8110-63710	UTILITIES	09/30/2015	7,614.24
DUST PROS JANITORIAL	600-8120-64090	MONTHLY CLEANING (SEPT.) - WATER DEP	09/22/2015	180.00
DUST PROS JANITORIAL	600-8120-64090	JANITORIAL SUPPLIES	09/22/2015	67.15
GRAYMONT WESTERN LIME IN	600-8110-65012	HIGH CALCIUM QUICKLIME	09/11/2015	4,167.39
ITRON INC.	600-8170-64990	QUARTERLY SUPPORT (10/1/15 - 12/31/15)	09/11/2015	523.56
JMK LAWNCARE	600-8110-64990	AUGUST MOWING CONTRACT - WATER	09/01/2015	860.00
LINDE LLC	600-8110-65010	LIQUID CARBON DIOXIDE	09/10/2015	1,597.18
MC COY HARDWARE INC	600-8120-65070	50' HOSE	09/15/2015	25.19
MC COY HARDWARE INC	600-8120-63100	TROWEL & BRICK JOINTER	09/26/2015	21.13
MC COY HARDWARE INC	600-8150-65072	BATTERIES	09/28/2015	13.49
THEISEN'S	600-8150-63453	SEED & FERTILIZER	09/22/2015	74.97
THEISEN'S	600-8120-63100	MORTAR MIX & LIME	09/24/2015	8.18
THEISEN'S	600-8120-63100	WELL 9	09/25/2015	22.43
U.S. CELLULAR	600-8110-63730	CELL PHONE - 4	09/12/2015	170.10
WARREN COUNTY ENGINEER	600-8160-65050	FUEL DISTRIBUTION	09/11/2015	706.02
Total WATER OPERATING FUND:				17,476.57
IMU ADMINISTRATION FUND				
911 ETC INC	620-8090-63730	911 MONTHLY ACCESS CHARGE	09/30/2015	25.83
AHLERS & COONEY P.C.	620-8090-64110	LABOR RELATIONS	09/24/2015	3,025.00
BRICK GENTRY P.C.	620-8090-64110	LEGAL SERVICES	09/25/2015	60.00
BRICK GENTRY P.C.	620-8090-64110	LEGAL SERVICES	09/25/2015	1,740.00
BRICK GENTRY P.C.	620-8090-64110	LEGAL SERVICES	09/25/2015	180.00
HY-VEE FOOD STORE	620-8090-65070	ELBERT FLOWERS	09/03/2015	53.00
INFOMAX OFFICE SYSTEMS IN	620-8090-64990	LEASE - OCTOBER	09/22/2015	211.24
INFOMAX OFFICE SYSTEMS IN	620-8090-64990	SAVIN - IMAGING UNIT CONTRACT	09/21/2015	58.69
INFOMAX OFFICE SYSTEMS IN	620-8090-64990	OVERAGE CHARGES (350)	09/21/2015	27.32
JK ENERGY CONSULTING LLC	620-8090-64900	2015 ELECTRIC RATE STUDY	09/25/2015	6,000.00
NOLASOFT DEVELOPMENT	620-8090-64990	4TH QTR WEBSITE HOSTING	09/17/2015	120.00
SHULL, DOUG	620-8090-64990	TREASURER CONTRACT	09/25/2015	83.34
WEBQA INC	620-8090-64990	ANNUAL SUBSCRIPTION	09/15/2015	1,080.00
Total IMU ADMINISTRATION FUND:				12,664.42
ELECTRIC OPERATING FUND				
ADAMS DOOR COMPANY INC.	630-8220-63100	REPAIR TO GARAGE DOOR 110 N B ST	09/16/2015	137.80
APPLE TREE INN	630-8290-67306	ATTIC INSULATION	06/15/2015	5,000.00
APPLE TREE INN	630-8290-67306	ATTIC INSULATION	07/06/2015	5,000.00
CITY OF INDIANOLA - REBATE	630-8290-67306	A/C REBATE	09/11/2015	100.00
CITY OF INDIANOLA - REBATE	630-8290-67306	A/C REBATE	09/10/2015	200.00
CITY OF INDIANOLA - REBATE	630-8290-67306	A/C REBATE	08/28/2015	250.00
CITY OF INDIANOLA - REBATE	630-8290-67306	A/C REBATE	09/14/2015	100.00
DUST PROS JANITORIAL	630-8220-64090	MONTHLY CLEANING (SEPT.) - ADMIN & ELE	09/22/2015	1,929.20
DUST PROS JANITORIAL	630-8220-64090	JANITORIAL SUPPLIES - ELECTRIC	09/22/2015	60.06
DUST PROS JANITORIAL	630-8220-64090	JANITORIAL SUPPLIES - ADMIN	09/22/2015	50.56
ELECTRICAL ENG & EQUIP	630-8225-63410	BLACK START MAINT.	09/16/2015	350.63
ELECTRICAL ENG & EQUIP	630-8225-63410	TURBINE #7 MAINT.	09/14/2015	60.50
ELECTRICAL ENG & EQUIP	630-8225-63410	RELAY PLUG-IN BLACK START	09/21/2015	78.08
ELECTRICAL ENG & EQUIP	630-8225-63410	8 PIN SNAP SOCKET FOR BLACK START	09/18/2015	10.49
ITRON INC.	630-8270-64990	QUARTERLY SUPPORT (10/1/15 - 12/31/15)	09/11/2015	523.56
JMK LAWNCARE	630-8250-64990	AUGUST MOWING CONTRACT - ELECTRIC	09/01/2015	620.00
MC COY HARDWARE INC	630-8225-63410	CLAMP CONNECTOR FOR TURBINE #7	09/15/2015	1.12
MC COY HARDWARE INC	630-8220-65072	SCREWDRIVER AND WIRE BRUSH	09/24/2015	5.60

Vendor Name	GL Account Number	Description	Invoice Date	Net Invoice Amount
MID AMERICAN ENERGY CO.	630-8210-63710	80950-24015 PLANT GAS 8/19/18 - 9/18/15	09/18/2015	55.00
MID AMERICAN ENERGY CO.	630-8240-63710	52180-25018 LINE SHOP GAS (0 THERSM)	09/17/2015	10.00
MID AMERICAN ENERGY CO.	630-8210-63710	52390-25019 BOILER GAS (1,204 THERMS)	09/18/2015	599.06
MID AMERICAN ENERGY CO.	630-8210-63710	07991-36014 WEST SUB (0 KWH)	09/11/2015	10.00
O'HALLORAN INTERNATIONAL	630-8260-63320	2004 INTERNATIONAL	09/15/2015	3,551.86
O'REILLY AUTO PARTS	630-8260-65072	HAND PAD	09/15/2015	6.48
O'REILLY AUTO PARTS	630-8260-65072	HAND PAD	09/15/2015	6.48-
O'REILLY AUTO PARTS	630-8260-65072	HAND PAD	09/15/2015	6.87
SAFT AMERICA INC.	630-8225-63410	CHARGER WITH OPTION TURBINE #7	09/14/2015	3,757.24
SKARSHAUG TESTING LABORA	630-8250-64200	ANNUAL TESTING ON LINE TOOLS FROM T	09/11/2015	2,895.05
SKARSHAUG TESTING LABORA	630-8250-64200	ANUGSUT TESTING ON PRIMARY GLOVES	09/11/2015	248.89
THEISEN'S	630-8225-63410	COVER TOGGLE SWITCH & BLANK TURBIN	09/15/2015	1.57
THEISEN'S	630-8225-63410	CASTER SWIVEL RUBBER HD TURBINE #7	09/18/2015	9.71
THEISEN'S	630-8220-65072	BATTERIES	09/24/2015	21.18
U.S. CELLULAR	630-8240-63730	CELL PHONE - 11	09/12/2015	473.62
WARREN COUNTY ENGINEER	630-8260-65050	FUEL DISTRIBUTION	09/11/2015	1,697.05
WESCO	630-8250-65072	SLINGS FOR PLANT AND DIGGER TRUCK	09/21/2015	56.05
Total ELECTRIC OPERATING FUND:				27,870.75
FIBER/COMMUNICATIONS FUND				
IOWA COMMUNICATIONS NET	640-8550-63464	3 MONTHS OVER PAYMENT FOR 2014 (OCT.	09/16/2015	48.75
IOWA COMMUNICATIONS NET	640-8550-63464	ANNUAL PAYMENT FOR 2015. WILL CONTIN	09/16/2015	195.00
Total FIBER/COMMUNICATIONS FUND:				243.75
WATER CAPITAL PROJECTS FUND				
METERING & TECHNOLOGY SO	700-8100-67905	METERS	09/18/2015	3,022.40
MUNICIPAL SUPPLY INC	700-8100-67905	METERS	09/22/2015	1,572.80
VEENSTRA & KIMM	700-8100-67406	2015 W IOWA WATER MAIN PROJECT	09/25/2015	666.00
Total WATER CAPITAL PROJECTS FUND:				5,261.20
ELECTRIC CAPITAL PROJECTS FUND				
ELECTRICAL ENG & EQUIP	730-8200-67906	1 1/4 LB, 1 1/4 90 SWEEPS, & YELLOW WIRE	09/16/2015	44.35
WESCO	730-8200-67906	400W N/C BULBS	09/11/2015	102.08
WESCO	730-8200-67906	6 HOLE LUGS	09/11/2015	295.74
WESCO	730-8200-67906	150W N/C BULBS, PHOTO CONTROLS & WE	09/11/2015	917.01
WESCO	730-8200-67906	2 BOLT CLAMP	09/15/2015	180.37
WESCO	730-8200-67906	3 PHASE TRANSFORMER BASEMENT	09/18/2015	1,733.52
WESCO	730-8200-67906	SIX BAY SWITCH GEAR	09/21/2015	27,942.66
Total ELECTRIC CAPITAL PROJECTS FUND:				31,215.73
IMU LIAB INS RESERVE FUND				
SMITH'S COLLISION CENTER	855-8200-64089	REPAIR TO LEFT DOOR METER TRUCK	09/16/2015	1,438.45
Total IMU LIAB INS RESERVE FUND:				1,438.45
Grand Totals:				96,170.87

Vendor Name	GL Account Number	Description	Invoice Date	Net Invoice Amount

Board of Trustees: ______________________________

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IMU Regular Downstairs **3. B.**

Meeting Date: 10/12/2015

Information

Subject

Minutes for September 28th, 2015

Information

Minutes for September 28th, 2015 are attached for your approval.

Financial Impact

N/A

Staff Recommendation

Simple motion to approve is in order.

Attachments

September 28, 2015 Minutes

BOARD OF TRUSTEE MINUTES
REGULAR SESSION – SEPTEMBER 28, 2015

The Board of Trustees met in regular session at 5:30 p.m. on September 28, 2015 in the City Hall Council Chambers. Co-Chairperson Deb White called the meeting to order and on roll call the following members were present: Heather Hulen, Jim McClymond, Adam Voigts and Deb White. Absent: Mike Rozga.

Ron Schuster, 502 N. Kenwood and Laramie Kelly, 1306 W. 14th Avenue, requested that fiber be extended into their neighborhood.

The consent agenda consisting of the following was approved on a motion by Hulen and seconded by Voigts. Question was called for and on voice vote Co-Chair White declared the motion carried unanimously.

September 21, 2015 claims

September 14 and 21, 2015 minutes

The Board previewed the 125th Electric Anniversary video.

The Memo of Understanding with the Iowa Department of Administrative Services was tabled until the next Board of Trustee meeting.

A motion was made by McClymond and seconded by Hulen that the Cost Of Power Adjustment will remain at $.0054/kWh for October 1, 2015 through December 1, 2015 billings during which time the cost of service study will be considered and a recommendation will be made. Question was called for and on voice vote Co-Chair White declared the motion carried unanimously.

Meeting adjourned on a motion by Voigts and seconded by McClymond.

Deb White, Co-Chair

Diana Bowlin, City Clerk

IMU Regular Downstairs **3. C.**

Meeting Date: 10/12/2015

Information

Subject

Electric Crew Chief Recommendation

Information

With the retirement of Rod Goodrich, a vacancy for an Electric Crew Chief was created. The vacancy was posted internally and two candidates expressed interest in the position. An interview with each candidate was held and the following recommendation is being made to Trustees:

Promotion of Jason Henle from Temporary Crew Chief to Lead Crew Chief, $65,287 plus longevity, effective October 12th, 2015.

Jason has temporarily filled in as crew chief during both the East Side Underground Conversion and West Hwy 92 Relocation projects. He completed the IMU Apprenticeship Program in 2003 and has been employed by the the utility for 19 years.

Financial Impact

N/A

Staff Recommendation

Simple motion to approve is in order.

IMU Regular Downstairs **4.**

Meeting Date: 10/12/2015

Information

Subject

Fiber Expansion Financial Feasibility, Michael Maloney, D.A. Davidson & Co.

Information

Jim McClymond and staff met with Michael Maloney on September 29th to preliminarily discuss financing options for the fiber system build-out. D.A. Davidson & Co. is a full-service investment banking company and Michael was involved in the Waverly fiber to the home project. He will be in attendance to give a brief overview and answer any questions the board may have at this point.

We also received word this week from Brick Gentry Law Firm that IMU can proceed with a feasibility study without an RFP process, as it is not a construction or maintenance item. This will help expedite the process, however the study itself is estimated to take 3-4 months.

Financial Impact

N/A

Staff Recommendation

IMU Regular Downstairs **5.**

Meeting Date: 10/12/2015

Information

Subject

Cost of Electric Service Study, John Krejewski, JK Energy Consulting

Information

John Krajewski, JK Energy Consulting, will present the 2016 Cost of Service & Rate Design Study and answer questions.

A first draft was presented to Deb White, Jim McClymond and staff on September 30th and a second draft of John's detailed report is attached to this agenda item. Acceptance of this report is the first step towards an anticipated December 1, 2015 electric rate increase.

Financial Impact

N/A

Staff Recommendation

The Board may accept the report as presented or raise questions and/or comments for discussion.

Attachments

2016 Cost of Electric Service Study

2016 Cost of Service / Rate Design Study

Indianola Municipal Utilities

BOARD REVIEW DRAFT

October 8, 2015

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JK *Energy Consulting LLC*

TABLE OF CONTENTS

Executive Summary

This study was prepared by JK Energy Consulting, LLC for Indianola Municipal Utilities (IMU). The purpose of the study was to review the electric rates charged by IMU and its electric utility, and ensure that electric rates are adequate to pay for projected expenses.

Based on the analyses completed, it appears the existing rates are projected to collect less revenue than projected revenue requirements in fiscal year (FY) 2016 and beyond. Projected retail revenue for FY 2016 were approximately $11.7 million (Table 5, Line 15), while projected revenue requirements (operating expenses, debt service and capital improvements less non-retail revenues) were approximately $13.0 million (Table 5, Line 15). This indicates there is insufficient revenue to cover projected expenses in FY 2016.

Of the projected revenue requirements, approximately $9.7 million (Table 1a, Line 9) was for purchased power from the Municipal Energy Agency of Nebraska (MEAN), including transmission service to deliver these purchases. This represents approximately 69% of projected revenue requirements (Table 3, Line 15). MEAN's rates have increased more than 30% over the last three years and have resulted in a significant increase in IMU's operating expenses. Purchased power costs are projected to increase 5% annually over the next four years. The primary cause of IMU's necessary retail rate increases is to pay for increased purchased power expense related to recent and future rate increases from MEAN.

By FY 2020, a cumulative rate increase of approximately 35% would be necessary to cover projected revenue requirements (including operating and maintenance expenses, capital improvements from revenue, and debt service) and ensure adequate debt service coverage requirements (Table 1a, Line 29). The analyses completed indicated that annual rate increases of approximately 7% in FY 2016 through FY 2018, 6% in FY 2019, and 5% in FY 2020 would recover sufficient revenue for projected expenses (Table 2a, Line 16), including debt service coverage requirements.

The cost of service analysis was completed to assess the amount that each rate class should be paying compared to the revenue that is being collected from existing rates. The analysis also indicated how much revenue is collected in each season compared to the cost of service in the respective season. In general, it appeared that future rate increases should be directed more towards Small Power rates (Table 5). Rates should be increased more in the winter season than in the summer season based on IMU's current cost structure and rates (Table 6).

The purpose of rate design is to develop rates that reflect the cost of service and accomplish other goals established by IMU. The proposed rate resolution would direct the necessary rate increase more toward winter rates than summer rates (Table 8). Small Power rates would increase more than other rate classes. These changes were consistent with the cost of service analysis.

Two rate design changes are proposed. The first change involves the Small Power and Large Power rates. Under the current rate structure, a customer could have a financial incentive to increase usage in order to reduce total costs. If a customer increases usage enough to be eligible for the Large Power rate, the end result could be lower costs under the new rate. This issue was resolved by combining the existing Small Power and Large Power rates and renaming the rate "Large Power Service," removing the word Industrial. A minimum billing demand of 150 kW was added to minimize the financial incentive to artificially add load for a short period of time in order to qualify for a lower rate. It is also proposed that the criteria for moving between Commercial and the new consolidated Large Power Service rates be refined to ensure proper rate application for all customers.

The second proposed rate design change would be to modify the base rate in the Cost of Energy (COE) adjustment and designate a portion of the base rate change to apply to the COE bank deficit. The City's power costs have increased approximately $1.5 million since the COE adjustment was established. It is recommended that $500,000 of the proposed rate increase, or 0.8 cents/kWh ($0.008/kWh), be applied to reduce the COE deficit. This adjustment should eliminate the COE deficit by November 2016, at which time the COE balance will be deemed to be zero. A revision of the COE adjustment is proposed to eliminate the quarterly calculation and only apply abnormal rate increases, such as a short-term rate adjustment assessed by IMU's power supplier or an unexpected internal expense. This will reduce the administrative burden on IMU staff. The base rate would be increased a like amount to coincide with the second step of the rate increase.

Administratively, it is proposed to add a "Qualification" section to each rate schedule. In addition, the name of the "Commercial Light and Power Service" rate was changed to "General Service." This is more consistent with industry standard terminology and ensures the rate class assignment is based on usage rather than zoning.

Even when the proposed rate increases are included, the proposed rates are competitive with neighboring utilities (Table 10 and Table 11). Rates were compared to MidAmerican Energy (MEC), Clarke Electric Cooperative, and the cities of Pella and Carlisle, Iowa. These neighboring utilities are experiencing power supply and operating cost increases and will likely be increasing rates in the near future, which will help keep IMU's rates competitive with these neighboring utilities.

Conclusions

The following conclusions were reached, based on the information provided and analyses completed:

1. The projected revenue requirement for FY 2016 was $13.0 million.
2. The largest component of the test year budget was purchased power expense, representing 69% of the projected test year budget.
3. Projected revenues from existing rates are approximately $11.7 million.
4. The primary driver for the need to increase retail rates is the increase in wholesale rates by MEAN over the last four years.
5. A rate increase of 7% in FY 2016 and FY 2017 would ensure sufficient revenue to cover projected test year expenses.

6. Rate increases of 6% in FY 2019 and 5% in FY 2020 would be necessary to help ensure sufficient revenue to cover projected expenses.
7. IMU has accumulated a deficit in the Cost of Energy (COE) bank over the last 12 months, primarily because MEAN's rates have increased significantly since the COE was established.
8. The cost of service analysis indicated rate increases should be directed toward winter usage.
9. The cost of service analysis indicated that Small Power customers should receive larger rate increases than other rate classes.
10. With the proposed rate increases in FY 2016, IMU's Residential rates will be competitive with or lower than those of neighboring utilities.
11. If IMU adopts the proposed rate changes, it would increase revenue by $5.12 per month for the typical residential customer. Of this amount, $3.12 would have been recovered through normal operation of the COE adjustment; therefore, the incremental base rate increase in December 2015 is $2.00 per month for a typical residential customer.
12. The proposed rate change in December 2016 is $5.31 per month for a typical residential customer.

Recommendations

The following recommendations were developed based on the analyses completed and conclusions reached:

1. IMU should adopt a retail rate increase of 7% on December 1, 2015 and 7% on December 1, 2016. These proposed rate increases would be implemented with the rate resolution included in Appendix A.
2. Retail rates for the winter season should be increased more than the summer season.
3. Rates for Small Power customers should be increased more than other rate classes. In addition, the Small Power and Large Power rates should be consolidated to eliminate transition issues for customers moving between the two rates.
4. The Commercial Light and Power Service rate class should be renamed General Service to reflect industry-accepted naming conventions.
5. Of the 7% rate increase, $500,000 should be applied to the COE deficit over the next 12 months. This would be accomplished by adding 0.8 cents/kWh ($0.008/kWh) of the proposed rate change to the COE bank for 12 months, beginning in December 2015.
6. The COE adjustment policy should be modified to only cover extraordinary power cost adjustments from the City's power suppliers. In addition, the balance in the COE bank should be set to zero as of December 2016.
7. IMU should review its rates on a regular basis, particularly as purchased power and transmission costs increase.

PURPOSE AND APPROACH

The purpose of this study was to review the electrical rates charged by IMU, and develop rates that were consistent with a number of goals established by IMU. The rate goals established by IMU included having rates that were competitive with neighboring utilities, providing sufficient revenues to cover projected operating expenses, and having rates that reflected the cost of service for each rate class.

The approach to the study involved completing several tasks. Retail sales, purchased power, operating expenses, capital projects, and financial information was collected. Test year expenses for FY 2016 were projected and future revenues and expenses were projected through FY 2020. A rate plan was developed to meet the financial goals established by IMU. The allocated cost of service for each rate class was calculated and compared to revenue from existing rates. Rates for each rate class were developed based on the cost of service and other goals established by IMU. A rate resolution was developed establishing new rates that would increase on December 1, 2015 and December 1, 2016. A written report was prepared and will be presented to the IMU Board of Trustees for action.

BACKGROUND

Indianola Municipal Utilities

IMU serves customers located within the City and in some areas adjacent to the City. IMU serves approximately 5,840 Residential customers, 734 Commercial customers, 11 Industrial (Large Power and Small Power) customers, 64 Governmental and City-owned accounts, and a number of street and private security lighting accounts.

Purchased Power

IMU purchases its total electric requirements from MEAN. MEAN supplies IMU's total capacity and energy requirements under its Service Schedule M (SSM) agreement. In FY 2016, the projected cost of purchased power from MEAN is 7.4¢/kWh, delivered to IMU.

Many factors affect IMU's electric rates:

- MEAN implemented a Pooled Energy Adjustment for several months during FY 2013-2014.
- A 12.8% rate increase went into effect on April 1, 2014 followed by a 6.5% rate increase that was implemented on November 1, 2014.
- MEAN implemented a customer charge of $529,275 that was spread over the months of February and March 2015.
- MEAN approved a rate structure change and implemented a Fixed Cost Recovery (FCR) Charge, effective April 1, 2015. This change increased power supply costs for high load factor customers and winter usage.

Purchased power represents approximately 69% of IMU's test year budget, a percentage that has increased over the last five years as MEAN has implemented a series of rate increases. Any increase in power costs most likely requires a rate increase at the retail level. There is also future power cost uncertainty related to environmental restrictions and wholesale market conditions.

These issues could result in a major change in IMU's future power costs and should be monitored because of their potential impact on IMU's retail rates.

PROJECTED FINANCIAL RESULTS

The purpose of preparing projected financial results is to compare projected revenues with projected expenses, and determining the need for future rate increases. Projections were prepared for the period FY 2015 through FY 2020 based on information provided by MEAN and IMU.

Parameters

The following parameters were used to develop the projected financial results.

1. Historical and projected results were prepared based on IMU's fiscal year (July through June).
2. The FY 2016 budget was used as the basis for the test year budget.
3. An 8% rate increase in April 2015 was included based on the MEAN SSM rates, adopted by the MEAN Board on in January 2015.
4. A customer charge of $529,275 was included in FY 2015. It was split between February and March 2015, as approved by the MEAN Board in November 2014.
5. MEAN rates were projected to increase 5% annually from FY 2017 through FY 2020.
6. Operating and maintenance expenses, administrative costs, and other internal expenses were projected to increase at a rate of 3% annually.
7. The operating and capital funds were combined for rate-making purposes.

Projected Financial Results

Tables 1a and 1b (see pages 6 and 7) show the projected financial results for FY 2015 through FY 2020 and historical financial results for FY 2013 and FY 2014. The projected financial results do not include rate increases or use of available funds for rate stabilization. Without a rate increase or use of reserves, the projected deficit would be approximately $1.3 million in FY 2016, increasing to approximately $4.1 million by FY 2020. The major cause of the deficits is increased purchased power expenses from MEAN. Existing rates would need to be increased by approximately 35% between now and FY 2020 to cover the projected deficits.

Return on rate base would decrease from -2.28% in FY 2016 to -10.24% by FY 2020 without a rate change. The target return on rate base was 4.49%, based on estimated long-term capital costs. A cumulative rate increase of 50.35% would be necessary to ensure the return on rate base was equal to the target return. This calculation was performed for information purposes only. Because the rate change under this methodology was so much greater than cash-basis ratemaking or ensuring adequate debt service coverage, the rate change was based on ensuring adequate cash flow.

Table 1a
Projected Financial Results
Existing Rates - Cash Basis
Indianola Municipal Utilities
2016 Cost of Service Study

Line	Description	Actual 2013	Actual 2014	Projected 2015	Test Year 2016	Projected 2017	Projected 2018	Projected 2019	Projected 2020
1	**Operating Revenues**								
2	Sale of Electricity	$ 11,541,231	$ 12,168,779	$ 11,705,304	$ 11,705,304	$ 11,705,304	$ 11,705,304	$ 11,705,304	$ 11,705,304
3	Electric Cost Adjustment	-	-	346,370	346,370	$ 346,370	$ 346,370	$ 346,370	$ 346,370
4	Capacity Compensation	378,840	532,920	489,000	487,000	487,000	487,000	487,000	487,000
5	MISO Revenue	314,670	544,971	504,461	481,983	481,983	481,983	481,983	481,983
6	Other	314,711	366,768	347,600	350,300	350,300	350,300	350,300	350,300
7	**Total Operating Revenue**	**$ 12,549,452**	**$ 13,613,438**	**$ 13,392,735**	**$ 13,370,957**	**$ 13,370,957**	**$ 13,370,957**	**$ 13,370,957**	**$ 13,370,957**
8	**Operating Expenses**								
9	Purchased Power	$ 7,152,377	$ 8,254,437	$ 9,425,048	$ 9,727,082	$ 10,585,298	$ 11,111,604	$ 11,663,847	$ 12,246,369
10	Plant Operation & Maintenance	481,600	379,986	383,500	376,500	387,795	399,429	411,412	423,754
11	Distribution Operation & Maintenance	1,160,928	1,170,810	1,181,900	1,204,000	1,240,120	1,277,324	1,315,643	1,355,113
12	Administrative & General	1,256,818	1,242,188	1,417,500	1,455,100	1,498,753	1,543,716	1,590,027	1,637,728
13	**Total Operating Expenses**	**$ 10,051,723**	**$ 11,047,421**	**$ 12,407,948**	**$ 12,762,682**	**$ 13,711,966**	**$ 14,332,072**	**$ 14,980,929**	**$ 15,662,964**
14	**Operating Income**	**$ 2,497,729**	**$ 2,566,017**	**$ 984,787**	**$ 608,275**	**$ (341,009)**	**$ (961,115)**	**$ (1,609,972)**	**$ (2,292,007)**
15	**Non-Operating Expense/(Revenue)**								
16	Interest Income	$ (147,056)	$ (104,842)	$ (110,000)	(110,000)	(110,000)	(110,000)	(110,000)	(110,000)
17	Debt Service Interest	342,481	306,607	157,404	180,466	162,708	144,508	125,840	106,678
18	Debt Service Principal	1,010,000	1,040,000	300,000	683,000	700,000	718,000	737,000	756,000
19	Sale of Capital Assets	14,346	-	-	-	-	-	-	-
20	Interfund Transfers	501,300	538,700	630,100	643,400	662,702	682,583	703,061	724,152
21	Capital Improvements	1,853,830	1,984,071	949,900	953,000	938,000	1,323,000	1,343,000	730,000
22	Future Capital Improvements	-	-	-	-	-	-	-	-
23	Fees and Charges	(27,468)	(32,833)	(25,000)	(25,000)	(25,750)	(26,523)	(27,318)	(28,138)
24	Interfund Debt Repayment	(686,695)	(610,816)	(590,800)	(270,800)	(270,800)	(270,800)	(270,800)	(270,800)
25	Developer Contributions	(107,950)	(61,875)	-	-				
26	Miscellaneous	(191,688)	(117,249)	(125,900)	(114,000)	(114,000)	(114,000)	(114,000)	(114,000)
27	**Total Non-Operating Expense/(Revenue)**	**$ 2,561,100**	**$ 2,941,763**	**$ 1,185,704**	**$ 1,940,066**	**$ 1,942,860**	**$ 2,346,769**	**$ 2,386,782**	**$ 1,793,893**
28	**Net Income - Cash Basis**	**$ (63,371)**	**$ (375,746)**	**$ (200,917)**	**$ (1,331,791)**	**$ (2,283,869)**	**$ (3,307,883)**	**$ (3,996,754)**	**$ (4,085,899)**
29	**Rate Change for Breakeven Cash Flow**	0.55%	3.09%	1.72%	11.38%	19.51%	28.26%	34.14%	34.91%
30	**Debt Service Coverage**								
31	Net Revenue	$ 3,049,336	$ 2,893,057	$ 1,206,387	$ 484,675	$ (483,161)	$ (1,122,375)	$ (1,790,914)	$ (2,493,221)
32	Debt Service	1,352,481	1,346,607	457,404	863,466	862,708	862,508	862,840	862,678
33	**Debt Service Coverage Ratio**	**225.46%**	**214.84%**	**263.75%**	**56.13%**	**-56.01%**	**-130.13%**	**-207.56%**	**-289.01%**
34	**Required Net Revenue**	1,622,977	1,615,928	548,884	1,036,159	1,035,250	1,035,010	1,035,408	1,035,214
35	**Rate Change for 125% Debt Coverage**	-12.36%	-10.50%	-5.62%	4.71%	12.97%	18.43%	24.15%	30.14%

Table 1b
Projected Financial Results
Existing Rates - Utility Base
Indianola Municipal Utilities
2016 Cost of Service Study

Line	Description	Projected 2015	Test Year 2016	Projected 2017	Projected 2018	Projected 2019	Projected 2020
1	**Net Income - Accrual Basis**						
2	Revenue	$ 13,392,735	$ 13,370,957	$ 13,370,957	$ 13,370,957	$ 13,370,957	$ 13,370,957
3	Operating Expenses (exc. Depreciation)	13,038,048	13,406,082	14,374,668	15,014,655	15,683,989	16,387,116
4	Depreciation/Amortization	1,343,648	1,343,648	1,371,715	1,555,065	1,720,535	1,804,798
5	Non-Operating Revenue/(Expenses)	-	-	-	-	-	-
6	**Net Income**	**$ (988,961)**	**$ (1,378,773)**	**$ (2,375,425)**	**$ (3,198,762)**	**$ (4,033,567)**	**$ (4,820,957)**
7	**Net Operating Income - Utility Basis (1)**	**$ (358,861)**	**$ (735,373)**	**$ (1,712,723)**	**$ (2,516,179)**	**$ (3,330,506)**	**$ (4,096,805)**
8	**Rate Base**						
9	Net Plant in Service	$ 29,412,178	$ 30,672,130	$ 30,142,415	$ 34,087,851	$ 37,331,416	$ 38,054,518
10	Working Capital (2)	$ 1,550,994	$ 1,595,335	$ 1,713,996	$ 1,791,509	$ 1,872,616	$ 1,957,870
11	**Projected Rate Base**	**$ 30,963,172**	**$ 32,267,465**	**$ 31,856,411**	**$ 35,879,360**	**$ 39,204,032**	**$ 40,012,388**
12	**Return on Rate Base**	-1.16%	-2.28%	-5.38%	-7.01%	-8.50%	-10.24%
13	**Target Return on Rate Base**	4.49%	4.49%	4.49%	4.49%	4.49%	4.49%
14	**Rate Change to Achieve Target Return ($)**	1,749,401	2,184,487	3,143,378	4,127,502	5,091,138	5,893,739
15	**(%)**	14.95%	18.66%	26.85%	35.26%	43.49%	50.35%

Note:
1. Excludes non-operating revenue and expenses and transfers to other funds.
2. Equal to 45 days of operating expenses.

Future Rate Changes

One of the rate design goals was to spread any major rate increases over a number of years. The proposed rate plan implements annual rate increases comparable to MEAN's power supply rate increases. Tables 2a and 2b (see pages 9 and 10) show projected financial results and return on rate base with rate increases of 7% annually in FY 2016 through FY 2018, 6% in FY 2019 and 5% in FY 2020. The proposed rate changes provide sufficient revenue to cover projected purchased power, operating and maintenance, debt service, and administrative and general costs. Debt service coverage would exceed the minimum requirement of 125% throughout the study period with the proposed rate changes. Return on rate base would increase to 0.4% by the end of the study period. While the projected return on rate base is lower than the target return on rate base, it is an improvement from the projection without the rate increases.

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Table 2a
Projected Financial Results
Proposed Rates - Cash Basis
Indianola Municipal Utilities
2016 Cost of Service Study

Line	Description	Actual 2013	Actual 2014	Projected 2015	Test Year 2016	Projected 2017	Projected 2018	Projected 2019	Projected 2020
1	**Operating Revenues**								
2	Sale of Electricity	$ 11,541,231	$ 12,168,779	$ 11,705,304	$ 11,705,304	$ 11,705,304	$ 11,705,304	$ 11,705,304	$ 11,705,304
3	Electric Cost Adjustment	-	-	346,370	346,370	346,370	346,370	346,370	346,370
4	Rate Changes	-	-	-	819,371	1,696,099	2,634,197	3,494,567	4,254,560
5	Capacity Compensation	378,840	532,920	489,000	487,000	487,000	487,000	487,000	487,000
6	MISO Revenue	-	-	504,461	481,983	481,983	481,983	481,983	481,983
7	Other	314,711	366,768	347,600	350,300	350,300	350,300	350,300	350,300
8	**Total Operating Revenue**	**$ 12,234,782**	**$ 13,068,467**	**$ 13,392,735**	**$ 14,190,328**	**$ 15,067,056**	**$ 16,005,154**	**$ 16,865,524**	**$ 17,625,517**
9	**Operating Expenses**								
10	Purchased Power	$ 7,152,377	$ 8,254,437	$ 9,425,048	$ 9,727,082	$ 10,585,298	$ 11,111,604	$ 11,663,847	$ 12,246,369
11	Plant Operation & Maintenance	481,600	379,986	383,500	376,500	387,795	399,429	411,412	423,754
12	Distribution Operation & Maintenance	1,160,928	1,170,810	1,181,900	1,204,000	1,240,120	1,277,324	1,315,643	1,355,113
13	Administrative & General	1,256,818	1,242,188	1,417,500	1,455,100	1,498,753	1,543,716	1,590,027	1,637,728
14	**Total Operating Expenses**	**$ 10,051,723**	**$ 11,047,421**	**$ 12,407,948**	**$ 12,762,682**	**$ 13,711,966**	**$ 14,332,072**	**$ 14,980,929**	**$ 15,662,964**
15	**Operating Income**	**$ 2,183,059**	**$ 2,021,046**	**$ 984,787**	**$ 1,427,646**	**$ 1,355,090**	**$ 1,673,082**	**$ 1,884,595**	**$ 1,962,554**
16	**Rate Change Implemented**				**7.0%**	**7.0%**	**7.0%**	**6.0%**	**5.0%**
17	**Non-Operating Expense/(Revenue)**								
18	Interest Income	$ (147,056)	$ (104,842)	$ (110,000)	(110,000)	(110,000)	(110,000)	(110,000)	(110,000)
19	Debt Service Interest	342,481	306,607	157,404	180,466	162,708	144,508	125,840	106,678
20	Debt Service Principal	1,010,000	1,040,000	300,000	683,000	700,000	718,000	737,000	756,000
21	Sale of Capital Assets	14,346	-	-	-	-	-	-	-
22	Interfund Transfers	501,300	538,700	630,100	643,400	662,702	682,583	703,061	724,152
23	Capital Improvements	1,853,830	1,984,071	949,900	953,000	938,000	1,323,000	1,343,000	730,000
24	Future Capital Improvements	-	-	-	-	-	-	-	-
25	Fees and Charges	(27,468)	(32,833)	(25,000)	(25,000)	(25,750)	(26,523)	(27,318)	(28,138)
26	Interfund Debt Repayment	(686,695)	(610,816)	(590,800)	(270,800)	(270,800)	(270,800)	(270,800)	(270,800)
27	Miscellaneous	(191,688)	(117,249)	(125,900)	(114,000)	(114,000)	(114,000)	(114,000)	(114,000)
28	**Total Non-Operating Expense/(Revenue)**	**$ 2,669,050**	**$ 3,003,638**	**$ 1,185,704**	**$ 1,940,066**	**$ 1,942,860**	**$ 2,346,769**	**$ 2,386,782**	**$ 1,793,893**
29	**Net Income - Cash Basis**	**$ (485,991)**	**$ (982,592)**	**$ (200,917)**	**$ (512,420)**	**$ (587,770)**	**$ (673,687)**	**$ (502,187)**	**$ 168,661**
30	**Rate Change for Breakeven Cash Flow**	4.21%	8.07%	1.72%	4.38%	5.02%	5.76%	4.29%	-1.44%
31	**Debt Service Coverage**								
32	Net Revenue	$ 2,734,666	$ 2,348,086	$ 1,206,387	$ 1,304,046	$ 1,212,938	$ 1,511,821	$ 1,703,653	$ 1,761,339
33	Debt Service	**$ 1,352,481**	**$ 1,346,607**	457,404	863,466	862,708	862,508	862,840	862,678
34	**Debt Service Coverage Ratio**	**202.20%**	**174.37%**	**263.75%**	**151.02%**	**140.60%**	**175.28%**	**197.45%**	**204.17%**
35	**Required Net Revenue**	**$ 1,622,977**	**$ 1,615,928**	548,884	1,036,159	1,035,250	1,035,010	1,035,408	1,035,214
36	**Rate Change for 125% Debt Coverage**	-9.63%	-6.02%	-5.62%	-2.29%	-1.52%	-4.07%	-5.71%	-6.20%

Table 2b
Projected Financial Results
Proposed Rates - Utility Base
Indianola Municipal Utilities
2016 Cost of Service Study

Line	Description	Projected 2015	Test Year 2016	Projected 2017	Projected 2018	Projected 2019	Projected 2020
1	**Estimated Return on Rate Base**						
2	Revenue	$ 13,392,735	$ 14,190,328	$ 15,067,056	$ 16,005,154	$ 16,865,524	$ 17,625,517
3	Operating Expenses (exc. Depreciation)	13,038,048	13,406,082	14,374,668	15,014,655	15,683,989	16,387,116
4	Depreciation	1,343,648	1,343,648	1,371,715	1,555,065	1,720,535	1,804,798
5	Non-Operating Revenue/(Expenses)	-	-	-	-	-	-
6	**Net Income (excluding Interest Expense)**	**$ (988,961)**	**$ (559,402)**	**$ (679,327)**	**$ (564,566)**	**$ (539,000)**	**$ (566,397)**
7	**Net Operating Income - Utility Basis**	**$ (358,861)**	**$ 83,998**	**$ (16,625)**	**$ 118,017**	**$ 164,061**	**$ 157,756**
8	**Rate Base**						
9	Net Plant in Service	$ 29,412,178	$ 30,672,130	$ 30,142,415	$ 34,087,851	$ 37,331,416	$ 38,054,518
10	Working Capital	1,550,994	1,595,335	1,713,996	1,791,509	1,872,616	1,957,870
11	**Projected Rate Base**	**$ 30,963,172**	**$ 32,267,465**	**$ 31,856,411**	**$ 35,879,360**	**$ 39,204,032**	**$ 40,012,388**
12	**Return on Rate Base**	-1.16%	0.26%	-0.05%	0.33%	0.42%	0.39%
13	**Target Return on Rate Base**	4.49%	4.49%	4.49%	4.49%	4.49%	4.49%
14	**Rate Change to Achieve Target Return ($)**	1,749,401	1,365,116	1,447,279	1,493,305	1,596,571	1,639,179
15	**(%)**	14.95%	11.66%	12.36%	12.76%	13.64%	14.00%

Cost of Service

The purpose of the cost of service analysis is to identify the costs related to serving each class of customers. Several steps were completed to prepare the cost of service analysis. A test year budget was prepared based on the FY 2016 operating budget with adjustments for known changes. Each expense item was identified and assigned to a utility function, and further classified as a demand, energy or customer related expense. This process is called "functionalization" and "classification." The costs related to each function are then allocated to each customer class based on generally accepted cost allocation principles for municipal electric utilities. The allocated costs were compared to revenues based on existing rates. The comparison of the cost of service to revenue from existing rates was used as a factor in designing rates.

Test Year Budget

The FY 2016 operating budget was used as the basis for the test year budget. The purpose of preparing a test year budget is to create a scenario that is as close to "normal" operating conditions as possible, reflecting known changes for the utility. The test year budget included the following adjustments to the FY 2016 operating budget:

1. Implementation of 8% increase in MEAN's rates, effective April 1, 2015.
2. Modification of the MEAN rate structure to eliminate the base/incremental rate with a fixed cost recovery methodology with a single energy rate.
3. Adjustments to capital improvements to reflect normal expenditures.
4. The operating and capital funds were combined. This reflects methodology used to calculate the debt service coverage because all revenues, including those transferred to the capital fund, are included in the net revenue calculation. Similarly, all capital expenditures and depreciation are excluded from the net revenue calculation.

The test year budget for FY 2016 was approximately $13 million and is summarized in Table 3 (see page 12). This figure represents the amount that needs to be collected from retail rates. It includes all operating expenses, debt service payments, capital improvements funded from rates, and is reduced for revenue from capacity compensation, interest income and other non-retail revenue.

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Table 3
Test Year Budget by Function
Indianola Municipal Utilities
Annual

Line	Rate Class	Production / Transmission	Subtrans/ Distribution	Customer/ Admin	Total
1	Residential	$ 3,029,024	$ 1,518,620	$ 445,882	$ 4,993,525
2	Residential - Good Cents	3,168	1,389	260	4,817
3	Residential All Electric	463,159	189,106	57,217	709,483
4	Residential All Electric - Good Cents	1,607	478	87	2,172
5	Residential & Farm	1,777	922	455	3,154
6	Time of Use - Residential	24,685	11,063	3,081	38,829
7	City Street Lights	87,610	43,726	14,791	146,127
8	Commercial Light & Power	2,915,971	1,026,650	63,590	4,006,211
9	Commercial Light & Power 2% Discount	10,621	5,096	87	15,803
9	Government	305,898	84,585	4,040	394,523
10	Municipal	333,680	104,812	10,356	448,848
11	Small Power	897,975	209,653	1,366	1,108,994
12	Large Power	934,130	225,943	1,062	1,161,135
13	Lights	2,378	892	203	3,474
14	**Total**	**$ 9,011,684**	**$ 3,422,933**	**$ 602,478**	**$ 13,037,095**
15	**Percentage**	**69.12%**	**26.26%**	**4.62%**	**100.00%**

Functionalization and Classification

Functionalization and classification involves assigning the expense items to a function and classifying those expenses by allocation method. Functions vary by utility and are based on power supply arrangements, size, and type of utility. The following functions were used for IMU:

1. Purchased power
2. Transmission and sub-transmission service
3. Distribution (primary and secondary)
4. Services
5. Meter reading
6. Billing and customer accounting
7. Street lighting
8. Local generation (including revenues and expenses)

Expenses were classified into demand-related, energy-related and customer-related classifications. Some costs are allocated solely to a single classification. For example, transmission service is classified as demand-related. Other functions, including primary distribution, are spread between the demand-related and customer-related classifications. The classifications were based on cost causation and how the costs should be recovered from IMU's retail rate classes.

Table 4 (see page 13) summarizes the classification of test year expenses, including the allocation to the various retail rate classes. Approximately $1.6 million is customer-related, $4.6 million is energy-related, and $6.9 million is demand-related expense. Based on this classification, 11.9%

of IMU's test year budget is customer-related, 35.2% is energy-related, and 52.9% is demand-related.

Table 4
Classification of Expenses
Indianola Municipal Utilities

Annual

Line	Rate Class	Customer ($)	Customer ($/mon)	Energy ($)	Energy (¢/kWh)	Demand ($)	Demand ¢/kWh	Demand $/kW
1	Residential	$ 1,083,355	$ 17.58	$ 1,635,591	3.80	$ 2,274,580	5.29	
2	Residential - Good Cents	633	17.58	1,743	3.81	2,442	5.34	
3	Residential All Electric	139,020	17.58	242,165	3.81	328,298	5.16	
4	Residential All Electric - Good Cents	211	17.58	855	3.80	1,106	4.92	
5	Residential & Farm	903	37.63	945	3.81	1,305	5.25	
6	Time of Use - Residential	7,487	17.58	13,128	3.80	18,214	5.28	
7	City Street Lights	35,556	1.74	47,712	3.80	62,860	5.01	
8	Commercial Light & Power	245,418	27.92	1,338,851	3.80	2,421,943	6.87	
9	Commercial Light & Power 2% Discount	211	17.58	5,439	3.81	10,154	7.11	
10	Government	8,446	39.65	154,191	3.80	231,887	5.72	
11	Municipal	21,649	39.65	159,143	3.67	268,055	6.18	
12	Small Power	5,588	77.61	491,985	3.80	611,421	4.72	
13	Large Power	4,346	77.61	494,718	3.80	662,071	5.08	
14	Lights	471	1.15	1,293	3.80	1,710	5.02	
15	**Total**	**$ 1,553,292**		**$ 4,587,758**		**$ 6,896,044**		
16	**Percentage**	**11.9%**		**35.2%**		**52.9%**		

Cost Allocation

The functionalized costs were allocated to the various rate classes using generally accepted methods for preparing embedded cost of service studies. There is no standard cost of service methodology set by a regulatory agency that IMU is required to follow. There are a number of guidelines that municipal utilities typically follow, including publications and guidelines from the American Public Power Association, the National Association of Regulatory Utility Commissioners, and the Federal Energy Regulatory Commission.

Demand-related costs were allocated on the basis of coincident or non-coincident demands, depending on the function, and adjusted for losses. Energy-related costs were allocated on the basis of energy sales, adjusted for losses. Customer-related costs were allocated on the basis of the weighted number of customers within each rate class, with weighting factors determined based on the cost of metering, customer billing or services.

Some expenses are not easily assigned to a particular function. Examples of expenses that are not easily assigned include interest income, general administrative expenses, and miscellaneous operating revenue. These expenses were assigned to functions at the same ratio as expenses that were directly assigned to functions, which is one of several generally accepted methods for assigning these costs to the appropriate function.

Comparison of Revenues to Cost of Service

Revenues collected from existing rates were compared to the allocated cost of service. The purpose of this comparison was to provide guidance on the adequacy of existing rates for each rate class. This comparison can be used to assess the general magnitude of rate changes needed for each rate class and is one factor in determining the need for rate adjustments for individual rate classes.

Table 5 compares the revenue from existing rates to the calculated cost of service. Overall, the cost of service indicated rates would need to increase approximately 11.4% in FY 2016, which is generally consistent with the rate plan that was shown in the projected operating results in Table 2. The change in MEAN's rate structure has tended to increase the difference between revenue and the cost of service more among large, high-load factor customers than among smaller customers operating at lower load factors.

Table 5
Comparison of Cost of Service
to Revenue from Existing Rates
Indianola Municipal Utilities
Annual

Line	Rate Class	Revenue Existing Rates	Cost of Service	Difference $	Difference %
1	Residential	$ 4,626,094	$ 4,993,525	$ 367,431	7.9%
2	Residential - Good Cents	4,220	4,817	597	14.2%
3	Residential All Electric	637,696	709,483	71,787	11.3%
4	Residential All Electric - Good Cents	1,808	2,172	364	20.1%
5	Residential & Farm	3,000	3,154	154	5.1%
6	Time of Use - Residential	34,540	38,829	4,289	12.4%
7	City Street Lights	141,369	146,127	4,759	3.4%
8	Commercial Light & Power	3,616,170	4,006,211	390,041	10.8%
9	Commercial Light & Power 2% Discount	14,226	15,803	1,577	11.1%
10	Government	360,805	394,523	33,718	9.3%
11	Municipal	393,184	448,848	55,664	14.2%
12	Small Power	904,864	1,108,994	204,130	22.6%
13	Large Power	965,313	1,161,135	195,823	20.3%
14	Lights	2,017	3,474	1,457	72.3%
15	**Total**	**$ 11,705,304**	**$ 13,037,095**	**$ 1,331,791**	**11.4%**

Table 6 (see page 15) shows the calculated cost of service for the summer and winter season. To fully recover the cost of service, summer season rates would require a decrease of 4.5% and winter season rates would need an increase of 22.2%. In general, this indicates that rate increases should be directed toward winter usage. This result is consistent with the MEAN rate change that tended to increase winter rates more than summer rates, and resulted in consistent fixed charges on a monthly basis throughout the year.

Table 6
Comparison of Cost of Service
to Revenue from Existing Rates
Indianola Municipal Utilities

Summer

Line	Rate Class	Revenue Existing Rates	Cost of Service	Difference $	Difference %
1	Residential	$ 1,977,455	$ 1,850,748	$ (126,706)	-6.4%
2	Residential - Good Cents	2,002	1,909	(93)	-4.6%
3	Residential All Electric	189,670	192,838	3,168	1.7%
4	Residential All Electric - Good Cents	637	631	(6)	-0.9%
5	Residential & Farm	1,172	1,102	(70)	-6.0%
6	Time of Use - Residential	14,722	13,751	(971)	-6.6%
7	City Street Lights	42,861	32,432	(10,429)	-24.3%
8	Commercial Light & Power	1,408,703	1,386,213	(22,489)	-1.6%
9	Commercial Light & Power 2% Discount	8,888	7,778	(1,110)	-12.5%
10	Government	144,544	131,223	(13,320)	-9.2%
11	Municipal	162,563	152,296	(10,267)	-6.3%
12	Small Power	375,563	365,044	(10,520)	-2.8%
13	Large Power	402,780	380,803	(21,977)	-5.5%
14	Lights	672	811	138	20.6%
15	**Total**	**$ 4,732,230**	**$ 4,517,578**	**$ (214,652)**	**-4.5%**

Winter

Line	Rate Class	Revenue Existing Rates	Cost of Service	Difference $	Difference %
1	Residential	$ 2,648,639	$ 3,142,777	$ 494,138	18.7%
2	Residential - Good Cents	2,218	2,908	690	31.1%
3	Residential All Electric	448,026	516,644	68,618	15.3%
4	Residential All Electric - Good Cents	1,171	1,541	370	31.6%
5	Residential & Farm	1,828	2,052	224	12.2%
6	Time of Use - Residential	19,818	25,078	5,260	26.5%
7	City Street Lights	98,508	113,695	15,188	15.4%
8	Commercial Light & Power	2,207,468	2,619,998	412,530	18.7%
9	Commercial Light & Power 2% Discount	5,338	8,025	2,687	50.3%
9	Government	216,261	263,300	47,038	21.8%
10	Municipal	230,621	296,552	65,931	28.6%
11	Small Power	529,301	743,950	214,649	40.6%
13	Large Power	562,532	780,333	217,800	38.7%
14	Lights	1,344	2,663	1,319	98.1%
15	**Total**	**$ 6,973,074**	**$ 8,519,517**	**$ 1,546,443**	**22.2%**

Rate Design

The purpose of rate design is to develop rates that help achieve established revenue and financial performance goals while balancing other rate goals established by IMU. This process involves meeting goals that sometimes conflict with each other. For example, a goal to have competitive rates may conflict with the need to have rates that recover sufficient revenue to pay for projected expenses.

The rates were designed to best meet several goals that were established by IMU and its consultant. These goals included:

1. Ensuring the long-term financial integrity of the utility.
2. Establishing rates that are fair, reasonable and non-discriminatory.
3. Developing rates that are competitive with neighboring utilities.
4. Encouraging usage during low cost time periods, while discouraging usage during high cost periods.
5. Recognizing the cost of service for rate classes and seasons.
6. Phasing in large rate increases to minimize rate impacts to customers.

Summary of Major Changes

The proposed rate resolution, included as Appendix A, would implement a rate increase that increases overall revenue by approximately 7% on December 1, 2015 and 7% on December 1, 2016. The proposed rate increase in FY 2017 is slightly higher than the cost of service indicated would be necessary as a result of rounding individual rate class increases and ensuring proper rate signals for each rate class.

The proposed rate increases would not be across the board, but would be directed more towards winter usage than summer usage. Small Power customers would receive a larger rate increase than other rate classes. The proposed rate changes are consistent with the cost of service results. The proposed changes by rate class are shown in Table 7 (see page 17) on an annual basis and Table 8 (see page 18) on a seasonal basis. Table 9 (see page 19) shows the proposed rate increases for FY 2017, effective December 1, 2016.

Two rate design changes are proposed. The first change involves the Small Power and Large Power rates. Under the current rate structure, a customer could have a financial incentive to increase usage in order to reduce total costs. If a customer increases usage enough to be eligible for the Large Power rate, the end result could be lower costs under the new rate. There are similar transition issues between the Commercial and Small Power rates that are addressed in the proposed rate design. It is also proposed that the criteria for moving between Commercial, Small Power and Large Power rates be refined to ensure proper rate application for all customers.

The second proposed rate design change would be to modify the base rate in the Cost of Energy (COE) adjustment and designate a portion of the base rate change to apply to the COE bank deficit. The City's power costs have increased approximately $1.5 million since the COE adjustment was established. It is recommended that $500,000 of the proposed rate increase, or 0.8 cents/kWh ($0.008/kWh), be applied to reduce the COE deficit. This would take the form of a deposit from the base rate increase, applied for 12 months beginning in December 1, 2015. After 12 months, the amount applied to the COE deficit would be discontinued. Beginning December 1, 2016, the COE adjustment will only be used to recover abnormal rate increases from MEAN. These would include unplanned customer charges, regulatory adjustments, or Pooled Energy Adjustments. This will reduce the administrative burden on IMU staff.

Administratively, it is proposed to add a "Qualification" section to each rate schedule. In addition, the name of the "Commercial Light and Power Service" rate was changed to "General Service." This is more consistent with industry standard terminology and ensures the rate class assignment is based on usage rather than zoning.

The December 2015 rate increase will increase rates from a typical residential customer by $5.12 per month. Of this amount, $3.12 is related to the COE adjustment and would have been recovered administrative without this proposed rate change. The remaining increase of $2.00 per month represents the base rate change being implemented with the proposed rate schedule. A second rate increase in December 2016 is included in the attached rate resolution. It would raise rates for a typical residential customer by $5.31 per month.

Table 7
Proposed Rate Change by Rate Class
Indianola Municipal Utilities
2016 Cost of Service Study
Annual

Line	Rate Class	Revenue Existing Rates	Revenue Proposed Rates	Difference $	Difference %
1	Residential	$ 4,626,094	$ 4,941,419	$ 315,325	6.8%
2	Residential - Good Cents	4,220	4,444	224	5.3%
3	Residential All Electric	637,696	681,544	43,848	6.9%
4	Residential All Electric - Good Cents	1,808	1,918	110	6.1%
5	Residential & Farm	3,000	3,212	213	7.1%
6	Time of Use - Residential	34,540	36,961	2,421	7.0%
7	City Street Lights	141,369	151,703	10,334	7.3%
8	Commercial Light & Power	3,616,170	3,862,432	246,261	6.8%
9	Commercial Light & Power 2% Discount	14,226	14,928	701	4.9%
10	Government	360,805	385,575	24,770	6.9%
11	Municipal	393,184	420,283	27,100	6.9%
12	Small Power	904,864	989,762	84,898	9.4%
13	Large Power	965,313	1,030,009	64,697	6.7%
14	Lights	2,017	2,158	141	7.0%
15	**Total**	**$ 11,705,304**	**$ 12,526,347**	**$ 820,902**	**7.0%**

Table 8
Proposed Rate Change by Rate Class
Indianola Municipal Utilities
2016 Cost of Service Study

Summer

Line	Rate Class	Revenue Existing Rates	Revenue Proposed Rates	Difference $	Difference %
1	Residential	$ 1,977,455	$ 2,027,424	$ 49,969	2.5%
2	Residential - Good Cents	2,002	2,047	46	2.3%
3	Residential All Electric	189,670	194,850	5,180	2.7%
4	Residential All Electric - Good Cents	637	651	15	2.3%
5	Residential & Farm	1,172	1,243	72	6.1%
6	Time of Use - Residential	14,722	15,146	425	2.9%
7	City Street Lights	42,861	46,033	3,172	7.4%
8	Commercial Light & Power	1,408,703	1,465,057	56,355	4.0%
9	Commercial Light & Power 2% Discount	8,888	9,226	337	3.8%
10	Government	144,544	153,024	8,480	5.9%
11	Municipal	162,563	172,183	9,620	5.9%
12	Small Power	375,563	392,738	17,174	4.6%
13	Large Power	402,780	421,119	18,339	4.6%
14	Lights	672	719	47	7.0%
15	**Total**	**$ 4,732,230**	**$ 4,901,462**	**$ 169,232**	**3.6%**

Winter

Line	Rate Class	Revenue Existing Rates	Revenue Proposed Rates	Difference $	Difference %
1	Residential	$ 2,648,639	$ 2,913,995	$ 265,356	10.0%
2	Residential - Good Cents	2,218	2,396	178	8.0%
3	Residential All Electric	448,026	486,694	38,668	8.6%
4	Residential All Electric - Good Cents	1,171	1,266	95	8.1%
5	Residential & Farm	1,828	1,969	141	7.7%
6	Time of Use - Residential	19,818	21,815	1,997	10.1%
7	City Street Lights	98,508	105,669	7,162	7.3%
8	Commercial Light & Power	2,207,468	2,397,374	189,907	8.6%
9	Commercial Light & Power 2% Discount	5,338	5,702	364	6.8%
10	Government	216,261	232,551	16,290	7.5%
11	Municipal	230,621	248,101	17,480	7.6%
12	Small Power	529,301	597,024	67,723	12.8%
13	Large Power	562,532	608,890	46,358	8.2%
14	Lights	1,344	1,439	94	7.0%
15	**Total**	**$ 6,973,074**	**$ 7,624,886**	**$ 651,812**	**9.3%**

Table 9
Proposed Rate Change by Rate Class - Year 2
Indianola Municipal Utilities
2016 Cost of Service Study
Annual

Line	Rate Class	Revenue Year 1 Rates	Revenue Year 2 Rates	Difference $	Difference %
1	Residential	$ 4,941,419	$ 5,268,466	$ 327,047	6.6%
2	Residential - Good Cents	4,444	4,711	267	6.0%
3	Residential All Electric	681,544	728,974	47,430	7.0%
4	Residential All Electric - Good Cents	1,918	2,064	146	7.6%
5	Residential & Farm	3,212	3,431	219	6.8%
6	Time of Use - Residential	36,961	39,581	2,620	7.1%
7	City Street Lights	151,703	162,037	10,334	6.8%
8	Commercial Light & Power	3,862,432	4,113,026	250,594	6.5%
9	Commercial Light & Power 2% Discount	14,928	15,569	641	4.3%
10	Government	385,575	413,124	27,549	7.1%
11	Municipal	420,283	450,470	30,186	7.2%
12	Small Power	989,762	1,080,826	91,064	9.2%
13	Large Power	1,030,009	1,087,453	57,444	5.6%
14	Lights	2,158	2,309	151	7.0%
15	**Total**	**$12,526,347**	**$13,372,041**	**$ 845,542**	**6.8%**

Rate Comparisons

With the proposed rate increases, IMU's electric rates will still be competitive with neighboring utilities. IMU's rates were compared to four neighboring utilities: MidAmerican Energy (MEC), Clarke Electric Cooperative, and the cities of Pella and Carlisle, Iowa. Table 10 compares Residential rates and Table 11 compares Commercial Service rates at various usage levels for the summer and winter seasons (see page 20).

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Table 10
Typical Bill Comparison
Rate Comparisons
Residential

Summer Comparisons					
Utility	**500 kWh**	**Utility**	**1,000 kWh**	**Utility**	**2,500 kWh**
MEC	61.38	MEC	114.25	**IMU**	**272.75**
IMU	**62.75**	**IMU**	**115.25**	MEC	272.88
Pella	67.77	Pella	126.27	Clarke	299.00
Clarke	73.00	Clarke	129.50	Pella	301.77
Carlisle	80.05	Carlisle	147.10	Carlisle	348.25
Winter Comparisons					
Utility	**500 kWh**	**Utility**	**1,000 kWh**	**Utility**	**2,500 kWh**
MEC	48.72	MEC	88.94	MEC	156.98
Pella	58.77	**IMU**	**104.65**	**IMU**	**239.65**
IMU	**59.65**	Pella	108.27	Pella	256.77
Clarke	73.00	Clarke	129.50	Clarke	299.00
Carlisle	75.05	Carlisle	137.10	Carlisle	305.25

Table 11
Typical Bill Comparison
Rate Comparisons
Commercial Service

Summer Comparisons					
Utility	**1,000 kWh**	**Utility**	**5,000 kWh**	**Utility**	**10,000 kWh**
Clarke (1)	-	Clarke (1)	-	Clarke (1)	-
IMU	**104.75**	**IMU**	**482.75**	MEC	948.95
MEC	108.70	MEC	503.50	**IMU**	**955.25**
Carlisle	151.15	Pella	635.90	Pella	1,240.90
Pella	151.90	Carlisle	668.65	Carlisle	1,306.15
Winter Comparisons					
Utility	**1,000 kWh**	**Utility**	**5,000 kWh**	**Utility**	**10,000 kWh**
Clarke (1)	-	Clarke (1)	-	Clarke (1)	-
MEC	80.56	MEC	362.80	MEC	579.75
IMU	**95.21**	**IMU**	**419.21**	**IMU**	**824.21**
Pella	130.90	Pella	530.90	Pella	1,030.90
Carlisle	141.15	Carlisle	606.65	Carlisle	1,134.15

(1) Clarke Electric Cooperative's General Service rate is customer based and includes a demand charge; therefore, it is not being used in the rate comparison

The proposed rates are competitive with or lower than neighboring utilities, even when considering the proposed rate increases. These neighboring utilities are experiencing power supply and operating cost increases, which may result in retail rate increases in the future comparable to IMU's proposed increases.

Rate comparisons are important, but cannot take into account other factors that cause rate differences. For example, transfers and discounted services to municipal accounts would not be available if MEC or Clarke served the City's retail customers. Municipally-owned utilities may transfer funds to the City as an in-lieu-of tax payment or provide free or discounted labor and equipment to the City. Rate comparisons were based on existing rate schedules for 2015 and do not consider future rate changes that may be implemented by other utilities. Neighboring utilities are experiencing similar cost pressures related to new resources, fuel and purchased power cost increases and general cost escalation.

CONCLUSIONS

The following conclusions were reached, based on the information provided and analyses completed:

1. The projected revenue requirement for FY 2016 was $13.0 million.
2. The largest component of the test year budget was purchased power expense, representing 69% of the projected test year budget.
3. Projected revenues from existing rates are approximately $11.7 million.
4. The primary driver for the need to increase retail rates is the increase in wholesale rates by MEAN over the last four years.
5. A rate increase of 7% in FY 2016 and FY 2017 would ensure sufficient revenue to cover projected test year expenses.
6. Rate increases of 6% in FY 2019 and 5% in FY 2020 would be necessary to help ensure sufficient revenue to cover projected expenses.
7. IMU has accumulated a deficit in the Cost of Energy (COE) bank over the last 12 months, primarily because MEAN's rates have increased significantly since the COE was established.
8. The cost of service analysis indicated rate increases should be directed toward winter usage.
9. The cost of service analysis indicated that Small Power customers should receive larger rate increases than other rate classes.
10. With the proposed rate increases in FY 2016, IMU's Residential rates will be competitive with or lower than those of neighboring utilities.
11. If IMU adopts the proposed rate changes, it would increase revenue by $5.12 per month for the typical residential customer. Of this amount, $3.12 would have been recovered through normal operation of the COE adjustment; therefore, the incremental base rate increase in December 2015 is $2.00 per month for a typical residential customer.
12. The proposed rate change in December 2016 is $5.31 per month for a typical residential customer.

RECOMMENDATIONS

The following recommendations were developed based on the analyses completed and conclusions reached:

1. IMU should adopt a retail rate increase of 7% on December 1, 2015 and 7% on December 1, 2016. These proposed rate increases would be implemented with the rate resolution included in Appendix A.
2. Retail rates for the winter season should be increased more than the summer season.
3. Rates for Small Power customers should be increased more than other rate classes. In addition, the Small Power and Large Power rates should be consolidated to eliminate transition issues for customers moving between the two rates.
4. The Commercial Light and Power Service rate class should be renamed General Service to reflect industry-accepted naming conventions.
5. Of the 7% rate increase, $500,000 should be applied to the COE deficit over the next 12 months. This would be accomplished by adding 0.8 cents/kWh ($0.008/kWh) of the proposed rate change to the COE bank for 12 months, beginning in December 2015.
6. The COE adjustment policy should be modified to only cover extraordinary power cost adjustments from the City's power suppliers. In addition, the balance in the COE bank should be set to zero as of December 2016.
7. IMU should review its rates on a regular basis, particularly as purchased power and transmission costs increase.

APPENDIX A

RESOLUTION NO. 162
OF
INDIANOLA MUNICIPAL UTILITIES
BOARD OF TRUSTEES

BE IT RESOLVED by the Indianola Municipal Utilities Board of Trustees that Resolution No. 155 be repealed and that this Resolution be substituted in lieu of it as follows:

1. **ELECTRIC RATES**. The rates for customer classes of service described in electric service plan Section 2.4 are:

Section 2.4 **Rates for Electric Service**

Rates for electric current shall apply to all customers according to their proper classifications as follows and where summer months are defined as all bills rendered in July, August, September and October. Winter months are defined as all bills rendered in November, December, January, February, March, April, May and June.

2.4(1) **Residential Service**

Qualification: For single-family residential customers where primary energy consumption is for domestic purposes. Not available for commercial purposes, including agriculture, manufacturing or other uses of a commercial nature.

Rates effective for all billings after December 1, 2015

Monthly Customer Charge	$10.25	
	Summer	Winter
First 400 kWh per month	10.5¢	10.1¢
Balance kWh per month	10.5¢	9.0¢

Rates effective for all billings after December 1, 2016

Monthly Customer Charge	$11.00	
	Summer	Winter
First 400 kWh per month	11.0¢	11.0¢
Balance kWh per month	11.0¢	9.5¢

2.4(2) **Residential Electric Primary Heat Source Service**

Qualification: For single-family residential customers where primary energy consumption is for domestic purposes and electricity is the primary source of space heating energy. Not available for commercial purposes, including agriculture, manufacturing or other uses of a commercial nature.

Rates effective for all billings after December 1, 2015

	Summer	Winter
Monthly Customer Charge	$10.25	
First 400 kWh per month	10.5¢	9.4¢
Next 600 kWh per month	10.5¢	9.4¢
Balance kWh per month	10.5¢	7.0¢

Rates effective for all billings after December 1, 2016

	Summer	Winter
Monthly Customer Charge	$11.00	
First 400 kWh per month	11.2¢	10.0¢
Next 600 kWh per month	11.2¢	10.0¢
Balance kWh per month	11.2¢	7.9¢

2.4(3) **Residential and Farm Service Outside the Corporate Limits**

Qualification: For single-family residential customers located outside corporate limits of the City of Indianola. Not available for commercial purposes, including agriculture, manufacturing or other uses of a commercial nature.

Rates effective for all billings after December 1, 2015

	Summer	Winter
Monthly Customer Charge	$24.00	
All kWh per month	11.3¢	10.2¢

Rates effective for all billings after December 1, 2016

	Summer	Winter
Monthly Customer Charge	$26.00	
All kWh per month	11.8¢	11.0¢

2.4(4) **General Service (Formerly Commercial Light and Power Service)**

Qualification: For any customer who does not qualify for service under another rate schedule.

Rates effective for all billings after December 1, 2015

	Summer	Winter
Monthly Customer Charge	$22.00	
First 3000 kWh per month	11.1¢	10.3¢
Balance kWh per month	11.1¢	9.1¢

Rates effective for all billings after December 1, 2016

	Summer	Winter
Monthly Customer Charge	$24.00	
First 3000 kWh per month	11.3¢	11.3¢
Balance kWh per month	11.3¢	9.7¢

2.4(5) **Large Power Service (Formerly Small Industrial Power Service)**

Qualification: Customer must have monthly demands of 200 kilowatts or greater for 3 consecutive months. If a customer's load decreases to less than 200 kilowatts for 12 consecutive months after being placed on the Large Power Service rate, it will be moved to the General Service rate. A General Service customer may ask to be billed under this rate for a minimum of 12 months.

Rates effective for all billings after December 1, 2015

	Summer	Winter
Monthly Customer Charge	$45.00	
Demand Charge per kW	$5.40	$4.50
All kWh (w/o primary discount)	7.0¢	5.8¢
All kWh (w/primary discount)	6.9¢	5.7¢

Rates effective for all billings after December 1, 2016

	Summer	Winter
Monthly Customer Charge	$50.00	
Demand Charge per kW	$6.50	$5.50
All kWh (w/o primary discount)	7.2¢	6.3¢
All kWh (w/primary discount)	7.1¢	6.2¢

Demand: The kW as shown by or computed from the readings of the Board's demand meter for the 15-minute period of customer's greatest use during the month determined to the nearest kW.

Minimum Demand: The minimum billing demand shall be the greater of:

1. 75% of the highest Demand established in any month during the 12 months ending with the current month, or
2. 150 kW

Primary Discount: The primary discount will apply for customers that own transformation equipment and take service at one of the Utility's standard primary voltages (>2.4 kV).

2.4(6) **Large Industrial Power Service**

Qualification: Any customer served under the Large Industrial Power Service rate as of December 1, 2015. This rate will be consolidated with the Large Power Service rate, effective December 1, 2016.

Rates effective for all billings after December 1, 2015

Monthly Customer Charge	$78.84	
	Summer	Winter
Demand Charge per kW	$7.50	$6.00
All kWh (w/o primary discount)	6.8¢	5.5¢
All kWh (w/primary discount)	6.7¢	5.4¢

Rates effective for all billings after December 1, 2016

Effective December 1, 2016, Large Industrial Power Service customers will be served under the Large Power Service rate schedule.

Minimum Demand Charge: The minimum demand charge shall be 75% of the highest Demand established in any month during the 12 months ending with the current month.

Demand: The kW as shown by or computed from the readings of the Board's demand meter for the 15-minute period of customer's greatest use during the month determined to the nearest kW.

Primary Discount: The primary discount will apply for customers that own transformation equipment and take service at one of the Utility's standard primary voltages (>2.4 kV).

Power Factor: The customer's power factor is calculated as the customer's real power demand (in kilowatts) divided by the customer's apparent power demand (in kilovolt-Amperes, or kVA). The apparent power demand is equal to the square root of the sum of the var usage squared and the kilowatt demand squared for the same interval. The customer is expected to maintain, at its own expense, a power factor of 90% or better at all times. If the power factor, as measured by the Utility, is lower than this, the customer will be sent a formal notice and given 90 days to correct the deficiency. If the power factor is not corrected within 90 days of notice, the entire monthly bill (including the customer charge) shall be increased by the ratio of 90% divided by the measured power factor, at the time of the customer's monthly peak in any given month, for all subsequent periods until the customer has demonstrated a minimum 90% power factor over a 3-month period.

2.4(7) **Government Service**

<u>City Departments and IMU Service</u>:

<u>Qualification</u>: Any accounts providing service to the City of Indianola or Indianola Municipal Utilities, excluding street lighting service.

<u>Rates effective for all billings after December 1, 2015</u>

Monthly Customer Charge		$22.00	
	Summer		Winter
All kWh per month	10.9¢		8.6¢

<u>Rates effective for all billings after December 1, 2016</u>

Monthly Customer Charge		$24.00	
	Summer		Winter
All kWh per month	11.7¢		9.2¢

<u>City Street Lights</u>:

<u>Qualification</u>: Street lighting service to the City of Indianola.

<u>Rates effective for all billings after December 1, 2015</u>

Monthly Customer Charge		$2.75	
	Summer		Winter
All kWh per month	6.7¢		6.2¢

<u>Rates effective for all billings after December 1, 2016</u>

Monthly Customer Charge		$3.00	
	Summer		Winter
All kWh per month	7.0¢		6.5¢

2.4(8) **Large Power Contracts**

Rates for electric current for Large Power Contracts shall be pursuant to the provisions of written contract entered into by the customer and Indianola Municipal Utilities.

2.4(9) **Cost of Energy Adjustment**

The Board of Trustees shall periodically establish a base energy allowance per kWh for all services. Any energy surcharge or credit may be administratively imposed and adjusted at the same rate per kWh for all services to recoup energy-related costs incurred that are in excess of the base energy allowance. Energy-related costs include production and transmission costs charged by the Utility's supplier(s), system losses, and costs for generating electricity not otherwise reimbursed.

2.4(10) **Maintenance/Capital Adjustment**

The Board of Trustees shall periodically make a determination of whether the electric utility has experienced an unusual maintenance or capital expenditure. The expenditure of the sum in excess of $150,000 for maintenance or $500,000 for capital improvement in any one calendar year shall be considered an unusual maintenance or capital expenditure. A maintenance surcharge or credit may be administratively imposed at the same rate per kWh for all services to recoup these unusual maintenance or capital expenditures.

2.4(11) **Temporary Service**

In addition to the use rates, as provided above, there shall be an additional charge for Temporary Service as follows:

Single-Phase	$35.00 plus cost of installation
Three-Phase	$65.00 plus cost of installation

2.4(12) **Residential Time-of-Use Meter Service**

Qualification: For single-family residential customers where primary energy consumption is for domestic purposes, and where customer has agreed to install a time-of-use meter. Not available for commercial purposes, including agriculture, manufacturing or other uses of a commercial nature.

Rates effective for all billings after December 1, 2015

Monthly Customer Charge	$13.00	
	Summer	Winter
kWh/mo. 8 a.m. to 8 p.m. Monday-Friday	15.8¢	14.0¢
kWh/mo. 8 p.m. to 8 a.m. Monday-Friday	7.0¢	5.5¢
kWh/mo. 8 p.m. Friday to 8 a.m. Monday	7.0¢	5.5¢

Rates effective for all billings after December 1, 2016

Monthly Customer Charge	$14.00	
	Summer	Winter
kWh/mo. 8 a.m. to 8 p.m. Monday-Friday	16.8¢	15.0¢
kWh/mo. 8 p.m. to 8 a.m. Monday-Friday	7.5¢	5.9¢
kWh/mo. 8 p.m. Friday to 8 a.m. Monday	7.5¢	5.9¢

2.4(13) **Delinquent Bills**

Net monthly bills, as computed under the provisions of this Resolution, are payable within 20 days from the date of bills. When not so paid, penalty at the rate of 18% per annum from due date until paid shall be charged. One month’s penalty shall be forgiven each year.

2.4(14) **Short-Term Demand Curtailment Option**

a. To qualify for this rate, a customer must be billed under the Large Power Service (formerly Small Industrial Power Service) or Large Industrial Power Service rate schedules. This curtailment option is available to all applicable customers who demonstrate a continuing capability and willingness to curtail at least 300 kW of load during Utility-specific curtailment periods.

b. Customers desiring service under this option must make application before November 1 for the following calendar year. The application must state the amount of load reduction being requested, the proposed curtailment demand level, and the method to be used to effect such a reduction. All requests are subject to review and acceptance by the Utility, with the review based on the customer's expected load at the time of system peak and the likelihood that the proposed reduction will be consistently achievable.

c. The load reduction will be calculated based on the customer's historical summer peak at the time of the Utility's peak and the proposed level of curtailment demand. If sufficient billing data is not available to allow an accurate determination of the historical peak data, the curtailment demand level will be set at an estimated value arrived by joint negotiation but subject to the approval of the Utility.

d. During a customer's first summer period under this option, the curtailment demand level and the amount of load reduction can be adjusted at the end of each billing period by mutual agreement of the Utility and the customer.

e. Customers who successfully comply with all curtailment requests during a summer period will be issued a credit as follows:

> Short Term Demand Curtailment Credit: $31.00 per kW. Credits will be applied to the customer's November bill. No credit will be issued unless the customer successfully complies with all curtailment requests.

f. This rate is available only on a year-by-year basis and is subject to modification or withdrawal at any time.

g. The Utility may establish a curtailment period at any time. Notice will be given to customers at least 2 hours in advance, except the advance notice may be reduced to 30 minutes if the customer has been advised of the possibility of curtailment during the prior day. Each curtailment period will continue until the Utility gives specific notice of its termination, up to a maximum of 6 hours. The number of curtailment periods during any one calendar year will not exceed 16.

Section 4.9(5) **Rates for Purchase from Small Power Production and Cogeneration Facilities**

Rates effective for all billings after December 1, 2015

	Summer	Winter
Solar Facilities 100 kW or less – per kWh	4.7¢	4.7¢

Rates effective for all billings after December 1, 2016

	Summer	Winter
Solar Facilities 100 kW or less – per kWh	4.7¢	4.7¢

2. **EFFECTIVE DATE.** This Resolution shall be in effect from and after its final passage and approval and publication as provided by law.

INTRODUCED AND ADOPTED this _____ day of October, 2015.

____
Chair, Board of Trustees

ATTEST:

____
City Clerk

Information

Subject

Set October 26, 2015 as the Date for a Public Hearing Setting Electric Rates

Information

Following acceptance of the cost of service study, the next step would be to establish October 26, 2015 as the public hearing date for setting Electric Utility rates. Staff will then prepare a notice for publication.

Attached to this agenda item is the proposed Electric Rate Resolution #162 that would be used for calculating utility bills received by customers on December 1, 2015. The proposed rate structure has been designed to recover the wholesale energy deficit (currently being recovered by a Cost of Energy Adjustment) by December of 2016. The intent of a Cost of Energy Adjustment is to cover extraordinary power cost adjustments from IMU's wholesale power provider only.

Once the public hearing date on this matter is set, staff will submit an official notice for publication and the proposed resolution will be available to the public.

Financial Impact

N/A

Staff Recommendation

Simple motion setting October 26, 2015 as the date of a public hearing on proposed Resolution #162 setting new Electric Utility rates is in order.

Attachments

Proposed Rate Resolution #162

RESOLUTION NO. 162
OF
INDIANOLA MUNICIPAL UTILITIES
BOARD OF TRUSTEES

BE IT RESOLVED by the Indianola Municipal Utilities Board of Trustees that Resolution No. 155 be repealed and that this Resolution be substituted in lieu of it as follows:

1. **ELECTRIC RATES**. The rates for customer classes of service described in electric service plan Section 2.4 are:

Section 2.4 **Rates for Electric Service**

Rates for electric current shall apply to all customers according to their proper classifications as follows and where summer months are defined as all bills rendered in July, August, September and October. Winter months are defined as all bills rendered in November, December, January, February, March, April, May and June.

2.4(1) **Residential Service**

Qualification: For single-family residential customers where primary energy consumption is for domestic purposes. Not available for commercial purposes, including agriculture, manufacturing or other uses of a commercial nature.

Rates effective for all billings after December 1, 2015

Monthly Customer Charge	$10.25	
	Summer	Winter
First 400 kWh per month	10.5¢	10.1¢
Balance kWh per month	10.5¢	9.0¢

Rates effective for all billings after December 1, 2016

Monthly Customer Charge	$11.00	
	Summer	Winter
First 400 kWh per month	11.0¢	11.0¢
Balance kWh per month	11.0¢	9.5¢

2.4(2) **Residential Electric Primary Heat Source Service**

Qualification: For single-family residential customers where primary energy consumption is for domestic purposes and electricity is the primary source of space heating energy. Not available for commercial purposes, including agriculture, manufacturing or other uses of a commercial nature.

Rates effective for all billings after December 1, 2015

	Summer	Winter
Monthly Customer Charge	$10.25	
First 400 kWh per month	10.5¢	9.4¢
Next 600 kWh per month	10.5¢	9.4¢
Balance kWh per month	10.5¢	7.0¢

Rates effective for all billings after December 1, 2016

	Summer	Winter
Monthly Customer Charge	$11.00	
First 400 kWh per month	11.2¢	10.0¢
Next 600 kWh per month	11.2¢	10.0¢
Balance kWh per month	11.2¢	7.9¢

2.4(3) **Residential and Farm Service Outside the Corporate Limits**

Qualification: For single-family residential customers located outside corporate limits of the City of Indianola. Not available for commercial purposes, including agriculture, manufacturing or other uses of a commercial nature.

Rates effective for all billings after December 1, 2015

	Summer	Winter
Monthly Customer Charge	$24.00	
All kWh per month	11.3¢	10.2¢

Rates effective for all billings after December 1, 2016

	Summer	Winter
Monthly Customer Charge	$26.00	
All kWh per month	11.8¢	11.0¢

2.4(4) **General Service (Formerly Commercial Light and Power Service)**

Qualification: For any customer who does not qualify for service under another rate schedule.

Rates effective for all billings after December 1, 2015

	Summer	Winter
Monthly Customer Charge	$22.00	
First 3000 kWh per month	11.1¢	10.3¢
Balance kWh per month	11.1¢	9.1¢

Rates effective for all billings after December 1, 2016

	Summer	Winter
Monthly Customer Charge	$24.00	
First 3000 kWh per month	11.3¢	11.3¢
Balance kWh per month	11.3¢	9.7¢

2.4(5) **Large Power Service (Formerly Small Industrial Power Service)**

Qualification: Customer must have monthly demands of 200 kilowatts or greater for 3 consecutive months. If a customer's load decreases to less than 200 kilowatts for 12 consecutive months after being placed on the Large Power Service rate, it will be moved to the General Service rate. A General Service customer may ask to be billed under this rate for a minimum of 12 months.

Rates effective for all billings after December 1, 2015

	Summer	Winter
Monthly Customer Charge	$45.00	
Demand Charge per kW	$5.40	$4.50
All kWh (w/o primary discount)	7.0¢	5.8¢
All kWh (w/primary discount)	6.9¢	5.7¢

Rates effective for all billings after December 1, 2016

	Summer	Winter
Monthly Customer Charge	$50.00	
Demand Charge per kW	$6.50	$5.50
All kWh (w/o primary discount)	7.2¢	6.3¢
All kWh (w/primary discount)	7.1¢	6.2¢

Demand: The kW as shown by or computed from the readings of the Board's demand meter for the 15-minute period of customer's greatest use during the month determined to the nearest kW.

Minimum Demand: The minimum billing demand shall be the greater of:

1. 75% of the highest Demand established in any month during the 12 months ending with the current month, or
2. 150 kW

Primary Discount: The primary discount will apply for customers that own transformation equipment and take service at one of the Utility's standard primary voltages (>2.4 kV).

2.4(6) **Large Industrial Power Service**

Qualification: Any customer served under the Large Industrial Power Service rate as of December 1, 2015. This rate will be consolidated with the Large Power Service rate, effective December 1, 2016.

Rates effective for all billings after December 1, 2015

Monthly Customer Charge	$78.84	
	Summer	Winter
Demand Charge per kW	$7.50	$6.00
All kWh (w/o primary discount)	6.8¢	5.5¢
All kWh (w/primary discount)	6.7¢	5.4¢

Rates effective for all billings after December 1, 2016

Effective December 1, 2016, Large Industrial Power Service customers will be served under the Large Power Service rate schedule.

Minimum Demand Charge: The minimum demand charge shall be 75% of the highest Demand established in any month during the 12 months ending with the current month.

Demand: The kW as shown by or computed from the readings of the Board's demand meter for the 15-minute period of customer's greatest use during the month determined to the nearest kW.

Primary Discount: The primary discount will apply for customers that own transformation equipment and take service at one of the Utility's standard primary voltages (>2.4 kV).

Power Factor: The customer's power factor is calculated as the customer's real power demand (in kilowatts) divided by the customer's apparent power demand (in kilovolt-Amperes, or kVA). The apparent power demand is equal to the square root of the sum of the var usage squared and the kilowatt demand squared for the same interval. The customer is expected to maintain, at its own expense, a power factor of 90% or better at all times. If the power factor, as measured by the Utility, is lower than this, the customer will be sent a formal notice and given 90 days to correct the deficiency. If the power factor is not corrected within 90 days of notice, the entire monthly bill (including the customer charge) shall be increased by the ratio of 90% divided by the measured power factor, at the time of the customer's monthly peak in any given month, for all subsequent periods until the customer has demonstrated a minimum 90% power factor over a 3-month period.

2.4(7) **Government Service**

<u>City Departments and IMU Service</u>:

<u>Qualification</u>: Any accounts providing service to the City of Indianola or Indianola Municipal Utilities, excluding street lighting service.

<u>Rates effective for all billings after December 1, 2015</u>

Monthly Customer Charge		$22.00	
	<u>Summer</u>		<u>Winter</u>
All kWh per month	10.9¢		8.6¢

<u>Rates effective for all billings after December 1, 2016</u>

Monthly Customer Charge		$24.00	
	<u>Summer</u>		<u>Winter</u>
All kWh per month	11.7¢		9.2¢

<u>City Street Lights</u>:

<u>Qualification</u>: Street lighting service to the City of Indianola.

<u>Rates effective for all billings after December 1, 2015</u>

Monthly Customer Charge		$2.75	
	<u>Summer</u>		<u>Winter</u>
All kWh per month	6.7¢		6.2¢

<u>Rates effective for all billings after December 1, 2016</u>

Monthly Customer Charge		$3.00	
	<u>Summer</u>		<u>Winter</u>
All kWh per month	7.0¢		6.5¢

2.4(8) **Large Power Contracts**

Rates for electric current for Large Power Contracts shall be pursuant to the provisions of written contract entered into by the customer and Indianola Municipal Utilities.

2.4(9) **Cost of Energy Adjustment**

The Board of Trustees shall periodically establish a base energy allowance per kWh for all services. Any energy surcharge or credit may be administratively imposed and adjusted at the same rate per kWh for all services to recoup energy-related costs incurred that are in excess of the base energy allowance. Energy-related costs include production and transmission costs charged by the Utility's supplier(s), system losses, and costs for generating electricity not otherwise reimbursed.

2.4(10) **Maintenance/Capital Adjustment**

The Board of Trustees shall periodically make a determination of whether the electric utility has experienced an unusual maintenance or capital expenditure. The expenditure of the sum in excess of $150,000 for maintenance or $500,000 for capital improvement in any one calendar year shall be considered an unusual maintenance or capital expenditure. A maintenance surcharge or credit may be administratively imposed at the same rate per kWh for all services to recoup these unusual maintenance or capital expenditures.

2.4(11) **Temporary Service**

In addition to the use rates, as provided above, there shall be an additional charge for Temporary Service as follows:

Single-Phase	$35.00 plus cost of installation
Three-Phase	$65.00 plus cost of installation

2.4(12) **Residential Time-of-Use Meter Service**

Qualification: For single-family residential customers where primary energy consumption is for domestic purposes, and where customer has agreed to install a time-of-use meter. Not available for commercial purposes, including agriculture, manufacturing or other uses of a commercial nature.

Rates effective for all billings after December 1, 2015

Monthly Customer Charge	$13.00	
	Summer	Winter
kWh/mo. 8 a.m. to 8 p.m. Monday-Friday	15.8¢	14.0¢
kWh/mo. 8 p.m. to 8 a.m. Monday-Friday	7.0¢	5.5¢
kWh/mo. 8 p.m. Friday to 8 a.m. Monday	7.0¢	5.5¢

Rates effective for all billings after December 1, 2016

Monthly Customer Charge	$14.00	
	Summer	Winter
kWh/mo. 8 a.m. to 8 p.m. Monday-Friday	16.8¢	15.0¢
kWh/mo. 8 p.m. to 8 a.m. Monday-Friday	7.5¢	5.9¢
kWh/mo. 8 p.m. Friday to 8 a.m. Monday	7.5¢	5.9¢

2.4(13) **Delinquent Bills**

Net monthly bills, as computed under the provisions of this Resolution, are payable within 20 days from the date of bills. When not so paid, penalty at the rate of 18% per annum from due date until paid shall be charged. One month’s penalty shall be forgiven each year.

2.4(14) **Short-Term Demand Curtailment Option**

a. To qualify for this rate, a customer must be billed under the Large Power Service (formerly Small Industrial Power Service) or Large Industrial Power Service rate schedules. This curtailment option is available to all applicable customers who demonstrate a continuing capability and willingness to curtail at least 300 kW of load during Utility-specific curtailment periods.

b. Customers desiring service under this option must make application before November 1 for the following calendar year. The application must state the amount of load reduction being requested, the proposed curtailment demand level, and the method to be used to effect such a reduction. All requests are subject to review and acceptance by the Utility, with the review based on the customer's expected load at the time of system peak and the likelihood that the proposed reduction will be consistently achievable.

c. The load reduction will be calculated based on the customer's historical summer peak at the time of the Utility's peak and the proposed level of curtailment demand. If sufficient billing data is not available to allow an accurate determination of the historical peak data, the curtailment demand level will be set at an estimated value arrived by joint negotiation but subject to the approval of the Utility.

d. During a customer's first summer period under this option, the curtailment demand level and the amount of load reduction can be adjusted at the end of each billing period by mutual agreement of the Utility and the customer.

e. Customers who successfully comply with all curtailment requests during a summer period will be issued a credit as follows:

> Short Term Demand Curtailment Credit: $31.00 per kW. Credits will be applied to the customer's November bill. No credit will be issued unless the customer successfully complies with all curtailment requests.

f. This rate is available only on a year-by-year basis and is subject to modification or withdrawal at any time.

g. The Utility may establish a curtailment period at any time. Notice will be given to customers at least 2 hours in advance, except the advance notice may be reduced to 30 minutes if the customer has been advised of the possibility of curtailment during the prior day. Each curtailment period will continue until the Utility gives specific notice of its termination, up to a maximum of 6 hours. The number of curtailment periods during any one calendar year will not exceed 16.

Section 4.9(5) **Rates for Purchase from Small Power Production and Cogeneration Facilities**

Rates effective for all billings after December 1, 2015

	Summer	Winter
Solar Facilities 100 kW or less – per kWh	4.7¢	4.7¢

Rates effective for all billings after December 1, 2016

	Summer	Winter
Solar Facilities 100 kW or less – per kWh	4.7¢	4.7¢

2. **EFFECTIVE DATE.** This Resolution shall be in effect from and after its final passage and approval and publication as provided by law.

INTRODUCED AND ADOPTED this _____ day of October, 2015.

____
Chair, Board of Trustees

ATTEST:

____
City Clerk

IMU Regular Downstairs **7.**

Meeting Date: 10/12/2015

Information

Subject

In-Kind Donation Request, Calamar Development

Information

Tom Grieb, Calamar Development, will be in attendance to request an In-Kind Donation for the installation of 118 individual meters (four banks of 29 residential meters and two house meters) at an independent senior living facility in the Summercrest Hills development area. This amounts to $11,800 ($100 per meter) which IMU charges to recover the cost of mobilization and labor to install each meter. A separate $100/meter is charged for the meter itself and is NOT being requested by Calamar to be waived.

In this case, where several meters will be set within the same "trip", the developer is asking that IMU waive the mobilization charge that would typically apply to each individual meter. However, the labor cost will still be incurred by the utility and there is no economy of scale to be gained here. Another factor to be considered is that it would be unusual that all 118 units will be ready for meters at the same time, so the number of "trips" is unknown unless some sort of installation schedule can be agreed upon by Clamar and IMU.

Similar requests have been approved by the General Manager in the past, albeit on a much smaller scale (a bank of 16 residential meters) that were installed in the same trip.

Financial Impact

$11,800

Staff Recommendation

The electric budget includes $35,000 for in-kind donations/support. In the past this money has been used for more community based activities such as the Aquatic Center, Downtown Holiday Lighting and the Indianola Tree Committee. Typically economic development incentives are given in the way of installation of the infrastructure, time and material that benefits the entire development area. This request is somewhat unprecedented given the amount requested and the Board should keep in mind there are other private developers who will be occupying the Summercrest Hills area.

Attachments

Calamar In-Kind Request

CALAMAR
Builder • Developer • Manager • Financier

October 08, 2015

Indianola Municipal Utilities
Board of Trustees
111 South Buxton
Indianola IA 50125

RE: Waiving Meter Fee of $11,800.00

Dear Trustees -

Summercrest Hills is an independent senior living community located at 610 East Scenic Valley Ave. Summercrest Hills is a three story, 116 unit, wood framed structure. A fire sprinkler system protects the building and is monitored by an addressable fire alarm system. Each floor is served by two elevators. The total gross square feet is 113,883 sf. The exterior skin will be vinyl siding with a stone band. Windows are insulated vinyl windows.

Planning Board approval has been obtained for Summercrest Hills. Site grading and utility installation has begun. The developer is completing this work. Calamar Construction MW, LLC has applied for the building permit. The plans have been reviewed and are ready to be picked up pending the resolution of the meter fee costs. There will be 118 meters for the building – 116 meters serve the living units and two meters serve the common areas. All the meters will be requested to be installed at the same time. Calamar Construction will begin construction November 15, 2016.

Calamar Construction is asking that the full meter fee of $11,800.00 be waived. We appreciate your consideration of this matter. Feel free to contact me via cell phone at 402.718.3333 or email

Sincerely,

Thomas P. Grieb RPM

Thomas P. Grieb Regional Project Manager

6614 South 118th Street • Omaha, Nebraska 68137
Phone: (402) 502-7500 • Fax: (402) 502-8780 • www.calamar.com • E-Mail: tgrieb@calamar.com

Indianola Municipal Utilities
Economic Incentive Application

This application must be completed for any project that requests financial assistance from Indianola Municipal Utilities under the economic incentive program. Please use additional or attached sheets to provide any information requested in this application.

Applicant Name:	Calamar Construction MW, LLC
Mailing Address:	6614 South 118th St.
	Omaha NE 68137
Telephone#	402.502.7500
FAX#	402.502.8780
E-mail address	tgrieb@calamar.com

Property Use

( ) Public entity
( ) Indianola Development Assoc.
(X) Other public/private partnership

( ) Proposed industrial use
( ) Commercial office in excess of $10M
( ) Other eligible use

Zoning classification: R2:Residential

Project Description

Description of the project (Physical location, building square feet, unique architectural aspects, etc.):

See Attached Sheet

Incentives Requested

( )	Infrastructure improvements	$
(X)	Electric service installation	$11,800
( )	Water service installation	$
( )	Communication service installation	$

CALAMAR
Builder • Developer • Manager • Financier

Project Description:
Summercrest Hills is an independent senior living community located at 610 East Scenic Valley Ave. Summercrest Hills is a three story, 116 unit wood framed structure. A fire sprinkler system protects the building and is monitored by an addressable fire alarm system. Each floor is served by two elevators. The total gross square feet is 113,883 sf. The exterior skin will be vinyl siding with a stone band. Windows are insulated vinyl windows.

6614 South 118th Street • Omaha, Nebraska 68137
Phone: (402) 502-7500 • Fax: (402) 502-8780 • www.calamar.com • E-Mail: tgrieb@calamar.com

Projected Utility Usage

Description of projected utility use over the next five years (use attached sheets if necessary):

Service	Year 1	Year 2	Year 3	Year 4	Year 5
Electric	$27,800.00	$57,900.00	$69,480.00	$73,340.00	$81,832.00
Water	$4,600.00	$9,600.00	$11,520.00	$12,160.00	$13,658.00
Communications	$10,008.00	$20,850.00	$25,500.00	$26,410.00	$29,468.00

Other information (types of employment, benefits, etc.):

A manager and maintenance tech will be hired to

operate the facitlity

Dollar value of property improvements to be constructed: $9,353,565.00

Description of compatibility with the community and surrounding properties:

Summercrest Hills market rate independent senior living.

Description of uses of public infrastructure or municipal services (utilities, special public safety considerations:

Water, sewer, storm sewer, power, communication

and pwer will be utilized. Access will be by new road extension.

FOR UTILITY USE ONLY:

Received by the City: ____________________

Reviewed by the General Manager: ____________________

Referred to Board of Trustees for Action: ______(YES) ______(NO)

Signed: ____________________
(General Manager)

Date: ____________________

Information

Subject

F-5 Passive Optical Network Equipment

Information

The cost to replace the F-5 Passive Optical Network Equipment has been determined. Attached to this agenda item are quotes from Calix and Adtran for the cost of the equipment. Also attached is the quote from MCG for the labor to change out the equipment. IMU is receiving quite a cost savings from MCG for the labor.

Financial Impact

N/A

Staff Recommendation

Mike Metcalf is recommending the purchase of the F-5 PON from Adtran at the cost of $74,698.91 and the installation by MCG at $21,307 for a total project cost of $96,005.91.

Attachments

Calix Quote
Adtran Quote
MCG Quote

Customer Name:	INDIANOLA MUNICIPAL UTILITIES	**Quote Reference Number:**	546224A - 1
Project Name:	Indianola F5 Repalcement	**Quote Type:**	Equipment
Quote Description:	546224-Indianola F5 Replacement 10-6-15	**Date Created:**	October 4, 2015
		Date Modified:	October 6, 2015
Author Name:	Bret McElwee	**Quote Expiration:**	November 3, 2015
Contact Name:			

Equipment Summary

Calix Part #	Part Description	CLEI	Price	Qty	Extended Price
	700GE ONT				
100-03246	711GE ONT, 2 POTS, 2 GE -CE	BVM9P00ARA	$267.50	11	$2,942.50
100-03249	717GE ONT, 4 POTS, 4 GE -CE	BVM9S00ARA	$309.00	18	$5,562.00
	760GX ONT				
100-01485	760GX ONT, 8 POTS, 4 GE, 4 RF, 1 RFX	BVL3ANNFAA	$893.75	13	$11,618.75
100-01551	766GX ONT, 8 POTS, 4 GE, 8 DS1, 4 RF, 1 RFX	BVL3ANSFAA	$1,764.75	26	$45,883.50
100-01693	766GX-R Rack Mount ONT, 8 POTS, 4 GE, 8 DS1, 4 RF, 1 RFX	BVM9G00ARA	$2,284.75	4	$9,139.00
	E7				
000-00372	E7-2 Field Install Package (CO & ODC/RT): Shelf with Blank Card, FTA, and Field installation Kit		$646.75	1	$646.75
100-03006	E7-2 GPON-8 card (8xGPON OIM, 4xGE SFP, 2x10GE SFP +)	BVL3AXYFTA	$9,096.75	2	$18,193.50
100-03590	E7-2 Fan Tray Assembly 2 - FTA2	BVC1AC3LAA	$354.25	1	$354.25
	OIM GPON				
100-01782	GPON SFP OIM, Class B+, 1490/1310nm Single Fiber Transceiver, C-Temp (CO), C- & E-Series		$895.00	6	$5,370.00
	OIM Transport				
100-01661	1GE SFP, UTP Copper, RJ-45, 100m, I-Temp		$106.25	5	$531.25
	ONT				
100-01010	SFU ONT Mounting Plate		$18.00	29	$522.00
			Equipment Total		$100,763.50
110-00054	Management One Time Discount				-$10,452.25
			One Time Management Discount Total		-$10,452.25
			Grand Total		$90,311.25

Package Details:

000-00372 package consists of the following:

Part #	Description	Qty
100-03590	E7-2 Fan Tray Assembly 2 - FTA2	1
100-01830	E7-2 Field Install Kit for CO & RT (19" and 23" mounting brackets, power and ground cables, etc)	1
100-01449	E7-2 Shelf, 1RU, 2 Slots, with 1 Blank Card	1

Notes & Optional Equipment and Services

ADTRAN Part Number	Description	Item List Price	Budgetary Price	2015 Qty	2015 Extended	2015 Total
4187040G31	TA5000 Bundle consisting of 1 chassis, High-Flow REAR fan, filter, and SMIO3. This bundle also includes 1-1187011G1 Bridging SCM and 2-1187040F1, 4x10GE Switch Modules. This bundle does not include blanks. This bundle also includes 1x1187940G1 Fiber Manager.	$30,961.00	$13,157.90	1	$13,157.90	$0.00
1187080G1	Fan kit for a TA5000 Chassis	?	$345.55	1	$345.55	$345.55
1187921E1	The TA5000 Access Module blank is a blank faceplate for an Access Module slot in the TA5000 chassis. This module is 5 of 6 RoHS compliant.	$53.00	$30.50	1	$30.50	$0.00
1187923G1	The TA5000 Access Module Input Output blank is a dual wide blank for the back of the card slot on the TA5000 chassis. RoHS Compliant.	$15.00	$8.45	10	$84.50	$0.00
1187925G1	The TA5000 Access Module Input Output blank is a single wide blank for the back of the card slot on the TA5000 chassis. It is used exclusively slot 11. RoHS Compliant.	$23.00	$13.70	1	$13.70	$0.00
1187922E1	The TA5000 Access Module blank is a dual wide blank faceplate for an Access Module slot in the TA5000 chassis. This module is 5 of 6 RoHS compliant.	$56.00	$32.65	10	$326.50	$0.00
1442401G1	SFP+ 10G MMF	$1,295.00	$626.30	2	$1,252.60	$0.00
1187503F1	8-Port GPON OLT with SFP interfaces. GPON SFPs (1442530G1) must be ordered separately or as part of a bundle (4187503G1).	$12,995.00	$7,157.90	1	$7,157.90	$0.00
1442530G1	The 30km GPON SFP is a inchesSmall Form Factor Pluggableinches single fiber SFP that operates on multiple wavelengths. It uses single mode fiber with a single SC fiber connector. It is Class B++ optics rated for GPON and has a maximum reach of 30KM.	$1,500.00	$473.70	8	$3,789.60	$0.00
1187801L1	The TA5000 DS1 Line Module provides 32 DS1 interface that can be configured to support Pseudowire Emulation Edge to Edge (PWE3) transport of DS1 circuits over Ethernet.	$2,995.00	$1,684.20	2	$3,368.40	$0.00
1187400G1	The TA5000 LMIO2-CH64 Bridged provides the physical input/output interface for the DS1 32-port Voice Gateway Line Module (1187800L1) and the DS1 32-port Line Module (1187801L1). It is a dual-wide module. RoHS compliant	$108.00	$63.15	1	$63.15	$0.00
11961000HL050	Cable Assembly, TA5000, 32 pair, 50 ft., 64 pin champ (M) to stub	$137.00	$112.60	2	$225.20	$0.00
?	The Total Access 372 GPON ONT is designed for SBU applications. Includes 8 POTS, 210/100/1000 Ethernet interface, and 4 T1/E1 for pseudowire DS1 applications. Supports IPTV, GR-303, GR-008, SIP and MGCP. This bundle includes the standard SBU housing in addition to the ONT.	$0.00	$1,010.51	6	$6,063.06	$0.00
1187735G1	Uninterruptable power supply (UPS) for the TA372 and TA372E SBU ONT. User-replaceable 20 Ah 12VDC battery included. UPS is rated for 30W.	$345.00	$200.00	6	$1,200.00	$0.00
1287786F1	Includes 1 10/100/1000 Ethernet interface. Supports IPTV.	$0.00	$0.00	0	$0.00	$0.00

1287787F1	Includes 1 POTS, 1 10/100/1000 Ethernet interface. Supports IPTV, GR-303, GR-008, SIP and MGCP.	$0.00	$0.00	0	**$0.00**	**$0.00**
1287702G1	Supports 1.25 Gbps upstream and 2.5 Gbps downstream GPON application as per ITU-T G.984.2 specification. Data services supported by two 10/100/1000Base-T Ethernet interfaces . Basic telephone service supported by two POTS interfaces.	$0.00	$335.79	37	**$12,424.23**	**$0.00**
?	4 POTs + 4 GE small MDU	$0.00	$338.73	46	**$15,581.58**	**$0.00**
ABE007	7dB Fiber Attenuators LC/UPC	$20.00	$17.75	8	**$142.00**	**$0.00**
4212908L1		$0.00	$671.75	12	**$8,061.00**	**$0.00**
4212924L1		$0.00	$1,065.99	1	**$1,065.99**	**$0.00**

Totals	**$74,353.36**	**$345.55**

F5 Replacement Quote Summary (Preliminary)

9/30/15 jh,fh

Labor, MCG Estimate	**Hrs**	**Rate**	**Ext. Cost**
Administrative (Design, Ordering, Coordination)	42	$ 89	$ 3,713
OLT Installation & Provisioning	34	$ 97	$ 3,300
ONT Replacement	475	$ 75	$ 35,600
Total Labor	550	$ 77	$ 42,613

Equipment, Recommending Adtran Quote	**Ext. Cost**
OLT	$ 30,161
ONT	$ 44,538
Total Adtran Equipment	$ 74,699
Subtotal	$ 117,311
Labor Discount	$ 21,306
Total	**$ 96,005**

IMU Regular Downstairs **9.**

Meeting Date: 10/12/2015

Information

Subject

Approval of Memo of Understanding with the Iowa Dept. of Administrative Services

Information

This item was tabled at the September 28, 2015 Trustee meeting in order to obtain legal review. Amy Beattie with Brick Gentry P.C. has reviewed the MOU and is agreeable to the approval and execution as long as IMU's procedure to contest the debt also provides that customers can contest the placement of the debt into the offset program. Per Chris DesPlanques, this is the case.

Financial Impact

N/A

Staff Recommendation

Simple motion to approve is in order.

Attachments

Dept. of Administrative Services MOU

August 27, 2015

281
INDIANOLA MUNICIPAL UTILITIES
PO BOX 299
INDIANOLA, IA 50125-0299

RE: Offset Program - Memorandum of Understanding (MOU)

Dear Offset Program Participant:

The Offset Program, administered by the Iowa Department of Administrative Services (DAS), is requiring a new Memorandum of Understanding (MOU) be signed and returned to DAS by all program participants no later than October 31, 2015. The revised MOU is a result of changes in the Iowa Administrative Rules governing the Offset Program that were updated in February 2015.

Please review the enclosed MOU carefully, as the updates center on the appeal process participants must have in place. In part, the MOU states:

Section 6: Public Agency's Responsibilities:

"6.8 Appeal Process. The Public Agency must provide an appeal process for debtors to challenge each offset after debtors are notified of a potential offset event. The appeal process shall include notice to the debtor and an opportunity for the debtor to contest the amount of the debt through a contested case procedure under Iowa Code chapter 17A or a substantially equivalent process, in accordance with Iowa Code section 8A.504(2)(f) and 11 IAC 40.4(6)."

Participants that do not return a signed MOU by October 31, 2015 may be deactivated from the Offset Program. Upon completing the MOU, please include a name, telephone number and email address of a contact person for the Offset Program. Taxpayers and service providers will be directed to this individual if questions regarding an offset come to our attention.

Sincerely,

Calvin McKelvogue

Calvin McKelvogue, Chief Operating Officer
Dept. of Administrative Services, State Accounting Enterprise
1305 East Walnut Street
Hoover State Office Building, Level 3
Des Moines, IA 50319
Calvin.McKelvogue@iowa.gov

MEMORANDUM OF UNDERSTANDING
between
The Iowa Department of Administrative Services
State Accounting Enterprise
and

____

for
Participation in the INCOME OFFSET PROGRAM

SECTION 1. Identity of the Parties. The parties to this Memorandum of Understanding (MOU) are the Iowa Department of Administrative Services, State Accounting Enterprise (DAS/SAE), and ___________________________(Public Agency).

SECTION 2. Purpose. The purpose of this MOU is to set forth the terms and conditions between DAS/SAE and Public Agency for reimbursement of offsetting liabilities owed to Public Agency as authorized in **Iowa Code section 8A.504** and **11 Iowa Administrative Code (IAC) 40, et seq.**

SECTION 3. Eligibility. To be eligible for offset, both the debt ("debt" means the liability owed to the Public Agency by a member of the public), and the claim ("claim" means the liability owed by the Public Agency to a member of the public), shall be in the form of a liquidated sum due, owing and payable. All applicable remedies with regard to such a debt and claim must be exhausted or the time frame for exhaustion must have expired as a condition precedent for eligibility to participate in the offset program, provided in 11 IAC 40.3 (3).

SECTION 4. Compensation.

4.1 Fee. The parties agree that in exchange for participation in the offset program, DAS/SAE shall charge a fee of seven dollars ($7.00) (the "fee") to the Public Agency to which the debt is owed for each individual debt that is placed in the offset program. The fee is to recover costs incurred by DAS/SAE in administering the offset program.

4.2 Deduction when Debt is Offset. If a debt is offset by DAS/SAE under this program, the fee will be deducted from the gross proceeds collected through offset. The fee will be charged for each individual offset event related to an individual debt.

4.3 Billing upon Termination. Following written notice of termination of this MOU, as provided in Section 7 below, DAS/SAE shall be entitled to compensation. DAS/SAE shall submit an invoice and proof of claim to the Public Agency within sixty (60) days of the receipt of the written notice of termination as required under Section 7 below.

4.4 Fee Review. DAS/SAE shall periodically review the costs of administering the offset program. Per Section 9.2 of this MOU, proposed adjustments to the specified fee shall require an amendment.

SECTION 5. DAS/SAE's Responsibilities.

5.1 Offset of Debt. DAS/SAE shall offset liabilities owed to Public Agency by implementing an offset program for Public Agency, developed and managed by DAS/SAE in accordance with **Iowa Code chapter 8A** and **11 Iowa Administrative Rules 40**.

5.2 Compliance with AGA. DAS/SAE will comply with the Accountable Government Act, Iowa Code chapter 8E, in the performance of this MOU.

5.3 Refund of Balance after Offset. Before issuing an authorized payment to a debtor, DAS/SAE shall request verification of the claim pursuant to subrule 40.5. If notification is not made to DAS/SAE by the Public Agency within forty-five (45) days, the amount of the payment shall be released to the debtor or entity. DAS/SAE will apply the offset to the debt only after the Public Agency has notified the debtor as prescribed in subrule 40.4(4). DAS/SAE shall then refund any balance amount due from the Public Agency to the debtor or entity.

SECTION 6. Public Agency's Responsibilities.

6.1 Offset Eligibility Program. The Public Agency shall be responsible for developing and maintaining a system for reporting debts eligible for offset and any subsequent claims associated with those debts as required under Iowa Code section 8A.504 and 11 IAC chapter 40 to DAS/SAE at Public Agency's expense.

6.1.1 Minimum Debt Amount. Before a debt may be placed into the offset program, the amount of a debtor's original liability must be at least $50, except when the source of the claim is a tax refund or tax rebate, in which case the debt may be as low as $25.

6.1.2 Debtor's opportunity to challenge placement of debt in offset program. Before a debt may be placed into the offset program, the Public Agency must have:

a. Made a good faith effort to collect the debt through other means;

b. Provided the debtor advance notice that the debt will be placed in the offset program if not paid when due; and

c. Provided a formal or informal opportunity for the debtor to challenge placement of the debt into the offset program, as described in 11 IAC 40.3(4).

6.2 Formatting Requirements of Debtor Lists. The Public Agency shall provide the list of debtors it wishes to place into the offset program in a format and type prescribed by DAS/SAE.

6.3 Proof of Liability. Public agencies may only place debts into the offset program if the debts are legally enforceable. To establish enforceability the debt shall have been confirmed by mutual agreement of the parties or have been reduced to a final judgment or final agency determination that is no longer subject to appeal, certiorari, or judicial review, or has been affirmed through appeal, certiorari, or judicial review.

6.4 Notification of Changes. The Public Agency shall notify DAS/SAE within thirty (30) calendar days of any changes in the status of a debt to the state.

6.5 Semi-Annual Certification. The Public Agency shall provide on at least a semi-annual basis, certification of the liability file as prescribed by DAS/SAE.

6.6 Debtor Notification. The Public Agency shall comply with 11 IAC 40.4 when sending notifications to the debtor under this MOU which shall occur within ten (10) calendar days from the date Public Agency was notified by the DAS/SAE of a potential offset.

6.7 Payment of Residual Funds to Debtor. It is the responsibility of the Public Agency to reimburse the debtor for the difference between the amount of liability payable and the amount of the claim payable to the debtor.

6.8 Appeal Process. The Public Agency must provide an appeal process for debtors to challenge each offset after debtors are notified of a potential offset event. The appeal process shall include notice to the debtor and an opportunity for the debtor to contest the amount of the debt through a contested case procedure under Iowa Code chapter 17A or a substantially equivalent process, in accordance with Iowa Code section 8A.504(2)(f) and 11 IAC 40.4(6).

SECTION 7. Termination. This MOU shall remain in full force and effect until terminated or cancelled for convenience by written notice of the party wishing to cancel the MOU. Each party agrees to provide the other party with a sixty (60) day written notice of any intent to terminate this MOU. Either party may terminate without advance notice to the other at any time upon a material breach of the Agreement, or violation of Iowa Code section 8A.504 or 11 IAC chapter 40.

SECTION 8. Confidentiality of Information. Information shared between DAS/SAE and the Public Agency shall be deemed confidential pursuant to Iowa Code section 8A.504(2)(b) and shall be disclosed only to the extent necessary to sufficiently identify the debtor(s) liable to the public agency. Identifying information is to be used only for the purpose of participation in the offset program.

SECTION 9. MOU Administration.

9.1 Compliance with the Law. The parties, their employees, agents, and subcontractors shall comply with all applicable federal, state, and local laws, rules, ordinances, regulations and orders when performing services under this MOU, including without limitation, all laws applicable for the prevention of discrimination in employment and the use of targeted small businesses as subcontractors or suppliers. The parties, their employees, agents and subcontractors shall also comply with all federal, state and local laws regarding business permits and licenses that may be required to carry out the activities performed under this MOU.

9.2 Amendments. This MOU may only be amended in writing by mutual consent of the parties. All amendments to this MOU must be in writing and fully executed by the parties.

9.3 Third Party Beneficiaries. There are no third party beneficiaries to this MOU. However, this MOU is intended to benefit the citizens and governments in the State of Iowa as well as DAS/SAE and Public Agency.

9.4 Assignment and Delegation. This MOU may not be assigned, transferred or conveyed in whole or in part without the prior written consent of the other party. For the purpose of construing this clause, a transfer of a controlling interest in Public Agency shall be considered an assignment.

9.5 Integration. This MOU represents the entire MOU between the parties regarding participation in the offset program. The parties shall not rely upon any representation that may have been made which is not included in this MOU.

9.6 Headings or Captions. The paragraph headings or captions used in this MOU are for identification purposes only and do not limit or construe the contents of the paragraphs.

9.7 Supersedes Former Agreements. This MOU supersedes all prior Agreements between the parties for services regarding participation in the offset program.

9.8 Notice. Notices, designations, consents, offers, acceptances or any other communication provided for herein shall be given in writing which shall be addressed to each party as set forth as follows:

If to DAS/SAE:

Calvin McKelvogue, Chief Operating Officer
Department of Administrative Services – State Accounting Enterprise
1305 East Walnut Street
Hoover State Office Building, Level 3
Des Moines, IA 50319

If to Public Agency:

____
Authorized Representative

____
Mailing Address

____
City, State, Zip Code

If a party changes its designated person and/or address hereunder, such change shall be in writing as provided herein.

9.9 Severability. If any provision of this MOU is determined by a court of competent jurisdiction to be invalid or unenforceable, such determination shall not affect the validity or enforceability of any other part or provision of this MOU.

9.10 Non-Appropriation. In the event a non-appropriation, de-appropriation, or other legislative or gubernatorial action significantly impairs DAS/SAE's budget or ability to perform the terms of this agreement, DAS/SAE may immediately terminate this Agreement.

9.11 Indemnification. The following indemnification provisions shall apply to Public Agencies that are not agencies of the State of Iowa subject to Iowa Code chapter 669 and Iowa Code section 679A.19.

9.11.1 Public Agency agrees to defend, indemnify and hold DAS/SAE and the State of Iowa, its officers, employees and agents, harmless from any and all liabilities, damages, losses, demands, causes of action, claims, settlements, judgments, costs, expenses, and attorney fees, including a reasonable cost attributed to the services of the Attorney General, related to or arising from any violation of this Agreement, any negligent or intentional act or omission of Public Agency, it officers, employees, or agents, and any failure of Public Agency, it officers, employees, or agents to comply with all applicable local, state, and federal laws, rules, and regulations.

9.11.2 Consistent with Article VII, Section I of the Iowa Constitution, Iowa Code chapter 669, and other applicable law, DAS/SAE agrees to defend and indemnify Public Agency and hold Public Agency harmless against all losses, costs, damages, expenses, attorney fees, claims, demands, causes of action, judgments, and settlements arising out the negligence or wrongful acts or omissions of DAS/SAE or its officers, employees or agents in the performance of this Agreement. DAS/SAE shall not defend, indemnify or hold harmless Public Agency or its officers, employees, or agents for any acts or omissions of any type attributable to Public Agency or its officers, employees, or agents.

Section 10. Execution

This MOU is fully executed by the following signatures:

IOWA DEPARTMENT OF ADMINISTRATIVE SERVICES:

________________________________ ____________________

Janet E. Phipps Burkhead, Director
Iowa Department of Administrative Services

Date

PUBLIC AGENCY:

________________________________ ____________________

Authorized Representative

Date

____

Public Agency

____

Printed Name of Authorized Representative

____

Title

Information

Subject

Lineman Hiring Process

Information

For several years now it has been known there would be significant turnover in the electric department simply due to our tenured workforce. In the last few months, the electric superintendent and one of three crew chiefs have retired and it is expected that within the next year a second crew chief will announce his retirement and so staff feels it is prudent to begin addressing the matter sooner rather than later.

To fill the current crew chief position, Line Mechanic Jason Henle has been promoted. Looking ahead to the next crew chief retirement, it is likely that position will also be filled from within and so it is important that we prepare for that transition now. Traditionally we have hired linemen at the apprentice level for a variety of reasons, but given that program is a minimum of four years to complete and we currently have two apprentices who will not yet be eligible to be on-call or perform other journeyman level tasks, staff is recommending hiring a journeyman lineperson to replace Jason. Reasons to hire at the journeyman level include:

• Experience – Already completed an apprenticeship program.
• Independence – Able to work on projects without supervision including on-call status.
• Cost – Even though a journeyman is more expensive up front, they can make up the difference in productivity.

Attached to this agenda item is a benefit package comparison for hiring a journeyman vs an apprentice. Also included is a chart that gives an overall picture of current staffing, years of service and retirement eligibility.

Financial Impact

N/A

Staff Recommendation

Chris Longer, Mike Metcalf, Roxanne Hunerdosse and two board members met to discuss staffing in the electric department shortly after the crew chief retirement. Staff is recommending posting for both a Journeyman Lineman and an Apprentice to fill the immediate vacancy and to prepare for other eligible retirements within the next five years.

Attachments

Compensation & Benefits Comparison

Workforce Planning Chart

Employee Compensation & Benefits
2015-16

Line Apprentice

Employee Base Salary - R 25-1	***$***	***46,279***
$22.249/Hour		

Compensation			**Benefits**		
FICA/Medicare	$	3,540	Deferred Compensation	$	-
IPERS - Regular	$	4,133	Health and RX Insurance - Family	$	15,642
	$	7,673	Health Reimbursement Arrangement	$	1,300
			Life, AD&D,Long Term Disability	$	160
			Short-Term Disability	$	185
			Wellness	$	300
				$	17,587

Wage & Benefits Hourly Rate	***$***	***34.394***
Wage & Benefit Total Package	***$***	***71,539***

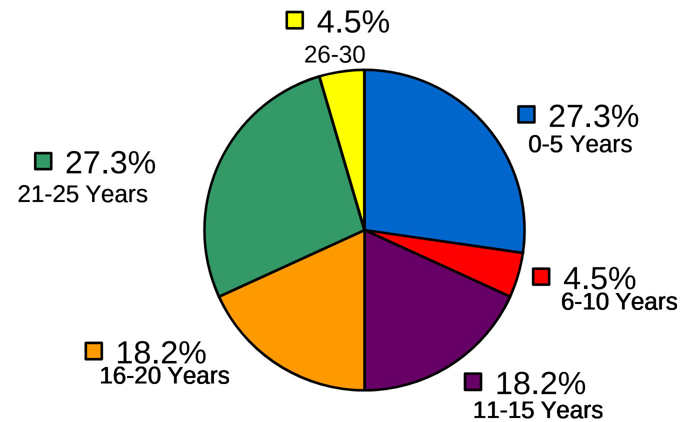
Line Journeyman

Employee Base Salary - R 26-6	***$***	***59,064***
$28.396/Hour		

Compensation			**Benefits**		
FICA/Medicare	$	4,518	Deferred Compensation	$	-
IPERS - Regular	$	5,274	Health and RX Insurance - Family	$	15,642
	$	9,793	Health Reimbursement Arrangement	$	1,300
			Life, AD&D,Long Term Disability	$	214
			Short-Term Disability	$	185
			Wellness	$	300
				$	17,641

Wage & Benefits Hourly Rate	***$***	***41.585***
Wage & Benefit Total Package	***$***	***86,498***

Employees Eligible for Retirement Under the IPERS Rule of 88



Classification:	0-5 Years	6-10 Years	11-15 Years	16-20 Years	21-25 Years	26-30 Years	
General Manager							
Administrative Staff		1	1	1			
Electric Superintendent							
Crew Chief	2		1				
Journeyman Lineman	1				2		
Apprentice				1	1		
Storekeeper					1		
Generation Operator			1	1			
Meter Reader	1				1		
Water Superintendent	1						
Water Operator	1		1	1	1	1	
	6	1	4	4	6	1	22