FORT PIERRE
MUNICIPAL UTILITIES

ELECTRIC RATE STUDY

MISSOURI RIVER
ENERGY SERVICES®

NOVEMBER 2008

MISSOURI RIVER ENERGY SERVICES®

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November 18, 2008

Fort Pierre City Council
8 East 2nd Avenue
Fort Pierre, SD 57532

Members of the Fort Pierre City Council:

Missouri River Energy Services (MRES) is pleased to submit this electric rate study report for Fort Pierre. This study had four principal objectives:

- To determine whether estimated total revenues will be sufficient to cover estimated revenue requirements and provide a reserve for replacements and contingencies
- To determine the cost to serve each customer class
- To design retail rates for the various classes
- To review the competitive position of Fort Pierre through utility rate comparisons

The proposed rates were designed to recover increasing operating costs and planned capital expenditures while building reserves above Fort Pierre's targeted minimum level. Section 5 of this report contains all of the recommendations, **but further adjustments to the rates may be necessary in future years if the system characteristics or financial needs of the utility change drastically.**

MRES appreciated the opportunity to prepare this study for Fort Pierre Municipal Utilities and would like to thank your staff for its valuable assistance.

Respectfully submitted,

Missouri River Energy Services

FORT PIERRE MUNICIPAL UTILITIES
ELECTRIC RATE STUDY
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This rate study was completed in accordance with the agreed upon terms as set forth in the Proposal Letter and Exhibit A, Scope of Services between Missouri River Energy Services and its member, Fort Pierre. In completing this study, Missouri River Energy Services has relied on the data and materials provided by Fort Pierre and others to be accurate, and has not independently verified their accuracy. The analysis, conclusions, and recommendations contained in this report constitute the opinions of Missouri River Energy Services based on the data and materials provided. Final responsibility for the implementation of the recommendations in this report rests with the staff and governing board of Fort Pierre.

EXECUTIVE SUMMARY

Missouri River Energy Services (MRES) has analyzed the revenue requirements, costs of service, and current electric rates of Fort Pierre for the purpose of assisting staff in proposing new rates. The primary reasons for the study were the need to evaluate the adequacy of projected revenues and reserves and the need to determine if each class is paying an appropriate share of the costs. Fort Pierre's electric rates were last adjusted in January 2008.

The system annual peak demand, total annual wholesale power billing demand, and energy requirements (MWh=1,000 kWh), as shown in the table below, are expected to increase in the long-term by an annual average of around 1.2% during the study period. A higher growth rate is expected in 2008 and 2009 in part due to new business loads. The projections are discussed in Section 1.

Historical and Forecasted Demand and Energy Requirements

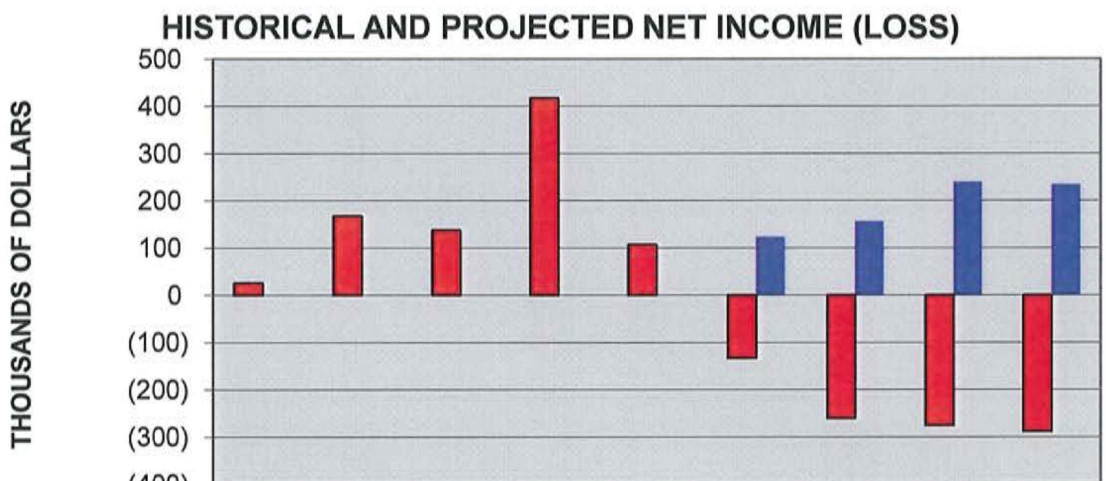
	Year	Peak Demand (kW)	Total Wholesale Billing Demand (kW)	% Change	Wholesale Energy (MWh)	% Change
Historica	2004	4,841	48,196		21,720	
	2005	5,342	51,000	5.8%	23,343	7.5%
	2006	5,558	51,803	1.6%	23,761	1.8%
	2007	5,754	55,529	7.2%	24,514	3.2%
Forecasted	2008	5,139	53,299	(4.0%)	25,013	2.0%
	2009	5,563	56,262	5.6%	25,558	2.2%
	2010	5,626	56,895	1.1%	25,846	1.1%
	2011	5,695	57,597	1.2%	26,165	1.2%
	2012	5,764	58,298	1.2%	26,483	1.2%

Based on the assumptions described in Section 2, MRES has projected the operating results and cash reserves as shown on the graphs on the next page. Cash reserves exclude funds restricted by bond covenants. The projections indicate rate increases are necessary to avoid cash deficits in 2009 and beyond. The projections under proposed rates assumed rate increases of 15% in 2009, 7% in 2010, and 4% in 2011.

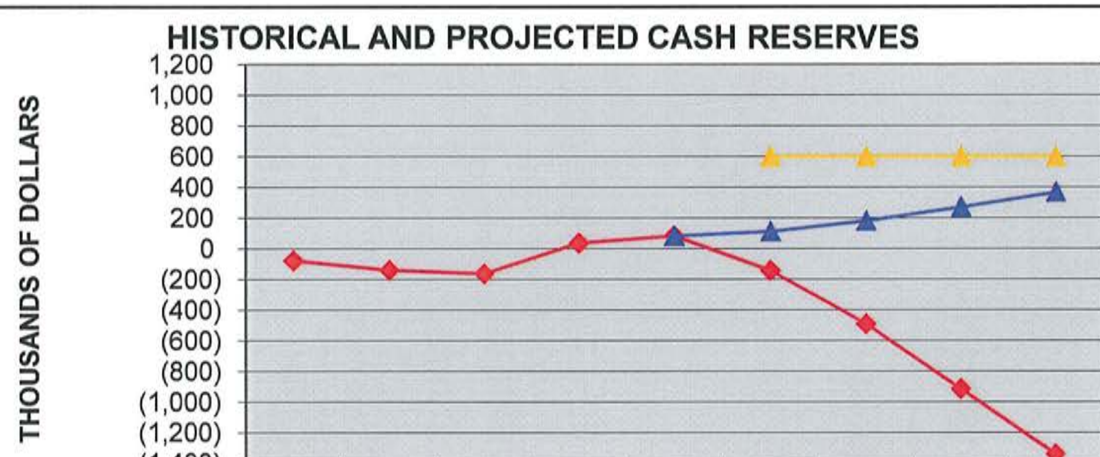
Changing power supply costs will have an impact on operating results. The Western Area Power Administration (WAPA) has increased rates a total of over 70% from 2004 to 2008 due to prolonged drought conditions. WAPA has proposed an increase of 19.8% in 2009, and an additional increase of 9% has been assumed for 2010. In 2009 alone, Fort Pierre will pay approximately $160,000 in drought-related costs, or 9.2% of metered sales revenue.

MRES has increased its rates by a total of 18.6% in 2007 and 2008. In addition, the MRES Board of Directors recently approved an increase of 18.4% for 2009. The study has also assumed an additional MRES increase of 9% in 2010. The table on the next page shows the estimated wholesale power expenses, which make up approximately 60% of the total operating expenses. The wholesale power cost assumptions are discussed in greater detail in Section 2.

Estimated Wholesale Power Expenses				
Year	WAPA	MRES	Total Expense	Percentage Increase
2008	$342,405	$581,759	$924,164	11.5%
2009	$409,852	$744,342	$1,154,194	24.9%
2010	$446,459	$833,212	$1,279,671	10.9%
2011	$441,848	$862,201	$1,304,049	1.9%
2012	$442,559	$881,722	$1,324,281	1.6%



	2004	2005	2006	2007	2008	2009	2010	2011	2012
Current Rates	26	168	138	417	107	(133)	(260)	(275)	(288)
Proposed Rates						124	157	240	235



	2004	2005	2006	2007	2008	2009	2010	2011	2012
Current Rates	(78)	(139)	(163)	37	83	(144)	(492)	(916)	(1,342)
Proposed Rates					83	112	181	271	368
Target Level						600	600	600	600

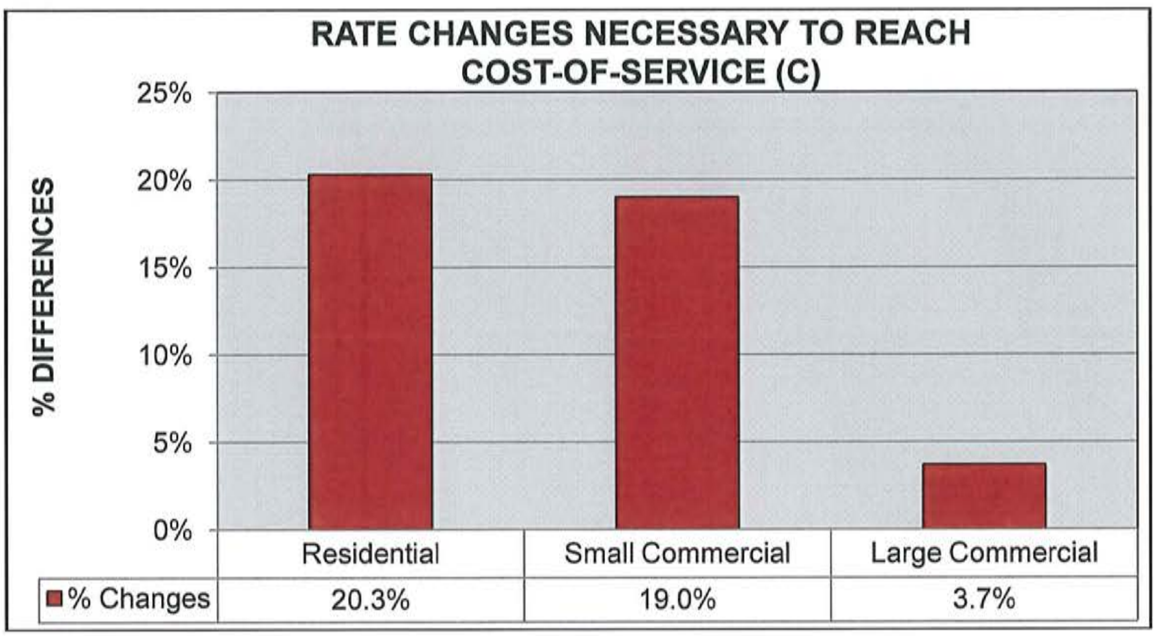
*Reserves exclude funds restricted by bond covenants

The cost-of-service study, discussed in Section 3, indicated that Large Commercial customers are paying more than the costs of providing service to them, while Residential and Small Commercial customers are paying less than the costs of service.

Percentage Comparison of Revenues and Allocated Costs				
Customer Classification	**Percentage of Allocated Costs**	**Percentage of Revenues**	**Increase/ Decrease (A)**	**Including Overall Rate Increase (B)**
Residential	54.6%	52.2%	**4.7%**	**20.3%**
Small Commercial	17.7%	17.1%	**3.5%**	**19.0%**
Large Commercial	27.7%	30.7%	**-9.9%**	**3.7%**
Total	100.0%	100.0%	**0.0%**	**15.0%**

(A) The percentages in this column do not represent proposed rate increases or decreases but rather represent the results of the cost-of-service study in percentage terms based on the Test Year data.

(B) This column represents the results of the cost-of-service study in percentage terms, and adding an overall 15% rate increase.



(C) The changes represent the results of the cost-of-service study in percentage terms, and adding the overall 15% rate increase.

Proposed Rate Recommendations

Rate increases will be necessary over the next three years due to rising wholesale power and operations costs. A portion of the increases is also necessary to build cash reserves.

Implementing the proposed rates shown on the next page would result in a 15% overall increase in 2009. Based on current projections, additional increases of 7% in 2010 and 4% in 2011 will likely be necessary. The Appendix shows the proposed 2010 and 2011 rates, which may need to be changed during each year's budget process based on revenue requirements.

The recommendations include a proposed rate structure change in the Residential class. From June through September, Residential customers would pay a flat energy rate for all usage to reflect higher wholesale power costs during those months. Residential power usage patterns in the summer tend to increase average power costs for the utility. In the future, Fort Pierre may wish to consider seasonal rates for all customer classes. Meanwhile, in October through May, customers would be charged a lower rate for monthly energy over 750 kWhs, which is primarily electric heating usage for many customers.

The other proposed rate structure change is to implement a flat energy rate for all usage by Small Commercial customers. Currently, approximately 75% of usage is billed in the last energy rate block, which includes usage over 500 kWhs per month. This change would simplify the rate schedule and better reflect the costs of providing service.

As a result of the 2009 proposed rates, a Residential customer with usage of 1,000 kWhs per month would see an increase of $15.40 per month from June through September, and $12.15 per month from October through May. The average increase at 1,000 kWhs would be $13.23 per month, or 18.2%. The rate proposals and customer impacts are discussed in greater detail in Section 5.

Other Observation

Prior to 2003, the City of Fort Pierre was charged a discounted rate for usage at various city facilities. In 2003, these meters were moved to the full commercial rates. Consistent with this change, MRES suggests that the electric utility begin billing the City of Fort Pierre for street lighting at a rate of $0.08 per kWh. Currently, there is no charge, but most utilities bill for street lighting so that the utility receives revenue for all electric service that is provided. The rate would recover not only the cost of power but also the costs of providing and maintaining street lights and poles, along with a small portion of distribution system costs. The annual revenues would be approximately $48,000 based on estimated street lighting energy of 600,000 kWhs. The utility could then either retain the additional revenues or transfer the amounts back to the City at the end of the year at the Council's discretion.

The rate study has assumed no additional net revenues from street lighting at this time. If this change is made in the future, the proposed rates could be reduced by approximately 2%, or these amounts could be used to build electric utility cash reserves.

Current and Proposed Rates				
Customer Class	**Rate Components**	**Current Rates**	**2009 Proposed Rates**	**2009 Percent Change (A)**
	Overall Increase		**15.0%**	
Residential	Customer Charge	$8.00	$9.00	
	Energy Charge – per kWh			
	All Months			18.2%
	0-500 kWh	0.0599		
	Over 500 kWh	0.0517		
	June-September		0.070	
	October –May			
	0-750 kWh		0.070	
	Over 750 kWh		0.057	
Small Commercial	Customer Charge			
	Single Phase	14.00	15.00	
	Three Phase	18.00	20.00	18.6%
	Energy Charge – per kWh			
	0-500 kWh	0.0635		
	Over 500 kWh	0.0568		
	All kWh		0.072	
Large Commercial (Over 25 kW)	Customer Charge	25.00	28.00	
	Energy Charge	0.033	0.033	7.5%
	Demand Charge	9.8483	11.25	
Outside City Limits Surcharge	All kWh	0.0215	0.023	7.0%
Generation Surcharge	All kWh	0.0088	0.009	N/A
Security Lights	Monthly Charge	10.00	10.00	0.0%
Street Lights	Energy Charge – All kWh	No Charge	0.080	N/A

(A) Percentage changes include generation surcharge revenues under current and proposed rates.

Targeted Minimum Reserve Level

Maintaining adequate reserve levels is always important, and especially in the electric utility industry since it is very capital intensive. In a study of 64 area municipal utility financial statements, MRES found that the median level of cash as a percentage of operating revenues was 55% for these utilities. Since the electric utility had a cash deficit at the end of three of the past four years, Fort Pierre had the lowest cash reserves among those 64 utilities.

MRES recommends a targeted minimum reserve level of $600,000, which would be about 24% of 2012 operating revenues under proposed rates. This total excludes restricted bond reserves.

Targeted Minimum Reserve Level (continued)

Maintaining at least this reserve level would provide for unanticipated expenses or contingencies that may arise. MRES recommends reserves for the following purposes:

- Capital improvements and equipment replacement fund would include a minimum of $150,000, which is equal to two years of average cash outlay.

- Operations fund would include $350,000, or two months of operating expenses. This fund would include the cash needed for daily operating costs, including paying the wholesale power bills and payroll.

- Contingencies and emergencies fund would include $100,000 to cover unexpected expenses or lost revenues due to storm damage; bankruptcy or closing of a large customer; substation failure; or other catastrophes. This fund would also pay any expenses until insurance reimbursement or government aid occurs.

SECTION 1 – RATE STUDY INTRODUCTION AND POWER REQUIREMENTS

INTRODUCTION

Fort Pierre Municipal Utilities, under the direction of the City Council, provides electric service to about 1,400 meters.

Missouri River Energy Services (MRES) was engaged to perform a review of Fort Pierre's rates, including an analysis of revenues and revenue requirements for the study period of 2008 to 2012, the allocation of costs to serve each customer class based on a Test Year, and the design of retail rates. The Fort Pierre study was prompted, in part, by the need to evaluate the adequacy of revenues due to rising wholesale power costs. Lastly, the study was to determine if each class is paying an appropriate share of the costs.

WHOLESALE DEMAND AND ENERGY REQUIREMENTS

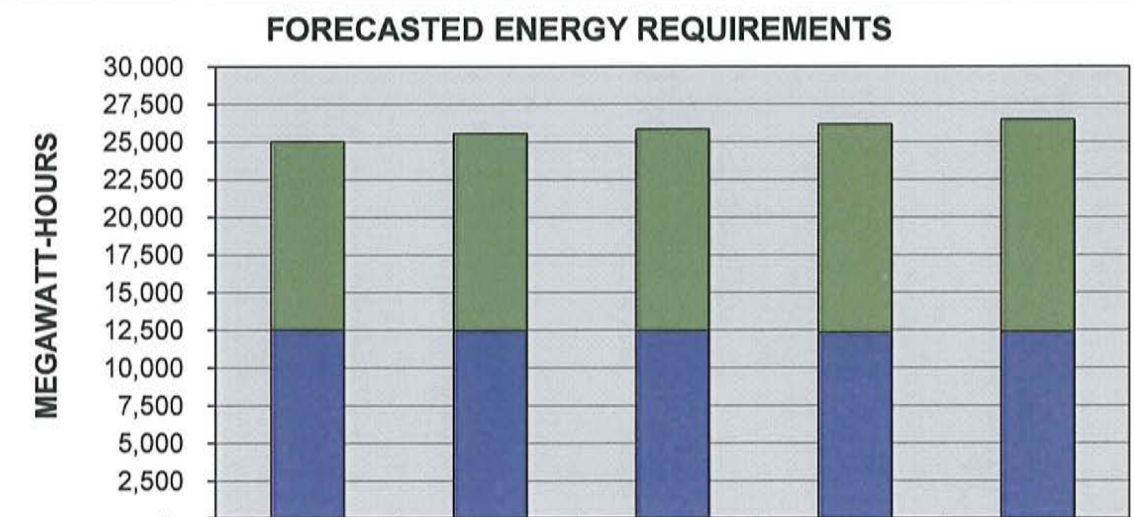
Fort Pierre Municipal Utilities receives a fixed monthly power allocation from the Western Area Power Administration (WAPA), which operates several hydroelectric plants on the Missouri River. Fort Pierre receives all requirements above the WAPA allocation from MRES.

The following table shows the total annual wholesale power billing demand and energy requirements (MWh=1,000 kWh) for Fort Pierre from 2004 to 2012. Demand and energy is measured at the city gate. The system annual peak typically occurs in July or August. Energy requirements have grown by an average of 4.2% per year from 2004 through 2007 as a result of strong growth in all three customer classes. The percentage increases are expected to drop to around 1.2% for 2010 through 2012, although the periodic addition of Large Commercial customers could increase these percentages.

Historical and Forecasted Demand and Energy Requirements

	Year	Peak Demand (kW)	Total Wholesale Billing Demand (kW)	% Change	Wholesale Energy (MWh)	% Change
Historical	2004	4,841 (July)	48,196		21,720	
	2005	5,342 (Aug.)	51,000	5.8%	23,343	7.5%
	2006	5,558 (July)	51,803	1.6%	23,761	1.8%
	2007	5,754 (July)	55,529	7.2%	24,514	3.2%
Forecasted	2008	5,139	53,299	(4.0%)	25,013	2.0%
	2009	5,563	56,262	5.6%	25,558	2.2%
	2010	5,626	56,895	1.1%	25,846	1.1%
	2011	5,695	57,597	1.2%	26,165	1.2%
	2012	5,764	58,298	1.2%	26,483	1.2%

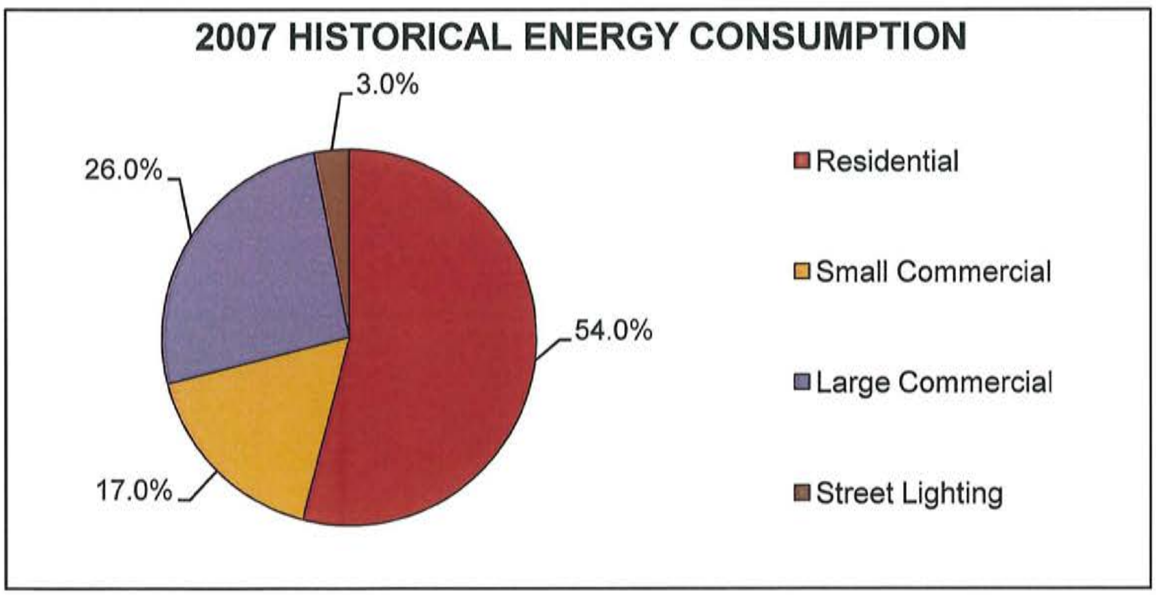
During the last four years, Fort Pierre has purchased between 42% and 49% of its energy requirements from MRES. That percentage is forecasted to increase to 53% by 2012 due to load growth and the anticipated loss of up to 1% of the WAPA energy (and demand) allocation on January 1, 2011. The chart below shows the forecasted energy requirements broken down between WAPA and MRES.



	2008	2009	2010	2011	2012
MRES (MWh)	12,508	13,092	13,380	13,829	14,108
WAPA (MWh)	12,505	12,466	12,466	12,336	12,375

HISTORICAL ENERGY CONSUMPTION BY CLASS

The Fort Pierre historical energy consumption by class for 2007 is shown in the pie chart below. The breakdown of MWhs consumed shows the Residential class used 54% of the total energy used, or about 986 kWhs per month per customer. The average consumption by Residential customers in other MRES member communities is approximately 42%.



PROJECTED CUSTOMER CLASS AND ENERGY GROWTH

Based on discussions with staff, Fort Pierre anticipates the following additional customers per year between 2008 and 2012:

- Residential – 15
- Small Commercial – 2
- Large Commercial – 1

Energy consumption in most classes is expected to remain stable or increase up to 1.5% per year. Higher Large Commercial growth of 6% per year is expected in 2008 and 2009 due to the addition of two new customers.

SECTION 2 - PROJECTED OPERATING RESULTS

Missouri River Energy Services (MRES) worked with Fort Pierre staff to estimate the annual revenues and the expenditures, "revenue requirements", for the five-year study period of 2008 to 2012. Revenue requirements must be compared to revenues to determine whether the electric utility will recover all of its costs and provide a margin for a reserve for system replacements, contingencies, and rate stabilization. The analyses and assumptions used in developing these estimates are described below. Exhibits 2-A and 2-B at the end of this section present the projected operating results and cash reserves.

ESTIMATED REVENUES

Estimated revenues consist of electric sales, generation capacity payments, and other operating revenues. Electric sales were estimated based on current rates and using the wholesale demand and energy forecasts and the customer class growth projections discussed in Section 1. Other operating revenues include connection fees, penalties, and sales of supplies and materials, and these revenues are expected to remain stable at approximately $52,000 per year from 2009 through 2012.

MRES capacity payments are based on the Dedicated Capacity Agreement with MRES and the payment schedule. Total revenues from the agreement during the study period are estimated at approximately $926,000.

ESTIMATED REVENUE REQUIREMENTS

The revenue requirements of the electric utility consist of purchased power and transmission expenses; other operating expenses, non-operating revenues and expenses, and capital expenditures. Revenue requirements projections were based on historical operating statements from 2004 through 2007; the 2008 and 2009 budgets; estimated purchased power expenses from the MRES forecast; and discussions with Fort Pierre staff.

Purchased Power and Transmission Expenses

The estimated wholesale power expenses are based on actual and projected Western Area Power Administration (WAPA) and MRES rates during the study period and forecasts by MRES of system demand and energy requirements, as outlined in Section 1. WAPA has been increasing its rates since 2004 and most recently increased rates by 25.3% on January 1, 2008.

According to WAPA, the major factors contributing to the rate increases are (1) the reduced hydropower generation due to several drought years, which have necessitated more purchases in the wholesale market and have decreased non-firm energy sales, (2) increased operating and maintenance expenses, (3) increased capital investments, (4) and interest expense on deficits from years in which revenues did not cover expenses.

The 2008 WAPA composite rate of 2.5 cents per kWh separates normal operating and maintenance costs from drought-related costs that have accumulated. Approximately 36%, or 0.9 cents per kWh, of the composite rate is due to the repayment of drought deficits. The drought portion of the rate will be analyzed annually and adjusted each January, if needed, up to 0.2 cents per kWh.

WAPA has proposed a composite rate increase from 2.45 cents per kWh in 2008 to 2.93 cents per kWh, or a 19.8% increase. Due to unpredictable water conditions, purchased power prices, and possible changes in transmission costs, WAPA has not finalized the necessary rate change for 2010. However, MRES assumed a composite rate increase of 0.27 cents to 3.2 cents per kWh, or 9%, in 2010. No further WAPA increases have been assumed for 2011 and 2012.

WAPA Actual and Projected Wholesale Demand and Energy Rates

Year	Demand Rate ($/kW-mo)	All Energy ($/MWh)
2008 (Actual)	$5.65	$13.99
2009 (Proposed)	$6.80	$16.71
2010-2012 (Projected)	$7.40	$18.21

Since 2004, MRES has seen several operating expenses significantly increase due to a variety of factors which has resulted in recent wholesale power rate increases. Rail transportation rates for shipping coal from the mine to the Laramie River Station power plant more than doubled since October 2004 and continue to increase annually. In the winter of 2006/2007, the widespread Nebraska ice storms that destroyed over 1,100 major transmission line structures resulted in MRES incurring significant replacement power costs, including operating higher-cost generation resources.

Most recently, other cost pressures include increasing costs of purchasing coal, higher ongoing purchased power costs, lower power sales on the open market, and the need to replenish reserves drawn down in 2006, 2007, and 2008. As a result, the MRES Board of Directors (Board) approved a rate increase of 18.4% for January 1, 2009. Furthermore, due to the need to continue replenishing reserves and due to other cost pressures, the study has assumed an additional increase of 9% in 2010, which will be discussed at the MRES Finance Committee meeting planned for February 2009.

In September 2008, the MRES Board approved a long-range plan to change the wholesale power rate structure. In 2009 and 2010, the plan includes moving the Tier 2 demand rate closer to the Tier 1 demand rate. By 2011, the Board's intention is to implement seasonal demand rates, which would better reflect the power supply costs during each operating season. The planned rate structure changes will likely have an impact on Fort Pierre's wholesale power costs and retail rate structure.

Actual and projected MRES rates used during the study period are shown on the next page.

MRES Actual and Projected Wholesale Rates (A)			
Year	**Tier 1 Demand ($/kW-mo.) (B)**	**Tier 2 Demand ($/kW-mo.) (B)**	**Energy ($/MWh)**
Jan. 1, 2008 (Actual)	$13.95	$8.35	$21.90
Jan. 1, 2009 (Projected)	$15.60	$11.90	$26.50
Jan. 1, 2010 (Projected)	$16.60	$14.75	$29.00
2011 - 2012 (Projected)	$16.25	$16.25	$29.00

(A) Rates are reviewed each year by the MRES Board of Directors. Future rates may be higher than shown above. The 2011 and 2012 demand rates are the possible average rates, although actual rates will vary by season.

(B) The demand rates include the $2.75 per kW-month S-1 transmission charge.

Finally, in April 2008, the MRES Board approved offering the T-1 (Transmission) Agreement along with a Member Transmission Lease (MTL) Agreement to the MRES membership in 2008 and 2009. Both agreements are optional, and the net impact to Fort Pierre's total transmission costs is unknown at this time. Therefore, the study did not assume any changes to Fort Pierre's projected costs. MRES staff will be discussing these agreements in detail with member utilities' staff and governing boards later this year and in 2009. The planned date of implementation for the T-1 and MTL agreements is January 2010.

Total purchased power expenses are expected to increase by an average of 8.4% per year, with higher percentages in 2008 and 2009 as a result of load growth and wholesale power rate increases. These expenses make up about 60% of total operating expenses.

The table below shows the estimated wholesale power expenses based on the forecasted purchases shown in the previous section and the rates in the tables on the previous pages.

Estimated Wholesale Power Expenses				
Year	**WAPA**	**MRES**	**Total Expense**	**Percentage Increase**
2008	$342,405	$581,759	$924,164	11.5%
2009	$409,852	$744,342	$1,154,194	24.9%
2010	$446,459	$833,212	$1,279,671	10.9%
2011	$441,848	$862,201	$1,304,049	1.9%
2012	$442,559	$881,722	$1,324,281	1.6%

The following table breaks down the cost per kWh in cents from the two suppliers. The WAPA and MRES amounts were calculated by dividing the costs by the kWhs purchased from each entity. The total blended costs were divided by total energy purchases.

Estimated Wholesale Power Cost per kWh Purchased by Supplier and Total Blended Cost per kWh Purchased				
Year	**WAPA**	**MRES**	**Total Blended Cost per kWh**	**Percentage Increase**
2008	$0.0274	$0.0465	$0.0370	9.3%
2009	$0.0329	$0.0569	$0.0452	22.2%
2010	$0.0358	$0.0623	$0.0495	9.5%
2011	$0.0358	$0.0624	$0.0498	0.6%
2012	$0.0358	$0.0625	$0.0500	0.4%

Other Operating Expenses

Other operating expenses include personnel services, other current expenses, and depreciation expense. Under personnel services, salaries and wages are expected to increase by 4% per year and health insurance is expected to increase by 8% per year. Other current expenses are expected to increase by 3% per year, and depreciation is based on planned capital expenditures.

Non-Operating Revenues and Expenses

Non-operating revenues and expenses include interest revenue and expense. Interest revenue is estimated at a rate of 3% of cash reserves. Interest expense is discussed next.

Debt-Financed Capital Expenditures

Following is a summary of the four debt issuances current outstanding:

Current Debt Issuances				
Improvement / Issuance	Issuance Date	Final Maturity	Original Principal Amount	Approx. Annual Debt Service
Irv Simmons Substation	1983	2015	$144,858	$6,000
Generation	2002	2019	$3,225,000	$300,000
Equipment (Electric portion)	2004	2010	$55,000	$10,000
Distribution Improvements	2007	2019	$750,000	$83,000
Total				$399,000

Amortization schedules provided by Fort Pierre were used to determine annual payments for each of these issuances. No additional borrowing is expected during the study period.

Revenue-Financed Capital Expenditures

The electrical system improvements and equipment purchases are based on Fort Pierre's capital plans and discussions with staff. The total capital expenditures during the study period of 2008 through 2012 are estimated at approximately $156,000. Funds remaining from the 2007 debt issuance will also be used for distribution reliability improvements in 2008 and 2009.

Exhibit 2-A

Fort Pierre Municipal Utilities
Electric Utility Operating Results
(Current Rates)

	Historical				Estimated				
	2004	2005	2006	2007	2008	2009	2010	2011	2012
Total system retail kWh sales	19,710,830	21,845,155	22,137,072	23,288,659	23,386,831	23,896,759	24,165,628	24,464,069	24,762,063
kWh Growth		10.8%	1.3%	5.2%	0.4%	2.2%	1.1%	1.2%	1.2%
OPERATING REVENUES									
Charges for goods and services	$ 1,128,238	$ 1,296,509	$ 1,346,615	$ 1,559,605	$ 1,711,330	$ 1,742,672	$ 1,762,282	$ 1,783,790	$ 1,805,277
MRES Capacity Payments	136,097	168,077	166,520	174,331	178,800	182,400	186,000	189,600	189,600
Other Operating Revenues	13,291	19,026	135,577	147,706	39,950	51,950	51,950	51,950	51,950
Total Operating Revenues	$ 1,277,625	$ 1,483,612	$ 1,648,712	$ 1,881,642	$ 1,930,080	$ 1,977,022	$ 2,000,232	$ 2,025,340	$ 2,046,827
OPERATING EXPENSES									
Cost of sales	607,522	669,883	712,217	828,909	924,164	1,154,194	1,279,671	1,304,049	1,324,281
Personnel Services	235,643	311,510	278,407	312,361	373,950	384,000	400,024	416,742	434,186
Other current expense	150,643	154,880	256,756	121,989	225,575	259,576	260,565	268,382	276,434
Depreciation Expense	120,591	143,321	148,169	150,489	152,000	173,000	174,000	175,000	176,000
Total Operating Expense	1,114,400	1,279,594	1,395,550	1,413,748	1,675,689	1,970,770	2,114,260	2,164,173	2,210,901
NET OPERATING INCOME (LOSS)	163,225	204,018	253,162	467,894	254,391	6,252	(114,028)	(138,833)	(164,074)
NON-OPERATING REVENUES (EXPENSE)									
Interest Revenue	17,526	13,203	23,307	25,847	16,000	16,000	-	-	-
Loss on Disposal of Fixed Assets	(11,850)	-	-	-	-	-	-	-	-
Interest Expense	(142,933)	(143,033)	(138,092)	(133,445)	(163,700)	(155,283)	(145,879)	(135,713)	(124,424)
Total Non-Operating Rev. (Exp.)	(137,257)	(129,830)	(114,785)	(107,598)	(147,700)	(139,283)	(145,879)	(135,713)	(124,424)
CAPITAL CONTRIBUTIONS	-	94,110	-	56,368	-	-	-	-	-
NET INCOME (LOSS)	$ 25,968	$ 168,298	$ 138,377	$ 416,664	$ 106,691	$ (133,031)	$ (259,907)	$ (274,546)	$ (288,497)
Net Income (Loss) as a % of Oper Rev	2.0%	11.3%	8.4%	22.1%	5.5%	-6.7%	-13.0%	-13.6%	-14.1%

Exhibit 2-B

Fort Pierre Municipal Utilities
Electric Utility Cash Reserves
(Current Rates)

	Historical				Estimated				
	2004	2005	2006	2007	2008	2009	2010	2011	2012
NET INCOME (LOSS)					$ 106,691	$ (133,031)	$ (259,907)	$ (274,546)	$ (288,497)
LESS: Revenue-Financed Capital Expenditures					(10,150)	(32,150)	(10,150)	(64,000)	(40,000)
ADD: Change in Accounts Receivable					20,000	-	-	-	-
LESS: Debt Principal Payments					(222,181)	(234,917)	(251,933)	(260,454)	(273,213)
ADD: Depreciation Expense					152,000	173,000	174,000	175,000	176,000
CHANGE IN AVAILABLE CASH					$ 46,360	$ (227,098)	$ (347,991)	$ (424,000)	$ (425,711)
Beginning of Year Available Cash					36,565	82,925	(144,173)	(492,164)	(916,164)
Change in Available Cash					46,360	(227,098)	(347,991)	(424,000)	(425,711)
END OF YEAR CASH (DEFICIT)	**$ (77,528)**	**$ (139,028)**	**$ (162,626)**	**$ 36,565**	**$ 82,925**	**$ (144,173)**	**$ (492,164)**	**$ (916,164)**	**$ (1,341,874)**
Reserves as % of Oper. Rev.	**-6.1%**	**-9.4%**	**-9.9%**	**1.9%**	**4.3%**	**-7.3%**	**-24.6%**	**-45.2%**	**-65.6%**
Project Fund - 2007 Debt Issuance	-	-	-	$ 655,000	-	-	-	-	-
Debt Service Reserve	331,000	331,000	331,000	331,000	331,000	331,000	331,000	331,000	331,000
Sinking Fund	16,619	14,397	13,205	32,400	32,400	32,400	32,400	32,400	32,400
End of Year Restricted Cash	**$ 347,619**	**$ 345,397**	**$ 344,205**	**$ 1,018,400**	**$ 363,400**	**$ 363,400**	**$ 363,400**	**$ 363,400**	**$ 363,400**

SECTION 3 - COST-OF-SERVICE STUDY

The purpose of this study is to determine the cost of providing service to each customer class so that these costs can be compared to actual customer revenues. The cost-of-service analysis has been based on the following factors:

- Test Year revenue requirements and revenues using current rates
- Total system and customer class demand and energy requirements
- Actual and assumed customer service characteristics
- Information obtained from customer records

Test Year revenue requirements are classified to cost components and allocated to each customer class based upon service characteristics. These allocated costs are then compared to revenues to determine if current rates recover the appropriate level of revenues from each customer class.

CLASSIFICATION OF COSTS

To allocate costs to customer classifications, costs must first be categorized to components. The six cost components and the types of costs assigned to each are as follows:

Coincident Peak Demand Component – The costs of purchasing sufficient power to meet the aggregate demand of all the customers at the time of the system peak. Coincident peak demand costs do not generally vary with the level of energy used. These costs include only capacity-related wholesale power costs.

Energy Component – The costs of supplying electricity to meet customer requirements. These costs will vary directly with the usage of electricity. This includes only the energy portions of the wholesale power bills.

Non-Coincident Peak Demand Component – The costs of operating and maintaining an electric system that will meet the individual peak demands of each customer class, regardless of when this peak occurs. The costs include all local generation costs (offset by generation capacity payments); a portion of administrative salaries, other current expenses, and capital expenditures; and 50% of the following: distribution salaries, distribution related revenues (cost offset), and the reserve for replacements.

Customer Facilities Component – The costs of providing and maintaining transformers, distribution secondary lines, and customer service drops. Customer facilities costs vary directly with the maximum demand of the customer and the type of facilities the customer requires. The costs include a portion of administrative salaries, other current expenses, and capital expenditures; and 50% of the following: distribution salaries, distribution related revenues (cost offset), and the reserve for replacements.

Customer Service Component – The costs associated with billing, collections, and customer assistance. Customer service costs do not vary greatly with peak demand or energy usage of the customer. The costs include all customer billing salaries and a portion of other current expenses.

Metering Component – The costs of reading meters to determine monthly bills and maintaining the meters. The costs include a portion salaries, other current expenses, and capital expenditures.

Indirect Revenues and Expenses

Certain revenues and expenses are not categorized to the six components above but rather are allocated to these components based on direct labor spent on each area and the percentage allocations of other distribution expenses. Allocated in this manner are items such as interest revenue, other revenue, and a portion of other current expenses.

Summary of Classifications

Exhibit 3-A at the end of this section shows the detailed classifications of test year revenue requirements. Purchased power costs make up approximately 62% of the total revenue requirements, while local costs make up the remaining 38% of requirements.

ALLOCATION TO CUSTOMER CLASSIFICATIONS

MRES has determined allocation factors for the Test Year based on actual and assumed customer service characteristics. These allocation factors represent historically accepted ratemaking principles and are based on fully distributed, embedded cost allocation procedures. While these principles may still be useful in establishing a baseline cost level upon which to set rates, it is important to note that in a competitive market some of the allocated costs may not be recovered.

The following summarizes the allocation factors used in the cost-of-service study. See Exhibit 3-B at the end of this section for the development of the factors.

Demand Allocations

Two demand allocators were developed to distribute costs: 12-month coincident peak demand and 12-month non-coincident peak demand. Coincident peak demand is the estimated class demand at the time of the system peak. This factor is used to allocate the wholesale demand costs. The non-coincident peak is the sum of the peaks of the individual customers at the time of the class peak, which may or may not occur at the same time as the system peak. This factor is used to allocate all demand-related distribution costs.

Monthly peak demands for the Large Commercial class were used to estimate demand allocators for these classes. For the non-demand billed classes, demand allocators were based on load research studies for other utilities and the system characteristics of Fort Pierre in relation to the specific classes of service.

Energy Allocations

Energy costs have been allocated based on the estimated energy requirements of each customer class as measured at the inlet to the Fort Pierre distribution system.

The following three allocations utilize weighted percentages that were developed by analyzing the number of customers in each class and the resources used to serve each class. The weighting factors were based on the experience of other utilities and Fort Pierre staff observations.

Customer Facilities Allocations

Customer facilities allocations are based on the complexity and size of the transformers, distribution secondary lines, and service lines used to serve the various customer classes.

Customer Service Allocations

Customer service allocations are based on the amount of labor and materials for customer billing and collection.

Metering Allocations

Metering allocations are based on the time spent reading and maintaining the meters of the various customer classes. These costs vary between customers who have or do not have a demand meter installed.

Based upon the cost classifications and allocation methods described above, MRES has estimated the cost to serve each customer classification during the Test Year. The results are shown on Exhibit 3-C at the end of this section.

Fort Pierre Municipal Utilities
Classification of Test Year Requirements

	Total	Coincident Peak (CP) Demand	Energy	Non-Coincident Peak (NCP) Demand	Customer Facilities (CF)	Customer Service (CS)	Metering (MR)	Basis for Classification
Purchase of Wholesale Power								
Generation	$ 998,289	$ 441,143	$ 557,146					Per Wholesale Billings
Transmission	155,904	155,904						100% CP
Operating Expenses (A)								
Personnel Services								
Distribution	275,627			137,814	137,814			50% NCP, 50% CF
Customer Billing and Assistance	36,124					36,124		100% CS
Metering	21,675						21,675	100% MR
Administrative and General	50,574			20,067	21,740	5,479	3,288	Indirect rev. and exp. allocation factors (C)
Other Current Expenses								
Insurance	18,500			9,250	9,250			100% CS
Professional Fees	1,000			397	430	108	65	Indirect rev. and exp. allocation factors (C)
Testing Services	500			198	215	54	33	Indirect rev. and exp. allocation factors (C)
Shipping Charge	100			40	43	11	7	Indirect rev. and exp. allocation factors (C)
Publishing	250			99	107	27	16	Indirect rev. and exp. allocation factors (C)
Rentals	5,000			2,500	2,500			50% NCP, 50% CF
Repairs & Maintenance	5,000			2,500	2,500			50% NCP, 50% CF
Motor Fuel	9,500			3,750	3,750		2,000	Per expense requirements
Vehicle Repair	4,000			2,000	2,000			50% NCP, 50% CF
Supplies & Materials	120,000			87,750	29,250		3,000	Per expense requirements
Travel & Conferences	1,000			500	500			50% NCP, 50% CF
Training	1,000			500	500			50% NCP, 50% CF
Utilities	4,500			2,250	2,250			50% NCP, 50% CF
Cellular Telephone	500			250	250			50% NCP, 50% CF
Administrative fee	18,313					18,313		100% CS
Public Works Fee	4,213			2,107	2,107			50% NCP, 50% CF
Dues and Fees	2,000			1,000	1,000			50% NCP, 50% CF
Shop Fee	7,250			3,625	3,625			50% NCP, 50% CF
Generation Station	56,950			56,950				100% NCP
Capital Expenditures	450,000			347,316	99,684		3,000	Per capital requirements
Generation Surcharge (B)	(204,964)			(204,964)				100% NCP
MRES Capacity Payments (B)	(182,400)			(182,400)				100% NCP
Distribution-Related Revenues (B)	(38,000)			(19,000)	(19,000)			50% NCP, 50% CF
Other Revenue (B)	(13,950)			(5,535)	(5,997)	(1,511)	(907)	Indirect rev. and exp. allocation factors (C)
Interest Income (B)	(16,000)			(6,349)	(6,878)	(1,733)	(1,040)	Indirect rev. and exp. allocation factors (C)
Reserve for Replacements	75,000			37,500	37,500			50% NCP, 50% CF
Revenue Requirements	$ 1,867,455	$ 597,047	$ 557,146	$ 300,114	$ 325,141	$ 56,872	$ 31,135	

(A) Expenses and revenues are adjusted to level of typical year.
(B) These amounts offset revenue requirements.
(C) Indirect revenue and expenses are allocated based on breakdown of direct labor expenses and classifications of other distribution expenses.

Exhibit 3-B

Fort Pierre Municipal Utilities
Allocation Factors

	Total	Residential	Small Commercial	Large Commercial
DEMAND ALLOCATION FACTORS				
12 Month Coincident Peak (kW)	55,708	29,816	9,856	16,036
Percentage - CP	100%	53.5%	17.7%	28.8%
12 Month Non-Coincident Peak (kW)	63,730	33,256	11,608	18,866
Percentage - NCP	100%	52.2%	18.2%	29.6%
ENERGY ALLOCATION FACTORS				
Annual Energy Requirements (kWh)	23,291,345	12,624,165	3,813,220	6,853,960
Percentage - E	100%	54.2%	16.4%	29.4%
CUSTOMER FACILITIES ALLOCATION FACTORS				
Average number of customers	1,382	1,105	231	46
Weighting factor		1.0	1.8	12.0
Weighted number of customers	2,073	1,105	416	552
Percentage - CF	100%	53.3%	20.1%	26.6%
CUSTOMER SERVICE ALLOCATION FACTORS				
Average number of customers	1,382	1,105	231	46
Weighting factor		1.0	1.0	2.0
Weighted number of customers	1,428	1,105	231	92
Percentage - CS	100%	77.4%	16.2%	6.4%
METERING SERVICE ALLOCATION FACTORS				
Average number of customers	1,382	1,105	231	46
Weighting factor		1.0	1.0	2.0
Weighted number of customers	1,428	1,105	231	92
Percentage - MR	100%	77.4%	16.2%	6.4%

Exhibit 3-C

Fort Pierre Municipal Utilities
Allocation of Revenue Requirements

Classification	Total	Residential	Small Commercial	Large Commercial
Coincident Peak Demand	$ 597,047	$ 319,554	$ 105,629	$ 171,864
Energy	557,146	301,979	91,215	163,952
Non-Coincident Peak Demand	300,114	156,609	54,664	88,841
Customer Facilities	325,141	173,331	65,223	86,587
Customer Service	56,872	44,008	9,200	3,664
Metering	31,135	24,093	5,037	2,006
Revenue Requirements	**$ 1,867,455**	**$ 1,019,574**	**$ 330,967**	**$ 516,913**

SECTION 4 - OTHER ELECTRIC UTILITY RATES

Historically, in a non-competitive environment where utility franchise territories were protected, a utility could reasonably set rates on a cost-of-service plus margin basis, or the utility could diverge from the cost study and set rates according to local policy objectives. However, some portions of the country have now been opened to retail competition. Although retail competition may be many years away in this area, it is still important to understand the competitive position of the utility for other reasons such as economic development. The information in this section is also useful in examining the various methods used by the utilities to recover costs from the different classes.

DIFFERENCE OF RATES AMONG MEMBER UTILITIES

Electric rates vary from utility to utility due to several factors. Some of the differences may be explained by the following factors:

- The percentage of power purchased from the Western Area Power Administration in comparison to the power purchased from Missouri River Energy Services (MRES)
- The cost of transmission for wheeling power from the generation source to the city gate
- The equitability of the rates across the various customer classes
- The blend of retail customers, such as the percentage of industrial energy sales to the percentage of residential and small commercial sales
- The percentage of revenues that is transferred to other non-electric funds
- The amount of expenses that may be subsidized by other utilities, for example, the electric utility paying for other city utilities' labor and / or other expenses
- The amount of funds spent in recent years on capital improvement projects, which correlates to the condition and reliability of the distribution system
- The amount of annual debt service, along with the covenants and restricted reserves
- The level of cash reserves and the governing board's philosophy towards reserves

RATE CLASSES INCLUDED IN THE COMPARISONS

To compare Fort Pierre to other utilities, MRES chose rates that would be charged to customers in the Residential, Small Commercial, and Large Commercial classes. The rates chosen were the basic rates offered by the utilities that would be applicable to the majority of the customers in the classes. These rates are not representative of all the different types of rates that are available.

UTILITIES INCLUDED IN THE COMPARISONS

MRES chose the rates of four investor-owned utilities, four municipal utilities, and one local rural electric cooperative for comparison purposes. For utilities that bill an energy adjustment, the factors are based on the average of the 12 monthly adjustments for 2007.

- Montana-Dakota Utilities (South Dakota rates)
  Bismarck, North Dakota

- NorthWestern Corporation (South Dakota rates)
  Huron, South Dakota

- Otter Tail Power (South Dakota rates)
  Fergus Falls, Minnesota

- Xcel Energy (South Dakota rates)
  Sioux Falls, South Dakota

- Beresford Municipal Utilities
  Beresford, South Dakota

- Flandreau Municipal Utilities
  Flandreau, South Dakota

- Pierre Municipal Utilities
  Pierre, South Dakota

- Winner Municipal Utilities
  Winner, South Dakota

- West Central Electric Cooperative
  Murdo, SD

Residential Rates

Utility	Monthly Customer Charge	Energy Charge (per kWh)	Energy Block (kWh)	Energy Adjustment (per kWh)
Ft. Pierre	$8.00	$0.05990 0.05170 0.00880	0-500 Over 500 Generation Surcharge	$-
Montana-Dakota Utilities	6.00	0.09210 0.08504 0.06964	0-450 451-750 Over 750	0.00669
NorthWestern Corporation	5.00	 0.06146 0.06046 0.05446 0.04346 0.02046 0.004628 0.002865	Base Charges: 0-200 201-800 801-1,000 1,001-1,200 Over 1,200 Plus: All (Delivered Cost of Energy) All (Ad Valorem Taxes)	0.02048
Otter Tail Power Company	5.80	0.07579 0.06453 0.05129	0-200 201-1,000 Over 1,000	0.01185
Xcel Energy	8.55	0.07250 0.06260 0.05750 0.04280	All (June – Sep.) 0-1,000 (Oct. – May) Over 1,000 (Oct. – May) Space Heating Over 1,000 (Oct. – May)	0.01740
Beresford	10.80	0.07980	All	-
Flandreau	9.40	0.05720	All	-
Pierre	8.50	0.05900	All	-
Winner	10.50	0.06800	All	-
West Central Electric Cooperative	-	0.20000 0.07800 0.06800 0.06000	0 - 150 151 - 350 351 - 500 Over 500	0.00300

Small Commercial Rates

Utility	Monthly Customer Charge	Energy Charge (per kWh)	Energy Block (kWh)	Energy Adjustment (per kWh)
Ft. Pierre				$-
Single-phase	$14.00	$0.06350	0-500	
Three-phase	18.00	0.05680	Over 500	
		0.00880	Generation Surcharge	
Montana-Dakota Utilities	12.00	0.08173	0-2,000	
		0.06006	2,001-10,000	0.00669
		0.05441	Over 10,000	
		-	0-10 kW	
		5.00	Over 10 kW	
NorthWestern Corporation	8.00		Base Charges:	
		0.08310	0-200	0.02048
		0.07310	201-1,000	
		0.07310	Over 1,000 (June-Sept)	
		0.05810	Over 1,000 (Oct-May)	
			Plus:	
		0.00357	All (Delivered Cost of Energy)	
		0.00413	All (Ad Valorem Taxes)	
Otter Tail Power Company	6.00	0.08275	0-1,000	
		0.07141	1,001-2,000	0.01185
		0.05237	Over 2,000	
		0.04268	All kWh in excess of 200 per kW	
		2.15	All kW over 10 kW	
Xcel Energy	7.25	0.06830	All (June – Sep.)	0.01740
		0.05830	All (Oct. – May)	
Beresford	16.25	0.07250	All	-
Flandreau	16.65	0.06140	All	-
Pierre	16.00	0.06300	All	-
Winner	15.00	0.07250	All	-
West Central Electric Cooperative	-	0.20000	0-150	0.00300
		0.09200	151-2,500	
		0.06000	Over 2,500	

Large Commercial Rates

Utility	Monthly Service Charge	Demand Charge (per kW)	Demand Block (kW-mos.)	Energy Charge (per kWh)	Energy Block (kWh)	Energy Adjustment (per kWh)
Ft. Pierre	$25.00	$9.8483	All	$0.03300 0.00880	All Generation Surcharge	$-
Montana-Dakota Utilities Over 50 kW	15.00	5.00	All	0.06262 0.04937 0.04467	0-2,000 2,001-10,000 Over 10,000	0.00669
Over 200 kW	20.00	4.25	All	0.03189	All	0.00669
NorthWestern Corp. Under 100 kW	-	6.13 1.09 0.675	All Plus: All (Delivered Cost of Energy) All (Ad Valorem Tax)	0.05358 0.03658 0.02158 0.01158	0-100 kWh per kW 101-400 kWh per kW 401-500 kWh per kW Over 500 kWh per kW	0.02048
Over 100 kW	-	6.13 5.43 4.73 1.09 0.675	0-100 101-500 Over 500 Plus: All (Delivered Cost of Energy) All (Ad Valorem Tax)	0.03258 0.01558 0.01058 0.00558	0-100 kWh per kW 101-400 kWh per kW 401-500 kWh per kW Over 500 kWh per kW	0.02048
Otter Tail Power Primary	25.50	6.75 4.85	0-100 Over 100	0.03362 0.02449	0-360 kWh per kW Over 360 kWh per kW	0.01185
Secondary	25.50	7.05 5.15	0-100 Over 100	0.03415 0.02498	0-360 kWh per kW Over 360 kWh per kW	0.01185
Xcel Energy Primary	15.25	8.55 5.94	June-Sep. Oct.-May	0.03030 (0.0055)	All Over 360 kWh per kW	0.01740
Secondary	15.25	9.35 6.74	June-Sep. Oct.-May	0.03090 (0.0055)	All Over 360 kWh per kW	0.01740
Beresford	26.40	11.29	All	0.03750	All	-
Flandreau	41.60	9.56	All	0.02700	All	-
Pierre	25.00	8.00	All	0.03000	All	-
Winner	25.00	7.30	All	0.04400	All	-
West Central Electric Cooperative	-	-	All	0.20000 0.09000 0.07500 0.06000	0-150 151-2,500 2,501 – 5,000 Over 5,000	0.00300

SECTION 5 - PROPOSED RATES

Several factors were considered in determining the proposed rates:

- Current rates
- Projected operating results (Section 2)
- Costs to serve each customer class (Section 3)
- Other utility rates (Section 4)
- Fort Pierre Municipal Utilities policies and objectives

RATE DESIGN

Rate increases will be necessary over the next three years due to rising wholesale power and distribution costs. A portion of the increases is also necessary to build cash reserves. **Implementing the proposed rates shown on the next page would result in a 15% overall increase in 2009. Based on current projections, additional increases of 7% in 2010 and 4% in 2011 will likely be necessary.** The Appendix shows the proposed 2010 and 2011 rates, which may need to be changed during each year's budget process based on revenue requirements.

Proposed Rate Recommendations

1. Increase the monthly customer charges for all three rate classes. The customer charge, which does not include any kWh usage, recovers the costs of serving customers in areas such as meter reading, meter maintenance, billing and record keeping, along with a portion of facilities costs.

2. Implement seasonal energy rates in the Residential class. From June through September, Residential customers would pay a higher energy rate to reflect higher wholesale power costs during those months. Residential power usage patterns in the summer tend to increase average power costs for the utility. In the future, Fort Pierre may wish to consider seasonal rates for all customer classes. In the months of October through May, customers would be charged a lower rate for monthly usage over 750 kWhs. Much of the usage above 750 kWhs is by customers with electric heating who often have a higher load factor and thus a lower cost of service than other Residential customers. This lower rate would also keep electric rates more competitive with other heating sources.

3. Charge a flat energy rate for all usage by Small Commercial customers. Currently, approximately 75% of usage is billed in the last energy rate block, which includes usage over 500 kWhs per month. This change would simplify the rate schedule and better reflect the costs of providing service.

4. Increase the Residential and Small Commercial rates by greater percentages than the Large Commercial rates. Both the cost-of-service study discussed in Section 3 and the rate comparisons discussed later in this section indicate that Large Commercial customers are paying more than they should based on the costs of serving them and based on what they would pay to other area utilities.

As a result of the 2009 proposed rates, a Residential customer with usage of 1,000 kWhs per month would see an increase of $15.40 per month from June through September, and $12.15 per month from October through May. The average increase at 1,000 kWhs would be $13.23 per month, or 18.2%.

Most Small Commercial customers would see an increase of 17% to 21% in 2009, with customers using more energy seeing slightly higher increases.

Finally, Large Commercial customers would see increases of 5% to 12% in 2009. Customers with higher load factors would have a smaller increase. Load factor is the relationship between the peak demand of the customer and quantity of energy usage. A higher load factor indicates more consistent and efficient use of power and the distribution system. (Most Fort Pierre Large Commercial customers have average load factors between 25% and 60%).

Current and Proposed Rates

Customer Class	Rate Components	Current Rates	2009 Proposed Rates	2009 Percent Change (A)
	Overall Increase		**15.0%**	
Residential	Customer Charge	$8.00	$9.00	
	Energy Charge – per kWh			
	All Months			18.2%
	0-500 kWh	0.0599		
	Over 500 kWh	0.0517		
	June-September		0.070	
	October –May			
	0-750 kWh		0.070	
	Over 750 kWh		0.057	
Small Commercial	Customer Charge			
	Single Phase	14.00	15.00	
	Three Phase	18.00	20.00	18.6%
	Energy Charge – per kWh			
	0-500 kWh	0.0635		
	Over 500 kWh	0.0568		
	All kWh		0.072	
Large Commercial (Over 25 kW)	Customer Charge	25.00	28.00	
	Energy Charge	0.033	0.033	7.5%
	Demand Charge	9.8483	11.25	
Outside City Limits Surcharge	All kWh	0.0215	0.023	7.0%
Generation Surcharge	All kWh	0.0088	0.009	N/A
Security Lights	Monthly Charge	10.00	10.00	0.0%
Street Lights	Energy Charge – All kWh	No Charge	0.080	N/A

(A) Percentage changes include generation surcharge revenues under current and proposed rates.

Other Observation

Prior to 2003, the City of Fort Pierre was charged a discounted rate for usage at various city facilities. In 2003, these meters were moved to the full commercial rates. Consistent with this change, MRES suggests that the electric utility begin billing the City of Fort Pierre for street lighting at a rate of $0.08 per kWh. Currently, there is no charge, but most utilities bill for street lighting so that the utility receives revenue for all electric service that is provided. The rate would recover not only the cost of power but also the costs of providing and maintaining street lights and poles, along with a small portion of distribution system costs. The annual revenues would be approximately $48,000 based on estimated street lighting energy of 600,000 kWhs. The utility could then either retain the additional revenues or transfer the amounts back to the City at the end of the year at the Council's discretion.

The rate study has assumed no additional net revenues from street lighting at this time. If this change is made in the future, the proposed rates could be reduced by approximately 2%, or these amounts could be used to build electric utility cash reserves.

Targeted Minimum Reserve Level

Maintaining adequate reserve levels is always important, and especially in the electric utility industry since it is very capital intensive. In a study of 64 area municipal utility financial statements, MRES found that the median level of cash as a percentage of operating revenues was 55% for these utilities. Since the electric utility had a cash deficit at the end of three of the past four years, Fort Pierre had the lowest cash reserves among those 64 utilities.

MRES recommends a targeted minimum reserve level of $600,000, which would be about 24% of 2012 operating revenues under proposed rates. This total excludes restricted bond reserves.

Maintaining at least this reserve level would provide for unanticipated expenses or contingencies that may arise. MRES recommends reserves for the following purposes:

- Capital improvements and equipment replacement fund would include a minimum of $150,000, which is equal to two years of average cash outlay.

- Operations fund would include $350,000, or two months of operating expenses along with operating transfers. This fund would include the cash needed for daily operating costs, including paying the wholesale power bills and payroll.

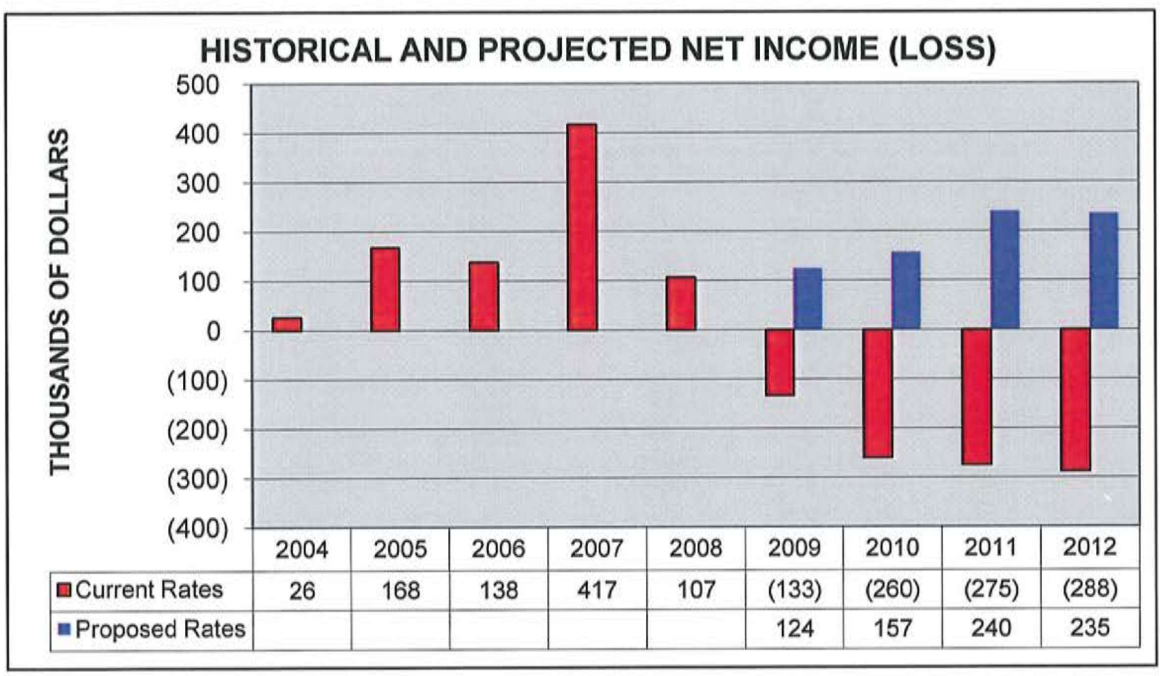
- Contingencies and emergencies fund would include $100,000 to cover unexpected expenses or lost revenues due to storm damage; bankruptcy or closing of a large customer; substation failure; or other catastrophes. This fund would also pay any expenses until insurance reimbursement or government aid occurs.

PROJECTED OPERATING RESULTS AT PROPOSED RATES

The table below shows the projected operating revenues, revenue requirements, and net income **assuming the implementation of increases of 15% in 2009, 7% in 2010, and 4% in 2011.** Depending on any changes to the key assumptions primarily discussed in Sections 1 and 2, additional rate increases may be necessary.

Projected Annual Operating Results (Proposed Rates)				
Year	**2009**	**2010**	**2011**	**2012**
Projected Operating Revenues	$2,233,585	$2,402,562	$2,523,091	$2,550,851
Projected Revenue Requirements	2,110,053	2,245,865	2,283,554	2,316,290
Net Income	**$123,532**	**$156,697**	**$239,537**	**$234,561**
Net Income as a Percent of Revenues	5.5%	6.5%	9.5%	9.2%

The following graph shows the historical and projected net income or loss with projected amounts shown under proposed rates. Under the proposed rates, income would increase to around $240,000 in 2011.

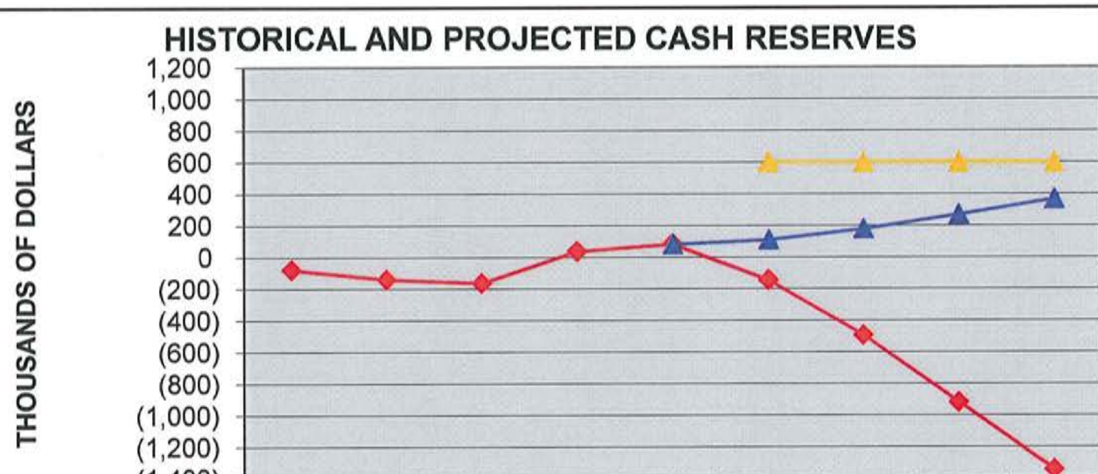


PROJECTED OPERATING RESULTS AT PROPOSED RATES (CONTINUED)

The following table and graph shows projected reserves under proposed rates. Reserves would increase slowly in 2009 and 2010 before rising to around $370,000 in 2012, based on the proposed increases and current cost projections. Additional increases may be necessary after 2011 to reach the targeted minimum reserve level of $600,000.

Projected Cash Reserves (Proposed Rates)

Year	2008	2009	2010	2011	2012
Projected Operating Revenues	$1,930,080	$2,233,585	$2,402,562	$2,523,091	$2,550,851
Beginning of Year Reserves	$36,565	$82,925	$112,390	$181,003	$271,086
Addition (Reduction) of Reserves	46,360	29,465	68,613	90,083	97,348
End of Year Reserves	**$82,925**	**$112,390**	**$181,003**	**$271,086**	**$368,434**
Reserves as a Percent of Revenues	4%	5%	8%	11%	14%
Targeted Min. Level	N/A	$600,000	$600,000	$600,000	$600,000



	2004	2005	2006	2007	2008	2009	2010	2011	2012
Current Rates	(78)	(139)	(163)	37	83	(144)	(492)	(916)	(1,342)
Proposed Rates					83	112	181	271	368
Target Level						600	600	600	600

*Reserves exclude funds restricted by bond covenants

CUSTOMER BILLS AND AVERAGE REVENUE PER KWH GRAPHS

Exhibits 5-A through 5-E at the end of this section contain graphs of customer bills for the Residential and Small Commercial classes and average revenue per kWh for the Large Commercial class.

All five graphs are calculated under current rates and proposed rates. The averages on 5-E can be used to calculate the bills under both sets of rates by knowing the load factor for these customers. In these graphs as well as the comparisons discussed next, the generation surcharge has been added to the base rates to determine customer bills.

COMPARISONS TO OTHER UTILITIES

Exhibits 5-F through 5-H at the end of this section contain comparisons between Fort Pierre and the regional utilities whose rates were listed in Section 4. The comparisons, using the rates shown in that section, are based on the following levels of usage per month:

- <u>Residential</u> – Average usage of 1,000 kWhs
- <u>Small Commercial (Single Phase)</u> – Average usage of 2,000 kWhs
- <u>Large Commercial</u> – 46,000 kWhs and average demand of 150 kW (42% Load Factor)

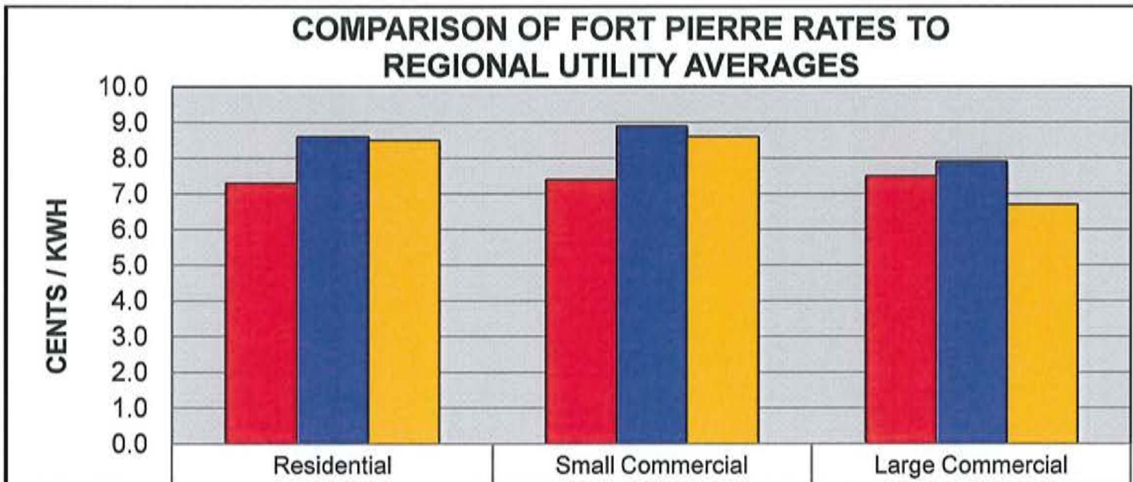
The top portion of each exhibit shows bills calculated using the various utilities' rates, and the bottom portion shows the percentage differences between other utilities and proposed Fort Pierre rates.

The last two graphs on the next page summarize the rate comparison information. The first graph compares cents per kWh for each class using the calculated bills and three sets of values: current Fort Pierre rates, 2009 proposed Fort Pierre rates, and an average of 9 regional utilities.

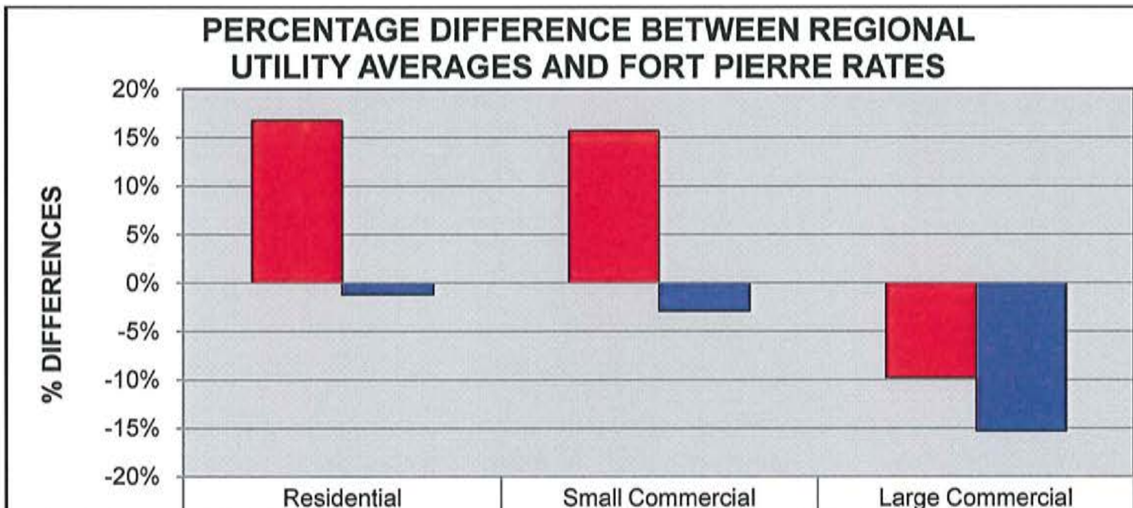
The second graph shows the percentage differences between the regional utility average and both the current and 2009 proposed Fort Pierre rates. This graph indicates that for Residential and Small Commercial customers, the regional utility average is 16% to 17% higher than Fort Pierre rates. Meanwhile, the utility average is 10% lower than Fort Pierre for Large Commercial customers.

After the 2009 rate adjustments, the regional utility averages will be 1% to 3% lower than Fort Pierre's rates for Residential and Small Commercial customers, and 15% lower for Large Commercial customers. However, several other utilities are experiencing cost pressures and may increase rates or pass along increased costs through their electric cost adjustment in 2009.

COMPARISONS TO OTHER UTILITIES (CONTINUED)



	Residential	Small Commercial	Large Commercial
Current	7.3	7.4	7.5
Proposed	8.6	8.9	7.9
Average	8.5	8.6	6.7



	Residential	Small Commercial	Large Commercial
Current	16.8%	15.7%	-9.8%
Proposed	-1.2%	-2.9%	-15.3%