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.

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.

Exhibit 3-A

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**