AQUILA NETWORKS - MISSOURI
INTEGRATED RESOURCE PLAN

February 2007

Submitted to the
MISSOURI PUBLIC SERVICE COMMISSION

EXECUTIVE SUMMARY

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2007 INTEGRATED RESOURCE PLAN (IRP) OVERVIEW

The key results of the Integrated Resource Plan can be summarized into the items in the following paragraphs:

- **Load Forecast and Demand-Side Management (DSM)**

  Peak Demand is projected to grow at an average annual rate of 2.0% for the next twenty years.

  The cost effective DSM programs included in the IRP would reduce demand growth to less than 1.6% per year. This DSM impact effectively eliminates the need for 218 MW of capacity over the next twenty years and reduces the growth rate of peak demand by more than twenty percent.

- **Power Supply**

  Preferred Plan of Resource Additions

  225 MW of Combustion Turbines in 2010
  250 MW of Combined Cycle in 2013
  200 MW of Coal Generation Participation in 2017
  300 MW of Nuclear Generation Participation in 2022

  It should be noted that Aquila would only be a participant in a larger nuclear generating project similar to its participation in Iatan 2. At this time our current cost estimates of nuclear construction and carbon emissions make nuclear power the most cost-effective resource to meet power supply demands in the 2020 to 2026 time frame. A combination of coal, coal gasification, and gas-fired resources could replace the nuclear additions for a small cost increase if participation in nuclear generation is not available or if cost estimates change.

- **Wind Power**

  Aquila currently has 60 MW of wind generation and continues to pursue opportunities to add more. At this time our offers for wind power are not cost effective, however, Aquila will be issuing a Request for Proposals (RFP) for power supply including renewable resources in the next month.

The Integrated Resource Plan developed for Aquila Networks – Missouri provides the framework for the planning horizon subject to the results of the upcoming RFP. The planning for generating resource additions is a continuous and iterative process. The following discusses in more detail the key findings of the IRP.

ES.1 LOAD FORECAST SUMMARY

Energy forecasts for residential, commercial, industrial, other, and wholesale classes were developed for the Aquila Networks - Missouri resource plan update in May 2006. Regional economic growth for Aquila's Missouri electric utility service areas (Missouri Public Service (MPS) and St. Joseph Light & Power (SJLP)) were used to forecast long-term growth in energy sales.

Actual summer peak demand for Aquila Networks - Missouri (MPS and SJLP combined) of 1,967 MW occurred at hour 18 on 8/9/06. MPS actual summer peak demand on 8/9/06 hour 18 was 1,521 MW. SJLP actual summer peak demand on 8/9/06 hour 18 was 446 MW.

Table ES-1 provides a load forecast summary of the Base-Case for Aquila Networks-Missouri utilities overall (MPS and SJLP) without the impacts of demand-side management which will be discussed later in the Executive Summary. Energy growth is forecast in the Base-Case to average 2.5% annually during 2006-2025. Coincident summer peak demand growth is forecast to average 2.0% annually during 2006-2025. Annual coincident system load factor in 2006 is forecast at 50.2% increasing to 55.4% by 2025.

Table ES-1
Load Forecast Summary (Base-Case)
(Annual Energy GWH and Summer Peak Demand MW)

Year	Base-MPS EnergyGWh	Base-SJLP EnergyGWh	Base-MO EnergyGWh	Base-MPS SPeakMW	Base-SJLP SPeakMW	Base-MO SPeakMW	Base-MPS LF%	Base-SJLP LF%	Base-MO LF%
1999	5,046.68	1,801.38	6,848.06	1,276	388	1,660	45.1%	53.0%	47.1%
2000	5,477.36	1,934.60	7,411.96	1,335	403	1,738	46.4%	54.3%	48.2%
2001	5,447.35	1,906.67	7,354.01	1,300	398	1,698	47.8%	54.7%	49.4%
2002	5,707.82	1,936.95	7,644.77	1,333	399	1,729	48.9%	55.4%	50.5%
2003	5,762.46	1,937.07	7,699.53	1,443	419	1,861	45.6%	52.8%	47.2%
2004	5,707.43	1,949.25	7,656.68	1,344	399	1,735	48.0%	55.3%	49.9%
2005	6,106.44	2,067.03	8,173.47	1,422	409	1,826	49.0%	57.7%	51.1%
2006	6,078.85	2,062.02	8,140.87	1,439	412	1,851	48.2%	57.1%	50.2%
2007	6,318.86	2,094.91	8,413.76	1,473	418	1,891	49.0%	57.2%	50.8%
2008	6,505.75	2,128.55	8,634.30	1,509	425	1,934	48.8%	56.7%	50.5%
2009	6,716.07	2,170.02	8,886.09	1,548	433	1,979	49.5%	57.2%	51.3%
2010	6,965.99	2,217.96	9,183.96	1,602	442	2,040	49.6%	57.3%	51.4%
2011	7,162.22	2,252.67	9,414.88	1,636	448	2,079	50.0%	57.4%	51.7%
2012	7,378.05	2,292.20	9,670.24	1,671	454	2,125	49.9%	57.1%	51.5%
2013	7,566.91	2,322.59	9,889.50	1,706	460	2,163	50.6%	57.6%	52.2%
2014	7,776.48	2,357.61	10,134.08	1,742	466	2,204	51.0%	57.8%	52.5%
2015	7,986.84	2,391.67	10,378.51	1,778	472	2,246	51.3%	57.8%	52.7%
2016	8,216.42	2,430.18	10,646.60	1,815	478	2,288	51.2%	57.5%	52.6%
2017	8,416.03	2,459.99	10,876.02	1,852	484	2,331	51.9%	58.0%	53.3%
2018	8,637.64	2,495.81	11,133.45	1,889	490	2,374	52.2%	58.1%	53.5%
2019	8,861.98	2,531.91	11,393.90	1,927	496	2,418	52.5%	58.3%	53.8%
2020	9,109.24	2,573.77	11,683.01	1,965	502	2,462	52.4%	58.0%	53.7%
2021	9,330.51	2,609.89	11,940.39	2,003	507	2,506	53.2%	58.8%	54.4%
2022	9,556.06	2,646.48	12,202.53	2,041	513	2,549	53.4%	58.9%	54.6%
2023	9,788.90	2,683.91	12,472.81	2,080	519	2,594	53.7%	59.0%	54.9%
2024	10,026.78	2,722.02	12,748.81	2,119	525	2,639	53.5%	58.7%	54.6%
2025	10,271.30	2,761.30	13,032.60	2,159	531	2,685	54.3%	59.4%	55.4%
1999-05	3.2%	2.3%	3.0%	1.8%	0.9%	1.6%	0.6%	0.8%	0.7%
2006-25	2.8%	1.5%	2.5%	2.2%	1.3%	2.0%	0.3%	0.1%	0.3%

Table ES-2 provides a load forecast summary of the High-Case and Low-Case economic growth scenarios for Aquila Networks - Missouri utilities overall (MPS and SJLP). Energy growth is forecast in the High-case to average 2.7% annually and 2.4% in the Low-Case during 2006-2025. Summer peak demand growth is forecast in the High-Case to average 2.1% annually and 1.9% in the Low-Case during 2006-2025. Annual coincident system load factor in the High-Case in 2006 is forecast at 50.2% increasing to 56.1% by 2025, and in the Low-Case increasing to 54.8%.

Table ES-2
Load Forecast Summary (High-Case and Low-Case)
(Annual Energy GWH and Summer Peak Demand MW)

Aquila Networks-Missouri (MPS and SJLP): High-Case and Low-Case Load Forecasts

Year	Base-Case GWH	High-Case GWH	Low-Case GWH	Base-Case PeakMW	High-Case PeakMW	Low-Case PeakMW	Base-Case LF%	High-Case LF%	Low-Case LF%
1999	6,848	6,848	6,848	1,660	1,660	1,660	47.1%	47.1%	47.1%
2000	7,412	7,412	7,412	1,738	1,738	1,738	48.7%	48.7%	48.7%
2001	7,354	7,354	7,354	1,698	1,698	1,698	49.4%	49.4%	49.4%
2002	7,645	7,645	7,645	1,729	1,729	1,729	50.5%	50.5%	50.5%
2003	7,700	7,700	7,700	1,861	1,861	1,861	47.2%	47.2%	47.2%
2004	7,657	7,657	7,657	1,735	1,735	1,735	50.4%	50.4%	50.4%
2005	8,173	8,173	8,173	1,826	1,826	1,826	51.1%	51.1%	51.1%
2006	8,141	8,141	8,141	1,851	1,851	1,851	50.2%	50.2%	50.2%
2007	8,414	8,414	8,414	1,891	1,891	1,891	50.8%	50.8%	50.8%
2008	8,634	8,634	8,634	1,934	1,934	1,934	51.0%	51.0%	51.0%
2009	8,886	8,886	8,886	1,979	1,979	1,979	51.3%	51.3%	51.3%
2010	9,184	9,228	9,140	2,040	2,045	2,035	51.4%	51.5%	51.3%
2011	9,415	9,474	9,360	2,079	2,085	2,073	51.7%	51.9%	51.5%
2012	9,670	9,746	9,602	2,125	2,133	2,118	51.9%	52.2%	51.8%
2013	9,890	9,982	9,807	2,163	2,173	2,155	52.2%	52.4%	52.0%
2014	10,134	10,244	10,037	2,204	2,216	2,194	52.5%	52.8%	52.2%
2015	10,379	10,506	10,267	2,246	2,260	2,234	52.7%	53.1%	52.5%
2016	10,647	10,793	10,520	2,288	2,304	2,274	53.1%	53.5%	52.8%
2017	10,876	11,042	10,733	2,331	2,349	2,315	53.3%	53.7%	52.9%
2018	11,133	11,321	10,974	2,374	2,394	2,358	53.5%	54.0%	53.1%
2019	11,394	11,603	11,218	2,418	2,441	2,399	53.8%	54.3%	53.4%
2020	11,683	11,914	11,490	2,462	2,486	2,441	54.2%	54.7%	53.7%
2021	11,940	12,195	11,731	2,506	2,533	2,483	54.4%	55.0%	53.9%
2022	12,203	12,481	11,975	2,549	2,578	2,524	54.6%	55.3%	54.2%
2023	12,473	12,776	12,227	2,594	2,626	2,568	54.9%	55.5%	54.4%
2024	12,749	13,078	12,484	2,639	2,674	2,611	55.1%	55.8%	54.6%
2025	13,033	13,390	12,747	2,685	2,723	2,655	55.4%	56.1%	54.8%
1999-05	3.0%	3.0%	3.0%	1.6%	1.6%	1.6%	0.7%	0.7%	0.7%
2006-25	2.5%	2.7%	2.4%	2.0%	2.1%	1.9%	0.3%	0.3%	0.2%

Table ES-3 provides a load and resource forecast for ANM from 2007-2016, the first ten years of the planning horizon. Recent power purchase agreements (PPAs) entered into by ANM for 300 MW of summer capacity will meet reserve margin requirements for the summer of 2007.

Table ES-3
Aquila Networks - Missouri Capacity Balance

Generation Capacity	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total Baseload Capacity	898.6	898.6	898.6	898.6	898.6	898.6	898.6	898.6	898.6	898.6
Total Peaking Capacity	843.0	843.0	843.0	843.0	843.0	843.0	843.0	843.0	843.0	843.0
New Generation Capacity	0.0	0.0	0.0	153.0	153.0	153.0	153.0	153.0	153.0	153.0
Total Generation Capacity	1741.6	1741.6	1741.6	1894.6	1894.6	1894.6	1894.6	1894.6	1894.6	1894.6
Transactions	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total Purchases, Executed	495.0	175.0	175.0	175.0	75.0	75.0	75.0	0.0	0.0	0.0
Total System Capacity	2236.6	1916.6	1916.6	2069.6	1969.6	1969.6	1969.6	1894.6	1894.6	1894.6
System Peaks & Reserves	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Forecasted Peak MPS	1473.0	1509.0	1548.0	1602.0	1636.0	1671.0	1706.0	1742.0	1778.0	1815.0
Forecasted Peak SJD	418.0	425.0	433.0	442.0	448.0	454.0	460.0	466.0	472.0	478.0
Coincident Peak Forecast	1891.0	1934.0	1979.0	2040.0	2079.0	2125.0	2163.0	2204.0	2246.0	2288.0
Capacity Reserves	345.6	-17.4	-62.4	29.6	-109.4	-155.4	-193.4	-309.4	-351.4	-393.4
Reserve Margin	18.28%	-0.90%	-3.15%	1.45%	-5.26%	-7.31%	-8.94%	-14.04%	-15.65%	-17.19%
Additional Capacity Required to meet 13.64% Reserve Margin	0.0	281.2	332.3	248.7	393.0	445.3	488.4	610.0	657.8	705.5

ES.2 PROBABLE ENVIRONMENTAL COSTS

Probable environmental costs were estimated for both existing resources and potential new supply options, based on estimates of specific emission rates for each supply resource and the most likely cost of expected mitigation. These probable environmental costs were utilized in screening supply-side resource options, and estimating avoided costs for evaluating demand-side resource options.

ANM utilized values for environmental emissions costs of SO_2, Hg, and NOx from the "Study of Emission Reduction Strategies to Comply with CAIR and CAMR" prepared for ANM by Sargent & Lundy on May 9, 2006. A copy of this study is included in Appendix 2-D. The equipment cost estimates in the study were updated in December, 2006 after bids for NOx controls were obtained. The "High" and "Low" emissions cost forecasts from this study were projected to be the future price range of emissions allowances. The "Probable" emission cost forecasts were calculated to be the average of the "high" and "low" forecasts based on our estimation of the equal probability of these forecasts.

The estimated costs of CO_2 emissions were taken from the Synapse Energy Economics, Inc. paper titled "Climate Change and Power: Carbon Dioxide Emissions

Costs and Electricity Resource Planning" dated June 8, 2006 and included as Appendix 2-E. The "Synapse Mid Case" forecast was chosen as the "Probable" forecast for the purposes of the IRP. As discussed in the Risk Analysis section of the IRP, the CO_2 cost forecast is a significant driver in the selection of future generating resources.

Table ES-4 summarizes the range of environmental costs from these studies for each emission.

Table ES-4
Environmental Costs Utilized in the 2007 ANM Integrated Resource Plan

Year	SO_2 ($/ton)			Ozone Season NOx ($/ton)			Annual NOx ($/ton)			Mercury ($/ounce)			Mercury ($/lb)			CO_2 (2005 $/short ton)		
	High	Base	Low	High	Base	Low	High	Base	Low	High	Base	Low	High	Base	Low	High	Base	Low
2006	1,100	1,100	1,100															
2007	900	900	900															
2008	850	850	850															
2009	800	800	800	2,500	1,925	1,350	2,000	1,500	1,000									
2010	828	789	750	2,600	1,994	1,388	2,083	1,567	1,050	3,300	1,900	500	52,800	30,400	8,000	10.0	5.0	0.0
2011	857	791	725	2,700	2,063	1,425	2,167	1,633	1,100	3,417	1,968	520	54,667	31,493	8,320	12.0	7.0	1.0
2012	887	793	700	2,800	2,131	1,463	2,250	1,700	1,150	3,533	2,037	540	56,533	32,587	8,640	14.0	9.0	2.0
2013	918	784	650	2,900	2,200	1,500	2,333	1,767	1,200	3,650	2,105	560	58,400	33,680	8,960	16.0	11.0	3.0
2014	950	788	625	3,000	2,281	1,563	2,417	1,833	1,250	3,767	2,173	580	60,267	34,773	9,280	18.0	13.0	4.0
2015	983	792	600	3,125	2,375	1,625	2,500	1,900	1,300	3,883	2,242	600	62,133	35,867	9,600	20.0	15.0	5.0
2016	1,018	796	575	3,250	2,469	1,688	2,600	1,975	1,350	4,000	2,310	620	64,000	36,960	9,920	22.0	17.0	6.0
2017	1,053	802	550	3,375	2,563	1,750	2,700	2,050	1,400	4,167	2,403	640	66,667	38,453	10,240	24.0	19.0	7.0
2018	1,090	808	525	3,500	2,656	1,813	2,800	2,125	1,450	4,333	2,497	660	69,333	39,947	10,560	26.0	21.0	8.0
2019	1,128	820	512	3,625	2,750	1,875	2,900	2,200	1,500	4,500	2,590	680	72,000	41,440	10,880	28.0	23.0	9.0
2020	1,168	834	500	3,750	2,844	1,938	3,000	2,275	1,550	4,667	2,683	700	74,667	42,933	11,200	40.0	25.0	10.0
2021	1,209	867	525	3,875	2,938	2,000	3,125	2,363	1,600	4,833	2,777	720	77,333	44,427	11,520	41.0	26.0	11.0
2022	1,251	901	550	4,000	3,042	2,083	3,250	2,450	1,650	5,000	2,870	740	80,000	45,920	11,840	42.0	27.0	12.0
2023	1,295	935	575	4,125	3,146	2,167	3,375	2,538	1,700	5,167	2,963	760	82,667	47,413	12,160	43.0	28.0	13.0
2024	1,340	970	600	4,250	3,250	2,250	3,500	2,625	1,750	5,333	3,057	780	85,333	48,907	12,480	44.0	29.0	14.0
2025	1,387	1,000	612	4,375	3,354	2,333	3,625	2,713	1,800	5,500	3,150	800	88,000	50,400	12,800	45.0	30.0	15.0
2026																46.0	31.0	16.0
2027																47.0	32.0	17.0
2028																48.0	33.0	18.0
2029																49.0	34.0	19.0
2030																50.0	35.0	20.0

High and low forecasts from the Sargent & Lundy study of 5/9/06, except for the CO2 forecast which is from the Synapse Energy Economics paper "Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resouce Planning" dated 6/8/06.

The probable environmental costs for these emissions as shown in Table ES-4 are the estimated mitigation costs for each pollutant for purposes of the supply-side and demand-side resource analysis. These environmental costs were used in the ANM Integrated Resource Plan for screening supply-side resources, and determining the optimal supply-side only plan for purposes of calculating avoided costs, which were, in turn, used to screen demand-side resources.

ES.3 SUPPLY-SIDE SCREENING ANALYSIS

From the Supply-Side Screening Analysis, it is shown that the proven technologies based on coal-fueled systems and combustion turbine systems prove to be the leaders in cost effective supply sources. A full list of generating resources carried forward into the resource planning process and the operating and cost data used in the production cost modeling are included in Appendix 2-G. It should be noted that for the generating resources that are typically built with high capacities for economies of scale (nuclear and coal for example), it was assumed that Aquila would not be the lead developer, but would be able to participate in ownership of these units in blocks of 100 MWs. The expected costs of emission control equipment are included in the capital cost estimate as appropriate.

Table ES-5 provides a summary of the fuel uncertainties and the capital and operating cost uncertainties for each of the resource options identified previously are included in Appendix 2-G. All of the probabilities are based on the judgment of decision makers within ANM. Because of recent increases in the cost of labor and construction materials, as evidenced by the price increases for the Iatan 2 project, the project capital costs and fixed O&M costs are more heavily weighted on the high side of our current base estimates.

Table ES-5
Fuel Price Forecast Ranges ($/mmBtu) (nominal $)

	Low Sulfur Coal [1]			High Sulfur Coal [2]			Blended Coal [3]			Natural Gas [4]		
Year	Low	Base	High	Low	Base	High	Low	Base	High	Low	Base	High
2007	0.80	0.85	0.87	2.65	2.88	2.88	1.48	1.60	1.61	9.46	9.46	10.03
2008	0.74	0.98	0.87	2.56	3.02	3.02	1.42	1.68	1.68	8.83	8.83	11.70
2009	0.71	0.97	0.91	2.50	3.08	3.21	1.40	1.72	1.79	6.65	6.71	17.79
2010	0.68	0.87	0.95	2.46	3.15	3.41	1.37	1.76	1.91	5.09	5.35	15.04
2011	0.96	1.23	1.35	2.51	3.22	3.52	1.40	1.79	1.97	4.83	5.30	15.18
2012	0.98	1.24	1.38	2.55	3.27	3.61	1.43	1.82	2.02	4.61	5.26	12.82
2013	0.98	1.26	1.41	2.59	3.32	3.71	1.45	1.85	2.07	4.88	5.57	11.53
2014	1.03	1.28	1.44	2.71	3.37	3.80	1.51	1.88	2.12	5.39	6.15	10.82
2015	1.07	1.29	1.47	2.83	3.42	3.90	1.58	1.91	2.18	5.09	5.81	9.82
2016	1.12	1.31	1.51	2.96	3.47	3.99	1.66	1.94	2.23	5.74	6.55	10.63
2017	1.18	1.34	1.56	3.10	3.53	4.09	1.73	1.97	2.29	5.69	6.49	10.11
2018	1.24	1.37	1.60	3.24	3.58	4.19	1.81	2.00	2.34	5.97	6.81	10.18
2019	1.30	1.40	1.66	3.41	3.65	4.33	1.90	2.04	2.42	5.96	6.80	9.76
2020	1.37	1.43	1.71	3.56	3.71	4.43	1.99	2.07	2.48	6.56	7.49	10.32
2021	1.41	1.45	1.76	3.65	3.76	4.54	2.04	2.10	2.54	6.87	7.85	10.38
2022	1.46	1.48	1.81	3.73	3.81	4.65	2.09	2.13	2.60	7.19	8.21	10.43
2023	1.50	1.51	1.86	3.85	3.89	4.79	2.15	2.17	2.68	7.53	8.59	10.47
2024	1.54	1.54	1.92	3.93	3.94	4.90	2.20	2.20	2.74	7.76	8.86	10.37
2025	1.57	1.57	1.97	3.98	3.99	5.01	2.22	2.23	2.80	8.09	9.24	10.37
2026	1.60	1.60	2.03	4.06	4.07	5.16	2.27	2.27	2.88	8.43	9.62	10.38
Probability	15.00%	70.00%	15.00%	15.00%	70.00%	15.00%	15.00%	70.00%	15.00%	10.00%	70.00%	20.00%

[1] Used for Generic coal and Generic Coal with CO_2 Sequestration
[2] Used for IGCC, and IGCC with CO_2 Sequestration
[3] Used for AFBC
[4] Used for 7EA CTs, generic CC, and LMS100

ES.4 DEMAND-SIDE MANAGEMENT

ES.4.1 Demand-Side Planning Process

Aquila has analyzed a wide variety of demand side management (DSM) programs in support of the IRP process. The company has retained the services of Quantec, LLC to assist with the identification and evaluation of various DSM initiatives. The scope, methodology, and results of this study are detailed in Quantec's final report and are included as Appendix 3-B to this document.

ES.4.2 Energy Efficiency Results

Technical energy efficiency (EE) program potentials in the residential and commercial sectors were based on an analysis of 130 unique electric measures. Six residential segments (existing single-family, manufactured, and multi-family; and new-construction single-family, manufactured, and multi-family) and 20 commercial segments (ten building types within each of the existing and new structure segments) were considered. Since many energy-efficiency measures are applied to multiple segments and building types, a total of 1,719 electric measure/structure combinations were included in the analysis. All major end uses in all 20 major industrial segments in Aquila's Missouri service areas were analyzed.

An accurate assessment of achievable EE potentials represented an important objective of this study. In addition, considering realistic market penetration rates, the achievable DSM potential analyses aggregated the estimates into "blocks" of available energy-efficiency resources that were sizable enough to compare to and evaluate against supply options on a balanced and consistent basis. The blocks, in this case, were the proposed Aquila programs:

- Comprehensive Commercial and Industrial
- Public Purpose
- Residential Audit
- Residential Envelope Measure Retrofit
- Residential HVAC and Appliance Rebates
- Residential Lighting
- Residential New Construction
- Residential Programmable Thermostats and HVAC

ES.4.3 Demand Response Results

The results of the assessment of various demand-response (DR) strategies indicate that direct load control and critical peak pricing, with respective achievable potentials of 12 MW and 11 MW, offer the largest opportunities for demand-response interventions. Opportunities resulting from curtailment contracts and demand buy-back are expected to be less, estimated at 0.5% and 0.3% of system peak, respectively.

ES.4.4 Program Portfolio Overview

Aquila's DSM programs for Missouri were designed to capture the achievable energy-efficiency and demand-response potential identified above. The portfolio of proposed programs is displayed in Table ES-6.

Table ES-6
Aquila Proposed Programs

Category	Sub-Category (If Applicable)
Residential Programs	
Residential Lighting	
Residential Audits	
Thermal Envelope Improvements	
HVAC Equipment and Appliances	
Programmable Thermostats & HVAC Maintenance	
Residential New Construction	
Non-Residential Programs	
Comprehensive Commercial and Industrial Program	Audits
	Custom and Prescriptive Rebates
Public Purpose Programs	
Low-income Assistance	Weatherization
	Energy Education through Community-Based Organizations
	Affordable Housing Initiative
School-Based Energy Education	
Research & Development	
Energy Efficiency	
Demand Response Programs	
Direct Load Control	
Curtailable Rates	
Demand Buyback	
Critical Peak Pricing	

The projected impacts of the energy-efficiency programs are shown in Table ES-7.

Table ES-7
Energy Efficiency Plan Impacts

	Incremental Impacts		Cumulative Impacts	
	kW	kWh	kW	kWh
Year 1	3,711	9,090,062	3,711	9,090,062
Year 2	7,824	19,414,689	11,535	28,504,751
Year 3	13,512	33,712,997	25,048	62,217,748
Year 4	13,577	33,907,729	38,625	96,125,478
Year 5	13,803	34,530,618	54,428	130,656,095

Based on the Quantec analysis of DSM programs, the twelve energy efficiency programs and four demand response programs were evaluated against the supply-side resources using the MIDAS Gold production cost model.

ES.5 RESOURCE INTEGRATION

As required by the Commission's rules, the primary objective utilized by ANM in developing the optimal energy plan was minimization of the present value of revenue requirements over the 2007-2026 planning period. In addition to this objective, alternative resource plans (ARPs) were also developed for other important planning objectives, as follows:

- Minimize CO_2 production – The "No New Coal Generation" ARP prohibits the addition of new coal-fired resources and thus lowers the systemwide production of CO_2. The "Green" ARP examines the cost impact of ANM unilaterally setting its own CO_2 emission rate limit at 6.5 million tons per year beginning in 2015, equivalent to the ANM level of CO_2 emissions in the year 2000.

- Minimize dependence on natural gas – The "No New Gas Generation" ARP provides an alternative plan for ANM to not increase its exposure to the volatile natural gas market in the generation of electricity.

ES.5.1 Resource Integration Process

The resource integration process is automated in the MIDAS Gold™ software to comply with the requirement in 4 CSR 240-22.010(2)(A) of the rules. This section of the rules states that the utility shall consider and analyze demand-side efficiency and energy management measures on an equivalent basis with supply-side alternatives in the resource planning process.

ES.5.2 Demand-Side Management Programs

The Demand-Side Management Programs identified in the demand-side management screening analysis were evaluated against the supply-side resources using the MIDAS Gold production cost model. The only DSM program that was not determined to be cost effective was the direct load control (DLC) program. Table ES-8 provides an overview of the DSM program impacts on ANM-system demand and energy along with the total costs of the cost-effective programs.

Table ES-8
Impact of Demand-Side Management Programs

	Energy Efficiency			Demand Response			Total		
Year	Total Non-Coincident Demand Impact (MW)	Energy Reduction (MWh)	Total Cost ($)	Total Non-Coincident Demand Impact (MW)	Energy Reduction (MWh)	Total Cost ($)	Total Coincident Peak Demand Impact (MW) [1]	Energy Reduction (MWh)	Total Cost ($)
2007	3.7	9,050	4,152,436	7.8	480	2,422,580	10.2	9,530	6,575,016
2008	11.5	28,390	7,510,036	15.7	950	1,613,628	23.1	29,340	9,123,663
2009	25.0	62,020	11,692,454	23.5	1,100	1,761,812	39.5	63,120	13,454,267
2010	38.6	95,750	11,752,850	24.1	1,490	967,394	48.8	97,240	12,720,244
2011	52.4	130,040	12,164,206	24.8	1,700	1,000,302	58.2	131,740	13,164,507
2012	66.4	164,830	12,483,859	25.4	1,970	1,041,767	67.8	166,800	13,525,627
2013	80.6	200,560	12,854,347	26.0	2,190	1,084,073	77.4	202,750	13,938,420
2014	95.0	236,720	13,485,491	26.7	2,410	1,128,192	87.2	239,130	14,613,683
2015	109.5	273,580	14,207,839	27.4	2,610	1,174,326	97.2	276,190	15,382,165
2016	124.3	310,360	14,969,457	28.0	2,920	1,222,249	107.3	313,280	16,191,706
2017	139.3	348,150	15,692,767	28.8	3,190	1,273,755	117.5	351,340	16,966,522
2018	154.5	386,530	16,412,567	29.5	3,150	1,327,139	127.9	389,680	17,739,706
2019	170.0	425,920	17,355,025	30.2	3,480	1,382,230	138.5	429,400	18,737,254
2020	185.7	466,470	17,852,616	31.0	3,830	1,441,090	149.3	470,300	19,293,707
2021	201.6	506,370	18,679,284	31.8	3,660	1,501,429	160.3	510,030	20,180,714
2022	217.9	547,170	19,991,271	32.6	3,870	1,565,525	171.4	551,040	21,556,796
2023	234.5	589,060	21,544,204	33.4	4,400	1,632,852	182.8	593,460	23,177,057
2024	251.3	631,980	23,050,903	34.3	3,650	1,703,235	194.5	635,630	24,754,138
2025	268.6	675,950	23,739,358	35.2	3,900	1,777,352	206.4	679,850	25,516,710
2026	285.7	719,950	24,051,420	36.1	3,840	1,854,635	218.3	723,790	25,906,055

[1] The sum of Energy Efficiency and Demand Response Demand Impact do not equal the total peak reduction due to non-coincidence of the program impacts.

The summer peak demand impacts of the cost-effective demand-side management programs represent an average annual peak demand growth reduction from 2.0% to 1.6% over the study period. The summer peak demand impact grows from 0.5% of forecasted peak demand in 2007 to 8.0% of peak demand in 2026. The energy impact increases from 0.1% of forecasted energy requirements in 2007 to 5.4% in 2026.

ES.5.3 Summary of Alternative Resource Plans with DSM

The Alternative Resource Plans (ARPs) developed for Aquila Networks - Missouri as a result of the resource integration process described above are based on the Commission's required planning objective of minimizing utility costs (revenue requirements) on a present value basis at the utility's cost of capital of 7.97% over the 20-year planning horizon (2007-2026).

Each ARP assumes that a different mix of generation types is available or constrained by environmental limits. The MIDAS capacity expansion module was used to determine the least cost capacity expansion plan using the limitations specific to each plan. A description of the ARPs is included in the following paragraphs.

ES.5.3.1 No New Coal Generation

The "No New Coal Generation" ARP assumes that PPAs are available through 2012 to meet all capacity requirements and also assumes no coal-fired generation additions are available during the study period. The financial and operating data output from the modeling of this plan are included as Appendix 4-B.

ES.5.3.2 Power Purchase Agreements Through 2012

The "PPAs Through 2012" ARP assumes that PPAs are available through 2012 and no other generation types are excluded during the entire study period. This plan was the least-cost supply-side only plan and remains the least cost plan with the integration of demand-side management programs. The financial and operating data output from the modeling of this plan are included as Appendix 4-C.

ES.5.3.3 Power Purchase Agreements Through 2009

The "PPAs Through 2009" ARP assumes that PPAs are available through 2009 and no other generation types are excluded during the entire study period. The financial and operating data output from the modeling of this plan are included as Appendix 4-D.

ES.5.3.4 No New Gas Generation

The "No New Gas Generation" ARP assumes that PPAs are available through 2012 and also assumes no gas-fired generation additions are available during the study period. The financial and operating data output from the modeling of this plan are included as Appendix 4-E.

ES.5.3.5 Green

The "Green" ARP assumes that PPAs are available through 2012 and also assumes that Aquila will self-impose a CO_2 emissions limit of 6.5 million tons beginning in 2015. This limit is equal to ANM's CO_2 emissions level in the year 2000. The generation additions in this plan are the least cost alternatives that allow ANM to meet the CO_2 limit. The financial and operating data output from the modeling of this plan are included as Appendix 4-F.

ES.6 SENSITIVITY ANALYSIS

This subsection presents the results of the sensitivity analysis conducted in MIDAS Gold using the alternative resource plans under the objective of minimization of revenue requirements with probable environmental costs. The high and low cases were based on the potential values of the critical variables. Optimal plans were not developed for each variation of the key variables and only the sensitivity of the alternative resource plans to changes in the key variables was analyzed.

Figures ES-1 and ES-2 present the results of the sensitivity analysis for the ARPs with the lowest 20-year net present value of revenue requirements (NPVRR). The figures show the low and high case effects of chance variables on the alternative resource plans. The data referenced in these figures can be found in Appendix 5-B.

Figure ES-1
Sensitivity Analysis for "No Coal" ARP
20-Year NPV ($M)

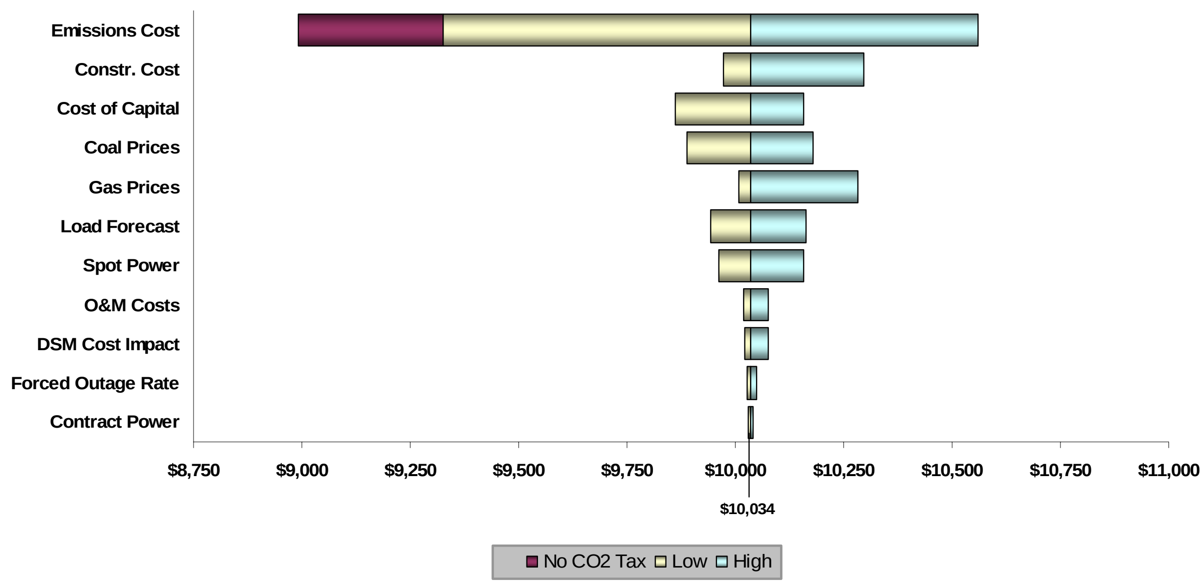
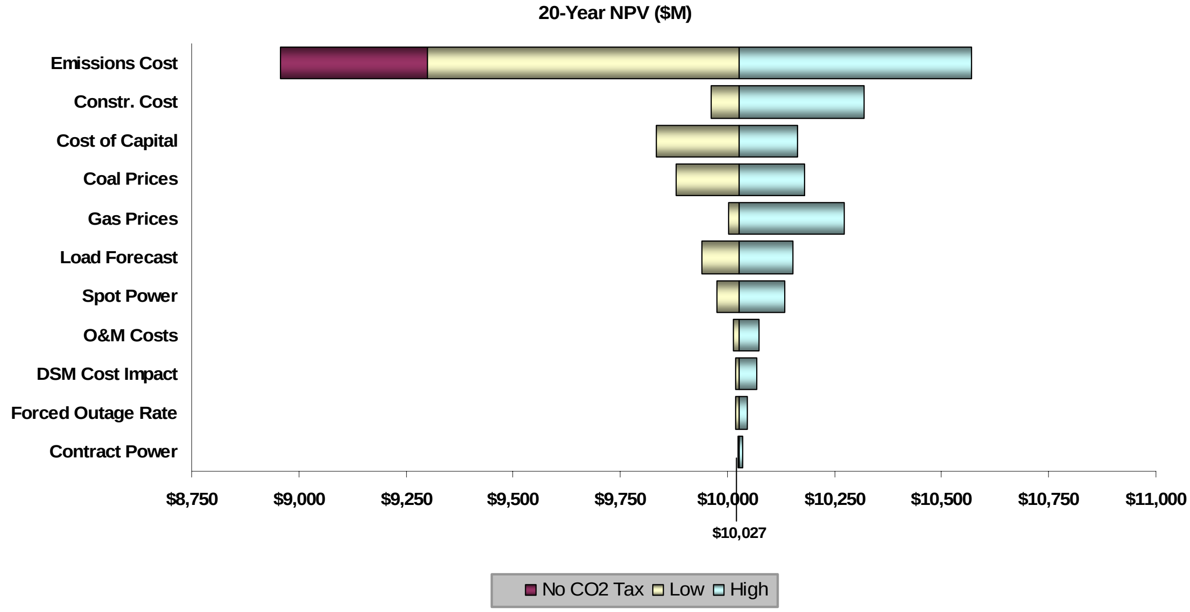


Figure ES-2
Sensitivity Analysis for "PPAs through 2012" ARP



The variables that consistently exhibited the most downside risk among the ARPs were:

- Probable Environmental Costs
- Cost of Capital
- Costs of Construction of New Generation Options
- Gas Prices

All of the alternative resource plans are more sensitive to the effect of environmental costs (particularly CO_2) than any other variable.

ES.7 PREFERRED PLAN SELECTION AND COMPARISON TO ALTERNATIVE RESOURCE PLANS

ES.7.1 Introduction

This section presents the preferred resource strategy for Aquila Networks - Missouri and the required implementation plan to acquire these resources. As required by the electric utility planning rules, ANM files the preferred plan as the one with NPVRR minimization with probable environmental costs as the primary objective.

ES.7.2 Preferred Resource Plan Selection

The preferred plan is a combination of the features of several of the ARPs. Similar to the "PPAs through 2009" plan, 225 MW of combustion turbine capacity is added in

2010. The second unit addition is a 250 MW combined cycle unit addition which was included in several of the ARPs. In the preferred plan this unit is installed in 2013. A 200 MW coal-fired generation participation is included in 2017. The final resource addition is 300 MW of nuclear capacity participation in 2022. This is a combination of the multiple nuclear resource additions identified in the other ARPs from 2020 to 2025. Table ES-9 provides the resource additions for the preferred plan which is also the least cost plan considering 20- and 10-year net present values of revenue requirements. Several other low-cost plans are included for comparison purposes. All references to PPAs in Table ES-9 represent the total PPA resource in that year. The PPA amounts are not additive from one year to the next.

Table ES-9
Generation Additions and Capacity Purchases for Alternative Resource Plans

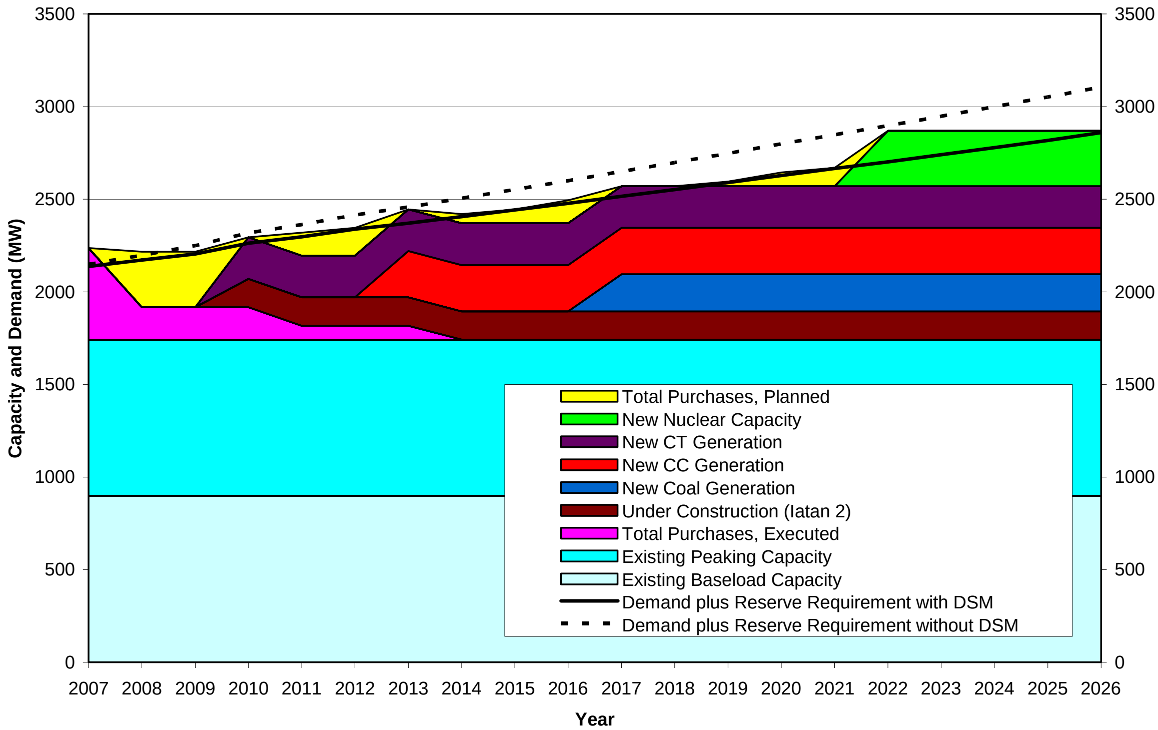
	Alternative Resource Plans			
Year	No Coal	PPAs through 2012	PPAs through 2009	Least Cost/Preferred
2007				
2008	300 MW PPA	300 MW PPA	300 MW PPA	300 MW PPA
2009	300 MW PPA	300 MW PPA	300 MW PPA	300 MW PPA
2010	200 MW PPA	200 MW PPA	225 MW CT	225 MW CT
2011	250 MW CC, 100 MW PPA	250 MW CC, 100 MW PPA	250 MW CC	125 MW PPA
2012	150 MW PPA	150 MW PPA		150 MW PPA
2013	250 MW CC	250 MW CC		250 MW CC
2014	75 MW CT	100 MW Coal Participation	100 MW Coal Participation	50 MW PPA
2015			100 MW Coal Participation	75 MW PPA
2016	150 MW CT	75 MW CT		125 MW PPA
2017				200 MW Coal Paticipation
2018			75 MW CT	
2019				25 MW PPA
2020	200 MW Nuclear Participation	100 MW Nuclear Participation	100 MW Nuclear Participation	75 MW PPA
2021				100 MW PPA
2022		100 MW Nuclear Participation	100 MW Nuclear Participation	300 MW Nuclear Participation
2023				
2024		100 MW Nuclear Participation	100 MW Nuclear Participation	
2025	100 MW Nuclear Participation			
2026				

20-Year NPVRR ($M)	$10,034	$10,029	$10,065	$10,026
% Above Min	0.1%	0.0%	0.4%	0.0%

10-Year NPVRR ($M)	$5,507	$5,522	$5,555	$5,495
% Above Min	0.2%	0.5%	1.1%	0.0%

Figure ES-3 is a plot of the loads and resources for the Preferred Expansion Plan including the resources outlined above and the addition of capacity from Iatan 2.

Figure ES-3
Loads and Resources with Preferred Expansion Plan



This preferred plan accomplishes several other objectives while remaining the lowest cost plan. The CT addition in 2010 reduces the reliance on large near-term power purchase agreements. The overall diversity of 200 MW of coal generation, 225 MW of peaking combustion turbines, and 250 MW of combined cycle reduces ANM's natural gas fuel supply risk and dependence on spot market energy purchases. By 2013, we expect certain high efficiency gas technologies to have matured. These include the General Electric LMS100 and Siemens Super Peaker. These technologies promise to combine the best features of peaking and combined cycle units but have limited operations at this time. Finally, the preferred plan minimizes the overlap of 2010 and 2013 construction schedules.

ES.7.3 Financial Analysis of Preferred Plan

This section provides key shareholder value performance measures for the Preferred Resource Plan. Table ES-10 shows the annual revenue requirements for the preferred plan with several of the lower cost ARPs provided for comparison. Table ES-11 shows the annual average rates (cents/kWh) including the levelized rates over the study period.

Table ES-10
Revenue Requirement Comparison

	No Coal		PPAs through 2012		PPAs through 2009		Preferred Plan	
Year	Annual Revenue Requirements ($M)	% Increase	Annual Revenue Requirements ($M)	% Increase	Annual Revenue Requirements ($M)	% Increase	Annual Revenue Requirements ($M)	% Increase
2007	609.33		609.33		609.33		609.40	
2008	654.44	7.4%	654.44	7.4%	654.93	7.5%	654.93	7.5%
2009	641.41	-2.0%	641.42	-2.0%	643.33	-1.8%	642.64	-1.9%
2010	758.66	18.3%	759.36	18.4%	777.52	20.9%	774.05	20.4%
2011	829.57	9.3%	831.17	9.5%	847.62	9.0%	825.38	6.6%
2012	873.79	5.3%	875.98	5.4%	891.02	5.1%	870.52	5.5%
2013	951.55	8.9%	953.98	8.9%	947.88	6.4%	947.93	8.9%
2014	1,034.26	8.7%	1,043.20	9.4%	1,038.78	9.6%	1,025.69	8.2%
2015	1,080.00	4.4%	1,090.78	4.6%	1,098.22	5.7%	1,071.27	4.4%
2016	1,158.57	7.3%	1,160.46	6.4%	1,157.63	5.4%	1,140.49	6.5%
2017	1,205.99	4.1%	1,206.53	4.0%	1,205.67	4.1%	1,218.25	6.8%
2018	1,266.53	5.0%	1,263.28	4.7%	1,269.80	5.3%	1,273.70	4.6%
2019	1,323.57	4.5%	1,318.97	4.4%	1,326.34	4.5%	1,330.68	4.5%
2020	1,423.98	7.6%	1,404.96	6.5%	1,409.18	6.2%	1,402.11	5.4%
2021	1,472.46	3.4%	1,458.59	3.8%	1,460.93	3.7%	1,459.32	4.1%
2022	1,522.45	3.4%	1,521.18	4.3%	1,521.58	4.2%	1,547.44	6.0%
2023	1,585.08	4.1%	1,579.69	3.8%	1,577.64	3.7%	1,594.65	3.1%
2024	1,639.42	3.4%	1,641.24	3.9%	1,637.47	3.8%	1,641.31	2.9%
2025	1,699.38	3.7%	1,686.17	2.7%	1,683.23	2.8%	1,687.11	2.8%
2026	1,751.54	3.1%	1,737.92	3.1%	1,733.16	3.0%	1,737.99	3.0%
Maximum Single-Year Increase ($M)	117.25		117.94		134.19		131.41	

Table ES-11
Average Annual Rate Comparison

	No Coal		PPAs through 2012		PPAs through 2009		Preferred Plan	
	Average Annual Rates (cents/kWh)	% Increase	Average Annual Rates (cents/kWh)	% Increase	Average Annual Rates (cents/kWh)	% Increase	Average Annual Rates (cents/kWh)	% Increase
2007	7.795¢		7.795¢		7.795¢		7.796¢	
2008	8.158¢	4.7%	8.158¢	4.7%	8.164¢	4.7%	8.164¢	4.7%
2009	7.770¢	-4.8%	7.770¢	-4.8%	7.793¢	-4.6%	7.784¢	-4.7%
2010	8.892¢	14.4%	8.900¢	14.5%	9.113¢	16.9%	9.072¢	16.5%
2011	9.485¢	6.7%	9.503¢	6.8%	9.691¢	6.3%	9.437¢	4.0%
2012	9.726¢	2.5%	9.751¢	2.6%	9.918¢	2.3%	9.690¢	2.7%
2013	10.357¢	6.5%	10.383¢	6.5%	10.317¢	4.0%	10.318¢	6.5%
2014	10.985¢	6.1%	11.080¢	6.7%	11.033¢	6.9%	10.894¢	5.6%
2015	11.201¢	2.0%	11.313¢	2.1%	11.390¢	3.2%	11.111¢	2.0%
2016	11.714¢	4.6%	11.733¢	3.7%	11.704¢	2.8%	11.531¢	3.8%
2017	11.936¢	1.9%	11.941¢	1.8%	11.933¢	2.0%	12.057¢	4.6%
2018	12.245¢	2.6%	12.214¢	2.3%	12.277¢	2.9%	12.315¢	2.1%
2019	12.504¢	2.1%	12.461¢	2.0%	12.530¢	2.1%	12.571¢	2.1%
2020	13.120¢	4.9%	12.945¢	3.9%	12.984¢	3.6%	12.918¢	2.8%
2021	13.274¢	1.2%	13.149¢	1.6%	13.170¢	1.4%	13.156¢	1.8%
2022	13.430¢	1.2%	13.419¢	2.1%	13.423¢	1.9%	13.651¢	3.8%
2023	13.680¢	1.9%	13.633¢	1.6%	13.616¢	1.4%	13.762¢	0.8%
2024	13.842¢	1.2%	13.858¢	1.6%	13.826¢	1.5%	13.858¢	0.7%
2025	14.036¢	1.4%	13.927¢	0.5%	13.903¢	0.6%	13.935¢	0.6%
2026	14.152¢	0.8%	14.042¢	0.8%	14.003¢	0.7%	14.042¢	0.8%
Levelized Rates	10.505¢		10.503¢		10.545¢		10.498¢	
Maximum Single-Year Rate Increase (cents/kWh)	1.122¢		1.130¢		1.320¢		1.288¢	

All plans show a large increase in revenue requirements and the resulting rates in the year 2010 due to the additions of Iatan 2 and planned environmental projects. The decrease in revenue requirements in the year 2009 is largely the result of forecasted natural gas price decreases which leads to lower forecasted spot market energy prices. The preferred plan has the lowest levelized rates over the 20-year planning horizon as shown in Table ES-11.

ES.7.4 Environmental Analysis of Preferred Plan

Table ES-12 shows the annual emission levels of NOx, SO_2, Hg, and CO_2 for the preferred plan. The annual emissions costs are largely driven by the forecast of CO_2 emissions costs as described in Part 2 of the IRP.

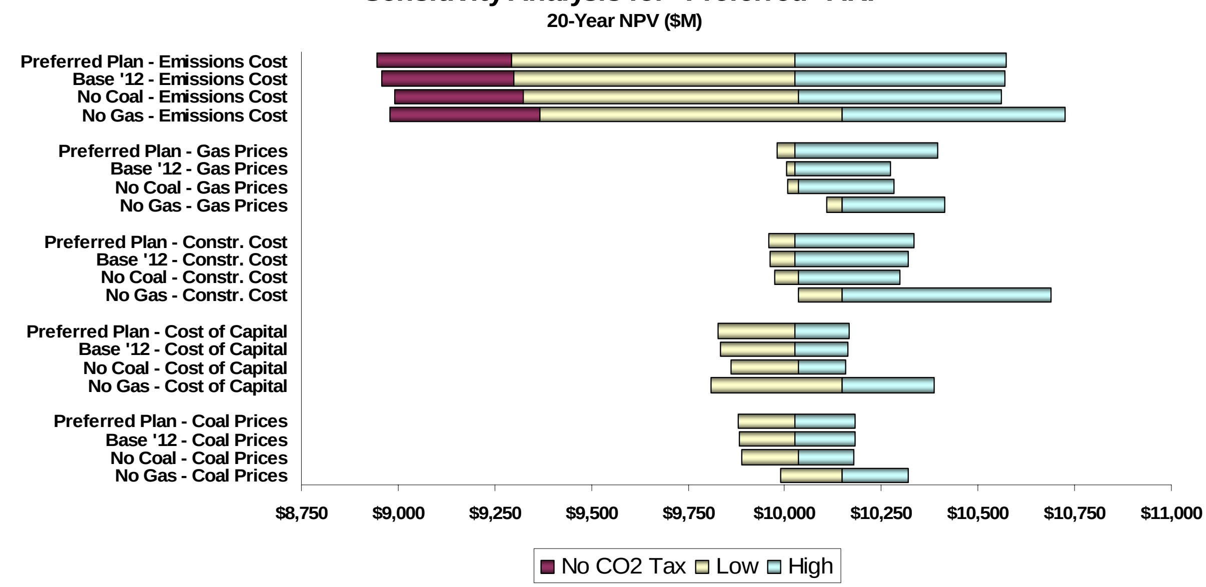
Table ES-12
Emission Level Comparison

	No Coal				PPAs through 2009				PPAs through 2012				Preferred Plan			
	NO_X	SO_2	Hg	CO2	NO_X	SO_2	Hg	CO2	NO_X	SO_2	Hg	CO2	NO_X	SO_2	Hg	CO2
Year	(tons)	(tons)	(lbs)	(tons)	(tons)	(tons)	(lbs)	(tons)	(tons)	(tons)	(lbs)	(tons)	(tons)	(tons)	(lbs)	(tons)
2007	1,053	17,109	71	5,708,574	1,053	17,109	71	5,708,574	1,053	17,109	71	5,708,574	1,053	17,109	71	5,707,901
2008	1,062	16,697	69	5,576,739	1,062	16,697	69	5,576,739	1,062	16,697	69	5,576,739	1,062	16,697	69	5,576,739
2009	1,065	17,553	72	5,781,230	1,065	17,553	72	5,781,230	1,065	17,553	72	5,781,230	1,063	17,553	72	5,772,835
2010	1,224	17,519	79	6,401,310	1,239	17,473	79	6,457,296	1,224	17,519	79	6,401,310	1,240	17,523	79	6,469,896
2011	1,362	17,784	84	7,100,587	1,363	17,758	84	7,145,906	1,362	17,784	84	7,100,587	1,345	17,783	84	6,953,220
2012	1,380	18,274	87	7,335,520	1,392	18,227	87	7,379,615	1,380	18,274	87	7,335,520	1,360	18,269	87	7,132,692
2013	1,431	18,351	87	7,614,820	1,424	18,367	87	7,500,826	1,431	18,351	87	7,614,820	1,425	18,441	87	7,504,390
2014	1,480	18,864	89	8,003,302	1,535	18,596	96	8,263,446	1,542	18,571	96	8,402,332	1,468	18,893	89	7,783,470
2015	1,502	18,870	88	8,111,477	1,611	18,279	102	8,735,470	1,563	18,616	95	8,509,393	1,482	18,940	89	7,832,618
2016	1,515	18,987	89	8,208,856	1,620	18,546	103	8,869,143	1,574	18,849	97	8,633,878	1,490	19,025	89	7,867,892
2017	1,527	18,958	89	8,242,700	1,650	18,658	103	8,901,336	1,595	18,869	96	8,671,592	1,652	18,698	103	8,905,339
2018	1,545	19,038	89	8,380,226	1,669	18,862	104	9,049,550	1,615	19,013	97	8,831,356	1,669	18,889	104	9,041,963
2019	1,556	19,041	89	8,440,559	1,684	18,960	104	9,082,290	1,627	19,075	97	8,885,848	1,681	19,010	104	9,080,283
2020	1,455	18,360	87	7,982,962	1,635	18,473	102	8,892,190	1,586	18,747	96	8,712,022	1,690	19,110	105	9,154,316
2021	1,472	18,467	87	8,014,903	1,647	18,636	102	8,925,275	1,594	18,818	95	8,718,792	1,695	19,212	104	9,146,985
2022	1,484	18,628	88	8,132,372	1,589	18,150	101	8,719,784	1,549	18,443	94	8,524,031	1,512	17,291	97	8,322,167
2023	1,500	18,706	87	8,174,232	1,603	18,368	101	8,766,512	1,564	18,574	94	8,583,273	1,529	17,577	98	8,407,646
2024	1,522	18,851	88	8,295,826	1,559	17,855	99	8,561,490	1,515	18,194	93	8,380,113	1,563	17,812	99	8,548,736
2025	1,529	19,869	92	8,433,605	1,627	19,156	104	8,984,220	1,587	19,590	98	8,799,956	1,628	19,210	104	8,997,760
2026	1,538	19,956	92	8,506,108	1,640	19,307	105	9,056,006	1,592	19,675	99	8,858,304	1,641	19,372	105	9,074,332

ES.7.5 Sensitivity Analysis of Key Variables

The sensitivity analysis of key variables on the preferred plan and the other lowest cost ARPs is shown in Figure ES-4. The sensitivities of the preferred plan are very similar to the “PPAs through 2012” and “No Coal” expansion plans because of the similarity of resource additions. A more pronounced difference is seen between the preferred and “No Gas” plans with the “No Gas” plan having significantly higher risk associated with emissions costs, construction costs, and cost of money.

Figure ES-4
Sensitivity Analysis for "Preferred" ARP



ES.7.6 Preferred Plan Alternatives and Flexibility

The integrated resource analysis produced not only a preferred plan, but also a substantial insight into possible alternative supply-side resource opportunities. ANM will embark in the direction of the preferred plan but attempt to maintain and enhance the flexibility to take advantage of resource opportunities that may develop. This subsection will expand upon the inherent flexibility available in the preferred plan.

The integrated analysis was performed considering an objective to minimize utility revenue requirements. This analysis indicated that the upcoming resource decision between combustion turbines and a combined cycle unit was only marginally different in cost impact. The final cost estimates of these technologies and the costs of power purchases (resulting from the Request for Proposals (RFP) to be issued in February 2007) will be the final determination in the ultimate preferred resource plan. In addition, because the current offers for wind generation were marginally not cost effective, the bids received for wind power in the upcoming RFP may be cost-effective and may alter the preferred plan.

The choice of combustion turbines in 2010 provides contingency benefits for natural gas fuel supply issues and purchase power availability. A significant reduction of the risk of gas supply issues during peak generating periods can be realized by making the combustion turbines dual-fuel capable. In addition, the combustion turbines reduce the dependence on the price and availability of PPAs in 2010.

The preferred plan utilizes 200 MW of new coal-fired generating capacity in 2017. This assumes that ANM will be able to purchase a 200 MW portion of a larger coal-fired resource. If this opportunity is not available or not available at a cost-effective price ANM may be able to replace the planned resource with a 200 MW fluidized bed unit at one of its existing sites to maintain the fuel diversity provided by a coal-fired resource addition.

Similarly the preferred plan calls for ANM to acquire 300 MW of nuclear generation participation in 2022. This opportunity may not be available to ANM. Even with the carbon tax that was included in the probable environmental costs, the inclusion of nuclear generation over coal-fired generation reduces the 20-year NPV by only a marginal amount.

Significant changes could occur during the next two years due to: capital costs of generation, fuel prices, load growth, and new generation technologies. Therefore, ANM could switch the later resources from the coal and nuclear resource participation to new turbine technologies, integrated gasification combined cycle units, and improved renewable resources, or a combination of these resources.   Although these resources are not listed explicitly as part of the preferred plan, they are integral elements of contingency options available in the preferred strategy.

ES.8 IMPLEMENTATION AND RESOURCE ACQUISITION STRATEGY

ES.8.1 Demand-Side Implementation

All of the cost-effective demand-side programs will begin to be implemented upon approval of the programs and establishment of an appropriate cost recovery mechanism by the Missouri Public Service Commission. Various implementation strategies will be investigated with input from Quantec.

The initial planning strategy is to promote customer awareness through brochures, bill inserts and other printed material; trade ally meetings; a program information telephone line; and through the Company web-site. Other options will be evaluated to promote energy-efficiency among customers including: (1) radio and television advertisements, (2) newspapers, magazines and billboards, (3) telemarketing, and (4) other innovative marketing methods. The demand-side programs will be implemented upon approval of the programs and establishment of an appropriate cost recovery mechanism by the Missouri Public Service Commission. Evaluation, measurement and verification of the programs will begin during 2008.

ES.8.2 Supply-Side Implementation and Contingency Monitoring

The preferred plan includes the addition of the following four supply-side resources over the planning horizon 2007-2026.

- 225 MW Combustion Turbine Addition in 2010
- 250 MW Combined Cycle Addition in 2013
- 200 MW Coal Participation in 2017
- 300 MW Nuclear Participation in 2022

ANM will be receiving detailed cost estimates of combustion turbine and combined cycle technologies from vendors in the next few months. In addition, ANM will be issuing an RFP for PPAs and wind generation PPAs in February, 2007. Finally, ANM will also be evaluating the results of the brownfield site study being performed by Black & Veatch to determine the potential for utilizing existing sites for new generation and the potential need for unit retirements.

The ANM electric planning group will be monitoring the emissions costs and fuel prices and updating the load forecasts to ensure that there is an ability to evaluate any contingency and develop additional strategies to respond to extreme scenarios.

In addition, ANM will undertake the following activities in the 2008 through 2012 period:

- Monitor the development of CO_2 emissions reduction legislation.

- Continue discussions to renew purchase power contracts that currently expire in 2011 and 2014.

- Pursue discussions with area utilities and independent power developers to determine the potential for unit participation in either coal or nuclear generating units in the 2015-2026 timeframe.

- Continue to evaluate the viability of renewable generation technology options in ANM service territory.

All of the above activities will facilitate the consideration of different types of supply resources to meet customer demand in the 2008-2026 timeframe.