AQUILA NETWORKS - MISSOURI
INTEGRATED RESOURCE PLAN

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MISSOURI PUBLIC SERVICE COMMISSION

PART 2
SUPPLY-SIDE RESOURCE ANALYSIS

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2.1 INTRODUCTION

2.1.1 Objectives

This Supply-Side Resource Analysis for Aquila Networks - Missouri (ANM) was developed in compliance with the rules for Electric Utility Resource Planning (4 CSR 240-22.040) of the Missouri Public Service Commission. The objective of the Supply-Side Resource Analysis is to identify candidate supply resource options that are the most cost-effective in supplying future load requirements. Appendix 2-A contains responses to the reporting requirements, referring to appropriate documentation within this report.

2.1.2 Supply-Side Planning Process

The Supply-Side Resource Analysis began with a review of existing generation, purchased power and transmission system resources. Based on future power requirements, a wide range of conventional, advanced, and renewable supply options were assessed qualitatively and screened based on their expected operating characteristics and life-cycle costs. The Capacity Expansion Module of the MIDAS Gold™ production cost modeling software was used for an extra level of screening and to determine optimal resource selection and timing. Finally, optimal supply-side only plans were developed with probable environmental costs using the MIDAS Gold™ resource planning model. A full description of the modeling software used in this analysis is included in Appendix 2-B and Appendix 2-C. These optimal supply-side plans were utilized to develop avoided costs for screening demand-side resource options. The candidate supply-side resource options that were the most cost-effective, considering sensitivities to key uncertain variables, were identified for further optimization along with demand-side options to be performed in the resource integration.

2.1.3 Data Sources and Assumptions

The primary data source for the Supply-Side Resource Analysis was the Technical Assessment Guide database of electric generation technologies licensed from Electric Power Research Institute (EPRI). Other major data sources included other EPRI generation information, reports from outside consultants, and Aquila operating reports and budgets.

Key data sources and assumptions utilized in the Supply-Side Resource Analysis are shown in Table 2-1.

Table 2-1
Data Sources and Assumptions

Topic	Assumptions	Data Sources
Inflation Rates (2007-2026)	CPI: 2.5% Construction Costs: 2.5% O&M Costs: 2.5%	Aquila Corporate Estimate for Budget Planning
Cost of Capital (Discount Rate)	Debt: 52.5% @ 7.75% Equity: 47.5% @ 11.50% Wtd. Before Tax ROR: 9.53% Wtd. After Tax ROR: 7.97%	Capital Structure is representative of both hypothetical utility, divisional books and long-term target.
Fuel Price Forecasts (2007-2026)		Gas Forecasts provided by Global Energy Decisions, Natural Gas Reference Case dated 4/26/06. Coal forecasts from internal and Iatan 2 estimates.
Reserve Margin	13.64% Reserve Margin	SPP Reserve Margin Requirement
Financial Data	Total Effective Tax Rate – 38.39%	Aquila Financial Data 2006-2008 Budget

2.2 EXISTING SUPPLY RESOURCES

2.2.1 Existing Generation

During 2006, ANM generating resources consisted of 27 generating units with an accredited capacity of 1,741.6 MW. ANM's generating capacity mix was 51.6% baseload and 48.4% peaking capacity in 2006. Table 2-2 details the capacity and total energy output for each of the units for the 2006 calendar year.

ANM also receives energy from two fractional MW wind turbines located on the site of the Jeffrey Energy Center in Kansas. While the company receives energy from these turbines, no capacity is accredited to them.

Table 2-2
ANM Generation Capacity by Unit

Unit	Fuel	Capacity (MW)	2006 Net Output (MWh)	Capacity Factor
Iatan	Coal	117.7	913,224	88.57%
Jeffrey Energy Center 1	Coal	58.4	397,279	77.66%
Jeffrey Energy Center 2	Coal	58.4	401,385	78.46%
Jeffrey Energy Center 3	Coal	58.4	438,601	85.73%
Lake Road 4	Coal	97.4	514,924	60.35%
Sibley 1	Coal	53.8	344,871	73.18%
Sibley 2	Coal	53.9	350,639	74.26%
Sibley 3	Coal	400.6	2,353,850	67.08%
Total Baseload Capacity		898.6	5,714,773	72.60%
Greenwood 1	Gas	58.0	19,790	3.90%
Greenwood 2	Gas	58.0	15,520	3.05%
Greenwood 3	Gas	58.0	15,275	3.01%
Greenwood 4	Gas	58.0	11,717	2.31%
Jeffrey Wind Turbine 1	Wind	0.0	38	n/a
Jeffrey Wind Turbine 2	Wind	0.0	1	n/a
KCI 1	Gas	16.7	0	0.00%
KCI 2	Gas	16.9	0	0.00%
Lake Road 1	Gas	21.7	0	0.00%
Lake Road 2	Coal	27.3	766	0.32%
Lake Road 3	Gas	11.2	1,124	1.15%
Lake Road 5	Gas	68.5	0	0.00%
Lake Road 6	Oil	21.0	235	0.13%
Lake Road 7	Oil	21.7	198	0.10%
Nevada	Oil	20.0	0	0.00%
Ralph Green 3	Gas	71.0	18,371	2.95%
South Harper 1	Gas	105.0	28,321	3.08%
South Harper 2	Gas	105.0	38,960	4.24%
South Harper 3	Gas	105.0	49,504	5.38%
Total Peaking Capacity		843.0	199,820	2.71%
Total Capacity		1741.6	5,914,593	38.77%

Table 2-3 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 2-3
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

2.2.2 Existing Purchased Power

Nebraska Public Power District (NPPD) provides 175 MW of baseload capacity and energy to ANM through 2010 with 75 MW of baseload capacity and energy continuing through 2013. In addition, ANM purchases 60 MW of capacity and energy from the 110 MW Gray County Wind Energy wind farm, totaling 20 MW of accredited power. Of this capacity, 7 megawatts is allocated to serve the needs of SJD customers and 13 MW serve ANM. Changes in SPP rules in 2008 are expected to reduce the capacity accredited to this plant to a minimal amount to be determined in 2008. The contract will expire in 2012 with a five-year option to extend the contract into 2017. At this time, ANM expects to receive energy from the contract through 2017.

2.2.3 Changes in Existing Generation

At the time that this study was conducted, ANM had no firm plans to retire any of its existing generation assets or significantly alter any unit output. Several of ANM's generating units are aging, but the company is still planning on maintaining the current level of capacity from the fleet with necessary preventative maintenance in accord with the equipment suppliers. Table 2-4 details the ages of Aquila Networks-Missouri current fleet of generating units.

Table 2-4
Age of Existing Generation Fleet

Unit	Online Date	Age
Greenwood 1	5/1/1975	31
Greenwood 2	5/1/1975	31
Greenwood 3	6/1/1977	29
Greenwood 4	6/1/1979	27
South Harper 1	6/2005	1
South Harper 2	7/2005	1
South Harper 3	8/2005	1
Iatan	5/1/1980	26
Jeffrey Energy Center 1	7/1/1978	28
Jeffrey Energy Center 2	5/1/1980	26
Jeffrey Energy Center 3	5/1/1983	23
Jeffrey Wind Turbine 1	1/1/1999	8
Jeffrey Wind Turbine 2	1/1/1999	8
KCI 1	4/1/1977	29
KCI 2	4/1/1977	29
Lake Road 1	7/1/1950	56
Lake Road 2	8/1/1958	48
Lake Road 3	6/1/1962	44
Lake Road 4	8/1/1966	40
Lake Road 5	3/1/1974	32
Lake Road 6	5/1/1989	17
Lake Road 7	12/1/1990	16
Nevada	6/1/1974	32
Ralph Green 3	6/1/1981	25
Sibley 1	6/1/1960	46
Sibley 2	5/1/1962	44
Sibley 3	6/1/1969	37

ANM has hired Black & Veatch (B&V) to perform a study of opportunities for generating unit additions, retirements, and modifications of existing units at existing ANM plant sites. This study is expected to be completed in the Spring/Summer of 2007.

2.2.4 Transmission System

The Aquila Networks – Missouri transmission system extends over portions of west central and northwest Missouri, and operates at the 345 kV, 161 kV, and 69 kV voltage levels. The system is a part of the eastern interconnected transmission grid of the United States and Canada. The ANM transmission system is interconnected with seven neighboring utility control areas. Security coordinatrion of ANM's transmission system is handled by Midwest Independent System Operator (MISO), while tariff administration is handled by the Southwest Power Pool (SPP). ANM has agreed to abide by all the reliability requirements of MISO and SPP, as well as the North American Electric Reliability Council

(NERC). The power pool has established reliability and transmission planning requirements which are essentially based on the NERC requirements. ANM system planning engineers follow the criteria of power pools and NERC planning guidelines when looking at future transmission additions and modifications.

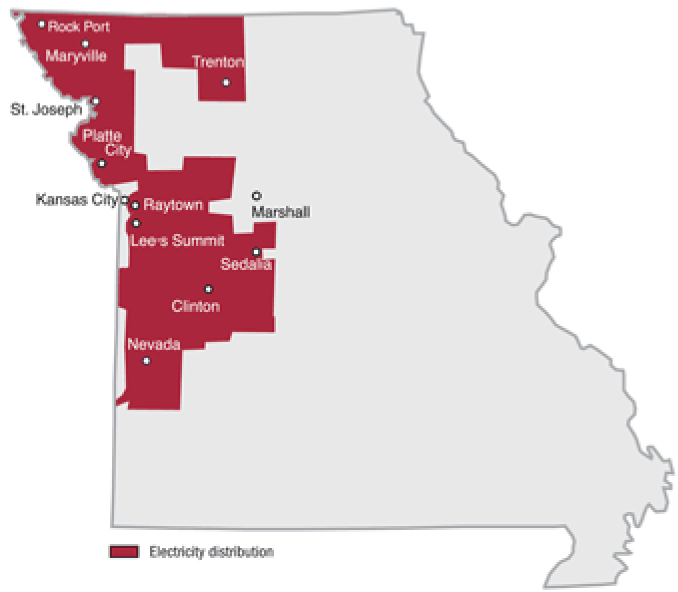
The generation and transmission groups within ANM are not allowed to share information under regulations of the Federal Energy Regulatory Commission (FERC). Because of this separation, the resource planning group within ANM is not allowed to perform or obtain any analysis of the age, condition, and efficiency level of the transmission system or the feasibility of loss-reduction measures as a supply-side resource as outlined in the IRP requirements. At the time of new generation project development, transmission studies can be requested by the generation side of ANM to be performed by the transmission side of ANM to determine transmission issues for a specific site and project. This process is the same as for non-Aquila power project developers.

When proposing the addition of generating facilities to the ANM system, transmission planning studies must be done to determine transmission additions necessary to meet all reliability and operating requirements, and to ensure that operation of the interconnected system will not be jeopardized. Moreover, none of the adjacent control areas should be adversely affected.

When new generation on the ANM system is being considered, currently the procedures are that a study is done utilizing the most current Southwest Power Pool load flow models to which all the appropriate transmission detail in the ANM system has been added. The proposed generation is then added to the model. A number of load flow cases must then be run with various transmission elements out of service to be sure that the system will perform adequately with any one element of the system out of service. Having one element of the system out of service is known as a "first contingency condition." According to accepted system planning criteria, the transmission system must be able to operate under a first contingency condition with no other elements of the system overloaded.

A map of the ANM service territory is shown in Figure 2-1. This map also shows the location of towns served by ANM.

Figure 2-1
Aquila Networks - Missouri
Service Territory Map



2.3 ENVIRONMENTAL IMPACTS

2.3.1 Environmental Assessment

In accordance with 4 CFR 240-22.040 (2)(B)(1), this section provides an environmental assessment of environmental laws and regulations that could impact ANM utility rates. Environmental laws and regulations that could impact utility rates are typically those that impact the company's generation facilities. Current regulations impact certain air emissions, water discharges and the handling and disposal of materials from these type of facilities. The following summarizes the current and potential regulations for controlling pollutants from generating facilities and the expected impact on utility operations.

2.3.1.1 Air Emissions

Air emissions are primarily regulated at the federal level under the Clean Air Act (CAA) and subsequent amendments. Pollutants associated with fossil fuel generation that are regulated as criteria pollutants include sulfur dioxide (SO_2), nitrogen oxides (NOx), particulates and carbon monoxide (CO). Other pollutants associated with fossil fuel combustion that may be regulated under the Clean Air Act Amendments of 1990 (CAAA) are hazardous air pollutants commonly referred to as air toxics. Additionally, utility boilers emit pollutants such as NOx and volatile organic compounds which lead to the formation of ozone. Under the CAA of 1970 national ambient air quality standards (NAAQS) were established for ozone, SO_2, and other emissions. A pollutant that may be regulated under future air legislation aimed at curbing global warming is carbon dioxide (CO_2).

a. Sulfur Dioxide (SO_2)

SO_2 is currently regulated under the 1990 Clean Air Act Amendments. This program is a cap and trade program where facilities are allocated allowances based on a 1.2 lb/mmBtu emissions rate times the average annual heat input from 1985 to 1987. Under this program, ANM's units (this excludes allowances from co-owned units at Jeffrey Energy Center and Iatan) were allocated 9396 allowances (1 allowance = 1 ton of SO2 emissions). Since our current annual heat input has increased since 1985 – 87, Aquila emits about 16,500 tons/year of SO2. We do not have enough allowances and are either required to buy allowances or put on pollution controls. Pollution control costs are over $3,000/ton and allowance costs have varied from less than $100 to in excess of $1,600/ton. Since pollution control costs are much greater than the allowance costs, we currently buy allowances.

New regulations have been written by EPA for further SO_2 reductions beginning in 2010. This regulation, the Clean Air Interstate Rule (CAIR), is a cap and trade program similar to the 1990 Clean Air Act Amendments but lowers the cap by 62% from 2003 levels in 2010 and by 73% from 2003 levels in 2015. In May, 2006, Sargent and Lundy produced a final report for Aquila comparing a multitude of options to comply with the CAIR rules. The results of the study indicate that SO_2 allowance prices would need to exceed $3200/ton average over a 20 year period to make pollution controls a feasible option. Since allowance prices have never been that high, even in any one day, Aquila will continue to buy allowances. The study assumes that all of our units will operate at a high capacity factor until at least 2029. Any reduction in unit life from 2029 or reduction in capacity factor makes allowances even more attractive.

Future legislation is possible that could tighten SO_2 limits. In May, 2006, Senator Carper introduced the Clean Air Planning Act of 2006. This bill would further tighten the SO_2 caps above and beyond the CAIR. It also would require units 50 years or older in the year 2020 to have SO_2 emission rates of 2 lb/MW-hour or less. Senator Jeffords has introduced similar legislation in the past that would also tighten the SO_2 cap. If any of these cap tightening proposals are passed, then Aquila will need to again perform a least cost analysis of the legislation. It is possible that a scrubber will be required on some or all of our units. There are two types of scrubbers, dry and wet. The dry scrubber has a lower annual cost than the wet scrubber however; the dry scrubber does not remove as much SO_2 as a wet scrubber. A wet scrubber is also believed to help reduce mercury emissions. According to the S&L study, the primarily wet scrubber scenario would cost about $223 million in total capital, $42 million annual levelized cost, and would reduce ANM's SO_2 emissions to about 1,185 tons/year. The dry scrubber scenario would cost about $188 million, $40 million annualized cost, and would reduce ANM's SO_2 emissions to about 1,488 tons/year.

Other legislation and regulations that could affect ANM's SO_2 control strategy is the Clean Air Visibility Rule (CAVR), Clean Air Mercury Rule (CAMR), the new particulate standards for PM2.5, New Source Review enforcement or non-attainment of areas in or near where we have our coal-fired plants. The CAVR requires certain units built between 1962 to 1977 to reduce visibility impacts in pristine Class I areas. Sibley and Lake Road units were built in this timeframe and may be impacted by this regulation. In Missouri, Hercules Glade in SW Missouri and Mingo in SE Missouri are determined to be Class I areas. Visibility is believed to be impacted by sulfates and nitrates. SO_2 is considered a precursor to sulfate formation. It has not been determined if either Sibley or Lake Road are significantly impacting visibility, but if so, some controls may need to be added. It is believed that the dry or wet scrubber options described above will meet the CAVR.

The CAMR rule establishes a two phase cap and trade system for nationwide mercury control similar to the SO_2 trading program. Since mercury control for coal-fired plants is relatively new, there is little long term operational data to determine what controls are effective in reducing mercury. It is believed that one of the effective controls would be a scrubber technology. Either scrubber technology would serve to help meet the CAMR however; activated carbon may need to be added. A further discussion on mercury will be presented in the following section.

EPA is required to protect human health and welfare. EPA reviews pollutants that are expected to cause health issues. One of those pollutants is particulate less than 2.5 microns in diameter which is known as PM-2.5. At this time, EPA believes SO_2 and NOx are precursors to PM-2.5 formation. At this time, EPA believes that the CAIR rule will suffice to control PM-2.5 from coal-fired power plants. However, some data suggests that the EPA needs to further control PM-2.5. If the PM2.5 standard becomes more stringent, it could require more utilities to install SO_2 and NOx controls. It is believed that the dry or wet scrubber options described above will meet any more stringent PM-2.5 standards. Selective Catalytic Reduction (SCR) or similar technology could be required for NOx reductions.

New Source Review enforcement issues have required some utilities to put on Best Available Control Technology (BACT). A scrubber has been determined to be BACT for both the Iatan 2 and City of Springfield air permits.

It is possible that the Kansas City or St. Joseph area could become non-attainment with the SO_2 standards. If that occurs, the MDNR and EPA could require the largest contributors to the non-attainment to put on controls. If required, it could mean a wet or dry scrubber on one or more units.

Both Jeffrey Energy Center and Iatan will be subject to most of the same regulations as the Aquila owned units. Both facilities have determined their least cost alternative is installing wet scrubbers. This technology should meet all currently known environmental regulations.

b. Nitrogen Oxides (NOx)
The 1990 Clean Air Act Amendments added a limit by boiler type on NOx emissions. Cyclone units were required to meet a 0.86 lb/mmBtu limit. The state of Missouri lowered the limit for cyclone units burning tire derived fuel to 0.68 lb/mmBtu. Cyclone boilers that do not burn tire derived fuels are subject to a 0.35 lb/mmBtu limit. Since ANM's affected owned and operated boilers are all cyclone units burning tire derived fuels, our current limit is 0.68 lb/mmBtu. Aquila had to install overfired air systems to meet this limit.

The CAIR set up an annual and seasonal NOx cap and trade program in 23 eastern states (including Missouri) and the District of Columbia. The annual trading program is a two phased approach beginning in 2009. The first phase budget cap is 1.5 million tons of NOx which represents a 53% reduction from the 2003 emission levels. The second phase of the program begins in 2015. The budget cap is 1.3 million tons of NOx. The annual allocations for this program are based on the three highest annual heat inputs from 2000 to 2004 multiplied by 0.15 lb/mmBtu for Phase I and by 0.125 lb/mmBtu for Phase II. Missouri DNR has not finalized the allocation to Aquila. However, based on draft rules, it is expected that Aquila will be allocated about 3,200 allowances (1 allowance = 1 ton of NOx) for Phase I and 2,600 allowances for Phase II. Our current NOx annual emissions are about 13,200 tons/year.

In addition to the allowances described above, ANM may receive additional NOx allowances as a result of burning tire-derived fuels. The draft Missouri regulations for the implementation of CAIR provide for a supplemental allowance pool for utilities in Western Missouri that burn 1,000 tons/year of tire-derived fuels. The supplemental pool allowances will have to be used the first two years of the NOx program. For 2009 and 2010, ANM is expecting 1,912 supplemental pool allowances based on the preliminary allowance allocation.

The seasonal NOx program is set up similar to the annual program but just covers emissions during the ozone season (May 1 through September 30). The ozone season cap in Phase I is 1,050,000 tons and for Phase II is 480,000 tons. Based on the draft rules, Aquila expects to receive about 1,400 allowances for Phase I and 1,150 allowances for Phase II. Our current ozone season NOx emissions are about 5,600 tons/year.

S&L performed a study of compliance options with the CAIR program. The least cost analysis is sensitive to the allowance costs. The NOx allowance market for the region is not mature and therefore, it is very difficult to predict costs. A higher NOx allowance costs makes controls more favorable ($2000 and higher) where a lower NOx allowance price ($1200 or less) makes allowance purchase more attractive. In October, 1998, EPA finalized the "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone" (Commonly called the NOx SIP Call). The NOx allowance price for the NOx SIP call region in the last year has ranged from about $1000 to $2000/ton. If controls are installed in ANM's system, we believe our least cost option that will meet or come close to meeting Phase II levels is installing deep staging on all coal-fired affected units, rich reagent on Sibley 1 and 2 and Lake Road, and selective catalytic reduction on Sibley 3. The total capital cost of these controls is approximately $125 million and the levelized costs are about $25 million.

Future legislation is possible that could tighten NOx limits. In May, 2006, Senator Carper introduced the Clean Air Planning Act of 2006. This bill would further tighten the NOx caps above and beyond the CAIR. It also would require units 50 years or older in the year 2020 to have NOx emission rates of 1 lb/MW-hour or less. Senator Jeffords has introduced similar legislation in the past that would also tighten the NOx cap. If any of these cap tightening proposals are passed, then Aquila will need to again perform a least cost analysis of the legislation. It is possible that additional SCR systems would be required on some or all of our units. According to the S&L study, additional SCR systems at Sibley 1 and 2 and Lake Road would be about $48 million in total capital.

Other legislation that could affect ANM's NOx control strategy is the Clean Air Visibility Rule (CAVR), the new particulate standards for PM2.5, NSR or non-attainment issues. The CAVR requires certain units built between 1962 to 1977 to reduce visibility impacts in pristine Class I areas. Sibley and Lake Road units were built in this timeframe and may be impacted by this regulation. In Missouri, Hercules Glade in SW Missouri and Mingo in SE Missouri are determined to be Class I areas. Visibility is believed to be impacted by sulfates and nitrates. NOx is considered a precursor to nitrate formation. It has not been determined if either Sibley or Lake Road are significantly impacting visibility, but if so, some controls may need to be added. It is believed that SCR will meet the CAVR.

EPA is required to protect human health and welfare. EPA reviews pollutants that are expected to cause health issues. One of those pollutants is particulate less than 2.5 microns in diameter which is known as PM-2.5. At this time, EPA believes SO2 and NOx are precursors to PM-2.5 formation. At this time, EPA believes that the CAIR rule will suffice to control PM-2.5 from coal-fired power plants. However, some data suggests that the EPA needs to further control PM-2.5. If the PM2.5 standard becomes more stringent, it could require more utilities to install NOx controls. It is believed that the SCR options described above will meet any more stringent PM-2.5 standards.

New Source Review enforcement issues have required some utilities to put on Best Available Control Technology (BACT). SCR has been determined to be BACT for both the Iatan 2 and City of Springfield air permits.

It is possible that the Kansas City or St. Joseph area could become non-attainment with the NOx or ozone standards. If that occurs, the MDNR and EPA could require the largest contributors to the non-attainment to put on controls. If required, it could mean SCR controls on Sibley 1 and 2 and/or Lake Road.

Iatan will be subject to the same regulations as the Aquila owned units. Iatan will be installing SCR and should meet currently known regulation. Jeffrey Energy Center is not subject to CAIR. However, it is subject to CAVR, PM-2.5, NSR and non-attainment issues. Jeffrey has installed ultra low NOx burners at one unit and plans to install this technology on the other two units. The new burners have achieved an emissions limit of approximately 0.16 lb/mmBtu. This limit could meet some of the emissions limits from the known programs. However, it may not meet NSR. SCR would meet NSR. The cost of SCR on Jeffrey would be approximately $120/kw or about $275 million. MPS owns 8% of Jeffrey.

c. Particulates

National Ambient Air Quality Standards for suspended particulate matter were established as a result of the CAA of 1970. In 1980, EPA set the allowable particulate emission standard for new electric utility steam generating units at 0.03 lb/mmBtu heat input. Due to the concern over inhalation of smaller particulate matter, EPA focused on regulation of fine particulates 10 microns or smaller, or PM10. In 1987 EPA revised the air quality standards for particulates by establishing primary and secondary standards for PM10. EPA is continuing the study of the health impacts of fine particulate and has revised the standard to address fine particulates defined as 2.5 micron in diameter.

The Sibley units employ electrostatic precipitators (ESP) to control particulate emissions. A new ESP was installed on Unit #3 as part of the coal conversion project. This ESP was sized with additional capacity in anticipation of future reductions of the allowable particulate emission standards. The ESPs on Sibley Units 1 and 2 were upgraded and expanded to accommodate combustion of low sulfur coal. Currently, the allowable emission rate for the Sibley Plant is 0.12 lbs/mmBtu. Performance tests on the ESPs measured a PM10 particulate emission rate Sibley Units 1, 2 and 3 were 0.02, 0.04, and 0.01 lbs/mmBtu, respectively.

d. Hazardous Air Pollutants (Air Toxics)

As described above, EPA’s emphasis on air toxics currently centers on the Clean Air Mercury Rule. The first phase in 2010 requires coal-fired boilers nationwide to achieve a mercury cap of 38 tons/year. In 2018, the cap is reduced to 15 tons/year. Mercury is a newly regulated pollutant and there is little long term experience in the control and continuous monitoring of such a small amount of pollutant. Because no continuous measurement technique is approved, it is difficult to establish a baseline emissions level. Without a baseline emissions level, it is impossible to know what is needed to comply with the regulation. Aquila has performed a mercury stack test at Lake Road. Results indicated very low mercury levels. If this test is representative of long term emissions at Lake Road and Sibley, no controls will be required. If the emissions test is not representative, then activated carbon injection, scrubbers and/or emerging technology could be required. Our current plan is that no mercury controls will be installed until we have more definitive emissions data.

There are several states that have or are contemplating additional controls above and beyond CAMR. The most stringent of these controls are requiring a 95% reduction in mercury or a 0.0025 lb/GW-hr limit by 2012 (Massachusetts). Also, there is proposed national legislation (Carper) that would tighten the mercury cap, require a percent removal rate or an emissions limit. Under Carper's plan, mercury would need to either be reduced by 60% or have a 0.02 lb/GW-hr limit by 2010. Carper's second phase further reduces mercury by 90% or a 0.006 lb/GW-hr limit in 2015.

A 95% reduction in mercury or 0.0025 lb/GW-hr limit would likely require a scrubber and activated carbon injection. The scrubber costs were given in the SO_2 section. An activated carbon injection system would be an additional $3 million in total capital and about $800,000 annualized cost over a 20 year period.

The primary air toxic emphasis has been in regards to mercury. At this time, we have not evaluated the possibility of any other air toxic regulations that would significantly affect ANM's boilers.

Both Jeffrey Energy Center and Iatan are installing wet scrubbers. If emission limits are tightened, then it is expected these facilities will comply with the wet scrubber or may need to add activated carbon injection or equivalent technology.

e. Greenhouse Gases (GHG) including CO_2

Currently there are no rules or regulations for greenhouse gases. However, there has been significant discussion in Congress about limiting GHG. Some states have mandated GHG limits. It is likely that some form of GHG legislation will be passed in the next ten years. The primary discussions have been around three concepts: a carbon tax, a cap and trade program similar to CAIR, and a carbon intensity target.

The carbon tax would add taxes to the fuel supply that would in turn pass those costs on to the utilities. This tax rate has not been established but it would likely be set at different rates for different fuels. The intent of the carbon tax would be to increase efficiency of the power plants, make lower carbon fuels more economical and to increase use of renewables.

The cap and trade program would cap carbon emissions and set up a trading program. There have been several attempts in Congress to enact this type of legislation. However, to date, these measures have failed. Some northeastern states have formed a group called Regional Greenhouse Gas Initiative (RGGI) that is a cap and trade program. The most likely cap and trade program would limit 2015 emissions to 2000 levels. Under this scenario, our preferred integrated resources plan from the 2005 IRP shows that Aquila would be about 2.1 million tons over the cap. Again, it is unknown what costs would be associated with buying a ton (one allowance) of emissions. In the European GHG market, a metric ton (1.1 US tons) has ranged from about $15 to $30. Assuming these same price levels would result in total allowance costs between $35 to $69 million under this scenario.

The carbon intensity program is set up to reduce the pounds of carbon emitted per megawatt hour produced. This program's intent is to increase plant efficiency. It is unknown how much of a reduction would be required at this point but Aquila has reduced our carbon intensity from 1.07 lb/MWh in 2000 to a projected level of 1.04 lb/MWh in 2015 based on the resource plan from the ANM 2005 IRP. It is likely that any reduction requirements would be at least 5%. Based on our current projects, Aquila will be below a 5% reduction in carbon intensity. This reduction includes our portion of Iatan and Jeffrey Energy Center.

2.3.1.2 Solid Wastes

The major solid waste stream generated at ANM power plants is coal ash. The EPA has determined that utility coal ash should not be regulated as a hazardous waste. Currently, fly ash generated at the Sibley Plant is ultimately disposed of in an on-site landfill. This facility is equipped with an engineered soil liner and has a leachate collection system. Therefore, any future regulations requiring further controls on existing ash disposal sites should not impact the Sibley Plant. At Lake Road, the fly ash is sold for beneficial uses.

2.3.1.3 Water Impacts

Potential water quality concerns for utility operations are additional regulation of priority pollutants and thermal discharges, and encroachment of zebra mussels.

Wastewater discharges from utility power plants are regulated by the Missouri Department of Natural Resources through the National Pollutant Discharge Elimination System (NPDES) program. Effluent standards for regulated pollutants are incorporated in facility operating permits. Current treatment processes have been adequate to address the pollutants targeted by EPA for the utility industry. However, EPA may expand the list of priority pollutants to be regulated in utility process wastewater to include toxic metals and organic toxic pollutants. Such future regulation is not expected to result in costs that would impact resource planning decisions.

The environmental impact of thermal discharges from power plants has attracted renewed interest from some regulators. Permit application for future power plants employing once through, noncontact cooling water would be heavily scrutinized relating to thermal impacts on receiving water. Thermal discharge from existing units such as the Sibley Plant may be affected by possible changes in thermal discharge regulations. The flow rate of the Missouri River will be a large factor to determine what if anything needs to be done. A high flow rate would likely serve to decrease the likelihood of thermal discharge impacts while a low flow would increase the likelihood of thermal impacts. The worst case impacts could require installation of cooling towers or equivalent technology.

Zebra mussels initially infiltrated the Great Lakes through a foreign ship, and are currently making their way down major river systems including the Missouri River. The possibility exists that zebra mussels could also infiltrate reservoirs. Zebra mussels are highly prolific and cause problems when colonies attach themselves to intake and discharge lines. Encroachment of zebra mussels has not been a problem at ANM facilities to date. However, should infestation occur, remedial action such as chemical treatment may require modification of the existing NPDES permit. Although managing such a problem would likely result in increased operating costs, such costs would not have a significant affect on new energy resource decisions.

2.3.1.4 Siting Impacts

Future generation facilities are expected to be located at existing power plant sites, or new sites located in rural or fringe metro areas. These facilities will be interconnected with existing or future transmission lines and substations. The specific siting impacts of such facilities are best assessed later when certification, licensing and permitting is required to develop these sites.

2.3.2 Probable Environmental Costs

The methodology for estimating probable environmental costs in 4 CSR 240-22.040(2)(B) of the Missouri electric utility resource planning rules consists of three major steps, as follows:

- Identify relevant environmental impacts that may require mitigation.
- Assess expected low and high mitigation levels for emissions with major impacts.
- Estimate the probable environmental cost of achieving expected mitigation levels.

Probable environmental cost is defined in 4 CSR 240-22.020(46), as follows:

> *Probable environmental cost means the expected cost to the utility of complying with new or additional environmental laws, regulations, taxes or other requirements that utility decision makers judge may be imposed at some point within the planning horizon which would result in compliance costs that could have a significant impact on utility rates.*

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.

Environmental costs to society related to electric utility power plant emissions are primarily caused by air emissions, namely SO_2, NOx, Hg, PM10, PM2.5 and CO_2, as described previously. These major emissions are considered to be "regional pollutants", which means generally that they affect the environment at or near the generating source.

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 2-5 summarizes the range of environmental costs from these studies for each emission.

Table 2-5
Environmental Costs Utilized in the 2007 ANM Integrated Resource Plan

	SO_2 ($/ton)			Ozone Season NO_X ($/ton)			Annual NOx ($/ton)			Mercury ($/ounce)			Mercury ($/lb)			CO2 (2005 $/short ton)		
Year	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 2-5 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.

2.4 SUPPLY-SIDE SCREENING ANALYSIS

2.4.1 Introduction

The growth of customer demand and expiration of existing purchase contracts result in the need for future resources. Numerous demand-side and supply-side options are available for ANM to consider and integrate into a resource strategy for the future. The purpose of this section is to systematically consider each alternative, and reduce the list of supply alternatives for further consideration to those which clearly are superior.

The selection of supply resources to meet customer needs must consider a broad range of criteria which could be important in the development of a resource strategy for ANM, including:

- Cost (including the cost of expected environmental equipment)
- Environmental impacts
- Current and projected status of technology development
- Size of increments of capacity
- Appropriateness of technologies to the ANM service territory
- Limitations to the amount of capacity that could be considered

The information for the supply-side alternatives was provided by many sources including manufacturers' information, consultants, in-house engineering staff and available EPRI studies including the EPRI Technical Assessment Guide. This information defining the supply-side technology characteristics has significant uncertainty. Therefore, it is critical that this uncertainty be directly considered in the screening process and resources not be eliminated inappropriately based upon uncertain assumptions.

The supply side screening exercise was performed in two phases. Each phase of the screening narrows the resource choices to be considered.

The Phase 1 exercise uses the EPRI Technical Assessment Guide (TAG)® documents, database and program to determine the technology types that are most cost effective for application. The results of the Phase 1 screening identify the least cost options for different load types of resources and the best in class for each type of resource. The screening results can also indicate a range of operating results for each type of resource.

Phase 2 applies screening curve methodology to self-build estimates and resource offers provided in the most recent request for proposals. The candidate resources in this exercise represent the latest options for supply additions. Recognizing that production modeling is superior to screening graphs, all candidates were passed from this exercise to production costing models. While this type of exercise is typically used to disqualify high cost resources, all candidates were passed because the number of choices remained manageable within the production cost model. The importance of this exercise therefore lies with its affirmation of the production results.

Phase 1 – Technology Screening

The initial supply-side screening was performed with “base” forecast assumptions: probable environmental costs, mid- range fuel price forecast, mid-range capital cost and a mid-range cost of capital, assuming a year 2005 in-service date. The screening analysis resulted in a $/kW-year cost (in 2005 dollars) for each resource alternative across a range of capacity factors. This screening identified the top options from an overall pool of 251. The results of the screening were separated into four categories: baseload, intermediate, peaking, and non-dispatchable. Sub-groups of baseload were pulverized coal, atmospheric fluidized bed, coal gasification, geothermal, nuclear, and waste burning. Sub-groups of intermediate power included combustion turbine combined cycle and fuel cells. Sub groups of the peaking category included combustion turbine, internal combustion engine, small combustion turbine and energy storage technologies. Non-dispatchable technologies had the subgroups solar photovoltaic, solar thermal and wind generation.

Although all available EPRI technologies were screened, some were eliminated based on conditions outside of economics. An example in the Aquila system is commercial geothermal generation. Similarly, power supply resources based on unproven technologies cannot be included for consideration as primary resources in the near term future. Technologies excluded are listed in Table 2-6.

Table 2-6
Technology Screening Summary

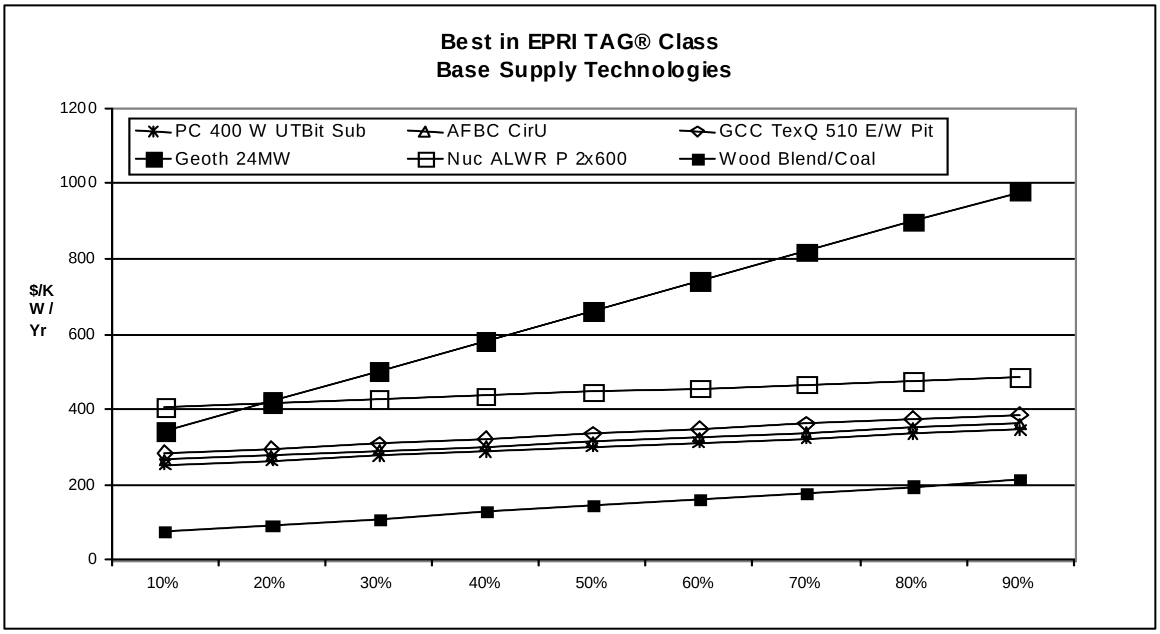
Technology	Reason for Exclusion
Geothermal	Geographically specific technology is not applicable to Aquila region.
Solar Photovoltaic	Aquila region does not have cost effective geographic and atmospheric conditions for this technology.
Solar Thermal	Aquila region does not have cost effective geographic and atmospheric conditions for this technology.
Waste Burning	Technology requires a support industry to supplement additional costs. Aquila has worked to identify possible waste burning support industries in our region and will evaluate specific proposals when they become available.

Refer to Appendix 2-F for complete results of the EPRI TAG® screening.

2.4.1.1 Baseload Technologies

Shown in Figure 2-2 are the results of the screening of baseload technologies. The Pulverized Coal and Atmospheric Fluidized Bed technologies were revealed to be the least cost options.

Figure 2-2
Screening Study Results – Baseload Technology Options



PC 400 W UTBit Sub –Pulverized Coal, 400 MW, Utah bituminous coal, Western United States location, Lime Spray Dryer Flue Gas Desulfurization, Subcritical

AFBC CirU – Atmospheric Fluidized-Bed Combustion – Circulating, Utah bituminous coal, Western location, 200 MW

GCC Tex Q 510 E/W Pit – Integrated Coal Gasification Combined Cycle, 510 MW, Pittsburgh No. 8 Coal, ChevronTexaco Power and Gasification Corp. technology, East Central/West Central location

Geoth 24MW – Geothermal Power Plant, Brine, Dual Flash, 24 MW, Air Cooled Heat Exchanger, Western location

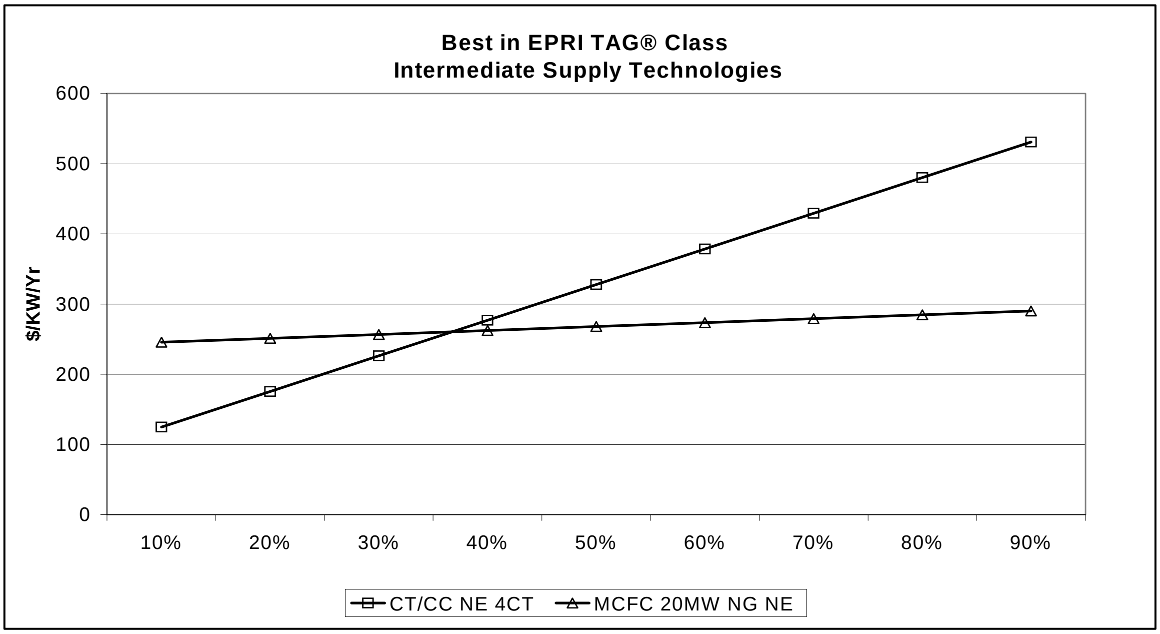
Nuc ALWR P 2x600 – Nuclear Advanced Light Water Reactor, Passive Safety, 2 X 600 MW, East Central/West Central location

Wood Blend/Coal – Wood Blend/Coal Cofired Boiler, 200 MW, Western region

2.4.1.2 Intermediate Technologies

Shown in Figure 2-3 are the results of the screen of intermediate technologies. Combined Cycle Combustion Turbine technology is favorable to Fuel Cell technology.

Figure 2-3
Screening Study Results – Intermediate Technology Options



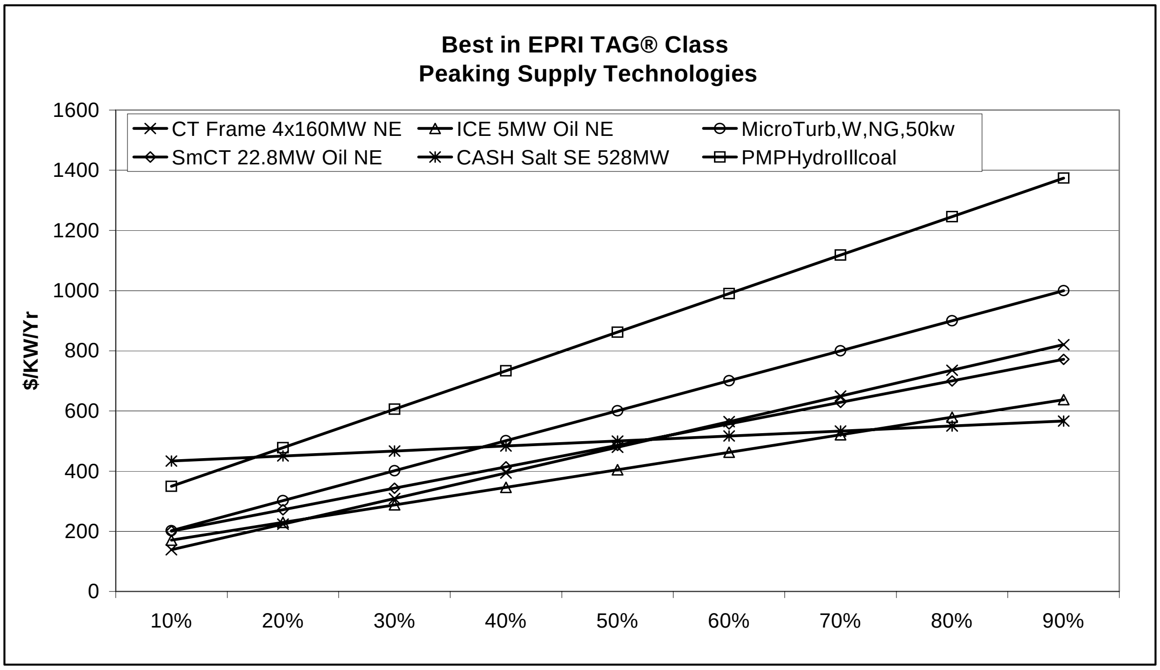
CT/CC NE 4CT – Combined Cycle Combustion Turbine, Natural Gas fuel, Northeast location, 235 MW

MCFC 20MW NG NE – Molten Carbonate Fuel Cell, 20 MW, Natural Gas fuel, Northeast location

2.4.1.3 Peaking Technologies

Shown in Figure 2-4 are the results of the screen of peaking technologies. Combustion Turbine technology is favorable to Internal Combustion Engine, Micro-turbine, Pumped Hydro, and Compressed Air energy storage technologies.

Figure 2-4
Screening Study Results – Peaking Technology Options

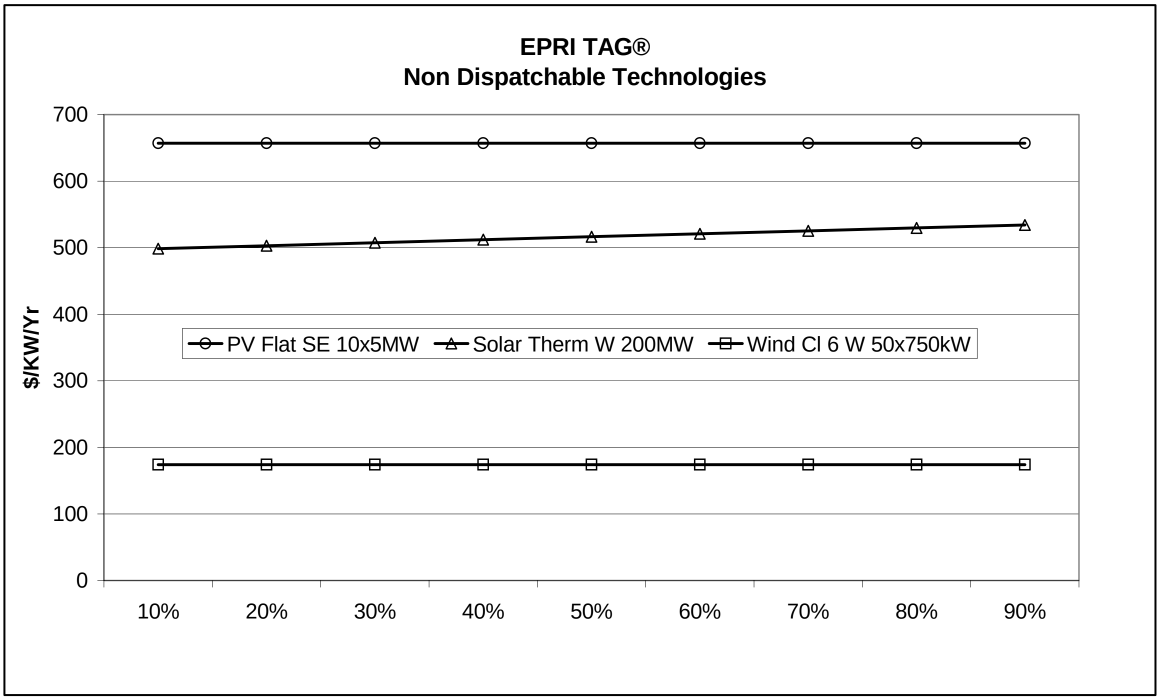


CT Frame 4x160MW NE – Combustion Turbine Heavy Duty, 4x160 MW each, Natural Gas fuel, Northeast location
ICE 5MW Oil NE – Internal Combustion Engine, 5 MW, oil fuel, Northeast location
MicroTurb W NG 50kw – Microturbine, 50 kW, natural gas fuel, Western location
SmCT 22.8 MW Oil NE – Small Combustion Turbine, Heavy Duty, 22.8 MW, Distillate fuel oil, Northeast location
CASH Salt SE 528 MW – Compressed Air Energy Storage with Humidification in Salt Dome, Southeast location, 528 MW
PMPHydroIllcoal – Pumped Hydro Energy Storage, Conventional, 3x350 MW, Northeast location

2.4.1.4 Non-Dispatchable Technologies

Shown in Figure 2-5 are the results of the screen of leading non-dispatchable technologies. Wind Power is favorable to Solar Thermal and Solar Photovoltaic technologies.

Figure 2-5
Screening Study Results – Non-Dispatchable Technology Options

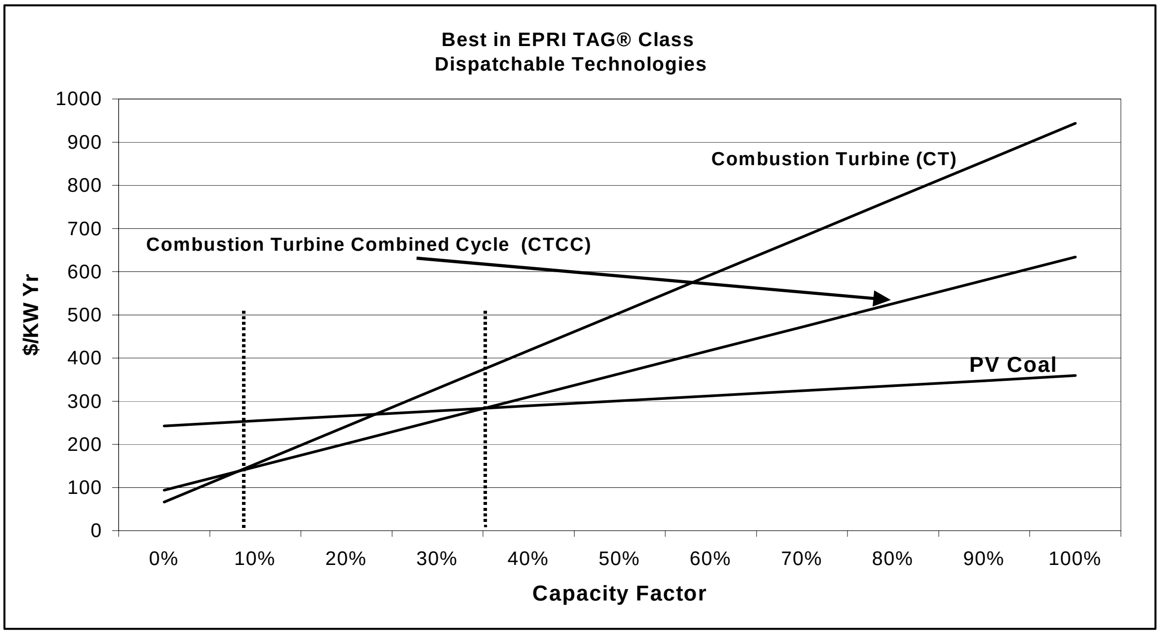


PV Flat SE 10x5MW – Solar Photovoltaic, Fixed Flat-Plate, Southeast location 10x5 MW
Solar Therm W 200MW – Solar Thermal, Parabolic Trough, Western location, 200 MW
Wind Cl 6 W 50x570kW – Wind Turbine, Class 6 Wind Speed, Western location, 50x570 kW

2.4.1.5 Summary of Dispatchable Technologies

Shown in Figure 2-6 is a combination of the screening curves from best in class of each type of technology. The graph demonstrates the approximate optimal load factor ranges of each of the technologies. From the graph, it is evident that combustion turbine technology is preferred for load factor operating ranges below 10% and coal technology is preferred for load factor operating ranges above 35%.

Figure 2-6
Screening Study Results – Technology Comparison



From the Technology Screening, 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. These results direct the analyst to prefer those technologies in the pursuit of least cost planning.

In addition to the types of resources described above, the uncertainty surrounding potential carbon dioxide costs led to the inclusion of additional resources that could potentially emit less CO_2 than the traditional resources. Included in this group of resources are integrated gasification combined cycle (IGCC), IGCC with carbon sequestration, coal with carbon sequestration, nuclear, and wind generation. 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.

2.4.2 Screening Analysis Without Environmental Costs

An important sensitivity to the resource screening was environmental costs. To inspect the impact of environmental costs, the screening analysis was repeated without any environmental costs. While this did change the capacity factors at which options the most cost effective alternative switched from one option to another, no new resource alternatives were included when the environmental cost was not considered. In addition, no resource that was selected in the previous screening was not selected in the screening without environmental costs. Table 2-7 provides a ranking of the levelized costs of resource options with and without environmental costs at a variety of load factors.

Table 2-7
Resource Option Cost and Rankings
2006$/MWh

5% Capacity Factor

	Utility Cost ($/MWh)	Utility Cost Ranking	Probable Environmental Cost ($/MWh)	Environmental Cost Ranking	Total Cost ($/MWh)	Total Cost Ranking
Generic Coal	$438.59	4	$19.13	9	$457.72	4
Generic Coal with CO_2 Sequestration	$629.69	8	$4.54	4	$634.23	8
AFBC	$555.44	6	$21.09	10	$576.54	6
Generic IGCC	$468.96	5	$17.12	8	$486.09	5
Generic IGCC with CO_2 Sequestration	$639.39	9	$3.20	3	$642.59	9
Generic Nuclear	$595.08	7	$0.00	1	$595.08	7
Generic CC	$237.94	2	$7.92	6	$245.86	2
Generic 7EA CT	$223.55	1	$10.76	7	$234.30	1
Generic LMS100 CT	$250.77	3	$7.80	5	$258.57	3
Generic Wind	$653.71	10	$0.00	1	$653.71	10

30% Capacity Factor

	Utility Cost ($/MWh)	Utility Cost Ranking	Probable Environmental Cost ($/MWh)	Environmental Cost Ranking	Total Cost ($/MWh)	Total Cost Ranking
Generic Coal	$86.06	1	$19.13	9	$105.20	5
Generic Coal with CO_2 Sequestration	$127.12	9	$4.54	4	$131.66	8
AFBC	$111.37	7	$21.09	10	$132.46	9
Generic IGCC	$106.65	6	$17.12	8	$123.77	7
Generic IGCC with CO_2 Sequestration	$144.28	10	$3.20	3	$147.48	10
Generic Nuclear	$104.27	5	$0.00	1	$104.27	4
Generic CC	$92.52	2	$7.92	6	$100.45	2
Generic 7EA CT	$112.07	8	$10.76	7	$122.82	6
Generic LMS100 CT	$95.47	3	$7.80	5	$103.27	3
Generic Wind	$98.56	4	$0.00	1	$98.56	1

85% Capacity Factor

	Utility Cost ($/MWh)	Utility Cost Ranking	Probable Environmental Cost ($/MWh)	Environmental Cost Ranking	Total Cost ($/MWh)	Total Cost Ranking
Generic Coal	$40.44	1	$19.13	8	$59.58	2
Generic Coal with CO_2 Sequestration	$62.08	5	$4.54	3	$66.62	3
AFBC	$53.90	3	$21.09	9	$74.99	4
Generic IGCC	$59.76	4	$17.12	7	$76.88	5
Generic IGCC with CO_2 Sequestration	$80.21	8	$3.20	2	$83.40	8
Generic Nuclear	$40.75	2	$0.00	1	$40.75	1
Generic CC	$73.70	6	$7.92	5	$81.63	6
Generic 7EA CT	$97.64	9	$10.76	6	$108.40	9
Generic LMS100 CT	$75.38	7	$7.80	4	$83.17	7
Generic Wind	NA		NA		NA	

2.4.3 Uncertainty Analysis

A number of assumptions used in the screening analysis are uncertain in addition to environmental costs. Therefore, ranges of the uncertainties in fuel cost forecasts, resource capital costs, fixed operation and maintenance costs, and cost of capital were developed. In the development of the preferred resource plan, all these sensitivities and additional uncertainties will be investigated.

Table 2-8 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 2-8
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

2.5 SUPPLY RESOURCE OPTIMIZATION

2.5.1 Introduction

An optimal plan consisting only of supply-side resources is necessary to produce avoided costs to be utilized to screen demand-side resource options. Although the supply alternatives have been screened on a life-cycle basis, the selection of the optimal integrated resource plan must consider more precisely the interaction of each demand-side and supply-side resource option with the existing generating resources and the forecasted demand growth.

The objective guiding the development of the optimal supply plan was to minimize total utility revenue requirements. In the case of supply-side alternatives, this objective is identical to minimizing total resource costs (the sum of utility and customer costs) since revenue requirements for supply resources are the only customer costs involved (e.g. there are no demand-side program costs). This objective is also identical to minimizing customer rates (assuming annual rate cases with perfect regulation to earn authorized returns), since customer energy usage is not directly impacted by supply-side alternatives, except through price elasticity effects on customer demand.

2.5.2 Production Cost Modeling

The screening analysis described earlier in this document is a quick and efficient method to develop the types of technologies that would possibly make for a least-cost portfolio of assets. However, it is very simplistic in its approach to estimating the actual costs of production a portfolio will incur. In order to provide a more accurate estimate of the costs of operating a portfolio of assets to meet the needs a given customer base, a production cost estimating method is used for the final determination of the least-cost options.

The production costing method of analysis utilizes a mathematical simulation of a dispatcher attempting to meet the hourly needs of forecasted demand by dispatching a portfolio in a least-cost of operation manner. The model also takes into account the capital costs of assets as they are being built and depreciated. Therefore, for a twenty-year study, the model will take a twenty-year hourly load forecast and for each hour dispatch units in the portfolio to meet the needs of that hour while minimizing total operating costs. By keeping loads and factor prices (such as fuel and labor) constant, the model can determine which portfolio would provide the lowest cost option solely based upon the operational parameters of the assets that make up the portfolio.

Production costing methods can be used to test the portfolio by a variety of factors, such as the type of generation unit to be built, its capacity and the optimal timing of commercial operation. Multiple scenarios can be modeled using this method as well.

The production costing model used by ANM is MIDAS Gold Analyst™. MIDAS Gold Analyst™ is an integrated suite of PC-based analytical tools designed exclusively for energy service providers. MIDAS Gold's™ unique ability to combine speed, multiple scenarios, and risk analytics combined with the integrated capabilities to model regional market prices, operations, customers, and financials, make it an invaluable tool.

The Capacity Expansion Module of MIDAS is a mid- to long-term company portfolio capacity optimization model for automated screening and evaluation of decisions for generation capacity expansion and retirement options, and contract transactions.

MIDAS Gold™ performs electricity market price forecasting, production analysis, acquisition analysis, asset valuation, power plant dispatch, portfolio risk management, and financial analysis and forecasting. The output of the model is an estimate of corporate cash flow for a utility. The value of this estimate is derived from the accurate modeling of power system operation.

MIDAS Gold™ uses a decision tree approach for selecting optimal choices. Each branch of a decision tree is a different portfolio of assets or similar portfolios with different construction timing. Decision tree structure is a powerful tool in determining scenario costs and making a direct comparison among alternatives.

Furthermore, recent enhancements to the MIDAS Gold™ model addressed significance of the impact of an accurate market model on operating costs. These enhancements have allowed ANM to take into account the effects of different potential environmental regulation proposals. A full description of the MIDAS Gold™ Model is included as Appendix 2-B and a full description of the MIDAS Capacity Expansion Module is included as Appendix 2-C.

2.5.3 Optimal Supply Plan

ANM intends to meet the power supply requirements of 2007 through at least 2009 by entering into purchase power agreements. The capacity and energy price assumptions for the PPAs modeled in the IRP are included in Appendix 2-G. The prices are based on peaking capacity and energy offers that Aquila has received in recent RFPs and discussions with neighboring utilities and independent power producers. It was assumed that the PPAs would be available in 50 MW blocks in sufficient quantity to meet the capacity requirements of ANM.

The first opportunity to add additional ANM-owned generation is for a commercial operation date of 2010 for generating capacity with a lead time of less than three years. With no new generation additions, ANM is projected to have a capacity deficit of 253 MW in 2010 with the addition of 153 MW of capacity from the Iatan 2 generating unit. The expiration of existing contracts in 2011 and 2014 will increase the capacity deficit to 615 MW in 2014 after which the capacity deficit is projected to grow at approximately 50 MW per year based on system load growth.

With the assumption that PPAs are available to meet capacity requirements through 2012, MIDAS Capacity Expansion Module optimization for the least cost plan indicates that a 250 MW combined-cycle unit addition is preferred in 2011 to meet a portion of the capacity requirements and provide balance to the existing baseload and peaking generation.   In 2013, 250 MW of additional combined-cycle generation is added. Later capacity additions include 200 MW of coal generation participation in 2014, 150 MW of 7EA combustion turbines in 2017 and 400 MW of nuclear generation participation from 2020 to 2025. This plan results in a balanced capacity mix with 52.5% coal-fired and nuclear capacity, 15.9% intermediate capacity and 31.6% gas and oil-fired peaking capacity by the year 2026.   Appendix 2-H provides results for the optimal supply plan.

The optimal supply plan with probable environmental costs is summarized in Table 2-9.

Table 2-9
Optimal Supply-Side Only Resource Plan
With Environmental Costs

Year	**Additional Supply-Side Resources**
2008	300 MW PPA
2009	350 MW PPA
2010	250 MW PPA
2011	150 MW PPA, 250 MW Combined Cycle
2012	200 MW PPA
2013	250 MW Combined Cycle
2014	200 MW Coal Participation
2017	150 MW 7EA CT
2020	100 MW Nuclear Participation
2021	100 MW Nuclear Participation
2023	100 MW Nuclear Participation
2025	100 MW Nuclear Participation

2.5.4 Alternative Resource Plans

Aquila developed several Alternative Resource Plans (ARPs) using the MIDAS Capacity Expansion Module to reflect the potential impact of basic power supply availability and preference assumptions. These ARPs included:

- No New Coal Generation Additions Available
- PPAs only available through 2009
- No New Natural Gas Generation Additions Available
- No Purchase Power Available
- Green Scenario (Aquila-only Limit of 6.5 Million tons of CO_2 generated beginning in 2015)

A summary of the capacity additions of each of the ARPs is included in Table 2-10. All of the plans had a higher net present value of revenue requirements (NPVRR) than the Optimal Plan. Further analysis of these plans will be discussed in parts 4 and 5 of the Integrated Resource Plan.

Table 2-10
Generation Additions and Capacity Purchases for Alternative Resource Plans

	Alternative Resource Plans				
Year	No Coal	PPAs through 2012 (Optimal Supply-Only Plan)	PPAs through 2009	No Gas	Green
2007					
2008	300 MW PPA	300 MW PPA	300 MW PPA	300 MW PPA	100 MW Wind PPA, 300 MW PPA
2009	350 MW PPA	350 MW PPA	350 MW PPA	350 MW PPA	350 MW PPA
2010	250 MW PPA	250 MW PPA	150 MW CT, 100 MW LMS	250 MW PPA	250 MW PPA
2011	250 MW CC, 150 MW PPA	250 MW CC, 150 MW PPA	250 MW CC	400 MW PPA	250 MW CC, 100 MW Wind PPA, 150 MW PPA
2012	200 MW PPA	200 MW PPA		450 MW PPA	200 MW PPA
2013	250 MW CC	250 MW CC		500 MW Coal Participation	300 MW Coal w/ CO_2 Capture Participation
2014	250 MW CC	200 MW Coal	200 MW Coal Participation	100 MW Coal Participation	100 MW Coal w/ CO_2 Capture Participation
2015				100 MW Coal Participation	100 MW Coal w/ CO_2 Capture Participation, 100 MW Wind PPA
2016			100 MW Coal Participation	100 MW Coal Participation	100 MW Coal w/ CO_2 Capture Participation
2017		150 MW CT			
2018	75 MW CT		75 MW CT		100 MW Wind PPA
2019					
2020	200 MW Nuclear Participation	100 MW Nuclear Participation	100 MW Nuclear Participation	200 MW Nuclear Participation	100 MW Nuclear Participation
2021	100 MW Nuclear Participation	100 MW Nuclear Participation			100 MW Nuclear Participation
2022			200 MW Nuclear Participation		100 MW Nuclear Participation
2023	100 MW Nuclear Participation	100 MW Nuclear Participation		100 MW Nuclear Participation	100 MW Wind PPA
2024					
2025		100 MW Nuclear Participation		100 MW Nuclear Participation	
2026	100 MW Nuclear Participation		100 MW Nuclear Participation		50 MW Wind PPA

20-Year NPVRR ($M)	$10,145	$10,142	$10,179	$10,307	$10,486
% Above Min	0.0%	0.0%	0.4%	1.6%	3.4%

10-Year NPVRR ($M)	$5,501	$5,518	$5,564	$5,619	$5,728
% Above Min	0.0%	0.3%	1.2%	2.2%	4.1%

2.5.5 Conclusions

Based on the results of the analysis of supply-side resources, the least-cost supply-side only resource plan for ANM includes a mix of the addition of gas-fired generating units (650 MW from 2011 to 2017) and participation in coal (200 MW in 2014) and nuclear generating facilities (400 MW from 2020 to 2026).

The optimal resource plan will likely change, depending on several other factors, including the results of the demand-side resource analysis and the integration of demand-side and wind resources as discussed in Part 4 of this report and the results of the risk analysis discussed in Part 5.

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