Scott•Balice Strategies

REVIEW AND QUANTIFICATION OF CERTAIN FINANCIAL RISKS

OF

AMERICAN MUNICIPAL POWER – OHIO AMP GENERATION STATION

AS OF FEBRUARY 1, 2008

CHICAGO OFFICE:
20 NORTH WACKER DRIVE
SUITE 2200
CHICAGO, ILLINOIS 60606
PHONE: (312) 263-7900
WWW.SCOTTBALICE.COM

ANCHORAGE OFFICE:
880 H STREET
SUITE 206
ANCHORAGE, ALASKA 99501
PHONE: (907) 343-3023

AMERICAN MUNICIPAL POWER- OHIO
AMP GENERATING STATION

Review and Quantification of Certain Financial Risks of the Project

Background

American Municipal Power-Ohio (AMP-Ohio), a nonprofit wholesale power supplier and services provider for 120 municipal electric systems, proposes to construct a new 960-megawatt net, base-load power plant, consisting of two 480-megawatt generating units, near the Ohio River in Meigs County, Ohio – the AMP Generating Station ("AMPGS"). The plant and related facilities has been proposed to supply energy to 92 public power systems. Public power systems that commit to purchase power generated by AMPGS are referred to as the "participants".

AMP-Ohio made applications for critical path permits related to the project in May 2007, and anticipates receiving major permits and approvals in the first quarter of 2009, permitting construction to start during the second quarter of 2009. On this schedule, the first unit would be operational in the second quarter of 2013, and the second unit would be operational in the fourth quarter of 2013.

This report reviews several of the key assumptions used in the projections in the Initial Project Feasibility Study prepared by R.W. Beck, Inc. (the "Feasibility Study"). In connection with the preparation of this report, we also reviewed, among other documents, the Consulting Engineer's Report for the American Municipal Power Generating Station (the "BREI Report"), prepared for the Division of Cleveland Public Power, City of Cleveland, by Burns and Roe Enterprises, Inc. ("BREI"), and the Direct Testimony of David A. Schlissel before the Ohio Power Siting Board, December 3, 2007 (the "Schlissel Testimony").

This report compares the assumptions used in the Feasibility Study to industry standards, and/or forecasts by other experts in the utility industry. The sensitivity analyses around several of these assumptions serve to quantify the additional financial risk assumed by each participant in the project.

Power Sales Contract

All costs of the project flow-through to the participants, whether or not AMPGS is completed or operational. Each participant is required to pass-through those costs to its customers.

Each participant's share may be increased by up to 25% in the event of a default by another participant. As a result, each participant assumes, at least in part, the credit/performance risk of each other participant.

Pass-Through of All Costs. AMP-Ohio proposes to finance the costs of the project based upon revenues received from power sales contracts with the participants. Pursuant to the power sales

contract, each participant is obligated to pay its pro rata share of costs of the project, including capital costs and operating and maintenance costs, as a pass-through from AMP-Ohio, as well as additional amounts to fund certain reserves. See Section 5(A) of the draft Power Sales Contract.

Performance Risk. The power sales contract is structured as a take-or-pay contract. As a result, each participant is obligated to make such payments, whether or not the project ever produces electricity or the participant requires such electricity. See Section 5(I) of the draft Power Sales Contract.

25% Step-Up Provision. In addition, in the event of a default by one of the participants, each participant's share will be increased up to 25% of its original commitment, in which case such participant will be required to purchase such additional power and pay the proportionate amount of the defaulting participant's obligations under the contract. See Section 18(B)(ii) of the draft Power Sales Contract. As a result, the obligation of a participant under the contract could be increased by 25% as a result of credit or operational issues with another participant, over which the participant has no control. In the event that the plant is not completed or is not operational, the participant could be required to bear that additional cost without the receipt of, or rights to, additional power.

It is unclear how this 25% step up provision would work in the event that there is a large exodus of participants. It should be recognized that systemic changes in Ohio may affect the ability of participants to meet payment obligations overall. Such event risk would need to be considered.

Pass-Through to Consumers. Finally, each participant is required to pass its costs under the power sales contract through to its customers. Section 17(A) of the draft Power Sales Contract requires each participant to maintain rates for electric power and energy to its consumers in an amount sufficient, together with other available funds, to meet its obligations to AMP-Ohio under the contract.

As a result of the pass-through of the costs of AMP-Ohio to each participant, each participant (and its customers), not AMP-Ohio, bears the full risk of increased costs in construction, financing and operation of the proposed plant. In addition, through the step-up provision, each participant (not AMP-Ohio) bears the credit risk of the other participants.

Construction Costs — **Construction costs could increase by 20 – 40%. Assuming a 10 – 30% increase over construction costs included in the Feasibility Study, the annual cost to the participants could increase by $2.00 to $6.00/MWh.**

Cost Escalation. The construction costs of the project were estimated to be approximately $2.5 billion.[1] Filings made by or on behalf of AMP-Ohio discuss the significant risk of price escalation. It notes that price increases of 10% in a single six month period are being reported.[2]

[1] Feasibility Study, page ES-6.

[2] Application to Ohio Power Siting Board of American Municipal Power-Ohio, Inc. requesting a certificate of environmental compatibility and public need for the construction of an electric generating facility, filed May 4, 2007, page 05-4

The budget appears to provide for an 11% increase in costs over the 5 year period until completion.[3] BREI indicated that additional funds may be required to cover the continued escalation in construction costs.

Experience shows that construction costs have increased far in excess of the cost of inflation. Actual projects have experienced cost escalation far in excess of the assumptions used in the Feasibility Study. As referenced in the Schlissel Testimony[4], increases of 10% over a six-month period are common. Westar experienced cost escalation in connection with its proposed coal-fired plant in Kansas of 20 – 40% over an 18-month period. The estimated cost of the Taylor Energy Center in Florida increased by 25% between November 2005 and March 2007. The estimated cost of Little Gypsy Repowering Project (gas to coal) increased by 55% between April 2007 and July 2007.

Mr. Schlissel suggested that cost increases of 20 – 40% could be expected in light of recent experience in the industry, and the expectation that worldwide demand will continue to drive costs to rise. Thus, costs of the AMPGS project could increase by 10 – 30% over the construction costs included in the Feasibility Study, which would increase the annual cost to the participants by 0.20 – 0.60 cents/kWh.

EPC Contract. AMP-Ohio has proposed employing a fixed price contract with an EPC contractor in order to minimize the risk of increased price. In addition, AMP-Ohio proposes to enter into a turn-key contract, pursuant to which the contractor would commit to construct the project on a defined schedule and would guarantee performance of the project to certain standards, subject to certain liquidated damages to be assessed if the contractor should fail to do so. As noted in the Feasibility Study (page 4-6), a fixed price EPC contract would reduce the risk to AMP-Ohio (and thus to the participants) by transferring the pricing risk, schedule, construction and operability risks to the EPC contractor.

The problem, however, is that it may not be possible to obtain a fixed price, turn-key contract on a project of this size at this time. Recent testimony of Appalachian Power Company before the West Virginia Public Service Commission stated that no contractor is willing to assume pricing risk in a multi-year project. In that proceeding, testimony was provided that GE/Bechtel is unable to fix its equipment pricing, material costs and labor rates in advance.[5] Also, in the BREI Report, BREI stated that recent experience on large U.S. coal projects indicates that major EPC contractors are not willing to fix prices for the entire project cost.

To the extent that a fixed price, turn-key contract cannot be obtained by AMP-Ohio for the project, AMP-Ohio, and more importantly the participants (and its customers), will bear the risk of increases in construction costs.

[3] BREI Report, page 10-6.
[4] Schlissel Testimony, page 60.
[5] 2007 Testimony of Appalachian Power Company witness William M. Jasper, West Virginia Public Service Commission Case No. 06-0033-E-CN, at page 15.

If construction costs were to increase by 20%, annual debt service costs would be increased by $15 million, or $2.00/MWh. If construction costs were to increase by 40%, annual debt service costs would be increased by $43 million, or $6.00/MWh.

Technology Risk **Powerspan technology is unproven, and performance may not be guaranteed. Any change in construction costs or O&M as a result of a change in technology is not disclosed.**

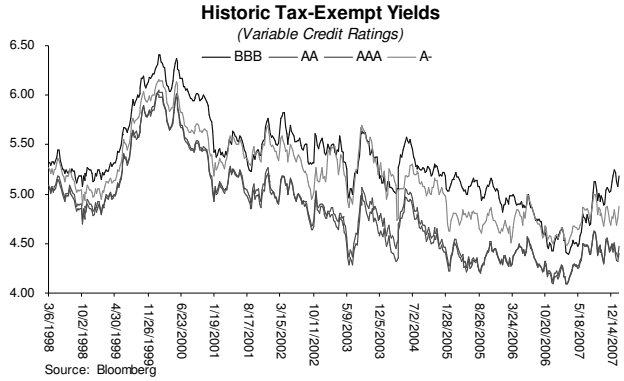
The plant will use pulverized coal technology. According to AMP-Ohio's website, the plant will employ "best available technology" for nitrogen oxide, sulfur dioxide, particulate matter, volatile organic compounds, carbon monoxide and sulfuric acid. The website further states, although CO_2 emissions are not currently regulated, the plant will be designed to accommodate future CO_2 capture equipment. However, the regulatory filings made by AMP-Ohio do not require that such technology be employed at the plant.

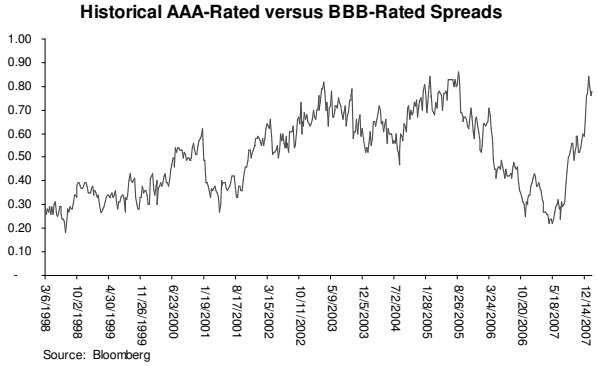
The Powerspan technology has not previously been operated on such a large scale. As noted in the BREI Report (page 2-13), the Powerspan process and its operations are a major unknown risk. In addition, economic feasibility of the ECO-SO_2 process is dependent on prices of urea and ammonium sulfate. If functioning as planned, the plant could produce 13 – 27% of U.S. total fertilizer consumption, which would likely result in downward pressure on prices. R.W. Beck estimated that the Powerspan ECO system could provide O&M savings of $4.5 - $5.5 million/year. However, such savings are not certain – as a result of technical and operational risk and commercial and market risks. (BREI Report, page 2-13).

In the BREI Report (page 2-13 – 2-14), BREI stated that Powerspan may not have the financial strength to stand behind a performance guarantee. BREI further noted that it is not likely that an EPC Contractor would assume the technological and performance risk of the Powerspan technology and provide such guarantee. The Feasibility Study (page ES-6) provides that if the Powerspan technology cannot be appropriately guaranteed by the EPC contractor, a limestone wet scrubber could be developed to satisfy air permitting requirements for the project. However, the effect on construction costs and O&M costs of using alternate technology and systems are not provided.

Financing Costs **Credit markets have been volatile. Financing costs will vary based upon interest rates at the time of the issuance of the debt, and/or executing an interest rate swap. Bond insurance premiums have increased, making credit quality more important. A 0.25% increase in interest rates will result in an increase in annual debt service of $6 million, or $0.82/MWh.**

Interest rates: The chart below shows the volatility in interest rates over a 10-year period. The interest rate on AAA-rated tax-exempt bonds reached a high of 6.01% on January 21, 2000, a low of 4.09% on December 8, 2006 and averaged 4.82% with a standard deviation of 0.46%. For BBB-rated tax-exempt bonds, the highest interest rate over the 10-year period was 6.41%, the lowest interest rate over that period was 4.39% and interest rates averaged 5.33% with a standard deviation of 0.43%.





Also, the spread between interest rates for AAA-rated tax-exempt bonds and BBB-rated tax-exempt bonds varied over the 10-year period, reaching a maximum of 0.86% on August 26, 2005, and a minimum of 0.18% on July 17, 1998. As recently as June 1, 2007, at the time of the Feasibility Study, the spread between AAA-rated bonds and BBB-rated bonds was 0.29%. In the current interest rate environment, the interest rate differential between AAA-rated bonds and BBB-rated bonds is considerable -- at 0.78% -- as underlying credit quality becomes more and more important to investors. Interest rate spreads between A- and AAA-rating bonds have been equally volatile, which is evident with spreads widening recently to 0.48% compared to the 10-year average of 0.36%.

	Interest Rate Increase		
	0.25%	**0.50%**	**1.00%**
Annual Debt Service Cost	$6 Mn	$12 Mn	$24 Mn
cents/kWh	0.082	0.166	0.336

The credit quality of the transaction can significantly impact the cost of financing, and the annual debt service costs. Bond insurance can be used to enhance the credit of a bond issue. However, given the recent turmoil in the credit markets as a result of exposure to sub-prime loans, the receptivity and benefits of bond insurance are uncertain. The benefit of credit enhancement to any transaction must be evaluated at or near the date of issuance. In the absence of bond insurance, additional reserves would be required, beyond the assumed 50% of maximum annual debt service reserves outlined in their finance plan. The debt service reserve referred to in the finance plan would be funded at the time of the issuance with proceeds of the bond sale. Any additional reserves required in the absence of bond insurance would also come from proceeds of the sale of the bonds, which would call for a larger issuance and thus increase annual debt service payments. Because of the slope of the yield curve, the reinvestment of funds held in reserve funds would be less than the cost of the borrowing. This negative arbitrage would directly impact project finances.

The Feasibility Study did not disclose the expected rating of the proposed bonds, or whether or not bond insurance was being considered. But, nonetheless, the project is subject to market risk and fluctuations in interest rates.

Construction Period Financing: The Feasibility Study stated that AMP-Ohio proposes to use variable rate, tax-exempt debt to fund construction of the project, to be refinanced with permanent, fixed rate debt upon completion of construction. The issuance of tax-exempt bonds

is proscribed by IRS Section 103 of the federal tax code, which enumerates many specific provisions to achieve tax-exempt status. Based on our preliminary assessment of this financing, this project appears to comply with such provisions however this could be explored further. The interest rate borne by variable rate debt fluctuates over time with market conditions. Thus, the interest rate on the construction financing will vary over the construction period. Over the period from 1998 to 2008, the SIFMA Index, a widely quoted and often used composite index of rates on variable rate tax-exempt bonds, has ranged from 5.84% on May 10, 2000 to 0.70% on July 8, 2003. As of January 23, 2008, the weekly SIFMA Index stood at 2.78%.

Given today's low level of interest rates, project sponsors may opt for a fixed rate transaction to lock in low rates. However as described above, this would introduce the possibility of negative arbitrage as reinvestment earnings prior to disbursement may be lower than the borrowing cost.

Post-Construction Financing: Upon completion, AMP-Ohio will "fix" the interest rate on the financing through the issuance of fixed rate, tax-exempt bonds. But, the permanent financing will bear fixed rates based upon market conditions at the time of issuance at completion of construction. Thus, there is the market risk that interest rates available in the market at such time will be higher than the interest rates used in the Feasibility Study, which assumed an approximate all-in true interest cost of 5.25%. During the period from 1998 to 2008, 20-year fixed rates on AA-rated tax-exempt bonds have ranged from 4.09% to 6.05%, averaging 4.86%. As of January 28, 2008, the rate on 20-year AA-rated tax-exempt bonds was 4.47%, while at the time of the Feasibility Report the rate was 4.35%. During the same period, 20-year BBB-rated tax-exempt yields have ranged from 4.39% to 6.41%, averaging 5.33%. As of January 28, 2008, the 20-year BBB-rated yield was 5.18%, while it stood at 4.62% at the time of the Feasibility Report. Note that these yields do not take into account issuance costs that contribute to the all-in true interest cost of the issuance.

The Feasibility Study (page 6-1) discloses that AMP-Ohio proposes to mitigate these risks by entering into interest rate swap transactions.

Swap Market: As discussed above, AMP-Ohio proposes to use variable rate debt, with an interest rate that fluctuates from time to time with market conditions, to pay construction costs during the construction period. Upon completion of the construction of the plant, AMP-Ohio would issue long-term, fixed rate debt to refinance the construction financing. AMP-Ohio proposes to use interest rate swaps to mitigate the interest rate risk. However, the Feasibility Study gives no details about the type of transaction or strategy that AMP-Ohio intends to execute.

Interest rate swaps introduce a number of additional risks that must be considered. One way in which AMP-Ohio could use interest rate swaps would be to fix the interest rate on the variable rate construction financing. Typically, such a transaction would provide that a third party (the counterparty) would pay AMP-Ohio a floating interest rate and AMP-Ohio would pay the counterparty a fixed interest rate. Ideally, the floating rate paid to AMP-Ohio from the counterparty would match, and would be used to pay, the interest owed by AMP-Ohio on the construction financing. If AMP-Ohio were able to do that, AMP-Ohio could effectively lock in a fixed interest rate for the term of the swap. Another issue is just that – the term of the swap. The

term of the swap could be designed to match the expected construction period. However, if the construction period is shorter or longer than planned, the swap will not match the term of the construction financing and could result in additional costs and/or interest rate exposure to AMP-Ohio.

AMP-Ohio may also seek to "lock-in" a fixed rate for the permanent financing. Swap transactions can be used to effectively fix in advance the interest rate on debt to be issued on a future date. But, again if the date of the issuance of the permanent financing cannot be identified with any certainty, the date to which the interest rate is locked may not coincide with the date on which the permanent financing is issued. In such event, AMP-Ohio would take interest rate risk during that interim period.

The following is a summary of some of the additional risks associated with swap transactions:

1) *Counterparty Credit Risk* – the risk that a counterparty owes you money and does not have the capacity to pay you when funds are due
2) *Basis Risk* – the risk that there is a mismatch between the rate you pay on your outstanding debt and the rate received from the counterparty
3) *Tax Risk* – the risk that changes in federal tax rates affects the relationship between taxable and tax-exempt interest rates
4) *Termination Risk* – the risk that some event forces a termination of the swap prior to the end of its stated term. At that time, the swap is valued in the market and you may owe the counterparty money at an inopportune time
5) *Operational Risk* – Swaps and derivative structures require detailed implementation and monitoring; must be marked to market and valued periodically, including for financial reporting

Carbon Costs **Costs of CO_2 emission allowances used in the Feasibility Study are below current estimates used by many of the investor-owned utilities, regulatory commissions and other experts. Using consensus prices could increase annual operating costs between 2.2 ¢/kWh and 3.9 ¢/kWh by 2030.**

The plant faces increased costs in order to comply with future regulations of carbon emissions. Although AMP-Ohio has indicated that it believes it is too speculative at this time to estimate the potential cost of such regulations, many experts in the field have sought to make such estimates.

Carbon Sequestration: The cost of carbon capture and sequestration would be considerable. AMP-Ohio has indicated that based upon estimates provided by Powerspan, the estimated cost of carbon dioxide capture on a power plant equipped with the Powerspan SO_2 process is $20/ton. However, it should be noted that Powerspan does not yet have a commercially, operational system for carbon capture. Further, this estimate does not include any additional cost for carbon sequestration.

As indicated in the Schlissel Testimony (page 34), other sources have estimated that carbon capture and sequestration at a pulverized coal-fired plant could increase costs by 60 – 80%, on a

$/MWh basis. The BREI report estimated costs of carbon dioxide capture at between $20 and $60 per ton of CO_2 avoided. The National Energy Technology Laboratory projects the cost of carbon capture and sequestration at $65/ton of CO_2 avoided. However, it should be recognized that there does not currently exist commercially viable technology for carbon capture and sequestration in a pulverized coal plant. The earliest such technology may be available on a commercial basis is projected to be 2015 – 2030.[6]

Carbon emissions allowances: Analysts predict that federal regulation of carbon emissions is likely to be in effect no later than 2012.[7] It is widely anticipated that any such federal regulation will be based upon a cap-and-trade system, where the cost of every ton of CO_2 emissions from coal will be determined by market forces of supply and demand for CO_2 allowances.[8] The price of CO_2 allowances will depend upon a number of factors, which are not readily known or estimable. Such factors include the emission reduction target, availability of offsets, ability to "bank" allowances and the extent (if any) of complementary energy efficiency programs and renewable electricity standards.[9] The CO_2 price forecasts used by AMP-Ohio in the Feasibility Study ranged between $5 and $15. These estimates are low, as compared to various studies and other industry participants. In his testimony, Davis Schlissel referenced carbon price forecasts prepared by Synapse Energy Economics. Synapse's forecast, based upon forecast models prepared by Massachusetts Institute of Technology, Energy Information Administration of the Department of Energy and the U.S. Environmental Protection Agency, is $8.23 in the low case, $19.83 in the mid case and $31.43 in the high case, levelized over 20 years, 2011 – 2030.[10]

AMP-Ohio has projected that the project will emit 7,367,000 tons of CO_2 annually. (Feasibility Study, Attachment ES-1) The annual expenditures on CO_2 emissions allowances that the participants would have to pay in 2015, 2020 and 2030 under the Synapse forecasts are as follows:[11]

YEAR	FEASIBILITY STUDY		SYNAPSE FORECAST					
			Low Case		Mid Case		High Case	
	$ Millions	¢/kWh	$ Millions	¢/kWh	$ Millions	¢/kWh	$ Millions	¢/kWh
2015	$52	0.71	$42	0.57	$125	1.70	$208	2.83
2020	$103	1.39	$83	1.13	$208	2.83	$333	4.53
2030	$130	1.77	$167	2.27	$292	3.97	$417	5.67

As you can see from the above chart, the assumptions used in the Feasibility Study are not too dissimilar from the consensus "Low Case". But, the annual differential between the consensus "Mid Case" and "High Case" as compared to the Feasibility Study ranges between 2.2 cents/kWh and 3.9 cents/kWh in 2030.

[6] Schlissel Testimony, page 35.

[7] See Citigroup Equity Research, Citigroup Equity Markets, Carbon Limits are Coming, September 11, 2006 and JPMorgan, North America Corporate Research, Warming to Rules on Climate Change, September 27, 2006.

[8] See Union of Concerned Scientists, "Gambling with Coal: How Future Climate Laws will make New Coal Power Plants More Expensive, by Barbara Freese and Steve Clemmer, September 2006.

[9] See Union of Concerned Scientists, "Gambling with Coal: How Future Climate Laws will make New Coal Power Plants More Expensive, by Barbara Freese and Steve Clemmer, September 2006.

[10] Schlissel Testimony, page 36-38.

[11] Schlissel Testimony, page 50-51.

Load Demand **Assumption of future demand for power used in the Feasibility Study exceeds current estimate of demand published by the Energy Information Administration of the Department of Energy. Based upon the EIA forecast, 2013 load demand would be 2,566MW, instead of 2,947MW, and load demand in 2027 would be 2,806MW instead of 3,360MW (a difference of 554 MW).**

On behalf of AMP-Ohio, R.W. Beck, Inc. prepared a 20-year load forecast for each member of AMP-Ohio. The reports were delivered in February 2007. The reports showed peak demand of 2,454 MW in 2006 for the members, increasing to 2,947 MW in 2013 and to 3,360 MW in 2027. Thus, it is assumed that demand will grow at an average annual rate of 2.65% between 2006 and 2013 and at an average annual rate of 0.94% between 2013 and 2027, for an average annual growth rate of 1.50% for the period 2006 to 2027.

We do not have the detail on the assumptions used in making the demand forecasts contained in the Power Supply Plans for the members. However, we question whether such demand forecasts adequately consider basic trends in the economy. Also, it appears that the plans may ignore the "macro" changes in demand for power, such as the implementation of efficiencies and conservation measures. The 2008 EIA Regional Projections for Electrical Load Growth projects regional electrical load growth, 2005 to 2030, of 0.64% for the Midwest Region, East North Central, including Indiana, Illinois, Michigan, Ohio and Wisconsin. It should be noted that the 2008 projected growth in demand is lower than the 2007 projection for that region of 0.90%. We understand that projections of load growth must take into account a number of local demographic and economic factors, including projected population growth or decline, employment forecasts, manufacturing, service and/or retail base and any forecasted changes in their level or mix. In addition, the forecast must take into account the demand side management programs and application of new efficiency technologies and conservation measures, which will reduce the demand for power.

Furthermore, the Energy Security and Climate Stewardship Platform for the Midwest, 2007, of the Midwestern Governors Association, endorsed by the governors of eight Midwest states, including Ohio, and the Province of Manitoba, calls for energy efficiency improvements of 2% of regional annual retail sales of electricity by 2015, and an additional 2% in efficiency improvements every year thereafter. The Platform also contains goals for increasing use of renewable resources, calling for 10% of electricity consumed in the region to be from renewable resources in 2015, 20% in 2020 and increasing to 30% in 2030. The implementation of these goals could significantly impact the demand for electricity and the choice of generation for development. It is not clear to what extent, if at all, the Platform was considered in the development of the power supply plans for the municipalities.

In any event, it should be noted that using the EIA projection of growth in demand of 0.64%, the aggregate demand in 2027 would be 2,806MW, as compared to the forecast demand of 3,360MW in the Feasibility Study. That is a difference of 554 MW, which is nearly 60 percent of the net capacity of the AMP Generating Station.

Coal Prices

Coal prices are quite volatile and unpredictable. Nonetheless, to give a sense of the impact of the change in coal prices, we have calculated the effect of a 5% increase in the price of coal at 0.06¢/kwh in 2013 to 0.86¢/kwh in 2032 in 2008 dollars and a 10% increase in the price of coal at 0.15¢/kwh in 2013 to 4.19¢/kwh in 2032 in 2008 dollars.

Coal prices have been quite volatile, and unpredictable. In its Annual Coal Report released in 2007, the EIA noted that average delivered coal prices of coal at electric utilities increased for the sixth consecutive year in 2006, experiencing an increase of 9.7% over the 2005 price.

In its Annual Energy Outlook 2008 (Early Release), the EIA does not expect the price of coal to continue to rise. The average real minemouth coal price (in 2006 dollars) is forecast to decline slightly until 2020 ($24.63 per short ton in 2006; $22.63 in 2020), and then to begin to rise again as a result of increased demand for coal as a result of construction of new coal-fired power plants. Forecast price of coal (without adjustment for inflation) in 2030 is forecast to be $36.97 per ton.

Coal transportation costs are also projected to rise. In the 2007 reference case, EIA projected eastern coal transportation costs to rise by 4% between 2005 and 2030 and western rates to rise by 3%.

Consideration of Alternative Sources of Power

Each municipality should consider alternative sources of power to meet the needs of its consumers, in order to determine the approach that provides the most benefit (and least cost) to its consumers.

Each municipality should consider to what extent, and at what price, power is, and will be, available from other sources. We have not, and are not qualified, to prepare such an analysis.

Nonetheless, it is instructional to note that the City of Martinsville did conduct such review. GDS Associates, Inc. prepared a report for the City of Martinsville that looked at a couple of options for the City of Martinsville to obtain power. The report indicates that the City of Martinsville could obtain power on a three-year contract at 7.01¢/kwh from one source, or pursuant to a 20-year contract from another source with prices of 6.15¢/kwh in 2009, 7.64¢/kwh in 2014, 9.23¢/kwh in 2020 and 10.68¢/kwh in 2027.

The analysis showed that participation in the AMP-Ohio projects, using the estimated costs in the Feasibility Study, showed expected cost of power at “almost equivalence” with the 20-year contract. The consultants further noted that 20-year contract precluded Martinsville from participation in any generating project for the term of the contract, and thus would not own any generation at the end of the term of the contract, and would have to renegotiate for power at that time.

It is important to note, however, that in preparing the analysis, the price of power from the AMP-Ohio projects did not take into account the significant risk of increased costs assumed by the municipalities as a result of participation in the AMP-Ohio projects. The risk of an increase in the price of power from AMP-Ohio as a result of the regulation of carbon emissions or cost of construction, or interest costs, could make the AMPGS project significantly more expensive than the prices available in the market.

Municipal Procurement **Prudent management and best practices requires that public entities use a competitive procurement process in purchasing goods and services. In the case of the AMPGS project, good public policy requires consideration of all alternatives, including purchased power and renewable energy.**

According to the 2006 Ohio Auditor of State Compliance Supplement, *Generally all contracts made by the legislative authority of a municipal government for material and labor which exceed $25,000 are subject to competitive bidding procedures.* However the Supplement goes on to say that contracts with "qualified non-profit organizations" may be authorized without bidding. Although AMP-Ohio is a non-profit organization and thus may be exempt from bidding procedures, we strongly believe that it is an obligation of municipalities to their constituents to consider all available options and to choose one with lowest costs and risks before entering into the contract. We do not believe that committing to 50 years of purchasing power from one source would be a prudent action on behalf of municipalities and furthermore this type of transaction could create a significant risk exposure.

SUMMARY

AMP-Ohio projects the cost of electricity to grow from 6.2¢/kwh in 2014, 7.5¢/kwh in 2020 and 8.6¢/kwh in 2027, but if construction costs increase 20%, those costs could actually increase by 0.20 cents per kWh to cover additional borrowing costs. If, in addition, CO_2 allowances were to cost $30 per ton, then the total cost could rise by 2.5 cents per kWh.

The following chart summarizes some of the risks identified above, and an estimate of the additional potential cost to the participants, based upon industry standards and/or forecasts of experts in the utility industry.

RISK	IMPLICATIONS	POTENTIAL COST	COST per kWh
Step-Up Provision	The obligations of a participant could be increased by up to 25% of its original commitment as a result of a default by another participant	25% of original commitment	
Construction Cost Escalation	Construction costs are expected to escalate at higher rates than those contained in the forecast	Constructions costs could escalate 20 – 40%	Additional annual cost of 0.20-0.60 ¢/kWh

RISK	IMPLICATIONS	POTENTIAL COST	COST per kWh
Technology Risk	Powerspan technology is not proven on a large, commercial scale; it is unlikely that a performance guarantee will support the technology	Change in construction costs or O&M as a result of alternate technology and systems	Unknown
Interest Rates	Interest rate volatility can impact the economics and financial viability of a project.	Over a 10-year period, interest rates have varied as much as 2%	0.25% - 1% increase in interest cost is 0.082 – 0.34 ¢/kWh
Carbon Emission Allowance Prices	Carbon regulation is coming.. Although the precise timing and terms of such regulation are not known, there is general consensus that the costs will exceed the levels included in the Feasibility Study.	Forecasts for carbon dioxide emission allowance prices range from $8.23 to $31.43, on a levelized basis over 20 years	Additional cost of 2.2¢/kWh to 3.9¢/kWh by 2030
Load Demand Factor	The load factor contained in the Power Supply Plans appears to overstate the future demand for power.	Participant's power purchase commitments could exceed future demand for power	

Projected Operating Results

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Average Project Costs																					
Net Cost to Participants	$000	176,733	442,606	458,222	479,165	498,929	518,922	528,072	537,837	548,574	558,666	568,399	579,043	590,948	604,068	615,990	627,315	640,603	654,268	668,713	684,549
Growth%			*150.44%*	*3.53%*	*4.57%*	*4.12%*	*4.01%*	*1.76%*	*1.85%*	*2.00%*	*1.84%*	*1.74%*	*1.87%*	*2.06%*	*2.22%*	*1.97%*	*1.84%*	*2.12%*	*2.13%*	*2.21%*	*2.37%*
Net Fixed Costs	$000	71,745	214,196	211,538	213,244	212,744	212,220	213,471	214,951	217,013	218,087	218,719	219,032	220,259	222,191	222,971	222,868	224,369	225,792	227,680	230,481
Growth%			*198.55%*	*-1.24%*	*0.81%*	*-0.23%*	*-0.25%*	*0.59%*	*0.69%*	*0.96%*	*0.49%*	*0.29%*	*0.14%*	*0.56%*	*0.88%*	*0.35%*	*-0.05%*	*0.67%*	*0.63%*	*0.84%*	*1.23%*
Net Non-Fuel Variable Costs	$000	31,721	78,581	94,353	110,631	127,711	145,385	149,647	154,064	158,305	162,774	167,327	171,973	176,851	181,899	187,123	192,461	197,978	203,767	209,681	215,877
Growth%			*147.72%*	*20.07%*	*17.25%*	*15.44%*	*13.84%*	*2.93%*	*2.95%*	*2.75%*	*2.82%*	*2.80%*	*2.78%*	*2.84%*	*2.85%*	*2.87%*	*2.85%*	*2.87%*	*2.92%*	*2.90%*	*2.96%*
Fuel Costs	$000	73,267	149,830	152,332	155,290	158,474	161,316	164,955	168,821	173,256	177,805	182,353	188,038	193,838	199,978	205,896	211,986	218,256	224,709	231,352	238,191
Growth%			*104.50%*	*1.67%*	*1.94%*	*2.05%*	*1.79%*	*2.26%*	*2.34%*	*2.63%*	*2.63%*	*2.56%*	*3.12%*	*3.08%*	*3.17%*	*2.96%*	*2.96%*	*2.96%*	*2.96%*	*2.96%*	*2.96%*
Net Capacity	MW	480.0	960.0	960.0	960.0	960.0	960.0	960.0	960.0	960.0	960.0	960.0	960.0	960.0	960.0	960.0	960.0	960.0	960.0	960.0	960.0
Gross Energy	GWh	3,674.6	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2
Plus: Replacement Energy Purchases	GWh	-	303.0	303.0	303.0	303.0	303.0	303.0	303.0	303.0	303.0	303.0	303.0	303.0	303.0	303.0	303.0	303.0	303.0	303.0	303.0
Less: Surplus Energy Sales	GWh	(100.5)	(504.0)	(504.0)	(504.0)	(504.0)	(504.0)	(504.0)	(504.0)	(504.0)	(504.0)	(504.0)	(504.0)	(504.0)	(504.0)	(504.0)	(504.0)	(504.0)	(504.0)	(504.0)	(504.0)
Net Energy	GWh	3,574.1	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2
Capacity Factor	%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
		3,574,080	7,148,160	7,148,160	7,148,160	7,148,160	7,148,160	7,148,160	7,148,160	7,148,160	7,148,160	7,148,160	7,148,160	7,148,160	7,148,160	7,148,160	7,148,160	7,148,160	7,148,160	7,148,160	7,148,160
Net Fixed Costs	$/KW-mo																				
Net Non-Fuel Variable Costs	$/MWh	8.88	10.99	13.20	15.48	17.87	20.34	20.93	21.55	22.15	22.77	23.41	24.06	24.74	25.45	26.18	26.92	27.70	28.51	29.33	30.20
Net Fuel Costs	$/MWh	19.94	20.39	20.73	21.13	21.56	21.95	22.45	22.97	23.57	24.19	24.81	25.59	26.38	27.21	28.02	28.84	29.70	30.58	31.48	32.41
Average Costs of Participants	$/MWh	49.45	61.92	64.10	67.03	69.80	72.59	73.87	75.24	76.74	78.15	79.52	81.01	82.67	84.51	86.17	87.76	89.62	91.53	93.55	95.77
Average Project Costs (w/o CO2)																					
Average Costs to Participants	$/MWh	45.96	56.57	56.81	57.70	58.32	58.90	59.85	60.87	62.04	63.09	64.09	65.22	66.50	67.94	69.21	70.39	71.84	73.32	74.91	76.67
Growth%			*23.07%*	*0.42%*	*1.57%*	*1.08%*	*1.00%*	*1.61%*	*1.71%*	*1.91%*	*1.69%*	*1.59%*	*1.76%*	*1.97%*	*2.17%*	*1.86%*	*1.71%*	*2.06%*	*2.06%*	*2.17%*	*2.35%*
Average Postage Stamp Rate	$000	176,733	442,606	458,222	479,165	498,929	518,922	528,072	537,837	548,574	558,666	568,399	579,043	590,948	604,068	615,990	627,315	640,603	654,268	668,713	684,549
	GWh	3,574.1	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2
	$/MWh	49.45	61.92	64.10	67.03	69.80	72.59	73.87	75.24	76.74	78.15	79.52	81.01	82.67	84.51	86.17	87.76	89.62	91.53	93.55	95.77
Growth%			*25.22%*	*3.53%*	*4.57%*	*4.12%*	*4.01%*	*1.76%*	*1.85%*	*2.00%*	*1.84%*	*1.74%*	*1.87%*	*2.06%*	*2.22%*	*1.97%*	*1.84%*	*2.12%*	*2.13%*	*2.21%*	*2.37%*
Participant Surplus Energy Sales	$000	16,227	16,234	15,741	14,143	13,848	14,128	13,289	13,545	12,446	12,304	11,553	12,168	11,939	11,165	12,266	12,266	12,266	12,266	12,266	12,266
	GWh	294.0	275.1	259.5	223.3	196.9	187.5	176.5	175.0	159.5	153.6	139.6	143.9	138.2	127.5	133.4	133.4	133.4	133.4	133.4	133.4
	$/MWh	55.19	59.01	60.66	63.34	70.33	75.35	75.29	77.40	78.03	80.10	82.76	84.56	86.39	87.57	91.95	91.95	91.95	91.95	91.95	91.95
Growth%			*6.92%*	*2.79%*	*4.41%*	*11.04%*	*7.14%*	*-0.08%*	*2.80%*	*0.82%*	*2.66%*	*3.31%*	*2.18%*	*2.16%*	*1.37%*	*5.00%*	*0.00%*	*0.00%*	*0.00%*	*0.00%*	*0.00%*
Net Participant Costs	$000	160,506	426,372	442,481	465,022	485,081	504,794	514,783	524,292	536,128	546,362	556,846	566,875	579,009	592,903	603,724	615,049	628,337	642,002	656,447	672,283
	GWh	3,280.1	6,873.1	6,888.7	6,924.9	6,951.3	6,960.7	6,971.7	6,973.2	6,988.7	6,994.6	7,008.6	7,004.3	7,010.0	7,020.7	7,014.8	7,014.8	7,014.8	7,014.8	7,014.8	7,014.8
	$/MWh	48.93	62.03	64.23	67.15	69.78	72.52	73.84	75.19	76.71	78.11	79.45	80.93	82.60	84.45	86.06	87.68	89.57	91.52	93.58	95.84
Growth%			*26.77%*	*3.54%*	*4.54%*	*3.92%*	*3.92%*	*1.82%*	*1.83%*	*2.03%*	*1.82%*	*1.72%*	*1.86%*	*2.06%*	*2.24%*	*1.91%*	*1.88%*	*2.16%*	*2.17%*	*2.25%*	*2.41%*

Source: Initial Project Feasibility Study, by R.W. Beck (Base Case)

Projected Operating Expenses

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gross Output	MWh	3,674,601	7,349,202	7,349,202	7,349,202	7,349,202	7,349,202	7,349,202	7,349,202	7,349,202	7,349,202	7,349,202	7,349,202	7,349,202	7,349,202	7,349,202	7,349,202	7,349,202	7,349,202	7,349,202	7,349,202
Net Capacity Rating	MW	480	960	960	960	960	960	960	960	960	960	960	960	960	960	960	960	960	960	960	960
Fuel Costs	$/MWh	19.94	20.39	20.73	21.13	21.56	21.95	22.45	22.97	23.57	24.19	24.81	25.59	26.38	27.21	28.02	28.84	29.70	30.58	31.48	32.41
Fuel Costs	$000	73,267	149,830	152,332	155,290	158,474	161,316	164,955	168,821	173,256	177,805	182,353	188,038	193,838	199,978	205,896	211,986	218,256	224,709	231,352	238,191
Heat Rate	Btu/kWh	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325
OPERATING COSTS																					
Fixed Operating Costs																					
Fixed O&M	$000	16,026	32,820	33,608	34,414	35,240	36,086	36,952	37,839	38,747	39,677	40,629	41,605	42,603	43,626	44,673	45,745	46,843	47,967	49,118	50,297
Major Maintenance	$000	6,053	12,396	12,694	12,998	13,310	13,630	13,957	14,292	14,635	14,986	15,346	15,714	16,091	16,477	16,873	17,278	17,692	18,117	18,552	18,997
Insurance	$000	1,402	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804
Property Taxes	$000	1,402	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804
Transmission Costs	$000	1,837	3,763	3,853	3,946	4,040	4,137	4,237	4,338	4,442	4,549	4,658	4,770	4,884	5,002	5,122	5,245	5,370	5,499	5,631	5,766
Variable Operating Costs																					
Gross Urea and Powerspan Costs	$000	28,873	59,132	60,551	62,004	63,492	65,016	66,577	68,175	69,811	71,486	73,202	74,959	76,758	78,600	80,486	82,418	84,396	86,422	88,496	90,620
Fertilizer Credits	$000	(22,737)	(46,564)	(47,682)	(48,826)	(49,998)	(51,198)	(52,427)	(53,685)	(54,974)	(56,293)	(57,644)	(59,027)	(60,444)	(61,895)	(63,380)	(64,901)	(66,459)	(68,054)	(69,687)	(71,360)
Variable O&M	$000	4,324	8,855	9,067	9,285	9,507	9,736	9,969	10,209	10,454	10,704	10,961	11,224	11,494	11,770	12,052	12,341	12,638	12,941	13,251	13,570
Transmission Costs	$000	1,837	3,763	3,853	3,946	4,040	4,137	4,237	4,338	4,442	4,549	4,658	4,770	4,884	5,002	5,122	5,245	5,370	5,499	5,631	5,766
ENVIRONMENTAL COSTS																					
Costs of SO2 Emissions																					
SO2 Emissions	lb/MMBTu	0.15000	0.15000	0.15000	0.15000	0.15000	0.15000	0.15000	0.15000	0.15000	0.15000	0.15000	0.15000	0.15000	0.15000	0.15000	0.15000	0.15000	0.15000	0.15000	0.15000
SO2 Emissions	tons/yr	2,570	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140
SO2 Allowance Price	$/ton	1,291	1,389	1,486	1,522	1,558	1,596	1,634	1,673	1,713	1,754	1,796	1,840	1,884	1,929	1,975	2,023	2,071	2,121	2,172	2,224
Cost of SO2 Emissions	$000	3,318	7,139	7,638	7,823	8,008	8,203	8,399	8,599	8,805	9,016	9,231	9,458	9,684	9,915	10,152	10,398	10,645	10,902	11,164	11,431
Cost of NO x Emissions																					
NO x Emissions	lb/MMBTu	0.07000	0.07000	0.07000	0.07000	0.07000	0.07000	0.07000	0.07000	0.07000	0.07000	0.07000	0.07000	0.07000	0.07000	0.07000	0.07000	0.07000	0.07000	0.07000	0.07000
NO x Emission Annual	tons/yr	1,199	2,399	2,399	2,399	2,399	2,399	2,399	2,399	2,399	2,399	2,399	2,399	2,399	2,399	2,399	2,399	2,399	2,399	2,399	2,399
NO x Allowance Annual Price	$/ton	1,322	1,411	1,505	1,606	1,714	1,829	1,951	2,082	2,221	2,370	2,529	2,699	2,879	3,072	3,278	3,498	3,732	3,982	4,249	4,535
NO x Emissions (Ozone)	tons/yr	500	999	999	999	999	999	999	999	999	999	999	999	999	999	999	999	999	999	999	999
NO x Allowance Ozone Price	$/ton	2,163	2,320	2,487	2,666	2,859	3,065	3,286	3,523	3,777	4,049	4,341	4,654	4,990	5,350	5,736	6,150	6,593	7,069	7,579	8,125
Cost of NO x Emissions	$000	2,667	5,703	6,095	6,516	6,968	7,450	7,963	8,514	9,101	9,731	10,404	11,124	11,892	12,714	13,594	14,536	15,539	16,615	17,765	18,996
Cost of Hg Emissions																					
Hg Emissions	lb/MMBTu	4.2576E-06	4.2576E-06	4.2576E-06	4.2576E-06	4.2576E-06	4.2576E-06	4.2576E-06	4.2576E-06	4.2576E-06	4.2576E-06	4.2576E-06	4.2576E-06	4.2576E-06	4.2576E-06	4.2576E-06	4.2576E-06	4.2576E-06	4.2576E-06	4.2576E-06	4.2576E-06
Hg Allowances Purchased	tons	0.07294	0.14589	0.14589	0.14589	0.14589	0.14589	0.14589	0.14589	0.14589	0.14589	0.14589	0.14589	0.14589	0.14589	0.14589	0.14589	0.14589	0.14589	0.14589	0.14589
Hg Allowance Price	$(000)/ton	38,748	41,676	44,722	48,549	52,534	56,682	60,999	65,491	68,404	71,447	74,625	77,944	81,411	85,032	88,814	92,765	96,891	101,201	105,702	110,404
Cost of Hg Emmissions	$000	2,826	6,080	6,524	7,083	7,664	8,269	8,899	9,554	9,979	10,423	10,887	11,371	11,877	12,405	12,957	13,533	14,135	14,764	15,421	16,107
Cost of CO2 Emissions																					
CO2 Emissions	lb/MMBTu	215.00000	215.00000	215.00000	215.00000	215.00000	215.00000	215.00000	215.00000	215.00000	215.00000	215.00000	215.00000	215.00000	215.00000	215.00000	215.00000	215.00000	215.00000	215.00000	215.00000
CO2 Emissions	tons/yr	3,683,558	7,367,116	7,367,116	7,367,116	7,367,116	7,367,116	7,367,116	7,367,116	7,367,116	7,367,116	7,367,116	7,367,116	7,367,116	7,367,116	7,367,116	7,367,116	7,367,116	7,367,116	7,367,116	7,367,116
CO2 Allowance Price	$/ton	3.38	5.19	7.08	9.06	11.14	13.29	13.61	13.94	14.27	14.62	14.97	15.32	15.69	16.07	16.46	16.85	17.25	17.67	18.09	18.53
Cost of CO2 Emissions	$000	12,450	38,235	52,159	66,746	82,070	97,909	100,266	102,698	105,129	107,707	110,286	112,864	115,590	118,390	121,263	124,136	127,083	130,177	133,271	136,513
Growth%			*207.10%*	*36.42%*	*27.97%*	*22.96%*	*19.30%*	*2.41%*	*2.42%*	*2.37%*	*2.45%*	*2.39%*	*2.34%*	*2.42%*	*2.42%*	*2.43%*	*2.37%*	*2.37%*	*2.43%*	*2.38%*	*2.43%*
Cost of CO2 Emissions	*$/MWh*	*3.39*	*5.20*	*7.10*	*9.08*	*11.17*	*13.32*	*13.64*	*13.97*	*14.30*	*14.66*	*15.01*	*15.36*	*15.73*	*16.11*	*16.50*	*16.89*	*17.29*	*17.71*	*18.13*	*18.58*
% of Total Environmental Costs	*%*	*58.56%*	*66.89%*	*72.03%*	*75.70%*	*78.38%*	*80.36%*	*79.88%*	*79.39%*	*79.04%*	*78.69%*	*78.32%*	*77.94%*	*77.56%*	*77.16%*	*76.77%*	*76.34%*	*75.91%*	*75.48%*	*75.03%*	*74.58%*
Total Environmental Costs	$/MWh	5.79	7.78	9.85	12.00	14.25	16.58	17.08	17.60	18.10	18.62	19.16	19.71	20.28	20.88	21.49	22.13	22.78	23.47	24.17	24.91
Total Environmental Costs	$000	21,261	57,158	72,417	88,168	104,710	121,831	125,528	129,365	133,014	136,877	140,808	144,817	149,043	153,424	157,965	162,603	167,403	172,458	177,621	183,047

Source: Initial Project Feasibility Study, by R.W. Beck (Base Case)

Projected Financing Debt Service

Target Debt Service Coverage **1.10x**

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
REVENUES																				
Operating Revenues	187,462	478,893	499,582	521,534	544,500	566,695	575,494	586,032	596,783	607,625	618,366	629,620	642,098	655,495	669,261	680,240	693,554	707,293	721,814	737,727
Operating Expenses	126,280	291,537	312,140	334,000	356,871	378,973	387,737	398,230	408,937	419,734	430,431	441,638	454,064	467,405	481,114	491,694	504,540	517,799	531,826	547,230
Net Revenues	61,182	187,357	187,443	187,534	187,629	187,721	187,758	187,801	187,846	187,891	187,935	187,982	188,034	188,090	188,147	188,546	189,014	189,494	189,988	190,497
Minimum Net Revenue Req.	60,063	186,142	186,142	186,142	186,142	186,142	186,142	186,142	186,142	186,142	186,142	186,142	186,142	186,142	186,142	186,141	186,142	186,142	186,142	186,142
Sufficient Coverage (Y/N)	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
Revenue Increase Necessary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PSR Increase ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DEBT SERVICE																				
Principal	-	60,015	62,265	64,600	67,023	69,536	72,144	74,849	77,656	80,568	83,589	86,724	89,976	93,350	96,851	100,482	104,251	108,160	112,216	116,424
Interest	54,603	109,205	106,955	104,620	102,197	99,684	97,076	94,371	91,564	88,652	85,631	82,496	79,244	75,870	72,369	68,737	64,969	61,060	57,004	52,796
Total Debt Service	54,603	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,219	169,220	169,220	169,220	169,220
Other Debt Payments	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Debt Service Require	54,603	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,219	169,220	169,220	169,220	169,220
Debt Service Coverage	*1.12x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.12x*	*1.12x*	*1.12x*	*1.13x*

Source: Initial Project Feasibility Study, by R.W. Beck (Base Case)

Proforma Cash Flows

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
REVENUES																				
Participant Revenue	176,733	442,606	458,222	479,165	498,929	518,922	528,072	537,837	548,574	558,666	568,399	579,043	590,948	604,068	615,990	627,315	640,603	654,268	668,713	684,549
Interest Earnings	5,181	6,541	6,263	6,212	6,196	6,184	6,178	6,214	6,249	6,286	6,325	6,366	6,408	6,450	6,490	6,540	6,615	6,689	6,765	6,842
Short-term Sales	5,548	29,746	30,571	31,929	35,451	37,977	37,952	39,016	39,330	40,386	41,706	42,635	43,534	44,146	46,336	46,336	46,336	46,336	46,336	46,336
Other Project Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transfer from R&C Fund	-	-	4,526	4,228	3,924	3,612	3,292	2,965	2,630	2,287	1,936	1,576	1,208	831	445	49	-	-	-	-
Other Receipts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Revenues	187,462	478,893	499,582	521,534	544,500	566,695	575,494	586,032	596,783	607,625	618,366	629,620	642,098	655,495	669,261	680,240	693,554	707,293	721,814	737,727
OPERATING EXPENSES																				
Fixed Operating Expenses																				
Fixed O&M	16,026	32,820	33,608	34,414	35,240	36,086	36,952	37,839	38,747	39,677	40,629	41,605	42,603	43,626	44,673	45,745	46,843	47,967	49,118	50,297
Insurance & Property Taxes	2,804	5,608	5,608	5,608	5,608	5,608	5,608	5,608	5,608	5,608	5,608	5,608	5,608	5,608	5,608	5,608	5,608	5,608	5,608	5,608
Transmission Costs	1,837	3,763	3,853	3,946	4,040	4,137	4,237	4,338	4,442	4,549	4,658	4,770	4,884	5,002	5,122	5,245	5,370	5,499	5,631	5,766
AMP-Ohio A&G Costs	500	512	524	537	550	563	576	590	604	619	634	649	665	681	697	714	731	748	766	785
Bank and Trustee Fees	125	128	131	134	137	141	144	148	151	155	158	162	166	170	174	178	183	187	192	196
Other Direct Project Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed Operating Costs	21,292	42,831	43,724	44,639	45,575	46,535	47,517	48,523	49,552	50,608	51,687	52,794	53,926	55,087	56,274	57,490	58,735	60,009	61,315	62,652
Variable Operating Costs																				
Fuel Costs	73,267	149,830	152,332	155,290	158,474	161,316	164,955	168,821	173,256	177,805	182,353	188,038	193,838	199,978	205,896	211,986	218,256	224,709	231,352	238,191
SO2 Emmissions Costs	3,318	7,139	7,638	7,823	8,008	8,203	8,399	8,599	8,805	9,016	9,231	9,458	9,684	9,915	10,152	10,398	10,645	10,902	11,164	11,431
NO x Emmissions Costs	2,667	5,703	6,095	6,516	6,968	7,450	7,963	8,514	9,101	9,731	10,404	11,124	11,892	12,714	13,594	14,536	15,539	16,615	17,765	18,996
Hg Emmissions Costs	2,826	6,080	6,524	7,083	7,664	8,269	8,899	9,554	9,979	10,423	10,887	11,371	11,877	12,405	12,957	13,533	14,135	14,764	15,421	16,107
CO2 Emmisions Costs	12,450	38,235	52,159	66,746	82,070	97,909	100,266	102,698	105,129	107,707	110,286	112,864	115,590	118,390	121,263	124,136	127,083	130,177	133,271	136,513
Variable O&M	4,324	8,855	9,067	9,285	9,507	9,736	9,969	10,209	10,454	10,704	10,961	11,224	11,494	11,770	12,052	12,341	12,638	12,941	13,251	13,570
Gross Urea and Powerspan Costs	28,873	59,132	60,551	62,004	63,492	65,016	66,577	68,175	69,811	71,486	73,202	74,959	76,758	78,600	80,486	82,418	84,396	86,422	88,496	90,620
Fertilizer Credits	(22,737)	(46,564)	(47,682)	(48,826)	(49,998)	(51,198)	(52,427)	(53,685)	(54,974)	(56,293)	(57,644)	(59,027)	(60,444)	(61,895)	(63,380)	(64,901)	(66,459)	(68,054)	(69,687)	(71,360)
Variable Operating Costs	104,988	228,411	246,685	265,921	286,185	306,701	314,602	322,885	331,561	340,579	349,680	360,011	370,689	381,877	393,019	404,447	416,234	428,476	441,033	454,068
Replacement Power																				
Capacity Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Purchases	-	20,295	21,731	23,440	25,111	25,737	25,618	26,822	27,824	28,547	29,064	28,833	29,449	30,441	31,821	29,757	29,571	29,314	29,478	30,510
Transmission Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Replacement Power Costs	-	20,295	21,731	23,440	25,111	25,737	25,618	26,822	27,824	28,547	29,064	28,833	29,449	30,441	31,821	29,757	29,571	29,314	29,478	30,510
TOTAL OPERATING EXPENSES	126,280	291,537	312,140	334,000	356,871	378,973	387,737	398,230	408,937	419,734	430,431	441,638	454,064	467,405	481,114	491,694	504,540	517,799	531,826	547,230
NET REVENUES																				
NET REVENUES	61,182	187,357	187,443	187,534	187,629	187,721	187,758	187,801	187,846	187,891	187,935	187,982	188,034	188,090	188,147	188,546	189,014	189,494	189,988	190,497
Deposit to Working Capital Reserve Account	526	1,215	1,301	1,392	1,487	1,579	1,616	1,659	1,704	1,749	1,793	1,840	1,892	1,948	2,005	2,049	2,102	2,157	2,216	2,280
DEBT SERVICE																				
Principal	-	60,015	62,265	64,600	67,023	69,536	72,144	74,849	77,656	80,568	83,589	86,724	89,976	93,350	96,851	100,482	104,251	108,160	112,216	116,424
Interest	54,603	109,205	106,955	104,620	102,197	99,684	97,076	94,371	91,564	88,652	85,631	82,496	79,244	75,870	72,369	68,737	64,969	61,060	57,004	52,796
Total Debt Service	54,603	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,219	169,220	169,220	169,220	169,220
Other Debt Payments	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Debt Service Requirement	54,603	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,220	169,219	169,220	169,220	169,220	169,220
Debt Service Coverage	*1.12x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.11x*	*1.12x*	*1.12x*	*1.12x*	*1.13x*
RESERVE AND CONTINGENCY FUND																				
Overhaul Account	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewal and Replacement Account	6,053	16,922	16,922	16,922	16,922	16,922	16,922	16,922	16,922	16,922	16,922	16,922	16,922	16,922	16,922	17,278	17,692	18,117	18,552	18,997
Capital Improvements Account	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rate Stabilization Account	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Environmental Improvement Account	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total R&C Fund	6,053	16,922	16,922	16,922	16,922	16,922	16,922	16,922	16,922	16,922	16,922	16,922	16,922	16,922	16,922	17,278	17,692	18,117	18,552	18,997
AVAILABLE FOR TRANSFER TO GENERAL ACCOUNT																				
Net Revenues Available	-	-	0	-	-	0	-	-	0	-	0	-	-	0	-	0	-	0	-	-
Available from R&C Fund	-	4,526	4,228	3,924	3,612	3,292	2,965	2,630	2,287	1,936	1,576	1,208	831	445	49	-	-	-	-	-
Total Revenue Requirements	187,462	478,893	499,582	521,534	544,500	566,695	575,494	586,032	596,783	607,625	618,366	629,620	642,098	655,495	669,261	680,240	693,554	707,293	721,814	737,727

Source: Initial Project Feasibility Study, by R.W. Beck (Base Case)