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NEW INSIGHTS INTO THE PROPOSED AMP GENERATING STATION

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PREFACE

THE SIERRA CLUB HAS PREPARED THIS REPORT to examine dramatic shifts in economic circumstances affecting the proposed American Municipal Power Generating Station (AMPGS). Since the project was proposed, both electric consumption and the cost of purchased power have dropped dramatically, while the cost of building and operating new electricity generation has increased significantly. As a result of these trends, which are likely to continue in the future, the proposed AMPGS would, for the first time in AMP's history, lock AMP members into paying much higher electricity rates than those enjoyed by neighboring towns and cities outside the AMP network. We identify a number of preferable methods of securing a more predictable and affordable future energy supply.

Currently, 81 municipal utilities have committed to a specific share of the AMPGS plant, with each share representing a different fraction of each utility's total electric consumption. This report examines four municipal power systems—Cleveland, Bowling Green, Painesville, and Shelby—in some detail, and also attempts to clarify the likely range of generalized impacts. While all economic projections inherently include some uncertainty, we believe this report presents a far more accurate estimate of the impact of the AMPGS on the electric rates of AMP's members than has been provided in the past.

If AMP proceeds with the AMPGS project, it will convert itself from a utility that owns approximately 20 percent of its generating capacity in the form of less expensive, fully amortized existing coal to a utility that owns approximately 85 percent of its generating requirements in the form of expensive new coal. Given the trends of falling electricity consumption and price, along with the serious economic risks that constructing new coal plants involves, such a transformation is highly misguided. This report identifies a large number of alternatives to the completion of AMPGS and encourages AMP members to cancel this project so that a more economically secure path can be followed.

The influences and evidence we consider in this report include the following:

- the evidence for rapid shifts in regional power availability;
- passage of Ohio Senate Bill 221 and its likely impact on the future availability of resources;
- the impact of the recession on regional power consumption;
- passage of the 2007 federal appliance standards and their likely impact on the future availability of resources;
- pending federal climate legislation and its likely impact on the future availability of resources; and
- key available alternatives to AMPGS.

We compare the cost of the proposed plant not only against the reasonable future costs that may be expected under these circumstances, but also against existing rates. Ultimately, the true cost of the plant depends on future events, including real construction costs and regulatory developments, which are presently unknown. We hope this presentation will prove useful to AMP member organizations in gauging the level of financial risk to which their customers will be subjected if construction of the AMPGS proceeds.

EXECUTIVE SUMMARY

WHEN THE AMERICAN Municipal Power Generating Station was originally proposed, many in the industry predicted serious regional capacity constraints in the near future. This was of great concern to the managers at AMP, through which AMP's 128 municipal utility members in Kentucky, Michigan, Ohio, Pennsylvania, Virginia, and West Virginia obtain at least some of their power. AMP has relied substantially on purchased power for several decades.

Circumstances surrounding AMP and its proposed plant have radically changed over the last three years. These developments should be thoroughly considered before proceeding with construction of AMPGS. Even assuming that the basic assumptions and projections used by AMP in past evaluations of the AMPGS were accurate, components of the electricity market in Ohio and the region have turned the appearance of a prudent project into a potential economic disaster for those customers who are typical of AMP's utility base.

In 2006, AMP (then called AMP-Ohio) issued a press release announcing that it would pursue construction of a new, coal-fired power plant near Letart Falls, located in southern Meigs County, Ohio. In 2007 and 2008, 81 of AMP's member municipalities voted to sign binding "take or pay" contracts which commit them to becoming owners of a certain number of 'shares' in the plant for 50 years, and to covering potential defaults of other municipalities. Pursuant to these contracts, each member utility must pay for shares of the financing and construction of the AMPGS, and purchase a defined amount of power from the plant, regardless of whether the member utility needs the power or could purchase power more cheaply from other sources. These contracts do not allow the cities any flexibility to adjust for future power needs or future power costs, and specify that failure to purchase the contracted amount of power would result in heavy penalties. A handful of municipalities declined to take part in AMPGS, some citing financial and/or environmental concerns. Others, such as Cleveland, reduced their level of commitment following protracted and sometimes bitter public debate.

Meanwhile, reports from several consulting firms, including one hired by AMP and one hired by the City of Cleveland, forecasted a range of costs for the plant and ranges of projected costs for market-based power purchases. Notably, there was an enormous increase in the projected cost of the plant over a two-year period, from $1.5 billion in May 2006 to a total estimated bond amount of $3.94 billion in October 2008.

AMP has historically performed well in providing its members with electricity at a lower cost than investor-owned utilities with neighboring service territories. For this reason, a certain amount of increased cost for AMPGS could be tolerated, though only if projections of rising rates for the alternative purchased power also proved true. These market projections, in turn, were based on several assumptions that none of AMP's or Cleveland's consultants chose to examine. Subsequent to these reports, the landscape has changed considerably because of economic developments, the passage of several important laws, and a growing likelihood that Congress will enact federal climate legislation.

Evidence now suggests that Ohio, which over the past two decades has consistently lagged behind national projections of growth in electric demand, may not see further growth in demand for the foreseeable future. Similar trends are at work in all the larger states in the Midwest, and in AMP's service territory in particular. In addition, the renewable and advanced energy requirements of Ohio Senate Bill 221, as well as new and proposed federal regulation and similar laws in other surrounding states, will deliver large energy savings while simultaneously adding new capacity to the electric generating mix:

- Any form of cap and trade, or carbon regulation in general, will place considerable value on strong efficiency measures.
- Efficiency measures--including methods of increasing efficiency in generation, such as combined heat and power--can be deployed in massive quantities in Ohio more quickly than AMPGS could be completed, for a fraction of the cost.
- Should AMP's customer base be constrained in its ability to develop strong efficiency programs, even in the face of solid developing programs by private-sector energy service providers in most of Ohio, efficiency measures under way because of Ohio 2008 Senate Bill 221 and parallel legislation in many other states will affect the availability of excess conventional resources anyway.
- Energy-sector economic stimulus provisions through the 2009 American Reinvestment and Recovery Act have begun and will continue to deliver a massive jump-start to both increased efficiency and new renewable generation.

In fact, it appears many of AMP's assumptions regarding the wisdom of acquiring a large new generation source have weakened. Figure 4—perhaps the single most important feature of this report—shows the extent to which dramatic shifts in the energy landscape have occurred. Under these circumstances, proceeding with the construction of AMPGS would prevent municipalities from taking advantage of low market prices resulting from ample, existing electric capacity in Ohio. While no one has a crystal ball, the available evidence shows that the most prudent option for AMP's members is to retain flexibility by canceling the AMPGS, investing in energy efficiency, and exploring emerging alternatives.

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I. THE TRADITIONAL ENERGY OUTLOOK

THROUGH 2007 AND EVEN EARLY 2008, it was reasonable to believe that Ohio and the region encompassing AMP's service territory were heading into a capacity-constrained environment. Pennsylvania and West Virginia (figures 2 and 3) are both significant exporters of electricity, while Ohio generation is in close parity with its electric sales. This suggests that AMP's future is strongly tied to the conditions of these three states.

U.S. economic growth was strong throughout 2007. Over the previous ten years, the nation as a whole had seen coal plant utilization rise from 63 to 73 percent. Ohio's coal capacity factor remained somewhat lower, rising from 55 to 68 percent over the same period. Still, the Clean Air Interstate Rule (see box) was expected to mandate pollution controls for sulfur dioxide on most of the remaining unscrubbed coal plants in the United States. This might have been expected to disproportionately affect Ohio and the lower Midwest, where many of the nation's oldest and dirtiest coal plants are located.

In fact, 30 percent of Ohio's fleet of coal plants is already equipped with flue gas desulfurization systems, which help reduce SO2 emissions and fine particulate formation. This is the same fraction as the scrubbed share of total U.S. coal plants. But Ohio remains substantially more dependent on coal than the nation as a whole: in 2007, coal supplied 49 percent of electricity nationally, but 85 percent in Ohio. (More recently, coal has dropped to 43 percent of total U.S. generation in 2009. Ohio fuel use shares are not yet available for 2009.)

Retrofit scrubbers are less efficient than scrubbers installed as part of a new plant. Because Clean Air Interstate Rule (CAIR) implementation promised to mandate emissions reductions that could only be met through the installation of retrofit scrubbers across a significant swath of the coal plant fleet regionally, it was reasonable to project a rapid loss of 3 to 5 percent of regional capacity. The heavy dependence on coal throughout the Midwest, combined with the parasitic energy usage of this newly installed pollution-control technology, seemed to indicate a future in which coal plant capacity would be severely constrained.

FIGURE 1. Most regions of Ohio, as well as many AMP members, are in the PJM Regional Transmission Organization. Map is courtesy of the Federal Energy Regulatory Commission.

The Clean Air Interstate Rule

In 1997, the U.S. EPA issued national standards for fine particulates and eight-hour ozone that were more protective of public health. Eight years later, the EPA issued CAIR, which was designed to use a cap-and-trade system over 28 states and the District of Columbia to achieve large cuts in sulfur dioxide and nitrogen oxides. The pollution reductions from CAIR were projected to save $85 billion to $100 billion in annual health visits and prevent 17,000 premature deaths each year. In July 2008, the U.S. Court of Appeals for the D.C. Circuit remanded the rule back to the EPA for development of a replacement rule. Until then, CAIR remains in place, but a schedule for enforcement has not yet been promulgated.

And while these trends took shape, the growth rate of U.S. electric consumption was projected to be between 1.6 and 1.8 percent per year. This was slightly lower than growth rates throughout the 1990s, but still substantial.

There is no practical way to know what the peak capacity factor for overall coal generation might be. But certainly, a national coal plant utilization of 73 percent with an annual energy demand growth rate over 1.6 percent and a potential acceleration of the reduction of available capacity due to CAIR would have made a dismal outlook for a utility that is as heavily reliant on the electricity marketplace as AMP has been.

AMP generation and sales profile

AMP sells electricity to most of the public power entities in Ohio, which collectively consume about 12.5 percent of Ohio's electricity. In 2007, AMP's annual report noted that AMP provided slightly less than 10.5 million MWH to its members, or roughly 6.7 percent of all Ohio electric sales that year. Most of the remaining 5.8 percent is consumed by Ohio's rural electric cooperatives, which are supplied by Buckeye Power.

Presently, AMP generates roughly 20 percent of the power it provides to its member groups. The rest has been purchased historically from the investor-owned utilities and/or independent power producers in the region. AMP has stated that the Richard H. Gorsuch plant in Marietta, Ohio, which is AMP's single largest generation asset and the source of about 20 percent of AMP's total electricity, may cease operations in 2014 if AMPGS is built—though no binding commitment to shut Gorsuch has been made. In March 2009, the U.S. EPA issued a Notice and Finding of Violation to the Gorsuch plant, alleging significant violations of the Clean Air Act.

In December 2007, AMP acquired a 368 MW share of the Prairie State Energy Campus, a coal-fired generating station under construction in Illinois. Together, AMP's share of AMPGS and AMP's share of Prairie State will generate about 85 percent of AMP's electricity requirements, pending growth of AMP customer consumption.

AMP's remaining resources include projects under way to build new hydropower, wind and landfill gas facilities. These resources are more variable than coal, but are likely to produce most if not all of the remaining electricity requirements. AMP's 2007 Annual Report notes the addition of 175 MW of non-coincidental peak load from new member communities. It is not possible for this report to take the new load into account without additional information about sales history. However, the overall picture does not change: AMP is converting itself from a utility that relies upon purchased power for about 80 percent of its resource to one that has virtually no flexibility, and this conversion is taking place in the midst of a rapidly changing economic environment.

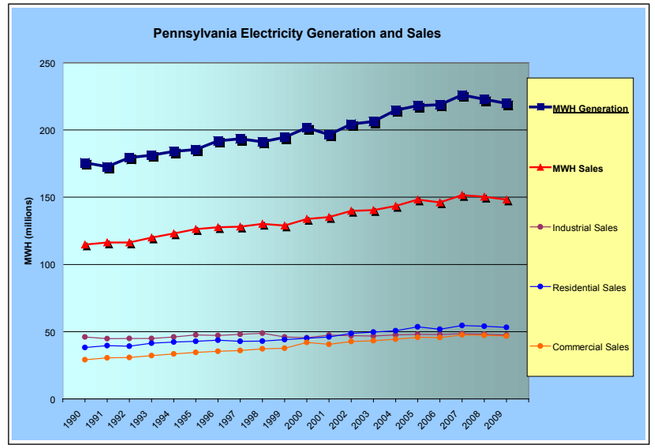

FIGURE 2. Pennsylvania is a substantial net exporter of electricity, though 2009 sales are down 1.4 percent over the same period in 2008. The 2008 data are preliminary; the 2009 data are also preliminary and reflect information available only through June.

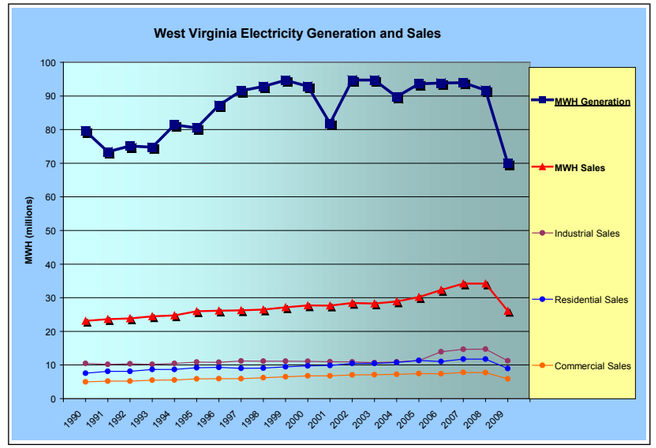

FIGURE 3. West Virginia exports over twice as much electricity as it uses, even during a downturn. Electric sales in West Virginia are down 23.7 percent over the same period in 2008. The 2008 data are preliminary; the 2009 data are also preliminary and reflect information available only through June.

II. THE REVISED ENERGY OUTLOOK

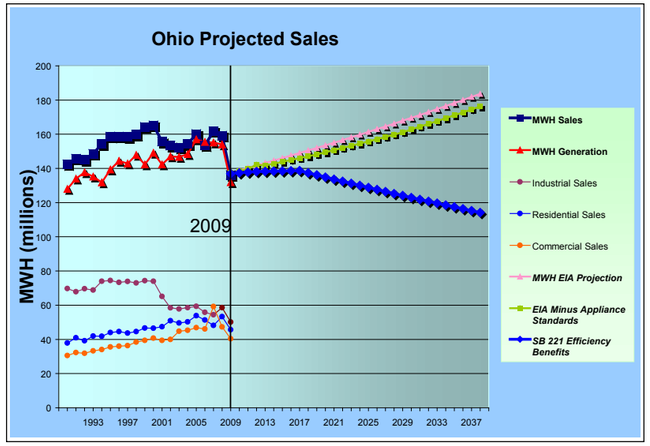

FIGURE 4. Historical Ohio electricity generation and sales, both total and by sector, and projected growth trends.[1] The 2008 and 2009 information is preliminary, and 2009 information includes data only through August.

OHIO HAS BEEN UNIQUELY UNAFFECTED by the population and commerce trends that have guided economic patterns for the rest of the nation. While most of the country experienced increasing electricity demand until early 2008, all-time high electric sales in Ohio occurred in the year 2000. Sales in 2006 were lower than any year since 1993, and sales in 2009 are likely to be much lower than in 1990.

Starting in 2008, the recession caused a dramatic change in Ohio's energy picture. According to preliminary data, electric sales were down in 2008, and 2009 will probably see massive further drops in sales, although year-end numbers are not yet available. Year-to-date Ohio electric sales are down 14.5 percent.[i] Nationally, electric sales are down over 6.8 percent. In light of past performance, Ohio is likely to experience lower or even negative electricity demand growth in 2010, but we use national estimates in the projections below in order to be conservative.

Figure 4 shows historical Ohio electricity generation and sales, broken down into residential, commercial, and industrial sales. The graph also shows various projected growth trends using the U.S. Energy Information Administration 2009 forecast. The base EIA forecast is shown in pink triangles. The base EIA forecast plus a correction for load reduction resulting from the 2007 Federal Appliance Efficiency Standards is in green squares. And the blue line is a projection of the energy efficiency savings of Ohio Senate Bill 221, plus the federal appliance efficiency standards, subtracted from the baseline EIA projections. As the graph shows, S.B. 221 implementation should mean that electricity demand will grow only very slightly, if at all, through 2014, and will subsequently fall.

Ohio Senate Bill 221

Governor Ted Strickland signed Substitute Senate Bill 221 into law on May 1, 2008. This critical step placed Ohio on the map with one of the strongest energy efficiency standards in the country. The efficiency savings start at 0.3 percent in 2009, ramping up to 2 percent new annual savings in 2019, with an estimated cumulative energy savings of 22 percent by 2025. S.B. 221 also contains "advanced energy" provisions that require Ohio to obtain 25 percent of its electricity through a diversified resource base, including a 12.5 percent renewable-energy requirement, by 2025.

The implementation of Senate Bill 221 should cause a net reduction in total electric sales in Ohio as a result of its efficiency provisions. Furthermore, its renewable and advanced energy provisions should be expected to replace a significant amount of existing generation capacity. Any form of federal climate legislation will reinforce—and likely accelerate—these trends.

The impact of the renewable and advanced energy provisions of S.B. 221 on available capacity in the state and region will be large. The law defines its advanced energy goals in terms of percentage of total sales. There is no doubt that utilities will retire existing coal capacity to the extent that provision to customers becomes feasible without the old plants. Some retirements and one large conversion to biomass have already been announced. The large-scale shifts in outlook identified in this report indicate that Ohio can preserve the availability of low-cost electric generation while these new resources are developed.

These trends are not limited to Ohio. Illinois and Ohio have nearly identical efficiency and renewable standards (Illinois is more than a year ahead of Ohio). Michigan and Pennsylvania have embarked on the same path, but have limited their legislated goals to the next four or five years of strong program expansion, with great likelihood that shifts in the cost of resources will cause them to continue expansion in the following years. This report anticipates complete elimination of all new growth in electric sales by 2014 for Ohio as a result of the efficiency portions of the law plus the federal efficiency standards—*not including the effects of the advanced energy provisions or renewable generation development elsewhere*. In 2014, these four states will merely have achieved a little over the 2008 national average for efficiency program activity. There will be ample room for sustained new efficiency expansion. Some states have run efficiency programs at the level our region will achieve in 2014, for decades on end. Some states run their programs at two times the 2014 rate.

Finally, a word about our assumptions: Figure 4 assumes that EIA's projection of national growth will occur in Ohio and the region in the coming decades, in spite of the fact that Ohio has not historically kept pace with the national average rate of growth. During most of the last decade, EIA projected growth approaching 2 percent per year, as figure 4 shows, yet Ohio saw no net growth at all between 1995 and 2008. If anything, figure 4 overstates predicted demand growth in Ohio, by treating the 1 percent average growth rate in the 2009 Annual Energy Outlook as the basis for assumptions. A more recent EIA statement predicts only 0.7 percent annual growth for the nation as a whole in 2010. In other words, we have intentionally discounted some of the information that most strongly supports the case for negative electricity growth in Ohio, and even so, the evidence is that S.B. 221 will cause a net reduction in electric sales across Ohio. This is in direct contrast to the traditional outlook, which held that capacity constraints were likely in the medium term.

The national recession has particularly affected the region served by AMP, including Pennsylvania and West Virginia. Net generation in the United States dropped by 6.8 percent from June 2008 to June 2009. Declines in West Virginia, Alabama, Pennsylvania, Ohio, Tennessee, North Carolina, and Georgia accounted for 53.5 percent of the national decrease in coal-fired generation, according to the September 2009 Electric Power Monthly from the Federal Energy Information Administration.[2]

III. AMPGS: A HIGH-STAKES GAMBLE

IN MAY 2006, AMP-Ohio issued a press release announcing its application for a permit to build a new 1,000 MW coal-burning power plant that would cost "approximately $1.5 billion." Subsequently, R. W. Beck, a consulting firm, was retained by AMP to prepare a feasibility study for the AMPGS project. In June 2007, R. W. Beck issued a report describing AMP's plans "to construct a 960 MW coal fired generating station consisting of two 480 MW units," identifying the total cost of construction at "approximately $2.532 billion." The report goes on to identify the total cost for construction and financing of the AMPGS at approximately $2.912 billion. The 2007 R. W. Beck report can be viewed at www.sierraclub.org/coal/oh.

On page ES 16 of the 2007 R. W. Beck report, cost per MWH for the AMPGS project in 2014 is identified as $57 without inclusion of an estimated cost for CO2 allowances, and $62 with CO2 costs. According to R. W. Beck, costs will rise to $77 without CO2 costs and $96 with CO2 costs in 2032. A slide show prepared for the Cleveland City Council and dated October 24, 2007 reiterates the $2.532 billion cost and identifies the full bond cost as the "installed cost" at $2,912 million. R. W. Beck cost estimates for 2013 are not included in this report as they reflect the operation of only one of the two units at the proposed AMPGS, and therefore do not reflect the full cost of the plant.

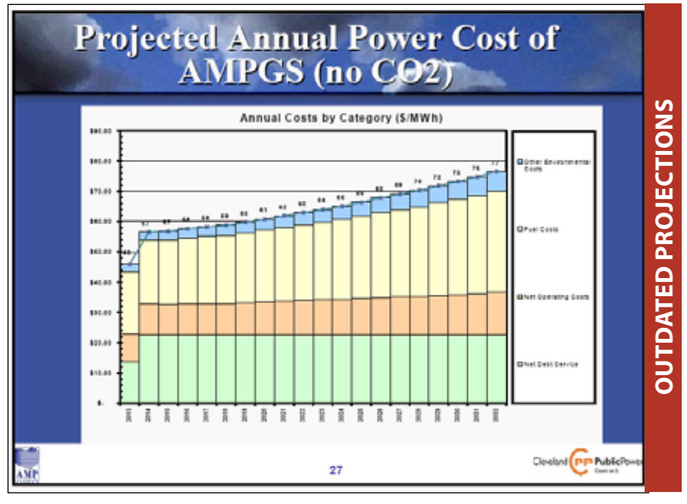

FIGURE 5. Slide 27 of AMP's presentation before the Cleveland City Council in 2007. This is a duplication of the projection of annual cost with CO2 from the R. W. Beck report. These data are also represented as the pink line in figure 8 of this report.

OUTDATED PROJECTIONS

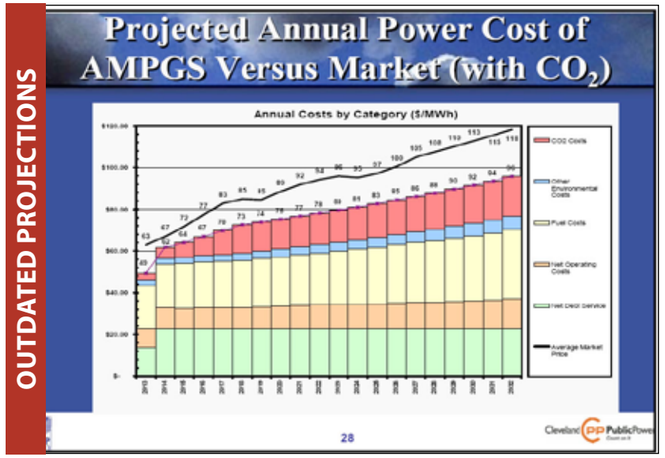

FIGURE 6. Slide 28 of AMP's presentation before the Cleveland City Council in 2007. These data indicate the average market price projection in a CO2-constrained future. They are also represented as the gold line in figure 8 of this report. They project that the average market price will remain above that of AMPGS for the duration of the time period.

OUTDATED PROJECTIONS

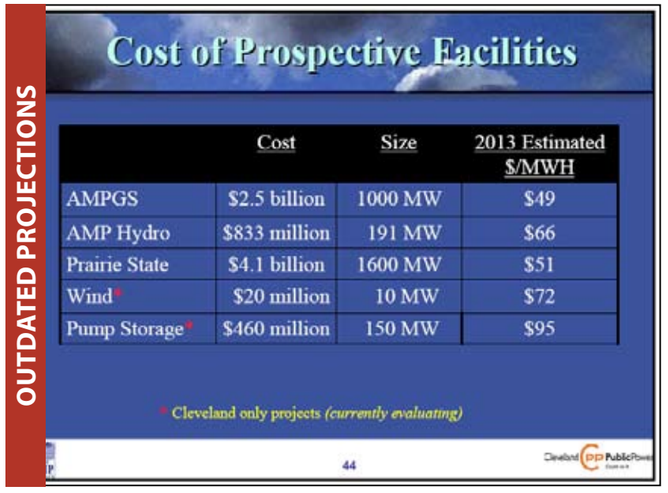

FIGURE 7. Slide 44 of AMP's presentation before the Cleveland City Council in 2007. This is a particularly misleading slide; it represents the cost of AMPGS at $2.5 billion, ignoring the $2.9 billion cost given earlier in the same presentation, and identifies the "2013 Estimated $/MWH" for AMPGS at $49. This $49/MWH figure reflects the R. W. Beck projection for 2013 only, a year when just one unit would be functioning, and ignores the $62/MWH cost for 2014, when both units would go on line. These misleading figures are then compared with a selected group of alternative options.

In January 2008, R. W. Beck issued a revised cost estimate of $2.9 billion to build the AMPGS, or $3.391 billion with financing costs included, in a report that can be viewed at www.sierraclub.org/coal/oh. The revised annual cost estimate with carbon costs is $67/MWH in 2014 and $103/MWH in 2032. Without carbon (shown as the green line in figure 8), those costs are $61/MWH in 2014 and $84/MWH in 2032.

In October 2008, R. W. Beck issued another revised estimate of $3.257 billion construction cost and a total bond cost of $3.940 billion. The base case cost per MWH is given as $73.69 in 2016, rising to $108.93 in 2033[iv]. The October 2008 R. W. Beck report identifies another element in the AMPGS story: the reduction of AMP's ownership share of the project from 100 percent to 87 percent. This division of ownership limits the dollar cost to AMP, but does nothing to reduce the cost per MWH of power generated at AMPGS. The change in ownership share does little or nothing to reduce the risk to AMP members, whose commitments to specific shares of the plant remain unchanged.

R. W. Beck attempted to justify the projected cost of the AMPGS on the grounds that purchasing power on the market would purportedly be more expensive. The R. W. Beck studies, however, provide little information as to the basis for these market purchase prices, outside of noting that they are based at least in part on the estimated cost of new coal, nuclear, combined cycle, and combustion turbine plants that may be added in the future. The focus on new generation and the inclusion of nuclear plants, which are too expensive to be built without significant taxpayer subsidies, likely leads to an overestimation of future market prices, especially to the extent that R. W. Beck's estimates ignore continued use of existing capacity, increased use of energy efficiency, and the continued decline in the cost of renewable energy resources.

Figure 8 combines these and other price projections for market power cost and for the cost of power from the proposed AMPGS plant, and puts them in context with historical AMP prices to members and historical local spot market prices:

The divergence between AMP's historical price to members and historical spot market prices at the AEP and PJM hubs indicates that AMP has served its member utilities well throughout tough times. Should the AMPGS project proceed, however, AMP members will face a complete shift from flexibility to inflexibility in responding to market trends. AMP-Ohio owned about 20 percent of its generating capacity until December 2007, when it acquired its 368 MW share of the Prairie State Energy Campus, scheduled to be operational in 2011–2012. AMP's existing generating capacity, mostly in the form of the Richard H. Gorsuch plant, provided some of the lowest-cost power currently available. Should AMP now proceed with AMPGS, it will own about 85 percent of its required capacity, at costs (at least $68.80/MWH) that are 50 percent or more above those in the spot market today. Individual AMP municipalities may end up with somewhat more or slightly less flexibility, depending on whether they own generation assets of their own and on what percentage of their demand will be supplied by nearly unalterable AMPGS contracts.

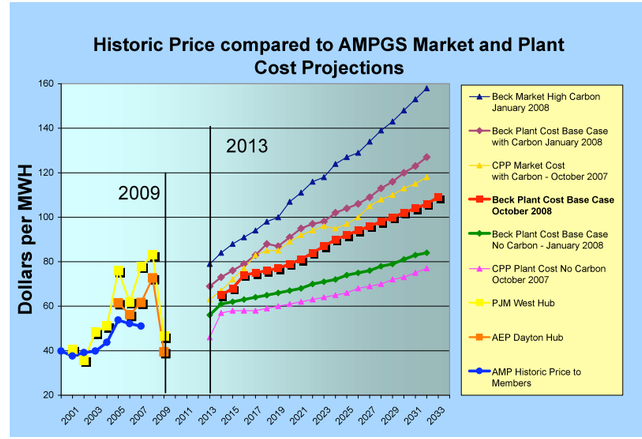

FIGURE 8. Historic price compared to AMPGS market and plant cost projections.[3] This graph shows historical PJM and AEP/Dayton short-term hub prices and AMP-Ohio historic average price to members, on the left, compared on the right to two projections of market prices (triangles) and three projections of AMPGS cost (squares) over the next 25 years. All five projections are from the 2007 or 2008 reports by R. W. Beck. The two plant cost projections from Cleveland Public Power (CPP) are dated, but are discussed in this report because the October 24, 2007, presentation to the Cleveland City Council contains some particularly misleading inferences and seems to have been given wide exposure relative to the more recent Beck report in January 2008. All CPP October 2007 data were taken from the June 2007 R. W. Beck report.

Effect of the American Recovery and Reinvestment Act

As of September 2009, Ohio has received slightly over $1 billion under the federal economic stimulus package for energy and environment projects, according to http://www.recovery.ohio.gov. Of these funds, $266 million is directed to weatherization and another $25–$40 million will fund efficiency and renewable generation. The impact of these savings will be spread between natural gas and electricity, so it is difficult to tell how it will impact either sector in advance. However, the money is intended for rapid expenditure, and the impact of this spending is likely to reinforce the downturn in total electric consumption for the following two years, even in the face of an economic recovery.

Two years ago, full implementation of the Clean Air Implementation Rule seemed imminent. Had that occurred, it would have been reasonable to expect a loss of 3 to 5 percent of regional capacity. However, CAIR was thrown into limbo in July 2008 when the D.C. circuit court vacated it. Though a subsequent order upheld the principles of the rule, the replacement rule will take years to write, finalize, and withstand challenge. Implementation of any new national regime to control fine particulates in the near term is therefore very uncertain.

In the meantime, there has been a growing awareness among federal decision-makers that global climate change demands a response that accelerates the use of energy efficiency and renewables. While adding scrubbers and other pollution controls to existing coal plants will reduce coal plant emissions, the most effective and least costly way to preventing deaths and sickness from such emissions is to close the dirtiest coal plants down. Avoiding the cost of pollution controls on these plants creates significant savings that can be more cost-effectively allocated to efficiency and renewable generation. As part of an overall climate response, it will be tremendously important to shift economic resources from reducing power plant emissions to replacing dirty power plants with sustainable energy resources. This suggests a strong shift away from the view that CAIR—or its successor—will cause significant loss of capacity in the region.

Since that shift fits well with other elements of a climate strategy and merely extends a delay in pollution reductions that have already been delayed more than a decade, this is a perspective that is likely to gain momentum among decision-makers in the coming years. Additionally, the Sierra Club will advocate for this perspective.

As with the implementation of S.B. 221, the fact that AMP-Ohio does not have coal capacity other than the Gorsuch plant isn't as important for the bottom line of AMP members as the prospect that shifting overall policies and strategies may preserve ample capacity in Ohio and surrounding states.

IV. ALTERNATIVES TO AMPGS

AMPGS REPRESENTS exactly the kind of large, inflexible and imprudent commitment that utilities in similar positions are continuing to abandon in this changing economy. Over the past few years, 106 proposed coal-fired power plants have been cancelled by companies throughout the United States. In 2009 alone, the list of cancelled plants includes:

- Alliant Energy's Sutherland Generating Station Unit 4 in Iowa
- LS Power's Elk Run Energy Station in Iowa
- LS Power's Mid-Michigan Energy Station in Michigan
- AES Corporation's Shady Point II coal plant in Oklahoma
- Basin Electric Power Cooperative's NextGen plant in South Dakota
- Santee Cooper's Pee Dee plant in South Carolina
- Southern Montana Electric Generation & Transmission Cooperative's Highwood Generating Station in Montana
- Nevada Power Co. and Sierra Pacific Power Co.'s Ely Energy Center in Nevada
- LS Power's White Pine Energy Station in Nevada
- NRG Texas Power LLC's Betron facility in Texas
- Intermountain Power Agency's proposed coal plant in Delta, Utah

In general, these plants have been cancelled either because new power plant costs have skyrocketed, or because old projections of growth in electricity consumption have proved unsupportable, or both. As has been discussed, Ohio has experienced a large drop in electricity consumption and is likely to see sustained capacity availability for some time to come.

Public Service Commissions in other Midwestern states have also recently found proposed coal plants to be unnecessary and/or not the most cost-effective options. In September of this year, the Michigan Public Service Commission issued two staff reports on new coal plants proposed by Wolverine Power Supply Cooperative and Consumers Energy, advising the utilities that the need for these plants has not been demonstrated. Wolverine is apparently basing the need for two 300 MW generators on the expiration of a 540 MW purchased power contract. The Staff report says in part: "Wolverine has presented no evidence that the capacity currently supporting this existing contract will be unavailable in the future."[vi] Similarly, the PSC report for Consumers Energy, in its discussion of a proposed 930 MW plant, says the need for the proposed plant "is based primarily on assumed retirement of approximately 950 MW of existing coal capacity."[vii] In both reports, the Michigan PSC staff found that the proposed coal plants were only "one alternative out of a range of alternatives that may be used" to fill whatever energy needs might exist.[viii.]

The PSC reports for both proposed Michigan plants contain lessons applicable to the AMPGS situation, especially in their identification of trends and suggestions for alternative resource strategies for the two utilities. Michigan's June 2009 electric sales were 12.9 percent below those of June 2008, reinforcing the consistent picture of ample capacity available in the region.

Faced with a similar situation, the Wisconsin Public Service Commission in the fall of 2008 rejected the proposed Nelson Dewey coal plant in Cassville, Wisconsin based on the fact that a combination of natural gas, energy efficiency, renewable energy, and market purchases were less costly in every planning scenario run by the Commission's staff and by the applicant.[vii] A thorough evaluation would almost certainly reach the same conclusion with regards to the AMPGS.

In deciding whether to proceed with the AMPGS, it is critical to separate AMP's indisputable need to provide secure and reliable power supply from the question of whether AMPGS is the right response to that need. As described below, there are more economically secure ways to meet that need. Therefore, we encourage AMP's members to cancel the project so that flexibility can be maintained and energy efficiency and the other alternatives featured on the next few pages can be fully pursued.

COMBINED HEAT AND POWER. We strongly encourage AMP and its member municipalities to consider the option of combined heat and power (CHP) as a low-cost and efficient way to generate power. CHP is a group of techniques that use waste heat created during industrial processes to generate electricity, or that harvest excess heat created during energy production to heat water and generate steam for industrial processes or other economically desirable purposes. CHP comes in many sizes and forms; most AMP members should be able to find small-to-medium CHP opportunities near or in their service areas. These potential CHP projects can generally be completed in less time and will produce power for about half the cost per unit of capacity as the AMPGS.

Although Ohio has a very large manufacturing base, it remains one of the weakest states in terms of adopting CHP, with only approximately 665 MW of CHP in the state.[viii] By contrast, Indiana has 2,308 MW of CHP installed,[ix] Michigan has 3,100 MW,[x] and Pennsylvania has 3,253 MW.[xi] A report on CHP opportunities in Ohio prepared by Recycled Energy Development, an engineering firm with a major role in developing CHP in the United States, is available for download at www.sierraclub.org/coal/oh. This report identifies 1,500 to 3,300 MW of potential generation from 55 industrial facilities in the state. A study conducted for the U.S. Department of Energy found a market potential of 3,075 MW of CHP in the commercial and institutional sectors in Ohio.[xii] AMP and its members should seize these cost-effective and efficient CHP opportunities as a primary alternative to the proposed AMPGS.

ENERGY EFFICIENCY PROGRAMS. End-use electric efficiency programs represent the quickest and most cost-effective tool for AMP and its members to address all new growth plus some net savings for some years to come. Through programs ranging from energy audits and incentives for more efficient residential lighting and appliances, to commercial building retrofits and industrial process changes, communities throughout the country have demonstrated that opportunities abound for saving money and reducing energy use.

Although delivering efficiency programs to rural customers poses some challenges, AMP is in a particularly good position to develop strong efficiency savings. Public power entities have historically led investor-owned utilities in developing such programs. Also, AMP members are surrounded in Ohio by the service areas of investor-owned utilities that are developing vendor-based efficiency services. And finally, the inherent conflict between shareholders and customers that causes investor-owned utility efficiency programs to require complex recovery treatment does not exist with public power companies.

The Ohio General Assembly's 2008 passage of Senate Bill 221 requires investor-owned utilities to save at least 22 percent of electricity consumption by 2025. A recent evaluation of the feasibility of this law, funded in part by the U.S. Department of Energy, reinforced that this goal can be achieved through the implementation of cost-effective energy efficiency programs.[xiii] In contrast to the projected cost of the AMPGS of $74/MWH in 2016, the report found that S.B. 221's goals could be achieved through programs that cost $29 per MWH of residential energy use saved, $16 per MWH of commercial energy use saved, and $23 per MWH of industrial energy use saved.[xiv]

These projections for energy efficiency in Ohio are consistent with real-world results in other states. For example, a September 2009 report[xv] found that 14 states with utility end-use efficiency programs report utility costs of saved energy ranging from $16 to $33 per MWH with an average cost of $25 per MWH. Through energy efficiency programs, Vermont and Connecticut achieved 1.0 and 1.1 percent energy savings, respectively, in 2005, and 1.8 and 1.3 percent savings, respectively, in 2007.[xvii] The Sacramento Municipal Utility District, meanwhile, achieved energy savings of 1.2 percent per year every year from 1991 through 1996 through energy efficiency. Similarly, a recent review of 20 state, regional, and national energy efficiency potential studies found average achievable energy savings of 1.5 percent per year, with Ohio and Illinois each averaging 2 percent annually.[xvii] In the last two years, Ohio and Illinois have passed nearly identical efficiency standards, while Michigan and Pennsylvania have passed standards that put them on an identical track through 2012 or 2013.

While S.B. 221 does not affect AMP and its members directly, it is directly relevant to the issue of whether the AMPGS should be canceled. The energy savings produced by S.B. 221 and the parallel laws in nearby states will contribute to the pool of available capacity, which will keep wholesale electricity prices low in the region while AMP develops cheaper alternatives to the proposed plant.

AMP and its members can achieve significant energy savings at a per unit of energy cost that is a third or less of the commensurate cost of AMPGS if they elect to participate in such efficiency programs. Energy efficiency cannot provide AMP with 960 MW of saved capacity in five years, but it will reduce the cost of any comprehensive plan in direct proportion to the amount of efficiency investment, up to the limits of the programs. 2 percent annual savings is near the peak rate that has been historically demonstrated, but it may not be the peak rate that can be achieved in a world where new coal-fired capacity is prohibitively expensive or where greenhouse gases are regulated.

RENEWABLE ENERGY: Substantial potential exists for renewable energy sources—including wind and hydroelectric—to play a major role in helping AMP members meet their energy needs. AMP has already made commendable investments in hydropower projects, and we encourage them to continue pursuing such opportunities throughout their service areas. Although Ohio is not recognized as a prime opportunity for wind power, the 100-meter wind map below demonstrates that a large fraction of the state has sufficient wind resource for cost-effective wind power development (Class IV and higher is generally considered commercially valuable wind resource). Recent estimates for the levelized cost of wind power range from $53 to $117 per MWH, which is competitive with AMPGS.

EXISTING UNUSED NATURAL GAS COMBINED CYCLE CAPACITY: As a supplement to the options discussed above, Ohio and the entire Midwest contains substantial amounts of unused natural gas combined cycle (NGCC) capacity that AMP and its members could try to obtain. For example, in 2008, the AEP Waterford, Hanging Rock, and Washington NGCC plants in Ohio operated at 3.3 percent, 6.7 percent, and 6.1 percent capacity, respectively. Those facilities have nominal respective capacities of 821 MW, 1,240 MW, and 620 MW, which means that there was approximately 2,500 MW of unused NGCC capacity at those three facilities in Ohio. Similarly, filings in a West Virginia Public Service Commission proceeding showed that existing NGCC facilities in Ohio, Indiana, Michigan, western Pennsylvania, West Virginia, and Kentucky operated at only a 9.4 percent capacity factor from 2002 through 2006.[xviii] While such low usage of NGCC in the past has been due to the high price of natural gas, those prices have fallen considerably in the past year. For example, the average price paid by electricity generators for natural gas in July 2009 was 63.9% lower than it was in July 2008.[xxi] Given such low prices, AMP and its members should pursue short and long term NGCC purchases to the extent they are needed to supplement efforts to enact energy efficiency and pursue CHP and renewable energy sources.

Considering all alternatives to AMPGS, it is CHP that offers the ability to secure an independent source of generation for less money and in less time than AMPGS. While energy efficiency cannot provide AMP with 960 MW of saved capacity in five years, it can play a significant role in a more cost-effective and flexible combination of alternatives to the AMPGS for meeting the energy needs of AMP's member communities.

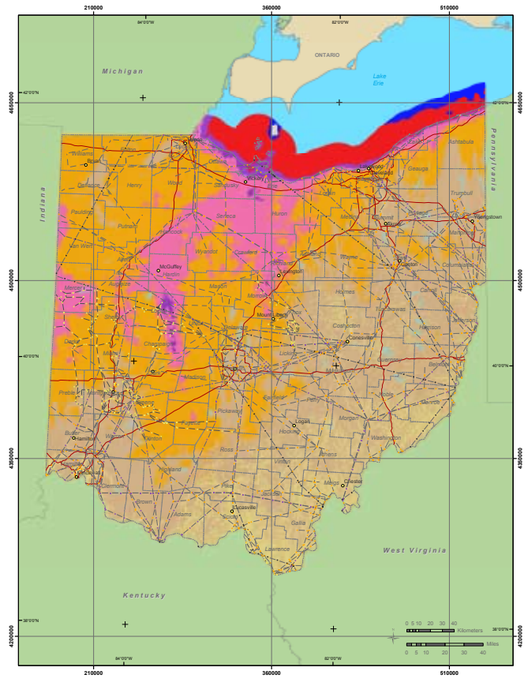

FIGURE 9. Map of Ohio's mean annual power density at a height of 100 meters. In this map, orange areas are Class III, pink areas are Class IV, dark purple areas are Class V, red areas are Class VI, and blue areas are Class VII. Wind becomes competitive with coal around Class IV. This map is courtesy of the Ohio Department of Development, via the Ohio Wind Working Group. A higher resolution version, complete with legend, is available for download at www.sierraclub.org/coal/oh.

V. COST IMPACTS ON FOUR OHIO CITIES

PRODUCING A CLEAR EXAMINATION of the rate impact of AMPGS for AMP customer utility systems presents substantial challenges. The most significant factor is that the AMPGS project represents such a large share of the AMP resource and that of most of its customer utilities. In 2007, AMP-Ohio sold approximately 10,500,000 MWH to customers. At 85 percent capacity factor, this would require roughly 1,400 MW of generating capacity. So AMP's share of AMPGS, at 835 MW, would potentially provide 59 percent of AMP's total load. AMP's 368 MW of Prairie State would produce 26 percent of AMP's load, fixing the cost of at least 85 percent of the power available to AMP's members.

Capacity

While the national average coal capacity factor was 73 percent in 2007 and Ohio's 2007 coal capacity factor was 68 percent, it is likely that any newly built coal plant would run at the highest possible level in order to earn more money through slightly higher fuel efficiency and considerably lower emissions. Practical issues of conforming to load shape and the size of AMPGS relative to AMP's customer base could work against achieving an optimum capacity factor. Throughout this report, we have used the 85 percent capacity factor assumed in the October 2008 R. W. Beck analysis.

Ordinarily, when a utility places a new plant in service, that plant is more expensive than the existing resource mix, but represents only a 5 to 10 percent share of the whole system. Distributing the cost of the new resource over the entire rate base thus results in a moderate rate increase. This situation is quite different. AMP has acquired 368 MW of the Prairie State Energy Campus. AMP also has several hundred megawatts of hydro and wind either already in operation or in development and scheduled to go on line before AMPGS would be completed. Since wind and hydropower typically have low capacity factors, these resources represent a much smaller share of AMP's total generating capacity than the sheer number of megawatts would suggest.

Prairie State consists of two 800 MW mine-mouth coal plants in southwest Illinois, scheduled for completion in 2011 and 2012, with a projected cost of $4 billion, or $2,500 per KW of capacity.[xxii] According to a March 2009 feasibility study, available for download at www.sierraclub.org/coal/oh, the Prairie State plant is expected to be fully operational and charge full cost to customers of $55.90/MWH in 2013.[xxiii] In order to reconcile different values for Prairie State and the AMPGS found in various R. W. Beck reports, this report uses a value of $57.03 for the cost of Prairie State power in 2016, which is the first year the most recent R. W. Beck report gives a full rate value for the AMPGS. These values are estimates and are subject to many changes that depend on project performance and outside influences such as fuel and labor costs.

Averaging the power from the AMPGS and Prairie State, assuming $74 and $57 per MWH respectively and 85 percent capacity factor for both, results in an average cost of generated power to AMP of $68.80/MWH.

While the cities discussed below are only committing approximately 30 percent of their power purchases to AMPGS, they are likely to be more dependent on AMPGS for a larger share of their power. This is because AMPGS will represent roughly 59 percent of AMP's resources, and AMP customers as a group take 100 percent of AMP's power generation, plus some additional power, to make up their total resources. Committing a large fraction of electric sales to AMPGS locks in unfavorable prices for AMP members and virtually eliminates their ability to remain flexible in a rapidly changing economic context. The average price of power sold to AMP members, as listed in AMP's 2008 annual report, is displayed in figure 8.

A. CLEVELAND PUBLIC POWER

At 80 MW, Cleveland Public Power is the largest municipal utility in Ohio committing to a share of AMPGS. CPP had revenues of $155,171,000 in 2007 and $146,347,000 in 2006. Expenses for purchased power were $83,523,000 in 2007 and $79,746,000 in 2006.[5] The 2007 data from the Federal Energy Information Administration indicate slightly different revenues of $154,855,000, sales of 1,625,206 MWH, and an average retail electricity price of 9.53 cents.[6]

One MW of capacity at 85 percent capacity factor would produce 7450.25 MWH during a year. The City of Cleveland's 80 MW share of AMPGS would produce approximately 596,020 MWH, or 36.6 percent of the city's 2007 sales.

The City of Cleveland owns four coal generators with a combined capacity of 160 MW, all on standby in 2006, and two 16 MW gas turbines with distillate fuel oil switching capacity, both operating in 2006. AMP also owns six 1.8 MW natural gas peaking plants in Cleveland. The standby status of the Cleveland coal plants indicates that it has been cheaper for the City of Cleveland to purchase power from AMP-Ohio than to run these plants for some time.

CPP's aggregate average power cost for 2006 was about 4.25 cents and the total including transmission was about 4.75 cents. The average is derived from multiple purchases of varying durations, prices, and types (on-peak, off-peak, baseload). If 36.6 percent of the city's total supply were to increase from 4.75 cents to 7.4 cents per KWH ($74/MWH from Beck October 2008), this would increase overall rates 10 percent from 9.53 to 10.49 cents in 2016, the first full year of operation of AMPGS. This is an average of all residential, commercial, and industrial sales, based on the Beck report value for 2016, so the percentages are accurate but do not reflect any particular individual rate.

Using the escalation rate provided by R. W. Beck in the October 2008 report base case, this indicates that Cleveland's average retail rate per KWH would be 11.48 cents in 2021, 13.32 cents in 2026 and 14.74 cents in 2031. This does not include any price on carbon.

However, in the 2007 presentation to city council, it was stated that 50 percent of CPP's power would come from AMPGS and 15 percent from Prairie State in 2013. At these percentages, rates would rise approximately 24 percent, to 11.79 cents per KWH in 2016 (under the optimistic assumption that the remaining 35 percent of supply would remain constant at 4.75 cents). AMP's average cost to members in 2006 was $52.14/MWH, so CPP managers have beaten that average slightly so far. By committing 65 percent of CPP load to Prairie State and AMPGS, much of that flexibility would be lost. CPP would substantially relinquish any ability to take advantage of low market prices should they prevail. Again, using the escalation rates in the October 2008 Beck report, Cleveland's average retail rate per KWH would be 12.91 cents in 2021, 14.97 cents in 2026, and 16.56 cents in 2031.

Current spot market prices are in the low $40s per MWH in the second half of 2009. This argues strongly against AMPGS as a reasonable investment at this time. Beck October 2008 projects market prices of $88 in 2016, $98 in 2021, $113 in 2026 and $126 in 2031 without carbon regulation.

R. W. Beck's October 2008 report also provides an estimate of future market costs with carbon limits, ranging from $103/MWH in 2014 to $178/MWH in 2033. These projected carbon costs are extremely high. Effectively, Beck's projections suggest that carbon credits will be valued at $200 each in 2033, with a nationwide carbon regime encompassing about 40 percent of the total electricity market at that point. A $200 carbon credit is hard to justify. It amounts to asserting that the United States will be willing to raise electric rates by about eight cents per KWH to solve global warming, and simultaneously will be unable to find a large resource of new efficiency or renewable energy that is cheaper than the existing fossil fuel mix plus eight cents/KWH. Since wind energy is already competitive with new coal plants without carbon controls, and photovoltaics are available for less than six cents more than a new coal plant, such high carbon costs seem an unlikely scenario.

CPP is in an unusually competitive position against First Energy, in that First Energy / Cleveland Electric Illuminating Company (CEI) owns parallel distribution infrastructure throughout much of CPP territory, allowing customers to switch from one to the other. For most of the past two decades, CPP rates have been substantially lower than CEI rates. In May 2009, First Energy conducted an auction to purchase its power for the next two years. The results of the auction lowered CEI rates by an average of 7.4 percent.[7] This may have moved CEI rates lower than CPP's, and AMPGS could force CPP to raise rates significantly above First Energy rates.

Transparency

Public utilities and AMP are not subject to the same open oversight by state regulators as investor-owned utilities, such as American Electric Power, Dayton Power and Light, Duke, and First Energy. This lack of oversight makes it difficult to obtain the information necessary to ensure that AMP customers and Ohio citizens are protected from questionable business decisions. The City of Cleveland provided purchased power costs for past years, which made our analysis of Cleveland Public Power more complete.

B. BOWLING GREEN

The City of Bowling Green's Electric Division 2007 revenues were $37,121,000. Sales were 530,492 MWH, and the average retail electricity price was 7.06 cents per KWH. Bowling Green's AMPGS commitment is 21 MW.

One MW of capacity at 85 percent capacity factor would produce 7450.25 MWH during a year. Bowling Green's 21 MW share of AMPGS would produce 156,455 MWH per year, or 29.5 percent of the system's 2007 sales. If Bowling Green only purchases its 21 MW share of AMPGS, and all other 2007 costs are held constant, rates would rise 9.6 percent in 2016, from 7.06 cents per KWH to 7.7 cents per KWH, based on the Beck report value for 2016.

However, Bowling Green has also committed to 35 MW of AMP's 368 MW share of the Prairie State Energy Campus. According to R. W. Beck's March 2009 feasibility study for Prairie State, Bowling Green is expected to pay $57.03 per MWH in 2016 for the power it purchases from Prairie State, roughly 49.15 percent of its total resource. This compares with the average price of AMP power to members of $51.02 in 2007. The combined effect of AMPGS plus Prairie State, holding all other factors constant, would be to raise rates 17.5 percent, from 7.06 cents per KWH in 2007 to 8.3 cents per KWH in 2016.

This would not be a terrific increase from 2007, but the market price for power in 2009 is around $40 per MWH, not the $51 that AMP provided in 2007 or the $60 - $80 range that the PJM and AEP/Dayton hubs averaged that year. If these low prices prevail as a result of strong commitment to energy efficiency in the region, strong renewable generation, impacts of the economic stimulus package, impacts of the recession, impacts of the Federal Appliance Standards, or a combination of these factors, Bowling Green's 21 MW share of AMPGS plus its 35 MW share of Prairie State would raise rates to all Bowling Green customers by 2.3 cents to 9.4 cents per KWH, or 33 percent more than the rates they might pay without these commitments.

Using the escalation rate provided by Beck in the October 2008 report base case, this indicates that Bowling Green's average retail rate per KWH would be 10.29 cents per KWH in 2021, 11.93 cents per KWH in 2026, and 13.2 cents per KWH in 2031.

AMP maintains 49.5 MW of natural gas combustion turbines, another 32 MW gas turbine identified as a peaking unit, four 1.8 MW wind turbines and two distillate fuel oil plants totaling 8.8 MW in capacity, all operating in 2006 in Bowling Green. Details of the contractual relationship between AMP and the City of Bowling Green Electric Division were not available for this report.

With a low retail price and the capacity to produce all its power from natural gas, Bowling Green would appear to be more protected from the negative potential of AMPGS. However, Bowling Green's capacity is all natural gas. The volatility of natural gas prices is extreme: Spot market prices climbed from a low of $2.50 to $4.96 during the five weeks beginning September 1, 2009. A climate-constrained future is expected to put price pressure on natural gas, and efficiency and alternative generation in the region will displace coal capacity. It may also displace natural gas, but there will be pressure to use natural gas instead of coal. Recent news about new discoveries of natural gas obscures the fact that these discoveries are years away from the market.

As with the city of Cleveland, the real risk to Bowling Green from the AMPGS project is the closure of options. By buying into both AMPGS and Prairie State, Bowling Green would be locking 78.6 percent of its 2007 energy use into costly new coal capacity for decades to come, rather than leaving itself open to the opportunities presented by energy efficiency, combined heat and power, currently low market costs, and other flexible and cost-effective options.

C. SHELBY

The Shelby Division of Electric reported 2007 revenues of $9,393,000, sales of 106,597 MWH, and an average retail electricity price of 8.81 cents/KWH. Shelby's AMPGS commitment is 5 MW.

One MW of capacity at 85 percent capacity factor would produce 7450.25 MWH during a year. Shelby's 5 MW share of AMPGS would produce 37,251 MWH, or 35 percent of Shelby's 2007 sales. Shelby has also committed to 3.981 MW of Prairie State which, at 85 percent capacity factor, would produce 29,659 MWH or 27.8 percent of Shelby's 2007 sales. According to the City of Shelby's

Web site (http://www.shelbyohio.org/light.html):

> *Since December of 1890 Shelby Municipal Light Plant has been generating electricity for the community. The power plant provides many functions, not only diesel peaking generation but also base load coal fired generation. Personnel within the plant are also responsible for the operation of the protection equipment on many of the circuits. Despite the constantly changing environmental impacts, the plant has been able to maintain generation availability over 90% of the time for many years.*
>
> *The plant currently supplies approximately 2/3 of the city's electric requirements, with purchases through American Municipal Power, Ohio supplying the remainder.*

Shelby's four small coal generators provide a total of 36 MW of capacity, plus one 3 MW natural gas internal combustion plant. Shelby has the capacity to switch all of these boilers to natural gas. One of the coal boilers, 5 MW, is operated on a standby basis.

Shelby's commitment of 35 percent of its 2007 requirements to AMPGS plus 27.8 percent of its 2007 requirements to Prairie State represents a dramatic shift from this history of independent power production. By 2016, Shelby will have committed to buying 62.8 percent of its 2007 requirements for an average price of $66.55 per MWH.

If 62.8 percent of Shelby's 2007 rates are increased by the difference between AMP's average $51 per MWH and the $66.55 projected by the Beck reports for 2016, while the remaining share of rates are produced at costs unchanged from 2007, the 2016 rates will be increased by 10.8 percent to 9.76 cents per KWH.

However, the market price for power in 2009 is around $40/MWH, not the $51 that AMP provided in 2007 or the $60-$80 range that the PJM and AEP/Dayton hubs averaged that year. If these low prices prevail as a result of strong commitment to energy efficiency in the region, strong renewable generation, impacts of the economic stimulus package, impacts of the recession, or a combination of these factors, Shelby's 5 MW share of AMPGS plus its 3.981 MW share of Prairie State would raise rates to all Shelby customers by 19 percent to 10.48 cents/KWH, assuming all other resources remained constant.

Using the escalation rate provided by Beck in the October 2008 report base case, this indicates that Shelby's average retail rate per KWH would be 11.47 cents in 2021, 13.31 cents in 2026 and 14.72 cents in 2031.

Clearly, Shelby has slightly lower rates than most Ohio public or private utilities, and has historically employed more flexibility than most municipal power companies. Still, Shelby is unlikely to be able to keep rates low if its purchased power cost rises from $51/MWH to $66.55/MWH (Shelby's average cost for its designated shares of AMPGS and Prairie State) or $68.80/MWH (AMP's average cost from AMPGS and Prairie State) or $68.80/MWH (AMP's average cost from AMPGS and Prairie State). By buying into both AMPGS and Prairie State, Shelby would be locking 62.8 percent of its 2007 energy use into costly new coal capacity for decades to come, rather than leaving itself open to the opportunities presented by energy efficiency, combined heat and power, currently low market costs, and other flexible and cost-effective options.

D. PAINESVILLE

The City of Painesville utility saw 2007 electric revenues of $22,277,000 and sales of 253,905 MWH, with an average retail electricity price of 9.13 cents/KWH. Painesville's AMPGS commitment is 13 MW.

One MW of capacity at 85 percent capacity factor would produce 7450.25 MWH during a year. The City of Painesville's 13 MW share of AMPGS would produce 96,853 MW, or 38.1 percent of the city's 2007 sales. Painesville has also committed to 9.952 MW of Prairie State, which would produce 74,145 MWH or 29.2 percent of Painesville's 2007 requirements.

Painesville owns and operates 38.5 MW of coal capacity and maintains another 15 MW (two 7.5 MW units) of coal capacity on standby. All the coal capacity can also be fueled with distillate oil, except one of the two 7.5 MW units, which can be fueled with natural gas. Painesville is in very much the same situation as the City of Cleveland, except that Painesville has its own ability to generate, whereas it is clear that the City of Cleveland purchases its power, with a large amount coming from AMP. However, with commitments to purchase 67.3 percent of its total 2007 sales from AMPGS and Prairie State, Painesvillle's flexibility will be significantly reduced.

Painesville's 13 MW share of AMPGS and its 9.952 MW share of Prairie State result in an average wholesale price of $66.62 per MWH in 2016. If all other 2007 costs are held constant, rates would rise 11.5 percent in 2016, from 9.13 cents/KWH to 10.1 cents/KWH. However, the market price for power in 2009 is around $40/MWH, not the $51 that AMP provided in 2007 or the $60-$80 range that the PJM and AEP/Dayton hubs averaged that year. If these low prices prevail as a result of strong commitment to energy efficiency in the region, strong renewable generation, impacts of the economic stimulus package, impacts of the recession, or a combination of these factors, Painesville's 13 MW share of AMPGS would cause a 19.8 percent rate penalty, raising the average cost per KWH to 10.9 cents for all Painesville customers, assuming all other resources remained constant.

Using the escalation rate provided by Beck in the October 2008 report base case, this indicates that Painesville's average retail rate per KWH would be 11.93 cents in 2021, 13.8 cents in 2026 and 15.31 cents in 2031.

Painesville may be exposed to a larger fraction of AMPGS if the plant is built; the alternatives are to purchase additional power independently or to self-generate. Either independent purchase or increased self-generation would help Painesville but expose AMP to additional economic penalty if AMP is unable to sell power from the uncommitted fraction of the plant.

Painesville's rates are slightly above the Ohio average. Painesville is unlikely to be able to keep rates low if its purchased power cost rises from $51/MWH to $68.80/MWH. By buying into both AMPGS and Prairie State, Painesville would be locking 67.3 percent of its 2007 energy use into costly new coal capacity for decades to come, rather than leaving itself open to the opportunities presented by energy efficiency, combined heat and power, currently low market costs, and other flexible and cost-effective options.

VI. CONCLUSIONS

OVER THE PAST SEVERAL YEARS, 106 proposed new U.S. coal plants have been abandoned because they lacked financing or a demonstrated need. Most of these plants were not abandoned because of climate concerns.

As the nation moves toward the adoption of climate legislation, the same economic pressures that drove the price of new coal capacity beyond the point of viability for those 106 projects are also driving a rapid and substantial shift toward serious investments in money-saving energy efficiency, combined heat and power, and renewable generation such as solar, wind and hydropower.

While this report has focused on the cost of CO2 allowances, it is likely that major sources of CO2 will be required to control such emissions, rather than simply pay for them. Post-combustion carbon capture and sequestration, if implemented on a commercial scale, would add about 40 percent to the capital cost of a new coal or natural gas plant and simultaneously require about 25 percent of the plant's energy to operate. This would make coal-fired power generation more costly than photovoltaics or even the most expensive form of generation, nuclear power. Therefore, the speculation that strong climate legislation will drive electricity costs toward the levels needed to make carbon sequestration cost-effective is not well-grounded. It is much more likely that strong climate legislation will accelerate the development of energy efficiency and low-cost renewable generation which, unlike carbon sequestration, will save consumers money.

Ultimately, the proposal to proceed with AMPGS raises significant economic concerns. The best strategy in the face of uncertainty in the current electricity market is to preserve flexibility. This report has identified combined heat and power as the most reasonable alternative for producing 960 MW of generating capacity within AMP's stated timeframe. But at the very least, AMP and its members should take this time to revisit the stated need of 960 MW and the perceived need to own a greater share of its generating capacity until it is clear where trends in electricity markets are heading.

The beauty of public power has always been its ability to work in concert with the electric consumer. AMP and its members rightfully take pride in their partnership, which over the years has yielded valuable economic benefits for all parties. The convergence of climate concerns and economic shifts are putting new technologies and conventions into motion faster than almost anyone can comprehend, and public power is well positioned to embrace these shifts. Making energy efficiency and renewable energy work will require a different sort of relationship between utility and customers—more cooperation, more communication, better understanding—than conventional central station generation usually provides. This sort of relationship is something that public power can already do well.

The path for AMP and its members and customers will not be free of obstacles. But developing innovative energy solutions based on the best and most cost-effective technologies can create a cleaner, more affordable future, and the nation's oldest grassroots environmental organization stands committed to work with the AMP community to see it through.

Ultimately, the proposal to proceed with AMPGS raises significant economic concerns. The best strategy in the face of uncertainty in the current electricity market is to preserve flexibility.

NOTES

i U.S. Energy Information Administration, Electric Power Monthly for Sept. 2009, available at http://www.eia.doe.gov/cneaf/electricity/epm/table1_6_a.html .

ii Figure 4: Ohio Projected Sales. Historical data in this graph come from EIA Form 861 for Ohio through 2007 (available at http://www.eia.doe.gov/cneaf/electricity/epa/epat7p2.html) with preliminary data from successive Tables 1.6b from EIA's Electric Power Monthly (available at http://www.eia.doe.gov/cneaf/electricity/epm/epm_ex_bkis.html).

The 2009 data are constructed—in that real preliminary data up to August 2009 shows a 14.4 percent drop in sales below the same period in 2008—so the data points that illustrate generation, sales, and sales for the three major sectors extend this 14.4 percent reduction through the end of the year. EIA's 2009 Annual Report projects 1 percent annual electric growth through the 20-year period, as seen at http://www.eia.doe.gov/oiaf/aeo/index.html (page 71 of the report).

The effects of the 2007 Energy Independence and Security Act (EISA) and some other relevant federal appliance standard rules are identified at http://www.standardsasap.org/state/2009%20federal%20analysis/states/fedappl_oh.pdf . The values used for Ohio projected sales are annualized values that converge with the 2020 and 2030 values provided at this reference. Energy efficiency benefits produced by Ohio Senate Bill 221 are embodied in Ohio Revised Code Sec. 4928.66. (A)(1)(a). An online version of this section is available at http://codes.ohio.gov/orc/4928.66 .

iii September 2009 Electric Power Monthly – Federal Energy Information Administration. http://www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html) .

iv In a June 5, 2009 letter, AMP announced that its consultant, R. W. Beck, had concluded that the estimated construction cost for the AMPGS had decreased from $3.25 billion to $3.074 billion. That estimate is still more than double the initial $1.5 billion cost estimate provided by AMP in 2006. The June 5, 2009 letter did not discuss whether there had been a change in expected financing costs and, to our knowledge, an updated R. W. Beck feasibility study for the AMPGS has not been released. Therefore, this report uses information from the R.W. Beck October 2008 feasibility study update, which is the most recent feasibility study available on AMP's website.

v Figure 8: Historic price compared to AMPGS market and plant cost projections. Data in this graph come from three sources with multiple references. The historical prices for the AEP /Dayton Hub and the PJM West Hub come from http://www.eia.doe.gov/cneaf/electricity/wholesale/wholesale.html . Individual years were combined in a single spreadsheet. The price projections for market prices and the plant cost projections are from the October 2008, January 2008 and June 2007 R. W. Beck reports. The prices from the June report were used in the CPP Powerpoint presentation to the Cleveland City Council. This presentation is of particular concern because it was distributed at such a time and in such a way as to place a more reasonable face on the project proposal than was justified at the time. While the October 2008 and January 2008 R. W. Beck reports are more reasonable, it is possible that some decision-makers have seen only the flawed CPP presentation and not the later Beck report. AMP's historical price to members comes from page 8 of the 2008 AMP-Ohio Annual Report, available at http://amppartners.org/pdf/annual-reports/2007_Amp_Ohio_Annual_Report.pdf .

vi Michigan Public Service Commission, Wolverine Power Supply Cooperative Electric Generation Alternatives Analysis for Proposed Permit to Install No. 317-07, Staff Report to the Michigan Department of Environmental Quality, Docket No. U-15996 (Sept. 8, 2009), available at http://efile.mpsc.state.mi.us/efile/docs/16000/0144.pdf .

vii Michigan Public Service Commission, Consumers Energy Electric Generation Alternatives Analysis for Proposed Permit to Install No. 341-07, Staff Report to the Michigan Department of Environmental Quality, Docket No. U-15996 (Sept. 8, 2009), available at http://efile.mpsc.state.mi.us/efile/docs/15996/0190.pdf .

viii Id . at 41.

ix Public Service Commission of Wisconsin, Application of Wisconsin Power and Light Company, d/b/a Alliant Energy, for Authority to Construct a New Coal-Fired Electric Generation Unit Known as the Nelson Dewey Generating Station in Cassville, Grant County, Wisconsin, Final Decision, Dec. 11, 2008

x Energy and Environmental Analysis, Inc., Combined Heat and Power Installation Database, Combined Heat and Power Installations in Ohio (last updated January 21, 2009), available at http://www.eea-inc.com/chpdata/States/OH.html .

xi Id. , Combined Heat and Power Installations in Indiana , available at http://www.eea-inc.com/chpdata/States/IN.html .

xii Id. , Combined Heat and Power Installations in Michigan , available at http://www.eea-inc.com/chpdata/States/MI.html .

xiii Id. , Combined Heat and Power Installations in Pennsylvania , available at http://www.eea-inc.com/chpdata/States/PA.html .

xiv The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector , Prepared for the US Dept. of Energy, Energy Information Administration by ONSITE SYCOM Energy Corporation, January 2000 (Revision 1), Table B-1, pages 57-58.

xv American Council for an Energy-Efficient Economy, Shaping Ohio's Energy Future: Energy Efficiency Works (Mar. 2009), available at http://aceee.org/store/proddetail.cfm?CFID=4177037&CFTOKEN=93915208&ItemID=458&CategoryID=7 .

xvi Id . at 12-17.

xvii American Council for an Energy-Efficient Economy, Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved Through Utility-Sector Energy Efficiency Programs (Sept. 2009), available at: http://aceee.org/pubs/u092.pdf?CFID=3508870&CFTOKEN=51745518

xviii Efficiency Vermont, 2007 Annual Report Executive Summary (Oct. 15, 2008), available at http://www.efficiencyvermont.com/pages/Common/AboutUs/AnnualReport/

xix Eldridge, M, R. N. Elliot, and Max Neubauer. 2008. State-Level Energy Efficiency Analysis: Goals, Methods, and Lessons Learned . American Council for an Energy-Efficient Economy.

xx Appalachian Power Company SCW Exhibit No. 12-A, page 2 of 2, in West Virginia Public

Service Commission Case No. 06-0033-E-CN.

xxi October 2009 Electric Power Monthly – Federal Energy Information Administration. http://www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html).

xxii AMP's share of the construction of the Prairie State plant is $971 million, an amount that is expected to increase to $1.334 billion with financing costs. R.W. Beck, Consulting Engineer's Report – American Municipal Power – Ohio , Inc. Prairie State Energy Campus Project (Mar. 24, 2009), at G-22, G-25.

xxiii A recent Official Statement regarding AMP's issuance of bonds for its portion of the Prairie State project cited the construction cost of the plant as $4.29 billion, which is an increase over the $4.066 figure presented in the latest R.W. Beck study and used in this report.

xxiv CPP Annual Report, page 30, http://www.cpp.org/bitsabout/CPP%2007_web.pdf .

xxv http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html (select Table 10 from the list at right).

xxvi PUCO news release, May 2009, available from this link: http://www.puco.ohio.gov/PUCO/MediaRoom/MediaRelease.cfm?id=9388 .

xxvii http://www.wtrg.com/daily/ngfclose.gif .

xxviii EIA Form 860. The most recent form available, as of September 2009, is for 2006. See http://www.eia.doe.gov/cneaf/electricity/epa/epat2p2.html ; select "Existing Electric Generating Units in the United States , 2005" from links below the chart.

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