FEASIBLE BASELOAD GENERATION ALTERNATIVES

FOR THE

CITY OF OBERLIN

FEBRUARY 2008

Prepared by:

CONCENTRIC ENERGY ADVISORS

293 Boston Post Road West, Suite 500
Marlborough, MA 01752
508.263.6200 • 508.303.3290 *fax*
www.ceadvisors.com

TABLE OF CONTENTS

APPENDICES

TABLES

FIGURES

I. EXECUTIVE SUMMARY

Background

American Municipal Power – Ohio, Inc. ("AMP-Ohio") is planning to construct a 960 megawatt[1] ("MW") coal-fired generating station in Meigs County, Ohio. The new plant, which will be known as the American Municipal Power Generating Station ("AMPGS"), has a scheduled on-line date of 2013, with its two 480MW units coming on line in the middle and end of that year. AMPGS's primary function in the AMP-Ohio portfolio will be to replace AMP-Ohio's existing 213MW RH Gorsuch coal-fired station ("Gorsuch") upon its retirement, which is also tentatively scheduled for 2013.[2] AMPGS will also supplement AMP-Ohio's current 1,340MW portfolio and provide for load growth of the AMP-Ohio member cities, which include 120 communities in Ohio and several neighboring states.

AMP-Ohio and its member cities have entered into contracts that provide for the members to participate in shares of the AMPGS project. These contracts, which were signed in November 2007, will provide for each member to receive its allocated share of the power produced by AMPGS. In return, each member signatory will be responsible to pay for its allocated share of all of the fixed and variable costs of the facility. The contracts contain a provision that allows each of the member signatories to fully withdraw from each of their contract commitments by giving notice to AMP-Ohio before March 1, 2008.

The City of Oberlin, OH ("the City") is a member of AMP-Ohio and a signatory to the AMPGS contract. The City's approximately 3,000 customers are served by the Oberlin Municipal Light and Power System ("OMLPS"). OMLPS has a total annual load of approximately 117 gigawatt-hours ("GWh") and a peak load of approximately 23 megawatts ("MW") primarily through contracts with AMP-Ohio and its member cities. The City's largest electric customer is Oberlin College ("the College"). The College, which has a liberal-arts curriculum and approximately 2,800 students, is fully incorporated within the City, and has approximately 25GWh in total annual load.

Scope

Through a partnership between OMLPS and the College, Concentric Energy Advisors ("CEA") was engaged to perform a study of alternatives with respect the AMPGS contract. The City and the College believe that, while AMPGS may be among the more economically advantageous baseload resources available to them, there is concern that the facility may provide risks and disadvantages that can be avoided by alternatively committing to other non-coal baseload alternatives. In order to address these concerns and as part of this report, CEA has:

---

[1] MW refers to generating capacity. Megawatt Hour ("MWh") refers to the amount of electricity that is actually generated. For example, a power plant with a capacity of 1 MW can produce 1 MWh of electricity every hour.

[2] AMP-Ohio is also considering a re-powering of Gorsuch. The City will be free to participate in its replacement, which could use one of a number of different technologies.

- Reviewed and analyzed the City's baseload requirements, the City's capability to modify its portfolio in order to best serve these requirements (either within AMP-Ohio or independently), and the RW Beck Supply Plan for the City.
- Reviewed and analyzed the AMPGS project, including a review of its benefits, costs and risks, along with a review of RW Beck's AMPGS Initial Project Feasibility Study, dated June 2007 ("the Feasibility Study"), RW Beck's AMPGS Initial Project Feasibility Study, Updated, dated January 2008 ("the Updated Feasibility Study"), and the Participant Beneficial Use Analysis for the City of Oberlin, dated June 22, 2007 ("the Beneficial Use Analysis).
- Compiled an analysis of the following generation technologies (including known opportunities where available, and generic profiles where not), along with costs, benefits and risks for each resource which, together or individually, may serve to provide for an alternative to AMPGS and/or provide perspective for decision-making purposes:

  - Coal (circulating fluidized bed technology)
  - Coal - Integrated Gasification Combined Cycle ("IGCC")
  - Nuclear
  - Natural Gas Combustion Turbine in Combined Cycle ("CTCC")
  - Natural Gas Combustion Turbine in Simple Cycle ("CT")
  - Hydro (including specific AMP-Ohio projects)
  - Wind (including both specific AMP-Ohio projects and potential small-scale projects near the City)
  - Biomass (including detailed analysis of wood-waste biomass)
  - Biogas (including detailed analysis of manure-based projects)
  - Landfill Gas (including specific AMP-Ohio projects)

Assumptions for this alternative technology analysis were derived almost entirely from CEA internal research and proprietary data. AMP-Ohio, the City and the College, also provided materials regarding certain initiatives and development opportunities.

- Researched and analyzed the cost and potential baseload resource that could be provided by demand-side management ("DSM") programs at AMP-Ohio, the City and the College.
- Researched and provided perspectives with respect to various collaborative opportunities that may be available to the City through power contracts or asset ownership opportunities.
- Created four possible portfolios that could be implemented as baseload alternatives to AMPGS, and analyzed the costs and risks associated with each portfolio.

Key Findings

Through the research and analysis described above, CEA finds the following:

1. **The City's baseload requirements exceed the proposed 9MW share of AMPGS.**

   The City will need approximately 13MW of baseload resources in 2013, and approximately 15MW of baseload resources by 2020. Therefore, even assuming that the City was to subscribe to a 9MW share of AMPGS, an additional 4MW of baseload capacity would be needed in 2013. Through its contracts with certain AMP-Ohio cities, the City will be free to procure up to 8.1MW outside of the AMP-Ohio portfolio; therefore, some but not all of this baseload need must come through AMP-Ohio if the City wishes to preserve that relationship.

2. **The City's generation portfolio currently contains a renewables component that is larger than that of most Ohio and US utilities, and is well balanced in terms of dispatch and fuel diversity for risk mitigation.**

   The City's resource portfolio contains a good balance of baseload, intermediate and peaking resources that are well matched to the City's load profile. Approximately 15% of the electric generation from these resources is derived from renewable resources. This proportion is comparable to the standard that many states have set for themselves in their respective Renewable Portfolio Standard ("RPS") initiatives, although most of these standards do not have to be met until 2015 or later. For comparison, 8.4% of the generation portfolio of the United States is renewable, primarily in the form of hydroelectric power.

3. **On an expected-value basis, DSM, Hydro and Nuclear are the three lowest-cost resources of the technologies explored.**

   According to the R.W. Beck Beneficial Use Analysis, the City's current portfolio has a levelized cost[3] of $79.01.[4] CEA calculates that the following technologies would lower the City's current levelized cost of power if any amount of their capacity were to be added to the City's portfolio:

   - DSM $33.52/MWh
   - Hydros $68.92/MWh
   - Nuclear $75.34/MWh

   CEA calculates that AMPGS will have a levelized cost of $85.74/MWh. Therefore, adding the AMPGS project would increase the City's cost of power slightly.

   There is substantial hydro generation potential on the Ohio River. The City has committed to participating in three projects with AMP-Ohio. Additional projects

[3] "Levelized cost" is equal to the payment, which if made every year for 20 years in equal installments, would result in the financial equivalent of the actual variable – and typically increasing – project payments over time.
[4] "Beneficial Use Analysis,", Attachment C, Page 1.

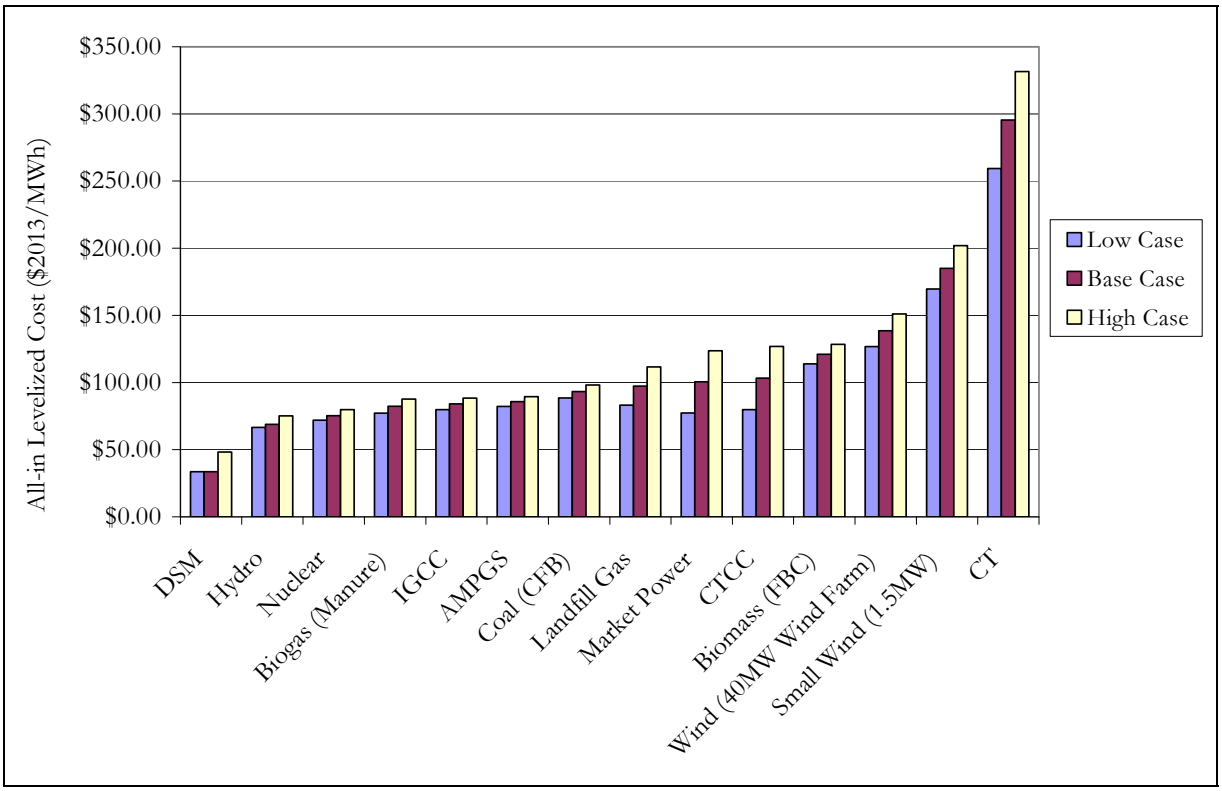
may become available through AMP-Ohio or may be pursued independently by the City.

Some baseload contracts to which the City is currently a party may include a nuclear generation component. However, no new nuclear generation has been proposed in the region that would likely serve as an acceptable alternative to AMPGS, especially given the timing of the City's baseload need and the environmental concerns surrounding this technology.

DSM is becoming increasingly recognized as an important contributor to generation portfolios. While it is inexpensive to implement, there is a limit to the reductions that can be expected to be achieved over time. This is discussed further in this Section and in Section V of this report.

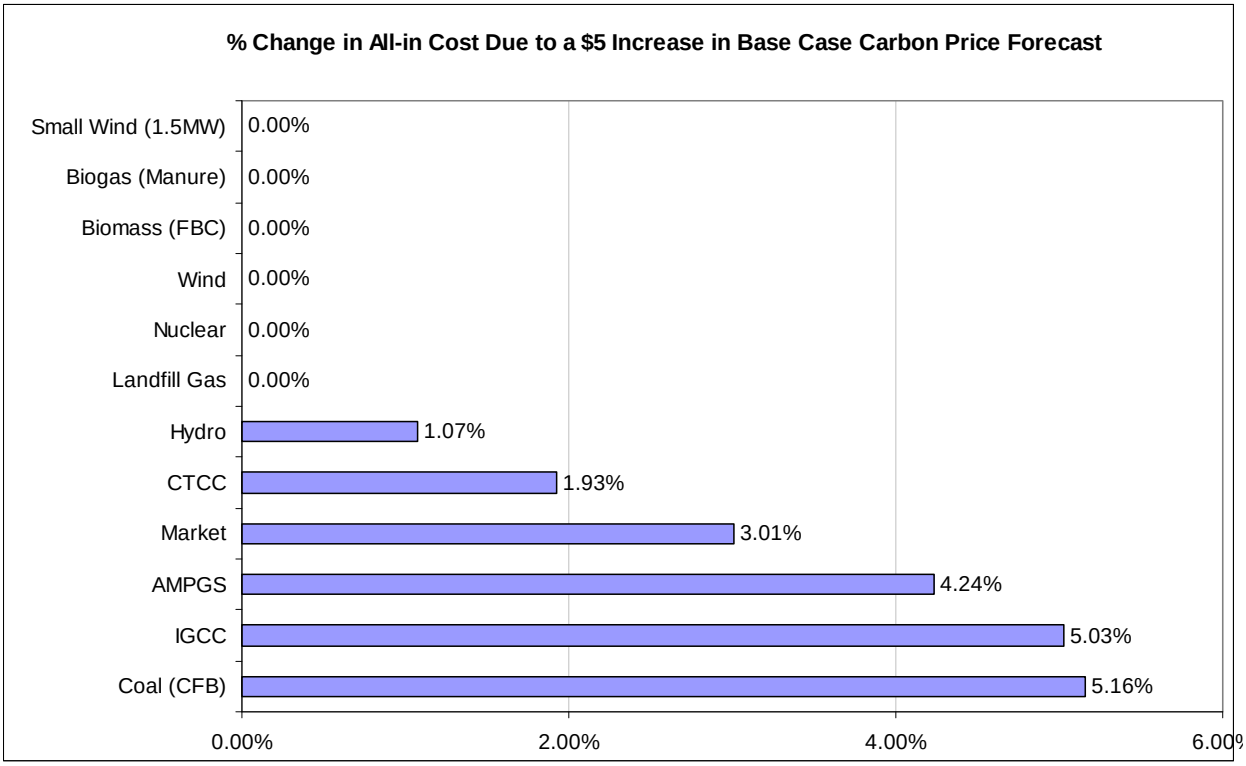
The remaining technologies are expected to have a higher levelized cost than the City's current portfolio, but should not be dismissed on that basis alone since each has risk or non-cost attributes that may be attractive. Figure 1 provides the full spectrum of technologies, ranked by their expected levelized cost in the base case. Each technology is accompanied by a high and low scenario representing a reasonable change in the variable that has the most effect on levelized cost to the upside and downside.

Figure 1 Levelized Cost Scenarios for Each Technology



4. **AMPGS has a relatively high exposure to the uncertainty surrounding CO_2 emissions costs, as compared to other technologies as shown in Figure 2.**

Figure 2 Sensitivity of Levelized Cost to the Price of Carbon Emissions



Legislation regarding carbon dioxide emissions has not yet been enacted, and price forecasts vary considerably. A $5.00/ton variation in the price of carbon allowance representing an approximate 30% deviation from CEA's carbon price forecast on a levelized basis results in a 4% change in the levelized cost of AMPGS. This on its own would not affect AMPGS's ranking among the other technologies on a levelized cost basis.

It should also be noted that while Wind and Hydro do not emit CO_2, these are intermittent sources that must be backed up by a dispatchable generation source, which is typically natural gas fired. Therefore there use as a baseload substitute will ultimately result in CO_2 emissions.

5. **As a coal-fired facility, AMPGS will emit SO_2, NO_X, CO_2, mercury and particulate matter. While levels of SO_2 and NO_X emissions from AMPGS are expected to be substantially lower than most existing facilities, and in line with recent plants, they remain an environmental hazard. CO_2 emissions are not mitigated and will be subject to the implementation of any CO_2 legislation in the future.**

The effectiveness of emissions technologies has improved substantially in recent years, meaning new plants that incorporate Best Available Control Technologies have a decided advantage over older plants, especially with regard to SO_2 and NO_X. Below is a table comparing the expected emissions from AMPGS to other plants.

Table 1 Emissions Rates for AMPGS, US Coal, and All Generation Types

	AMPGS	Duke Energy Cliffside 6 & 7	DOE New Super-critical	Coal-Fired Only		All Generation Types	
				Ohio Coal Average	US Coal Average	Ohio Average	US Average
SO2 (lbs/MWh)	1.6	1.4	0.7	17.2	10.0	15.1	5.4
NOx (lbs/MWh)	0.8	1.0	0.6	4.2	3.6	3.7	2.1
CO2 (lbs/MWh)	1,933	NA*	1,681	2,010	2,138	1,779	1,363
Mercury (lbs/GWh)	0.018	0.020 - 0.066	0.01	0.06	0.05	0.05	0.03

* Duke Energy agreed to various CO_2 offsets.
Source: AMP-Ohio; USEPA EGrid Database, 2006 (2004 data); DOE/NETL for New Supercritical.

Further, while the Powerspan technology has the capability of accommodating a CO2 capture system in the future, there is currently no viable technology that can effectively sequester CO_2 once it is captured. Sequestration, which would likely involve condensing and burying liquid CO_2, is necessary in order to effectively reduce CO_2 emissions. Legislation regarding CO2 emissions is broadly expected to be enacted within the next several years. Therefore AMPGS will likely need to purchase CO_2 allowances in order to comply with any such legislation.

6. **Aggressive demand-side management programs at AMP-Ohio, the City and the College have a reasonable potential of achieving 3.7MW of peak demand savings and an 11GWh of total load savings by 2020.**

   These amounts represent 41% and 17% of the capacity and generation provided by the proposed 9MW of AMPGS, respectively. New technologies have reduced the cost and increased the effectiveness of DSM, and such programs would likely have an all-in $/MWh levelized cost well below all available generation technologies. The City and the College would therefore benefit from pursuing an aggressive DSM program regardless of the near-term baseload resource decision.

7. **The City could potentially develop a variety of renewable projects that, together with AMP-Ohio renewable projects currently in development, could comprise an alternative portfolio large enough displace AMPGS if combined with enough market purchases to fulfill baseload needs. However such a portfolio would incur the high cost and risks of these market purchases.**

   CEA has compiled an alternative portfolio that could be constructed of DSM combined with additional shares of renewable resources currently under development by AMP-Ohio and also including biogas and wind projects conducted independently by the City.[5] Together, these resources would fulfill 5.4MW of

[5] Referred to in Section VII as "Portfolio 4 – Renewable Buildup."

baseload-equivalent capacity[6] as compared to the City's 13MW baseload need. The remainder would be filled by purchases of market power. The cost of this portfolio would be $87.85/MWh on a levelized basis, which is higher than the $80.74/MWh cost of a portfolio composed only of AMPGS and DSM.

Similarly, the City could purchase market power in order to wait for technologies to develop that may offer better emissions profiles at a lower cost than what is currently available. These costs and emissions profiles have been declining moderately over time, with noticeable improvement in SO_2 and NO_X reduction technologies. CO_2 reduction technologies are likely more than ten years away, as there has been almost no progress made on carbon sequestration.[7]

However, portfolios that include a substantial degree of market power purchases would be costly and have a high degree of risk due to power price volatility. A portfolio of market power and DSM sufficient to satisfy the 13MW baseload need is expected to cost $97.50/MWh on a levelized basis. Given that there is currently a shortage of baseload capacity in the Midwest ISO power market ("MISO"), the real price of market power is expected to rise through at least 2015, at which point it is expected to decline slightly through 2025.[8] Moreover, market power purchases have a tendency to change approximately 23% from their long-run average.[9]

Finally, the City's baseload need is expect to grow to at least 15MW by 2020, further increasing the amount of power that must be purchased from the market. This forecast assumes RW Beck's demand forecast is accurate, but given recent development in Oberlin, there is reason to believe that the Beck demand forecast is probably low.[10]

8. The Oberlin (Lorain County) landfill gas facility cannot likely fulfill the City's baseload need that would otherwise be fulfilled by AMPGS.

Energy Development, Inc. ("EDI"), the owner of the Lorain Country landfill gas facility, has stated its intention to expand that facility from its current 13MW to approximately 20MW, with an online date of late 2010. Given their existing contract with EDI, AMP-Ohio would be the likely candidate to acquire this additional capacity. If so, the City could expect to receive approximately 1.4% of this additional capacity, which is a similar percentage share to that which the City received in AMPGS. This landfill share would amount to 0.1MW. In addition, CEA

[6] Total capacity, adjusted for its capacity factor relative to an 85% baseload capacity factor.
[7] In fact, in January 2008 the US Department of Energy reduced its commitment to investment in its "FutureGen" small scale carbon capture and sequestration project, placing more emphasis on private market initiatives to develop the required technologies.
[8] According to both US Department of Energy projections and the RW Beck forecast. Please see Section IV – MISO Energy subsection, for a discussion of the current shortage of baseload capacity in MISO.
[9] Based on an assumed 50/50 split between daily contracts, which tend to change up to 33% from day to day, and one-year contracts, which tend to change 13% from year to year. Based on prices at the Cinergy Hub, 2005-Present. See Section IV, "MISO Energy" subsection, for details.
[10] Section II provides an assessment of the Beck demand forecast.

calculates the levelized cost of this landfill capacity to be $97.31/MWh, which exceeds the AMPGS cost of $85.74/MWh by 13%.

While it is conceivable that the City could offer to buy additional shares from other AMP-Ohio member cities – and there is at least one example where this has been done before – it is not likely that the City could accumulate enough of this additional capacity to make any substantial quantity with which to displace AMPGS.

The only way to procure enough of the Lorain County landfill to substitute for the full 9MW of AMPGS capacity would be to compete directly against AMP-Ohio when and if this additional capacity is put out for bids. The City may have a similar opportunity when AMP-Ohio's existing contract expires in 2011. However, to bid against AMP-Ohio may jeopardize the favorable and economically advantageous relationship that the City has enjoyed over the years with AMP-Ohio and its member cities. Further, AMP-Ohio has at least a practical if not a legal right of first refusal on this capacity, so these opportunities will likely never arise. Finally, the City currently receives approximately $600,000 per year by contracting with AMP-Ohio member cities for capacity from City's peaking facilities, and this arrangement may be threatened by such a move.

Conclusion

An alternative baseload portfolio can be created by combining all reasonably available opportunities, including DSM, small wind, biogas as well as AMP-Ohio's ongoing development projects. This portfolio results in a slightly lower expected cost and lower emissions than AMPGS. This alternative portfolio[11] would be composed of the City's allocated shares of the hydro, landfill gas, and wind under development at AMP-Ohio, and would also include an aggressive DSM program. However, this alternative portfolio would amount to 5.2MW of baseload-equivalent capacity in 2013, as compared to the City's need of at approximately 13MW in that year. The City's baseload need is expected to increase to 15MW by 2020. Therefore, it is likely that the City will need to acquire at least 8MW of baseload capacity *and* this alternative portfolio or other similarly sized asset(s) in order to meet its total baseload needs in 2013 and beyond. DSM measures, if enacted aggressively, will assist significantly and cost-effectively in building this total portfolio.

[11] Referred to as Portfolio 5 – Renewable Buildup, in Section VII of this report.

II. GENERATION PORTFOLIO REVIEW

Overview of the City's Supply Mix

Oberlin Municipal Light & Power System ("OMLPS") 2008 generation portfolio contains a broad mix of resources in order to meet the need of its customers. The portfolio is compiled in order to economically serve the City's fluctuating demand for power during a given day and a given time of year. The portfolio also includes generating assets that rely on a broad mix of fuels in order to 1) reduce risk; 2) take advantage of local low-cost resources such as coal, landfill gas and hydroelectric power; and 3) include renewable resources, which contain favorable environmental attributes.

Table 2 OMLPS 2008 Capacity Resources

Resource	Capacity (MW)	Capacity (% Total)	Energy (MWh)	Energy (% Total)	Fuel	Dispatch
Gorsuch	6.89	28%	44,675	36%	Coal	Baseload
Spot Market Purchases	4.58	18%	6,361	5%	Blend	Intermediate
Baseload Contracts	4.58	18%	45,688	37%	Blend	Baseload
AMP-Ohio Gas Turbines	2.70	11%	62	0%	Gas	Peaking
Peaking Contracts	1.76	7%	7,960	6%	Gas/Diesel	Peaking
JV5 Hydro	1.27	5%	11,165	9%	Hydro	Baseload
JV2 Peakers (Natural Gas)	1.04	4%	24	0%	Gas	Peaking
AMP-Ohio Landfill Gas (incl. EDI)	0.65	3%	5,650	5%	Landfill Gas	Baseload
NYPA Hydro	0.58	2%	2,766	2%	Hydro	Baseload
JV1 Diesels	0.35	1%	8	0%	Diesel	Peaking
JV6 Wind	0.25	1%	521	0%	Wind	Baseload
Oberlin Peakers	0.20	1%	15	0%	Gas/Diesel	Peaking
Prospect, Lodi Peakers	0.06	0%	1	0%	Diesel	Peaking
Total Capacity	24.90	100%	124,897	0%		

Sources: AMP-Ohio; OMLPS

Of course, this portfolio will change over time as plants retire and contracts expire, and are replaced by other resources in order to meet growing load requirements. One example of this is the retirement of Gorsuch in 2013, with the potential replacement of the Gorsuch baseload resource with AMPGS.

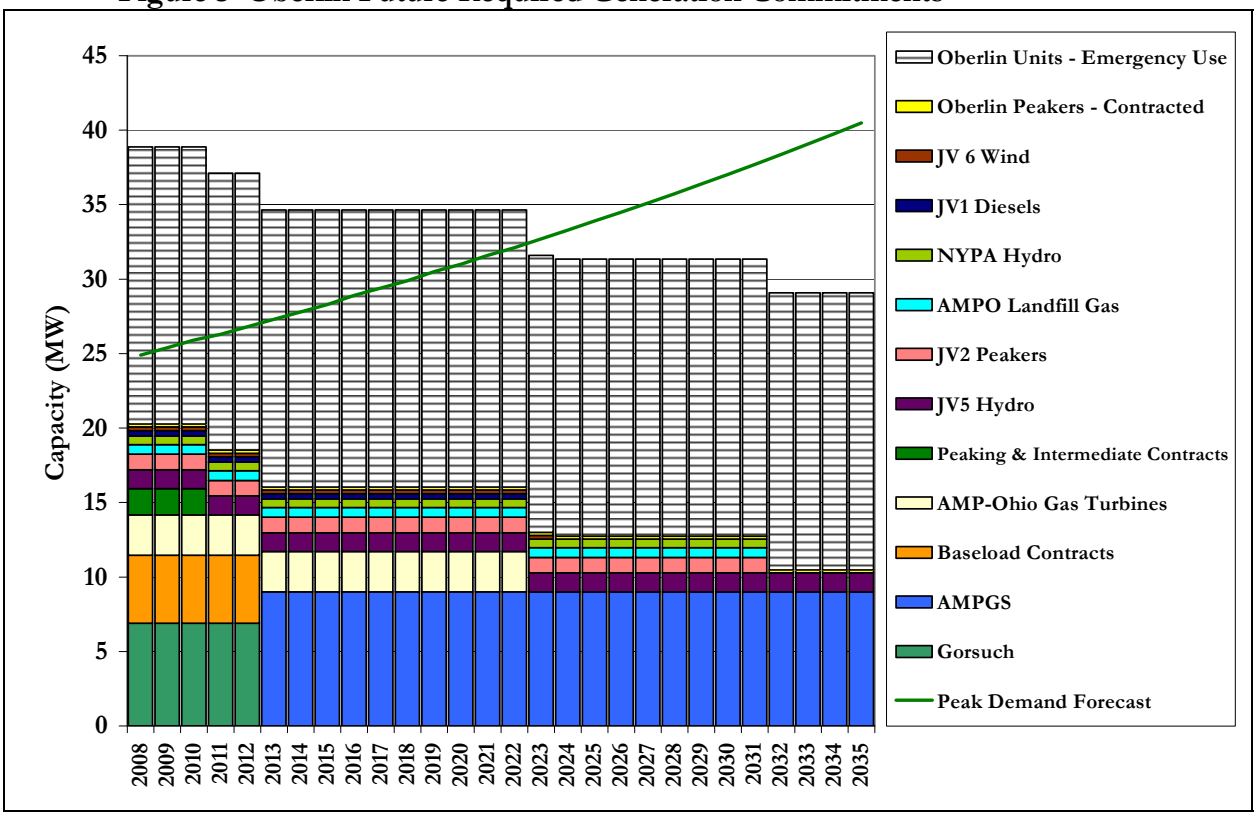
Table 2 shows the current resource commitments, including AMPGS, and the supply gap created as these resources expire. Oberlin currently has 20.3MW of committed capacity; and an additional 4.6MW will be purchased from the market in order to provide for this year's 24.9MW of forecast[12] peak demand.[13] Given contract expirations and plant retirements, substantial capacity purchases will be required in the next 25 years in order to meet forecast demand growth. For example, even assuming that the City subscribes to AMPGS, an additional 12.2MW of total capacity will be needed by 2015, and 21.2MW of additional total capacity will be needed by 2025.[14]

[12] Assuming peak RW Beck peak demand forecast. Source: "Power Supply Plan for City of Oberlin," February 17, 2007.

[13] Note that 18MW of the 18.8MW provided by Oberlin's peakers are almost entirely under contract with the NEASG, and therefore is unavailable to Oberlin except for emergency backup.

[14] Assumes that Oberlin opts into the AMPGS contract, asset-specific contracts are renewed at expiration, market-based contracts expire without renewal, and physical assets retire according to standard useful lives for specific asset classes.

Figure 3 Oberlin Future Required Generation Commitments



The Portfolio's Ability to Economically Serve Load

As noted above, even assuming that the City will accept the AMPGS contract, the City will need to enter into a substantial amount of additional generation capacity commitments during the coming years. However, from an economic perspective, the *type* of capacity acquired is just as important as the amount of capacity purchased.

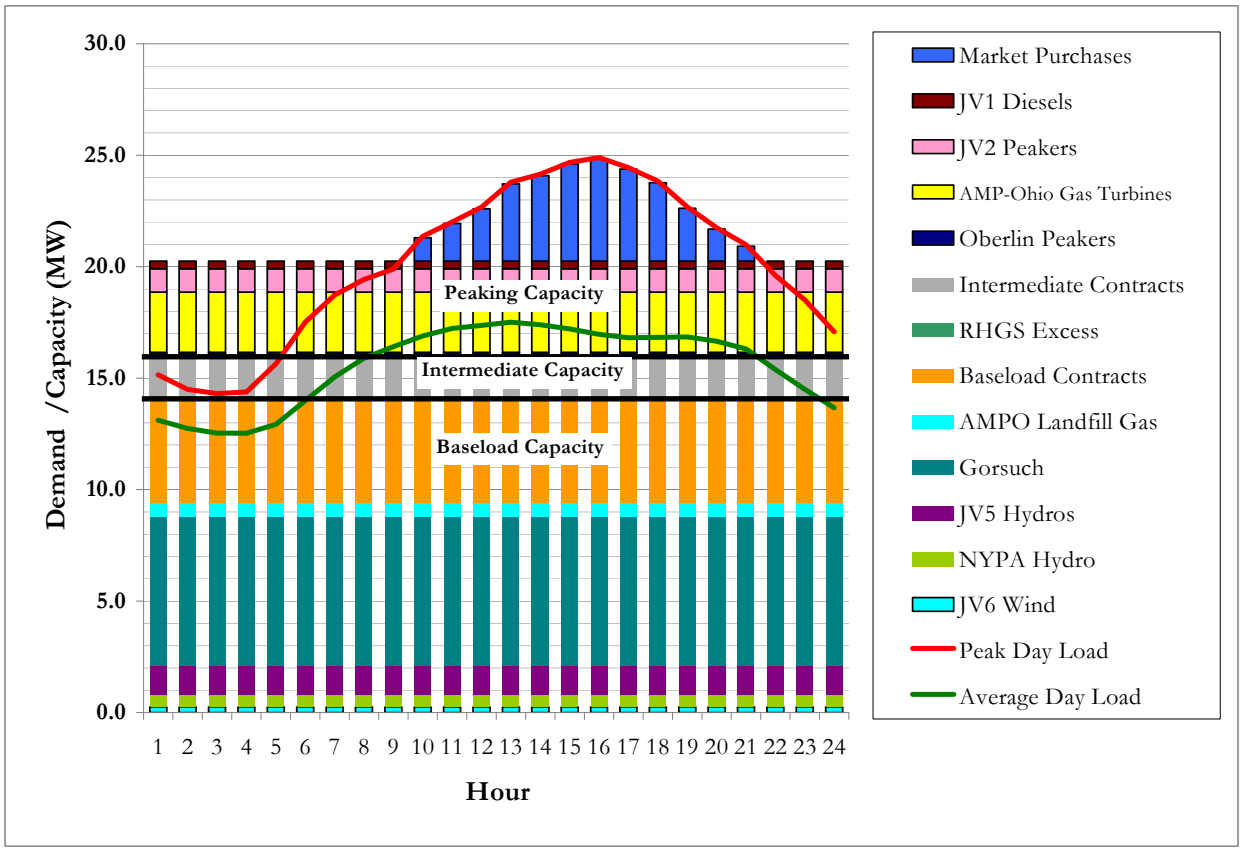
First, some background: The three economic classes of generation capacity are known as "baseload", "peaking" and "intermediate" capacity. Baseload resources are those that produce incremental energy relatively inexpensively, but are relatively costly to install. Peaking resources are those that produce incremental energy at a relatively high cost, but are relatively inexpensive to install. Intermediate capacity lies within this range.[15] Each of these classes of generation capacity serve an important role in meeting electricity demand as it changes throughout the day (based primarily on hourly usage patterns) and throughout the year (based primarily on heating and cooling requirements).

Figure 3 provides a picture of forecast electricity demand in Oberlin in 2008 and the capacity resources that will likely be dispatched to serve that demand on an hourly basis. The bars are stacked in each hour according to their incremental or "dispatch" cost, with the least expensive

[15] Some "intermediate" capacity technologies, such as the natural gas combined cycle, also have the ability to change their generation output quickly, and can therefore respond to hour-by-hour or even minute-by-minute fluctuations in demand. This capability is known as "load following."

baseload resources on the bottom. These costs reflect the cost of the next MWh of electricity only, and do not consider any costs associated with building or buying the plant in the first place. Baseload resources, including Gorsuch – and also, if accepted, AMPGS starting in 2013 – are dispatched to serve load in almost every hour of even an average day. As demand increases, as it would in the middle of an average day or in the summer months, more costly resources are added until demand is satisfied.

Figure 4 Forecast Demand and Economic Dispatch in 2008



Sources: AMP-Ohio; OMLPS; RW Beck; CEA Analysis

The difference between the incremental cost of Oberlin's baseload resources and that of its peaking resources can be substantial. While Oberlin is charged $10 - $20 for an incremental MWh of electricity from its hydro or wind resources, and in the mid-$30s for an hour of electricity from Gorsuch, it may be charged $100 or more for its peaking resources, depending on the price of fuel at the time. Market purchases made at peak hours can be more costly still.[16]

[16] This large range in the cost of the next MWh is due primarily to differences in both the cost of fuel and the relative efficiency by which a generator can convert fuel to power. For example, Gorsuch can turn coal that costs approximately $1.50/MMBtu into electricity at a rate of approximately 15MWh/MMBtu, resulting in its mid $30/MWh price after including other incremental costs. AMPGS is forecast to turn coal that costs $1.82/MMBtu into electricity at a rate of 8.9MWh/MMBtu, resulting in an initial cost of $33/MWh, after other incremental costs (Source: RW Beck, "Initial Project Feasibility Study for AMPGS," June 2007, p. ES-1). In contrast, Oberlin's peaking resources primarily turn natural gas that costs $8/MMBtu into electricity at a rate of 10 to 12MWh/MMBtu, resulting in a price of $100 to $120/MWh after other incremental costs.

However, the relatively low price of an incremental MWh of electricity from a baseload resource comes at a cost. Baseload resources are more expensive to build or buy than peaking resources, and this construction or purchase cost is also passed through to Oberlin in the form of a fixed "demand" or "capacity" charge.[17] For example, Oberlin is forecast to be charged $28.84/kW-month for its AMPO Hydro capacity, but only $10.06/kW-month for its Gorsuch capacity. The comparable charge for AMPGS would be $18.59/kW-month.[18]

Given the fixed and variable cost structure of generating assets, the general approach to creating a portfolio of these resources is to have as much baseload generation as possible in the portfolio as long as it can be run nearly all the time. The general rule of thumb is that baseload capacity should comprise approximately 50-65% of peak demand, or approximately 12-15MW in the case of the City.[19] The City's 2008 portfolio includes approximately 13MW of baseload capacity (52% of 2008 peak demand), and so is currently well balanced in this regard. It should be noted that Oberlin's wind and hydro assets can generate electricity only intermittently, depending on wind and river conditions respectively, and are therefore not true baseload resources unless they are combined or "firmed up" with a resource that can be utilized on demand, such as a natural gas turbine.

While the City currently has a good balance of peaking and baseload assets in its 2008 portfolio, the retirement of Gorsuch along with the expiration of 4.6MW of baseload contracts will create a need for baseload capacity beginning in 2013. Assuming that the City would like to maintain its baseload/peak ratio of 50-55%, and RW Beck's peak demand forecast of 27.3MW for 2013, the City will have a 2013 baseload need of approximately 13MW. As shown in Figure 3, this baseload need will increase over time, given increasing demand as well as contract expirations and plant retirements. Using these assumptions, the City's baseload need will grow to approximately 15MW by 2020. Therefore, while the City's proposed 9.0MW of AMPGS is appropriately sized to serve most of its 2013 baseload needs, the City will have additional and substantial baseload needs in the near future.

[17] Given that these charges are based on the amount of firm capacity at the City's disposal, and that the charges are fixed over time, they are expressed in the form of $/kW-month.
[18] In 2014.
[19] This proportion is based on a typical variation in demand during a given day. For example, on an average day in 2007, the City's minimum load was 65.1% of its peak demand (including 10% reserves), while on the peak day in 2007 the City's minimum load was 52.2% of its peak demand (including reserves).

Review of the RW Beck Power Supply Plan

In its "Power Supply Plan for the City of Oberlin" (the "Supply Plan"), RW Beck first creates a demand forecast, then proposes a variety of potential forms of new capacity that may be available, and finally runs an optimization program to determine the lowest-cost portfolio of these resources that should be selected to meet demand. Beck runs both a "Base Case," which is unconstrained in its ability to select resources, and an "RPS Case," which is constrained to always assure that, beginning in 2015, at least 10% of the City's total capacity is derived from technologies that use renewable fuel sources. Finally, the Supply Plan determines how the Base Case and RPS recommendations would change according to variations in demand, implied heat rate and/or gas prices. While Beck's approach to the Supply Plan approach is appropriate, there are several points that should be noted while reviewing and interpreting the results:

1) The Supply Plan's Capital Cost Assumption for AMPGS is Low

The Power Supply Plan assumes that AMPGS will have a capital cost of $1,720/kW.[20] This data reflects February 2006 information, and is outdated. More recent data provided in Beck's "Initial Project Feasibility Study" for AMPGS, dated June 2007 (the "Feasibility Study') cites a cost of $2,638/kW,[21] or $2,013/kW on an equivalent 2006 basis. Both of these studies have been superceded by the Updated Feasibility Study, dated January 2008. The Updated Feasibility Study shows a still-higher capital cost, but is based on a more capital-intensive technology. Although it is also likely that capital costs of other generic and identified resource options in the Supply Plan have also increased, Beck's recommendation regarding the appropriate level of AMPGS capacity may have been different had this more recent data been known and incorporated, at least as part of the sensitivity analysis.

Moreover, given the recent and unprecedented capital cost escalation that CEA has observed, it is likely that the cost of AMPGS will be higher than the figures provided in the Updated Feasibility Study by the time the engineering, procurement and construction ("EPC") contract is completed. The EPC contract is scheduled for completion in March 2009, but it is not likely that AMP-Ohio will be able to have full price certainty built into the contract at that time.[22] CEA has assumed a capital cost inflation rate of 7.0% per year (4% above an assumed 3% general inflation rate) in its technology-by-technology assessment in Section IV of this report.[23]

2) The Supply Plan's Demand Forecast May Be Low

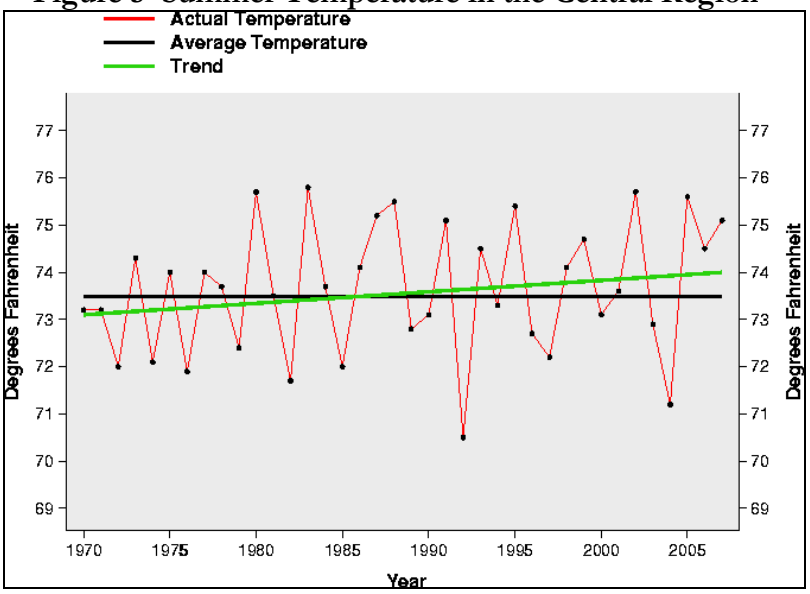
RW Beck's forecast of the expected value of electricity demand may understate the load growth projections for the City by not addressing long-term climate change trends and by not accounting for the added economic stimulus that Oberlin College is likely to provide. While demand growth may be offset at least in part by

[20] Supply Plan, Attachment D, Page 8. Excludes transmission interconnection and upgrade costs.
[21] $2,638/kW = $2,533 million/960,000 kW. Source: Feasibility Study, p. ES-7.
[22] Source: Feasibility Study, Page ES-3.
[23] Based on cost data supplied by the Handy Whitman Index of Public Utility Construction Costs.

conservation and demand-side management ("DSM") efforts at the City and/or the College, it is important to consider the assumptions behind the Supply Plan Expected Value demand forecast. Any revised forecast that considered these effects would very likely fall within the Supply Plan's 5%/95% confidence bands, however.

The load forecast in the Power Supply Plan is based on the most recent 30-year data provided by NOAA, which is from the period 1971-2000. This data does not reflect more recent climate warming trends, and is therefore likely to be conservative. The Supply Plan forecasts Cooling Degree Days (CDD) in the City to be a constant 712 CDD between 2006 and 2027.[24] Figure 5 illustrates the long-term trend of a 0.025 degree annual increase in average annual summer temperature in the Central Region of the U.S. [25]

Figure 5 Summer Temperature in the Central Region[26]



If applied to the Power Supply Plan, this trend would result in a steady increase in CDD from 712 to more than 800 by 2027, and would almost certainly result in a higher demand forecast.

Also, recent residential and commercial development in undeveloped land around the intersection of U.S. 20 and S.R. 58 may drive population growth beyond the projections made in R.W. Beck's load forecast. The planning area comprises 779 acres in the southern portion of the city of Oberlin and 2,101 acres in the adjacent

[24] Power Supply Plan, Attachment A, Table 2.

[25] CEA recognizes that forecasting climate change effects at particular location is a contentious task. We suggest this number as an example and recommend that the City consult scientifically-based projections.

[26] Based on mean summer (June-August) temperature data for the Central Region of the United States between 1970 and 2007 at National Oceanic & Atmospheric Administration, National Climatic Data Center, *U.S. Climate at a Glance*, 14 January 2008.

townships of New Russia and Pittsfield. The planning study forecasts total population growth of 1,880 persons (712 new homes) by 2016, including an additional 470 residents (178 new homes) in the City of Oberlin.[27] By comparison, Oberlin served a population of approximately 7,000 (2,664 residential homes or 2.64 people/home) in 2006.[28] The planning areas are all available to be served by OMLPS and it is highly likely that these areas would be annexed into the City. It is therefore conceivable that the residential customer base of OMLPS could grow 27 percent between 2006 and 2016. The planning study further states that growth in the U.S. 20/S.R. 58 area is projected to drive peak summer demand up to 28 MW by 2010.[29] By contrast, the study by R.W. Beck forecasts peak summer demand of 25.9 MW by 2010. It appears that the Beck forecast underestimates potential load growth resulting from new residential and commercial development underway in Oberlin.

In addition, the Supply Plan's demand forecast also relies on economic data from Lorain Country, and not the City of Oberlin specifically. The territory served by OMLPS likely has superior growth prospects than the surrounding parts of Lorain County. Oberlin College has a significant impact on the local economy and has a secure future given its reputation and endowment. It is also well-documented that college towns are projected to attract increased numbers of retirees in the years ahead.[30]

Finally, the Supply Plan economic data for the individual AMP-Ohio members is also revealing. Peak demand in the City is estimated to grow by 41% from 2006-2027. This is equal to the average level of growth for all AMP members. Interestingly, the projected growth rates for the AMP members that are closest to Oberlin geographically are higher than the average, including Grafton (56%), Amherst (46%), and Wellington (54%). It is also noteworthy that peak demand in Bowling Green KY, another college city (albeit a much larger one), is project to grow by 80% over the same period. Given the economic effect of Oberlin College on the City, load growth may be higher for the City than the AMP-Ohio membership average.

3) The RPS Scenario Includes Less Renewable Capacity than the Base Case

The City already has a strong position in renewable resources, with 15% of 2008 generation sourced from hydro, landfill or wind.[31] The Supply Plan therefore recommends very few changes to this portfolio in order to maintain a standard of 10% renewable generation through 2027. Curiously, however, the Base Case seems to have more renewable resources in its portfolio than does the RPS Case. While the Base Case recommends subscribing to 5.9MW of future hydro resources in 2025,

[27] U.S. 20/S.R. 58 Infrastructure Planning Study for the City of Oberlin, February 2007, p. 3-6.
[28] City of Oberlin Financing Feasibility Study, October 29, 2007
[29] U.S. 20/S.R. 58 Infrastructure Planning Study for the City of Oberlin, February 2007, p. 4-21.
[30] We note several recent articles in major newspapers describing the increased attractiveness of college towns and the buoyant effect this is having on the real estate market in these locales.
[31] Excluding any renewable resources that may be attributed to the City's Baseload contracts.

this is not recommended in the RPS case.[32] In its place are a 1.7MW increase in Hydro by 2025 and a 0.2MW increase in Wind by 2027. A 1.6MW increase in a peaking contract – peaking generation is rarely derived from a renewable resource – makes up the difference in total capacity additions between the two scenarios. Readers who prefer a portfolio that is more heavily weighted to renewables would therefore prefer the Base Case to the RPS Case.

4) Coal Provides a Valuable Hedge Against Market Price Volatility

According to the Supply Plan, the most significant variable in the supply decision is the price of market power. Variations in the price of market power are modeled by varying the implied heat rate, as well as the gas price.[33] The Supply Plan indicates that only a very low market power price (10th percentile) would cause a change in the Base Case conclusions. Similarly, only a very high gas price (90th percentile) would cause a change in the Base Case conclusions. In this high-price scenario, the Supply Plan provides an "Alternate Build" conclusion, which retains the Base Case portfolio, but adds 5.9MW of Prairie State.[34] While these extreme price changes are unlikely, the Alternative Build is a logical response since it would take advantage of the natural hedge that comes with owning a higher proportion of coal fired assets in a high gas and therefore high power price environment.

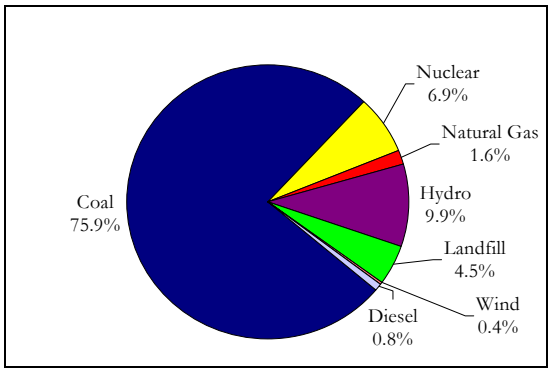
Fuel Mix Considerations

While the City's largest generation resource is coal-based, and would remain so with AMPGS, it has and would continue to have a well diversified portfolio with a relatively high component of renewable generation as compared to other US utilities and utilities in the Ohio power market.

Figures 6 and 7 show the fuel sources for the City's generation, both in 2008 and assuming the addition of AMPGS capacity in 2013.[35] The OMLPS 2008 generation portfolio relies more on coal and less on nuclear than the US as a whole, but these two categories comprise approximately three-quarters of both the City and the US portfolio. However, while the remainder of the US portfolio is mostly natural gas (19.0% of total) and renewables (8.4% of total), the remainder of the OMLPS portfolio is composed mostly of renewables (14.8% of total and a smaller slice of natural gas (1.6% of total).

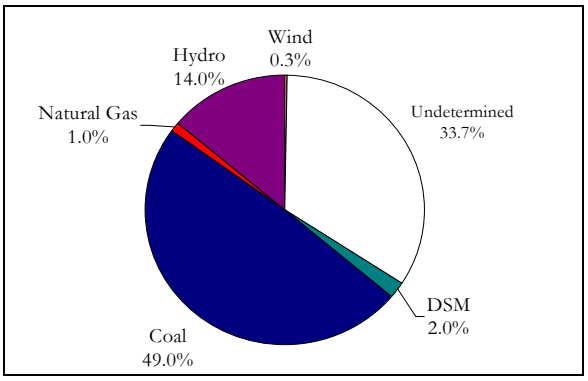
[32] These are generic hydro resources for purposes of this study; but it is reasonable to assume that at least 5.9MW of hydro could become available to the City by 20123 through AMP-Ohio's current and prospective Ohio River projects.
[33] It should be noted that the implied heat rate, which is equal to the market price of power divided by the gas price, and the gas price itself are both reasonable proxies for the price of market power in the marketplace.
[34] The Supply Plan assumes that the City would have used up the available AMPGS capacity with an initial 11.8MW purchase.
[35] This latter chart assumes that no other resources are purchased to serve demand other than market power.

Figure 6 OMLPS Fuel Mix 2008



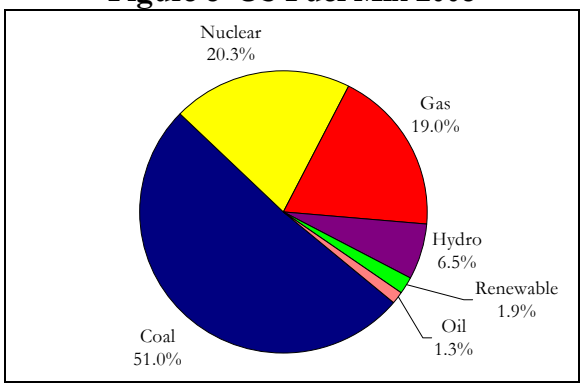
Source: OMLPS.

Figure 7 OMLPS Fuel Mix 2015 With 9 MW



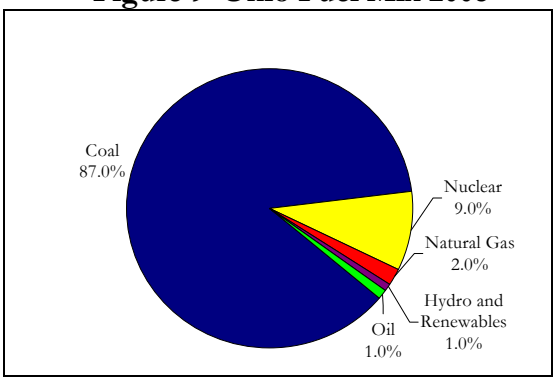
Source: OMLPS.

Figure 8 US Fuel Mix 2008



Source: SNL Energy.

Figure 9 Ohio Fuel Mix 2008



Source: SNL Energy.

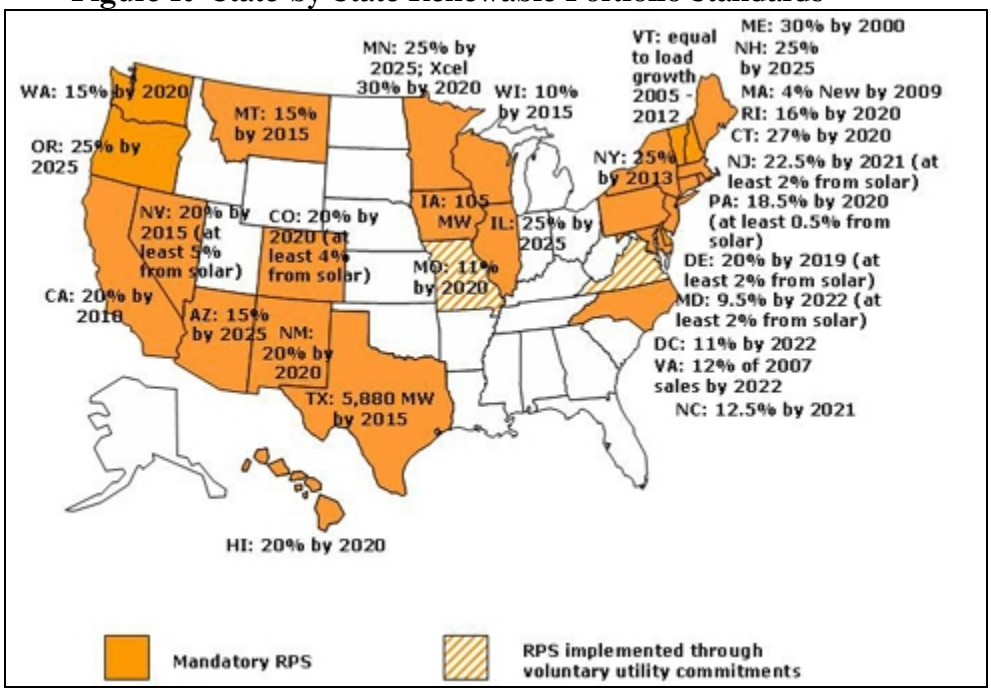
The 2008 OMLPS portfolio compares especially well with the 2008 State of Ohio fuel mix (Figure 9) in terms of both fuel diversity and renewables content. Coal dominates the Ohio portfolio.

The 2015 portfolio with AMPGS will at least maintain its proportion of renewables, but the complete fuel mix is currently undetermined. The AMP-Ohio landfill gas contract will expire before that date, as will the City's existing baseload and peaking contracts with marketers. OMLPS intends to renew these contracts, however, and will likely take advantage of the capacity increases expected in AMP-Ohio's hydro, landfill gas and wind portfolios.

With 15% of its 2008 generation derived from renewable resources, the City has a renewables portfolio that even some of the more renewables-focused states will not likely achieve until 2015, as illustrated in Figure 10. Neighboring Pennsylvania, for example, which has a similar coal-based fuel mix to Ohio, has a target of 18.5% renewables by 2020. Excluding the City's existing hydro resources, which are sometimes not qualified as renewable in RPS legislation, leaves the City with 5% of its 2008 portfolio as fully RPS-qualifying. In comparison, the US portfolio contains 1.9% non-hydro renewable resources, and the US Department of Energy projects that, with a continued

policy push and technological advancement, non-hydro renewables could account for 3.6% of electric production by 2030.[36]

Figure 10 State-by-State Renewable Portfolio Standards



Source: Pew Center on Global Climate Change.

Oberlin's Ability to Modify its Generation Portfolio

In connection with its membership in AMP-Ohio, the City is also a member of the Northeast AMP-Ohio Service Group ("NEASG"), a group that was formed to take best advantage of group buying power and load diversity. This group has agreed to act together to procure generation resources ("Pool Power") through AMP-Ohio. Each member of the NEASG has agreed that "AMP-Ohio shall be the full requirements provider of all electric power and energy required"[37] by each NEASG municipality. OMLPS intends to renew the NEASG contract upon its 2012 expiration date.

The only exception to this "full requirements" provision is that each member is permitted a certain amount of capacity that is free to be filled by sources outside the pool ("Non-Pool"[38]). The City currently has 9.6MW of Non-Pool Capacity, which, for calculation purposes, includes Gorsuch, the NYPA Hydro contract, the JV5 Hydros, the Landfill Gas resources and the JV6 Wind resources. The Non-Pool capacity can be increased each year by 50% of the increase in a member's peak load from the previous year in order to make space for new Non-Pool resources. This new Non-Pool Capacity can then be filled by new Non-Pool resources. The increase is not granted, however, if the new total Non-Pool Capacity would be above 40% of a member's peak load. Also, any component

[36] "Annual Energy Outlook 2007," Energy Information Agency, USDOE, February 2007, p. 86.
[37] "NEASG Pool Participant Agreement," Section C (1). "Full requirements" means that AMP-Ohio has committed to provide up to 100% of Oberlin's power needs, if necessary.
[38] The contract actually refers to "Substitute Capacity", but the term "Non-Pool" is used in this report for clarity.

of Non-Pool Capacity may be replaced with a new component of Non-Pool Capacity when that contract expires. Gorsuch is planned to be retired in 2013, while the landfill contract expires at the end of 2011.

Given these provisions, CEA calculates that, in 2013, the City will have 8.1MW of Non-Pool Capacity available with which it may procure Non-Pool resources if it does not participate in AMPGS. These calculations are shown in Table 3. It should be apparent from Table 3 that the Base load need, shown in Column J, exceeds the Non-Pool Capacity (Column I) in 2013 and beyond. This means that some, but not all of the Base load need can be satisfied by resources that are developed internally at the will of the City. It is likely that upon the start of the AMPGS project that the allowable Non-Pool Capacity will be increased beyond the 40% limit since all of the NEASG members will own Non-Pool resources in excess of 40% of their peak. Additionally, any current long-term pool resources procured by AMP-Ohio currently expire prior to the beginning of 2013.

Table 3 Calculation of Non-Pool Capacity by Year

Year	Gorsuch Capacity	Other Original Non-Pool Capacity*	Base Non-Pool Capacity	Allowable Addition to Non-Pool Capacity	Non-Pool Capacity Available Before 40% Test	40% of Peak Demand	Balance, After 40% Test	Non-Pool Capacity Used	Non-Pool Capacity Available	Baseload Need
	A	B	C = A + B	D = 50% of Incr in Peak	E = Prior Year + D	F	G = Lesser of E or F	H = C	I = G - H	J
2008	6.7	2.7	9.6	0.0	9.6	10.0	9.6	9.6	0.0	1.1
2009	6.7	2.7	9.6	0.3	9.9	10.2	9.9	9.6	0.3	0.4
2010	6.7	2.7	9.6	0.3	10.1	10.4	10.1	9.6	0.5	0.7
2011	6.7	2.7	9.6	0.2	10.3	10.5	10.3	9.6	0.7	0.9
2012	6.7	2.7	9.6	0.3	10.6	10.7	10.6	9.6	1.0	1.2
2013	0.0	2.7	2.7	0.3	10.8	10.9	10.8	2.7	8.1	12.9
2014	0.0	2.7	2.7	0.3	11.1	11.1	11.1	2.7	8.3	13.2
2015	0.0	2.7	2.7	0.3	11.3	11.3	11.3	2.7	8.6	13.5
2016	0.0	2.7	2.7	0.3	11.6	11.6	11.6	2.7	8.8	13.8
2017	0.0	2.7	2.7	0.3	11.9	11.8	11.8	2.7	9.0	14.1
2018	0.0	2.7	2.7	0.3	12.1	12.0	12.0	2.7	9.2	14.4
2019	0.0	2.7	2.7	0.3	12.4	12.2	12.2	2.7	9.5	14.7
2020	0.0	2.7	2.7	0.3	12.7	12.4	12.4	2.7	9.7	15.0

* Assumes landfill contract renewal in 2012.

In order for the City to increase its capacity to develop resources internally, the City could conceivably let the NEASG contract expire in 2012. However, this step would be accompanied by significant downside risk. The City has a productive working relationship with AMP-Ohio, its members and specifically NEASG. The NEASG agreement allows the City to purchase a diversified portfolio of capacity and spread risk associated with load loss or growth among the 21 members of the NEASG. It also allows the City to sell its excess peaking capacity to the pool. Abandoning the NEASG would put at risk the favorable relationships that the City enjoys with AMP-Ohio and with its member cities. AMP-Ohio provides a valuable service to the City in that it provides 1) economies of scale by spreading fixed generation development and portfolio management costs across a large pool of load; and 2) diversification by offering a variety of technologies from which its members are free to choose. Acting independently would increase OMLPS's administrative costs and would likely decrease its portfolio diversity. Such a move would likely alienate the other NEASG members, and may thereby jeopardize the possibility of future collaboration in the region.

III. AMPGS PROJECT ANALYSIS

Project Overview

AMPGS is a 960MW coal-fired generating station to be located in Meigs County, OH on the Ohio River. When it begins operations as scheduled in 2013, AMPGS will be one of approximately 35 coal plants in Ohio and will represent approximately 4% of Ohio's coal-fired capacity.[39]

Project Performance and Costs

Table 4 provides a comparison of AMPGS project performance and costs with CEA estimated performance and costs based on studies of plants with similar configurations. We find that AMPGS's forecast cost and performance characteristics are comparable to plants with similar configurations, although capital costs are higher than expected. These performance metrics are based on a "supercritical" plant configuration, as provided for in the Updated Feasibility Study. A supercritical plant has a higher up-front capital cost, but increased efficiency and emissions profile due to the fact that it produces steam at a higher pressure than a "subcritical" configuration, which was proposed in the initial Feasibility Study of June 2007.

Capital costs are higher than expected, perhaps indicating that capital cost inflation will continue to be a significant risk. CEA has applied a 7% annual escalator to these costs through the construction period in order to take into account our expectation that AMPGS's costs will continue to increase. This increased capital cost, combined with CEA's slightly higher CO_2allowance price forecast, results in a levelized cost of $85.74/MWh for AMPGS.

The heat rate, a measure of the plant's efficiency to convert the heat content of fuel into electricity, is improved from the subcritical configuration, and is comparable to other supercritical plants. AMPGS's Variable O&M costs are higher than would be expected for a plant of its configuration, but this category tends to be a catch-all for a variety of items that could skew the total, so is not always a reliable measure. CEA finds these parameters to be reasonable and has retained them for modeling purposes.

Table 4 Performance and Cost Comparison ($2008)

	AMPGS	CEA Comparable
Heat Rate (Btu/kWh)	8,990	8,879
Overnight Cost (2008$/kW)	$2,683 *	$2,238
Fixed O&M Cost ($2008/kW-year)	$34.12	$33.38
Variable O&M Cost ($2008/MWh)	$7.59	$5.98

* Based on $2.949 million Total Capital Costs in Feasibility Study less plant cost inflation at 7% per year for two years.

It should be noted, however, that AMPGS will likely burn a blend of relatively high-sulfur local Ohio coal and lower sulfur coal from Central Appalachia or Western states. Local Ohio coal is less

[39] Source: SNL Energy.

costly, but includes more sulfur, a source of sulfur dioxide emissions and acid rain. The composition of this coal blend has not been determined, but the two alternatives differ in cost by only 2% and differ in overall sulfur content by 13%. However, coal mining in Central Appalachia can be controversial due to the increasing use of environmentally destructive mountaintop mining techniques.

Beneficial Use Analysis Review

As a component of the Initial Project Feasibility Study, R.W. Beck conducted a Beneficial Use Analysis for each participant in the study, including the City. This data is now outdated and has been replaced with a Feasibility Study Update of February 2008. A Beneficial Use Analysis was not performed as part of the Feasibility Study Update. However, the Feasibility Study Update does provide that, according to RW Beck, AMPGS's levelized cost is expected to be $85.72/MWh, with a standard deviation of $10.74/MWh, or 12.5%.[40] The analysis below was retained in this report as these updated statistics can be compared to earlier data in order to provide a context of cost and risk with respect to the City's existing portfolio.

The purpose of the Beneficial Use Analysis was to determine whether each participant could beneficially utilize its slice of the AMPGS project. Beck based its determination of beneficial use on stochastic projections of regional power prices for the period 2007-2027.[41] The stochastic forecasts produce a range of costs resulting from the estimated volatility in loads, fuel prices, market prices, and CO_2 costs. Beck's analysis of each participant's projected power costs and risks compares two scenarios, the City's existing portfolio and its portfolio with AMPGS. As shown in Table 5, Beck found that both levelized cost and risk would be reduced by including AMPGS in the City's generation portfolio.

Table 5 Conclusions from the Beneficial Use Study

Scenario	Levelized Average Cost ($/MWh)	Standard Deviation ($/MWh)	Coefficient of Variation (%)
Existing Portfolio	$79.01	$9.54	12.1%
Portfolio with AMPGS	$72.97	$7.48	10.3%

The Standard Deviation column in Table 5 indicates the level of risk in each portfolio, but is only meaningful if viewed in proportion to the expected value of Levelized Average Cost. The coefficient of variation, which is the standard deviation divided by the Levelized Average Cost, is a more meaningful standalone risk indicator. Using this metric to review the results above, we can confirm that the Portfolio with AMPGS is slightly lower in risk than the Existing Portfolio. Using statistics, the numbers tell us that the Portfolio with AMPGS has a 68% chance of having an *actual* Levelized Average Cost that is within 10.3% of its *expected* Levelized Average Cost. However, the

[40] Updated Feasibility Study, p. 24.

[41] Stochastic projections use a random sampling of variable input levels in order to create a probabilistic distribution of outcomes. This methodology is used to reflect the uncertainty and volatility in forecasting variables such as fuel costs and electric loads.

existing portfolio has a 68% chance of having an *actual* Levelized Average Cost that is within 12.1% of its *expected* Levelized Average Cost, and therefore a wider margin of error.

Key Risks

CEA has identified the following key risks to the AMPGS project. All of these risks were previously identified in the Feasibility Study. However, the section below prioritizes the risks that we feel need the greatest attention, and provides additional context around these issues.

1) Increases in Capital Costs

Capital costs for all power plants have increased substantially in recent years. To illustrate:

- Based on power plant construction cost data provided by the Handy Whitman Index, CEA calculates that there has been a 7.0% annual increase in construction costs in the last two years, and forecasts that this trend will continue through at least 2012. This 7% increase has been assumed in CEA's modeling.
- One study identifies a Duke Energy coal plant that experienced a 50% increase from a May 2005 filing with regulators to a second filing only five months later. The most recent estimate is 20% higher still.[42]
- The feasibility study for the new AMP-Ohio hydros notes the "extreme volatility and price increase in raw commodities [used in power plant construction] such as copper, steel and nickel in recent years."[43]

The construction cost of AMPGS has also increased over time and may continue to increase through the construction period. For example, the Power Supply Plan lists the total capital cost of AMPGS to be $1,720/kW in $2006 after interconnection and owners' costs. This cost is based on information from February 2006. However, the initial Feasibility Study, dated June 2007, provides that the same cost items stated in equivalent dollar terms would be approximately $2,344/kW. This change represents a 36% increase in slightly more than one year. The Updated Feasibility Study incorporates a different plant configuration, so the capital cost provided in that study is not comparable with the previous studies.

CEA uses the $2,683/kW cost for modeling purposes, and also assumes that capital costs will continue to increase at 7.0% per year through 2012. This 7.0% increase reflects the Handy Whitman survey noted above.

[42] "Rising Utility Construction Costs: Sources and Impacts," The Brattle Group, September 2007.
[43] "Report on Hydroelectric and Economic Feasibility Study," AMP-Ohio and Sawvel & Associates, September 2007, p. 63.

2) Significant Increase in Allowance Prices, Particularly CO_2

Emissions allowances comprise approximately 25% of AMPGS's operating expenses. CO_2 allowance costs will likely comprise 50-80% this total allowance figure. Legislation for CO_2 allowances has not been established, although it is broadly expected to be enacted within the next Presidential term. Therefore, forecasts for CO_2 prices vary considerably from one to another, although there is some consensus around a starting 2013 value of approximately $10/ton in real terms. The Beck forecast assumes a price of $3.38/ton in 2013, escalating to $13.94/ton by 2020. This forecast is approximately $5.00/ton lower than the early years of CEA's own forecast, and $7.00-$10.00/ton lower than forecasts contained in other studies. CEA calculates that, for every $5.00/ton increase from CEA's forecast price of CO_2 allowances, AMPGS's all-in levelized cost will increase by 4.2%. Such a deviation means in CO_2 allowance prices would increase CEA's estimate of AMPGS's levelized cost from $85.74/MWh to $89.37/MWh, which is not enough to substantially change the relative economics of AMPGS versus the alternatives by itself. Given its coal input AMPGS is one of the more sensitive technologies to this variable than that of any of the technologies studied in this report.[44]

3) Change in Environmental Regulations

Changing environmental regulation is one of the most important drivers of the change in coal plant economics over the last thirty years. There was little if any air regulation before the Clean Air Act of 1970. As noted above, soon air-quality-related costs may make up more than 25% of a coal plant's operating expenses. While most likely scenarios are accounted for in the Feasibility Study, there remain issues such as increased coal mining regulation that could create unforeseen costs over the expected 40-year life of AMPGS. Further, it has been suggested that there may be future legal claims against CO2-emitting sources – which include most current fossil-fuel fired technologies – regarding the climate effects of these emissions. While the risk of a change in environmental regulation is high for coal-fired facilities, similar risks may apply to other technologies as well (e.g.: natural gas drilling regulations).

4) Take-or-Pay Contract Structure for a Long-Lived Asset

All generating assets that AMP-Ohio provides to the City are based on a "take-or-pay" contract structure. This means that, while it is not a legal owner of any resource, the City is responsible for paying 100% of the costs of all AMP-Ohio projects to which it subscribes on a pro-rata basis through the useful life of each project.[45] This structure is advantageous in that it reduces the credit risk of AMP-Ohio and therefore lowers the financing costs that are passed on to the City. However, this structure also commits the City to AMPGS for approximately 40 years, regardless of the multitude of changes that

---

[44] The sensitivity of the levelized cost of market power to changes in CO_2prices is assumed to the same as if market power were composed only of a 2/3rds – 1/3rd split of the emissions of a natural gas unit and a coal unit, respectively, since these are typically the units that is setting the marginal price in MISO.

[45] In fact, through a "step-up" provision and subject to a cap, the City may become responsible for a pro-rata share of the obligations of one or more other participant member cities if any participant member city were to default on its own obligations.

may occur at the City or AMPGS over that time period. There are also a number of restrictions imposed on the rights of any individual participant City with respect to decisions that affect other participants. Partially mitigating this risk, however, is that a 9MW share of AMPGS will represent only 33% of the City's peak demand in 2013, and this proportion will continue to shrink over time.

AMPGS Emissions Profile

There are five important effluents than are nearly always associated with the combustion of coal, and emissions of which are regulated by the EPA and/or state authorities. They are: sulfur dioxide (SO_2), nitrogen oxides (NOx), carbon dioxide (CO_2), mercury (Hg), and airborne particulate matter (PM10).[46] AMPGS will mitigate emissions of SO_2 and mercury through flue-gas desulfurization, NOx through selective catalytic reduction, and particulate matter through filtration. These are standard, effective and well proven technologies. However, the Powerspan flue-gas desulfurization technology is a recent innovation, and is discussed in detail in Appendix A - Powerspan Analysis.

AMPGS will benefit from the significant technological strides that have been made in emissions control technologies in recent years, and will greatly outperform nearly all existing coal-fired units in terms of emissions rates, but its emissions are higher than what would be expected for new supercritical coal plants. Table 6 compares AMPGS emissions rates with permitted emissions rates for a Duke Energy supercritical coal plant under construction[47] as well as supercritical plants as provided by the US Department of Energy's National Energy Technology Laboratory.[48] The table also provides data for coal plants and all generation resources in the US and Ohio. AMPGS's SO_2 and NOx emissions rates are expected to be significantly lower than emissions rates of those effluents at other existing coal plants, and comparable to the Duke Cliffside units. The plant will likely have a poorer emissions profile than what the US DOE expects for a supercritical plant, but specific configurations and coal sources may differ. It is important to note that the type of coal selected for the AMPGS, which has not yet been decided, will have a slight effect on emissions rates. Comparable data for PM10 is not readily available.

Table 6 Emissions Rates for AMPGS, US Coal, and All Generation Types

	AMPGS	Duke Energy Cliffside 6 & 7	DOE New Super-critical	Coal-Fired Only		All Generation Types	
				Ohio Coal Average	US Coal Average	Ohio Average	US Average
SO2 (lbs/MWh)	1.6	1.4	0.7	17.2	10.0	15.1	5.4
NOx (lbs/MWh)	0.8	1.0	0.6	4.2	3.6	3.7	2.1
CO2 (lbs/MWh)	1,933	NA*	1,681	2,010	2,138	1,779	1,363
Mercury (lbs/GWh)	0.018	0.020 - 0.066	0.01	0.06	0.05	0.05	0.03

* Duke Energy agreed to various CO_2 offsets.
Source: AMP-Ohio; USEPA EGrid Database, 2006 (2004 data); DOE/NETL for New Supercritical.

An effective method has not been developed for either mitigating the production of CO_2 through coal combustion or capturing and storing the CO_2 produced from the combustion process. While

[46] Note that CO2 emissions are not currently regulated at either the state or Federal level. However, several Northeast states have enacted legislation regarding CO2 restrictions that will be effective in 2009. It is broadly expected that similar Federal legislation will emerge within the next five years.
[47] Duke Energy's Cliffside Units 6 and 7.
[48] Source: US Department of Energy / NETL, "Cost and Performance Baseline for Fossil Energy Plants", Volume 1, Bituminous Coal and Natural Gas to Electricity, May 2007, p. 374.

Powerspan and other developers are testing potential applications for CO_2 capture, "Powerspan estimates the cost of an ammonia absorption system on a power plant equipped [with Powerspan's CO_2 removal technology] to be $20 per ton of CO_2 avoided."[49] There will also be significant but to-date-unknowable costs to sequester the CO_2 once it is captured. To date, an effective technology has not been developed to both capture and sequester CO_2. Capturing large volumes of CO_2 with a plan for long-term sequestration in meaningless. Therefore the total cost of CO_2 mitigation is above the price of many CO_2 allowance forecast prices, including CEA's forecast, and would likely prove to be uneconomic even if an effective sequestration technology were developed.

[49] Feasibility Study, p. 2-11.

IV. ALTERNATIVE TECHNOLOGY ANALYSIS

Section Overview

This section provides an overview of siting requirements, fuel considerations, unit attributes, costs, risks, development time and environmental characteristics of various alternatives generation technologies. In some instances (as noted on a case by case basis), the discussion revolves around a "generic" unit; i.e. not an actual project/investment opportunity. This is important to keep in mind when comparing these alternatives to the City of Oberlin's existing portfolio and its existing opportunity to participate in AMPGS.

It should be noted that over the long term, we expect the capital costs for generating to come down (on a real basis) and for unit efficiency to go up (as advances in technology reduce unit heat rates and improve other operating characteristics). Given the approaching baseload capacity requirements the City of Oberlin faces, it is necessary to assess what opportunities exist now. There will be opportunities in the future, as older units are retired and as power contracts roll off, to participate in and take advantage of advancements in generation technology to reduce overall portfolio costs.

Assumptions

The following table details the assumptions that went in to our levelized cost analysis. Sources used to develop these assumptions include the EIA's annual Energy Outlook, various other DOE reports, State commission findings about costs of various generation technologies, Owners of various types of generation, costs of recently built generating units, and CEA's internal knowledge base.

Table 7 CEA Key Cost and Performance Assumptions

Assumption	Biomass (FBC)	Coal, CFB	CT	CTCC	Hydro
Capacity (MW)	50	750	25	540	296
Total Leadtime	4	6	2	4	2
Total Investment - No AFUDC (2006$/kW)	$2,445	$2,355	$1,100	$709	$2,300
Fixed Costs ($/kW-yr) 2006$s	$45.72	$32.44	$11.29	$10.78	$58.95
Incremental mils/kWh 2006$s	1.28	8.77	3.0694	2.25	0.00
Heat Rate at Full Load (Btu/kWh)	12,500	9,700	10,300	6,719	0
Capacity Factor	83%	84%	10%	85%	54%
Forward Capacity Market Credit	90%	85%	92%	87%	50%
Useful Life (years)	30	40	30	30	40
Air Emissions - CO2 (lbs/MWh)	0	1,999	1,269	797	0
Air Emissions - SO2 (lbs/MWh)	0.00	1.80	0.00	0.00	0.00
Air Emissions - NOx (lbs/MWh)	0.500	0.656	0.278	0.060	0.000
Air Emissions - Mercury (lbs/MWh)	0.000000	0.000007	0.000000	0.000000	0.000000

Assumption	IGCC	Landfill Gas	Nuclear	JV6 Wind	Small Wind
Capacity (MW)	640	22	1,350	40	1.5
Total Leadtime	6	1	10	5	3
Total Investment - No AFUDC (2006$/kW)	$2,198	$1,500	$2,556	$2,000	$2,295
Fixed Costs ($/kW-yr) 2006$s	$53.89	$20.73	$74.37	$30.00	$35.00
Incremental mils/kWh 2006$s	3.11	1.554	12	0	0
Heat Rate at Full Load (Btu/kWh)	8,922	11,566	10,400	0	0
Capacity Factor	80%	85%	89%	25%	21%
Forward Capacity Market Credit	85%	85%	90%	25%	25%
Useful Life (years)	40	30	50	20	20
Air Emissions - CO2 (lbs/MWh)	1,755	0	0	0	0
Air Emissions - SO2 (lbs/MWh)	0.09	0.34	0.00	0.00	0.00
Air Emissions - NOx (lbs/MWh)	0.406	1.700	0.000	0.000	0.000
Air Emissions - Mercury (lbs/MWh)	0.000004	0.000000	0.000000	0.000000	0.000000

Cost of CO_2 Emissions

The regulation of carbon dioxide emissions in the United States by 2013 seems highly probable. The United States government has demonstrated increasing willingness to sign onto an international accord to reduce CO_2 emissions.[50] The U.S. Congress has recently introduced several bills that would impose a federal cap on CO_2 emissions or a federal carbon tax. An impetus and possible model for federal regulation may be the Regional Greenhouse Gas Initiative, a cooperative effort by nine Northeast and Mid-Atlantic states to design a regional cap-and-trade program to limit CO_2 emissions from power plants. The mandatory program will be the first of its kind in North America to set a price on CO_2. The targets and stringency of these proposed programs vary considerably, which makes forecasting the price of carbon a speculative exercise.

CEA reviewed the long-term CO_2 price forecasts of several sources, as shown in Table 8 and Figure 11. Reports by the Intergovernmental Panel on Climate Change (IPCC) and the MIT Joint Program on the Science and Policy of Global Climate Change estimate the price necessary to achieve targeted levels of emission reductions in the future. Climate change regulation that has been proposed in the U.S. generally takes into account the heavily burdensome cost that carbon emissions may impose by establishing a ceiling or safety valve on the price of carbon. The financial industry currently recognizes that future regulation will impose a cost on carbon emissions, but that this cost will likely be tempered by political pressures to prevent slowing of the economy.

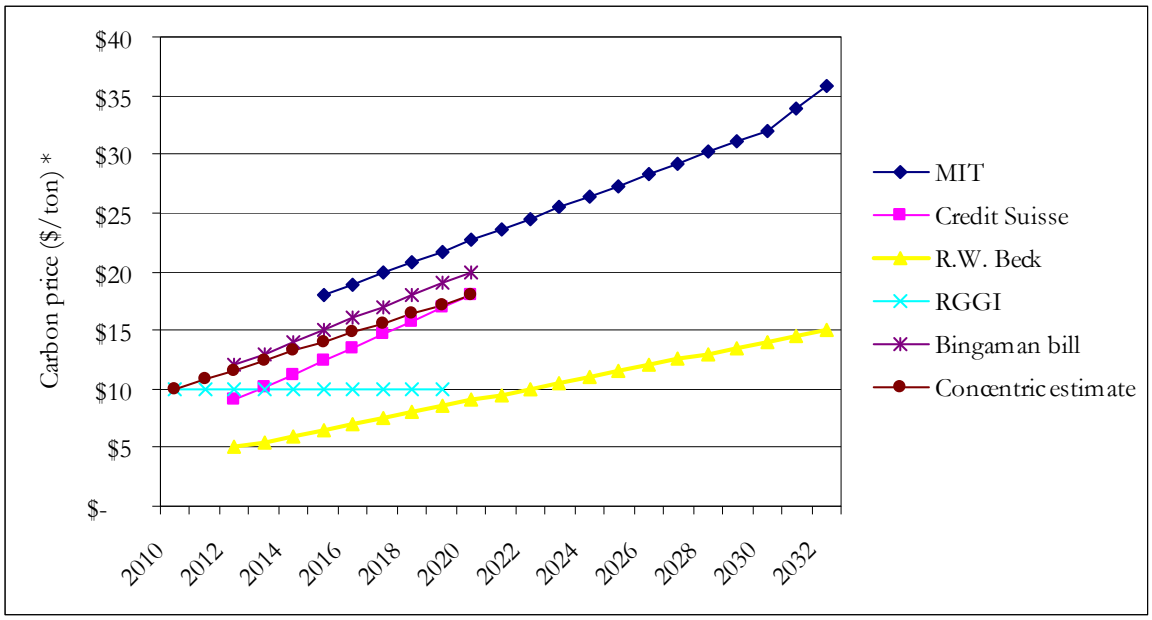
[50] The United Nations has set a deadline of 2009 to end negotiations on a treaty that will replace the commitments under the Kyoto Protocol, which expires in 2012. In December 2007, the UN Framework Convention on Climate Change held a conference in Bali to begin the process of negotiating a treaty.

CEA's modeling analysis assumes a CO_2 allowance price of $10 per ton in 2010, escalating to $18 per ton in 2019 (and remaining at $18 per ton throughout the life of our forecast). This forecast is conservative and is based on the range of regional and federal proposals under review. The following table outlines several carbon price scenarios from various sources. It is followed by a chart depicting each scenario's CO2 price forecast.

Table 8 Various CO_2 Allowance Price Forecasts

CO_2 Allowance Price Forecast	Source
$5 to $65 per ton in 2030 and $15 to $130 per ton in 2050	IPCC Working Group III Summary for Policy Makers. Price ranges assume CO_2 stabilization at around 550 ppm by 2050, taking into account technological change.
$18 per ton in 2015, $32 per ton in 2030, and $70 per ton in 2050	MIT Joint Program on the Science and Policy of Global Climate Change, Assessment of U.S. Cap-and-Trade Proposals (April 2007), at 16-17. Price assumes a scenario that 287 billion metric tons in carbon allowances would be made between 2012 and 2050, with the goal of holding emissions at 2008 levels by 2050.
$12 per ton in 2012 escalating to $20 per ton by 2020	S.B. 1766, Low Carbon Economy Act (Bingaman/Specter bill)
$12 per ton in 2012, increasing 5% a year above the rate of inflation in subsequent years	Low Carbon Act of 2007, which proposes a cap and trade system.
$10 per ton	Carbon tax proposed in U.S. Congress, H.R. 2069, the Save Our Climate Act of 2007
$10 per ton	Regional Greenhouse Gas Initiative (RGGI), proposed safety valve price for CO_2 emissions.
$9 per ton in 2012, increasing to $18 per ton in 2020	Credit Suisse Equity Research, November 2007. Credit Suisse assigns weighted values to various climate change policy scenarios.
$12.50 per ton	Lehman Brothers Equity Research, February 2007. Estimates base case carbon allowance price.
$5 to $15 per ton, beginning at some point between 2012 and 2018 through 2032	R.W. Beck, Feasibility Study of AMPGS, June 2007.

Figure 11 Range of CO2 Allowance Price Forecasts



Levelized Cost Model Overview

CEA used a 20-year levelized cost model to determine the cost to the City of building and operating each technology. The main output of the model is a real levelized cost of electricity for each technology on a 2013$/MWh basis. The real levelized cost of electricity was calculated using the formula below. This is also the approach used by RW Beck in the Feasibility Study, which we found to be reasonable:

All-in Real Levelized Cost ($/MWh) = A / B

Where;

A = NPV (GENERAL_INFLATION_RATE, COP_1, COP_2, COP_3,…COP_{20})

And

B= NPV (GENERAL_INFLATION_RATE, MWh_1, MWh_2, MWh_3,…MWh_{20})

NPV = Net Present Value

GENERAL_INFLATION_RATE = 3.00%

COP = Total Costs of Production (including AFUDC, fixed and variable O&M, maintenance capital, fuel expenses, depreciation, financing costs, and property taxes)

MISO Capacity

It is possible (if not likely) that in the next several years MISO will implement a capacity market of some kind. Capacity will become a separate and distinct product from energy. Load Serving Entities ("LSE") such as the City of Oberlin, will need to procure sufficient capacity to meet their peak demand requirements plus some reserve margin. The mechanism for procuring this capacity (above the amount which is owned by the LSE) will likely be an auction conducted by MISO (or entity acting on behalf of MISO).

Capacity markets are designed to make certain there is adequate generating capacity installed in a market, thereby ensuring reliability during periods of peak demand, or unexpected unit outages. The market accomplishes this goal by providing capacity payments to existing owners of generation who choose to participate in the capacity auction process, and sending a price signal to capacity resources (i.e. indicating when capacity payments alone will make it profitable enough for an owner of new capacity to build additional generation).

The potential for a MISO capacity market is an important consideration for the City of Oberlin given the large percentage of energy it buys through market contracts. The total cost of these contracts could significantly increase if/when MISO implements a capacity market. The City of Oberlin will then need to procure energy and capacity. The contract counterparty would have the opportunity to participate in the capacity market and receive the clearing price for its capacity. In order to provide the City of Oberlin with the capacity and energy, it would need to increase the cost of the contract to account for the opportunity cost of not participating in the capacity auction and receiving the associated capacity payments. If the City of Oberlin participated in AMPGS, or owned any other capacity resource, it would benefit not only from the energy the unit generated, but also from the capacity the resource provides.

For the time being, it appears that MISO has its capacity market plans on hold. Both PJM and New England ISO have capacity markets (or will soon implement capacity markets). It is entirely possible that MISO will wait to see how these two capacity markets perform, before designing a capacity market of its own.

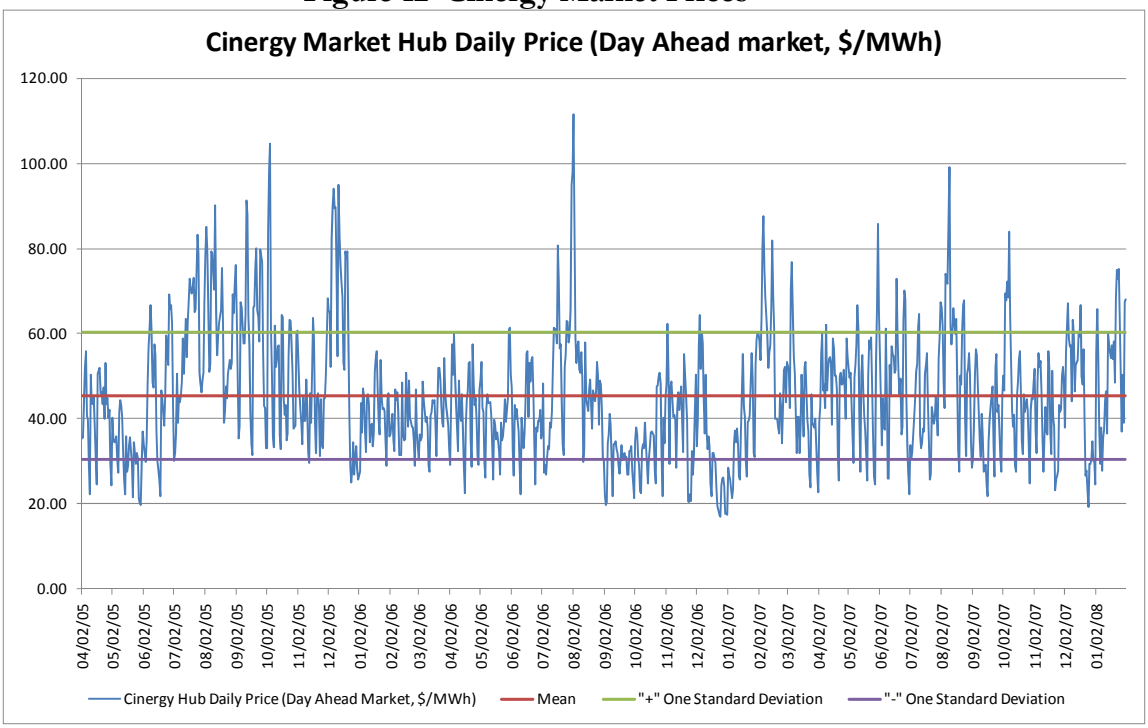
MISO Energy

Market Power contracts add risk to the City of Oberlin's portfolio for two main reasons. The first is the possibility that the implementation of a MISO capacity market will increase costs for LSE's. The second is the inherent volatility of the price of market power. In the last three years, the daily price of market power has had a standard deviation of 33%, and the annual price of market power has had a standard deviation of 13%.[51]

Figure 12 shows the daily price for energy at the Cinergy Hub (a liquid pricing point relatively close to Oberlin's load center). As demonstrated by the "Average" and "+/- One Standard Deviation" lines, market energy prices are extremely volatile. To the extent the City of Oberlin purchases energy in the market, it, and ultimately its customers, is exposed to this volatility.

[51] One standard deviation comprises 68% of all observations. Therefore, it can be said, for example, that 68% of daily prices are within 33% of the mean price, and 32% of daily prices are more than 33% higher or lower than the mean price.

Figure 12 Cinergy Market Prices



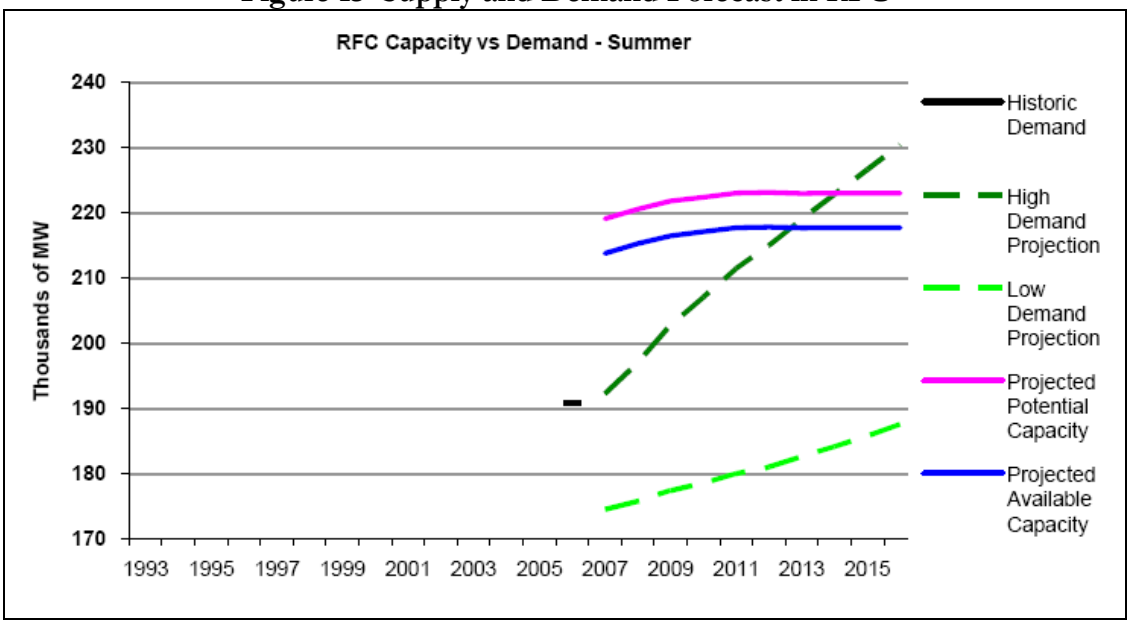
The City will have to purchase baseload market power to fill every MW of demand for which the City does not have firm baseload equivalent capacity. The City can purchase long-term (1 to 3-year) contracts to make up the difference between baseload needs and total capacity (firm plus non-firm/intermittent capacity). These long-term contracts would be expected to have moderate volatility, reflecting the typical 13% change in average annual prices. However, the City must also purchase spot market contacts to supplement its non-firm/intermittent capacity (such as hydro and wind, whose generation is subject to daily conditions). These spot market contracts reflect the typical 33% change in daily prices. For modeling purposes, we have assumed that the City will be required to purchase 50% of each type for all market power purchases. This results in an average volatility of market power of 23%.

Production costs from a baseload facility, like AMPGS, demonstrate far less volatility. The variable costs of production are largely driven by fuel prices. The historical volatility of coal is significantly lower than that of energy prices at the Cinergy Hub.

MISO market prices will also be sensitive to changes in CO_2 emissions prices (albeit to a lesser extent than AMPGS). In a wholesale energy market such as MISO, the market clearing price is set based on the marginal cost to run the marginal unit available at that time. If we assume that natural a gas unit is the marginal unit (setting the clearing price) 2/3rds of the time and a coal plant is the marginal units 1/3rd of the time, and that the emissions rates of these units are 1,000 lbs/MWh and 2,000lbs/MWh, respectively, then each $1 increase in the price of CO_2 emissions would result in an increase in wholesale energy prices of $0.66.

In addition, market prices tend to be cyclical, based largely on cycles of supply and demand. These forces are likely to cause market prices in MISO to rise in real terms through approximately 2015, although they may begin to decline in real terms following that date. Both the US Department of Energy forecast and RW Beck's assumptions follow this general pattern. The expectation for continuing market price increases in MISO through 2015 is driven largely by a current stagnation in new construction of baseload capacity in MISO, combined with steadily increasing demand. Figure 13 illustrates these trends (Note: RFC refers to the Reliability First Corporation, which is the reliability region that contains MISO).[52]

Figure 13 Supply and Demand Forecast in RFC



Biogas

Biogas generation units burn the methane produced by the anaerobic digestion of agricultural livestock manure, food waste and crop residues. AMP-Ohio does not currently own or purchase power from biogas units.

Biogas units require a significant amount of on-site waste matter to serve as fuel in the anaerobic digestion process. Historically, biogas units have been constructed on farms where livestock manure has served as the primary fuel source. In Europe and in states such as Vermont where biogas technology has received strong support, biogas units are increasingly utilized to co-digest livestock manure with food waste and crop residue.

Concentric finds it reasonable that Oberlin could collaborate with farm owners to develop biogas units at two different sites in the region. Given the cost of transporting agricultural waste, it would likely be more economic to locate the generating units on separate farm sites. It is also likely that these facilities would be developed consecutively, so that the lessons learned from developing the first unit could be applied to the second.

[52] Source: North American Electric Reliability Corporation, "2007 Long-Term Reliability Assessment," October 2007, p. 173.

The amount of available agricultural waste is a limiting factor in the potential viability of biogas as a generation alternative. Two dairy farms are located in the vicinity of Oberlin that have a total of approximately 1,000 head of cattle.[53] Nearby hog farms may provide an added source of available livestock manure. A "plug-flow" biogas unit that runs entirely on livestock manure may produce an output of 200 kW from 1,000 head of cattle.[54] The more advanced "complete-mix" system operates at twice the efficiency of the plug-flow unit,[55] and so could produce 0.4 MW from the same amount of livestock manure. Alternate fuel sources could increase the potential capacity of the biogas units. For example, farms located in Vermont have successfully doubled output from biogas plants by using dairy waste from cheese manufacturers and ice cream manufacturers as fuel.[56] Given that such potential fuel inputs might not be as accessible in the Oberlin vicinity as in Vermont, Concentric assumes that Oberlin could reasonably produce another 0.2 MW from these alternate resources. Therefore, development of two biogas units with a total generating capacity of 0.6 MW represents a reasonable stretch scenario for this technology.

The economics of biogas generation reflect that this technology is currently at the early stage of commercial development. Total up-front capital costs are estimated at $4,196/kW. This capital cost is the least competitive of all generation alternatives considered in this analysis.

Co-products of the anaerobic biodigestion process include solids for animal bedding, which may be used or sold; compost material, which may be used or sold; and waste heat, which may be recovered to heat buildings. These co-products may reduce the net cost of generating electricity from biogas units.

Assumed capacity for technology:	0.30 MW
Lead Time (years))	1 Year
Earliest On-line Date (default to 2013)	2009
CEA Overnight Capital Cost ($2008/kW):	$3,062/kW
CEA Overnight Capital Cost ($2008):	$0.9 million
CEA Installed Cost ($2013/kW):	$4,196/kW
CEA Installed Cost ($2013):	$1.2million
All-in Real Levelized Cost ($2013/MWh):	**$82.34MWh**

Possible Locations

- Any nearby farm with at least several hundred head of livestock.

Environmental Considerations

- Biogas plants emit carbon dioxide and NOx. Biogas plants do not emit SO_2 or mercury. Overall, biogas units are considered a net negative source of greenhouse gas emissions. The CO_2 emissions produced are equivalent to the amount of CO_2 captured by the plant matter that feeds the livestock. Furthermore, the continuous on-site processing of

[53] Communication with Keith Logan, founder of Dairy Electric, on February 8, 2008.
[54] Alliant Energy . January 2005, Anaerobic digesters and methane production in the agricultural sector of states served by Alliant Energy.
[55] Communication with Keith Logan, founder of Dairy Electric, on February 8, 2008.
[56] Communication with Keith Logan, founder of Dairy Electric, on February 8, 2008.

manure reduces the amount of methane released by approximately 4 to 5 tons per head of cattle.[57].

- Biogas units have numerous environmental benefits, including: reducing water quality problems and managing nutrients, odor control, and reducing pathogen load.

Key Risks

- Unclear financial incentives
- Unpredictable capital costs and fuel costs.
- Length of contracts with digester owner
- Maintenance costs can drive costs higher due to small size and limited penetration of similar technologies, which can make spare parts costly.

Coal (CFB)

This technology uses bituminous coal, in conjunction with upward blowing jets of air to create a combustion process that heats water, creating steam, causing a turbine to rotate, thereby generating electricity. The CFB technology is designed specifically to control emissions of sulfur dioxide ('SO_2"), but has a higher capital cost than the typical pulverized coal technology (and AMPGS). Because coal is a relatively inexpensive fuel source, the marginal cost of operating a Coal (CFB) plant is low, so it is generally used as a baseload source of electricity. Coal is an abundant domestic resource and remains a stable and relatively inexpensive source of fuel for electric power despite recent price increases. Coal (CFB) plants emit carbon dioxide ("CO_2"), SO_2, nitrogen oxides ("NOx"), and mercury.

Assumed Capacity for technology:	750 MW
Lead Time (years))	6 Years
Earliest On-line Date	2014
CEA Overnight Capital Cost ($2008/kW):	$2,696/kW
CEA Overnight Capital Cost: ($2008)	$2,022 million
CEA Installed Cost ($2013/kW):	$3,874/kW
CEA Installed Cost ($2013):	$2,905 million
All-in Real Levelized Cost ($2013/MWh):	**$93.25/MWh**

Emissions Control Technologies Assumed

- *NOx Reduction* - Less NOx is created because combustion takes place at a lower temperature than pulverized coal units (e.g., 800-900 degrees Celsius for CFB vs. 1,300-1,400 degrees Celsius in the case of pulverized coal technology).
- *SO_2 Reduction* – Limestone is injected into the bed to remove SO_2. Limestone is also used to remove ash byproduct.
- *Particulate Matter Reduction* – Particulate matter is contained in the fuel gas. After passing through the combustion chamber, the fuel gas enters a cyclone where larger particulate matter is recycled back through the combustion chamber and smaller particulate matter is removed with a fabric filter.

[57] Communication with Keith Logan, founder of Dairy Electric, on February 8, 2008.

Siting Considerations

Considerations for siting a Coal (CFB) plant include:

- *Fuel Delivery* – Coal is typically delivered to power plants by rail, barge and truck. Therefore, proximity to existing or potential rail and truck-accessible highways are critical siting considerations. For context, a 750MW unit would require approximately 178,000 tons of coal delivered every month, which would require more than 4,000 deliveries per month by a 40-ton truck or eighteen full rail deliveries per month from a 10,000-ton train. Barge delivery is also a viable option.
- *Cooling Water Source* - Coal (CFB) plants require a large source of cooling water. Therefore, proximity to a lake or river with significant reserves is a critical siting consideration.
- *Land* – A 750MW coal plant would require approximately 50-100 acres of land.
- *Proximity to Transmission* – As with all other technologies, proximity to existing transmission infrastructure makes siting a Coal (CFB) plant more feasible and cost-effective.

Environmental Considerations

- Coal (CFB) plants emit CO_2, SO_2, NOx, and Mercury. All of these emissions are reduced by the fluidized bed combustion process. However, more stringent emissions caps than expected may make coal-fired plants uneconomic.
- Fuel delivery via truck causes roadway erosion and congestion; rail and barge transportation can have similar congestion effects.
- As with any technology that requires cooling water, increases in source cooling water temperatures may occur, with potential damage to underwater ecosystems.

Key Risks

Future environmental mandates may increase capital or emissions allowance costs.

- Efficient unit size is relatively large, potentially creating portfolio diversification concerns, unless Oberlin is able to purchase a minority stake.

Combustion Turbines ("CT")

CTs are a popular peaking resource due to their mature technology, low capital costs and variety of sizes and configurations. Similar to an aircraft jet engine, a CT uses natural gas or oil in a combustion chamber to rotate the turbine to generate electricity. The relatively low capital investment is offset in part by the CT's relatively poor efficiency, meaning that owners of CTs usually run their units only when the price of power is high or when the power system requires operating reserves. CTs emit CO_2 and NOx, but do not emit SO_2 or mercury.

Primarily for environmental reasons, the general preference is to run on natural gas at sites where it is available, although oil is sometimes burned during periods of high natural gas prices.

Assumed capacity for technology:	25 MW
Lead Time (years))	2 Years
Earliest On-line Date (default to 2013)	2013
CEA Overnight Capital Cost ($2008/kW):	$1,259/kW

CEA Overnight Capital Cost ($2008):	$31.5 million
CEA Installed Cost ($2013/kW):	$1,725/kW
CEA Installed Cost ($2013):	$43.1 million
All-in Real Levelized Cost ($2008/MWh):	**$295.37/MWh**

While CT's are available in many configurations and sizes, a smaller unit may be better able to fit an existing generation site, or may face lower required costs for generation upgrades. Combinations of smaller units may also make it possible to defer transmission investments more effectively than a smaller number of larger units.

Emissions Technologies Assumed

- NOx Reduction - Low-NOx burners

Possible Locations

Gas infrastructure requirements limit potential sites to areas served by reliable natural gas pipelines. High-level Considerations for siting a CT include:

- *Fuel Delivery* – Natural Gas is delivered to power plants through gas pipelines. Therefore, proximity to existing or potential gas infrastructure is a critical siting consideration.

Environmental Considerations

- Gas-fired plants emit CO_2 and NOx, albeit in significantly smaller quantities than other types of fossil fuel-fired plants.
- In addition to natural gas, CTs can burn diesel fuel. While these units are expected to burn diesel only as a backup fuel source, oil is a more polluting fuel than natural gas.

Key Risks

- Price competitiveness of natural gas as a fuel source.
- Natural gas prices are volatile and comprise a large percentage of all-in costs. In the CEA Base Case, a one standard deviation change in the price of fuel causes a 12% change in all-in power costs.
- CTs have high heat rates (low efficiency) at full load and are therefore only useful during periods of peak power prices.
- CTs can have high levels of de-rating in summer months causing a reduction in output capacity.

Combustion Turbine Combined Cycle ("CTCC")

Combined cycle combustion turbine units use natural gas in a combustion process similar to the CT, but then utilize the waste heat to create steam to rotate a turbine generating additional electricity. It is an efficient process that often allows the CTCC to operate as an intermediate or baseload resource. The short-run economics of a CTCC are similar to purchasing electricity in the MISO market because the economics of both alternatives are driven primarily by the prevailing price of natural gas. Like the CT, the CTCC emits CO_2 and NOx (albeit at lower rates than the CT), but does not emit SO_2 or mercury.

Assumed capacity for technology:	560 MW
Lead Time (years))	4 Years
Earliest On-line Date (default to 2013)	2013
CEA Overnight Capital Cost ($2008/kW):	$811/kW
CEA Overnight Capital Cost ($2008):	$454 million
CEA Installed Cost ($2013/kW):	$1,041/kW
CEA Installed Cost ($2013):	$583.2 million
All-in Real Levelized Cost ($2013/MWh):	**$103.28/MWh**

Emissions Technologies Assumed

- NOx Reduction - Low-NOx burners

Possible Locations

Gas infrastructure requirements limit potential sites to areas served by reliable natural gas pipelines. High-level Considerations for siting a CTCC include:

- *Fuel Delivery* – Natural Gas delivered to a CTCC through gas pipelines. Therefore, proximity to existing or potential gas infrastructure is a critical siting consideration.
- *Land* – A 560MW CTCC would likely require 20–50 acres of land, a relatively small footprint among baseload facilities.

Environmental Considerations

- Gas-fired plants emit CO_2 and NOx, albeit at significantly lower rates than other types of fossil fuel-fired plants. CTCCs emit CO_2 and NOx at a lower rate that conventional CTs.

Key Risks

- Natural gas prices are volatile and comprise a large percentage of overall operating costs. In the CEA Base Case, a one standard deviation change in the price of fuel causes a 22% change in all-in power costs.
- Efficient unit size is relatively large, potentially creating portfolio diversification concerns.
- Price competitiveness of natural gas as a fuel source.

Integrated Gasification Combined Cycle ("IGCC")

IGCCs are baseload, coal-fired units. An IGCC unit heats coal in a "gasifier" to turn the coal into gas, which is then combusted to rotate the combustion turbine in order to generate electricity. The waste heat from the combustion process heats water into steam and turns a turbine to generate additional electricity. While an IGCC unit emits CO_2, SO_2, NOx and mercury like the other coal technologies, the SO_2, NOx and mercury emissions are significantly lower (on a per-megawatt-hour basis) because of the efficiency of the unit design and the use of the waste heat from the initial combustion process. The capture and sequestration of CO_2 is an emerging technology that is not expected to reach commercial feasibility during in the immediate future, and is therefore not assumed. However, it will be possible to add this technology to an existing IGCC if it becomes feasible at a future date.

Assumed capacity for technology:	640 MW
Lead Time (years))	6 Years
Earliest On-line Date (default to 2013)	2014
CEA Overnight Capital Cost ($2008/kW):	$2,516/kW
CEA Overnight Capital Cost ($2008):	$1,610 million
CEA Installed Cost ($2013/kW):	$3,616/kW
CEA Installed Cost ($2013):	$2,313 million
All-in Real Levelized Cost ($2013/MWh):	**$84.01/MWh**

Emissions Technology Assumptions

- *NOx Reduction* – Low NOx burners
- *SO_2 Reduction* – Solvent used at the end of the gasification cooling process

Possible Locations

High-level Considerations for siting an IGCC plant include:

- *Fuel Delivery* – Coal is typically delivered to power plants by rail, barge or truck. Therefore, proximity to existing or potential rail and truck-accessible highway are critical siting considerations. A 640MW IGCC plant would require approximately 130,000 tons of coal delivered every month, which would require more than 3,000 deliveries per month by a 40-ton truck or thirteen rail deliveries per month from a 10,000-ton train. Barge delivery is also a viable option.
- *Cooling Water Source* - IGCC plants require a large source of cooling water. Therefore, proximity to a lake or river with significant reserves is a critical siting consideration.
- *Proximity to Transmission* – As with all other technologies, proximity to existing transmission infrastructure makes siting an IGCC plant more feasible and cost-effective.
- *Land* – Land requirements for a IGCC would be similar for those of a pulverized or CFB coal-fired facility

Environmental Considerations

- As with any technology that requires cooling water, increases in source cooling water temperatures may occur, with potential damage to underwater ecosystems.
- IGCC plants emit CO_2, SO_2, NOx, and Mercury. SO_2, NOx, and Mercury are reduced by the gasification process. However, more stringent emissions caps than expected may make coal-fired plants uneconomic.

Key Risks

- Future environmental mandates requiring reduced CO_2, NOx, and/or Mercury emissions may be costly.
- Efficient unit size is relatively large, potentially creating portfolio diversification concerns.
- Price competitiveness of coal as a fuel source.
- IGCC technology is still in its commercial infancy in the US, creating uncertainty around durability, capital and operating cost predictability, and unit life.

Nuclear

Nuclear plants use uranium-filled rods in a controlled radioactive process to convert water into steam which rotates a turbine, generating electricity. Nuclear plants are capital intensive and are typically built (economically) in sizes 1,000 MW and larger. Given their large capital costs, the relatively low (albeit rising) cost of nuclear fuel, and operational characteristics, a nuclear plant will always serve as a baseload resource. Nuclear plants do not emit CO_2, NOx, SO_2 or mercury.

Assumed capacity for technology:	1,350 MW
Lead Time (years))	10 Years
Earliest On-line Date (default to 2013)	2018
CEA Overnight Capital Cost ($2008/kW):	$2,926/kW
CEA Overnight Capital Cost ($2008):	$3,950 million
CEA Installed Cost ($2013/kW):	$5,296/kW
CEA Installed Cost ($2013):	$7,149 million
All-in Real Levelized Cost ($2013/MWh):	**$75.34/MWh**

Possible Locations

Given the extensive environmental and geographical characteristics required to site a new nuclear unit, the most likely feasible site would be at or adjacent to an existing nuclear plant. Existing plant sites would be best suited to provide the necessary infrastructure (with upgrades) at the lowest cost.

Environmental Considerations

- There is currently no long-term solution in the US for the disposal and storage of spent nuclear fuel and high-level nuclear waste. The interim solution is on-site storage, which poses additional safety and environmental risks.
- As with any technology that requires cooling water, increases in source cooling water temperatures may occur, with potential damage to underwater ecosystems as noted above.
- Nuclear plants do not emit CO_2, NOx, SO_2 or Mercury (if NOx, Mercury and/or CO_2 emissions are further restricted, operation of the plant will become more economic).
- It is not uncommon for environmental studies to reveal the seepage of radioactive material (tritium etc.) in to the ground, and eventually the groundwater of the site and the land directly around the site.
- The repercussions of an accident at a nuclear plant could have far more negative consequences than a similar accident at a non-nuclear facility.
- Closed-loop water circulation technology, which cools through evaporation, would eliminate the return of warmer water into the natural water supply. While the closed loop system addresses the environmental concerns about heating natural water sources, it can place significant demand on the local water supply.

Key Risks

- There is at least a 10-year lead time required to site and build a nuclear power plant. This extends well beyond the initial years of the Supply Gap, and increases the risk

that the plant's capital cost and other financial considerations will vary during that time period.

- A costly issue discovered at one nuclear plant would have the potential to spur NRC mandates requiring significant capital spending at all other nuclear plants.
- Nuclear plants are subject to homeland security risk due to on-site storage of nuclear materials.
- Efficient unit size is relatively large, potentially creating portfolio diversification concerns.
- A new nuclear plant has not been built in the U.S. for decades. Current technology is therefore still in its commercial infancy, creating uncertainty around durability, capital and operating cost predictability, and unit life.
- Price competitiveness of uranium as a fuel source.

Wind

Wind turbines rely on the wind to rotate a turbine to generate electricity. Because a wind farm is typically comprised of several small (1-2 MW) wind turbines, the size of the farm is usually flexible. Some Midwest wind farms exceed 300MW, however. Wind turbines must be sited in areas that meet specific meteorological requirements in order to operate economically. Capacity factor for wind technologies varies considerably with the wind regime at the site. Wind units are not dispatchable. These units do not emit CO_2, NOx, SO_2 or mercury, but due to their intermittent nature they must be supplemented by a dispatchable resource such as a CT in order to be considered suitable for baseload service.

40MW Wind Farm Alternative	
Assumed capacity for technology:	40 MW
Lead Time (years))	5 Years
Earliest On-line Date (default to 2013)	2014
CEA Overnight Capital Cost ($2008/kW):	$2,290/kW
CEA Overnight Capital Cost ($2008):	$91 million
CEA Installed Cost ($2013/kW):	$3,284/kW
CEA Installed Cost ($2013):	$131 million
All-in Real Levelized Cost ($2013/MWh):	**$138.48/MWh**

The College has recently concluded a three-year study of the potential for wind power to serve the City through local resources. The study included construction of a 50-meter wind monitoring tower in 2006, and subsequent economic evaluation. The study concluded that Oberlin's specific wind resources are less advantageous than those at the JV6 location, but still may be capable of producing power "at an unsubsidized cost of about $0.08/kwh."[58] The City should have the opportunity to participate in the expansion of the JV6 wind facility. CEA used the actual cost data for this facility provided in the R.W. Beck Power Supply Plan (issued in February, 2007). As a result, it may be feasible for the City to develop one or more 1.5MW wind turbines in the Oberlin area, albeit with slightly less favorable economics than those provided by a larger-scale project at a slightly better site. This 1.5MW alternative produces the following economic results:

[58] "Characterization of Wind Resources in Oberlin, OH for Commercial Wind Power," Oberlin College, OMLPS.

1.5MW Oberlin Wind Turbine Alternative

Assumed capacity for technology:	1.5 MW
Lead Time (years))	5 Years
Earliest On-line Date (default to 2013)	2014
CEA Overnight Capital Cost ($2008/kW):	$2,627/kW
CEA Overnight Capital Cost ($2008):	$3.9 million
CEA Installed Cost ($2013/kW):	$3,659/kW
CEA Installed Cost ($2013):	$5,489 million
All-in Real Levelized Cost ($2013/MWh):	**$185.08/MWh**

Possible Locations

High-level considerations for siting a wind farm include:

- *Proximity to Transmission* – As with all other technologies, proximity to existing transmission infrastructure makes siting wind turbines more feasible and cost-effective.
- *Meteorological Characteristics* – A feasible site requires attractive seasonal, directional and time-of-day wind characteristics that can be ascertained through a meteorological study.
- *Viewshed* –Preferred locations are away from population centers.
- *Land Use* – Depending on the meteorological characteristics of a site, significant land might be required to site a wind farm.

Environmental Considerations

- Potential to disturb local bird and bat populations.

Key Risks

- *Capacity factor* – Capacity factors for wind technologies varies considerably with the wind regime at the site. Based on information from various sources, CEA estimates a 25% capacity factor for a large-scale Ohio-based project, and 21%[59] for a smaller-scale 1.5MW Oberlin project. This is a compromise between the historical capacity factor of JV6 (22-23%) and slightly higher capacity factors expected from a possible Cleveland lakeshore project. It should be noted that there is a limited supply of these favorable sites, and capacity factors can fluctuate by as much as 10% downward over the course of a given year, regardless of the site selected. Further, wind generation is difficult to forecast on an hour-to-hour basis, and therefore cannot be relied upon as a significant capacity resource.
- *Construction Cost Escalation* – Costs to develop wind farms have been increasing at a faster pace than costs associated with any of the other technologies included in this study.

Biomass (Fluidized Bed Combustion, "FBC")

Biomass (FBC) units utilize the same technology as the coal (CFB) units except that they burn solid biomass instead of coal. Like coal, the cost of biomass fuel is relatively low allowing Biomass (FBC)

[59] Based on the College's study of wind power capability in the Oberlin area.

units to serve as an intermediate or baseload resource. The College has studied the biomass potential in Ohio and determined that the State ranks 11th in terms of the volume and Btu content of biomass available for electric generation. FBC units reduce NOx emissions and have no emissions of CO_2, SO_2 or mercury. While carbon monoxide is produced, wood biomass generation is neutral with respect to CO_2 emissions since the wood fuel emits the same amount of CO_2 regardless of whether it decays on the ground or is burned at the plant.

For purposes of this study, CEA has chosen to focus on wood waste biomass, a leading form in Ohio. According to the Public Utilities Commission of Ohio, there are four biomass power plants currently operating in Ohio:

Facility	Location	Capacity (MW)	Commercial Operation Date
Hodge Lumber	New Knoxville, OH	3.75	1986
Mead	Chillicothe, OH	10.50	1975
Sauder	Archbold, OH	7.50	1993
Stone Corp.	Coshocton, OH	16.50	1982

Although biomass generation is considered a viable utility scale option, the fact that none has been built in Ohio since 1993 may indicate that the economics of siting such a plant in Ohio are questionable. Our results indicate that there are several other technologies that are less expensive on a levelized $/MWh basis. It is important to point out, however, that variations in fuel assumptions can significantly reduce the levelized cost. As shown in the sensitivities analysis below, a one standard deviation reduction in fuel prices, can reduce the levelized cost by 6%, to $115/MWh.

Assumed capacity for technology:	50 MW
Lead Time (years)	4 Years
Earliest On-line Date (default to 2013)	2013
CEA Overnight Capital Cost ($2008/kW):	$2,799/kW
CEA Overnight Capital Cost ($2008):	$139 million
CEA Installed Cost ($2013/kW):	$3,726/kW
CEA Installed Cost ($2013):	$186 million
All-in Real Levelized Cost ($2013/MWh):	**$121.10/MWh**

Possible Locations

To keep costs low, wood biomass technology should be sited to ensure access to a low cost, abundant source of fuel.

Environmental Considerations

- While Biomass (FBC) plants emit carbon monoxide and NOx, they emit no CO_2, SO_2 or mercury.
- Can contribute to degradation of forests in the event of over-harvesting.
- Fuel transportation via train and/or truck is an additional source of air pollution and highway congestion.

Key Risks

- Unpredictable capital costs and fuel costs.

- Limited efficiency.
- Wood-fired plants require more personnel than fossil fuel plants.

Landfill Gas

Landfill gas units burn the methane produced by the anaerobic decomposition of municipal solid waste. AMP-Ohio has contracted for capacity through 2011 with owners of landfill gas facilities at the locations shown in the table below. The City of Oberlin is a participant in these projects, with a 0.6MW share. EDI, the developer of the facilities, in which AMP-Ohio has a capacity share, has indicated that it plans to expand these facilities by approximately 20-25MW with on-line dates of 2009-2010.[60] The Lorain County landfill is located adjacent to the City, and there has been discussion of the potential for the City to take a more active role in this particular facility, perhaps through a larger capacity share.

Table 9 AMP-Ohio-Contracted Facilities

Facility	Capacity (MW)
Ottawa County	3.75
Lorain County	10.00
Carbon Limestone	16.25

In addition to the AMP-Ohio-contracted facilities, there seven other operational landfill gas generation projects in Ohio, and the EPA has identified more than 80 landfills in Ohio that are potential candidates for these facilities.[61]

The economics of landfill gas generation are reasonably compelling. Total up-front capital costs are typically in the range of $1,500/kW, although this can vary considerably depending on the size and configuration of the landfill. This capital cost is relatively competitive with a small natural gas peaking plant. However, fuel costs are typically lower than the cost of natural gas if it were to be purchased on the market.

Assumed capacity for technology:	22 MW
Lead Time (years))	1 Year
Earliest On-line Date (default to 2013)	2009
CEA Overnight Capital Cost ($2008/kW):	$1,717/kW
CEA Overnight Capital Cost ($2008):	$38 million
CEA Installed Cost ($2013/kW):	$2,938/kW
CEA Installed Cost ($2013):	$53 million
All-in Real Levelized Cost ($2013/MWh):	**$97.31/MWh**

Possible Locations

Any municipal landfill with sufficient methane production.

Environmental Considerations

[60] Please see the Executive Summary for a more complete discussion of this potential opportunity for the City.
[61] Source: Public Utilities Commission of Ohio.

- Landfill gas plants emit carbon dioxide and NOx. However, their CO_2 emissions are no more than what would have been emitted from flaring (methane is a more potent greenhouse gas than CO_2). Landfill gas plants do not emit SO_2 or mercury.

Key Risks

- Unpredictable capital costs and fuel costs.
- Maintenance costs can drive costs higher due to small size and limited penetration of similar technologies, which can make spare parts costly.

Hydro

AMP-Ohio is developing several hydro projects along the Ohio River. These projects include:

- Meldahl, 107MW
- Cannelton, 87MW
- Smithland, 78MW
- Willow Island, 35MW

In the case of the hydro technology analysis, CEA used the actual cost data of the four hydro projects AMP-Ohio is planning. Cost data for these projects came directly from the R.W. Beck Power Supply Plan (dated February, 2007). The City of Oberlin should have the opportunity to participate in this additional generation being developed along the Ohio River. These hydro resources are a renewable source of clean electricity that emit no CO_2, NOx, SO_2 or mercury. The environmental benefits of this technology are somewhat offset by the unpredictability of river flows and therefore unit capacity factor.

Assumed capacity for technology:	296 MW
Lead Time (years))	2 Years
Earliest On-line Date (default to 2013)	2013
CEA Overnight Capital Cost ($2008/kW):	$2,633/kW
CEA Overnight Capital Cost ($2008):	$779 million
CEA Installed Cost ($2013/kW):	$3,620/kW
CEA Installed Cost ($2013):	$1,067 million
All-in Real Levelized Cost ($2013/MWh):	**$68.92/MWh**

Possible Locations

The most likely sites for new hydro capacity are at existing sites along the Ohio River.

Environmental Considerations

- Hydro units emit no CO_2, SO_2, NOx or mercury.
- Can have a somewhat negative effect on native fish populations.

Key Risks

- Unpredictable river flows reduce dependability on hydro as a baseload resource.

Alternative Technology Summary

Table 10 Summary of Results from All Technologies

(1) Generation Type/Size	Nominal Capacity (MW)	Annual Generation (MWh)	(2013$) (2) Real Levelized Capacity $/Kw-yr	(2013$) (3) Real Levelized Energy $/Mwh	(4) CF	(2013$) (5) Real Levelized All-in $/Mwh
AMPGS	960	6,973,200	$245.77	$49.78	85%	$85.74
Biomass (Wood)	50	363,540	$329.22	$75.82	83%	$121.10
Biogas (Manure)	0.3	2,234	$393.13	$29.55	85%	$82.34
Coal (CFB)	750	5,518,800	$289.06	$56.09	84%	$93.25
CT	25	21,900	$136.56	$139.48	10%	$295.37
CTCC	540	4,020,840	$91.45	$90.99	85%	$103.28
DSM	1.4	9,120				$33.52
Hydro	296	1,400,198	$326.02	$0.00	54%	$68.92
IGCC	640	4,485,120	$306.17	$42.75	80%	$84.01
Landfill Gas	22	134,904	$263.86	$54.28	70%	$97.31
Nuclear	1,350	10,525,140	$357.23	$44.38	89%	$75.34
Small Wind (1.5MW)	1.5	2,759	$340.48	$0.00	21%	$185.08
Wind (40MW Wind Farm)	40	87,600	$303.27	$0.00	25%	$138.48

(1) - Type and scale of technology
(2) - (3) Real levelizeded capacity and energy costs
[4] - Projected capacity factor
(5) - Real levelized all-in cost at representative capacity factor for technology
(6) - Real levelized emissions cost $/Mwh
(7-8) - Relative score reflecting volatility of capacity and energy cost
(9] - Required lead time

Sensitivity Analysis

Figure 14 Fuel Price Sensitivity

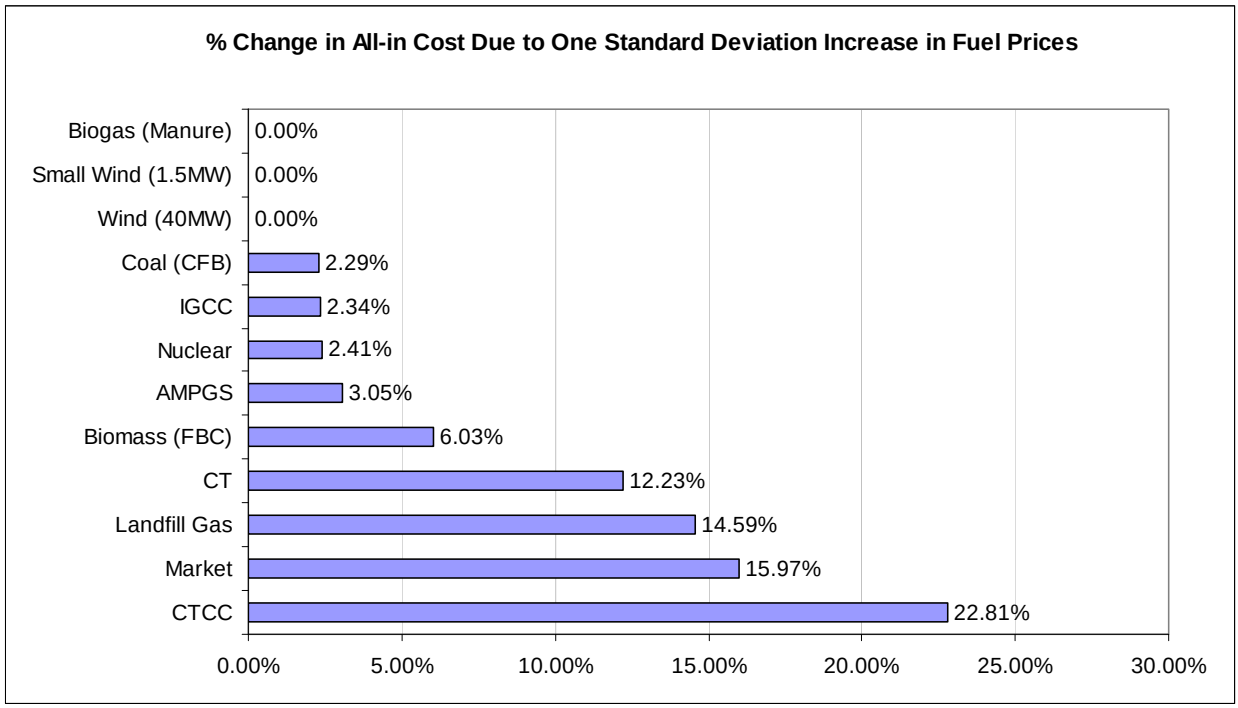


Figure 15 Capital Cost Sensitivity

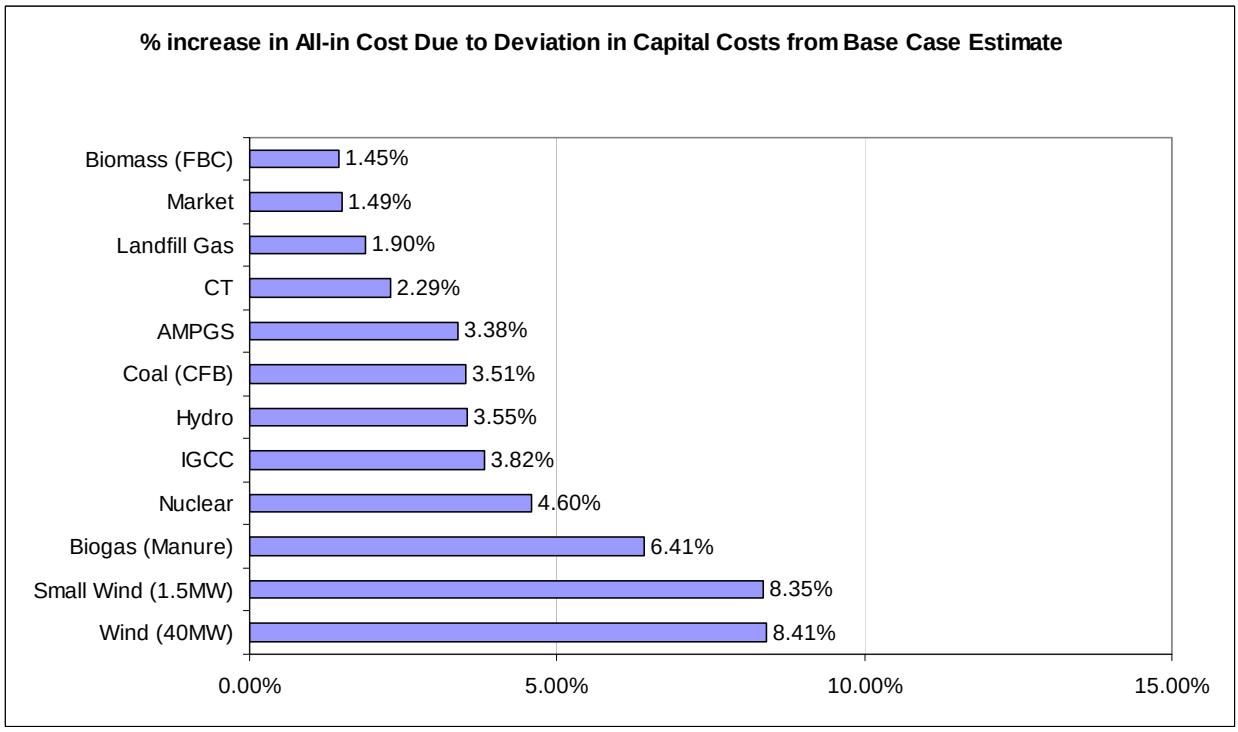


Figure 16 Capacity Factor Sensitivity

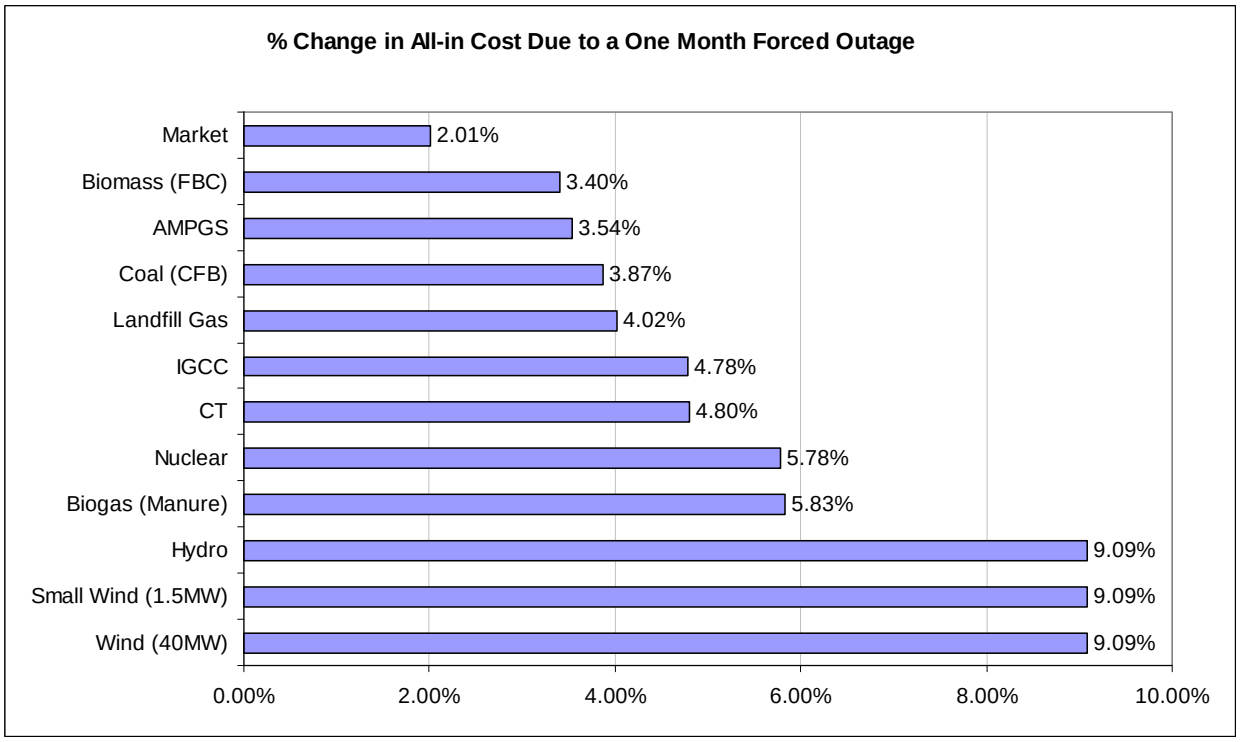
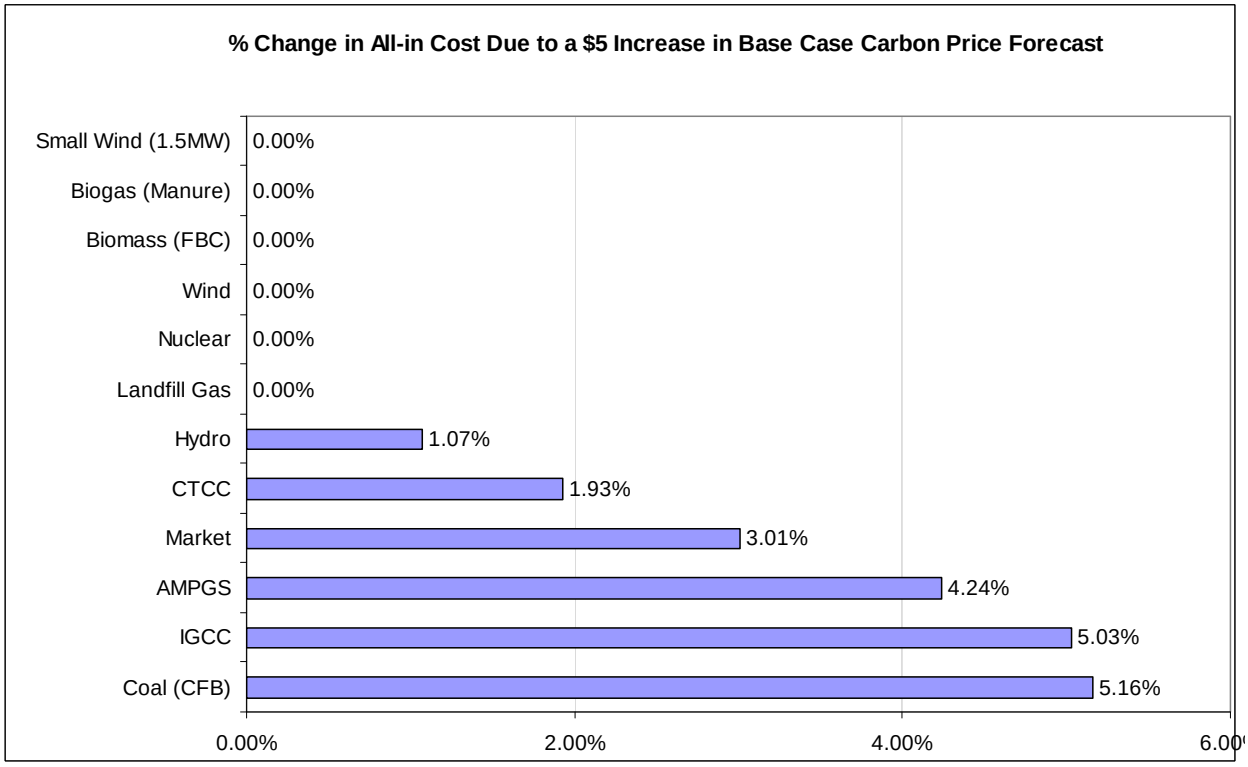


Figure 17 CO2 Emissions Prices Sensitivity



V. ANALYSIS OF DSM/CONSERVATION PROGRAMS

Demand Side Management ("DSM") refers to utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. DSM primarily consists of programs that can be categorized as either Energy Efficiency or Demand Response (also referred to as load management).

Energy Efficiency Overview

An Energy Efficiency program aims to reduce the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption, often without explicit consideration for the timing of program-induced savings. Energy efficiency programs are primarily designed to reduce electricity consumption.

Typical energy efficiency programs for residential customers may include:

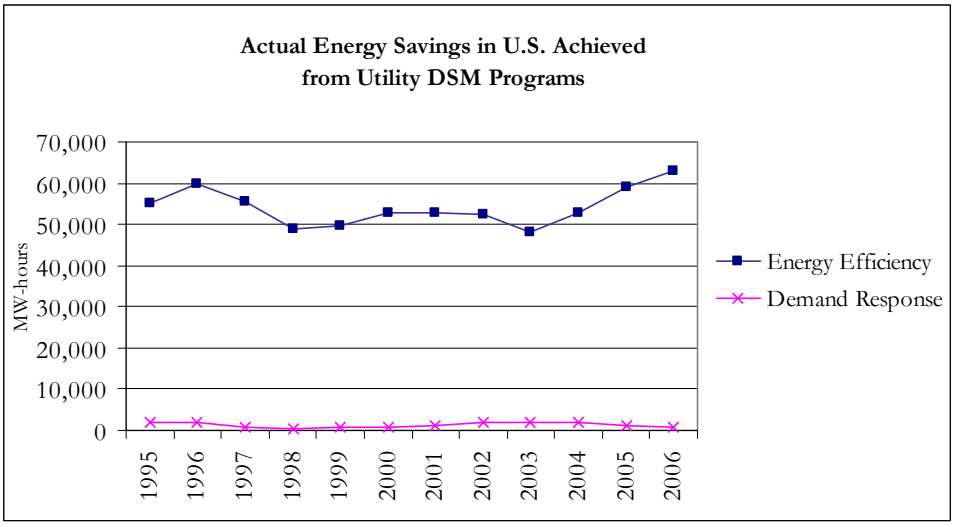
- Information campaigns
- Rebates or giveaways of efficient light bulbs
- Rebates of energy efficient appliances and hot water heaters
- Household energy audits

Typical programs for commercial and industrial customers may include:

- HVAC audits and rebates
- Information campaigns
- Reduced rate financing for efficiency investments

Between 2003 and 2006, energy efficiency programs demonstrated a substantial increase in energy savings, as shown in Figure 18. The amount of energy savings from load management programs, which produce electricity savings only during peak use periods, is negligible by comparison.

Figure 18 Energy Savings in the U.S.

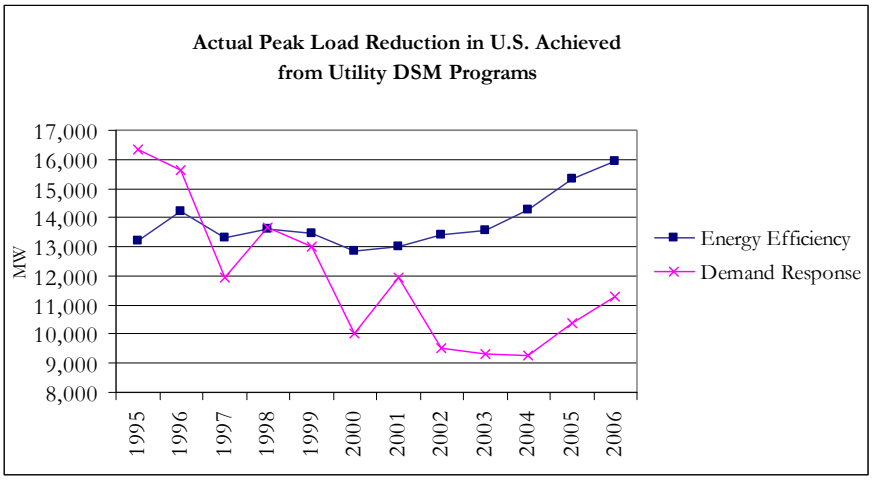


Demand Response Overview

Demand Response refers to a tariff or program established to motivate customers to shift the timing of their electricity use in response to changes in the price of electricity over time, or to give incentive payments designed to reduce peak demand at times of high market prices or when grid reliability is jeopardized. Demand Response measures reduce load during peak demand events, typically by curtailing customer load no more than 50 to 100 hours annually. Utilities implement load management programs by offering interruptible rate options or introducing time-varying rates. A utility and end use customer may enter into separate contracts with a third party energy service provider to curtail customer load during peak events.

On a national level, utility-sponsored DSM programs have yielded increased levels of peak demand savings between 2003 and 2006, as shown in Figure 19 below.[62]

Figure 19 Peak Load Reduction in the U.S.



Summary of the City's DSM Potential and Costs

CEA estimates the energy savings and demand savings that are achievable in Oberlin through the implementation of DSM programs. We have assumed two different scenarios: 1) Base Achievable Case ("Base Case") and 2) High Achievable Case ("High Case"). The Base Case scenario assumes that all customers in the City, including the college, implement an aggressive DSM program that is achievable given considerations of technical feasibility, cost effectiveness, and customer participation. The High Case scenario assumes that Oberlin implements a DSM program on par with the country's leading DSM programs, which have been implemented in California and Vermont.[63] Additionally, the High Case assumes that Oberlin College could implement an even more ambitious DSM program, with the goal of entirely offsetting the institution's projected load growth. The High Case would result in an unprecedented level of Conservation savings, and would involve significantly more costs in terms of both up-front capital and management attention.

[62] Source: U.S. DOE-Energy Information Administration, Electric Power Annual, Table 9.1
[63] Appendix B describes the achievements of DSM programs in California and Vermont.

Base Case

Under the Base Case scenario, CEA expects that the City can reduce its peak load by 3.7 MW (11.9%) and reduce its consumption by 11.6 GWh (7.4%) by 2020. This is equivalent to approximately 15% of the City's share of the energy provided by AMPGS in 2020 and approximately 40% of its capacity. The cost to achieve these results will be $50/kW for peak load reduction and $25/MWh for reduction in consumption. Table 11 presents our summary findings.

A complete discussion of CEA's DSM research and assumptions can be found in Appendix B.

Table 11 Summary of Base Case DSM Potential and Costs

	2010	2015	2020
Energy Savings			
Base Case Achievable Energy Savings (MWh)	2,707	6,691	11,562
Beck Demand Forecast (MWh)	129,616	142,016	155,340
Reduction in Projected Consumption	2.1%	4.7%	7.4%
Levelized cost of saved energy ($/MWh)	$ 25	$ 25	$ 25
Demand Savings			
Base Case Achievable Reduction in Peak Summer Demand (MW)	0.7	2.0	3.7
from Energy Efficiency	0.6	1.5	2.6
from Demand Response	0.1	0.5	1.1
Beck Summer Peak Demand Forecast (MW)	25.9	28.3	31.0
Reduction in Projected Summer Peak Demand	2.7%	7.2%	11.8%
Demand Response program cost ($/kW)	$ 50	$ 50	$ 50
Total Annual Cost of Demand Side Management Program (2008$)	$ 829,981	$ 235,754	$ 318,884

High Case

Under the High Case scenario, CEA expects that the City can reduce its peak load by 5.5 MW (17.8%) and reduce its consumption by 19.9 GWh (12.8%) by 2020. This is equivalent to approximately 26% of the City's share of the energy provided by AMPGS in 2020 and approximately 60% of its capacity. The cost to achieve these results will be $50/kW for peak load reduction and $40/MWh for reduction in consumption. Table 12 presents our summary findings. Please note that while 2010 shows a lower demand and energy savings in the High Case than in the Base Case, this result is a function of the unique data sources used for each case which assume different ramp rates for demand and energy savings. In general, we would expect the savings in each year of the High Case to be higher than those in the same years of the Base Case.

Table 12 Summary of High Case DSM Potential and Costs

	2010	2015	2020
Energy Savings			
High Case Achievable Energy Savings (MWh)	1,507	9,897	19,844
Beck Demand Forecast (MWh)	129,616	142,016	155,340
Reduction in Projected Consumption	1.2%	7.0%	12.8%
Total cost of Energy Efficiency Programs (2006$)	$ 723,145	$ 862,434	$ 1,018,455
Levelized cost of saved energy ($/MWh)	$ 40	$ 40	$ 40
Demand Savings			
High Case Achievable Reduction in Peak Summer Demand (MW)	0.4	2.8	5.5
from Energy Efficiency	0.3	2.2	4.4
from Demand Response	0.1	0.5	1.1
Beck Summer Peak Demand Forecast (MW)	25.9	28.3	31.0
Reduction in Summer Peak Demand	1.6%	9.7%	17.8%
Demand Response program cost ($/kW)	$ 50	$ 50	$ 50
Total Annual Cost of Demand Side Management Program (2008$)	$ 727,279	$ 889,557	$ 1,072,821

Figure 20 compares energy savings under the Base Case and High Case scenarios to the consumption forecast for the City of Oberlin.

Figure 20 Energy Savings Scenarios

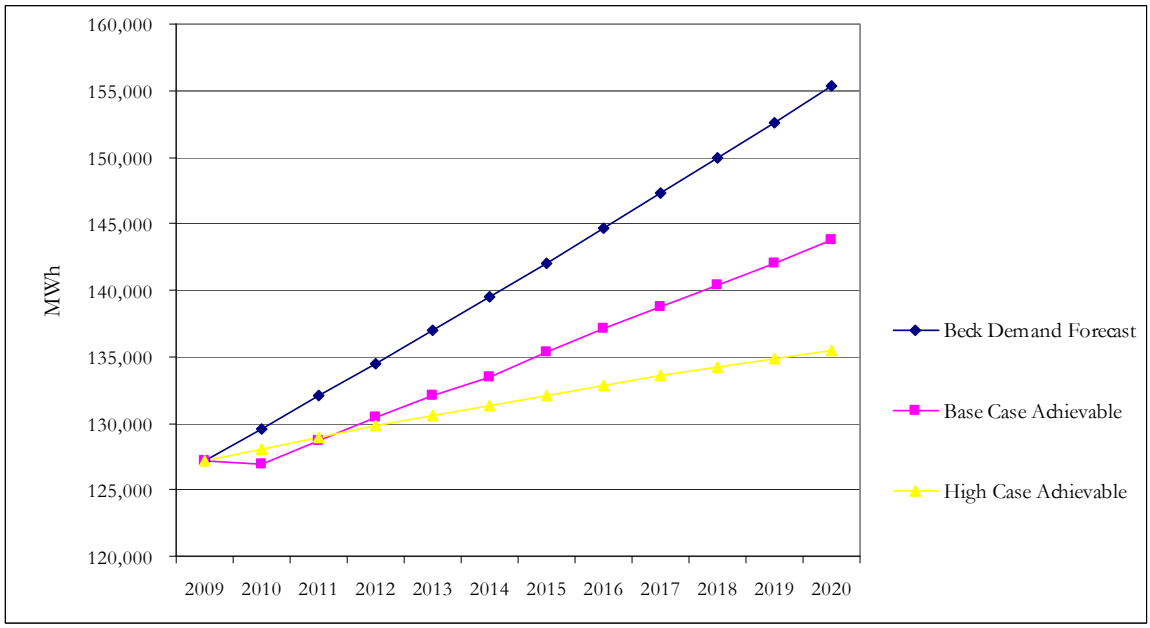
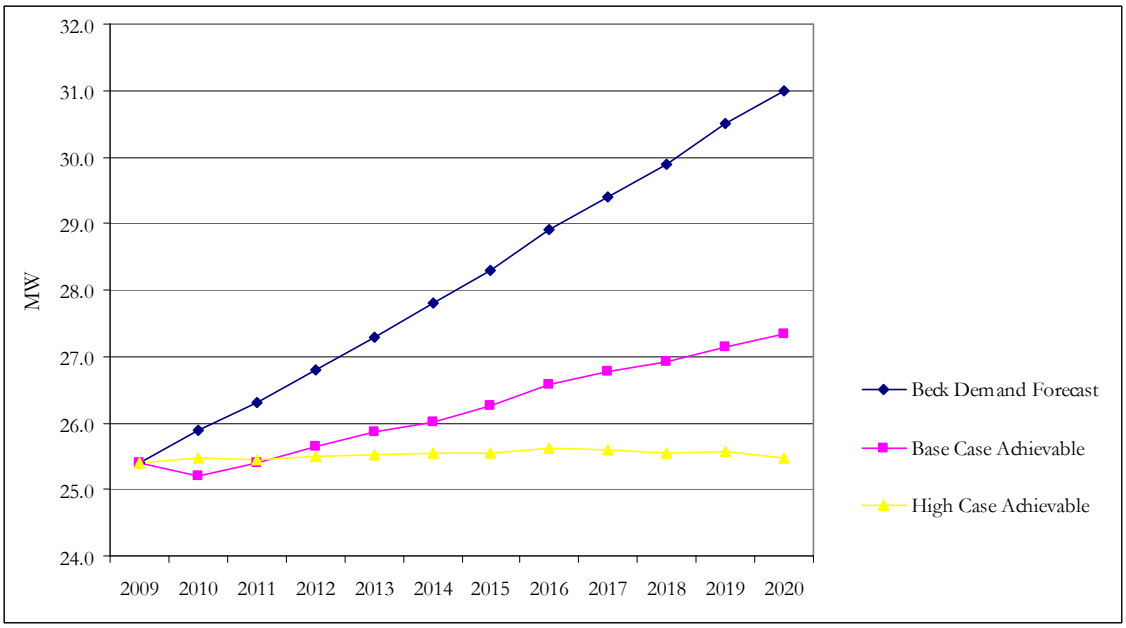


Figure 21 compares demand savings under the Base Case and High Case scenarios to the peak summer demand forecast for the City of Oberlin.

Figure 21 Demand Savings Scenarios



VI. COLLABORATIVE OPPORTUNITIES

Power Contracting Overview

Structures and Suppliers for PPAs

Power contracts can generally be grouped into two categories: 1) asset based, which are tied to specific assets and have power delivery obligations that generally follow the generation pattern of the asset(s) of the seller and 2) market-based, which are sourced more generally from the wholesale energy market and have delivery schedules which tend to be shaped based on the buyer's load requirements. Asset based contracts tend to include terms that reflect the operating characteristic of the underlying generation; availability and delivery commitments are frequently based on unit characteristics, maintenance schedules, start and stop times etc. Alternatively, market-based contracts tend to be structured so that the deliveries are shaped based on the load requirements. For example, market based contracts may be structured for 5 days a week, 16 hours per day in order to meet peak hours of peak days or for 7 days a week, 24 hours a day to meet baseload needs. Broadly speaking, it is easier to get long-term contracts (beyond 5 years) that are asset-based when costs can be tied to a particular generator and transmission path, although, for a price, almost any type of contract can be structured from the wholesale market.

Suppliers differ depending on whether one seeks an asset-based or market-based contract. For an asset-based contract, companies that own or are developing generation are the obvious choice. These would include utilities that want to offer shared ownership in a generating facility as well as owners of merchant plants that either sell into the market or can arrange power purchase agreements tied to assets in their portfolio. A number of merchant generators also offer market-based contracts and use the generation they own to hedge and structure contracts that are market-based. Examples of merchant generators that offer an array of asset-based or market-based contracts would include: AEP, Constellation, Dominion, Exelon, PPL Energy Plus, Sempra and WPS. Other companies with more of a financial focus that generally provide market-based contracts or hedge agreements[64] would include: Barclays Bank, Cargill, Deutsche Bank, J. Aron (subsidiary of Goldman Sachs), JP Morgan, Lehman Brothers, Merrill Lynch, Morgan Stanley and UBS.

Key Contract Terms

In preparing to obtain baseload power for deliveries beginning in 2013, the City will need to determine the key commercial terms for the City and based on that develop a strategy for acquiring power. Possible key issues might include:

- Price
  - Market or other
  - Two-part rate or energy only

[64] The companies have assets or agreements that underpin their sales but tend to offer structured agreements rather than PPAs tied to specific assets.

  - Escalation and rails
  - Shaping (either shape price or penalty)
- Term
- Delivery commitment (and take commitment by the City)
- Capacity factor/load shape
- Products (energy, capacity ancillary services)
- Future attributes (RECs, carbon credits etc.)
- Credit Support
- Other cost responsibility for asset-based contracts (e.g., extraordinary capital expenditures)

Focusing on the contract elements that are most important will help define the resources that the City should consider and drive the schedule for contracting for those resources in order to serve load beginning in 2013. In addition, over the next several years a policy for limiting and pricing CO_2 emissions may evolve. A number of possible clean technologies are under development and in the R&D stages. A buyer's perspectives on these developments, both economic and technological may well play a factor in the type of contract sought and the term. For example, if the City expects a new clean and low-cost technology for baseload will be commercially viable by 2020, then it may wish to enter an intermediate term contract for 2013 deliveries and monitor the options that evolve on that timeframe. Alternatively, if the City anticipates that baseload resources are and will continue to be constrained and that market prices will increase as CO_2 policies add costs to existing resources and new development does not keep pace with growth and retirement of older resources, then it may wish to establish a cost-based contract for baseload power sooner rather than later. However, in both cases it is important that the City recognize that the price of market power is far more volatile than a commitment to any technology, and weigh this key risk in its decision making.

For large baseload projects under development (such as AMPGS) it is common for partners or other long-term buyers of power to commit several years ahead of construction to support the demonstration of need and development of the resource. Typically, if a potential partner or purchaser elects not to buy from that station the opportunity is lost. However, the size of the City's load is such a small portion of the output of the AMPGS project[65], it may well be that that "slice" of the station will continue to be available for some time, albeit at different pricing. However, the relatively small load of the City is a double-edged sword in that it also means that the City cannot be the anchor load for any significant resources, so in order to benefit from the economies of scale of a large project, and will therefore need to find an asset that others are supporting as well.

[65] The project will not be re-sized simply to reflect to loss of the City's commitment although if a significant number of potential purchasers do not support the project it could be re-sized or cancelled.

Price

In considering the likely options for the City in lieu of the AMPGS resource, it is helpful to look at the drivers for certain key commercial elements. First, there is always risk associated with providing a forward price, and any seller will include some "premium" to provide future price certainty (either through a specific price, caps on the pricing or limits on the escalation that may differ from the seller's actual cost). To the extent that the City is looking for price certainty or stabilization, the level of that premium is reduced as the contract date gets closer to the power sales date. However, the city needs to compare that perceived premium with its expected cost of power to determine which is the better value for its ratepayers. If the city is not looking for any price certainty, and is simply willing to pay then-current market prices, there is little reason to contract in advance.

Term

The contract term, or duration, that is available from the market again is a function of price. At full market prices there is no obstacle to a long-term contract but there is also no particular benefit. The following discussion of term is focused on contracts that have some pricing or performance criteria which differ from the market, thereby meeting a particular need of the power buyer and imposing some risk relative to market on the power seller. In addition, the discussion addresses only baseload power contracts, in keeping with the current focus of the City.

The length and availability of "long-term" baseload contracts for baseload power have changed over time. In the early 1990s, as the first wave of independent power projects (IPP) were being developed, virtually every IPP was seeking a long-term off-take contract ranging from 10 – 20 years to match the term of the project financing. As that market matured, power markets developed and lenders became more comfortable with project risk. The need for and availability of long-term contracts then began to diminish. The merchant power market (before the Enron bankruptcy in 2001) was viewed as strong, and "long-term" contracts beyond 5 years were rare. During this time very few large baseload plants were built in the US. Now that the credit markets have recovered and demand has continued to grow, we are again entering a phase when utilities and some merchants are looking to build large (1,000 – 3,000 MW) baseload plants. Unlike the gas-fired generation that has been the technology of choice for the past decade or more, the new baseload generation under development is capital intensive, and accordingly most sponsors are seeking long-term agreements to establish the market need. The agreements are generally in the form of a partner in developing and owning the facility or a long-term PPA. To compete with these asset based options, marketers will likely begin to once again offer longer-term market based PPAs. The large new baseload generation under development is mostly coal (including IGCC) and nuclear, although combinations of intermittent renewable resources and dispatchable fossil resources can be combined to achieve baseload characteristics.

Other Terms

The level of on-going involvement that the City wants with its power supply will also drive the best choice. A market-based contract or an asset-based agreement with a "wrap," a contract the fills in the delivery gaps from the asset, will enable City to meet its load without actively managing its supply. A pure asset-based agreement may offer lower costs but the buyer is responsible for managing the remainder of its load through other resources. The contract terms that drive delivery commitment, cover payments and shaping of payments or penalties also have important impact on the overall value of the power supply and risks to the buyer.

Credit Support

In all PPAs, credit support from each party is a critical term but the amount of credit support can vary widely depending on the type of agreement, the pricing structure and the spread between market price and the price of power under the agreement. In particular from the City's perspective the credit support from the counter-party and the credit rating of the counter party will be important. It is not possible to quantify the level of support that the City should seek without knowledge of the deal structure and pricing. Table 13 indicates the current credit ratings for some of the potential marketers noted above:

Table 13 Credit Ratings

Counter-Party	S&P Rating	Moody's
AEP	BBB	Baa2
Constellation Energy Group	BBB+	Baa1
Dominion Resources	A-	Baa2
Exelon	BBB+	Baa1
PPL Energy Plus	BBB	Baa2
Sempra Energy	BBB+	Baa1
WPS	A	A1
Barclay's	AA-	Aa2
Cargill	A	A2
Deutsche Bank	AA	Aa1
J. Aron	AA-	Aa3
JP Morgan	AA-	Aa2
Merrill Lynch	A+	A1
Morgan Stanley	AA-	Aa3
UBS	AA	Aaa
Sources: SNL Energy and Bloomberg, ratings as of 1/16/2008		

While credit rating is a key element of credit support, negotiating sufficient credit support in the power purchase agreement is equally, if not more important. The power purchaser wants to ensure that the counter-party can, for a reasonable time, provide financial assurance of the "benefit of the bargain." Conversely the seller will look to the City for support sufficient to ensure payment. The market participants may well change between now and the date that the City seeks to execute a power purchase agreement. However, the market, in recent years, has enjoyed a sufficient number of creditworthy players to provide buyers with a competitive

field of viable potential suppliers. It is likely that the City will have a group of potential suppliers from which to solicit offers at the time it elects to procure power.

Summary of Options

The options that the City is likely to have for 2013 include entering market-based and asset-based contracts. Market-based purchases are likely to have 5 to 10 year terms, depending on the pricing structure. For asset-based contracts, the City may still be able to contract for AMPGS if the station is not fully subscribed or committed to the market. The City may also contract for another baseload generation project that may be proposed but that option cannot be assured in the 2013 timeframe. This option will be especially opportunistic for the City since it has insufficient load to be the "anchor load" for such a facility.

Specific Potential Contracts and Contracting Counterparties for the City

The City has never independently entered into a power supply contract outside of its obligations to AMP. The City prefers not to pursue such an approach because it desires to maintain a strong relationship with other member cities of AMP. CEA will therefore focus on collaborative opportunities that may exist if The City partners with other AMP members to enter into a contract with power plant owners or developers.

Potential Contracting Parties

The City and other AMP members may enter into a contract with one of many different types of power generation owners. Table 14 provides a representative list of potential contracting parties each of whom have developed a generating resource in MISO that has either entered commercial operation within the past 7 years or that is currently under development. Most entities in this list are Independent Power Producers that are focused singularly on one form of generation technology. For example, the generation portfolio of Brookfield Power is comprised exclusively of small hydro plants, while that of John Deere Renewables is focused around wind. This reflects the degree to which certain generation technologies require special operational expertise that make these distinct from other forms of generation.

Table 14 Potential Generation Project Sponsors

Generation Type	Potential Sponsor	Representative Project
Biomass	Tamarack Energy	Currently developing the 30 MW Watertown (wood) Biomass Project in CT
Coal	MidAmerican Energy Holdings Co.	Owns 71% of 923 MW Council Bluffs plant in IA, remaining 29% is owned by public power utilities.
Hydro	Brookfield Power	Owns 100% of 6 MW Higley hydro facility in NY.
Landfill Gas	Ameresco	Owns 100% of 3 MW Janesville Landfill facility in WI
Landfill Gas	PPL Energy Services Group LLC	Owns 100% of 3.2 MW Frey Farm Landfill facility in PA.

Landfill Gas	U.S. Energy Biogas Corp.	Owns 100% of 3.3 MW Upper Rock facility in IL
Landfill Gas	Waste Management Inc.	Owns 100% of 3 MW Timberline Trail LFG facility in WI.
Natural Gas	American Electric Power Inc.	Owns 100% of 921 MW Waterford Energy Facility in OH.
Natural Gas	GE Energy Financial Svcs	Owns 100% of 185 MW Fox Energy Center in WI.
Natural Gas	Great River Energy	Owns 100% of 190 MW Cambridge Peaker plant in WI.
Natural Gas	Hoosier Energy R E C Inc	Owns 67% of 400 MW Lawrence County Generating Station in IN, remaining 33% is owned by Wabash Valley Power Assn.
Natural Gas	NRG Energy	Owns 100% of 484 MW Rockford Energy Center peaker plant in IL.
Renewable (generic)	Cleveland Public Power	City is considering legislation require minimum of 25% of city's power needs from advanced and renewable energy sources by 2025.
Wind	Babcock & Brown Wind Partners	Owns 82% of 22 MW Bear Creek Wind Project in PA and 100%; Iberdrola Renewable Energies (9%) and CH Energy Group (9%) own remainder of wind project.
Wind	Edison Mission Energy	Owns 100% of 21 MW Crosswinds wind project in IA.
Wind	FPL Energy	Owns 100% of 99 MW Mower County wind project in MN
Wind	Horizon Wind Energy LLC	Owns 100% of 101 MW Prairie Star wind project in MN.
Wind	John Deere Renewables LLC	Owns 99% of 57 MW Bluegrass Ridge wind project in MO; Wind Capital Group (1%) owns remainder.

Source: SNL Energy

Potential contracting parties generally follow one of three different models:

- Develop project and take equity interest from public power entities
- Develop project and sell output through contract
- Build project and then sell ownership to public power entities

Any decision by the City and other AMP members to contract for power instead of owning capacity involves a key disadvantage. The price of a power contract from a private owner will reflect that owner's private cost of capital (on the order of 9-11%). However, if Oberlin were to own an asset, this ownership position will reflect Oberlin's significantly lower tax-exempt cost of capital (on the order of 5-6%).

Asset Ownership Opportunities

Several power generation projects are currently under construction in Ohio, as shown in Table 15. The developers of these projects range from large investor owned utilities (AEP-Ohio) to small Independent Power Producers (EverPower Renewables). Prairie State Energy Campus, a 1,600 MW advanced pulverized coal facility under construction at the site of a coal mine in Illinois, is also included in this list, since AMP-Ohio recently reached an agreement to purchase 23% of the plant's future output. Prairie State is the only generation project under development in which a public entity in Ohio is partnering with a private developer. It should be noted that smaller projects, on the order of 1 MW or less, may be under development in Ohio but are not reflected in this list.

Table 15 Projects Under Development in Ohio

Power Plant Name	Fuel Type	Nameplate Capacity (MW)	Owner	Notes
American Municipal Power Generating Station	Coal	1000	American Municipal Power of Ohio	The Ohio Power Siting Board is currently reviewing the AMPGS siting application.
Ohio River Clean Fuels	Coal	1180	Baard Energy	In December 2007, Baard applied for state air permits for a coal-to-liquids project to be located along the line of Jefferson and Columbiana counties.
Great Bend Integrated Gasification Combined Cycle (IGCC)	Coal	629	American Electric Power Company, Inc.	Project received siting approval in 2007.
Lima Energy IGCC	Coal	580	Global Energy, Inc.	Construction commenced in November 2005. Global Energy is a developer and operator of gasification facilities. The combustion turbines will use synthetic gas, generated by a gasifier fueled with pellets containing municipal-solid-waste and Ohio coal. AMP-Ohio had an agreement for 125MW from this facility (Oberlin's share would have been 6MW), but the project failed to meet milestones.

Power Plant Name	Fuel Type	Nameplate Capacity (MW)	Owner	Notes
Prairie State Energy Campus*	Coal	1600	Prairie State equity partner group includes the Illinois Municipal Electric Agency, Peabody Energy subsidiary Lively Grove Energy Partners, and several other public entities.	In January 2008, AMP-Ohio closed on agreement to purchase 368 MW, or 23% of plant output. The power plant is expected to enter commercial service in August 2011.
Haverhill Cogeneration Facility	Cogen	67	SunCoke Company	Haverhill Coke is proposing to construct a cogeneration facility, using waste heat from a second set of 100 coke ovens to be constructed at its Haverhill coke facility.
FDS Co-Generation Facility	Coke	135	FDS Coke Plant, LLC	FDS is developing a coking plant in Lucas County. In conjunction with the coke plant, FDS proposes to capture waste heat and use it to generate electricity.
Norton Energy Storage	Energy Storage	2700	CAES Development Company	Compressed air energy storage facility that would use the existing PPG limestone underground mine in the city of Norton for storing compressed air to generate electricity during peak demands. Construction has not yet commenced.
Dresden Energy	Gas	550	American Electric Power Company, Inc.	Construction is underway and commercial operation of this facility is projected for 2008.
Fremont Energy Center	Gas	700	Calpine Corporation	Project was 50% complete when construction ceased in 2004; FirstEnergy will purchase this project out of bankruptcy in 2008.
EC-LGES	Landfill Gas	3	Bio-Gas Technologies, LTD.	Landfill gas project located in Erie County is projected to enter service in April 2008.

Power Plant Name	Fuel Type	Nameplate Capacity (MW)	Owner	Notes
South Point Biomass	Waste	200	Biomass Group, LLC	Development of a wood waste fired power plant in Lawrence County, which was proposed in 2003, has been suspended.
Buckeye Wind Project	Wind	300	EverPower Renewables	Everpower has reached agreements with a number of landowners in Logan and Champaign County. The company has been given a $3m grant from the state for the project. A portion of the project is expected to be installed and operational by June 2009.

* Located in Illinois

Sources: SNL Energy, Ohio Power Siting Board (website and 2006 Annual Report)

VII. ALTERNATIVE BASELOAD GENERATION PORTFOLIOS

Overview and Status of Potential Resources

Using the cost information derived from the Alternative Technology Analysis and the DSM analysis, CEA has developed five alternative portfolios, each of which could serve as potential substitutes for AMPGS in terms of peak capacity (9MW) and annual generation (MWh) that AMPGS is forecast to provide. These five portfolios are then also compared with the City's 13MW baseload capacity need in 2013. Generation portfolio components are assumed to be available if they are expected to be operating before 2015.

Below are the near-term projects that will likely become available to the City: Many of these projects are expected to become available through the AMP-Ohio relationship. However, DSM, Small Wind, and Biogas projects are proposed as projects that the City would develop independently. In addition, Scenario 3 – Lorain Landfill, assumes that the City breaks its ties to AMP-Ohio and purchases a share in the Lorain Landfill of a size sufficient to accommodate all of the City's baseload requirements.

Natural Gas

AMP-Ohio was recently unsuccessful in its bid to purchase Calpine Corporation's Fremont natural gas-fired combined cycle facility out of bankruptcy. AMP-Ohio is also investigating combined cycle (intermediate) and combustion turbine (peaking) projects for development.

Coal

Aside from the AMPGS project, AMP-Ohio will own 23% of Prairie State Energy Campus, which is scheduled to enter commercial service in 2012. The City of Oberlin has to-date declined to participate in this facility.

Coal Example – Prairie State

Prairie State is owned by a consortium of public power entities (95%) and the developer, Peabody Energy (5%). In January 2008, AMP-Ohio closed on an agreement to purchase 368 MW, or 23% of plant output.[66] Most but not all of AMP-Ohio's share is subscribed for by the member municipalities. The EPC is already locked in. Prairie State Energy Campus has attractive power cost, but a less favorable environmental profile due primarily to its mine-mouth operation of high-sulfur coal .

Nuclear

[66] SNL Energy. December 20, 2007. American Municipal Power-Ohio to purchase 368 MW at Prairie State from Peabody

AMP-Ohio has no current plans to own a nuclear facility, although potential projects are occasionally evaluated.

Hydro

Three hydro projects are in active development and are expected to enter service in 2012: Cannelton (84MW), Smithland (72MW) and Willow Island (35MW). The City has entered into a purchase agreement to permit for a 2.6MW share of these projects, which have an expected on-line date of 2012.[67] These projects were three of the top five sites identified by an MWH Consulting study as the best for future development of hydro power facilities along the Ohio River. All Ohio River projects are developed at existing locks on the Ohio River and are "run of the river" projects, subject to the Army Corps of Engineer's control of water flow. The City's purchase contract also permits AMP-Ohio to move forward under the supervision of a committee of the member cities and the AMP-Ohio Board of Trustees ("the Participants' Committee") to pursue all projects identified by MWH Consulting as AMP-Ohio sees fit.

In addition, certain AMP-Ohio member cities have moved forward to jointly with AMP-Ohio to assess Ohio River hydro projects as follows:

- Hamilton has applied for a license for one project, the proposed 105 MW Meldahl plant (1st-ranked site).
- Wadsworth is well-positioned to obtain the license to develop the proposed 48MW R.C. Byrd plant (4th-ranked site).

Landfill Gas

AMP-Ohio is currently under contract with Energy Developments, Inc ("EDI") for 24 MW of power from three Ohio landfill gas facilities, including the Lorain County landfill gas plant. AMP-Ohio is in negotiations to continue this contract beyond its 2011 expiration date.

In addition, EDI is evaluating expansion opportunities at existing sites as well as new development projects. AMP-Ohio finds these facilities to be an attractive supply option and is pursuing other landfill gas developers in Ohio. AMP-Ohio expects to have an additional 16 MW of capacity available to its members from the development of new generating units and expansion of existing units as follows:

- Lorain County – Currently 10MW, EDI intends to begin permitting in 2008 for an expansion to 20MW, with an on-line date of late 2009. AMP-Ohio will have a right of first refusal on this capacity through the expiration of its current contract, at which point EDI will conduct a request for proposals for the sale of future capacity.
- Carbon Limestone – Currently 20MW, EDI intends to expand this facility to 30-35MW, with an on-line date in mid-2010.
- Ottawa County – EDI is considering potential future expansion from 4MW to 5-6MW.

[67] "Power Sales Contract Regarding the American Municipal Power Hydroelectric System," November 1, 2007.

AMP-Ohio notes however that the heightened desirability and improved performance of landfill gas plants have put upward pressure on the cost of their output.

Wind

AMP-Ohio is pursuing several options to add significant amounts of capacity from wind to its supply portfolio, including:

- An MOU contract with JW Great Lakes, for development of up to 50 MW of wind in Wood County, OH. The construction of this project is expected to begin at the end of 2008.
- Working with North Coast Wind to develop a proposed 50 MW to 100MW wind farm in the vicinity of Clyde and Monroeville, Ohio.
- Participating with the City of Cleveland in pursuing the development of proposed 20 MW offshore wind farm.
- Development of a 5 to 6 MW wind farm in Pennsylvania. The expected availability of this wind farm is 35%, compared to a lower range of 23% to 30% for the other proposed wind assets. The anticipated on-line date is 2009.

In addition, the College has made a long-term study of winds surrounding the City as well as the economic feasibility of constructing a 1.5MW wind turbine. While the capacity factor may be somewhat lower than the existing JV-6 project, the turbine appears to be economic, and is therefore included as a potential portfolio contributor.

Biomass

Several AMP-Ohio members are pursuing biomass projects. The cities of Cleveland and Clyde are working with a New Jersey based developer, the Princeton Environmental Group, to develop plans for one or more projects. The Oberlin community is studying the potential for a plant that would convert animal and food waste into energy.

Biogas

The College has investigated the potential for based biogas in Ohio and discovered that the potential is significant. While there are few biogas facilities in Ohio to date, biogas development programs at Central Vermont Public Service (CVPS) and Alliant Energy, Inc. (WI) have each developed manure-based biogas programs at local farms. Based on manure available in Lorain County, the City could develop such a program which we estimate may attract two 0.2MW projects over the next several years. For comparison the CVPS program, which was developed in 2004 has developed four such projects to date.

DSM

AMP-Ohio has ambitious plans to develop a comprehensive Demand Side Management program that will have broad participation of its member cities. AMP-Ohio hopes to

mitigate new load growth, but does not expect to offset existing load. AMP-Ohio has hired Vermont Energy Investment Corp to design a DSM program and coordinate with its members in the implementation phase. VEIC clients include consumer advocates, environmental groups, government agencies, utilities and other energy efficiency administrators in more than 20 states.

A complete description of current and future AMP-Ohio DSM programs is available in the Analysis of DSM/Conservation Programs section of this report.

Cogeneration

AMP-Ohio has several ongoing cogeneration development projects in collaboration with the projects' industrial owners. The identity and details of these projects are currently confidential.

Green Credits

AMP-Ohio offers a green energy program for participants for an additional $0.013/kWh. Fewer than 1% of member customers have signed on.

Potential Portfolio Alternatives to AMPGS

Figure 22 on the following page depicts the components of six alternative portfolios that could be constructed from assets available or potentially available to the City to fulfill its 13MW baseload need in 2013. Each portfolio totals 13.0MW of baseload equivalent capacity. Baseload equivalent capacity is equal to the amount of a given project's total capacity that can be considered baseload (85% capacity-equivalent).[68] Levelized costs are provided for each alternative in the portfolio descriptions that follow. The ranges of levelized cost for each portfolio are based on weighted technology costs using the High and Low technology scenarios as provided in Figure 1.

Portfolio	Levelized Cost	Range
Portfolio 1 – AMP-Ohio Projects	$88.00/MWh	$77.31/MWh - $106.59/MWh
Portfolio 2 – Lorain Landfill	$91.18/MWh	$78.35/MWh - $105.42/MWh
Portfolio 3 – Market Purchases	$97.50/MWh	$73.10/MWh - $116.47/MWh
Portfolio 4 – Renewable Buildup	$87.85/MWh	$80.21/MWh - $116.60/MWh
AMPGS (11.6MW) + DSM (1.4MW)	$82.53/MWh	$79.17/MWh - $ 87.31/MWh
AMPGS (9MW) + DSM (1.4MW)	$84.42/MWh	$76.49/MWh - $ 92.81/MWh

.

[68] For example, a 10MW project with a 50% capacity factor would receive 5.8MW of baseload equivalent capacity (10 x (50/85) = 5.8)

Figure 22 Portfolios to Satisfy the 13MW Baseload Need in 2013

Portfolio 1- AMP-Ohio Projects

Portfolio 1 contains as much new AMP-Ohio renewable capacity as may be reasonably expected to become available by 2015. The construction of this portfolio assumes that the City is awarded the same 1.39% share of all future AMP-Ohio projects that the City was awarded for AMPGS.

Portfolio Components:

Hydro	2.6MW – Includes the City's currently contracted allocation of Willow Island, Smithland and Canelton, plus a 1.5MW (1.39%) allocation of Meldahl)
Market Purchases	8.5 MW
DSM	1.4 MW
Wind (share of 40MW farm)	0.2 MW
Landfill Gas	0.3 MW

Levelized Cost: $88.00/MWh

Analysis: This portfolio has a higher cost than the AMPGS portfolio, primarily as a result of including 6.0MW of market purchases, which have a levelized cost of $97.94/MWh. Also, while most of this portfolio contains assets with low risk, the significant need for additional market power purchases makes the risk of this portfolio significantly higher than AMPGS Alone.

Portfolio 2 – Lorain Landfill

Portfolio Components

Landfill Gas	11.6 MW (this assumes Oberlin would replace the AMPGS capacity, after DSM, with capacity from the EDI Lorain County Landfill Gas Project).
DSM	1.4 MW

Levelized Cost: $91.18/MWh

Analysis: With a levelized cost of $97.31/MW, landfill gas is a relatively expensive portfolio component. As discussed at length in the Executive Summary, it is unlikely that the City could acquire much more than the City's likely 1.9% pro-rata share of the approximately 25MW in new landfill capacity that is expected to come on-line and to be offered to the City before 2012.

Portfolio 3 – Market Purchases

Portfolio Components

Market Power	11.6MW

DSM	1.4MW

Levelized Cost: $97.50/MWh

Analysis: Market power prices are high and volatile, making this the least attractive portfolio of the four. Moreover, these market purchases mean that the City would be essentially buying a pro-rata slice of the Midwest-ISO portfolio, which is 60% coal, 25% gas and 8% nuclear.

Portfolio 4 – Renewable Buildup

Portfolio Components

Market Power	7.6MW
Hydro	2.6MW
DSM	1.4MW
Small Wind (1.5MW)	0.4MW
Biogas	0.6MW
Landfill Gas	0.3MW
Wind (Share of 40MW farm)	0.2MW

Levelized Cost: $87.85/MWh

Analysis: This is both the least costly alternative to the AMPGS/DSM portfolio and contains the largest share of renewable power that can be reasonably expected to be brought on line in the next five to ten years.

APPENDIX A - POWERSPAN ANALYSIS

AMP plans to install Powerspan technology to control emissions of multiple pollutants at its AMPGS plant. Powerspan's patented Electro-Catalytic Oxidation (ECO) technology causes the pollutant, sulfur dioxide (SO_2), to undergo a chemical reaction with ammonia, known as a wet scrubbing process, to produce ammonium sulfate (AS). Ammonium sulfate can be sold as fertilizer, eliminating the need to dispose of the waste product in a landfill. The ECO process will also assist in the mitigation of NOx, Hg, $PM_{2.5}$. Powerspan is currently developing a new ammonia absorption system, known as ECO_2, to capture CO_2 emissions, but has no current plan as to how those emissions may be sequestered. CO_2 cannot be contained without a sequestration technology as well. AMP's decision to install Powerspan technology at AMPGS was driven by the promise that the ECO_2 system will be able to integrate with the ECO system to enable the plant to capture CO_2 emissions in the future.[69]

Powerspan technology is an alternative to other air quality control systems installed to remove specific constituents of the exhaust gas stream from a fossil fuel-fired power plant. The conventional air pollutant control technology, Limestone Flue Gas Desulfurization ("FGD"), also uses a wet scrubbing process. The track record of Powerspan's technology is limited to a commercial demonstration that took place from 2004 to 2005 at First Energy's R.E. Burger Plant located in Shadyside, Ohio. The demonstration showed that Powerspan's ECO process meets all current performance requirements for NOx, SO_2, and particulate control. Additionally, an EPRI commissioned study by Burns & McDonnell concluded that the ECO equipment is at least as reliable as conventional FGD equipment, predicting better than 99% availability.[70]

The AMPGS Feasibility Study estimates capital costs of $207 million for the Powerspan technology and $230 million for the standard Limestone FGD technology.[71] This is equivalent to $216/kW and $240/kW, respectively, or approximately 10% of the total AMPGS capital cost. In May 2007, First Energy reached an estimated $168 million agreement with Powerspan to install the ECO multipollutant control system on two units at the R.E. Burger Plant which have a combined capacity of 312 MW.[72] This is equivalent to over $500/kW, which is more than double the estimated cost of the system to be installed at AMPGS. However, we note that without more knowledge of the terms of this agreement, it is difficult to compare this project to AMPGS. A recent survey by the Electric Utility Cost Group ("EUCG") of scrubbers found the average capital cost of an FGD scrubber for a unit larger than 300 MW at about $300/kW.[73]

Powerspan is in the process of commercializing its carbon capture technology, known as ECO_2; however this technology is several years away from reaching commercial viability. In December 2007, Powerspan exclusively licensed the new technology patented by the U.S. Department of Energy's National Energy Technology Laboratory (NETL) that uses an ammonia-based solution to capture CO_2 from flue gas.[74] Powerspan plans to perform a pilot test of the technology at First

[69] Top Plants: R.E. Burger Plant, Shadyside, Ohio. October 2007. Power Magazine, p. 58.
[70] Top Plants: R.E. Burger Plant, Shadyside, Ohio. October 2007. Power Magazine, p. 60.
[71] AMPGS Feasibility Study, Appendix D, p. 3-2. Based on 2007 dollars.
[72] FirstEnergy plans $168 million emissions control system at Burger plant. SNL Energy. May 30, 2007
[73] July 2007. Power Magazine, p. 56
[74] Powerspan licenses carbon capture technology for current coal fleet from DOE. SNL Energy. December 03, 2007

Energy's R.E. Burger Plant in 2008 and plans a later commercial scale demonstration at NRG's WA Parish plant in Texas. Powerspan's technology represents only one of several types of carbon capture technology that are currently in the R&D phase throughout the world. The Feasibility Study caveats that "CO_2 capture technologies are at the infant stages of development and as such, costs and/or technologies that could emerge as preferable cannot be accurately defined."[75] In addition, no plants in the U.S., including AMPGS, have a proven plan to sequester CO_2 once it is captured.

Given that the process of carbon capture and storage has not reached commercial stage for any technology, it is difficult to assess the costs of Powerspan's ECO_2 technology compared to alternatives. Powerspan estimates the cost of its ammonia CO_2 absorption system on a power plant equipped with the ECO-SO_2 process to be approximately $20 per ton of CO_2 avoided.[76] By comparison, the cost of capturing CO_2 using current technologies is on the order of $150 per ton of carbon.[77] CEA believes that the Powerspan estimate represents a best possible case scenario. The necessity of carbon capture and storage depends on future regulations that limit CO_2 emission levels from power plants. Under any future regulatory environment, the cost of carbon capture technology would need to be competitive with the cost of purchasing a carbon allowance in order for the technology to be commercially viable. Therefore, if Powerspan's ECO_2 technology were to cost the equivalent of $20 per ton of carbon, it may still be an uneconomic alternative if the price of a carbon allowance were only $10 per ton.

[75] AMPGS Feasibility Study, p. 2-11
[76] AMPGS Feasibility Study, p. 2-11
[77] U.S. Department of Energy, http://www.fossil.energy.gov/programs/sequestration/capture/

APPENDIX B – DSM ASSUMPTIONS AND CALCULATIONS

The DSM initiatives instituted by OMLPS have primarily consisted of energy auditing and light bulb replacement.[78] OMLPS has not tracked the results from these initiatives to be able to estimate energy savings or demand savings. OMLPS staff members utilize an infrared camera to conduct heat loss inspections in area homes and businesses. Based on these inspections, the staff makes recommendations regarding caulking and insulation measures. In recent years, OMLPS offered a home energy efficiency kit at cost to city residents. The compact fluorescent light ("CFL") bulbs within the kit were popular, however the hot water heater insulating blankets and low flow water fixtures were not broadly utilized. In 2007, OMLPS distributed 1,100 CFL bulbs to customers at no charge. OMLPS experimented with another initiative to offer rebates to customers to dispose of second refrigerators, however this was discontinued due to lack of customer participation.

OMLPS currently implements a voluntary load management initiative by alerting the city's 10 largest commercial and industrial customers when wholesale power prices approach peak levels. The customers are under no obligation to curtail load during these events. The 2007 Financing Feasibility Study developed for AMP-Ohio describes the existing Interruptible Electric Service Agreements that OMLPS has with two of its major customers, Federal Aviation Administration ("FAA") and Quebecor World:

Under the terms of the FAA contract, OMLPS shall contact FAA on the day prior to the anticipated interruption with at least sixty (60) minutes notice that electric service shall be interrupted. FAA's agreement limits the hours of interruption to eight (8) hours per day, forty (40) hours per month, and two hundred and forty (240) hours per year. FAA receives a credit of $3.00 per kW of demand coincident to the NEASG monthly peak demand. FAA is able to enter into an interruptible agreement due to their own on-site generation. However, if FAA is unable to generate power when an interruption is requested, then OMLPS shall supply supplemental electricity and service to FAA shall not be interrupted. The contract with FAA was renewed in September, 2003 for a five (5) year term. The contract with Quebecor World includes a confidentiality clause whereby OMLPS agrees not to reveal the contents of the Contract to any entity other than appropriate governmental authorities or as otherwise required by law.

The City's Future DSM Programs

The City is engaged through AMP-Ohio with VEIC and will be making specific recommendations to Oberlin City Council with respect to those programs. In addition, OMLPS may consider utilizing the City's new Reverse 911 Emergency Notification System to notify residential customer of electricity price alerts.

[78] Communication with Steve Dupee, General Manager of OMLPS on 12/19/2007.

The College's Current DSM Programs

Oberlin College has implemented several DSM initiatives over the past several years, including the following:

- Retrofitting lights with CFL bulbs and other lighting upgrades;
- Installation of premium efficiency water pump motors;
- Implementing a campus resource monitoring system that provides real-time display of energy data to members of the college community
- Curtailment of electricity usage during winter break period in December.

The measures installed to date, which contribute to an increased level of energy efficiency on the campus, have not been implemented as part of a comprehensive energy plan.

Oberlin College is not currently under any demand response agreement with OMLPS or with an energy service provider. The system for monitoring electricity usage in the residence halls could potentially serve as the basis of a load management program.

The College's Future DSM Programs

In 2007, Oberlin College signed the American College and University Presidents' Climate Commitment, an agreement in which signatories pledge to make the transition to a climate neutral society a major priority. The college therefore plans to set tangible goals for implementing a demand side management program in the near future. One possible, highly ambitious target that the college could set is to stabilize electricity consumption at current levels. The plan would be implemented as part of an ongoing effort to remodel the college's residence halls and to replace aging equipment.[79] Any DSM program would emphasize changing the behavior of college students and faculty through such means as an awareness campaign or award contest.

Table 16 shows the energy savings and demand savings that would result from two energy efficiency program scenarios implemented at Oberlin College. Table 16 provides further explanation of how demand savings from energy efficiency programs are calculated.

[79] Communication with Nathan Engstrom, Coordinator, Oberlin College Office of Environmental Sustainability on 1/7/2008.

Table 16 Potential Energy Savings Scenarios for Oberlin College

	2010	2015	2020
Oberlin College Demand Forecast (MWh)[1]	26,414	28,879	31,573
Achievable energy savings from efficiency programs			
8% reduction by 2020[2]	2.3%	5.2%	8.1%
20% reduction in baseload by 2020[3]	1.8%	10.8%	19.8%
Achievable energy savings from efficiency programs (MWh)			
8% reduction in electricity consumption by 2020	608	1,494	2,560
20% reduction in electricity consumption by 2020	475	3,119	6,251
Achievable summer peak demand savings from efficiency programs (MW)			
Peak demand savings from 8% reduction in consumption	0.1	0.3	0.6
Peak demand savings from 20% reduction in consumption	0.1	0.7	1.5

Sources:

[1] R.W. Beck. 2007. Power Supply Plan for City of Oberlin. CEA used the annual growth rate from this study to escalate Oberlin College actual peak demand from 2006 into future years.

[2] As explained in Table DSM-3, Commercial customers in the city of Oberlin could potentially achieve an 8.1% reduction in base case energy consumption by 2020.

[2] A 20% reduction in energy consumption by 2020 would offset Oberlin College's projected load growth over this period.

AMP-Ohio's Current Programs

AMP-Ohio currently offers three energy efficiency programs to customers of its member utilities. AMP offers discounted CFL bulbs and instituted an education campaign dubbed "Change a Light". AMP has also produced energy conservation brochures for the general use of its members. Most recently, AMP-Ohio established an online home energy audit tool that member customers can access through its website.

AMP-Ohio's Future Programs

The AMP-Ohio Board of Trustees approved a contract with Vermont Energy Investment Corporation (VEIC) in November 2007 to develop a set of state-of-the-art energy efficiency programs for AMP-Ohio member communities. The first phase of this initiative will involve the design of a menu of efficiency programs which will include programs suitable for industrial, commercial and residential customers. At the end of this phase of partnership with VEIC, AMP-Ohio will be able to determine which programs make sense to pursue, the potential megawatt and

megawatt-hour savings, and the program costs and benefits. AMP-Ohio members will have before them a set of basic program designs and an implementation strategy that will allow the organization to issue request-for proposals to contractors. This phase is projected to be complete in February 2008.

Programs at Investor-Owned Utilities in Ohio

Relatively little precedent exists for implementing electricity DSM programs in the state of Ohio. Duke Energy, operating as Cincinnati Gas and Electric, obtained approval from the Public Utilities Commission of Ohio (PUCO) in July 2007 to carry out a regulated DSM program. The program will target residential and small commercial and industrial customers, offering a range of services to the utility's 680,000 electric customers. First Energy is currently in the process of implementing a far more scaled back DSM program to its electric customers. The three year, $28 million program consists of two components: 1) home performance testing and retrofitting; and 2) direct load control of air conditioning in home residences through installation of two-way meters. Both the Duke Energy and First Energy DSM programs are funded through PUCO-approved DSM riders on the customer bill. The state's other two major investor owned utilities, American Electric Power and Dayton Power and Light, have not established DSM for electric customers beyond offering home weatherization assistance to low income customers.[80]

State of Ohio Programs

The State of Ohio administers the Advanced Energy Program, a potential, though quite limited source of grant funding for energy efficiency projects as well as renewable energy or distributed energy resources. The Advanced Energy Fund, which is the funding source of the Advanced Energy Program, is administered by the Ohio Department of Development's Office of Energy Efficiency (OEE) and replenished through a uniform fee on the electric bills of customers of the state's four investor-owned utilities. Electric cooperatives and municipal utilities may voluntarily participate in the Advanced Energy Fund. However, since no electric cooperatives or municipal utilities are currently participating, customers of these utilities are not eligible for Fund incentives. A municipality would be eligible to obtain benefits of the Advanced Energy Program by collecting a quarterly surcharge of $0.09 per customer.[81]

Ohio Governor Ted Strickland signed the "Energy Security and Climate Stewardship Platform" (the "Platform") at a meeting of the Midwest Governors Association held on November 16, 2007. The Platform serves as a regional strategy to achieve energy security and reduce greenhouse gas emissions. The Platform created a goal of meeting "at least 2 percent of regional annual retail sales of natural gas and electricity through energy efficiency improvements by 2015, and continue to achieve an additional 2 percent in efficiency improvements every year thereafter." [82] The agreement may lead the way to future policy or regulatory changes that enable implementation of cost-effective energy efficiency investments in Ohio and throughout the region.

---

[80] Communication on January 7, 2008 with Wilson Gonzalez, Senior Regulatory Analyst, Ohio Office of Consumer Counsel

[81] Communication on January 4, 2008 with Judy Pacifico, Operations Manager, Department of Development Office of Energy Efficiency.

[82] Energy Security and Climate Stewardship Platform for the Midwest 2007, presented at Midwestern Governors Association meeting on November 16, 2007

The Potential for Energy Efficiency and Demand Response Programs in Oberlin

CEA attempts to estimate the energy savings and demand savings that an aggressively implemented DSM program could achieve in the City of Oberlin. We assume that all energy conservation measures implemented are considered technically feasible from an engineering perspective and are considered cost-effective compared to supply-side alternatives.

CEA's estimate of achievable energy savings in Oberlin is based primarily on data from the American Council for an Energy-Efficient Economy (ACEEE) that provides a forecast for energy savings potential in Ohio.[83] Table 17 shows CEA's estimate of potential energy savings from DSM initiatives. The City can expect to achieve 7.4% consumption savings from its energy efficiency and demand response programs by 2020.[84] This is equivalent to approximately 15% of the City's share of the MWh output of AMPGS.

[83] Elliot, R.N., et al. 2003. Natural Gas Price Effects of Energy Efficiency and Renewable Energy Practices and Policies, ACEEE. This study estimated the implementable savings from the residential and commercial sectors by using a "bottoms-up" approach. The analysis began with data on energy use in each of the 48 states by end-use (e.g., lighting, cooling, heating, etc.). A variety of published studies were then used to estimate average annual electric and gas savings over five years from energy efficiency programs, including adjustments for reasonable savings by end-use. The study looked at current policy initiatives to promote efficiency in each of the 48 states, and adjusted savings downward in states without strong efficiency policies. Subsequent ACEEE reports have cited the energy savings estimated in this study.

[84] CEA notes that the City of Oberlin can achieve a small amount of energy savings from demand response programs. Given that such programs typically only curtail load for 50 hours per year, the reduction in energy consumption is negligible in comparison to energy efficiency programs.

Table 17 Estimate of Potentially Achievable Energy Savings in Oberlin

	Oberlin Load Profile[2]	2010	2015	2020
Beck Demand Forecast (MWh)[1]				
Total	100%	129,616	142,016	155,340
Achievable electric savings from energy efficiency programs by sector[3]				
Residential	20%	2.0%	3.5%	5.0%
Commercial	55%	2.3%	5.2%	8.1%
Industrial	25%	1.7%	4.7%	8.0%
Weighted overall energy savings	100%	2.1%	4.7%	7.4%
Achievable electric savings from energy efficiency programs (MWh)[4]				
Residential	20%	518	982	1,548
Commercial	55%	1,630	4,018	6,887
Industrial	25%	558	1,691	3,127
Total	100%	2,707	6,691	11,562

Sources:

[1] Power Supply Plan for City of Oberlin.

[2] OMPLS provided breakdown of load by customer segment.

[3] Kushler, Martin, et al. 2005. Examining the potential for energy efficiency to help address the natural gas crisis in the Midwest. ACEEE. Data presented in this report are derived from Elliott, R.N., et al. 2003.

[4] To calculate achievable electric savings from energy efficiency programs, CEA multiplies the base case consumption by load profile share by energy efficiency potential.

Energy efficiency measures, which vary widely by cost and function, produce a similarly wide range of peak demand reduction effects. Data from ACEEE quantifies the relationship between energy savings and peak demand savings across a range of energy efficiency measures. CEA has applied the findings in this study to estimate the potentially achievable electric demand savings in Oberlin, as shown in Table 17. CEA makes the conservative assumption that 75% of energy savings achieved in the city of Oberlin are due to CFL replacement bulbs and that energy efficient HVAC installations account for the remaining 25% of energy savings.[85]

Demand response measures are implemented with the specific intention of reducing demand during peak usage events. Large end-use customers are the most likely to participate in these programs, as these customers can have the greatest effect on reducing peak demand. Therefore, CEA assumes that only Large Commercial customers in Oberlin would participate in demand response programs.

The potentially achievable level of peak load reduction is highly customer specific. Some customers may be able to switch to backup generation during peak usage events, while other customers will

[85] York, Dan et al. 2007. Examining the peak demand impacts of energy efficiency: a review of program experience and industry practices. ACEEE, p. 31. CFL bulbs demonstrate the lowest median ratio of peak demand savings per energy savings of all energy efficiency measures examined in this study. Energy efficient HVAC installations demonstrate a ratio that is in the middle of the range of energy efficiency measures.

only be able to curtail a portion of load. Load curtailment typically occurs during peak usage events when the electricity price rises above $200/MWh. CEA finds that demand response programs in Oberlin will curtail load for an average of 50 hours per year.[86]

Table 18 shows the potentially achievable peak demand savings from DSM programs in Oberlin. The City can expect to achieve peak demand reduction of 3.7 MW by 2020.

[86] In 2007, the hourly price at the First Energy Hub in Ohio was above $200/MWh in 32 hours and above $150/MWh in 108 hours.

* Table 18 Estimate of Potentially Achievable Demand Savings

	2010	2015	2020	
Beck Peak Summer Demand Forecast (MW)[1]				
Total	25.9	28.3	31.0	A
Achievable energy savings from energy efficiency programs (MWh)[2]				
Total	2,707	6,691	11,562	B
Achievable demand savings from energy efficiency programs				
Peak Demand Savings per Energy Savings from CFLs (MW/MWh)[3]	0.0001	0.0001	0.0001	C
Peak reduction potential for CFLs in Oberlin (MW)	0.3	0.7	1.2	B*C = D
Peak Demand Savings per Energy Savings from installation of efficient HVAC units (MW/MWh)[3]	0.00074	0.00074	0.00074	E
Peak reduction for installation of efficient HVAC units (MW)	2.0	5.0	8.6	B*E = F
Realization rate[4]	86%	86%	86%	G
Weighted average peak demand reduction from energy efficiency measures (MW)[5]	0.6	1.5	2.6	(75%*D+ 25%*F)*G = H
Achievable demand savings from demand response programs				
Summer peak load of large commercial customers in Oberlin (MW)[6]	16.5	18.1	19.8	I
Achievable potential for peak shaving[7]	0.5%	3.0%	5.5%	J
Achievable peak demand reduction (MW)	0.1	0.5	1.1	I*J = K
Total achievable peak demand reduction (MW)[8]	0.7	2.0	3.7	H + K = L
Achievable peak demand reduction as a percentage of peak demand forecast	3%	7%	12%	L / A = M

Sources:

[1] Power Supply Plan for City of Oberlin.

[2] Potential energy savings estimate as calculated in Table DSM-4.

[3] York, Dan et al. 2007. Examining the peak demand impacts of energy efficiency: a review of program experience and industry practices. ACEEE, p. 31.

[4] York, Dan et al. 2007. p. 65. The realization rate reflects the net demand reduction actually achieved.

[5] Weighted average peak demand reduction assumes that CFLs account for 75% of total energy savings and HVAC installations account for the remaining 25% of energy savings.

[6] OMPLS. CEA estimated future summer peak demand for large commercial customers by applying the overall peak demand growth rate for the city.

[7] Midwest Energy Efficiency Alliance. CEA assumes that a demand response program could achieve incremental demand savings of 0.5% per year as new large commercial customers are added.

The Cost of Potential Energy Efficiency and Demand Response Programs in Oberlin

The expected cost to the City to implement a DSM program is $33.52/MWh in the Base Achievable Case. To accurately compare the costs of an energy efficiency program to the cost of a power plant, one must represent cost in levelized terms. The levelized cost of an energy efficiency program is calculated by dividing the fixed cost to implement the measure over its useful life by the forecasted energy savings from the measure over its useful life.[87] Levelized cost for a typical, economically feasible portfolio of energy efficiency programs is in the range of $30 to $50/MWh for electricity. The U.S. EPA assumes a levelized cost of $35/MWh, which is comprised of $20/MWh in administrator costs and $15/MWh in participant costs.[88] ACEEE estimates the cost of implementing an economically achievable energy efficiency program in the Midwest. ACEEE estimates costs by customer segment and distinguishes between the technology and administrative portions of program cost.[89] As shown in Table 19, CEA applied the ACEEE cost estimates to the load profile of Oberlin in order to estimate the cost of energy savings in Oberlin.

[87] CEA assumes costs are the same in each year. If costs are weighted toward the earlier years of the program, the levelized cost could be higher.
[88] U.S. EPA. 2007. National Action Plan for Energy Efficiency: Vision for 2025.
[89] Kushler, Martin et al. 2005. Examining the potential for energy efficiency to help address the natural gas crisis in the Midwest, ACEEE, Table 22.

Table 19 Cost to Achieve Energy Savings for Base Achievable Case

Cost to achieve electric savings from energy efficiency programs[1]					
Customer segment	Oberlin Load Profile	Technology Cost ($/MWh)	Administrative Adder	Cost of Saved Energy ($/MWh)	
Residential	20%	$ 33.00	25%	$ 41.25	A
Commercial	55%	$ 19.00	20%	$ 22.80	
Industrial	25%	$ 16.00	15%	$ 18.40	
Weighted overall cost				$ 25.38	
	Oberlin Load Profile	**2010**	**2015**	**2020**	
Achievable electric savings from energy efficiency programs (MWh)[2]					
Residential	20%	518	982	1,548	B
Commercial	55%	1,630	4,018	6,887	
Industrial	25%	558	1,691	3,127	
Total	100%	2,707	6,691	11,562	
Incremental electric savings (MWh)					
Residential	20%	518	89	114	C
Commercial	55%	1,630	434	545	
Industrial	25%	558	208	268	
Total	100%	2,707	731	926	
Lifetime electric savings of new efficiency measures (MWh)[3]					
Residential	20%	6,222	1,067	1,366	C * 12 = D
Commercial	55%	19,564	5,204	6,536	
Industrial	25%	6,693	2,498	3,216	
Total	100%	32,478	8,769	11,117	
Total Cost (2008 $)					
Residential	20%	$ 256,640	$ 44,017	$ 56,327	A * D = E
Commercial	55%	$ 446,049	$ 118,653	$ 149,018	
Industrial	25%	$ 123,157	$ 45,961	$ 59,174	
Total	100%	$ 825,846	$ 208,631	$ 264,519	

Sources:

[1] Kushler, Martin, et al. 2005. Examining the potential for energy efficiency to help address the natural gas crisis in the Midwest. ACEEE, p. 33. Levelized cost estimate is based on a survey of earlier studies.

[2] Refer to Table DSM-3

[3] Kushler, Martin, et.al. 2005. p. 34. Study assumes that energy efficiency measures have a useful life of 12 years and a discount rate of 5 percent applies.

The cost associated with implementing a load management program are represented on a demand basis ($/MW) rather than on consumption basis ($/MWh). Typically, a utility or energy service provider will enter into a contract with an end use customer that will pay the customer an incentive amount for agreeing to curtail load during peak periods. The fixed cost of installing an advanced meter is generally minor in comparison to making incentive payments to the customer for avoided energy use. CEA implemented a benchmark study in 2007 to determine the typical levelized cost borne by the utility for entering into a load management contract with an end use customer, and found that levelized cost of implementing a typical demand response program is approximately $50/kW per year.[90] As shown in Table 20, CEA applies this average cost to our peak demand savings potential estimate for demand response programs.

[90] CEA previously developed a benchmark study to determine the average levelized costs of demand response programs.

Table 20 Cost to Achieve Summer Peak Demand Savings

	2010	2015	2020	
Levelized cost of demand reduction from demand response programs ($/kW-year) 1	$ 50	$ 50	$ 50	A
Achievable peak demand reduction from demand response (MW-yr)[2]	0.1	0.5	1.1	B
Total cost of demand response programs (2008 $)	$ 4,135	$ 27,123	$ 54,365	A*B = C

Sources:

[1] CEA approximates the the levelized cost to implement a demand response program from a benchmark study which the firm conducted 2007.

[2] Refer to Table DSM-4

High Achievable Case Estimate

Concentric bases its High Case scenario on the achievements of DSM programs implemented in California and Vermont. These states are considered national leaders in achieving energy savings and demand savings.

Electricity consumption per capita in California has remained nearly unchanged since the mid-1970s. Utility efficiency programs account for approximately half of the energy savings achieved over this period, with the other half of savings produced by enacting more stringent building standards and appliance standards. Utility energy efficiency programs accounted for approximately 8.0% of total electricity consumption in California in 2003.[91] By comparison, the Base Case in this analysis estimates that energy savings in Oberlin could account for 8.0% of total electricity consumption by 2020. In 2004, the California Public Utility Commission set a new target that annual electricity savings reach 1% of total annual load by 2007.[92]

Two DSM programs operating in Vermont have achieved similar results to those in California. The energy efficiency program operated by Burlington Electric Department (BED), the municipal utility for the city of Burlington, has successfully maintained load at 1989 levels. Since electricity consumption had been projected to grow at a rate of 1% per year over the period between 1989 and 2006, BED therefore achieved energy savings at 1% of total projected annual load.[93] A main reason for BED's success is the utility's involvement in the planning and zoning process.[94] Efficiency Vermont, a statewide DSM initiative that began in 2000, has successfully reduced by two-thirds the

[91] Arthur Rosenfeld, California Energy Commission Commissioner
[92] Source: http://www.nrdc.org/air/energy/fcagoals.asp
[93] BED 2006 Energy Efficiency Annual Report
[94] Communication with Chris Burns, BED Director of Energy Services on February 4, 2008.

state's projected annual load growth of 1.4%.[95] Taken together, the two programs in Vermont achieve annual electricity savings of 1% of projected annual load.

The High Case for Oberlin estimates that the city could achieve annual electricity savings of 1% of projected annual load. This would offset more than half of projected annual load growth of 1.8%. The High Case also considers that Oberlin College will establish a more ambitious program with the goal of entirely offsetting the institution's projected load growth.

Concentric assumes that costs of implementing the high achievable case in Oberlin will be on par with those of implementing the Efficiency Vermont program, or approximately $40/MWh.[96] The levelized costs of implementing the High Case are not drastically higher than those of implementing the Base Case. Meeting more aggressive program goals would likely require a broader marketing campaign aimed at OMLPS customers. Additionally, the city may need to make available more options for financing energy efficiency measures. The city may also need to change zoning rules and building codes to mandate energy efficient construction. These steps may increase the administrative costs of implementing a DSM program, but it is difficult to quantify this in levelized cost terms. The even more aggressive DSM program assumed to be pursued by Oberlin College would likely cost more on a levelized basis than the city-wide DSM program. However, a large portion of these costs will be born in the construction of new residential buildings, which will achieve substantial energy savings over the buildings replaced. Concentric does not attempt to separately quantify the costs born by Oberlin College in the High Case scenario.

Important Considerations with Respect to CEA's DSM/Conservation Forecasts

The potential to successfully implement a DSM program is a function of many location-specific factors including:

- Regulatory structure;
- Power market characteristics;
- Age of existing residential and commercial infrastructure;
- Socioeconomic characteristics of the population; and
- Climate conditions.

Given that utility DSM programs tend to be customized, it is therefore difficult to find similar past programs that can be used as benchmarks for assessing the future performance in another locale. We further caveat that there is uncertainty regarding the future cost of DSM measures, just as uncertainty exists around the future cost of various forms of electricity generation. CEA bases its forecast for the potential and cost of a DSM program on a selection of national and regional studies which we feel adequately account these uncertainties.

It is important to note that a DSM program is subject to the law of diminishing marginal returns. Customers that are ready and willing to participate in the program are the least expensive to reach and so are likely to comprise the first wave of program participants. In order to induce additional

[95] Efficiency Vermont 2006 Results Summary. Concentric notes that Vermont Energy Investment Corporation, the organization hired by AMP-Ohio to design a DSM program for its members, provides services to the Efficiency Vermont program.
[96] Efficiency Vermont 2006 Results Summary.

customers to participate, the utility may have to undertake an advertising campaign, increase the level of incentive, or build new expertise. However, in many cases utilities actually reduce their payments over time as technology costs fall. For example, the costs of compact fluorescent light bulbs have fallen over time and major retailers such as Home Depot now stock these items. Utilities therefore utilities no longer offer much in the way of rebates for CFLs compared to very high subsidies in the past.

APPENDIX C – MODELING ASSUMPTIONS

Development and Construction Costs

CEA's development and construction cost assumptions are provided in Appendix "XX" on a $2006 basis, excluding AFUDC. CEA generally based its assumptions on data from one of the two DOE reports where such information was available. In instances in which a significant disparity existed between the figures in the two reports, and non-DOE figures seemed plausible, CEA made its assumption by taking an approximate average of the data. CEA used other sources of information to supplement the existing data for certain assumptions. For example, CEA communicated with EDI, the owner/operator a landfill gas generating facility to obtain cost and performance information for landfill gas stations.

Adjustment for Cost Differences Due to Geography

CEA has also adjusted certain assumptions to reflect the unique conditions of constructing a generating facility in Ohio. First, the nameplate capacity of certain technologies as reported by DOE appeared to be a mismatch with the State's energy needs and resource constraints. For example, the 2007 Annual Energy Outlook assumes that a typical natural gas combined cycle plant would have a 3-on-2 unit configuration. Because this size seemed excessively large for Oberlin's purposes, CEA downwardly adjusted the capacity assumption to match that of a 2-on-1 unit configuration. Also, costs reported in the DOE reports represent a national average, and as such must be adjusted to reflect the cost of construction in the Ohio. In order to adjust for these differences, CEA multiplied national costs by a factor of 3.5%[97] to obtain North Central costs. Finally, there is potential for still higher costs due to the fact that Oberlin will compete with larger developers who may receive cost advantages due to scale. Because of the situation-specific nature of this potential difference, CEA has not made a specific adjustment in the Base Case, but instead we have created a sensitivity analysis that tests the effect of likely variability in construction costs on the all-in levelized power cost.

Adjustment for Cost Increases Due to the Passage of Time

Construction costs for power plants have been increasing rapidly over the past three years, primarily as a result of tight markets for labor and steel, coupled with high demand for power plant components. CEA expects these costs to continue to increase rapidly through 2013 the assumed on-line date for most of the technologies covered in this report. CEA's source data for these costs is derived from the Handy Whitman index and also from recently performed studies. From these data, CEA escalated these costs in each year through each plant's completion date at a 7.0% annual estimated inflation rate. This rate reflects an estimate of inflation for power plant construction in the Northeast. We expect this trend to continue as steel and other commodity prices increase along with the demand for new generation.

[97] Based on Handy-Whitman Index.

CEA's analysis assumes a desired on-line year of 2013. Some of the technologies would not be able to achieve this deadline. Therefore, for modeling purposes, we assume that for technologies which cannot be on line in 2012, the project will have to purchase power in the MISO market in order to fill the gap between 2013 and the plant's on line time.

We assumed that 100% of the capital cost is spent evenly over the construction period. We also assumed that two percent of the total construction cost is spent each year of the pre-construction period on permitting and siting (items not included in our overnight capital cost estimate). To arrive at the nominal expenditure each year, we inflated the 2006 capital cost estimate by 7.0%/year (consistent with recent Handy Whitman Index increases).

Below is an example of how CEA translates an overnight 2006 capital cost number into a stream of capital expenditures and eventually a year-one rate-base figure. In this example, the CTCC technology has a $2006 overnight capital cost estimate of $709/kW. However, by the on-line date, the cumulative project cost is $1,080. Construction cost inflation, preconstruction permitting and siting costs and AFUDC have increased the $2006 overnight cost by 52.3%.

Sample Translation of Overnight Capital Costs to Nominal Capital Costs

	2006	2007	2008	2009	2010	2011	2012	TOTALS
Pre-construction Siting and Permitting Costs	[1]			[2]	[3]	[4]	[5]	[6]
Construction Costs	$382,680,375			9,375,998	10,032,318	268,364,511	287,150,027	574,922,854
AFUDC [7]							8,284,413	8,284,413
Total ($)	$382,680,375							583,207,267
Total ($/kW)	$709							$1,080

[1] 2006 overnight cost of $709/kW ($382.7 mm)
[2] 2% of 2006 capital cost escalated at 7%
[3] 2% of 2006 capital cost escalated at 7%
[4] 50% of 2006 capital cost escalated at 7%
[5] 50% of 2006 capital cost escalated at 7%
[6] sum of 2009 thorugh 2012 figures
[7] AFUDC earned on all capital costs (AFUDC rate = 10%)

Fuels

CEA developed fuel price forecasts from several sources. This analysis relies primarily on fuel forecast data from DOE/EIA's 2007 Annual Energy Outlook. Fuel assumptions were also drawn from data received from owners of generation facilities, and CEA's internal expertise. Adjustments to the price projections are made for several factors, as noted in the individual fuels sections below. Please see Appendix D for a chart of CEA's fuel price forecast.

Natural Gas and Coal

CEA used the fuel price forecast from the 2007 AESC study, which is based on EIA fuel price projections for the electric power industry. The projections apply only to electric generating facilities and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.

Landfill Gas

Based on conversations with the operator of the EDI Landfill Facility, we have assumed that landfill gas will cost 35% of the price of natural gas. Our forecast for landfill gas, is therefore 35% of the price of natural gas in any given year.

Nuclear

CEA's nuclear fuel price forecast is based on CEA research, benchmarked against various proprietary forecasts available to CEA.

Biomass

Biomass wood costs are based on a CEA poll of several biomass owners.

Biogas

Fuel cost is assumed to be zero. Participant farmers are "paid" through use of residual heat output and their ability to use the solid waste end-product as cattle bedding.

Wholesale Price Forecast

The wholesale market price forecast is used to model the interim costs of purchasing wholesale power between 2013 and the operational start date of potential new generation facilities. It is also used to compare market power purchases as an alternative to the other technologies presented in this report. This analysis draws the Cinergy Hub Price forecasts from the AMPGS Feasibility study performed by R.W. Beck.

Fuel Price Forecasts (Nominal $/MMBtu)