Oberlin Municipal Light and Power System

Power Supply Study

B&V Project No. 165649

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Table of Contents

Table of Contents (Continued)

Figures

Table of Contents (Continued)

Figures (Continued)

Table of Contents (Continued)

Figures (Continued)

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Acronym List

AEO2009	Annual Energy Outlook, 2009
AMP	American Municipal Power, Inc.
BACT	Best Available Control Technology
CPWC	Cumulative Present Worth Cost
CREBs	Clean Renewable Energy Bonds
CTs	Combustion Turbines
DI	Diffuse Insolation
DNI	Direct Normal Insolation
DOE	Department of Energy
DSM	Demand-Side Management
EDI	Energy Developments, Inc.
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
FCR	Fixed Charge Rate
FTR	Financial Transmission Rights
Gorsuch	Gorsuch Power Station
ICE	Intercontinental Exchange
IGCC	Integrated Gasification Combined Cycle
ITC	Investment Tax Credit
JV 1	Omega JV 1
JV 2	Omega JV 2
JV 5	Omega JV 5
LD	Liquidated Damages
LFG	Landfill Gas
LMP	Locational Marginal Prices
LNG	Liquefied Natural Gas
MACRS	Modified Accelerated Cost Recovery System
MISO	Midwest Independent Transmission System Operator
MRO	Midwest Reliability Organization
MW	Megawatts

MWh	Megawatt-Hour
NEASG	Northeast Area Service Group
NEL	Net Energy for Load
NYPA	New York Power Authority
O&M	Operations and Maintenance
OMLPS	Oberlin Municipal Light and Power System
PM	Particulate Matter
PPA	Power Purchase Agreement
PTC	Production Tax Credit
PV	Photovoltaic
REAP	Rural Energy for America Program
REPI	Renewable Energy Production Incentive
RFC	Reliabilityfirst Corporation
RFP	Request for Proposal
RTO	Regional Transmission Organization
SEGS	Solar Electric Generating Station
SERC	Southeastern Electric Reliability Council
SES	Stirling Energy Systems
SNL	Sandia National Laboratories
USDA	US Department of Agriculture
VEIC	Vermont Energy Investment Corporation
WTE	Waste-to-Energy

1.0 Executive Summary

1.1 Study Purpose

Black & Veatch was retained by the City of Oberlin to analyze, evaluate, and recommend power supply alternatives to serve the City's future power supply requirements. Oberlin Municipal Light and Power System (OMLPS) generates, purchases, transmits, and distributes electric power to over 3,000 residential and commercial customers. OMLPS owns some peaking generation, purchases wholesale power as a member of American Municipal Power, Inc. (AMP), and utilizes other resources to meet its needs. OMLPS's major baseload resource is currently the Richard H. Gorsuch Station, which is scheduled to retire at the end of 2012. As a result, a significant baseload resource shortfall is expected to begin in 2013.

The purpose of this study is to find the best long-term resource plan for OMLPS that considers cost, reliability, and lower emissions technologies. The need for future resources is determined based on the availability of existing resources and the expected growth in future demand. Several renewable energy alternatives were evaluated for the power supply study including wind, solar photovoltaic (PV), biomass, biogas, and hydroelectric. Various factors were considered in the analysis including resource availability, cost and performance characteristics, and environmental impacts. For fossil generation alternatives, including market purchases, fuel price volatility and emissions profiles were considered in addition to cost. Potential legislation related to reduction of greenhouse gases such as CO_2 were considered by evaluating fossil fuels and market purchases with a "carbon tax." These and other factors were considered to develop a plan with appropriate balance of cost, long-term reliability, and sustainability with minimal environmental impact.

1.2 Overview of the Oberlin System

OMLPS is a full requirements wholesale power member of AMP. OMLPS's power supply portfolio consists of pool power and non-pool power. Non-pool power resources are contracted on an individual basis. Pool power resources are shared amongst 21 northeast Ohio municipal electric systems. Figure 1-1 summarizes the OMLPS capacity situation of non-pool, pool, and other resources in 2009 and forecast for 2013. As shown, OMLPS's available resources will decline significantly with the retirement of Gorsuch and expiration of various existing contracts by 2013.

Figure 1-1
Summary of OMLPS Capacity Resources

Capacity Resource	2009	2013
Gorsuch (Coal Unit)	6.695	--
NYPA Purchase (Hydro)	0.450	0.450
JV 5 (Hydro Unit)	1.270	1.270
Landfill Gas Plant	0.645	0.645
JV 6 (Wind Farm)	0.025	0.025
Oberlin Power Plant (Gas Units)	18.000	18.000
Capacity Sales to AMP	(18.000)	(18.000)
OMLPS Pool Resources	8.463	2.500
Capacity from Interruptible Load	3.90	--
Short-Term Capacity Purchases	2.50	--
Committed Capacity Additions	--	1.650
Total Available Resources	23.95	6.54

1.2.1 Non-Pool Power Resources

Non-pool resources include the Richard H. Gorsuch Power Station (Gorsuch), New York Power Authority (NYPA) purchase, JV 5, landfill gas purchase, and JV 6. Gorsuch is a 213 megawatts (MW) coal fired power plant that is owned and operated by AMP and located in Marietta, Ohio on the Ohio River. The plant has four generating units each rated at 53.3 MW. Oberlin's 6.695 MW share of Gorsuch is the largest portion of its non-pool resources other than the Oberlin power plant, which is resold to AMP.

The OMEGA JV 5 Belleville Hydro Project consists of the Belleville Hydroelectric Plant and associated transmission facilities, backup generation facilities, and power purchased on behalf of OMEGA JV 5 participants. The JV 5 project also includes 39 MW of natural gas and diesel-fired backup generation located in AMP member communities. The NYPA Hydro Plant provides the city capacity and energy from the Niagara and St. Lawrence Projects. Energy Developments, Inc. (EDI) provides landfill gas generation from three Ohio methane gas generation sites located at the Lorain County Landfill, the Ottawa County Landfill, and Carbon Limestone Landfill in Mahoning County. The OMEGA JV 6 project consists of four 1.8 MW wind turbine generators located at the Wood County Landfill site near Bowling Green, Ohio. For the purpose of this study, wind generation is assumed to have a reliable capacity value of

20 percent of nameplate. Available non-pool resources are forecast to decrease from approximately 9.1 MW to 2.4 MW from 2009 to 2013.

1.2.2 Pool Power Resources

In 1990, the City entered into a "Pool Participant" agreement with AMP to participate in a power pool with 20 other subdivisions of the State of Ohio located in the northeast portion of the state. These municipalities form the Northeast Area Service Group (NEASG). Pool power resources include the following: JV 1, JV 2, AMP combustion turbines (CTs), J Aron purchase, Barclays 7x24 short-term power purchase agreement (PPA), Lehman Brothers 7x24 short-term PPA, Morgan Stanley short-term 5x16 PPA, JV 5 second call, municipal peaking, and Oberlin's peaking power. Pool resources are forecast to decline from 8.463 MW in 2009 to 2.5 MW in 2013 as many of these purchase contracts expire.

1.3 Study Approach

The Oberlin Power Supply Study approach consisted of several key stages including: data collection, data analysis, data modeling, analysis of the findings, and documentation of the study in this report. Data was collected from OMLPS, AMP, and a variety of publicly available sources. Separately, Oberlin issued a request for power supply for baseload renewable resources during the course of this study. Several of the renewable baseload responses received in the request for power supply process were evaluated in this power supply study process. Throughout this process, data for generic supply-side alternatives were compiled, reviewed, screened for appropriateness, and modeled using typical power supply study methods and tools, taking into account special considerations and sensitivities to derive the least-cost expansion plan for Oberlin, while trying to reduce emissions as well.

1.3.1 Data Collection

The data collection stage included the compilation and review of both historical and forecast data. This data included: historical peak demand and energy, forecast peak demand and energy, previous power supply studies, hourly energy profile, demand side management forecasts, details of current PPAs, historical operating costs and performance characteristics for owned and pool resources, historical energy sources and emissions, power supply alternatives available to OMLPS, and other data and assumptions. This data was requested, reviewed, and used as input assumptions for the power supply study.

1.3.2 Data Analysis and Modeling

After collection, the data was analyzed and used as a basis for developing an optimization expansion planning model in Strategist™ to evaluate a variety of alternative expansion scenarios. Strategist™ is an optimization expansion planning tool that enables determination of the least cost plan as well as competing plans with a given set of system parameters and available resources. In developing expansion plans, the model considers the load forecast, existing resources, emissions constraints and allowance prices, fuel prices, cost and performance characteristics of new alternatives, and other factors to estimate the total system cost. Several available generation alternatives were screened and then various expansion plans were created and evaluated. Generating alternatives that were evaluated included landfill gas, solar, wind, biomass, hydro, natural gas combined cycle and combustion turbine, and market purchases. As a result, a variety of technologies, including low and zero emission type resources, were evaluated. The costs of these expansion plans were evaluated and compared.

1.4 Findings and Conclusions

Based on its analyses and evaluations, Black & Veatch has developed several findings and recommendations for OMLPS's consideration. These are summarized below:

- OMLPS has a significant baseload resource need by 2013 as a result of the planned Gorsuch station retirement and expiration of existing PPAs.
- Resources remaining available to OMLPS in 2013 will be heavily weighted towards peaking or intermittent type resources. As a result, OMLPS will need to acquire intermediate and baseload resources to achieve a more balanced resource mix.
- Several peaking, intermittent, intermediate, and baseload resource alternatives appear to be available to OMLPS to meet its resource needs including: firm liquidated damages (LD) energy contracts, market purchases, natural gas fired combined cycle and simple cycle, landfill gas, hydroelectric, biomass, solar PV, and wind.
- With the execution of the Vermont Energy Investment Corporation (VEIC) contract for energy efficiency and demand-side management (DSM) savings, OMLPS has a good foundation for implementing energy efficiency savings over the next few years. It is recommended that VEIC's performance and achieved savings under this program be monitored and future energy and demand forecasts be adjusted as needed to account for changes in energy and demand savings.

- The load forecast from the previous power supply study appears to be too high. The cooler recent summers and reduced energy consumption from the economic slowdown were not anticipated when the previous forecast was developed. As a result, the load forecast was adjusted downward to account for these factors.
- As a result of the low growth rates assumed in the study and projected savings from energy efficiency, it is recommended that OMLPS monitor actual results in the near term in order to adjust its resource plans if growth increases higher than forecast.
- It appears that 8 to 10 MW of baseload capacity is needed and 4 to 5 MW of intermediate capacity is needed in the near term.
- Viable resources for new baseload capacity and energy include landfill gas, biomass, hydroelectric purchases, firm LD 7x24 energy PPA with backup peaking capacity, and natural gas combined cycle. Of these resources, hydroelectric and landfill gas appear to be the most economical, particularly some of the responses received to the request for proposal process.
- Viable intermediate resources include natural gas combined cycle, firm LD 5x16 energy PPA with backup peaking capacity, and hydroelectric. The additional hydroelectric purchase of 0.79 MW offered to OMLPS appears to be economically attractive and it is recommended that OMLPS continue to pursue this purchase. Since the hydroelectric capacity offered to OMLPS appears to be economically attractive, OMLPS can acquire more of this resource if it becomes available.

2.0 Forecasts and Economic Parameters

This section summarizes the forecasts and economic parameters utilized throughout the Power Supply Study. The forecast annual peak demand and energy requirements were developed from historical data provided by OMLPS and other forecasts previously prepared for Oberlin. Fuel price forecasts for oil and gas were derived from the Energy Information Administration (EIA) and published in the Annual Energy Outlook, 2009 (AEO2009). Black & Veatch utilized an emission allowance price forecast for CO_2 from the EIA, which was used for sensitivity analysis to show the potential impacts from CO_2 legislation. The economic parameters for this study, and further details related to these forecasts and economic parameters are discussed in this section.

2.1 Load Forecast

The load forecast is an important consideration in the overall Power Supply Study process as it allows for determination of capacity requirements through comparison with capacity resources and reserve margin requirements. OMLPS has provided a forecast of annual peak demand and energy requirements for 2009 through 2029 under base case assumptions. The forecast and methodology used in developing these forecasts are presented in the 2007 “Power Supply Plan for City of Oberlin,” a copy of which was provided by OMLPS to Black & Veatch. In general, recent growth trends have been much lower than originally forecast in this study. As a result, Black & Veatch reviewed the forecast and updated it based on recent historical trends and forecast growth projected by the EIA.

2.1.1 Historical Peak Demand and Net Energy for Load

OMLPS has historically experienced annual peaks in the summer period. Figure 2-1 indicates the historical system peak from 2000 through 2009. The summer peak demand remained generally constant during the period of 2001 to 2007. The peak demands in 2001 and 2007 were 22.4 MW and 22.3 MW, respectively, which is a negative average annual growth rate of approximately 0.1 percent. However, due to the economic slowdown in the United States, OMLPS experienced lower demand in 2008 and 2009, which is a similar trend experienced by other utilities in many other states. In its “Electric Power Industry 2008: Year in Review” report, EIA noted that nationally net electric power generation decreased 0.9 percent, peak demand decreased 3.8 percent, and the average annual temperature for the contiguous states was the coolest in more than 10 years.

Figure 2-1
Historical Peak Demand and NEL

	Peak Demand		NEL	
	Summer (MW)	**Percentage Change**	**Annual (MWh)**	**Percentage Change**
2001	22.4		108,272	
2002	23.7	5.6	115,661	6.4
2003	19.6	-17.3	112,469	-2.8
2004	19.9	1.5	109,801	-2.4
2005	22.3	12.1	117,552	6.6
2006	23.0	2.9	117,139	-0.4
2007	22.3	-2.8	121,745	3.8
2008	21.1	-5.2	117,427	-3.7
2009	20.8	-1.8	114,200	-2.7
Average Annual Growth Rate	-0.98%		0.67%	
Average of Annual Percentage Changes		-0.4		0.6

For Oberlin, the peak demand in 2008 was 21.1 MW, which is a drop of 5.2 percent from the previous year. In 2009, the peak demand dropped to 20.8 MW. The average annual growth rate for the period of 2001 through 2009 is a negative 0.98 percent. Figure 2-2 shows the historical peak demand.

In the 2007 "Power Supply Plan for City of Oberlin" prepared by R.W. Beck, peak load was forecast to increase at 1.8 percent per year from 2008 to 2017 and at 1.9 percent from 2019 onwards. This forecast was developed based on historical demand for 2001 through 2006 and current economic conditions prevalent at the time. The actual annual average growth rate for 2001 through 2006 was 0.45 percent. Figure 2-2 shows the peak demand forecast in this study.

For this power supply study a more moderate growth rate of 1.1 percent for demand was assumed for future years. Figure 2-2 shows the forecast peak demand through 2029.

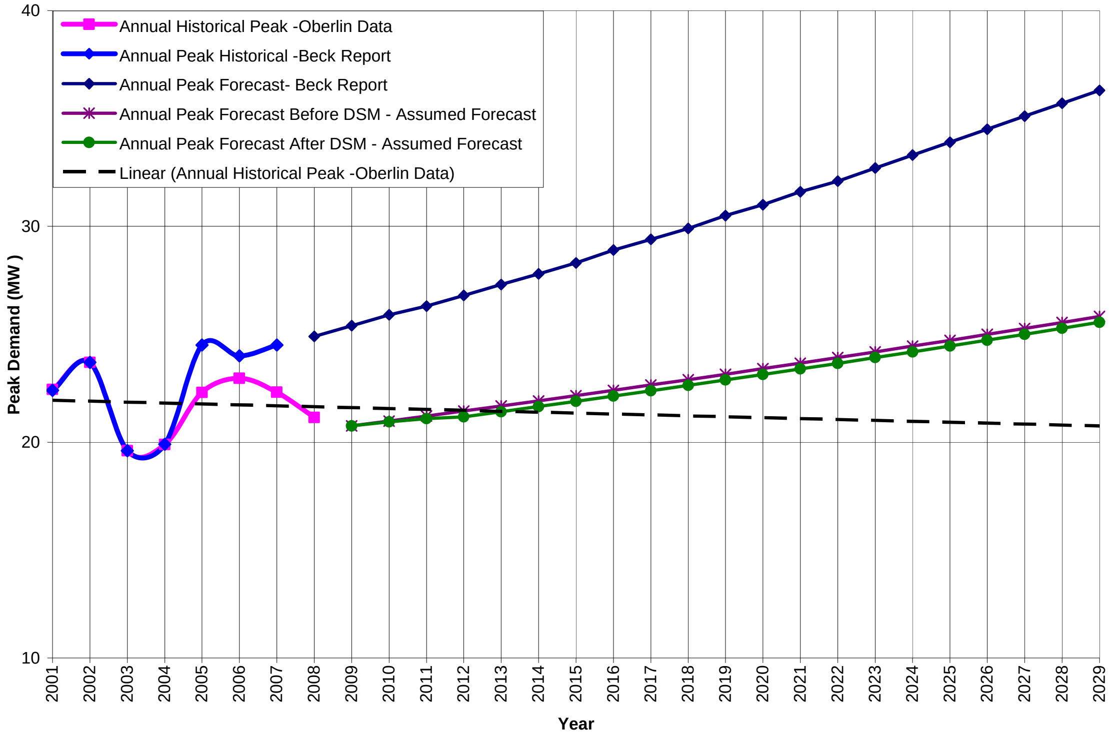


Figure 2-2
Historical and Peak Demand Forecast

OMLPS's historical net energy for load (NEL) requirements are also shown on Figure 2-1. NEL is the net energy required for OMLPS's customers and does not include off-system sales. From 2000 through 2007, total NEL requirements increased from 108,272 megawatt-hour (MWh) to 121,745 MWh at an annual average growth rate of 1.97 percent. However, due to the economic slowdown in the United States, OMLPS experienced lower energy requirements in 2008 and 2009. The drop in NEL year over year for 2008 and 2009 was 3.7 percent and 2.7 percent, respectively. The annual average growth rate for the period 2001 through 2008 was 0.6 percent. Figure 2-3 shows historical NEL as well as forecast NEL through 2029.

In the 2007 "Power Supply Plan for City of Oberlin," NEL was forecast to increase at 1.8 percent per year from 2008 to 2017 and at 1.9 percent from 2019 onwards. This forecast was developed based on historical demand for 2001 through 2006 and current economic conditions prevalent at the time. The annual average growth rate for 2001 through 2006 was 0.45 percent. Figure 2-3 shows the peak demand forecast in this study.

For this power supply study, a more moderate growth rate of 1.1 percent for NEL was assumed for future years. Figure 2-3 shows historical NEL as well as forecast NEL through 2029.

2.1.2 Base Case Peak Demand and NEL Forecasts

The results of OMLPS peak demand forecasts are shown on Figure 2-4. As per the historical peak demand numbers from 2001 through 2008, OMLPS has seen wide variations in peak demand year over year. While some years, like 2005, have seen significant increase in peak demand, other years like 2002 and 2008 have seen significant drop in peak demand. According to AEO2009, utilities are expected to experience such swings in demand in the short run due to uncertainties attributed to the weather and the regional economy. However, over the long run, average growth in annual peak demand in the United Stares is expected to be approximately 1 percent for the period 2007 through 2030, though commercial and industrial growth is expected to be 1.4 percent and 0.8 percent, respectively. Based on this AEO2009 forecast, Black & Veatch assumed that the average annual growth rate for peak and energy for OMLPS would be 1.1 percent for the study period. This growth rate is lower than prior forecasts developed for Oberlin, but is consistent with the long-term EIA projections. Figure 2-4 also indicates that the peak demand before DSM savings in 2010 is projected to be 21.0 MW while the 2029 peak demand before DSM savings is projected to be 25.8 MW.

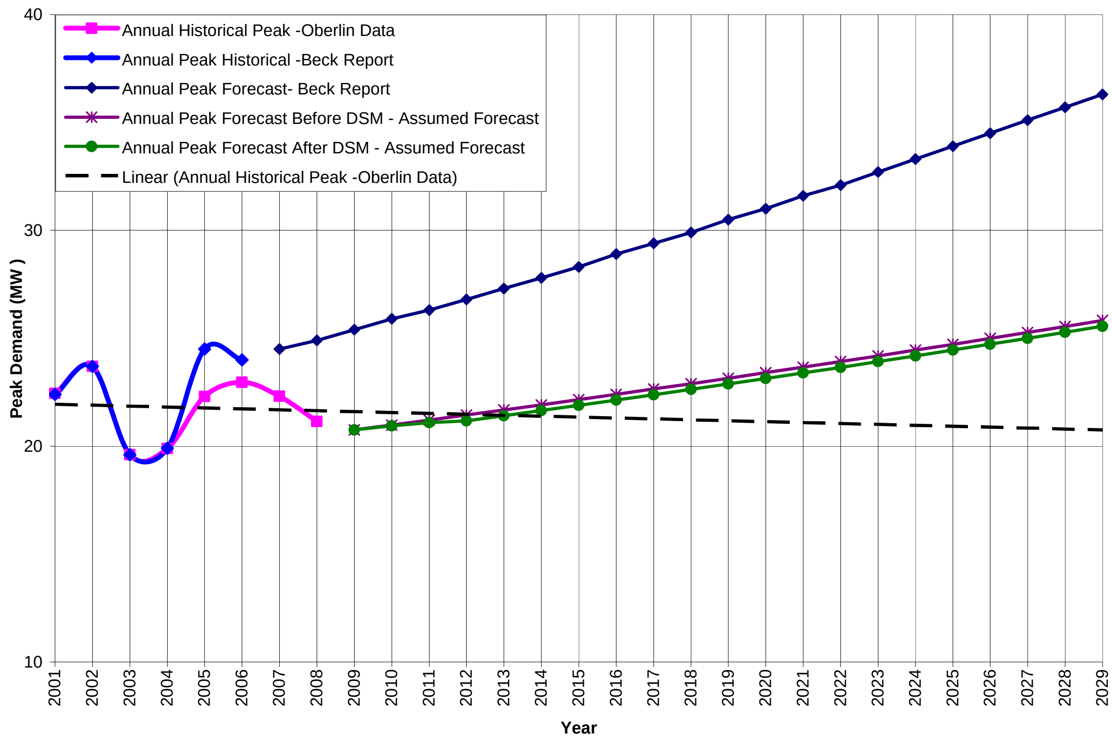


Figure 2-3
Historical and Forecast NEL

Figure 2-4
OMLPS Base Case Peak Demand Forecast

Year	Peak Demand Forecast Before DSM (MW)	DSM Savings Assumed in Forecast (MW)	Peak Demand Forecast After DSM Savings Adjustments (MW)
2010	21.0	0.04	20.9
2011	21.2	0.11	21.1
2012	21.4	0.27	21.2
2013	21.7	0.27	21.4
2014	21.9	0.27	21.6
2015	22.2	0.27	21.9
2016	22.4	0.27	22.1
2017	22.6	0.27	22.4
2018	22.9	0.27	22.6
2019	23.1	0.27	22.9
2020	23.4	0.27	23.1
2021	23.7	0.27	23.4
2022	23.9	0.27	23.7
2023	24.2	0.27	23.9
2024	24.5	0.27	24.2
2025	24.7	0.27	24.5
2026	25.0	0.27	24.7
2027	25.3	0.27	25.0
2028	25.5	0.27	25.3
2029	25.8	0.27	25.5

Note: Values may not net exactly due to rounding.

Figure 2-5 presents the NEL forecast, which increases from 115,006 MWh in 2010 to 140,681 MWh in 2029 at an average annual growth rate of 1.1 percent, which is comparable to the AEO2009 forecast. Figure 2-3 shows the forecasted NEL for OMLPS along with historical NEL.

Figure 2-2 and Figure 2-3 also show the peak demand and NEL forecast from the 2007 "Power Supply Plan for City of Oberlin," respectively. The forecast developed during that study assumes an average annual growth rate of 1.6 percent and 1.7 percent for peak and NEL, respectively. The previous forecast values were developed based on historical data up to 2006. However, due to the recent decrease in peak and NEL demand, Black & Veatch revised the growth rate to a lower value.

2.1.3 Base Case DSM Peak and Energy Savings Forecasts

Black & Veatch received information from OMLPS on the DSM savings proposed by VEIC. VEIC has indicated to OMLPS's wholesale energy provider, AMP, that it will market certain cost effective DSM measures to OMLPS customers, which would further reduce the energy needs of its customers, and potentially may reduce the peak demand. These measures and programs are expected to cost around 3.5 cents/kWh.

VEIC has projected that it would be able to reduce the peak demand by 0.27 MW annually from 2012 onwards through an energy savings program after an initial period of 3 years and would be able to maintain the savings thereafter. However, no guaranteed figure for minimum peak savings has been provided by VEIC.

Black & Veatch reviewed a study report on "Achievement of Achievable Potential from Energy Efficiency and Demand Response Programs in the US (2010-2030)" prepared by the Electric Power Research Institute (EPRI). In that report, EPRI has indicated that the "Realistic Achievable Potential" in peak demand savings for the entire United States is likely to be 0.2 percent in 2010 and would subsequently increase to 3.6 percent in 2020 and 7 percent in 2030.[1]

[1] Refer to Figure 5-2 of the "Achievement of Achievable Potential from Energy Efficiency and Demand Response Programs in the US (2010-2030)" report.

Figure 2-5
OMLPS Base Case NEL Forecast

Year	NEL Forecast Before DSM (MWh)	DSM Energy Savings Guaranteed by VEIC (MWh)	Annual Forecast After Guaranteed DSM Savings Adjustments (MWh)
2010	115,456	450	115,006
2011	116,726	950	115,776
2012	118,010	1,450	116,560
2013	119,308	1,450	117,858
2014	120,621	1,450	119,171
2015	121,948	1,450	120,498
2016	123,289	1,450	121,839
2017	124,645	1,450	123,195
2018	126,016	1,450	124,566
2019	127,402	1,450	125,952
2020	128,804	1,450	127,354
2021	130,221	1,450	128,771
2022	131,653	1,450	130,203
2023	133,101	1,450	131,651
2024	134,565	1,450	133,115
2025	136,046	1,450	134,596
2026	137,542	1,450	136,092
2027	139,055	1,450	137,605
2028	140,585	1,450	139,135
2029	142,131	1,450	140,681

The demand savings proposed by VEIC indicate that VEIC expects to reduce peak demand by 1.25 percent in 2012. Over the next few years as the demand savings remain constant and the forecast peak demand increases, the percentage savings reduce. As a result, the percentage savings in peak demand are 1.025 percent in 2029. Comparing the demand savings forecast with the information from the “Achievement of Achievable Potential from Energy Efficiency and Demand Response Programs in the US (2010-2030)” report, Black & Veatch is of the opinion that the demand savings proposed by VEIC are reasonable. However, it may take more than the initial 3 years proposed to achieve this level of savings. On the other hand, over time, VEIC may be able to save more than the proposed 0.27 MW annually. However, for planning purposes, Black & Veatch used a conservative approach and limited the demand savings to 0.27 MW annually for all years after 2012. Peak savings assumptions from the energy savings programs are presented on Figure 2-4 and net peak demand after DSM savings is shown on Figure 2-2.

VEIC has also projected that they are likely to save 1,450 MWh in the first 3 years of the program ending in 2012. The total lifetime savings from this program are expected to be 19,415 MWh. Based on this information, Black & Veatch assumed for the base case that OMLPS would be able to save 450 MWh, 950 MWh, and 1,450 MWh in NEL annually in 2010, 2011, and 2012, respectively. It is also assumed that beyond 2012, OMLPS would be able to save 1,450 MWh in NEL annually for all years in the study period. The energy savings projections are shown on Figure 2-5 and the net NEL requirements after accounting for DSM savings are presented on Figure 2-3.

2.2 Existing Resources and Capacity Requirements

Prudent utility practices require a utility to plan for sufficient capacity resources to meet its peak demand and to maintain an additional margin of capacity should unforeseen events result in higher system demand or lower than anticipated available capacity. This section presents the development and analysis of the reliability criteria used by OMLPS.

For this Power Supply Study, OMLPS will use the 12 percent reserve margin for planning in the summer season. The planning reserve margin covers uncertainties in extreme weather, forced outages for generators, and uncertainty in load projections. OMLPS plans to maintain the 12 percent reserve margin for firm load obligations. This is also consistent with previous power supply studies for OMLPS.

Midwest Independent Transmission System Operator (MISO) suggests using a 15.4[2] percent reserve margin in the planning studies, but Oberlin has used a 12 percent reserve margin requirements for its previous planning studies. Generally, reserve margins are dependent on the region a utility is located, interconnections, and other factors, but planning reserve margins generally range in the 12 to 20 percent. As such, Black & Veatch used the 12 percent reserve margin requirement for this study. By doing so, Black & Veatch is taking a more conservative approach, which would reduce the need for additional capacity in future.

2.2.1 Existing and Committed Resources

To determine OMLPS's need for power, a forecast of system peak demand was developed as previously discussed. Available net system capacity and resources were also considered for the 2010 through 2029 period, and includes consideration of existing generation resources, existing system purchases, firm capacity additions, and retirements, if planned.

OMLPS is a full requirements wholesale member of AMP. OMLPS existing generating resources are either "pool resources" or "non–pool resources." Non-pool resources are owned or contracted capacity resources for individual use of respective members only, while pool resources are shared amongst 20 other member municipal utilities in northeast Ohio. These 21 members are together known as the NEASG members. The Northeast Area Service Group Pool Agreement with AMP limits the amount of non-pool resources for each member to 40 percent of the peak load of the previous year and an additional 50 percent of the increase in demand from previous year to the current peak load. This potentially limits the ability of OMLPS to add any new resources exclusively by itself in 2013. However, this constraint will be relaxed soon with the retirement of the Gorsuch station. An amendment to the clause would give sufficient flexibility to OMLPS to directly add as much capacity as required by it to meet its load and reliability obligations.

OMLPS owns a 6.695 MW share of the 213 MW Gorsuch plant located in Marietta, Ohio. This unit is planned for retirement in December 2012. The Gorsuch plant, a non-pool resource to OMLPS, is a baseload unit that operates at a minimum load of 70 percent. OMLPS has a take or pay contract with the plant through AMP and is required to take at least 70 percent of the energy from its share of the plant at all times. This unit provides baseload energy for OMLPS.

[2] Refer to the MISO document "Midwest_ISO_Summer_Reliability_Presentation_2009.pdf"

OMLPS receives capacity and energy from the Niagara and St. Lawrence hydro power plants. Oberlin receives 0.387 MW of baseload power and an additional 0.075 MW of peaking power from this project everyday. This resource is a non-pool resource to OMLPS. Historically, the unit has been generating at approximately 70 percent capacity factor.

OMLPS owns a 1.270 MW share of the 42 MW Belleville Hydro Power project, also referred to as the OMEGA JV 5 (JV 5) project. The plant is located on the Ohio River close to the Belleville Lock and Dam in West Virginia. The JV 5 plant, a non-pool resource to OMLPS, is assumed to be dispatched at 100 percent capacity factor at all times. Whenever the unit is not able to generate electricity, AMP provides replacement power to the city from different market power purchases.

OMLPS contracts for 0.645 MW share from three landfill gas plants owned and operated by EDI totaling 35 MW. The three plants are located in Lorain County, Mahoning County, and Ottawa County in Ohio. These plants also provide baseload capacity and have been operating at high capacity factors in the recent past (2005-2008).

In addition to the above, OMLPS also owns their own generating units totaling 18 MW. These generators have very high heat rates and are usually operated during peak hours or emergency need hours as peaking units only. OMLPS sells the entire capacity from these peaking units to the NEASG pool through AMP. AMP uses these units to provide peaking capacity to JV 5 and the NEASG. OMLPS gets a small portion of the capacity back as its share of the NEASG pool. OMLPS has different contracts with AMP for sale of the peaking capacity. Eighteen (18) MW become available to OMLPS in December 2010 when another contract expires. However, due to high fuel costs, emissions limitations, and high maintenance costs, these units are not expected to run at high capacity factors. Historically, these units have provided less than 1 percent of the energy needs of OMLPS and this trend is expected to continue in the future as well. For the purposes of this Power Supply Study, it is assumed that these resources are not returned to OMLPS, and their contracts are renewed for backup peaking service by AMP.

In addition to the above non-pool resources, OMLPS receives capacity and energy from different pool resources. OMLPS receives a 0.497 MW share of the 9 MW distributed peaking units, also referred to as the OMEGA JV 1 (JV 1) unit. OMLPS also owns 1.217 MW of the 138.7 MW OMEGA JV 2 (JV 2) peaking generation project. In addition, OMLPS has also contracted 2.5 MW share of the 142 MW peaking generation unit owned by AMP. This contract is set to expire in December 2022, but is expected to be renewed. Black & Veatch has assumed that the contract will be extended at least until the end of the study period. All the pool resources are peaking resources and historically, all of these resources have contributed less than 1 percent of the energy requirements of OMLPS.

Apart from these resources, AMP procures energy for the NEASG pool from different energy traders. As OMLPS is part of the NEASG pool, it gets a share of the energy purchased by AMP. Currently, OMLPS gets a 0.7 MW share of the 5x16 intermediate resource PPA with Morgan Stanley. OMLPS also has a 0.788 MW share of the J. Aron PPA. In addition, OMLPS has 1.577 MW and 1.072 MW shares of the 7x24 baseload resource PPAs with Barclays and Lehman Brothers, respectively. These market purchases allow OMLPS to meet its energy requirements. The market purchase agreements are not backed by any generating assets and so AMP provides the NEASG pool with the backup capacity needed for these purchases. As such, these purchases are treated as firm capacity resources and are considered for meeting OMLPS reserve margin requirements. All these agreements expire on or before 2012, when the existing NEASG pool agreement is to expire. For modeling purposes, it is assumed that these PPAs will not be extended beyond their current expiration dates.

OMLPS has committed itself to buying 2.6 MW of the 208 MW (net total) new hydro power plants being developed by AMP at Cannelton, Indiana; Smithland, Kentucky; and Willow Island, West Virginia. All of these plants are on the Ohio River, as is the existing JV 5 project. This project is a run-of-the-river hydro project and is scheduled to be online in 2013 and 2014. Expected capacity factors for the plants are 57 percent. These new hydro units have been assumed to be planned additions for the purpose of this Power Supply Study.

2.2.2 Need for Future Capacity and Generation Resources

The need for future resources is determined based on the availability of existing resources and the expected growth in future demand. The capacity and reliability needs for 2010 through 2029 are shown in the capacity balance on Figure 2-6. Based on the information presented on Figure 2-6, it is noted that Oberlin has excess capacity in the initial years of the study, but would need additional capacity to meet its reliability needs from 2023 onwards. Though OMLPS has sufficient capacity to cover its reliability needs for the immediate future up to 2012, it would need additional resources to meet its obligations beyond 2012. At present, a very large portion of the capacity is peaking capacity as shown on Figure 2-7 and Figure 2-8. It would need substantial baseload resources upon retirement of Gorsuch and the expiration of the baseload PPAs.

Figure 2-6
Current Summary Capacity Balance Forecast for OMLPS

Year	Forecast Peak Demand Before DSM (MW)	DSM Peak Savings (MW)	Peak Demand After DSM (MW)	12.0% Reserves (MW)	Total Peak + Reserves (MW)	Installed Capacity (From Pool and Non Pool Resources)	Interruptible Capacity (MW)	Total Short Term Capacity Purchased (MW)	Cumulative Retired Capacity (MW)	Cumulative Committed Capacity Addition (MW)	Capacity Sold (MW)	Total Available Capacity (MW)	Excess/ (Deficit) Capacity to Maintain 12% Reserve Margin (MW)
2009	20.750	-	20.750	2.490	23.240	35.548	3.900	2.500	-	-	18.000	23.948	0.708
2010	20.978	0.042	20.936	2.512	23.449	35.548	3.900	2.675	-	-	18.000	24.123	0.674
2011	21.209	0.115	21.094	2.531	23.626	33.971	3.900	4.395	-	-	18.000	24.266	0.640
2012	21.442	0.267	21.175	2.541	23.716	33.272	3.900	5.275	-	-	18.000	24.447	0.731
2013	21.678	0.267	21.411	2.569	23.980	22.890	3.900	-	(6.695)	1.650	18.000	10.440	(13.540)
2014	21.917	0.267	21.649	2.598	24.247	22.890	3.900	-	(6.695)	2.600	18.000	11.390	(12.857)
2015	22.158	0.267	21.890	2.627	24.517	22.890	3.900	-	(6.695)	2.600	18.000	11.390	(13.127)
2016	22.401	0.267	22.134	2.656	24.790	22.890	3.900	-	(6.695)	2.600	18.000	11.390	(13.400)
2017	22.648	0.267	22.380	2.686	25.066	22.890	3.900	-	(6.695)	2.600	18.000	11.390	(13.676)
2018	22.897	0.267	22.630	2.716	25.345	22.890	3.900	-	(6.695)	2.600	18.000	11.390	(13.955)
2019	23.149	0.267	22.881	2.746	25.627	22.890	3.900	-	(6.695)	2.600	18.000	11.390	(14.237)
2020	23.404	0.267	23.136	2.776	25.912	22.890	3.900	-	(6.695)	2.600	18.000	11.390	(14.522)
2021	23.661	0.267	23.394	2.807	26.201	22.890	3.900	-	(6.695)	2.600	18.000	11.390	(14.811)
2022	23.921	0.267	23.654	2.838	26.492	22.890	3.900	-	(6.695)	2.600	18.000	11.390	(15.102)
2023	24.184	0.267	23.917	2.870	26.787	22.890	3.900	-	(6.695)	2.600	18.000	11.390	(15.397)
2024	24.450	0.267	24.183	2.902	27.085	22.890	3.900	-	(6.695)	2.600	18.000	11.390	(15.695)
2025	24.719	0.267	24.452	2.934	27.386	22.890	3.900	-	(6.695)	2.600	18.000	11.390	(15.996)
2026	24.991	0.267	24.724	2.967	27.691	22.890	3.900	-	(6.695)	2.600	18.000	11.390	(16.301)
2027	25.266	0.267	24.999	3.000	27.999	22.890	3.900	-	(6.695)	2.600	18.000	11.390	(16.609)
2028	25.544	0.267	25.277	3.033	28.310	22.440	3.900	-	(7.145)	2.600	18.000	10.940	(17.370)
2029	25.825	0.267	25.558	3.067	28.625	22.440	3.900	-	(7.145)	2.600	18.000	10.940	(17.685)

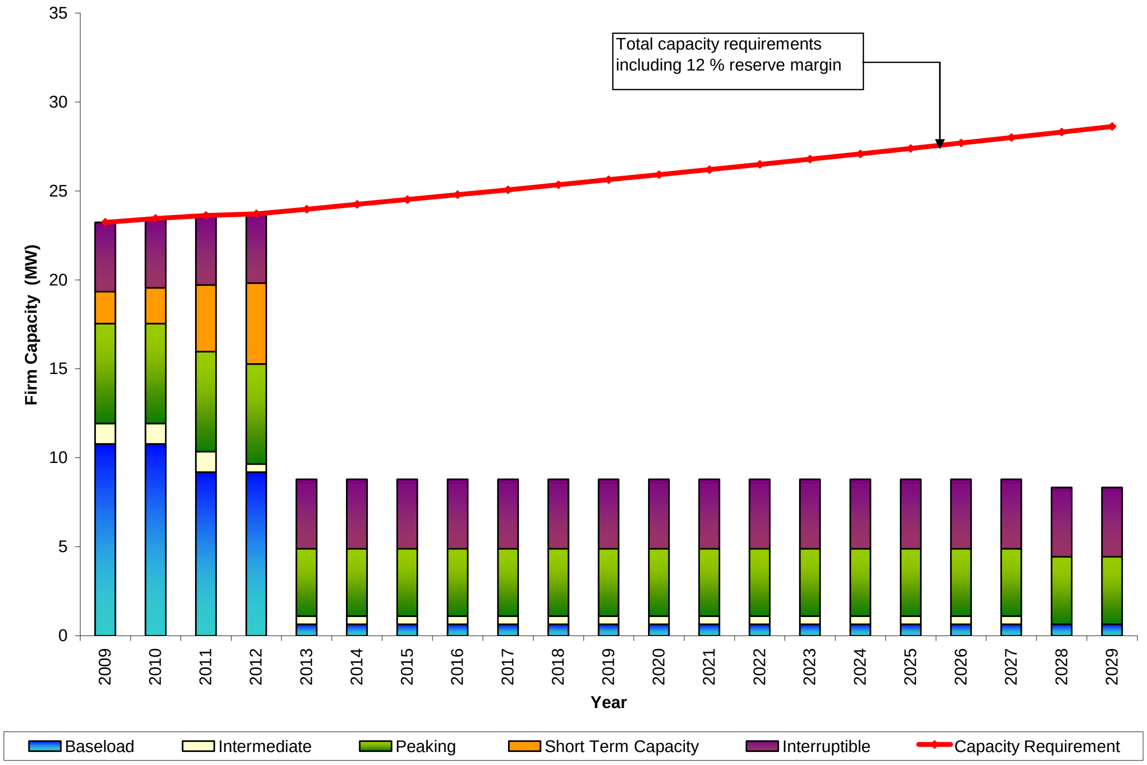
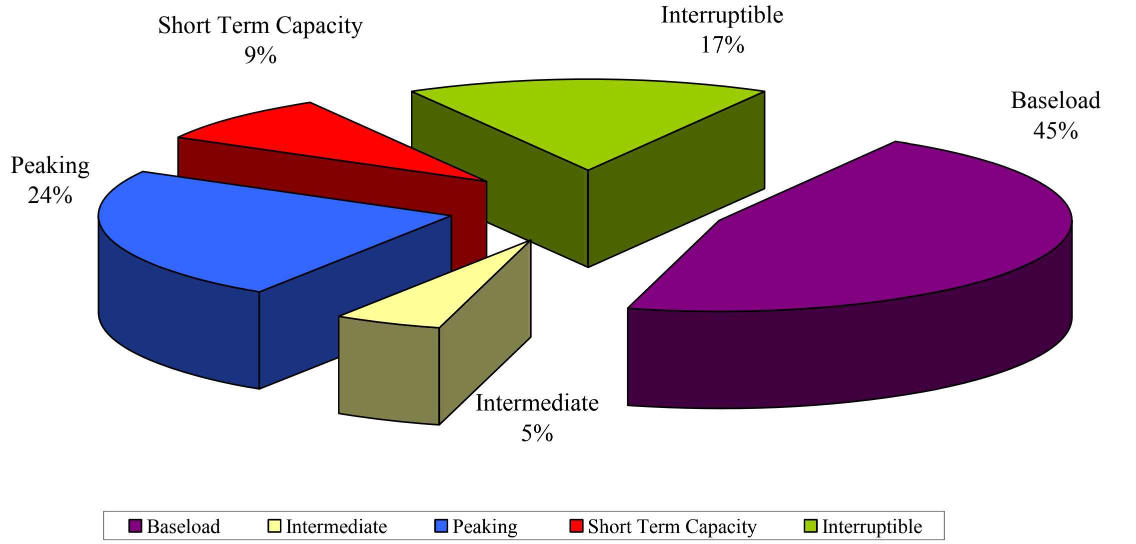


Figure 2-7
Capacity Mix of Existing and Committed Resources



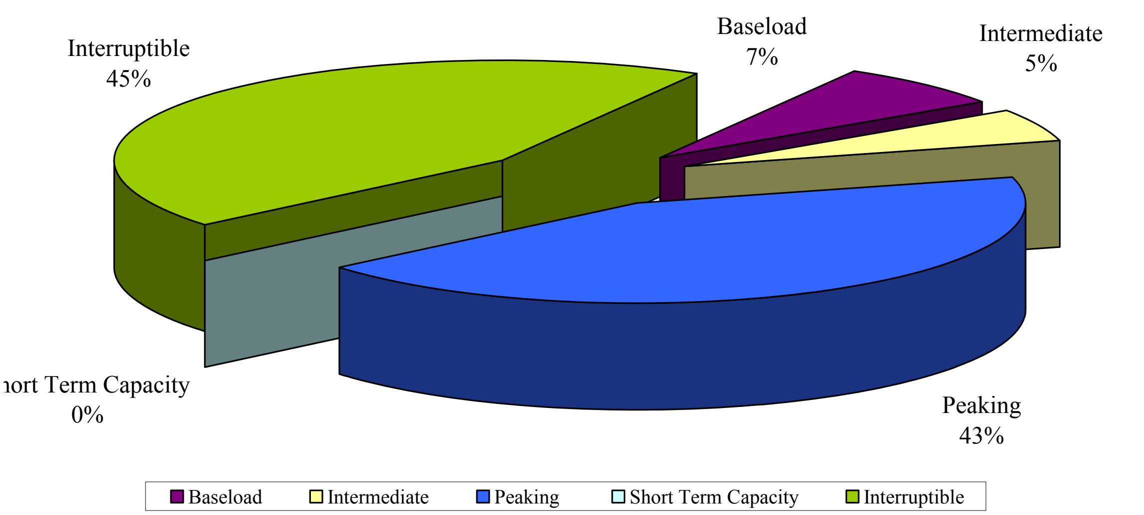


Figure 2-8
Capacity Mix (Percentage) of Existing and
Committed Resources - 2010 (Top) and 2013 (Bottom)

Peaking units make up a vast majority of OMLPS capacity resources. In 2010, 24 percent of the capacity resources are peaking units and interruptible loads account for about 17 percent of the capacity resources. In 2013, after the Gorsuch plant is retired, the capacity mix of OMLPS becomes heavily biased towards peaking units and interruptible load as they make up around 88 percent of OMLPS capacity resources.

Typically, peaking units should comprise less than 20 percent of a utility's resource mix. Figures 2-9 and 2-10 show the capacity mix for Ohio and for the entire United States. The baseload capacity for Ohio is approximately 72 percent of its total resources, while peaking resources comprise 19 percent of the total. In comparison, the baseload resources for the whole United States are 54 percent while peaking is 16 percent. The above statistics reiterate that OMLPS will be heavily dependent on peaking capacity once Gorsuch retires. Black & Veatch believes that obtaining additional baseload generation to more favorably balance baseload and peaking resources should be a priority in the near term for OMLPS.

Apart from looking at the capacity mix of the system, it is a prudent industry practice to analyze the generation mix of the system. Generally, the baseload units of a system generate at least 50 percent of the energy requirements of the system, with the rest being generated from intermediate, peaking, and intermittent resources. This mix of baseload and other types of generation would depend upon the load factor and the mix of residential, commercial, and industrial customers. With higher load factors, more generation would be expected from baseload resources. In Ohio, which has a higher concentration of industrial customers, load factors are generally higher. OMLPS has a high load factor of approximately 65 percent compared to a typical load factor in the 50 to 55 percent range. Due to this high load factor, generation from baseload resources is expected to be higher (70 to 80 percent) in comparison to other regions of the country. Figure 2-11 shows the historical and forecast generation mix from the existing and committed resources of OMLPS. In coming up with this graph, it is assumed that the generation mix from existing resources would be the same as it has been in the recent past (2005-2009), except for the retirement of Gorsuch. It is also assumed that OMLPS has planned ahead until 2012 and has sufficient energy from market purchases, and pool and non-pool resources to meet its energy obligations. From Figure 2-11, it is evident that there is a significant shortfall of baseload energy supply once the Gorsuch station is retired in 2012. It will be difficult and very expensive to meet this energy shortfall from the existing resources of OMLPS, which are predominantly peaking units. As a result, OMLPS should acquire baseload capacity and generation resources to fulfill its obligations in a cost effective and efficient manner.

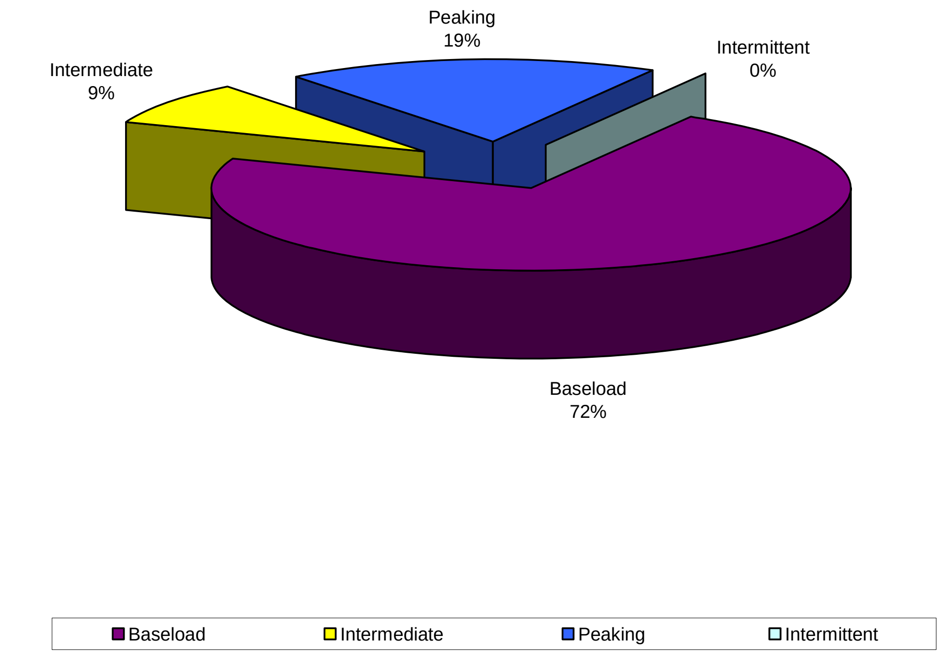


Figure 2-9
Capacity Mix (Percentage) of Existing Resources for Ohio in 2008

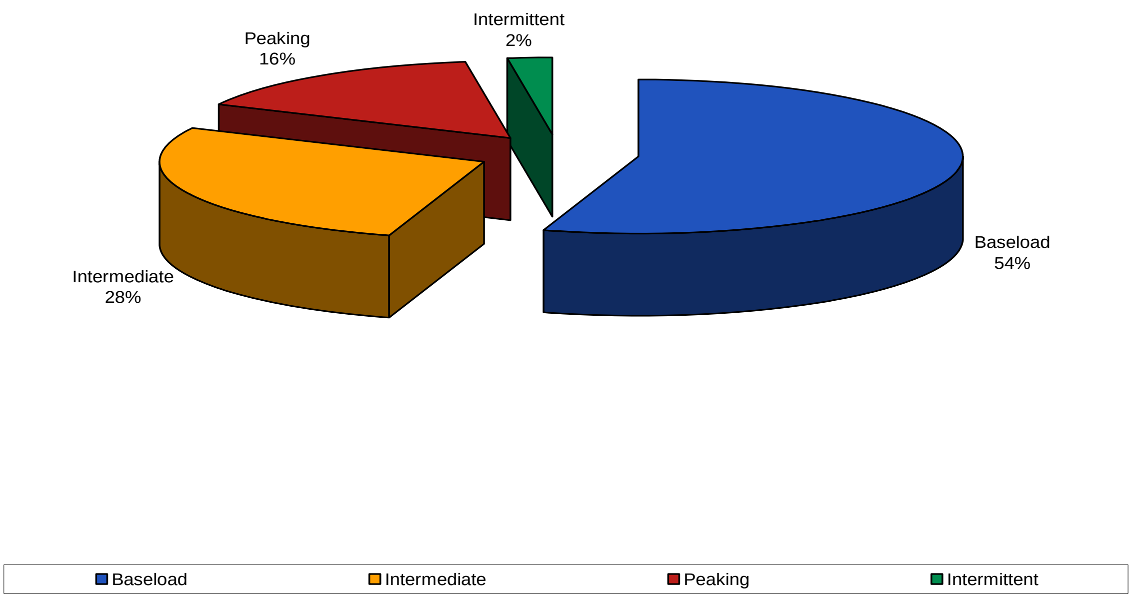


Figure 2-10
Capacity Mix (Percentage) of Existing Resources for US in 2008

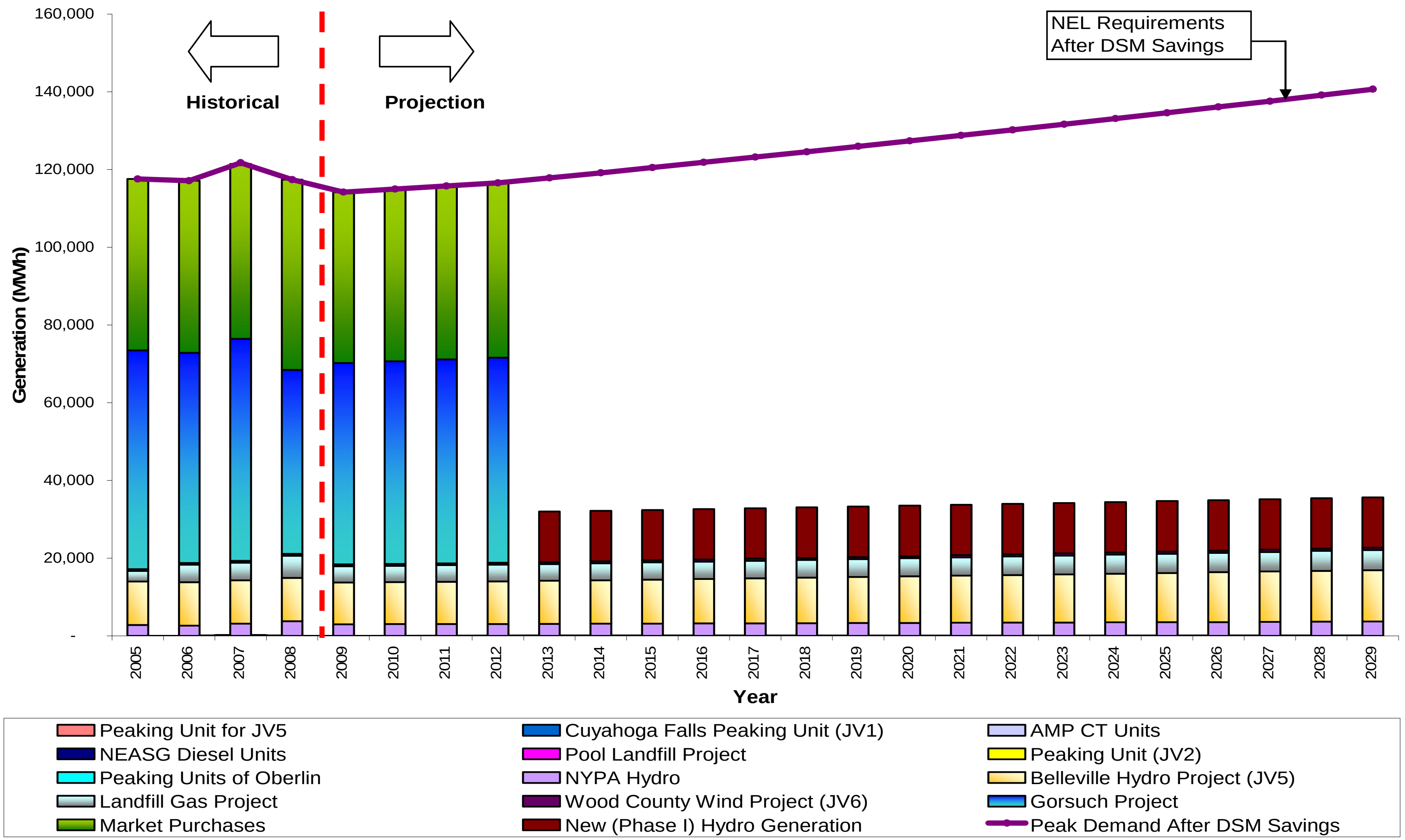


Figure 2-11
Generation Mix of Existing and Committed Resources

2.2.3 Capacity Values of Different Technologies

One of the important decisions in planning for future resources is to consider the firm capacity of each resource. Firm capacity or capacity value of any unit is defined as the generating capacity of any resource to meet the peak load of the system. Conventional units like coal fired steam turbines, natural gas fired units, and some renewable units (such as landfill gas [LFG] and biomass) can generate at maximum capacity or close to their maximum capacity during any hour including peak demand hours as long as the unit has a continuous supply of fuel. Baseload plants generally have a long-term fuel supply plan and/or also have fuel storage facilities onsite, which allow these plants to generate electricity whenever required. As such, baseload units generally have high capacity value (firm capacity) which usually ranges from 80 percent to 100 percent of its maximum capacity. Adding baseload units to a system gives high capacity credit, which reduces the need for additional resources in meeting the capacity and reliability needs for the system.

However, only some renewable resources have high capacity credits. Renewable resources like wind, solar, and run-of-the-river hydro are not available at all times. In addition, these resources are also not available in the same quantity for all hours that they are available. Also, some resources such as wind exhibit a general inverse relationship with load (higher generation in off peak hours and months in comparison to on peak periods). As such, it is difficult to ascertain how much electricity can be generated from these resources during the peak demand hour.

Figure 2-12 shows the actual average hourly generation for each season in a year from a typical 100 MW wind farm in the Midwest region. Summer months are May through August, shoulder months are March, April, October, and November and the remaining months are grouped as winter months. As can be seen from the figure, wind generation is highest during the non-summer months. In addition, on a daily basis, wind generation is higher during evening and early morning hours and lower during the day during the typical peak usage hours. The peak demand hour for most systems in the Ohio region occurs in summer months and during the middle of the day. This shows that the wind generation profile is largely inversely correlated to the demand pattern. As such, adding wind resources to a system gives very little capacity credit to the system compared to baseload resources. Often, wind is given a capacity credit value in the 10 to 20 percent range of nameplate capacity. Black & Veatch assumed a 20 percent capacity credit for wind resource for this planning study, which is consistent with the typical generation profile shown on Figure 2-12.

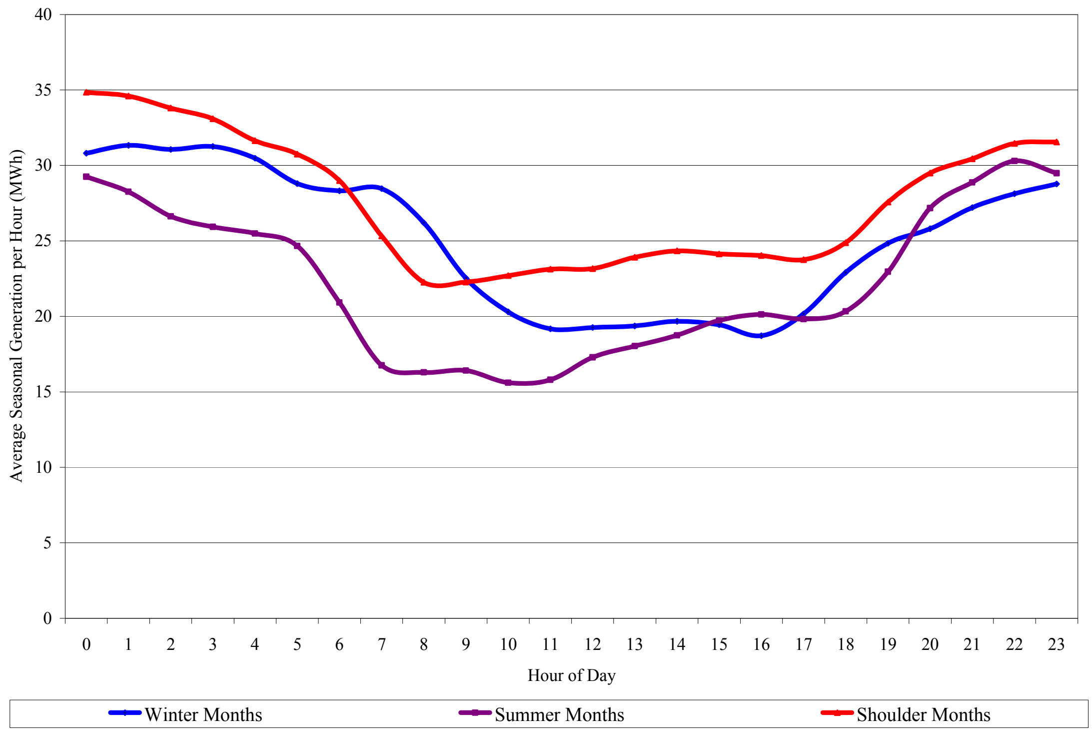


Figure 2-12
Seasonal Average Hourly Generation from a Typical 100 MW Wind Farm in Midwest

For similar reasons as explained above, solar and hydro were assigned 55 percent and 57 percent capacity credit, respectively, for this planning study. The hydro capacity assumption is consistent with OMLPS experience with their existing hydro generation. Black & Veatch assumed a 60 percent capacity credit for solar PV based on its experience with these units. Although solar PV typically operates at much lower capacity factors (generally in the 15 to 25 percent range), its generation is highly correlated to demand. As a result of the correlation between peak solar daily generation and the typical utility demand profile it is often reasonable to expect solar generation to be available during high demand periods, and thus its generation is often given a higher capacity value than wind.

Other renewable resources like biomass and landfill gas resources were assigned higher capacity credits, similar to conventional units, due to the stable nature of the fuel supply.

2.3 Fuel Forecast

The fuel price forecast is a component in OMLPS's evaluation of future resource plans. The prices of the fuels used in power generation are volatile and are difficult to accurately forecast due to a variety of unforeseeable factors. EIA forecasts published in AEO2009 were used for the study. The natural gas price forecast from AEO2009 presented in this section will be used for a new ownership interest in a combined cycle plant. In addition, since many of the existing units run on diesel, the price forecast for light fuel oil (ultra low sulfur diesel) residual fuel oil from AEO2009 are also presented in this section.

The forecast for natural gas includes the cost of the commodity itself at the Henry Hub delivery point and the cost of variable transportation up to the Lebanon hub in Ohio. The commodity price forecast was obtained from AEO2009. EIA projects that natural gas prices will recover from current depressed levels associated with lower economic output. After 2015, the ramping up of shale gas and other new domestic resource production, moderates price increases for awhile. Black & Veatch developed the transportation cost forecast based on its gas industry experience in the region. A 2009$ delivery cost of $0.344 per MMBtu was assumed.

Natural gas is a clean burning, combustible mixture of hydrocarbon gases, primarily composed of methane. Methane is principally formed from the decomposition of organic waste and mineral fuel extraction. Methane can be extracted from mineral deposits. Natural gas can be liquefied for shipment as liquefied natural gas (LNG) and then regasified for injection into pipeline systems. The monthly price forecasts are shown on Figure 2-13.

Small quantities of ultra-low sulfur diesel are currently used at the existing OMLPS owned generating units. Ultra-low sulfur diesel is a product derived during the refinement of crude oil. The average annual price for ultra-low sulfur diesel was calculated from this monthly price forecast and is presented on Figure 2-14.

2.4 Emission Allowance Price Forecast

As a result of potential legislation related to reduction of greenhouse gases, particularly CO_2, a sensitivity case was developed to evaluate potential impacts of various plans as a result of emission allowance prices being applicable for such emissions. As a result of a Congressional request, the EIA developed a CO_2 allowance price forecast, which is summarized on Figure 2-15.

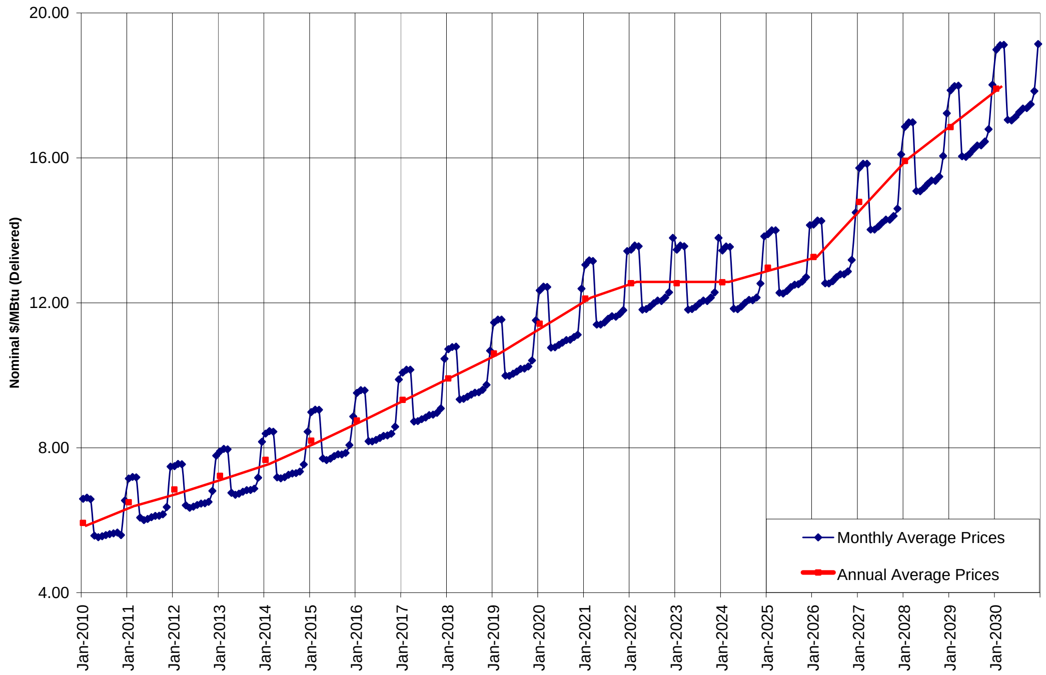


Figure 2-13
Natural Gas Price Forecast

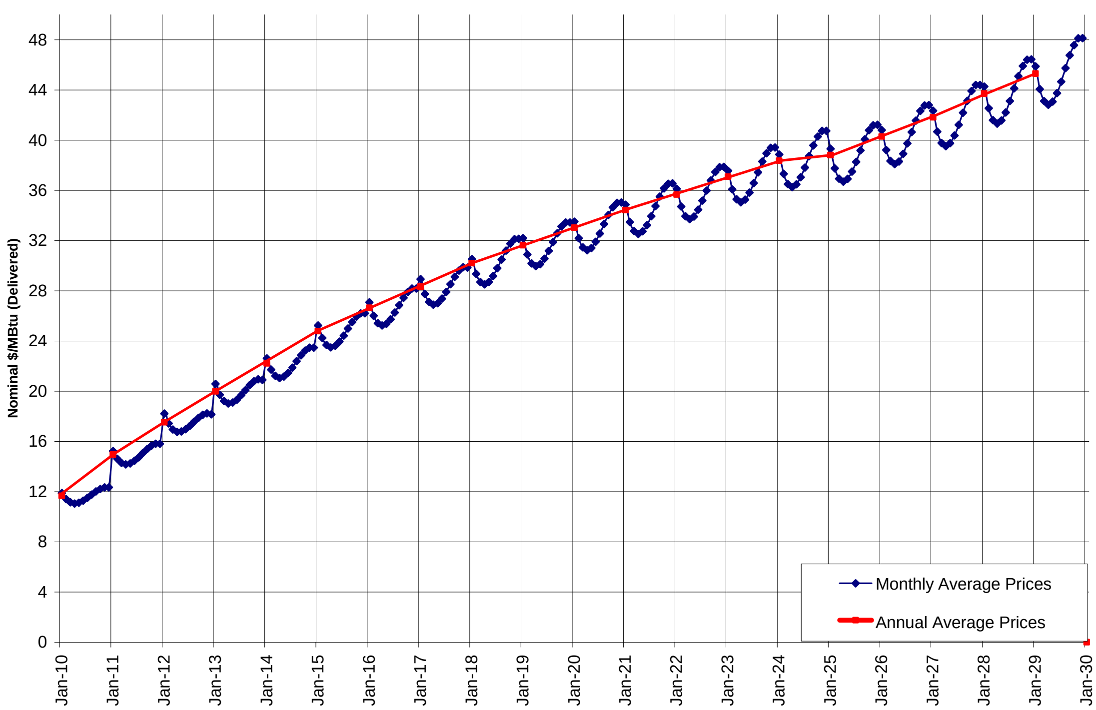


Figure 2-14
Ultra Low Sulfur Diesel Price Forecast

Figure 2-15
Potential CO_2 Emission Allowance Prices (Nominal Dollars)

Year	($/ton)
2009	0.00
2010	0.00
2011	0.00
2012	18.86
2013	20.87
2014	23.08
2015	25.53
2016	28.25
2017	31.25
2018	34.56
2019	38.24
2020	42.30
2021	46.79
2022	51.76
2023	57.26
2024	63.34
2025	70.07
2026	77.51
2027	85.74
2028	94.85
2029	104.93

2.5 Economic Parameters

This section presents the economic parameters that were developed by Black & Veatch and assumed for OMLPS's Power Supply Study. The economic parameters are consistently applied throughout the study.

2.5.1 Inflation and Escalation Rates

Figure 2-16 presents the assumed general inflation rate, construction cost escalation rate, and fixed and nonfuel variable operations and maintenance (O&M) escalation rates.

Figure 2-16
Assumed Inflation and Escalation Rates

Component	Annual Rate (percent)
General Inflation	3.0
Construction Cost Escalation	3.0
Fixed O&M Escalation	3.0
Nonfuel Variable O&M Escalation	3.0

2.5.2 Debt Interest Rate and Discount Rate

The debt interest rate assumed for 30 year debt is 5.50 percent. The present worth discount rate was assumed to be equal to the debt interest rate of 5.5 percent. The assumption is conservative in comparison to recent interest rates that AMP has been able to obtain.

2.5.3 Levelized Fixed Charge Rate

The fixed charge rate (FCR) represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. A separate FCR can be calculated and applied to each year of an economic analysis, but it is common practice to use a single, levelized FCR that has the same present value as the year-by-year fixed charge rate.

Different technologies evaluated for this Power Supply Study have been levelized across different periods in accordance with prudent industry practice. The different FCR for different terms are highlighted on Figure 2-17. The FCR rate includes a 0 percent bond issuance fee, and 1 percent assumed for payment in lieu of taxes and insurance cost.

Figure 2-17
Different FCR for Different Time Periods

Bond Financing Period (years)	Bond Interest Rate (%)	FCR
40	5.50	7.23%
35	5.50	7.50%
30	5.50	7.88%
25	5.50	8.46%
20	5.50	9.37%
15	5.50	10.96%

3.0 Analysis and Screening of Potential Alternatives

3.1 Generic Characteristics for Renewable Alternatives

Several renewable energy alternatives were evaluated for the Power Supply Study including wind, solar PV, biomass, biogas, and hydroelectric. The technical feasibility and cost of energy from nearly every form of renewable energy has improved since the early 1980s. However, most renewable energy technologies struggle to compete economically with conventional fossil fuel technologies and, in most countries, the renewable fraction of total electricity generation remains small. Nevertheless, the field is rapidly expanding from occupying niche markets to making meaningful contributions to the world's electricity supply. This section provides an overview and analysis of various renewable energy technologies, including the following:

- Solid biomass (direct-fired).
- Landfill gas.
- Wind (onshore).
- Solar (photovoltaic).
- Hydroelectric.

Generally, each technology is described with respect to its operating principles, applications, resource availability in Ohio, cost and performance characteristics, and environmental impacts. Estimates for costs and performance parameters were based on Black & Veatch project experience, and past vendor inquiries. Capital costs are in 2009 dollars and reflect the total project cost, including direct and indirect costs plus an allowance for owner's costs.

Federal Incentives Available

A number of financial incentives are available for the installation and operation of renewable energy technologies. The following discussion summarizes the Federal tax-related incentives that are available to new renewable energy facilities. Entities that are not subject to taxes, such as Oberlin, are not able to directly take advantage of many incentives. However, there are some incentives that apply to tax-exempt entities. By working with taxable entities via co-ownership or PPAs, Oberlin may be able to find optimal ways of utilizing the incentives to lower the cost of energy.

Tax-Related Incentives

The predominant incentive offered by the federal government for renewable energy has been through the US tax code in the form of tax deductions, tax credits, or accelerated depreciation. An advantage of this form of incentive is that it is defined in the tax code and is not subject to annual congressional appropriations or other limited budget pools (such as grants and loans). Tax-related incentives include the Section 45 Production Tax Credit (PTC), Section 48 Investment Tax Credit (ITC), and accelerated depreciation. The ability to utilize tax credits is limited not only by specific legal considerations, but also by practical considerations. For example, it can be difficult to line up the risks and benefits of a specific transaction with the appropriate participants and their tax status.

With the recent passage of the American Recovery and Reinvestment Act (also known as the Stimulus Package) in February 2009, many of these benefits were extended and/or expanded in some cases. There is also a grant that is valued up to 30 percent of the cost of a project and is paid to the developer at the beginning of a project. For wind projects, many of these benefits will apply to projects that come on-line by the end of 2012. As a result, there will be an urgency to site, permit, and develop such projects within the next 3 years.

American Recovery and Reinvestment Act of 2009

The key provisions of the Stimulus Package are focused on moving renewable projects ahead in the next 3 years by expanding development incentives to a wider range of investors. Investors will be able to choose from one of three large incentive mechanisms described below to offset the cost of renewable energy projects.

1. **PTC Time Frame:** The time frame by which projects must be placed into service to take advantage of the PTC incentive ($10 to $21/MWh depending on the renewable resource) has been extended by 3 years. Projects in operation by the end of 2012 (wind) or 2013 (most others) can claim this credit.
2. **ITC to Include More Resources:** In lieu of the PTC, renewable energy developers can opt to use the ITC, equal to 30 percent of the capital cost of the project. While this option was historically only available to solar projects, most other renewable resources (including wind, biomass, geothermal, and anaerobic digestion) can now apply it toward their projects. Developers will be able to take full advantage of this funding option regardless of whether other subsidies, typically at the state level, are being utilized. This has the same project development timeline as the PTC.
3. **30 Percent Grant Program:** A major issue with the ITC was that it was only of interest to investors with a large tax burden that could apply the credit. With the economic downturn, the number of these types of

investors has decreased considerably. The Stimulus Package includes a new grant program equal in size to the ITC (30 percent of the capital cost) that US taxpayers can apply for in lieu of the PTC or ITC, expanding interest to a much broader set of investors. To qualify, projects must begin "construction" by the end of 2010, although the parameters of "construction" are still being defined. Grants will come from the Treasury Department and will not be distributed until the project is placed in service. The details of the grant program are still being developed, so any restrictions associated with the grant program are unknown at this time.

In addition to these Stimulus Package incentives, to help counter the difficulties facing the financial sector, renewable projects will be able to benefit from an **expanded loan guarantee program**. An estimated \$60 to \$150 billion of loans could stem from this Department of Energy-administered program to support renewables. The impact will be to **reduce the interest rate** for renewable projects.

Other Tax Benefits

In addition to direct incentives that projects can receive, special tax treatment for renewable energy projects will also help improve project economics.

1. **5-Year Modified Accelerated Cost Recovery System (MACRS) (Accelerated Depreciation):** This allows projects that are normally depreciated over 20 years to be depreciated at an accelerated rate and over only 5 years, which helps to improve project returns.
2. **50 Percent Bonus Depreciation for 2009:** As part of the Stimulus Package, wind projects that come on-line by 2009 can also benefit from a 50 percent bonus depreciation in the first year of the project. MACRS will apply to the remaining tax basis.

Tax-Exempt Entities - Structures and Incentives

For tax-exempt entities, such as municipals and cooperatives, that cannot directly take advantage of incentives to reduce income taxes, there are alternative programs and incentives offered by the federal and state government, albeit with certain funding caps.

Clean Renewable Energy Bonds

The Energy Improvement and Extension Act of 2008 allocated $800 million for new Clean Renewable Energy Bonds (CREBs).[3] The American Recovery and Reinvestment Act of 2009 allocated an additional $1.6 billion for CREBs. ***The Internal Revenue Services has yet to announce dates for accepting new applications for the new allocations.*** Key features of CREBs for purposes of financial modeling are as follows:

- CREBs are essentially equivalent to zero-interest loans for financing qualified energy projects.[4]
- The maximum term of the bond is calculated through a formula developed by the Treasury Department and updated daily on the following Web site: https://www.treasurydirect.gov/SZ/SPESRates?type=CREBS.
- At current interest rates, the maximum term is about 15 years.
- The payments are equal annual installments based on the term of the bond, and repayment begins in the first year following bond issuance—not when the project comes on-line.
- While CREBs are issued without interest costs, there may be transaction costs and discounts necessary, depending on the market's perception of the underlying credit of the borrower or issuer. ***Note: These costs may add 1-2 percent to the project cost that is paid back each year.***
- Ninety-five (95) percent of the CREB proceeds must be spent on qualifying capital expenditures and within 5 years of receiving the allocation.
- The allocation of funds will be based on ranking eligible projects from smallest to largest dollar amount of CREBs requested, with the smallest getting first priority. [5] ***The maximum allocation to a single project for the last round of applicants was $30 million. This means larger projects (>$30 million) will likely not be able to be fully funded through CREBs alone.***

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[3] The Energy Improvement and Extension Act of 2008 also extended the deadline for previously reserved allocations until December 31, 2009.
[4] The value of the CREB to a bondholder for any year is equal to the credit, less the amount of tax payable on the credit.
[5] For the 2007 allocations, see http://www.irs.gov/pub/irs-tege/creb_2007_disclosure.pdf

Other

In addition to CREBs, tax-exempt entities could possibly qualify for the following additional incentives, though the allocation to any single project is limited for larger renewable energy projects.

- **Federal Renewable Energy Production Incentive (REPI):** REPI provides incentive payments for electricity produced and sold by new qualifying renewable energy facilities. Qualifying systems are eligible for annual incentive payments of 1.5¢ per kilowatt-hour (in 1993 dollars and indexed for inflation) for the first 10-year period of their operation, subject to the availability of annual appropriations in each federal fiscal year of operation. Eligible electric production facilities include not-for-profit electrical cooperatives, public utilities, state governments, commonwealths, territories, possessions of the United States, the District of Columbia, Indian tribal governments, or a political subdivision thereof, and Native Corporations. ***Two significant limits to the REPI are: 1) the production payment applies only to the electricity sold to another entity, and 2) while REPI mirrors the PTC in concept, REPI payments will be for a portion of requested incentives because they are subject to annual appropriations. In 2007, the payout to applicants totaled less than 20 percent of total requests.***
- **Rural Energy for America Program (REAP):** REAP promotes energy efficiency and renewable energy for agricultural producers and rural small businesses through the use of (1) grants and loan guarantees for energy efficiency improvements and renewable energy systems, and (2) grants for energy audits and renewable energy development assistance. Congress has allocated funding for the new program in the following amounts: $55 million for FY 2009, $60 million for FY 2010, $70 million for FY 2011, and $70 million for FY 2012. The REAP is administered by the US Department of Agriculture (USDA). Since the annual funding allocation is small, the USDA is likely not to fund large wind projects.

3.1.1 Biomass

Biomass is any material of recent biological origin; the most common form is wood. Electricity generation from biomass is the second most prolific source of renewable electric generation after hydroelectric power. Solid biomass power generation options include direct-fired biomass, co-fired biomass, and biomass gasification.

Direct-Fired Biomass

According to the US Department of Energy (DOE), there is approximately 35,000 MW of installed biomass combustion capacity worldwide.[6] Combined heat and power applications in the pulp and paper industry comprise the majority of this capacity.

Operating Principles

Direct-fired biomass combustion power plants in operation today use the same steam Rankine cycle introduced commercially 100 years ago. In many respects, biomass power plants are similar to other solid fuel plants. When burning biomass, pressurized steam is produced in a boiler and then expanded through a turbine to produce electricity. Prior to its combustion in the boiler, the biomass fuel may require processing to improve the physical and chemical properties of the feedstock. Furnaces used in biomass combustion include spreader stoker fired, suspension fired, fluidized bed, cyclone, and pile burners. Advanced technologies, such as integrated biomass gasification combined cycle and biomass pyrolysis, are currently under development; however, there are no integrated gasification combined cycle (IGCC) plants currently operating with biomass as a primary fuel.

Applications

Although wood is the most common biomass fuel, other biomass fuels include agricultural residues such as bagasse (sugar cane residues), dried manure and sewage sludge, black liquor from pulp mills, and dedicated fuel crops such as fast growing grasses and eucalyptus.

Biomass plants usually have a capacity of less than 50 MW because of the dispersed nature of the feedstock and the large quantities of fuel required; however, larger plants are being developed. As a result of the smaller scale of the plants and lower heating value of the fuels, biomass plants are commonly less efficient than modern fossil fuel plants. In addition to being less efficient, biomass is generally more expensive than conventional fossil fuels on a $/MBtu basis because of added transportation costs. These factors usually limit the use of direct-fired biomass technology to inexpensive or waste biomass sources.

[6]US Department of Energy, Oak Ridge National Laboratory, "Biomass Frequently Asked Questions," available at: http://bioenergy.ornl.gov/

Resource Availability

To be economically feasible, dedicated biomass plants are generally located either at the source of a fuel supply (such as a sawmill) or within 100 miles of numerous suppliers. Wood and wood waste are the primary biomass resources and are typically concentrated in areas of high forest product industry activity. In rural areas, agricultural production can often yield significant fuel resources that can be collected and burned in biomass plants. These agricultural resources include bagasse, corn stover, rice hulls, wheat straw, and other residues. Energy crops, such as switchgrass and short rotation woody crops, have also been identified as potential biomass sources. In urban areas, biomass is typically comprised of wood wastes such as construction debris, pallets, yard and tree trimmings, and railroad ties. Locally grown and collected biomass fuels are relatively labor intensive and can provide substantial employment benefits to rural economies. In general, the availability of sufficient quantities of biomass is less of a feasibility concern than the high costs associated with transportation and delivery of the fuel.

Like other Midwestern states, Ohio has a relatively strong supply of biomass resources, including large amounts of urban wood waste in more heavily populated areas. The expected cost of clean wood residues can vary by up to 50 percent, depending on the type of residue, quantity, and hauling distance. A base delivered value of $3.00/MBtu was assumed in this analysis, and includes the cost to procure biomass fuel and deliver the fuel to the plant. This is an approximate estimate based upon the distance the biomass needs to be transported. Usually, biomass is transported on trucks to the plant site and this cost goes up exponentially if the distance travelled from the biomass site to the plant is greater than 50 miles. The above cost assumption assumes that the plant site is generally within a 50 mile radius.

Cost and Performance Characteristics

Figure 3-1 presents typical characteristics of a 30 MW boiler biomass plant with Rankine cycle using wood waste as fuel.

Environmental Impacts

Biomass power projects must maintain a careful balance to ensure long-term sustainability with minimal environmental impact. Most biomass projects target use of biomass waste material for energy production, saving valuable landfill space. Biomass projects that burn forestry or agricultural products must ensure that both fuel harvesting and collection practices are sustainable and do not adversely affect the environment.

Figure 3-1
Direct Biomass Combustion Technology Characteristics

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	30
Net Plant Heat Rate (HHV, Btu/kWh)	14,500
Capacity Factor (percent)	70 to 90
Economics ($2009)	
Total Project Cost ($/kW)	4,500 to 5,100
Fixed O&M ($/kW-yr)	100
Variable O&M ($/MWh)	3.00
Levelized Cost(1) ($/MWh)	
Municipal	140 to 190
PPA(2)	120 to 140
Applicable Federal Incentives	Open loop: $10/MWh PTC *or* 30% ITC *or* 30% grant, 7-yr MACRS, Closed loop: $21/MWh PTC *or* 30% ITC *or* 30% grant, 7-yr MACRS
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	7,000

(1)The low ends of the levelized costs are based on a 90 percent capacity factor and a capital cost of $4,500/kW. The high ends of the levelized costs are based on a 70 percent capacity factor and a capital cost of $5,100/kW. Fuel cost is assumed to be $3.00/MBtu.
(2)Assumes that the project can take advantage of Federal Tax Incentives to reduce the cost of energy.

Unlike fossil fuels, biomass is viewed as a carbon-neutral power generation fuel. While CO_2 is emitted during biomass combustion, a nearly equal amount of CO_2 is absorbed from the atmosphere during the biomass growth phase. Further, biomass fuels contain little sulfur compared to coal and, therefore, produce less SO_2. Finally, unlike coal, biomass fuels typically contain only trace amounts of toxic metals, such as mercury, cadmium, and lead. However, biomass combustion still must include technologies to control emissions of NO_x, particulate matter (PM), and CO to maintain best available control technology (BACT) standards.

3.1.2 Landfill Gas

Operating Principles

LFG is produced by the decomposition of the organic portion of landfill waste. LFG typically has a methane content in the range of 45 to 55 percent. There is increased political and public pressure to reduce air and ground water pollution and to hedge the risk of explosion associated with LFG. From a generating perspective, LFG is a valuable resource that can be burned as fuel by reciprocating engines, small gas turbines, or other devices. LFG energy recovery is currently regarded as one of the more mature and successful waste-to-energy (WTE) technologies. Currently, there are more than 600 LFG energy recovery systems installed in 20 countries.

Applications

LFG can be used to generate electricity and process heat or can be upgraded for pipeline sales. Power production from an LFG facility is typically less than 10 MW. There are several types of commercial power generation technologies that can be easily modified to burn LFG. Internal combustion engines are by far the most common generating technology choice. Approximately 75 percent of the landfills that generate electricity use internal combustion engines.[7] The balance is primarily used in cofiring steam boiler or gas turbine installations. Depending on the scale of the gas collection facility, it may be feasible to generate power via a CT or a boiler and steam turbine. Testing with microturbines and fuel cells is also under way, although these technologies do not appear to be economically viable for power generation.

[7] EPA Landfill Methane Outreach Program, http://www.epa.gov/lmop/proj/index.htm.

Resource Availability

Gas production at a landfill is dependent on the depth and age of waste in place and the amount of precipitation received by the landfill. In general, LFG recovery may be economically feasible at sites that have more than 1 million tons of waste in place, more than 30 acres available for gas recovery, a waste depth greater than 40 feet, and at least 25 inches of annual precipitation.

Cost and Performance Characteristics

The economics of installing an LFG energy facility depend heavily on the characteristics of the candidate landfill. The payback period of an LFG energy facility at a landfill that has an existing gas collection system can be as short as 2 to 5 years, especially if environmental credits are available. However, the cost of installing a new gas collection system at a landfill can prohibit installing an LFG facility. Figure 3-2 presents cost and performance estimates for typical LFG projects using reciprocating engines, the most common LFG technology. Fuel costs are assumed to be $2/MBtu, and include procurement and delivery of the landfill gas from the landfill. The value is an approximation of the market value of the fuel.

Environmental Impacts

LFG combustion releases pollutants similar to many other fuels but is generally perceived as environmentally beneficial. Since LFG is principally composed of methane, if not combusted, LFG is released into the atmosphere as a greenhouse gas. As a greenhouse gas, methane is 23 times more harmful than CO_2. Collecting the gas and converting the methane to CO_2 through combustion greatly reduces the potency of LFG as a source of greenhouse gas emissions.

3.1.3 Wind

Operating Principles

Wind power systems convert the movement of air to power by means of a rotating turbine and a generator. Wind power has been the fastest growing energy source of the last decade, in percentage terms, with around 30 percent annual growth in worldwide capacity over the last 5 years. Cumulative worldwide wind capacity is now estimated to be more than 93,000 MW. Total installed wind capacity in the United States exceeded 21,000 MW as of October 2008. The US wind market has been driven by a combination of growing state mandates and the PTC, which provides an economic incentive for wind power. The PTC has been renewed several times and is currently set to expire on December 31, 2012.

Figure 3-2
Landfill Gas Technology Characteristics

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	0.2 to 15
Net Plant Heat Rate (HHV, Btu/kWh)	11,500
Capacity Factor (percent)	70 to 90
Economics ($2009)	
Total Project Cost ($/kW)	1,700 to 2,800
Fixed O&M ($/kW-yr)	27
Variable O&M ($/MWh)	17
Levelized Cost(1) ($/MWh)	
Municipal	70 to 100
PPA(2)	60 to 80
Applicable Federal Incentives	$10/MWh PTC *or* 30% ITC *or* 30% grant
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	1,100

(1)The low end of the levelized cost is based on a net plant capacity of 15 MW, a 90 percent capacity factor, and a capital cost of $1,700/kW. The high end is based on a net plant capacity of 0.2 MW, a 70 percent capacity factor, and a $2,800/kW capital cost.

(2)Assumes that the project can take advantage of Federal Tax Incentives to reduce the cost of energy.

Applications

Typical utility scale wind energy systems consist of multiple wind turbines that range in size from 1 to 3 MW. Wind energy system installations may total 5 to 300 MW, although the use of single, smaller turbines is also common in the United States for powering schools, factories, water treatment plants, and other distributed loads. Furthermore, offshore wind energy projects are now being built in Europe and are planned in the United States, encouraging the development of larger turbines (up to 5 MW) and larger wind farm sizes.

Wind is an intermittent resource, with average capacity factors generally ranging from 25 to 40 percent. The capacity factor of an installation depends on the wind regime in the area and energy capture characteristics of the wind turbine. Capacity factor directly affects economic performance; thus, reasonably strong wind sites are required for cost-effective installations. Since wind is intermittent, it cannot be relied upon as firm capacity for peak power demands at its nameplate capacity. To provide a dependable resource, wind energy systems may be coupled with some type of energy storage to provide power when required, but this is not common and adds considerable expense to a system.

Resource Availability

Turbine power output is proportional to the cube of wind speed, which makes small differences in wind speed very significant. Wind strength is rated on a scale from Class 1 to Class 7, as shown on Figure 3-3. Ohio is not a national leader in wind energy installations as a result of the available wind resources. As of May 2009, Ohio only had 7 MW of installed wind power capacity, but large wind farms have been proposed. Wind resources are best in the Northwest portion of the sate and along the coast of Lake Erie. There are also significant offshore resources in Lake Erie, but offshore wind development is very rare in the United States. Winds in these areas are generally Class 2 and 3, with smaller areas of higher class winds.

Figure 3-3
US DOE Classes of Wind Power

Wind Power Class	Height Above Ground: 50 m (164 ft)[1]	
	Wind Power Density (W/m^2)	Speed[2] (m/s)
1	0 to 200	0 to 5.60
2	200 to 300	5.60 to 6.40
3	300 to 400	6.40 to 7.00
4	400 to 500	7.00 to 7.50
5	500 to 600	7.50 to 8.00
6	600 to 800	8.00 to 8.80
7	800 to 2000	≥ 8.80

(1)Vertical extrapolation of wind speed based on the 1/7 power law, as defined in Appendix A of the *Wind Energy Resource Atlas of the US, 1991*.

(2)Mean wind speed is based on Rayleigh speed distribution of equivalent mean wind power density. Wind speed is for standard sea level conditions. To maintain the same power density, wind speed must increase 3 percent per 1,000 meters (5 percent per 5,000 ft) elevation.

Cost and Performance Characteristics

Figure 3-4 provides typical characteristics for a 100 to 200 MW wind farm. Substantially higher costs are necessary for wind projects that require grid upgrades or long transmission tie lines. After several years of high price escalation, capital costs for new onshore wind projects have stabilized. While the PTC has been extended recently, there is always some uncertainty regarding future extensions. Significant gains have been made in recent years in identifying and developing sites with better wind resources and improving turbine reliability. As a result, the average capacity factor for newly installed wind projects in the United States has increased from about 24 percent before 1999 to around 32 percent currently.

Environmental Impacts

Wind is a clean generation technology from the emissions perspective. However, there are still environmental considerations associated with wind turbines. Opponents of wind energy frequently cite visual impacts and noise as drawbacks. Turbines are approaching and exceeding heights of 400 feet and, for maximum wind capture, tend to be located on ridgelines and other elevated topography. Turbines can cause avian fatalities and other wildlife impacts if sited in sensitive areas. To some degree, these issues can be partially mitigated through proper siting, environmental review, and public involvement during the planning process.

3.1.4 Solar

Solar radiation can be captured in numerous ways with a variety of technologies. The two major groups of technologies are solar thermal and solar PVs.

3.1.4.1 Solar Thermal.

Operating Principles

Solar thermal technologies convert the sun's energy to electricity by capturing heat. Technological advances have expanded solar thermal applications to high magnitude energy collection and power conversion on a utility scale. The leading solar thermal technologies include parabolic trough, parabolic dish, power tower (central receiver), and solar chimney.

With adequate resources, solar thermal technologies are appropriate for a wide range of intermediate and peak load applications, including central station power plants and modular power stations in both remote and grid-connected areas. Commercial solar thermal parabolic trough plants in California currently generate more than 350 MW.

Figure 3-4
Wind Technology Characteristics

Performance	
Typical Duty Cycle	As Available
Net Plant Capacity, MW	100-200
Capacity Factor, percent	28-35[(1)]
Economics ($2009)	
Total Project Cost, $/kW	2,400 to 3,000
Fixed O&M, $/kW-yr	50
Variable O&M, $/MWh	(included with Fixed O&M)
Levelized Cost[(2)] ($/MWh)	
Municipal	85 to 130
PPA[(3)]	50 to 70
Applicable Federal Incentives	$21/MWh PTC *or* 30% ITC *or* 30% grant, 5-yr MACRS
Technology Status	
Commercial Status	Commercial
Installed US Capacity, MW	21,000

[(1)]Representative of existing projects in Ohio.

[(2)]The low end of the levelized cost is based on net plant capacity of 200 MW, capacity factor of 35 percent, and capital cost of $2,400/kW. The high end of the levelized cost is based on net plant capacity of 50 MW, capacity factor of 28 percent, and capital cost of $3,000/kW.

[(3)]Assumes that the project can take advantage of Federal Tax Incentives to reduce the cost of energy.

Most solar thermal systems (parabolic trough, parabolic dish, and central receiver) transfer the heat in solar insolation to a heat transfer fluid, typically a molten salt or heat transfer oil. By using thermal storage or by combining the solar generation system with a fossil fired system (a hybrid solar/fossil system), a solar thermal plant can provide dispatchable electric power.

Unlike the three other solar thermal technologies, solar chimneys do not generate power using a thermal heat cycle. Instead, they generate and collect hot air in a large (several square miles) greenhouse. A tall chimney is located in the center of the greenhouse. As the air in the greenhouse is heated by the sun, it rises and enters the chimney. The natural draft produces a wind current that rotates a collection of air turbines.

Applications

The larger solar thermal technologies (parabolic trough, central receiver, and solar chimney) are currently not economically competitive with other central station generation options (such as a natural gas fired combined cycle unit). Parabolic dish engine systems are small and modular and can be placed at load sites, directly offsetting retail electricity purchases. However, these systems have not been used in commercial applications.

Of the four technologies, parabolic trough represents the vast majority of installed capacity, primarily in the southwest US desert. There are nine Solar Electric Generating Station (SEGS) parabolic trough plants in the Mojave Desert that have a combined capacity of 354 MW. Other parabolic trough plants are being developed, including a 64 MW plant in Nevada and several 50 MW plants in Spain.

Parabolic dish engine systems of approximately 25 kW have been developed and are now being actively marketed. Recently, installation was completed on a six-dish test deployment at Sandia National Laboratories (SNL) in Albuquerque, New Mexico. On August 2, 2005, Southern California Edison publicly announced the completion of negotiations on a 20 year PPA with Stirling Energy Systems (SES) for between 500 to 850 MW of capacity of dish/Stirling units. On September 7, 2005, SES announced a contract with San Diego Gas & Electric to provide between 300 and 900 MW of solar power using the dish technology. Pricing for these PPAs remains confidential. If large deployments of dish/Stirling systems materialize, they are expected to drastically reduce capital and O&M costs and increase system reliability.

The US government has funded two utility-scale central receiver power plants: Solar One and its retrofit, Solar Two. Solar Two was a 10 MW installation near Barstow, California, but it is no longer operating because of reduced federal support and high operating costs.

The first commercial chimney project has been proposed in Australia. Originally, this project was planned to be 200 MW with a chimney 1 kilometer (0.62 mile) tall and a greenhouse 5 kilometers (3.1 miles) in diameter. More recently, the project has been scaled down to 50 MW. Cost and dimension data for the scaled down system are not available.

Resource Availability

Solar radiation reaching the earth's surface, often called insolation, has two components: direct normal insolation (DNI) and diffuse insolation (DI). DNI, which typically comprises about 80 percent of the total insolation, is that part of the radiation which comes directly from the sun. DI is the part that has been scattered by the atmosphere or is reflected off the ground or other surfaces. On a cloudy day, all of the radiation is diffuse. The vector sum of DNI and DI is termed global insolation. Systems that concentrate solar energy use only DNI, while nonconcentrating systems use global insolation. Concentrating solar thermal systems (troughs, dishes, and central receivers) use DNI. Lower latitudes with minimum cloud coverage offer the greatest solar concentrator potential. In Ohio, DNI ranges from about 2.8 $kW/m^2/day$ in the Northeastern part of the state to about 4.0 $kW/m^2/day$ in the Southwest part of the state, both of which are considered low. Some locations in the southwestern United States can have DNI as high as 8.5 $kW/m^2/day$.

A general feature of solar thermal systems and solar technologies is that peak output typically occurs on summer days when electrical demand is high. Solar thermal systems that include storage allow dispatch that can improve the ability to meet peaking requirements. Land requirements for solar thermal systems are about 5 to 8 acres/MW.

Cost and Performance Characteristics

Because the solar trough technology is by far the most commercial form of solar thermal energy systems, it was further analyzed for performance characteristics in northern Ohio. Representative characteristics for the parabolic trough solar thermal power plant technology previously described are presented on Figure 3-5. As a result of the high capital cost of solar thermal plants and lower DNI in Ohio in comparison to the southwestern United States, solar thermal generation is not likely to be viable within Ohio.

Figure 3-5
Parabolic Trough Performance Characteristics[1]

Performance	
Typical Duty Cycle	Peaking - Intermediate
Net Plant Capacity (MW)	100
Integrated Storage	3 hours
Capacity Factor (percent)	8.7
Economics ($2009)	
Total Project Cost ($/kW)	7,000 to 9,000
Total O&M ($/MWh)	67
Levelized Cost[2] ($/MWh)	
Municipal	740 to 920
PPA[3]	410 to 500
Applicable Federal Incentives	30% ITC *or* 30% grant, 5-yr MACRS
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	415

R&D = Research and Development.
(1) Parabolic trough cost estimates have a high degree of uncertainty for near-term applications.

(2) The low ends of the levelized costs are based on the higher capacity factors and the lower capital and O&M costs. The high ends of the levelized costs are based on the lower capacity factors and higher capital and O&M costs.

(3) Assumes that the project can take advantage of Federal Tax Incentives to reduce the cost of energy.

3.1.4.2 Solar Photovoltaic. Solar PVs have achieved considerable consumer acceptance over the last few years. PV module production tripled between 1999 and 2002. In recent years, PV systems as large as 51 MW_{ac} have been installed in Europe, a 12.8 MW_{ac} system was installed at Nellis Air Force Base in Nevada, and a 7 MW_{ac} system was installed in Alamosa, Colorado. PV installations reached a projected worldwide capacity of more than 2,079 MW_{ac} in 2007.[8] The majority of these installations were in Japan and Germany, where strong subsidy programs have made the economics of PV attractive. Annual US PV installations increased from 120 MW_{ac} in 2006 to an estimated 220 MW_{ac} in 2007, an increase of 100 MW_{ac} in one year. [9]

Operating Principles

The amount of power produced by PV installations depends on the material used and the intensity of the solar radiation incident on the cell. Single or polycrystalline silicon cells are most widely used today. Single crystal cells are manufactured by growing single crystal ingots, which are then sliced into thin cell-sized material. The cost of the crystalline material is significant. The production of polycrystalline cells can cut material costs, with some reduction in cell efficiency. Thin film cells significantly reduce cost per unit area, but result in lower efficiency cells. Gallium arsenide cells are among the most efficient solar cells and have other technical advantages, but they are also more costly and typically are used only where high efficiency is required even at a high cost, such as space applications or in concentrating PV applications.

Applications

The modularity, simple operation, and low maintenance requirements of solar PV make it ideal for distributed, remote, or off-grid applications. Most PV applications are smaller than 1 kW, although larger, utility-scale installations are becoming more prevalent. Worldwide, there are more than two dozen PV installations over 10 MW_{dc} and more than 600 systems that are 1 MW_{dc} or greater in capacity. Furthermore, Pacific Gas & Electric signed two PPAs in 2008 for 700 MW of PV generation. The largest system in the United States is Nellis Air Force Base PV plant, with nearly 12.8 MW of capacity.

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[8] *Renewable Energy World,* PV Market Update, source: PV News July 2007.

[9] The nomenclature used by the solar industry can be confusing. Most solar output and costs are quoted in $ per watt "peak" or "dc" (shown as MWp). This is the peak rating of the solar module, and does not take into account degradation resulting from wiring loss, inverter efficiency, temperature and other factors. For instance, the ranking of large systems uses only the peak power of the panels in "dc", not the net power output in "ac". To accurately compare to other technologies, an "ac" rating should be used (MWe). The derate factor ranges from 77 to 85 percent, depending on the photovoltaic technology and location. All of the costs for other technologies in this report are quoted on a net ac basis, and solar PV output and costs are presented in this report in a similar manner.

There have been several proposals in the United States for new PV plants with a capacity of 20 MW or higher.

Resource Availability

Most PV systems installed today are flat plate systems that use global insolation. Concentrating PV systems, which use DNI, are being developed, but are not considered commercial at this time. Global insolation on latitude tilt surfaces in Ohio ranges from about 3.0 kW/m^2/day in the Northern part of the state up to about 4.0 kW/m^2/day in the Southwestern edge of the state, compared with up to 7 kW/m^2/day in the southwestern United States. In the vicinity of Oberlin, global insolation is generally close to 3.5 kW/m^2/day.

Cost and Performance Characteristics

Figure 3-6 presents cost and performance characteristics of a 20 MW utility scale PV energy center, comparing crystalline single-axis tracking and thin film modules.

Environmental Impacts

A key attribute of solar PV cells is that they have virtually no emissions after installation. Some thin film technologies have the potential for discharge of heavy metals during manufacturing; however, proper monitoring and control can adequately address this issue.

3.1.5 Hydroelectric

Operating Principles

Hydroelectric power is generated by capturing the kinetic energy of water as it moves from a higher elevation to a lower elevation by passing it through a turbine. The amount of kinetic energy captured by a turbine is dependent on the head (distance the water is falling) and the flow rate of the water. Often, the water is raised to a higher potential energy by blocking its natural flow with a dam. If a dam is not feasible, it is possible to divert water out of the natural waterway, through a penstock, and back to the waterway. Such “run-of-river” applications allow for hydroelectric generation without the impact of damming the waterway. The existing worldwide installed capacity for hydroelectric power is by far the largest source of renewable energy at 740,000 MW.[10]

[10] International Energy Agency, 2002.

Figure 3-6
Solar PV Technology Characteristics

	Crystalline, Single-Axis Tracking	Thin Film
Performance		
Typical Duty Cycle	As Available, Peaking	As Available, Peaking
Net Plant Capacity (kW)	20	20
Capacity Factor (percent)	16	15.3
Economics ($2009)		
Total Project Cost ($/kW)	6,400 to 7,000	3,600 to 4,600
Total O&M ($/kW-yr)	65	55
Levelized Cost[2] ($/MWh)		
Municipal	380 to 410	245 to 295
PPA[3]	280 to 300	195 to 230
Applicable Federal Incentives	30% ITC *or* 30% grant, 5-yr MACRS	
Technology Status		
Commercial Status	Commercial	
Installed US Capacity (MW)	650	

[1]Includes inverter replacement after 10 years.

[2]The lower levelized costs are based on the low ends of the total project costs, and the high levelized costs are based on the high ends of the total project costs.

[3]Assumes that the project can take advantage of Federal Tax Incentives to reduce the cost of energy.

Applications

Hydroelectric projects are divided into a number of categories on the basis of their size. Micro hydroelectric projects generate below 100 kW. Systems generating 100 kW and 1.5 MW are classified as mini hydroelectric projects. Small hydroelectric systems generate between 1.5 MW and 30 MW. Medium hydroelectric projects generate up to 100 MW, and large hydroelectric projects generate more than 100 MW. Medium and large hydroelectric projects are good resources for baseload power generation if they have the ability to store a large amount of potential energy behind a dam and release it consistently throughout the year. Small hydroelectric projects generally do not have large storage reservoirs and are not dependable as dispatchable resources.

Resource Availability

A hydroelectric resource can be defined as any flow of water that can be used to capture the kinetic energy. Projects that store large amounts of water behind a dam can regulate the release of water through turbines and generate electricity regardless of the season. These facilities can generally serve baseload. Run-of-river projects do not impound the water but, instead, divert a part or all of the current through a turbine to generate electricity. At “run-of-river” projects, power generation varies with seasonal flows and can sometimes help serve summer peak loads.

All hydroelectric projects are susceptible to drought. In fact, the variability in hydropower output is rather large, even when compared to other renewable resources. The aggregate annual capacity factor for all hydroelectric plants in the United States has ranged from about 31 percent to 53 percent over the last decade.[11]

Ohio has many megawatts of developed small hydropower resources, with an estimated 319 MW of additional potential capacity.[12]

Cost and Performance Characteristics

Hydroelectric generation is regarded as a mature technology that is unlikely to advance measurably. Turbine efficiency and costs have remained somewhat stable, but construction techniques and costs continue to change. Capital costs are highly dependent on site characteristics and vary widely. Figure 3-7 provides ranges for performance and cost estimates for new hydroelectric projects, specifically at the Green-up and Meldahl sites. These values are for representative comparison purposes only. Capacity factors are highly resource dependent and can range from 10 to more than 90 percent. Capital costs also vary widely with site conditions.

[11] Based on analysis of reported data from Global Energy Solutions, 2006.
[12] Idaho National Engineering and Environmental Laboratory, “Feasibility Assessment of the Water Energy Resources of the United States for New Low Power and Small Hydro Classes of Hydroelectric Plants,” January 2006.

Figure 3-7
Hydroelectric Technology Characteristics

	New Hydro Installations
Performance	
Typical Duty Cycle	Varies with Resource
Net Plant Capacity (MW)	70 to 105
Capacity Factor (percent)	57
Economics ($2006)	
Total Project Cost ($/kW)	4,000 to 5,000
Fixed O&M ($/kW-yr)	50
Variable O&M ($/MWh)	(included in Fixed O&M)
Levelized Cost[(1)] ($/MWh)	
Municipal	115 to 140
PPA[(2)]	100 to 130
Applicable Federal Incentives	$10/MWh PTC
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	79,842

[(1)]The low end of the levelized cost is based on the higher capacity factors and the lower capital and O&M costs. The high end of the levelized cost is based on the lower capacity factors and the higher capital and O&M costs.

[(2)]Assumes that the project can take advantage of Federal Tax Incentives to reduce the cost of energy.

Environmental Impacts

The damming of rivers for small- and large-scale hydroelectric applications may have environmental impacts. One major issue involves the migration of fish and disruption of spawning habits. For dam projects, one of the common solutions to this problem is the construction of “fish ladders” to aid the fish in bypassing the dam when they swim upstream to spawn.

A second issue involves flooding existing valleys that often contain wilderness areas, residential areas, or archeologically significant remains. There are also concerns about the consequences of disrupting the natural flow of water downstream and disrupting the natural course of nature.

3.2 Resources Available from AMP

AMP has provided OMLPS with a list of different conventional and renewable alternatives that are currently available to OMLPS to consider in their long term resource planning. These resources include natural gas fired combustion turbines, combined cycle units and renewable resources like hydro, wind, and solar. Of the above resources, the combined cycle unit could be operated as an intermediate and baseload resource, while the combustion turbine could be operated as a peaking unit. Both the combined cycle and combustion turbine units would have much greater capacity than required by OMLPS to meet its long term peak demand and energy requirements. As result, it is assumed that OMLPS would need to buy a portion of the capacity and energy available from these resources to meet its obligations. The renewable resources are intermittent resources, which could be used to generate energy as and when they are available. The characteristic of the renewable resources are similar to those discussed in Section 3.1.

3.3 Market Purchases

AMP provided information to OMLPS from a power marketer, JP Morgan, for market purchases. The market purchases are based on firm LD energy. The pricing varies depending on the term of a potential power purchase agreement beginning 2012. Four different options have been offered to OMLPS, which are listed on Figure 3-8. These prices do not include any transmission or wheeling charges. OMLPS would have to pay First Energy additional network transmission charges for using their transmission lines for moving the purchased energy to its load areas. These agreements are usually not linked to any generating assets and as such these agreements are treated as energy agreements only and not as firm capacity. However, historically, AMP has provided OMLPS with backup generation capacity for market purchases or PPAs with power marketers. Assuming that AMP would continue to do so for OMLPS for these proposed energy purchases, Black & Veatch has assumed that these agreements would provide firm capacity to OMLPS's system. A capacity charge of $2.5 per kW month was used for backup capacity.

Figure 3-8
Firm LD Energy Offers

Offer Period	Price ($/MWh)
2012-2015	49.04
2012-2017	51.84
2012-2019	53.98
2012-2021	56.09

3.4 Cost and Performance Estimates for Available Resources

In addition to the cost and performance of potential renewable resources alternatives, Black & Veatch developed cost and performance estimates for some conventional generation technologies that are proven, commercially available, and widely used in the power industry. The technologies considered include simple cycle combustion turbines and combined cycle units and closely resemble the available resources indicated by AMP to be available.

Although the combustion turbines and the combined cycle alternatives discussed herein assume a specific manufacturer (GE) and specific models (i.e., aeroderivative and frame combustion turbines), doing so is not intended to limit the alternatives considered solely to GE models. Rather, such assumptions were made in order to provide indicative output and performance data. Several manufacturers offer similar generating technologies with similar attributes, and the performance data presented in this analysis should be considered indicative of comparable technologies across a wide array of manufacturers.

The capital cost estimates developed include both direct and indirect costs. The cost estimates were developed for inside the fence costs only and does not include other costs like site infrastructure development that are assumed to be outside the fence. The cost and performance estimates for the different technologies are presented on Figure 3-9.

Figure 3-9
Resources Available to OMLPS

	Green-up Hydro	Meldahl Hydro	Combined Cycle	Simple Cycle	Direct Biomass	LandFill Gas	Wind	Solar Photo Voltaics	New Hydro
Type			2x1 GE 7FA	GE LM 6000					
Total Capacity (MW)	70.2	105	550	40	30	15	100	20	70
AMP Capacity (MW)	33.7	51							
Hamilton Capacity (MW)	36.5	54							
First Year In Service Date	2014	2014	2013	2012	2013	2012	2014	2014	2016
Capital Cost w/IDC (2008$/kW)	$4,249	$4,975	1,400	1,450	4,660	1,650	2,330	3,800	5,000
Financing Period (years)	35	40	30	20	25	20	20	15	40
Bond Rate for DS %	5.50%	5.50%							
Fixed O&M (2008$/kW-year)	50.64	50.64	6.7	12.14	100	27.50	51.00	65.00	55.00
Variable O&M (2008$/MWh)	0	0	4.00	3.6	2.75	16.5	--	--	--
Full-Load Heat Rate (Btu/kWh)	N/A	N/A	6,900	9,900	14,500	11,500	--	--	--
CO_2 Emission Rate (lb/MMBtu)	--	--	118	118	--	--	--		--
NO_X Emission Rate (lb/MMBtu)	--	--	0.0072	0.0072	--	--	--		--
SO_2 Emission Rate (lb/MMBtu)	--	--	0.0006	0.0006	--	--	--		--
Capacity Credit	100%	100%	100%	100%	100%	100%	20%	57%	100%
Availability/Capacity Factor(%)	57%	57%	40-70%	5-15%	85%	85%	35%	15%	57%

3.5 Screening of Available Alternatives

A supply-side screening was performed on each of the alternatives discussed in the previous section. The supply-side screening considers each alternative's levelized cost at various capacity factors. The levelized cost for each alternative is determined on a dollar per MWh basis and includes capital costs, fuel costs, and O&M costs. The levelized cost is calculated to reflect an all-in cost for energy at a given capacity factor and is used to make screening-level comparisons of different technologies. The costs for each alternative were levelized.

The alternatives that appear favorable in the supply-side screening were evaluated further by Black & Veatch using Strategist™ software. A summary of the alternatives that will be considered further in the detailed economic analysis will be developed from these initial screenings.

A number of economic assumptions were used to develop the levelized cost screening curves. These generic assumptions included fuel price forecasts, interest rate, discount rate, and inflation rate. In addition a fixed charge rate was developed for the conventional alternatives to allocate the capital cost of the plant over a 30 year period. The FCR assumed was 8.27 percent. The other assumptions have been discussed in Section 2.0 of this report.

Figures 3-10 and 3-11 show the range of levelized costs for different alternatives considered in the study. The low end of the levelized cost is based on the higher capacity factors and the lower capital and O&M costs. The high end of the levelized cost is based on the lower capacity factors and the higher capital and O&M costs. Figure 3-10 shows the levelized cost for baseload and intermediate load technologies and Figure 3-11 shows the levelized cost for peak load technologies. Refer to Figures 3-1 to 3-9 for the assumptions used for each busbar range presented. The levelized busbar costs do not include potential renewable energy credits or emissions costs from potential CO_2 legislation.

As shown in the screening curves presented above, the cost effectiveness of various technologies will depend on the expected capacity factors at which these plants are likely to operate and their expected range of capital costs. For the intermediate and baseload units, the different types of combined cycle and landfill gas units are most cost effective. For intermittent or peak load resources, simple cycle and wind units are the most cost resources. These units were evaluated in further detailed during the economic analysis using Strategist™.

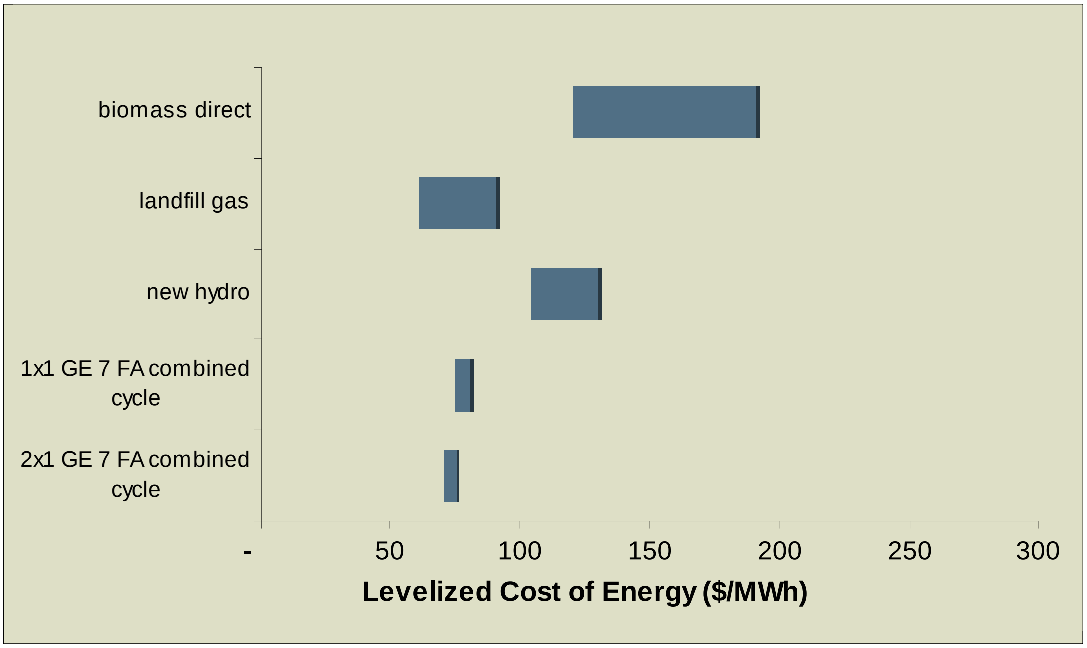


Figure 3-10
Levelized Cost ($/MWh) of Baseload and Intermediate Load Resources

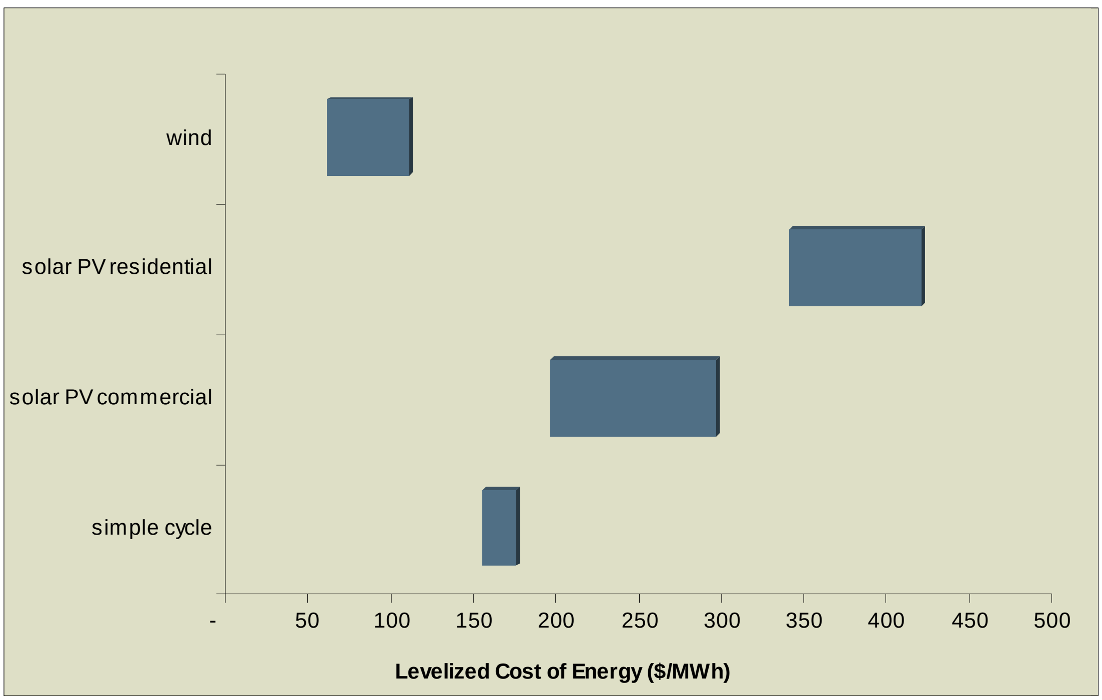


Figure 3-11
Levelized Cost ($/MWh) of Intermittent Resources

4.0 Regional Capacity Market Assessment

This section summarizes the current capacity and energy market scenario within the MISO, which is the regional transmission organization (RTO) for the OMLPS region. Historically, OMLPS has depended upon the MISO market for their energy resources. By looking at the current and near term regional market scenario, Black & Veatch has assessed the potential for OMLPS to continue to get cost effective energy resources from the MISO market.

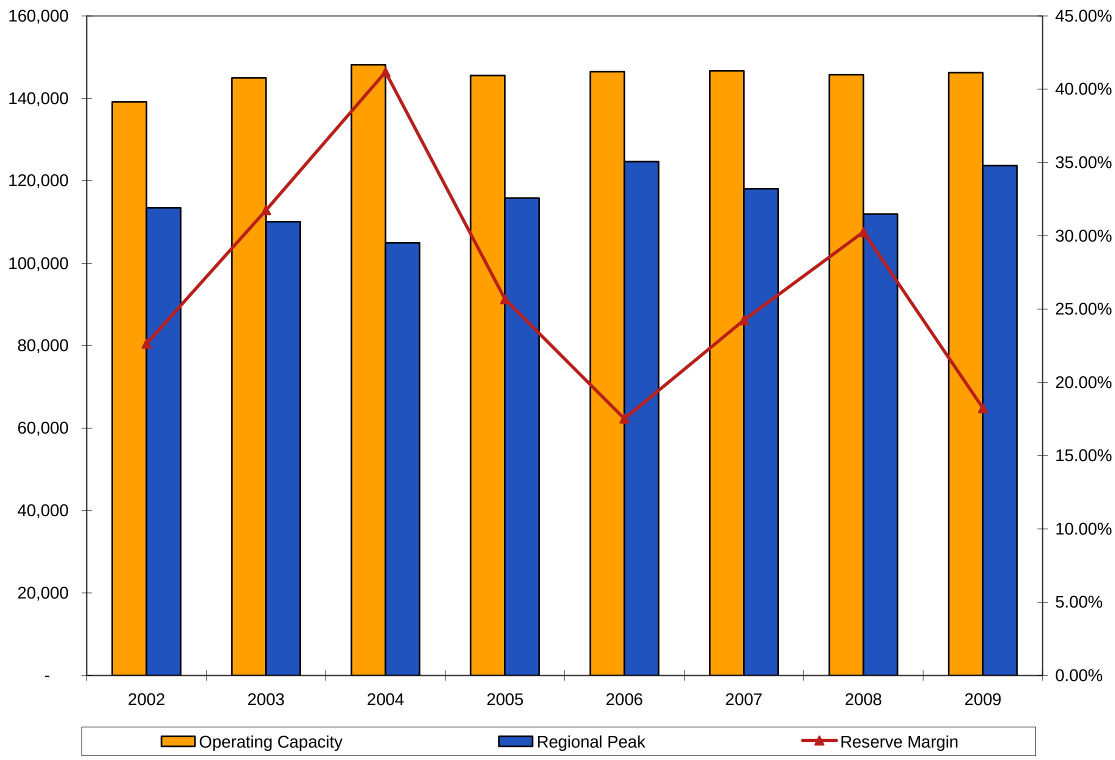
4.1 MISO Overview

MISO was formed in 2002. It is a member-based organization that provides services related to reliable cost-effective systems and operations, dependable and transparent prices, open access to energy and transmission markets, and planning for long-term efficiency. It covers all or most of Minnesota, Wisconsin, Illinois, Indiana, Michigan, Missouri, Kentucky, and Ohio. The MISO area covers three different NERC reliability regions: the Midwest Reliability Organization (MRO), Southeastern Electric Reliability Council (SERC) and ReliabilityFirst Corporation (RFC). The Cinergy, First Energy, Illinois, Michigan, Minnesota energy market hubs also fall within this region. MISO administers a two-settlement (day ahead and real-time) energy market known as the Day-2 market. It produces hourly locational marginal prices (LMP) that are rolled up into the five regional hub prices mentioned above. MISO also administers a monthly financial transmission rights (FTR) allocation and auction. In 2009, MISO implemented Ancillary Services Markets for regulating, supplemental and spinning reserves. Midwest bilateral trading is active on the Intercontinental Exchange (ICE) at the Cinergy Hub and Northern Illinois Hub.

The MISO region is dominated by coal fired generation. Coal fired resources are typically on the margin 70 to 80 percent of the time. Natural gas fired resources are on the margin for 10 to 20 percent of the time while oil fired resources are on the margin for a smaller portion of the time, in the range of 1 to 5 percent.

4.2 Historical Capacity Market

In the recent past, the RFC region of MISO has been an over built region with excess generating capacity. Figure 4-1 shows the historic peak load and capacity resources for the region. In 2002, the available capacity in the region was approximately 136,000 MW, but the load in the region was only about 115,000 MW. This resulted in a very high reserve margin in the region at that time. Since 2002, the peak load in the region has grown at an annual average growth rate of 1.24 percent. However, there has not been any significant capacity addition in the region since 2004. As a result the reserve margin in the region has declined to about 18 percent in 2009 from about 42 percent in 2004. Due to the excess capacity in the region, OMLPS has been able to acquire capacity and energy resources from the regional market in a cost effective manner.

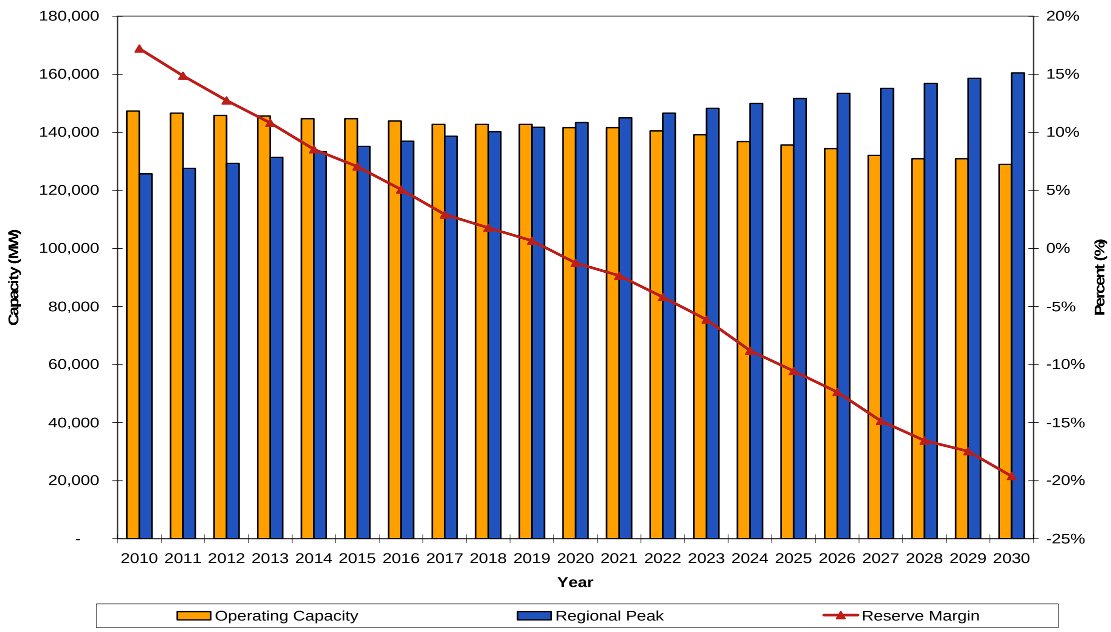


Source: Energy Velocity Database

Figure 4-1
Historical Capacity and Peak Load for RFC region in MISO

4.3 Future Capacity Market

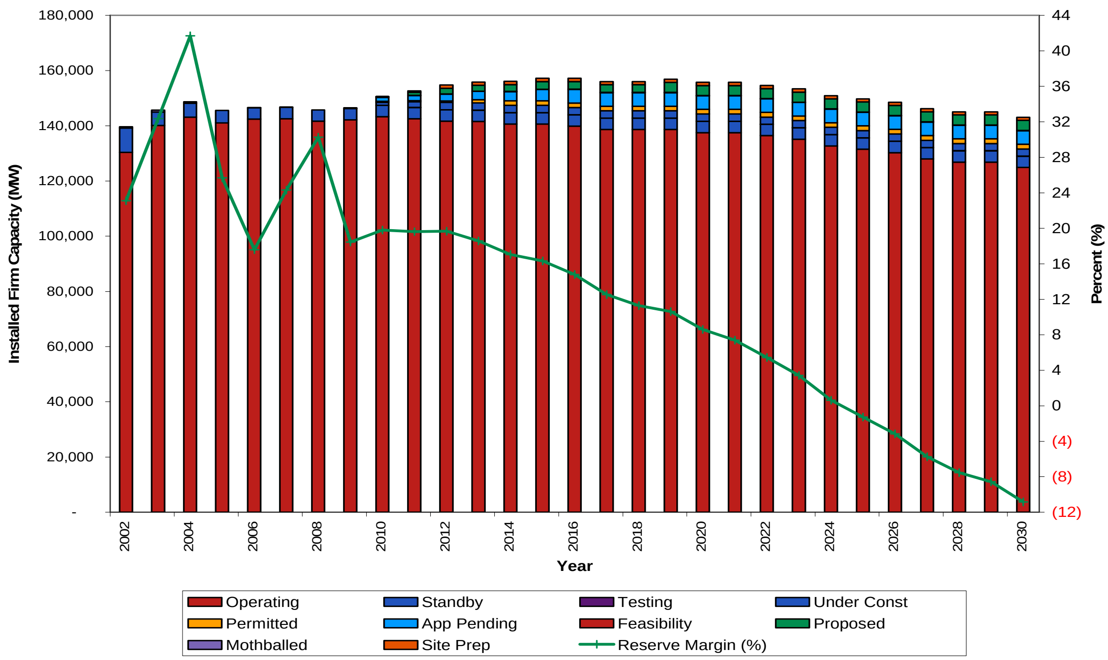
Black & Veatch also analyzed the future capacity market in the region. In doing this analysis, Black & Veatch assumed that the regional coincident peak would grow at 1.1 percent annually. This growth rate is more conservative or lower than the historical growth rate in the region. This assumption, however, is consistent with the growth rate assumed for OMLPS. Figure 4-2 shows the projected capacity and peak load resources from 2010 to 2030, assuming no new capacity resources are added in the region. If no new capacity is added, the region would experience a shortfall in capacity around 2020. However, the reserve margin in the region would be below 12 percent around 2013-2014, which is close to the time that OMLPS would need new capacity. As the reserve margin drops to around 12 percent or less, capacity and energy prices are likely to become higher and more volatile (particularly during periods of higher than average demand or large unit outages) until new resources are brought online. As a result, OMLPS may not be able to acquire capacity and energy resources from the market as cost effectively as it has done historically.



Source: Energy Velocity Database and Black & Veatch Estimates

Figure 4-2
Future Capacity and Peak Load and Reserve Margins for RFC Region in MISO Assuming No New Capacity Additions

In the next step of the analysis, Black & Veatch assessed the proposed new plants that have been announced in the region and analyzed how the projected new capacity additions would affect the capacity market in the region. Black & Veatch assumed that all new power plant projects that have been announced and are in various phases of development would all get built as planned and none of these projects would be cancelled. Black & Veatch has also assumed a 20 percent capacity value for wind resources to be consistent with the assumptions used for OMLPS. Figure 4-3 shows the historical and projected reserve margins for the region assuming all new projects are completed. The figure also indicates the different phases of development that these new projects are in at present. As a result of various factors, it is not likely that all planned resources will be placed in service as planned. However, this represents a case with the highest potential capacity available based on current plans in the region.



Source: Energy Velocity Database and Black & Veatch estimates

Figure 4-3
Historic and Projected Reserve Margins for RFC Region in MISO
Assuming New Capacity Additions

Under this full build out of planned resources, it is evident that the region would still require additional new capacity resources than those already announced. In this scenario, the reserve margin would fall below the 12 percent level by 2018 and become negative by 2024.

Many factors will affect the overall capacity balance in the region. A higher than assumed growth rate, larger number of coal and other fossil plant retirements, increased DSM or energy efficiency, delays in commercializing planned projects, and other factors will all potentially impact the capacity balance. As a result, it is possible that the reserve margins could drop below 12 percent earlier than forecast. The current trends could impact OMLPS ability to buy new cost effective capacity resources beyond 2013. In general, utilities often mitigate market price risk by entering into longer term purchases. In order to mitigate this risk, OMLPS should consider acquiring long-term capacity resources once its existing contracts expire and the Gorsuch unit is retired.

4.4 Capacity Price

As a result of current excess capacity available, capacity prices in the region have been relatively low when procuring long-term power purchases from the market. As shown on Figure 4-3, no new capacity is expected to be operational until the 2013-2017 time frame. Black & Veatch expects that capacity prices in the region should continue in the $25 to $35/kW-year until 2012 to 2013 time frame. As new capacity is added in the region from 2013 onwards, regional capacity prices are likely to increase to around $130/kW-year or higher to cover the cost of adding new combustion turbine units for capacity, which units have the lowest cost for capacity additions. How quickly prices adjust will depend on how quickly the market changes from an excess capacity situation to a deficit capacity situation.

5.0 Economic Modeling of Expansion Plan Scenarios

In order to consider the demand and energy forecast, impact of fuel prices, emissions, and other factors, a detailed economic analysis was performed to determine the least-cost capacity expansion plan to meet OMLPS's forecast capacity requirements during the planning horizon. These assumptions and methodology used in the economic analysis, as well as the results of the base case analysis, are presented below.

Black & Veatch used a capacity expansion optimization computer model, Ventyx Strategist™ (Strategist) to evaluate combinations of resources available to OMLPS to meet future demand and energy requirements. Strategist has been used in various public service commission resource planning filings in Colorado, Florida, Michigan, and other states. Strategist evaluates a typical week in each month of the year over the analysis period to optimize the least-cost generation alternatives considering peak demand, energy needs, fuel and emissions prices, fixed and variable operating costs, capital costs, and other factors and estimate annual system costs. The software also has the capability to evaluate renewable resources. Multiple combinations of future resource additions were selected by the model to meet forecast capacity and energy requirements. The resources evaluated included all the supply-side alternatives described in Section 3.0 to come up with the least cost plan.

As presented in Section 2.0, a forecast of peak demand and NEL was provided and adjusted for recent growth trends for OMLPS's system through 2029. The peak load and NEL forecasts were also reduced for the projected demand and energy savings proposed by VEIC. OMLPS forecast capacity requirements are developed considering the peak demand forecast, a 12.0 percent reserve requirement, and existing generating resources.

The economic analysis evaluated several different plans as well as sensitivities to determine the impact of various changes to the resource mix of these plans.

5.1 Modeling Assumptions and Methodology

The supply-side evaluations of generating resource alternatives were performed using Strategist, an optimal generation expansion and production cost model licensed by Black & Veatch.

Strategist evaluates all combinations of generating unit alternatives, renewable resources, and purchase power options, in conjunction with existing capacity resources, while maintaining user-defined reliability criteria. All capacity expansion plans were analyzed over a 20 year period from 2010 through 2029.

OMLPS has in the past and continues to utilize market priced purchased power transactions to meet its peak demand and energy requirements. AMP, which is a wholesale electric service provider to OMLPS, provides projected prices for these purchased power transactions and procures the necessary energy resources to meet the requirements of OMLPS. OMLPS informed Black & Veatch that AMP has procured or is in the process of procuring all resources necessary to meet OMLPS's obligations until 2012, and OMLPS would not need to plan for additional resources for this period. As such, Black & Veatch allowed the energy and capacity from market purchases to fulfill all obligations of OMLPS until 2012 and no new units or long-term PPAs were selected for this period. Beyond 2012, Black & Veatch made available all resources as discussed in Section 3.0 Black & Veatch then used Strategist to develop capacity expansion plans in which owned and purchased capacity equaled or slightly exceed the projected peak demand plus reserve margin requirements each year.

Strategist utilizes emergency energy purchases in those times that the energy requirement exceeds the energy capability of the generating resources due to forced outages. In any given year, emergency energy purchases represent a very small portion of the total annual energy requirement. Emergency energy purchases are priced at a constant $300 per MWh throughout the study period.

Strategist also utilizes economy energy purchases from the market to meet the system energy requirements during those times when the energy price in the market is lower than the cost of generating electricity from the most efficient and least cost available generating resource or purchase agreement available to OMLPS. From a modeling perspective, in any given year, the amount of market purchases can be limited to any specified amount. In order to ensure that adequate supplies are available and reliable service is provided to customers, it is generally not recommended to rely on large amounts of market purchases.

Historically, AMP has purchased some energy on the spot market on behalf of its members. Black & Veatch assumed up to 5 MW of spot market purchases per hour for every hour in the year for the period 2010 to 2012 to account for short-term PPAs as well as market purchases. This assumption was also made to prevent new resources from being added to the system during this period. Beyond 2012, Black & Veatch assumed that only a maximum of 0.5 MW per hour would be purchased from the spot market. As OMLPS does not actively trade in the spot market, no energy export or sales were assumed for the entire study period. Black & Veatch considers these assumptions to be reasonable for OMLPS system evaluation. As discussed further below, a long-term firm LD energy market based PPA was also evaluated.

Strategist estimates annual production costs for each expansion plan and ranks the plans from lowest to highest cumulative present worth cost. Strategist simulates the operation of a power supply system over the 20 year planning period by economically dispatching available resources to meet the projected capacity and energy requirements. Strategist includes variable O&M, emission costs, and fuel costs when determining the dispatch order for available generating resources. As a result, renewable resources will be dispatched first, followed by resources with the lowest total variable operating cost.

Required inputs for the model include the performance characteristics of generating units, fuel costs, fixed and variable O&M costs, emission rates and costs, demand and energy charges for purchase power resources, capital costs for future resource additions, system load profile, and projected capacity requirements including reserves.

Strategist summarizes each resource's operating characteristics for every year of the planning horizon. These characteristics include, among others, each resource's annual generation, fuel consumption, fuel cost, emissions cost, and variable O&M costs. Fixed O&M costs are included separately for new unit additions. Typically, fixed O&M costs for existing units are generally considered sunk costs that will not vary from one expansion plan to another and are not included in production cost modeling. However, Black & Veatch has included total O&M costs (including fixed O&M costs) for existing units. These costs were applied across all plans. Annual capacity charges for OMLPS existing and future power purchases were included. The cumulative present worth cost (CPWC) of each expansion plan was calculated based on projected total annual costs.

OMLPS provided the operating and cost data (including emission rates) for its existing resources. Black & Veatch provided the operating and cost data for the future new generic generation alternatives available from AMP. In addition, to these resources two landfill gas alternative responses to the request for proposal (RFP) were considered. Potential emission allowance costs for CO_2 were evaluated.

The CPWC calculation accounts for annual system costs (fuel and energy, fixed O&M, variable O&M, emissions, and levelized capital) for each year of the planning period and discounts each back to 2010 at the present worth discount rate of 5.5 percent. The total of these annual present worth costs over the 2010 through 2029 period is the resulting CPWC of the expansion plan being considered. Such analysis allows for a comparison of CPWC between various capacity expansion plans, and the plan with the lowest CPWC is considered the least-cost capacity expansion plan.

Black & Veatch followed a two step process in conducting these evaluations. In the first step, Black & Veatch identified a few base case scenario expansion plans and applied all the above assumptions to those scenarios. Once the base cases were evaluated, CO_2 price sensitivity analysis was done on these plans to estimate the likely impact of CO_2 taxes on the system cost and on the selection of new units.

5.2 Committed Resources and Other Specific Resources

In addition to the above new alternatives, Black & Veatch also included some committed units that are expected to come on line after 2012. These units include OMLPS's share of the Smithland Willow Island and Cannelton hydro units, totaling 2.6 MW. It is assumed that 1.65 MW of the hydro unit capacity comes on line in 2013 and the rest in 2014.

Black & Veatch also evaluated two low cost energy supply bids from landfill gas unit operators that were received in response to the RFP issued by OMLPS. These bids offered a start date of 2011, which is prior to OMLPS's needs. As such, Black & Veatch evaluated these PPA offers with a start date of 2011 and 2013, when OMLPS needs new generating resources for their system. This case shows the impact of commencing these purchases earlier than currently needed. Additionally, Black & Veatch assumed that the Gorsuch unit would be retired at the end of 2012.

5.3 Baseload Resources in Expansion Plan

As discussed previously, OMLPS will have predominantly peak load resources in its capacity mix in 2013. The total capacity requirement to maintain a minimum 12 percent reserve margin for 2013 is estimated to be approximately 13.5 MW. It also appears that 10 MW of this requirement can be met with baseload (or must take) resources, while the remaining 3.5 MW may require a combination of baseload, intermediate load, and peak load resources that can be dispatched to avoid having excess energy for sale during off peak periods.

As a result, Black & Veatch has selected a new, generic 10 MW block of a baseload resource in 2013 for all the expansion plans except where the RFP responses were evaluated. In cases where a 10 MW baseload unit is selected, Black & Veatch let the Strategist model optimize the remaining expansion units and selected the expansion plan that resulted in the least cost CPWC value. The different baseload units considered included: a 10 MW block of a generic 500 MW nominal 2x1 combined cycle unit, a 10 MW block of a generic 20 MW nominal landfill gas unit, and 10 MW block of a 7x24 firm LD energy market based PPA. Of these units, only the combined cycle unit is considered dispatchable.

For the case where two landfill gas RFP responses were evaluated, the RFP respondent units were considered baseload, with energy available for 92 percent of the time. Other resources were selected by the Strategist optimization model. The RFP responses were for two blocks of 4.4 MW blocks from two landfill gas units, one with a 15 year term and the other with a 20 year term.

Once the two least-cost plans were identified, Black & Veatch also evaluated adding 0.79 MW share of the Meldahl and Greenup hydro units in 2015 to estimate the impact on system costs from these unit additions.

5.4 Capacity Expansion Plans

The previous sections described the assumptions and methodology that were used to select least-cost capacity expansion plans for OMLPS. Strategist was used to estimate the total annual system costs and to establish the CPWC associated with each expansion plan. The advantage of using a program such as Strategist is that the CPWC for a large number of plans are developed and the program then ranks the expansion plans from lowest to highest CPWC.

Figure 5-1 shows the 10 least-cost plans developed for the OMLPS in order of their ranks along with their respective CPWC values and their 20 year levelized cost on a $/MWh basis . No new generic options are included prior to 2011 except when the RFP responses were evaluated for a 2011 start date. From 2010 through 2012, each plan except the above mentioned plan, is identical and relies on market-based purchases to meet projected demand and energy requirements. The cost difference between the different cases is shown on Figure 5-2. Figure 5-3 shows the detailed expansion plan for four of the ten plans shown on Figure 5-1. The four plans were selected based on the different baseload units discussed in Section 5.3.

The least-cost expansion plan for OMLPS includes the two blocks of 4.4 MW from two different landfill gas units as proposed by the RFP respondents (8.8 MW total) in 2013 along with other resources as highlighted on Figure 5-3. The CPWC for the plan is $144.084 million ($91.06/MWh on a levelized cost basis). From a CPWC basis, the difference between the RFP response PPAs starting in 2013 and 2011 is relatively small. In addition, the CPWC increase to enter into a PPA for a 0.79 MW share of the Meldahl and Greenup hydro units in 2015 is relatively small with an increase of only 0.5 percent to $144.811 million ($91.51/MWh on a levelized cost basis).

Figure 5-1
Ranking of Different Expansion Plans with CPWC Values

Plan Description	CPWC Value 2010 Dollars (000s)	Levelized Cost ($/MWh)	Rank	Percent Difference
8.8 MW block of landfill gas unit from RFP respondents in 2013 with CO_2 taxes assumed	144,084	91.06	1	
8.8 MW block of landfill gas unit from RFP respondents in 2013 with CO_2 taxes implemented and with 0.79 MW of new hydro added in 2015	144,811	91.51	2	0.5%
8.8 MW block of landfill gas unit from RFP respondents in 2011 from RFP respondents with CO_2 taxes implemented	145,171	91.81	3	0.8%
8.8 MW block of landfill gas unit from RFP respondents in 2013 with CO_2 taxes implemented and with 2 MW nameplate capacity of new wind resources (0.4 MW Firm Capacity) added in 2015	146,807	92.74	4	1.9%
10 MW block of generic landfill gas unit with CO_2 taxes implemented	149,824	94.64	5	4.0%
10 MW block of generic landfill gas unit with CO_2 taxes implemented and with 0.79 MW of new hydro resources added in 2015	150,225	94.9	6	4.3%
10 MW block of generic landfill gas unit with CO_2 taxes implemented and with 2 MW nameplate capacity of new wind resources (0.4 MW Firm Capacity) added in 2015	152,348	96.21	7	5.7%
10 MW block of generic 500 MW 2x1 combined cycle or equivalent unit with CO_2 taxes implemented	154,478	97.44	8	7.2%
10 MW new PPA (2013-2021) with 10 MW block of generic landfill gas unit in 2022 with CO_2 taxes implemented	156,575	98.87	9	8.7%
10 MW new PPA (2013-2021) with 10 MW block of generic combined cycle unit in 2022 with CO_2 taxes implemented	164,510	103.59	10	14.2%

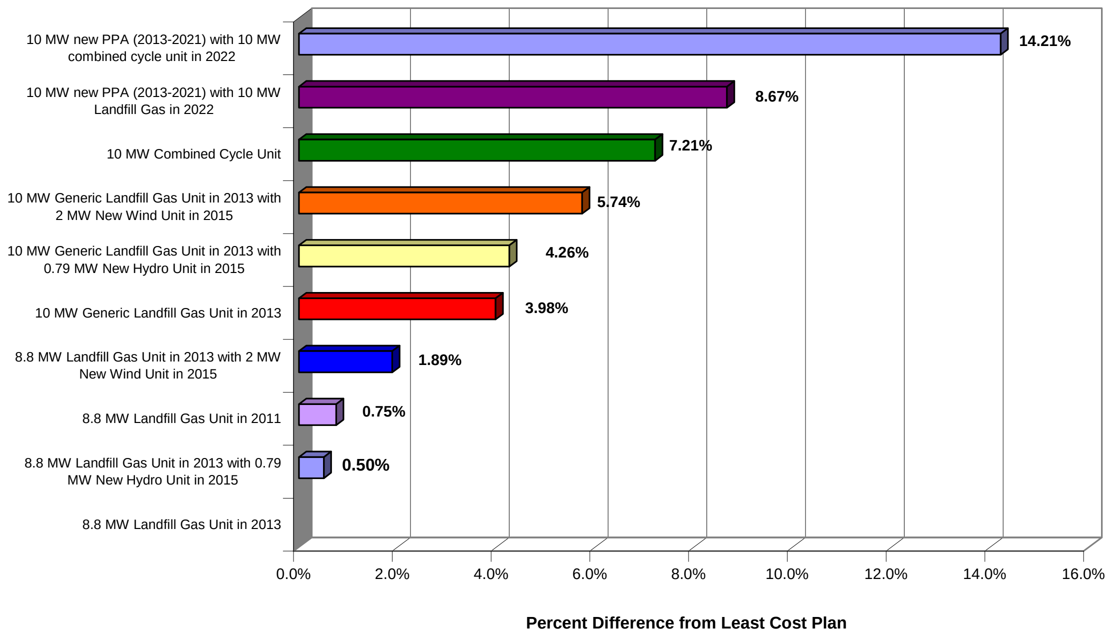


Figure 5-2
Percent Difference in Cost of Selected Expansion Plans Compared to Least Cost Expansion Plan

Figure 5-3
Detailed Expansion Units for Selected Plans

Year	Plan 1			Plan 2			Plan 3			Plan 4		
	8.8 MW block of landfill gas unit from RFP respondents in 2012 with CO_2 taxes implemented			10 MW block of generic landfill gas unit with CO_2 taxes implemented			10 MW block of 500 MW generic 2x1 combined cycle or equivalent unit with CO_2 taxes implemented			10 MW new PPA (2013 - 2021) with 10 MW block of generic landfill gas unit in 2022 with CO_2 taxes implemented		
	Resource	Units	MW	Resource	Units	MW	Resource	Units	MW	Resource	Units	MW
2010												
2011												
2012												
2013	RFP I LFG	1	4.4	Landfill Gas	1	10	Combined Cycle	1	10	PPA	1	10
	RFP II LFG	1	4.4	Combined Cycle	4	4	Landfill Gas	4	4	Combined Cycle	4	4
	Combined Cycle	5	5									
2014												
2015												
2016							Landfill Gas	1	1			
2017												
2018	Landfill Gas	1	1									
2019				Combined Cycle	1	1	Landfill Gas	1	1	Combined Cycle	1	1
2020												
2021	Landfill Gas	1	1							10 MW PPA Retired	1	(10)
2022				Landfill Gas	1	1	Landfill Gas	1	1	Landfill Gas	1	1
										Landfill Gas	1	10
2023												
2024												
2025	4.4 MW RFP II Retired	1	(4.4)	Landfill Gas	1	1				Landfill Gas	1	1
	Landfill Gas	2	2									
2026	Landfill Gas	2	2				Landfill Gas	1	1			
	Combined Cycle	1	1									
2027	Landfill Gas	1	1									
2028	Landfill Gas	1	1	Landfill Gas	1	1				Landfill Gas	1	1
2029												
Total Capacity Added			18			18			18			18

In addition to the above cases, Black & Veatch also evaluated the scenario where OMLPS does not acquire any long term resources, but instead relies on the short term capacity and energy purchases from the over the counter energy trading markets. In evaluating this scenario, Black & Veatch assumed that OMLPS would have to pay for capacity charges at the going market rate in addition to the energy charges. It was assumed that capacity prices would be $130/kW-year in 2013 with an annual escalation of 3 percent in subsequent years. Although current capacity prices are much lower ($25 to $35/kW-year), it is expected that capacity prices will increase up to this level or higher once the oversupply situation in MISO dissipates. The energy charges assumed in this case also include CO_2 taxes.

Under this scenario, the CPWC of OMLPS is expected to be around $206.241 million, which is 43.1 percent higher than the least cost plan. In addition, this plan exposes OMLPS to the risks associated with market price volatility. Energy market prices can be extremely volatile as they are dependent on the spot market fuel prices. As fuel prices vary, the cost to purchase energy can easily deviate appreciably from the expected or anticipated value. This scenario would expose OMLPS to buying inefficient and expensive energy resources during portions of the year when supply may be constrained.

One of the other key assumptions of this scenario is that OMLPS would have sufficient supply of capacity and energy from the spot market. While this may be possible currently due to the overbuilt MISO market, resources may become scarce in the future unless new resources are added to meet load growth when required.

The impact of adding 2 MW of wind was also evaluated. Because wind is an intermittent resource, additional capacity resources are required to back up the wind. Only 20 percent of the wind nameplate was considered as capacity, as is often assumed. The CPWC for this option was $146.807 million ($92.74/MWh on a levelized cost basis), which is 1.9 percent higher than the least-cost plan.

All of the above options have lower CPWC than the next lowest cost baseload alternative resource, which is the 10 MW block of a generic landfill gas unit. The CPWC of that plan is $149.824 million ($94.64/MWh on a levelized cost basis) and is 3.9 percent higher than the least cost plan. The detailed expansion plan for this option is shown on Figure 5-3. Adding hydro and wind resources in 2015 increases the CPWC of OMLPS to $150.225 million ($94.9/MWh on a levelized cost basis) and $152.348 million ($96.21/MWh on a levelized cost basis), respectively.

The next lowest cost baseload alternative resource is the 10 MW block of a generic 500 MW 2x1 combined cycle unit. The CPWC of that plan is $154.478 million ($ 97.44/MWh on a levelized cost basis) and is 7.2 percent higher than the least cost plan. The detailed expansion plan for this option is shown on Figure 5-3.

The most expensive baseload resource was the proposed 10 MW 7x24 baseload PPA offer when potential CO_2 emission allowance prices are considered in the evaluation. Two different options were evaluated. The first option looked at adding 10 MW landfill gas units in 2022 to replace the PPA and the other option looked at adding additional 10 MW combined cycle units in 2022 to replace the PPA. The CPWC of the option with landfill gas units as replacements in 2022 was $156.675 million ($98.87/MWh on a levelized cost basis) and that of the other option was $164.557 million ($103.59/MWh on a levelized cost basis). The 7x24 firm LD energy PPA included different tenors, and all of these were considered. The least cost firm LD energy PPA plan was the 9 year PPA, which starts at the beginning of 2013 and expires in 2021. Since the PPA expires prior to the end of the study period, additional generic generating resources were added to replace this PPA once it expired. Alternatives considered at the end of this PPA included a block of combined cycle and a block of landfill gas. The detailed expansion plans for both of these options are similar. As the option with the 10 MW landfill gas units has the lower cost of the two options discussed above, the detailed expansion units for this plan are included on Figure 5-3.

5.5 Sensitivity Analysis

In order to further evaluate the cases, additional sensitivities were evaluated as some of the variables may show high variation with the projected values. This could change the rankings of the different plans. It is therefore important to look at different sensitivities based on different assumptions for some of the key inputs to the economic model. Some of the typical variables on which sensitivities can be done include capital costs of new units, load forecast, market power and gas costs, coal prices, and CO_2 emission allowance prices. Based on experience, fuel prices and potential CO_2 allowance price sensitivities are the most critical for planning studies.

The alternatives evaluated in general included various mixes of renewable resources, gas fired resources, or direct market power purchases with a fixed energy and capacity cost. These alternatives were evaluated with the potential impact of possible CO_2 legislation. In the base case, alternatives were evaluated assuming a CO_2 price forecast from AEO2009, which has a significant impact on market purchases. As a result, four different plans shown on Figure 5-3 were evaluated where no CO_2 allowance prices were considered. The percent difference in cost for the four different plans is shown on Figures 5-4 and 5-5.

Figure 5-4
Ranking of Selected Expansion Plans With No CO_2 Allowance Costs

Plan Description	CPWC Value -2010 Dollars (000s)	Levelized Cost ($/Mh)	Rank	Percent Difference
10 MW new PPA (2013-2021) with 10 MW block of generic landfill gas unit in 2022	135,322	85.37	1	--
8.8 MW block of landfill gas unit from RFP respondents in 2013	140,264	88.70	2	3.7%
10 MW block of generic 500 MW 2x1 combined cycle or equivalent unit	144,923	91.56	3	7.1%
10 MW block of generic landfill gas unit	145,031	91.70	4	7.2%

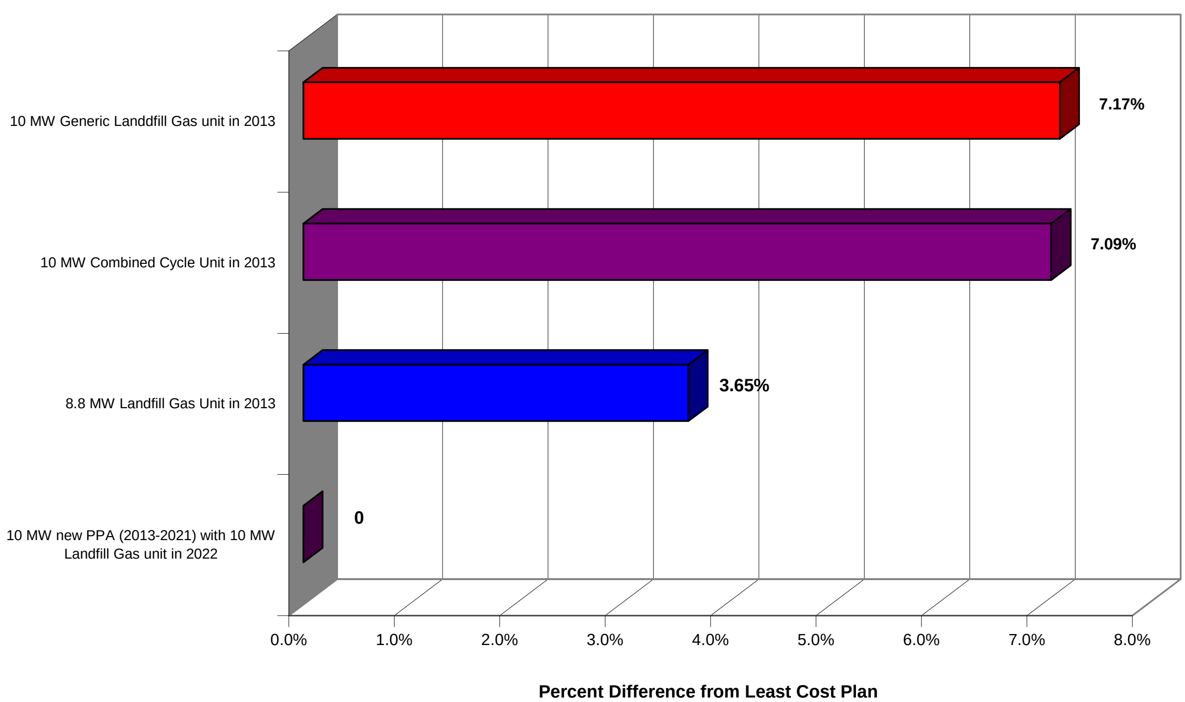


Figure 5-5
Expansion Plan Cost Differentials Without Impact of Potential CO_2 Allowance Cost

Under this scenario, the ranking of the plans does change. As expected, the plan that is impacted the most is the 10 MW market purchase PPA (2013-2021) plan. As explained in the above paragraph, this plan is the most carbon intensive plan as most of the generation is likely to be supplied by coal based plants in Ohio. This plan now becomes the least cost plan. Compared to the base case, where CO_2 taxes were assumed, the total change in the CPWC for this plan is $21.253 million, which equates to a levelized cost difference of $13.5/MWh. As a result, the market purchase based plan would be the lowest under a no carbon legislation scenario, but also would be much more exposed to higher prices should carbon legislation be adopted.

The market energy offered to OMLPS also would not typically be backed by any generating assets and only provide for liquidated damages if energy is not supplied in accordance with the contract. Under such circumstances, OMLPS would need to purchase energy on the spot market, which is typically more volatile, or rely on peaking generators, which have a high cost of generation. These factors are difficult to quantify, but nevertheless are potential risks of firm LD energy contracts.

As expected, the 10 MW combined cycle plan in 2013, has a lower CPWC under this scenario as compared to the base case, although its cost savings is not as much as the market purchase case. The smaller CPWC reduction is a result of this plan's lower CO_2 emission profile. Natural gas fired units are generally considered highly reliable, with a lower CO_2 emissions profile compared to market or coal purchases. However, natural gas units can experience price volatility associated with changes in gas prices.

The other two plans are heavily dependent on landfill gas resources, which are considered carbon neutral. So the difference in CPWC for these plans under the scenario without CO_2 allowances is not significant. The reduction in plan cost is due to the carbon emissions associated with the gas based peaking and intermediate units, which are part of the long-term expansion plan, as well as small market purchases.

Although landfill gas resources are considered carbon neutral, these resources can experience higher forced outages than other units. This can be mitigated by having multiple smaller units or purchases to some degree. The least cost plan in the base case evaluation includes two purchases of 4.4 MW landfill gas from separate plants. The RFP respondent provided an estimate of 92 percent availability for these plants. If this plan is adopted, a large portion of the baseload supply for OMLPS will come from landfill gas units, which could experience higher levels of forced outage. To assess this potential risk, a sensitivity case was evaluated that reduced these plant availabilities to 75 percent.

Under this reduced availability scenario, the CPWC increased slightly to $146.167 million ($92.35/MWh on a levelized basis) from $144.084 million ($91.06/MWh on a levelized basis). This cost difference is small because the expansion plan under this scenario includes the addition of 4 MW of combined cycle units in 2013 in addition to these landfill gas units. The combined cycle units are supplying much of the back-up power for the landfill gas units in this scenario and when the availability of the landfill gas units is reduced, the combined cycle units are ramped up to provide the necessary energy. At this time, OMLPS does not have combined cycle capacity in its portfolio. As a result, it may be prudent to consider adding combined cycle and landfill gas concurrently.

6.0 Emissions Profile

This section summarizes the emissions profile of the different plans discussed in Section 5.0. Historical annual emissions quantities have been documented and compared to projected emissions for selected plans to show the level of emission reduction achieved in all the cases. Forecast emissions are based on estimated emissions rates, forecast operation for new units, and Ohio averages for market and PPA purchases. Insufficient information was available to estimate potential changes in mercury emissions. In general, mercury emissions will be a function of mercury content in the fuel source.

6.1 Emissions Overview

Coal generation has the greatest impact on the emission profile of the region as it typically has the highest rate of emissions for every unit of fuel burned. On the other hand, natural gas fired resources have the lowest emission rates amongst all fossil fuels. Renewable resources including wind, solar, and hydro units do not have any emissions at all. Landfill gas and biomass will have emissions of various pollutants, but are generally considered carbon neutral with no CO_2 emissions.

Nuclear units also do not emit any of the above mentioned emissions, except for minor emissions from support or backup systems. The emission rates of CO_2 gases are dependent on the quality of the fuel burned. In general, the CO_2 emission rate for coal based generation usually varies between 200-220 lb/MMbtu. In comparison, CO_2 emission rate for gas and oil based generation usually varies between 115-120 lb/MMbtu and 155-170 lb/MMbtu, respectively.

6.2 Emissions Overview for the State of Ohio

Black & Veatch estimated the existing and projected emissions for the OMLPS system. In doing so Black & Veatch needed to estimate a system wide emission rates for the CO_2 in order to estimate the emissions from the energy purchased from on the spot market or from the long term market purchases contracts.

Total generation in Ohio in 2008 was approximately 145,334 GWh, of which 127,804 GWh were generated from fossil fuel at an average heat rate of 10,170 Btu/kWh (according to the Energy Velocity Database). Fossil fuels include coal, natural gas, and oil. The estimated total CO_2 emissions in Ohio for power generation for 2008 were approximately 132,341,000 tons. This quantity corresponds to an average rate of CO_2 emissions in Ohio of approximately 1.04 tons/MWh.

Black & Veatch used this average emission rate to estimate the emissions from the present and future market power purchases and for the energy purchased under existing and future PPA. The cost impact of CO_2 emissions for these resources was computed on a dollar per megawatt hour basis by applying the above emission allowance rates to the emission allowance price forecast previously discussed, and then added to the energy price to come up with a composite cost of energy on a dollar per megawatt hour basis.

6.3 CO_2 Emissions Profile

The CO_2 emission profile for the four key expansion plans discussed in Section 5.0 was analyzed. Figure 6-1 shows the historical and projected CO_2 emissions for OMLPS for the different expansion plans considered.

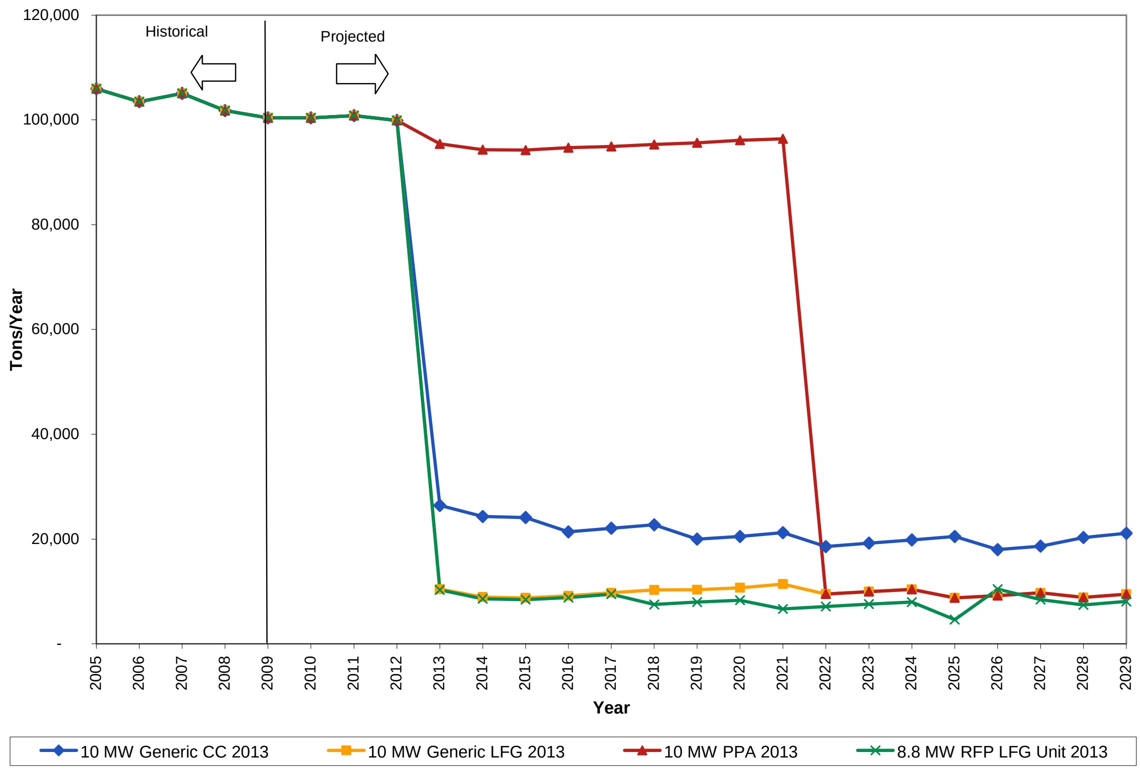


Figure 6-1
Historical and Projected CO_2 Emissions

The emission profile is similar for all the plans until 2012, as no new resources are added in any of the plans for the period 2010 to 2012. Beyond 2012, the plan that includes 8.8 MW of landfill gas units has the greatest reduction in CO_2 emission after the new resources come online in 2013. The total reduction is forecast to be 74 percent compared to the previous year. As a result, the landfill gas units are attractive in terms of cost and emissions profile. The plan which includes the 10 MW purchase under PPAs has the highest emissions profile for CO_2. It is also the highest cost option of all plans evaluated. However, this plan becomes the least cost plan under the "without CO_2" scenario as it has the highest CO_2 profile. The reduction in emissions for this plan after the new resources come online in 2013 is only about 2 percent compared to the previous year. CO_2 emissions remain elevated under this plan until the PPA expires and new generic resources come online. The 10 MW combined cycle plan and the 10 MW generic landfill gas plans also reduce CO_2 emissions profile significantly in 2013, but at a slightly higher level than the least-cost plan.

6.4 SO_2 Emissions Profile

The SO_2 emissions profile for the four key expansion plans discussed in Section 5.0 was also evaluated. Figure 6-2 shows the historical and projected SO_2 emissions for OMLPS for the different expansion plans considered.

The emissions profile is similar for all the plans until 2012, as no new resources are added in any of the plans for the period 2010 to 2012. Beyond 2012, the plan that includes 10 MW of generic combined cycle units has the greatest reduction in SO_2 emissions after the new resources come online in 2013. The total reduction is forecast to be 98 percent compared to the previous year. The PPA plan has the highest emissions profile for the period 2013-2021, when the PPA is assumed in effect, as a result of the fact that coal generation has high SO_2 emissions. Beyond 2021, the PPA is assumed to be replaced by landfill gas units, and the SO_2 profile is similar to the other plans with landfill gas units. The other plans with landfill gas have similar emissions profiles.

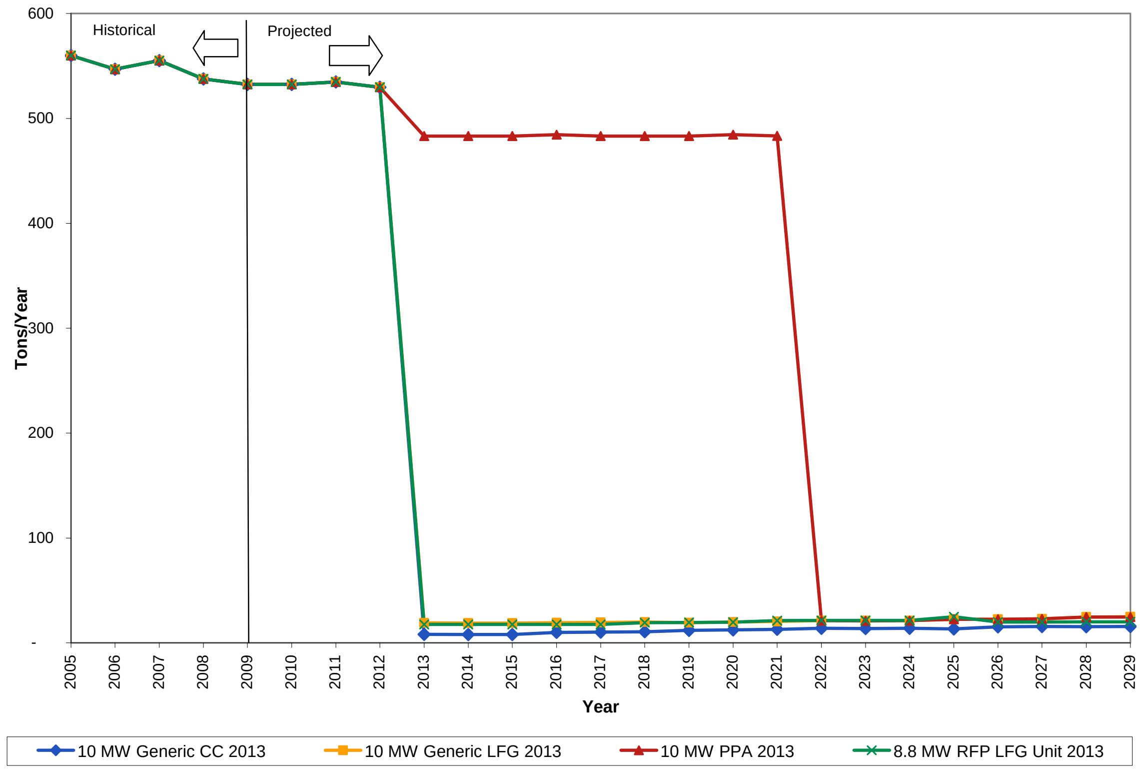


Figure 6-2
Historical and Projected SO_2 Emissions

6.5 NO_x Emissions Profile

The NO_x emissions profile for the four key expansion plans discussed in Section 5.0 was also analyzed. Figure 6-3 shows the historical and projected NO_x emissions for OMLPS for the different expansion plans considered.

The emission profile is similar for all the plans until 2012, as no new resources are added in any of the plans for the period 2010 to 2012. Beyond 2012, the plan that includes 10 MW of generic combined cycle units has the greatest reduction in NO_x emission after the new resources come online in 2013. The total reduction is forecast to be 76 percent compared to the previous year. The 10 MW PPA has the least reduction in NO_x until the PPA ends, after which the emission profile is similar to the 10 MW generic landfill gas (2013) plan. The least cost plan with 8.8 MW of landfill gas has a relatively high NO_x profile as landfill gas units have high NO_x emissions.

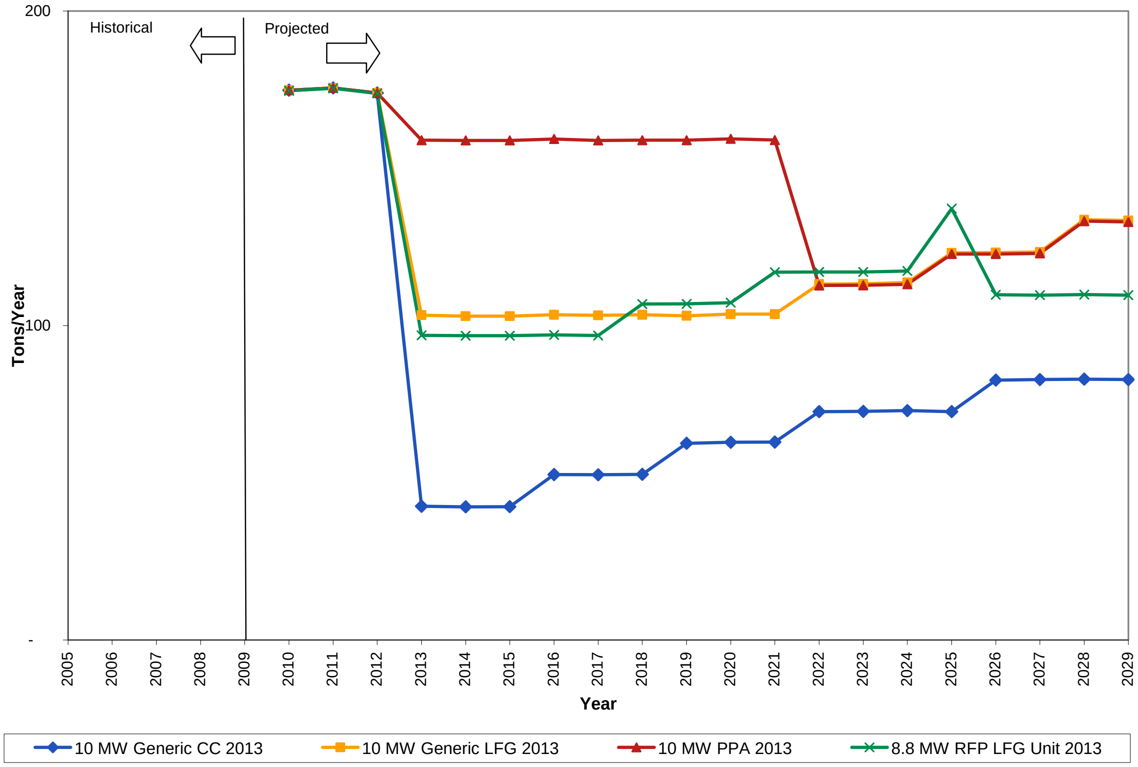


Figure 6-3
Historical and Projected NO_x Emissions

7.0 Recommendations

Based on the analyses and evaluations, Black & Veatch recommends the following for OMLPS to consider in procuring capacity and energy resources needed in the near term:

- As the Gorsuch station is planned to be retired in 2012 and other short-term contracts are scheduled to expire, it is recommended that OMLPS obtain new baseload and intermediate resources to provide for reliable service to its customers.
- Based on information available at the time of this study, the hydroelectric purchase that has been offered to the OMLPS appears to be relatively economical and has a zero emissions profile. In addition, it appears that OMLPS system should be able to accommodate the addition of 0.79 MW (or moderate increases to this amount if available). It is recommended that OMLPS continue to pursue the hydroelectric capacity and energy for its system.
- It is recommended that OMLPS pursue negotiations and purchases of economical landfill gas capacity. Some of the landfill gas RFP responses appeared economically attractive based on Black & Veatch's analyses. In addition, landfill gas resources are considered carbon neutral and, therefore, will help OMLPS in pursuing its goal of minimizing CO_2 emissions.
- To minimize potential for landfill gas unit availability risk, Black & Veatch recommends that OMLPS consider mitigating measures such as availability penalties in purchase contracts, diversifying landfill gas resources to the extent possible, and including dispatchable resources in its portfolio mix that can be used to provide economical backup energy as needed.
- In addition to a large baseload energy need, OMLPS also has a need for additional intermediate energy. This need can be filled with partial ownership/purchase from a combined cycle facility. It is recommended that OMLPS consider purchase of combined cycle capacity as available.
- If OMLPS is unsuccessful in negotiating acceptable landfill gas or intermediate power purchases, it is recommended that intermediate term wholesale contracts be pursued to maintain reliable service.

- Black & Veatch recommends that OMLPS continue to monitor actual DSM and energy efficiency savings achieved by VEIC, and adjust its resources as needed.
- Since recent historical growth rates are low and negative because of the recession, a low growth rate has been forecast for future years of the study. Black & Veatch recommends that OMLPS monitor its load growth closely and adjust its resources if growth resumes at higher rates.