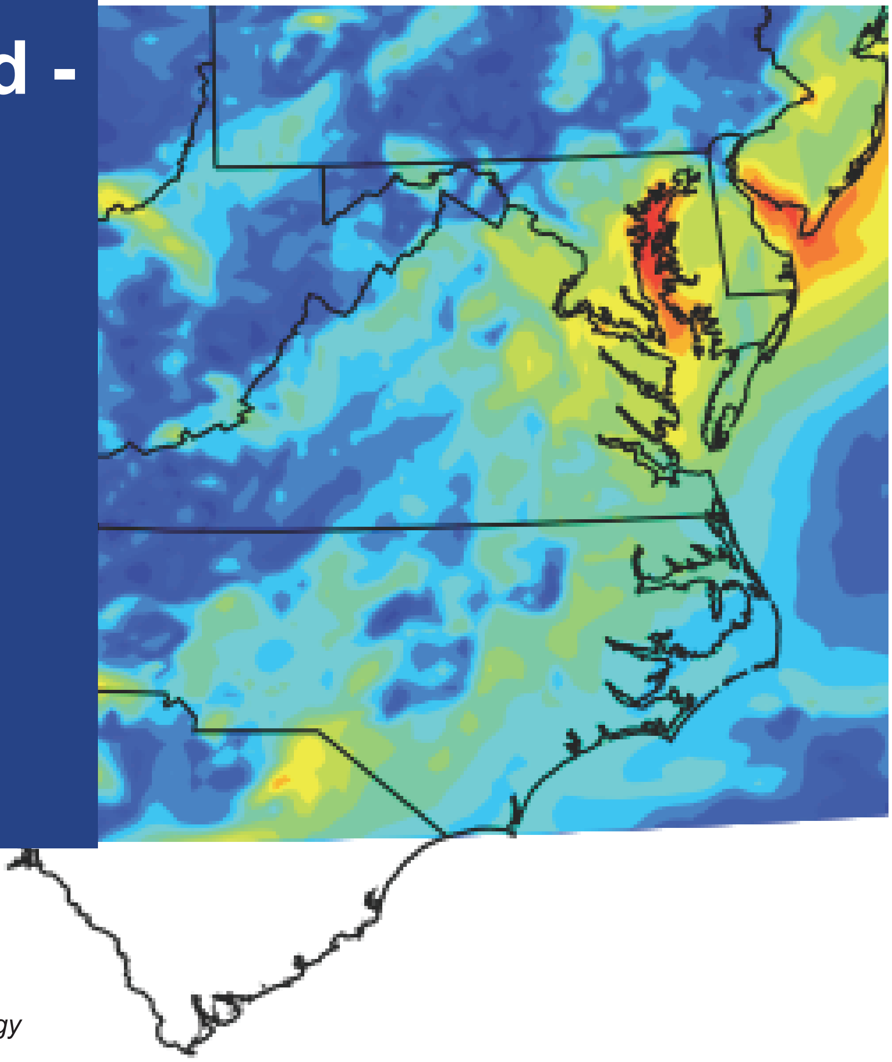
Mid-Atlantic Wind - Overcoming the Challenges



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Contract Information:

Contract No.: DE-EE0000513
US Department of Energy, Wind and Hydropower Technologies Program

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May 31, 2012

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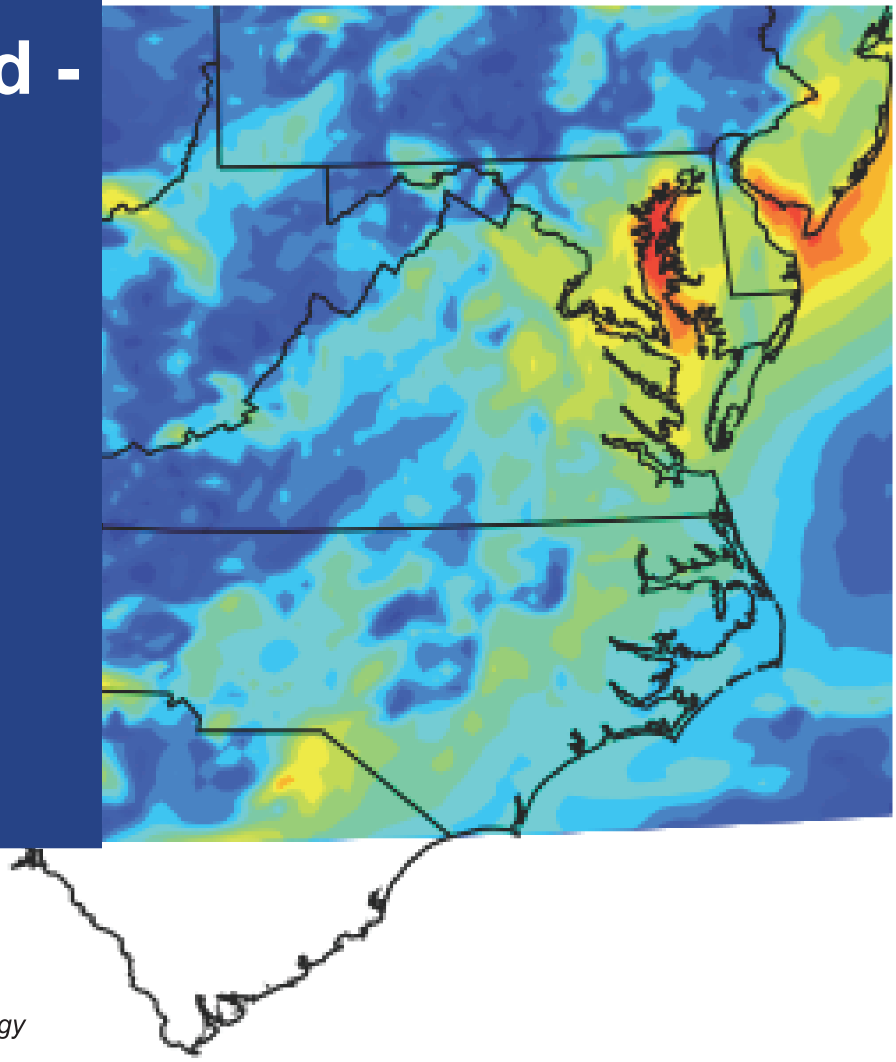

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Front Cover: Early evening low-level jet at 140 meters computed with Weather Research Forecast Model at a 9 km horizontal resolution using the Mellor-Yamada-Janjic (MYJ) boundary layer scheme, with warmer colors indicating stronger mean wind speeds.

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Abbreviations	Definition
AEP	Annual energy production
AGL	Above Ground Level
AOE	Annual operating expenses
APCO	Appalachian Power Company
AWEA	American Wind Energy Association
bp	Basis point
BNEF	Bloomberg New Energy Finance
BOEM	Bureau of Ocean Energy Management (formerly the DOI Bureau of Ocean Energy Management, Regulation and Enforcement)
BOS	Balance of station
BWEA	British Wind Energy Association
CAA	Clean Air Act
CBF	Chesapeake Bay Foundation
CF	Capacity factor
COE	Cost of energy
Cp	Coefficient of performance
CPCN	Certificate of Public Convenience and Necessity
db	Decibel
DCF-ROI	Discounted Cash Flow - Return on Investment
DELMARVA	Delaware-Maryland-Virginia Peninsula
DNR	Maryland Department of Natural Resources
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
Dominion	Dominion Electric Power Company
DPL-ODEC	Delmarva Power and Light - Old Dominion Electric Company
DSIRE	Database of State Incentives for Renewable Energy and Efficiency
EIA	Energy Information Administration
EPC	Engineering procurement and construction
EPRI	Electric Power Research Institute
EU	European Union
EWITS	Eastern Wind Integration Study
FCR	Fixed charge rate
FERC	Federal Energy Regulatory Commission
GW	Gigawatts
GHG	Greenhouse Gas
HAP	Hazardous Air Pollutant
HURDAT	Hurricane Database
HVDC	High-voltage direct current
ICC	Installed capital cost
IEC	International Electrotechnical Commission
IPPs	Independent power producers
IRR	Internal Rate of Return

ITC	Investment Tax Credit
Km	Kilometers
kWh	Kilowatt-hour
LCOE	Levelized Cost of energy
LDA	Locational Deliverability Area
LIBOR	London Interbank offered rate
LLJ	Low Level Jet
LMP	Locational Marginal Pricing
m	Meters
m/s	Meters per second
MAAC	Mid-Atlantic Area Council
MACT	Maximum Achievable Control Technology
MARCS	Modified accelerated cost recovery system
MRPA	Mountain Ridge Protection Act
MW	Megawatt
MWh	Megawatt-hour
NCUC	North Carolina Utilities Commission
NGO	Non-Government Organization
Nm	Nautical Mile
NOS	National Ocean Service
NO_X	Nitrogen oxides
NREL	National Renewable Energy Laboratory
NUG	Non-Utility Generator
O&M	Operations and Maintenance
PACE	Property-Assessed Clean Energy
PERI	Princeton Energy Resources International, LCC
PJM	Pennsylvania-Jersey-Maryland Interconnection
PPA	Power purchase agreement
PSC	Public Service Commission
PTC	Production tax credit
PUC	Public Utility Commission
REC	Renewable energy certificate
RGGI	Regional Greenhouse Gas Initiative
RPS/RPG	Renewable Portfolio Standards or Goals
SO_X	Sulfur Oxides
SPP	Southwest Power Pool
TVA	Tennessee Valley Authority
UMBC	University of Maryland Baltimore County
VCERC	Virginia Coastal Energy Research Consortium
WPD	Wind Power Density
WRF	Weather Research and Forecast

1.0 Executive Summary

The Mid-Atlantic region, including Delaware, Maryland, North Carolina, Virginia, and the District of Columbia, has areas with excellent wind energy potential yet has only two utility scale projects installed to date. The absence of wind energy projects for bulk power generation continues despite a growing demand for electricity that is among the highest in the nation. Ample wind resources are available at Appalachian mountain ridgeline sites, on the coastal plains, at shallow sheltered water sites in Delaware and Chesapeake Bays, Albemarle and Pamlico Sounds, and at deeper water sites off the Atlantic coast. As this report is being written, construction is commencing on yet another wind plant in Pennsylvania - in wind and terrain conditions similar to ridgeline sites in our study area. Yet in the Mid-Atlantic States there are no new utility-scale wind power plant projects underway. The question is why wind power development is continuing in the mid-west and west, but not in the Mid-Atlantic region.

To address this deficiency, the actual, as opposed to theoretical, barriers to wind energy development in this region are analyzed and are presented along with reduction mechanisms or mitigation measures. The PERI team including: a wind energy engineer, power market expert, a regulatory and policy expert, financial analyst, atmospheric scientist, and environmental engineer. The team approach was not to accept theoretical or "reported" barriers at face value, rather to investigate in depth by personnel experienced in the field by means that go beyond "literature reviews" including, but not limited to, in depth interviews of key stakeholders and policy makers, and ground truthing of all underlying assumptions. This investigation was followed by objective quantitative analysis and unbiased reporting along with possible responses or mitigation options to overcome the challenges. In addition, critical new technical information concerning the wind resources in region is explored and factored into the local wind market projections.

This process identified a number of minor challenges and barriers to the development of wind energy in the region. Individually, these lesser barriers alone may not derail wind energy development, but lessen the likelihood that developers will invest in commercial scale wind farms in the region. The review also identified several major barriers to wind energy development which will effectively preclude development of wind energy in those areas where they exist. This section summarizes the identified barriers, both major and minor, and provides recommendations to possible solutions or mitigation measures to overcome these barriers.

1.1 Primary Barriers and Mitigation Measures

The primary barriers to wind development outlined in this report can be grouped into four general categories; policy and regulatory issues, wind resource uncertainty, business/ economic issues, and public interest. These issues in these categories are not wholly independent of each other and do interact. Wind resources in the region are limited primarily to four areas – Ridgeline sites in the Appalachian Mountains in the western portion of the region, Coastal land areas, shallow Bays and Sounds in the east, and offshore on the continental shelf in the Atlantic Ocean. The wind resource in the central plain that makes up most of the region is generally considered to be inadequate to support commercial scale wind development, although it is possible that local terrain may provide usable sites for "low wind speed" turbines coming on the market. Many of the potential ridgeline sites in the area have been determined to be "off limits" by state or local governments concerned with the potential adverse impact on view sheds in the region, noise, and avian species collision issues. Coastal wind resources have not been adequately characterized and, so, economic uncertainty constrains wind power development in those areas although recent data indicates suitable resources are available. State-level support for wind power varies widely within the region and, to a substantial degree, development of potential offshore wind resources has eclipsed state policy development for onshore and shallow water wind power development.

One of the largest, and most difficult, barriers to wind development in the Mid-Atlantic is uncertainty. Uncertainties facing regional wind project developers fall into several categories: wind resources, economic, technical (e.g., relating to grid interconnection capacity) and environmental. Of course there is the overriding uncertainty regarding the future of the Section 45 Federal Production Tax Credit.

1.2 Policy and Regulatory Issues

In each State in the region, policies and programs are in place that nominally are intended to support the development of wind and other forms of renewable energy through renewable portfolio mandates (RPS) and tax incentives. A review of the detailed structure of RPS programs in each jurisdiction reveals that these programs currently transfer payments from ratepayers to pre-existing facilities that fall into broadly defined categories of "renewable resources," and do not provide an incentive for the development of new renewable resources. Tax incentives are generally limited in scope and amount and do not generally rise to levels that would provide a significant incentive for onshore commercial scale wind power development. Certain local zoning and noise ordinances have been enacted that effectively bar wind power development in those jurisdictions and in North Carolina, the interpretation of a state stature by the Attorney General and the Public Utility Commission chills development of almost all of that state's ridgeline resources.

1.2.1 RPS and RPGs are Ineffective

As Renewable Energy Portfolio Standards and Goals (RPS/RPG) are currently structured, they do not provide the intended incentive for development of wind and other renewables. Renewable Energy Certificates (RECs) required to fulfill the mandates are allowed to come from anywhere in the PJM system and there is no requirement for creating new facilities. Consequently REC requirements are being fulfilled largely with "anyway" credits. Many credits are generated from facilities that were built long ago and would operate anyway for reasons other than RPS/RPG. These facilities include hydropower plants installed in the early 1900s for economic reasons and pulp mills that have for decades combusted pulping wastes (known as black liquor) for energy needs. North Carolina is an exception. Its RPS requires that RECs be limited to facilities deployed after the RPS law was passed and that 75 percent must come from in-state sources. The North Carolina RPS requirements escalate gradually over time, and have not yet reached levels sufficient to incentivize commercial wind power development. A proposed coastal wind power project in North Carolina has recently been suspended because of the failure of the U.S. Congress to extend the Federal Section 45 Production Tax Credit.

It is likely that as the North Carolina requirements become more stringent over time, the program will be effective in incentivizing in-state renewable energy, including wind power. However, the RPS programs in other states in the region are unlikely to be effective unless and until they require that RECs be limited to new renewable sources and that a portion, say 75 percent, of RECs originate in-state.

1.2.2 RPGs are treated as Caps

In Virginia the State Corporation Commission ruled that the portfolio goal shall be treated as a ceiling for renewable energy sold under the Commonwealth's renewable portfolio program, rather than as a minimum target to be met or exceeded. The Commission was asked to determine if two power purchase agreements (PPA) for new wind power generation were "reasonable and prudent" as required by the RPG statute. The Commission determined that the goals of the RPG were caps on the amount of renewables supported under the program and that any new renewable generation that was not needed to meet the currently applicable goal was not prudent. The Commission applied this test even though it was asserted that the project would be used to meet the renewable goal established for later years. The Commission also suggested that if low cost RECs generated by pre-existing sources were available as a lower cost method of compliance than new wind plants, then they should be utilized.

One legislative attempt has been made to correct this situation, but it is not yet clear whether it will be successful. It is also not clear whether other states with regulated utilities, such as North Carolina, will face similar issues.

1.2.3 RPS-RPGs Face Indirect Constraints

Maryland State law requires that a wind plant greater than 70 MW must obtain a Certificate of Public Convenience and Necessity (CPCN) from the Public Service Commission (PSC). The issuance of a CPCN is a formal adjudicatory process that involves public participation and addresses all relevant issues, including technical, economic and environmental issues. This process can be lengthy, expensive and the outcome is uncertain. In Virginia, the "permit-by-rule" project approval process applies to "small" wind projects less than 100 MW. These limits and inconsistencies between states may be deterrents but are clearly defined process and consequently are not barriers to development.

1.2.4 Restrictive State Statutes and Local Zoning and Noise Ordinances

North Carolina's Ridgeline Protection Act was enacted to bar development of unsightly resort condominiums on high ridgeline sites and specifically excludes "windmills" from its terms. However, this statute was informally interpreted by the North Carolina Attorney General as applying to wind farms. The State PUC has adopted the interpretation of the Attorney General, but several counties have adopted a contrary view. The resulting uncertainty is a significant barrier to development of North Carolina's most valuable wind resources.

In North Carolina and Virginia, several counties have adopted zoning and/or noise ordinances that effectively bar development in those jurisdictions. One county in Maryland is considering a similar ordinance. Developers of wind farms should recognize that commercial scale wind plants are industrial activities that can have local impacts. For the most part, developers have accepted this notion and have shown a willingness to work with local communities to strike the appropriate balance. However, in some instances it appears that the siting of wind plants has acquired a political cast and local restrictive ordinances have been adopted that bear no reasonable relationship to the potential impact of a wind farm, such as one ordinance that bars development of a wind farm within one mile of a school, have been adopted. Several of the states in the region have recognized the need to properly balance competing interests and have passed statutes setting out model noise and zoning restrictions and limiting the authority of local governments.

1.2.5 State Supported Studies

Environmental permitting has not been shown to be a barrier to the development of wind power in the region. Generally environmental issues can be defined, and avoided or mitigated. These issues can preclude the use of environmentally sensitive sites, but adequate "non-sensitive" areas appear reasonably available in the region. However, the cost of conducting baseline environmental studies can pose a financial barrier, especially for smaller projects that might be more appropriate in some areas. To facilitate development of such projects, the states in the region could conduct broad environmental baseline studies that can identify sensitive areas. New Jersey has conducted such a study for its offshore wind development program, but no state in the study region has conducted such a study in sufficient detail.

An overly broad and insufficiently resourced study can, however, do more harm than good. In Virginia, the legislature directed the Virginia Marine Resources Commission (VMRC) to determine the feasibility of leasing state-owned bottomlands in the Chesapeake Bay and its environs. In the absence of adequate resources, the VMRC report provided only a superficial examination of potential issues and did not consider the economic value of possible wind sites and possible compatible uses of bottom land. The result was a widely disseminated and quoted report, in which it was reported that the Commission had determined that existing competing uses ruled out any commercial scale wind farms in the Chesapeake Bay. This report effectively ended further consideration of this resource in the Commonwealth. As discussed later in this report, this issue also arises in the context of mapping the wind resources of the state, where state supported research could remove an economic barrier to the development of smaller scale projects.

1.3 Policy Changes or Mitigation Options

1.3.1 Emphasis on Offshore Wind Power Development

In recent years the attention of state governments in the Mid-Atlantic region has shifted from land-based applications to offshore in Federal waters. The U.S. Department of Interior, Bureau of Ocean Energy Management (BOEM) has kindled much of this interest from the states and potential project developers. The National Offshore Wind Strategy prepared by U.S. Department of Energy in consort with BOEM enhanced commercial interest in offshore wind development. BOEM has defined three potential lease blocks in the Atlantic Ocean off the coast of Delaware, Maryland, and Virginia, solicited project proposals and has completed necessary environmental assessments with favorable results showing “no significant impact.” All this effort has created substantial interest for projects beyond the 12 nautical mile (nm) limit in federal waters.

This large emphasis on offshore ocean applications has drawn attention and resources away from consideration of possible sites in and near the Delaware and Chesapeake Bays, Albemarle and Pamlico Sounds, and from land-based sites along the Atlantic coast. Consequently, offshore wind development has created a barrier to onshore and Bay wind development.

Our study team reexamined the previously over looked applications in the shallow sheltered waters of bays and sounds. Wind resources appear to be marginally better offshore compared to bays, but capital costs are significantly higher, due partly to the platform cost in the ocean for deeper water and survival in hurricane generated waves up to 20 m height. Operations and maintenance expense are higher for plants in the ocean than for those in the bays. COE results are described below with **Figure 1-3**.

Figure 1-1 Near-shore wind plant in Denmark - produces electricity and serves as aids to navigation

Based on detailed economic analysis, the levelized cost of energy (in 2013 constant dollars) was estimated at $0.091 per kWh (kilowatt-hour) for bay installation vs. $0.167 per kWh for ocean installations. Under possible favorable financing, eventually the COEs (in 2013 constant dollars) are $0.063 per kWh Bay and $0.119 per kWh Ocean. These estimates appear to be consistent with offshore project cost trends in Europe and with detailed engineering studies completed by DOE early in the Federal Wind Program.

There are issues associated with deploying turbines in the bays and sounds but these have been resolved in Europe and we believe can be overcome here. Environmental issues, such as birds, bats and view shed concerns must be addressed and balanced against the benefits to bay water and air quality from reduced coal mining and thermal power plant emissions. While it may be politically tempting to avoid those issues by focusing on offshore wind, it is not clear whether offshore wind can be developed at an economically feasible cost. While setback from shipping channels is required, turbines installed on shoals can serve as navigation aids, rather than obstacles. See **Figure 1.1**. The Mid-Atlantic States all have access to vast areas of potential shallow water wind sites that are sheltered from the challenging conditions in the ocean.

Large shallow bays and sounds are a unique resource area in the Mid-Atlantic. They are much larger than similar areas in Europe that have now been largely built out. Additional technical, economic and environmental analysis is needed to quantify and recognize this unique opportunity.

1.3.2 State Energy Programs emphasize small scale projects

All of the Mid-Atlantic State energy plans mention policies favoring renewable energy and reducing energy imports by developing indigenous resources. There are a variety of grant programs aimed mainly at residential applications along with property and sales tax and property wavers available in some states but not in others. All states are strapped for funding these programs. Small projects tend to be favored because they benefit more individuals. Funding is small, but can be easily limited. However, the programs are popular although they result in overall small energy contributions.

In Delaware and Maryland, money is available for renewable energy programs from the Regional Greenhouse Gas Initiative (RGGI), a ten-state cap-and-trade program meant to reduce CO_2 emissions 10% from power plants by 2019. RGGI operates carbon trading auctions quarterly for these states based on each state's individual CO_2 limits and cycles a portion of the revenue generated from the auction back to the states to be invested in consumer programs and clean energy development. To date 15 auctions have been held. Maryland has received $188,828,931 and Delaware $25,412,511 in cumulative proceeds. This source of funding is available only to states that are RGGI members.

All states should consider adding emphasis on promoting commercial wind plant development. The District of Columbia, Virginia, and North Carolina should reconsider joining the RGGI. Revenues generated from RGGI's periodic carbon credit auctions are likely to increase in value and could serve to conduct needed wind resource measurements and baseline environmental studies and other actions that help all potential commercial developers.

1.4 Wind Resource Uncertainty

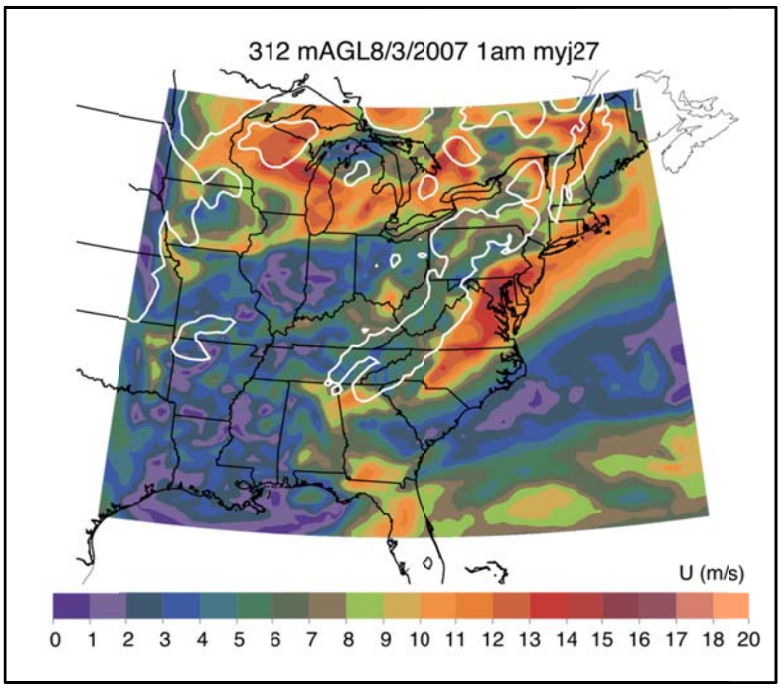
There is a paucity of wind resource data suitable for planning utility-scale wind plant. Commonly referenced data consists of modeled estimates of wind speed from Eastern Wind Integration Study (EWITS) [1]. To examine the accuracy of these wind resource estimates, data from seven sites in Maryland and Virginia were obtained and reviewed. These data were also used as input to the economic modeling for each of the four wind market areas that will be discussed later. These sites were the only measured data sources available that included hub height of greater than 70 meters in the region. The wind measurements for one or more years at multiple heights were compiled. This data was used to estimate the average diurnal and seasonal average wind speeds for a typical site in each of the market areas. Results were compared to modeled estimates from EWITS.

Four of the measured wind sites were described in detail in the Tall Tower Study [2]. Additional data came from NASA's Wallops Island site; Crisfield, Maryland (collected under a Maryland Energy Administration program); and NOAA measurements from Chesapeake Light off the Virginia coast. Together these seven data sets were used to estimate the average wind speeds in each of the four market areas. These data were used to estimate average wind speeds and plant capacity factors for on-peak and off-peak energy output as well as monthly and seasonal differences. Unfortunately not all of the data was collected during the same years.

Significant differences were noted between the measured wind strength and the EWITS model results. The Ridgeline data wind speeds and capacity factors were similar. But looking at the high wind shear measured at 100 meter (m) hub height and above on the Delmarva at Wallops and Eastville leads to the conclusion that average onshore coastal area wind speeds at those heights may be underestimated by at least one wind power class.

The reverse is true on the ocean. The analysis showed that the EWITS estimates for average seasonal wind speed offshore were about 15% higher than estimates in this study. These differences are considered to be statistically and economically significant.

An additional wind resource uncertainty is evidence of the presence of Low Level Jets (LLJ) across the Mid-Atlantic region. LLJ may significantly increase wind plant production during spring and summer months. These jets are powerful winds that arise from large scale topographic/thermal forcing due to surface cooling of the elevated western region during the warm season. This forcing often gives rise to a nocturnal LLJ over the coastal plain. The LLJ is a sheet of fast wind that occurs under stable boundary layer conditions at night during the summer months. It begins around sunset and persists for most of the night. To illustrate the spatial characteristics of the LLJ, **Figure 1.2** shows a model simulation for one night on August 2, 2007 using the state-of-the-art Weather Research and Forecast (WRF) model at 9 km resolution. This model run was at 312 m height but direct measurements on that date show the jets can dramatically increase wind speeds at turbine rotor height. Much additional data is needed to determine the scale, locations and frequency that LLJ occur in the Mid-Atlantic. LLJs are known to occur frequently in the Midwest as shown but with different drivers, yet they can significantly increase wind plant energy production.



Many factors contribute to uncertainty regarding the regional wind resource characteristics including: the lack of long-term, hub height or above wind measurements, the atmospheric complexity and variability at the land-sea boundary, and the presence of low level jets. For areas where current lower level data show an inadequate resource, this uncertainty is a potential barrier for developers.

1.5 Business and Economic Issues

Economic issues pose other barriers to wind development. Although wind plants run on “free fuel”, they are capital intensive; the viability of such projects depends on initial cost, on the amount and timing of the available wind resource, on operating expenses, and on projected demand and price paid for the project’s power. Published data on land-based turbine project costs and local wind strength estimates, discussed above, were used to evaluate the economics of potential coastal and ridgeline projects in the region. We used data from NREL and other sources that were based on actual costs for European projects that were built and operating to evaluate bay and ocean based projects. No “proposed” project costs were considered due to the uncertain nature of such estimates.

European offshore project costs were analyzed to determine possible trends in project prices. The study team found that most early projects were built in very shallow sheltered waters less than 15 m deep and near shore. As these “easy” sites were built out, project development shifted to deeper water, up to 30 m depth and 25 km from shore. The European experiences on prices for foundations, installation, commissioning and maintenance were factored into wind plant cost estimates for bay and ocean applications for this project.

The study team then prepared a forward pricing model based on historical wholesale prices in the PJM region and actual futures pricing traded on the NYMEX commodities trading exchange. PJM refers to the Penn-Jersey-Maryland Interconnection, which is the Regional Transmission Organization (RTO) for the Mid-Atlantic States and certain nearby areas. Four existing nodes were selected on the PJM system as connection points representing each of the wind market areas, namely Cloverdale node for Ridgeline projects, Delmarva Power and Light – Old Dominion Electric Company (DPL-ODEC) for Coastal projects, Calvert Cliffs for Bay projects, and Fentress for Ocean projects.

Using the measured wind characteristics (on-peak, off-peak and seasonal) for a simulated 100 MW wind plant at each node, the value of electricity was determined by extrapolating forward for 25 years. Two different PJM forward pricing scenarios were used, including 2.5% price escalation, which is a conservative estimate given recent fuel and power forecasts, and another, higher-priced scenario termed 2015 Adder Prices, which assumes EPA Utility Maximum Achievable Control Technology (MACT) and interstate transport standards, requiring additional pollution controls on coal-fired plants, are implemented. Of course these standards will not change costs for natural gas or nuclear plants that are a large fraction of regional generation.

PERI then performed discounted cash flow-return on investment (DCF-ROI) analysis. Two types of project structure and financing were employed: (1) merchant power sales with current (first half 2012), likely financing, with debt rated one level below investment-grade and (2) Power Purchase Agreement (PPA) or other well-guaranteed sales with favorable financing, and debt rated at investment-grade. PERI ran the model to calculate after-tax IRR, which is the rate of return for equity investors, and debt coverage, which demonstrates ease of repayment for lenders.

Another method of analysis, to better compare the projects, PERI performed a DCF-ROI analysis starting with a satisfactory IRR and debt coverage, and then using the model to calculate the revenue stream that meets those requirements. From this, we calculated levelized nominal-dollar and constant-dollar Costs of Energy (COEs), where the latter figure excludes inflation.

The land-based plants were found to be economically viable and with favorable financing the bay plant could also work financially. The ocean projects show a broad gap over market prices. The Ocean plants offer potential, but there are technical and economic problems to solve. If Shallow Bay plants were built first, drawing on lessons learned in Europe, the field experience gained would benefit Ocean plants. **Figure 1-3** shows the favorable financing COEs.

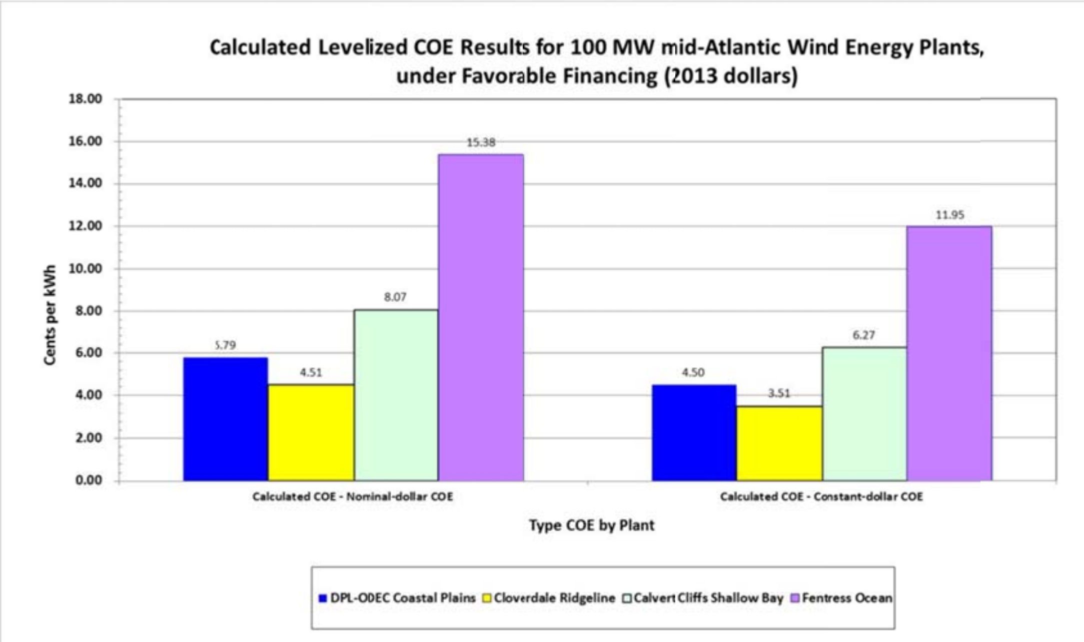


Figure 1-3. COEs of Four Plants with Favorable Financing using PJM Forward Prices (2013 Dollars).

There are two other potential barriers. First, the price of natural gas has fallen in recent years to record lows, which some observers forecast to stay low for up to five years till excess capacity is absorbed by the system. This has reduced PJM's wholesale power prices, because PJM is a spot market. This is a recent issue facing wind and other renewables but has not been a barrier preventing wind development in the past.

Second, the study team assumed that required transmission lines will be available when needed to handle the energy from the 100 MW plants. Transmission line projects like the Mid-Atlantic Power Pathway (MAPP) are assumed to be available. We did not evaluate the potential impact from the proposed offshore backbone.

In conclusion, the levelized cost of energy from potential coastal sites appears to be attractive for near-term development in the Mid-Atlantic. Next most attractive potential sites are in sheltered shallow waters of bays and sounds due to proximity to load and because the wind resources are probably underestimated. Ridgeline sites are lowest cost, but the distance to load centers, associated transmission issues and environmental factors must be considered.

1.6 Public Interest Issues

Public opinion of wind energy plays a key role in wind development. It can become a barrier if it is not addressed properly in the project planning process. In North Carolina a judicial interpretation of the Mountain Ridge Protection Act has effectively blocked all wind development in the western part of the state. Reasonable zoning ordinances can go a long way to address siting issues before projects become controversial. Model zoning policies are available and in use except in a few communities where projects began before model ordinances were ready.

Generally environmental issues can be defined, avoided or mitigated. These can preclude the use of environmentally sensitive sites but are not considered a barrier to development. Bird sanctuaries and fly ways should be avoided. Bats issues can largely be avoided by raising the turbine cut-in wind speed. Noise and aesthetics are issues that can generally be handled through open dialog citing the value and benefits from wind power that result from reducing coal and other fossil fuel burning, and from shrinking the “dead zones” in the bay and ocean. Although changing public opinion can be a challenging task, doing so is possible. However, because of potential initial opposition, public interest is considered a barrier to wind energy development for the purposes of this report.

2.0 Introduction

This report presents results of work conducted by Princeton Energy Resources International, LLC (PERI), in response to the U.S. Department of Energy, "20% Wind by 2030: Topic2A Wind Powering America" barrier reduction program, competitive Funding Opportunity Announcement Number: DE-PS36-09GO99009. Cost shared funding support came from the Maryland Department of Natural Resources (DNR).

Princeton Energy Resources International (PERI) organized a team including the University of Maryland Baltimore County (UMBC) and the Chesapeake Bay Foundation (CBF). PERI staff are experienced in wind and other renewable energy plant design, conventional power plant implementation, project finance, and federal and state energy policy planning and management. In addition to PERI staff, key consultants included: Dr. Lynn Sparling Atmospheric Physicist from UMBC, Bruce C. Buckheit, addressing regulatory issues, and Dan Lobue on regional transmission organizational considerations. These consultants have experience in wind energy and also bring detailed and broad perspectives on environmental and regional power generation issues. Dr. Sparling is a prominent scientist on atmospheric physics, dynamics, and air pollution transport. Mr. Buckheit has consulted on a number of fossil fuel-fired and wind power generation policy issues in this country and abroad since retiring from the government where he served as senior counsel at the Justice Department's Environmental Enforcement Section and as a senior manager in the Environmental Protection Agency's air program. Mr. Lobue with his experience in the electric power business has helped in structuring and optimizing transmission agreements for conventional power plants and for wind power projects.

The team's approach was to identify and investigate technical, business and regulatory issues that could be impediments to wind energy development. We did not accept theoretical or "reported" barriers at face value, but rather investigated in depth by means that go beyond "literature reviews" including, but not limited to, in depth interviews of key stakeholders and policy makers, and ground truthing of all underlying assumptions. This investigation was followed by objective quantitative analysis and unbiased reporting along with possible responses or mitigation options to overcome the challenges. In addition, critical new technical information concerning the wind resources in the region was exposed and factored into the local wind market projections.

Benefits of wind energy are widely recognized. Renewable Portfolio Standards or Goals (RPS/RPG) in all of the Mid-Atlantic States include wind energy, acknowledging its value in terms of sustainability, long-term power price stability, reduced energy imports, job creation and reduced air and water pollution. Consequently these benefits will not be discussed here. Regionally specific or unique market drivers are identified and discussed. However, this report is more specifically focused on defining and overcoming barriers to wind development.

Results were communicated in meetings and presentations at regional workshops, seminars and directly to groups in regional business, governments and universities. In addition the CBF hosted a meeting of regional environmental groups and Non-Governmental Organizations (NGOs).

3.0 Goals and Objectives

The objective of this study is to define technical, economic and policy issues that have been impeding the development of wind energy in the Mid-Atlantic region and to identify mechanisms for overcoming or mitigating those barriers.

Specific objectives are: 1) to refine the understanding of the nature of the regional wind energy market, 2) to define specific technical, business, and regulatory barriers along with options for overcoming them, 3) to analyze the economic factors that may impact project development decisions, 4) to quantify characteristics and uncertainties in the local wind resource potential and 5) to put wind energy environmental considerations in perspective with other power generation technologies.

Our goal was also to dispel or reduce myths about Mid-Atlantic wind power markets. These myths include:

1. "The only useful winds are at ridgeline sites and most of those are on protected land."
2. "Population density is too high on coastal plains."
3. "Wind resource is not sufficient in coastal plains, bay(s) and sounds."
4. "Coastal wind power cannot compete with stronger offshore wind strengths."
5. "Competing uses rule out most of the otherwise available bottomland."

4.0 Regional Energy Situation - Ripe for Wind Market Development

The region chosen for this study: Delaware, Maryland, North Carolina, Virginia, and the District of Columbia, generally has similar wind energy market characteristics. These include: reasonably good wind resources, growing demand for electricity and yet almost no development of the available wind energy potential. For purposes of this study, the wind energy market is divided into four segments each with different development issues and potential

As shown in **Figure 4-1**, the market segments are: 1) Ridgeline - along the tops of Appalachian mountains, 2) Coastal – on the plains east of the Piedmont, 3) Sheltered Waters – in the shallow waters in Delaware and Chesapeake Bays, Albemarle and Pamlico Sounds, and 4) Ocean – offshore in deeper water over the Continental shelf off the Atlantic coast.

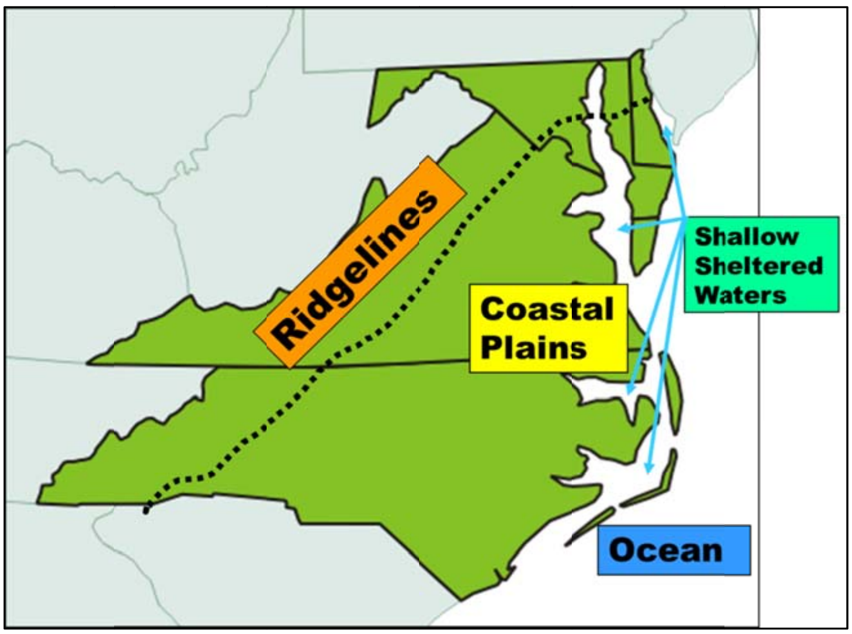


Figure 4-1. Mid-Atlantic States Wind Plant Market Areas

To quantify these markets , the authors of this report expanded on the data and models used by the National Renewable Energy Laboratory (NREL) in preparing their study for the U.S. Department of Energy (DOE) titled *20% Wind Energy by 2030*. This report estimated the usable Mid-Atlantic regional wind resource potential by 2030 at 16 to 43 thousand megawatts (MW) [3]. DOE's estimates for individual state are: Maryland 1,483 MW onshore and 53,782 offshore (not counting potential sites in the Chesapeake Bay), Delaware 9.5 MW onshore (likely underestimated) and similar to Maryland offshore again not including Delaware Bay, Virginia 1,793 on land and 94,448 offshore plus the Bay, and North Carolina 807 MW on and offshore potential larger than the other Mid-Atlantic States combined. These data are summarized in Table 4-1 that also describes land areas that were excluded from consideration. These exclusions could be reconsidered but more important is the omission of possible sites in bays or sounds. The potential capacity could equal the offshore estimates provided potential environmental issues can be overcome.

If fully developed, assuming an average 35% capacity factor[1], wind could supply at least 50 million megawatt-hours (MWh) annually. That amount of electricity is equivalent to 15% of the current five-state

[1] NREL estimated an average capacity factor of 35% in 2010 increasing to 38% by 2030 for Class 3 wind resource measured at 50 m height. See Table B-10 in reference 1.

consumption, based on Energy Information Administration (EIA) data from 2010 [4]. Analysis later in this report will show that potential electricity production from wind may be substantially underestimated.

Table 4-1 DOE Estimates of land-based and offshore wind energy potential by 2030 (but not counting potential sites in bays and sounds).

	Windy Land Area ≥ 30% Gross Capacity Factor at 80 m					Land-Based Wind Energy Potential		Offshore Potential
State	Total (km^2)	Excluded (km^2)	Available (km^2)	Available % of State	% of Total Windy Land Excluded	Installed Capacity (MW)	Annual Generation (GWh)	Estimated Capacity (MW)
Maryland	567.7	271.1	296.6	1.18%	47.80%	1,483	4,269	53,782
North Carolina	1,155.60	994.1	161.5	0.13%	86.00%	807	2,395	Very Large
Delaware	36.6	34.7	1.9	0.04%	94.80%	9.5	26	Similar to Maryland
Virginia	1,567.20	1,208.50	358.7	0.35%	77.10%	1,793	5,395	94,448

The wind resource data available at the time of the DOE study resulted in nearly all of the projected wind turbine capacity being located either on ridgelines or at offshore ocean sites. In the DOE study, sites estimated as Class 2 or below were considered too “marginal” to be considered. Looking at wind resource maps drawn at 50 meter (50 m) height that were used in the study, virtually all of the land area was below Class 3 and excluded except ridgelines [5]. More recent wind resource measurements, some measured at higher altitudes, indicate that Mid-Atlantic coastal areas may be several power classes higher than earlier estimates. The basis for new higher wind resource estimates is discussed in detail later in this report and could dramatically increase the wind energy potential for land-based sites.

4.1 Mid-Atlantic Wind Energy Market Segments

4.1.1 Ridgeline Sites

Ridgeline sites have encountered serious opposition in Maryland, Virginia and North Carolina, although 120 MW in two wind plants have been built in Maryland. Opposition from some members of the public, some local governments and in North Carolina the “Mountain Ridge Protection Act,” have delayed projects or caused them to be abandoned. These issues are discussed in detail later in this report but it is notable that in nearby Pennsylvania, wind development is proceeding well on similar terrain. Nearly all of the 790 MW of wind plants in Pennsylvania at the end of 2011 are currently located on ridgelines. Five new ridgeline projects are being built this year including a 131 MW plant that began installation in Mehoopany beginning in June of 2012. In some cases the initial projects were placed on mountains that had already been damaged by strip mining, later other ridges and farm lands were employed. Seeing wind plants operating, and recognizing their economic and environmental benefits, has helped to open markets in Pennsylvania. Although in some cases there is still organized opposition, several years ago the Pennsylvania Department of Environment had a policy to support wind demonstration projects in every county. This was aimed at educating the public and winning general acceptance based on increased familiarity wind turbines through small projects. This leads to a possible solution in the target states.

Barrier – Visual impact from ridgeline sites.

Mitigation Option – Support demonstration projects with turbines installed in communities near potential wind power plant sites in an effort to increase technology acceptance and to overcome misinformation about noise and visual impact.

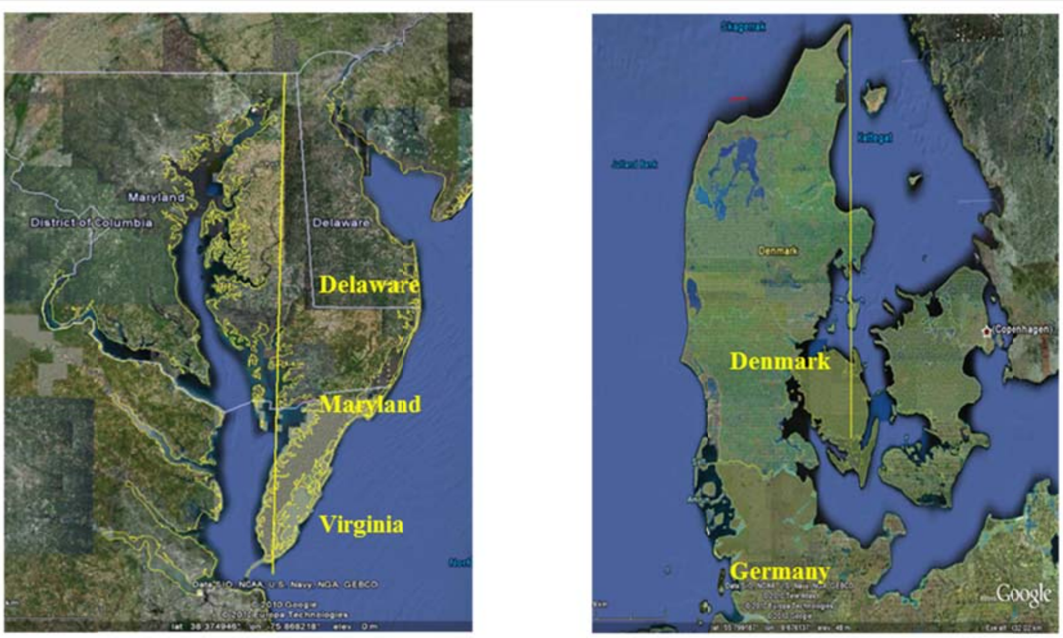
4.1.2 Coastal Plain Sites

This study concludes the plains east of the Appalachian Mountains contain many sites suitable for wind energy development. Terrain varies from rolling hills in the west to large relatively flat areas near the coast. As mentioned previously, the wind resources once thought to be marginal are now considered usable given better wind measurements and modern turbines with taller towers and larger rotors.

Population high density is often cited as a reason for lack of regional wind development. In fact, 25 million people live in the five-state Region, mainly in urban and suburban areas along the Interstate highway corridors. However, the high density urban areas in the region are generally more than 50 miles from ridgeline areas and agricultural areas along the coast that have stronger wind resources.

For perspective, the coastal plain in Denmark can be compared to the Delaware – Maryland – Virginia (DELMARVA) peninsula. The Danish Jutland Peninsula is approximately 300 km from the border with Germany to the northern tip. DELMARVA has similar dimensions and topography, as shown in **Figure 4-2**. Both regions are mainly agricultural with some urban and industrial areas.

Wind resources are comparable with open plains in Denmark reported at 6.5 to 7.5 m/s average annual average measured at 50 m above ground level [6]. This is only slightly better than DELMARVA with an estimated Class 3 resource of 6.4 to 7.0 m/s at 50 m height (the standard height used in the European Wind Atlas). In 2010, Jutland had more than 2,400 MW of land-based wind plants producing at times enough energy to meet 100% of the Danish electrical load. Highest wind generation penetration occurred during low demand periods at night when actually much of the wind energy was exported to Norway, Sweden and Germany. Electric power was later returned from other generating sources during low wind periods in Denmark [7].



DELMARVA w/ 300 km line

Jutland Peninsula, Denmark - w/300 km line – and 2,400 of wind plants at times producing 100% of load

Figure 4-2. DELMARVA-Jutland Comparison where 2,400 MW of land-based wind plants are operating (300 km line is to indicate scale)

4.1.3 Bay and Sound Sites

The potential value of installations in the shallow sheltered waters of bays and sounds in the Mid-Atlantic has received little attention. Early in the Federal wind program, a detailed study of 6.5 to 10 MW turbines on 100 m towers in offshore applications was completed by Westinghouse Electric Company [8]. It concluded that the cost of energy from offshore applications was two to three times higher than land based installations. As a result that path of research was dropped in 1980.

That initial study focused on ocean based applications where water depth and extreme weather and wave driven requirements dictated much of the cost difference between land and sea based installations. The metocean[2] assumptions used by Westinghouse and their marine contractors are summarized in **Table 4-2** and it should be noted that their assumptions are for open ocean applications around the U.S. coast including Alaska. Of more direct relevance in the Mid-Atlantic are the more recent measurements of maximum winds, wave heights and currents. Measurement data shown are by National Oceanographic and Atmospheric Administration (NOAA) on two buoys located in the Chesapeake Bay and one in the ocean near Chesapeake Light House (CHLV2) near one of Department of Interior's wind energy lease blocks. The location of NOAA measurement sites near Point Lookout, Stingray Point and near CHLV2 is shown in **Figure 4-3**.

Wind, wave and current characteristics are described in standards for offshore wind turbines developed by the American Ship Builders. This standard requires the use of the so called "100-year storm" as the basis for design and structural load prediction. Long-term and extreme-value predictions for sustained and wind gusts are to be based on recognized techniques and clearly described in the design document, however these criteria need to be modified to apply to Bay applications. Also the wind shear used in standard for extrapolating surface wind speed up to turbine hub height is based on the 1/7 Power Law.
This will likely overestimate the wind speed and consequently the structural loads (see **Section 9** for more detailed discussion of this issue). Consequently the assumptions used here are qualitative adjustments based on the admittedly limited data recorded by NOAA, yet are considered reasonable for preliminary economic studies. Data for the Ocean application are also consistent with the extreme wind estimates presented by James Madison University at a meeting of the Virginia Offshore Wind Development Authority (VOWDA)[3].

For major tropical cyclones of Saffir-Simpson category 3 or higher, it is not unusual to find wave heights of over 30 m in deep water as described in the Westinghouse report. However these waves break in water depths of approximately 20 m and "feel" the ocean bottom at much greater depths, well offshore along the continental shelf. Data from measurements from Germany in the North Sea indicate 8-11m maximum wave height or 0.22 x depth (varies by location). Theoretical wave models predict the maximum height of waves in shallow water is, to a first approximation, about 75% of the local oceanic depth [4]. Consequently the maximum possible wave height is 22 to 30 m for lease blocks ranging in depth from 30 to 40 m. For the bays sheltered from ocean swell and surge, the measured significant[5] waves are 2.2 m with the maximum wave height of 3.8 m.

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[2] Metocean is a term coined recently to include meteorological and oceanographic characteristics including wind speed, direction, and turbulence at different heights above the water, sea state and currents.
[3] Miles, J.J. et al., "Offshore Wind Advanced Technology Demonstration Site Development", 15 February 2012.
[4] Australian Bureau of meteorology Research Centre, The Centre for Australian Weather and Climate Research, http://cawcr.gov.au/bmrc/pubs/tcguide/ch4/ch4_3.htm
[5] NOAA National Data Buoy Center definition: "Significant wave height, is approximately equal to the average of the highest one-third of the waves, as measured from the trough to the crest of the waves".

Table 4-2. Metocean assumptions used for bay, sound and ocean lease block applications.

Wind (100-year storm) on Bay and Ocean	**Location**	**Estimated Maximum**	**Est. Max Sustained @ 100 m Hub Height**	**Est. Max Sustained @ 100 m Hub Height**	**Max Gust**	**Max Gust @ Hub Height**
	Units	(Knots)	(Knots or m/s)	(m/s)	(Knots)	(m/s)
Worst-case for open-ocean	Maximum Design Load Requiremnts for Ocean Survival all US regions [1]	104.2 (@ 10 m)	215.0 kts	110.5	275.0	141.4
Measured at Chesapeake Light	CHLV @ 43.3 m height [4] 1996 -2010	72	37.0	-		
100-Year Storm	Design max @hub. [10, 11]	-	36.6 (IEC [10])	56.0		69.7
Waves (trough to crest)	**Location**	**Ocean Design Wave Hgt. in 100-yr. Storm** [3, 7]	**Measured Max. Ocean Wave @ Cape Henry Buoy 44099 2008 - 2011**		**Bay Est. Survival Max.** [6, 8]	**Bay Measured off Stingray Point**
	Units	(m)	(m)		(m)	(m)
Worst-case extremes for open-ocean	Maximum Design Load Requiremnts for Ocean Survival all US regions [1]	30.5				
100-Year Storm	Design for significant waves in ocean operation [2, 3]	15.6	4.7		3.0	2.2
100-Year Storm	Design for survival (Extreme Wave in 30 m water depth) [5]	22.5	6.7		4.0	3.8
Current	**Location**	**Ocean Design** [3]	**Measured Max. @ Cape Henry Buoy 44099 2008 - 2011**		**Bay Est. Survival Max.** [6, 8, 9]	**Bay Measured off Stingray Point**
	Units	(m/s)	(m/s)		(m/s)	(m/s)
	Design for ocean operation	1.8	-		1.0	0.7
	Design for Survival (Extreme)	2.2	-		1.5	1.1

Refereences and Notes:

1. Kilar, L.A., *Design Study and Economic Assessment of Multi-Unit Offshore Wind Energy Conversion Systems Application, Volume II - Apparatis Designs and Costs,* WASH-2330-78/4(Vol. 2), Westinghouse Electric Corporation, June 14, 1979.
2. NOAA definition -Significant wave height is calculated as the average of the highest one-third of all of the wave heights during the 20-minute sampling period.
3. Kilar, L.A., *Design Study and Economic Assessment of Multi-Unit Offshore Wind Energy Conversion Systems Application, Volume IV - Meteorological and Oceanographic Surveys,* WASH-2330-78/4(Vol. 4), Westinghouse Electric Corporation, June 14, 1979.
4. National Data Buoy Center, NOAA, http://www.ndbc.noaa.gov/station_history.php?station=chlv2
5. Kinsman, Blair (1984), *Wind Waves: their Generation and Propagation on the Ocean Surface* , Dover Publications, ISBN 0-486-49511-6.
6. Estimate of wave height in sheltered waters - NOAA Chesapeake Bay Interpretive Buoy System (CBIBS) operating since 2007, Potomac Buoy, http://buoybay.noaa.gov/observations/data-graphing-tool.html
7. SCRIPPS Institute of Oceanography, Coastal Data Information Program (CDIP), http://cdip.ucsd.edu/?nav=historic&sub=data&stn=147&stream=p1&xyrmo=200806&xitem=product33
8. Chesapeake Bay Interpretive Buoy System (CBIBS), NOAA, http://buoybay.noaa.gov/locations/potomac.html
9. Reeds Nautical Alminac, East Coast Edition, 2008
10. IEC 61400-1 for Class I assumes extreem wind of 50 m/s at hub in 50-year storm but not category 3 hurricanes.
11. JMU presentation to VA Offshore Wind Development Authority 15 January 2012.

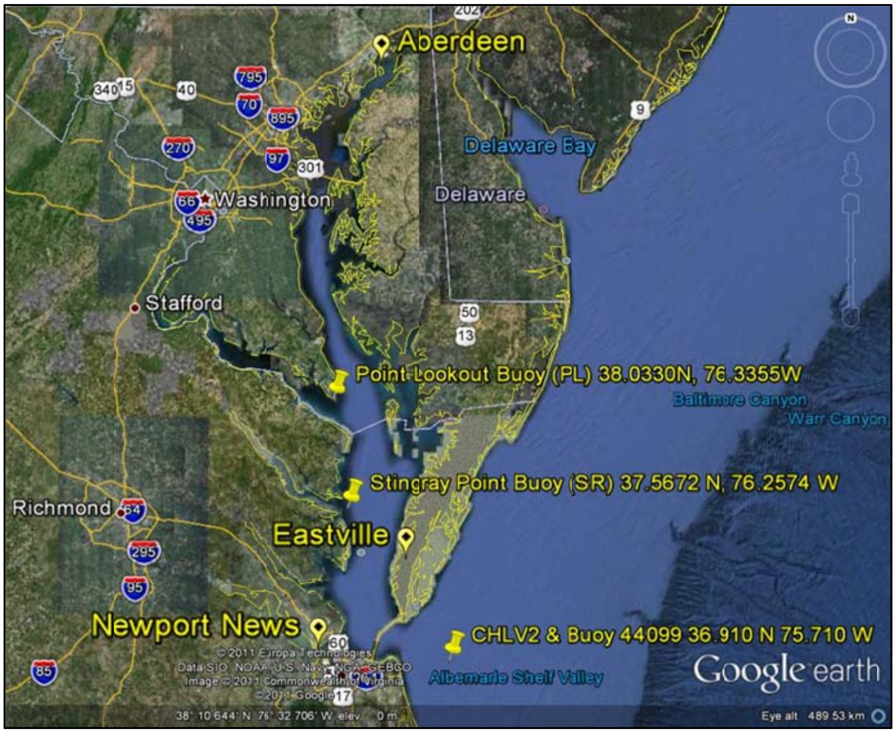

Figure 4-3. Location of NOAA Buoys

The available NOAA measurements are short term (less than five years) and do not include conditions associated with an extreme 100-year storm that would be needed to update the Westinghouse estimates. Regardless, significant wave heights and extreme waves are a factor of 8-10 higher offshore compared to an installation in the shallow waters of bays and sounds that are sheltered from extreme conditions offshore in the ocean. This difference is reflected in the cost studies later in this report.

The cost benefit of deployments in shallow sheltered waters can be seen from initial offshore projects in Europe. The first sea-based plants were located near shore in very shallow sheltered waters, and were slightly more costly than land-based installations. The land-based and offshore plant locations in Denmark in 1996 are shown in **Figure 4-4** along with comment reported to the International Energy Agency (IEA) regarding offshore applications. By 2009, Denmark reported that offshore installation cost had risen to $3.88 million per MW (double land-based costs) as projects were built in up to 15 m water depth, with most early plants less than 10 km from shore. Later projects were built further from shore in more challenging conditions in the North Sea [7]. These cost trends are analyzed in more detail later in this report.

Figure 4-4. Onshore & Offshore Plants in Denmark, Circa 1996

4.1.4 Offshore Ocean Sites

There are vast areas offshore along the East coast and elsewhere in the U.S., in both state and federal waters, where large wind power plants can be deployed. This includes the ocean area where the continental shelf is up to 200 nautical miles (nm) wide with relatively shallow 30 to 60 m water depth in the Mid-Atlantic Bight, see **Figure 4-5**.

DOE in consort with Department of Interior's Bureau of Ocean Energy Management (BOEM) (formerly the Bureau of Ocean Energy Management, Regulation and Enforcement) are aggressively working to lease blocks in Federal water for wind energy project development by accepting lease offers and completing a regional environmental assessment [9]. These efforts are designed to promote and accelerate growth of a commercial offshore wind industry in the U.S. The intent of these federal efforts are described in the National Offshore Wind Strategy, which is designed to draw on lessons learned from the extensive offshore deployment in Europe and move on directly to the next generation of larger hopefully more cost-effective turbines. A goal is to have installed 10 GW at $0.10 per kWh by 2020 [10].

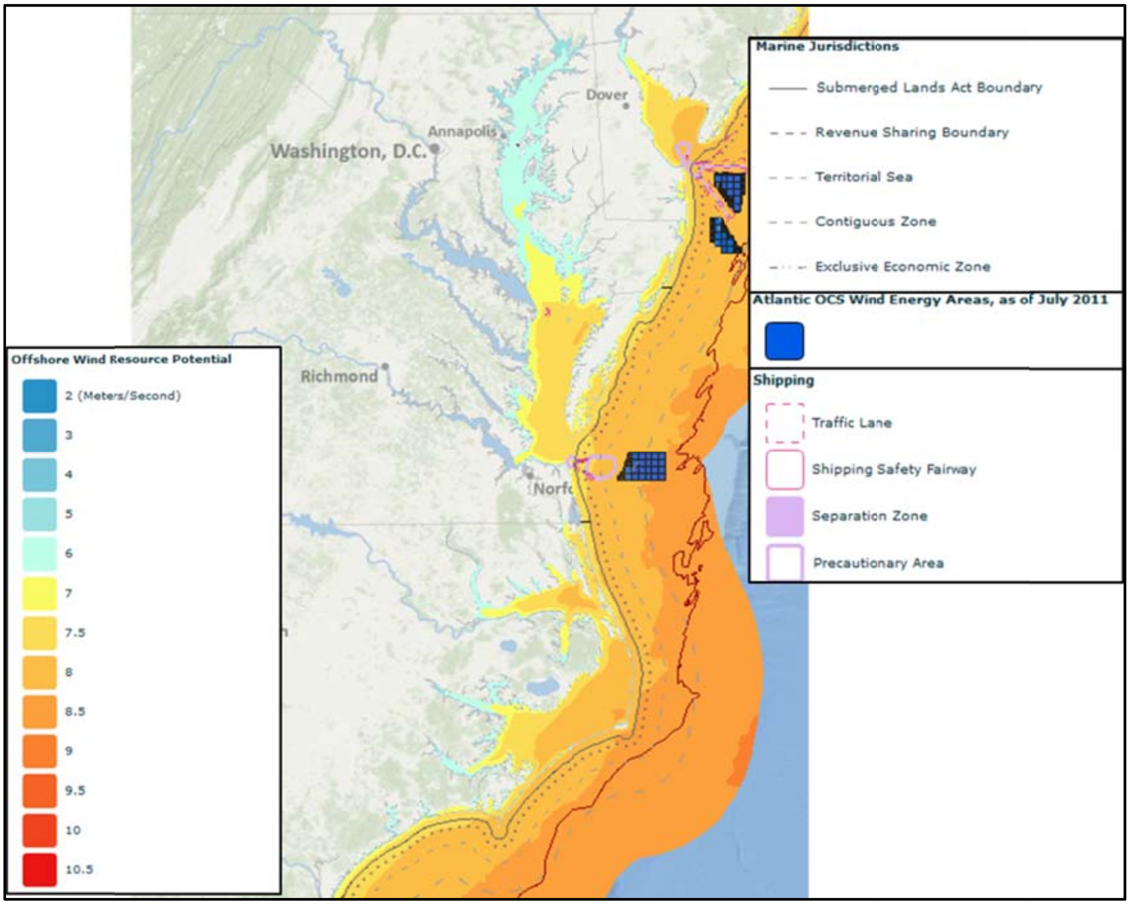

Figure 4-5. Mid-Atlantic Bight Regional Offshore Lease Blocks and Wind Resources at 90m Hub Height -

BOEM-NOAA Multipurpose Marine Cadastre[6] Using NREL Wind Speed Data at 90m Hub Height, April 2012. Lease blocks for DE, MD and VA are shown. NC has yet to be allocated by BOEM.

The National Offshore Wind Energy Strategy includes extensive research and demonstration programs that are hopefully supported by continuation of the essential federal Section 45 Production Tax Credit (PTC) incentive that is currently set to expire in the end of 2012. Assuming the PTC is extended, there are still technical and economic uncertainties and concerns that are described in this report. The DOE Offshore Wind Technology Demonstration Projects have been fast tracked with a plan to have one or more turbines in the water and operating by 2014.

Other possible paths are discussed here to help overcome technical and economic barriers by reducing development risk. One scenario could be to deploy the first blocks of machines (possibly 500 MW) in waters that are not exposed to the extreme conditions of the open ocean. This option is discussed in more detail later in this report.

[6] http://www.boem.gov/Oil-and-Gas-Energy-Program/Mapping-and-Data/Multi-Purpose-Marine-Cadastre-Map-Viewer/Index.aspx

Barrier – Federal and Mid-Atlantic State program emphasis is on offshore, drawing attention away from coastal and sheltered water applications that will be less costly.

Mitigation Option – State and Federal programs can be expanded to emphasize wind resources measurements, economic/regulatory analysis, and environmental assessments for coastal areas, bays and sounds.

4.2 Energy Situation in the Mid-Atlantic States

The Mid-Atlantic States have seen continuing growth in demand for electricity that is among the highest in the nation. According to EIA, annual growth in power demand in the five states ranges from 2.0 to 3.2%. All of the Sates have energy plans and goals that place importance on increasing the use of renewable energy from in-state sources, reducing Greenhouse Gas (GHG) and other emissions, and promoting local job creation. However state policies and incentives needed to achieve these goals have not proven to be sufficient to encourage significant wind or other renewable energy deployment in the region.

As a result, all of the Mid-Atlantic States are increasing electricity imports and are buying a majority of RECs from pre-World War II hydroelectric and old industrial plants or from renewable energy projects located in other states. This has the effect of creating equipment manufacturing and renewable energy project construction jobs elsewhere.

The energy supply shortfall will be complicated by planned phase out of aging thermal power plants. There is currently only one new 600 MW coal plant under construction in Virginia and there are a dozen old plants supplying nearly half of that state’s electricity generated. In Maryland there are no new coal plants planned, and all but three of the units in the eight existing coal plants are over 40 years old.

Wind resources can work well to act, along with combined cycle natural gas units, as a replacement for the inevitable decommissioning of these outdated coal plants.

4.3 European Offshore Project Cost Trends

NREL reported, “Of the 50 installed and proposed projects in the [NREL] dataset, 48 are in shallow water (depth of 30 m or less) and an average depth is 12.9 m.” As mentioned previously, many of these initial projects were constructed in sheltered waters in Nordic countries. This was intended and did effectively minimize development cost and risk.

Since 2007, other European Union (EU) countries have entered the offshore wind market with larger projects in deeper water further from shore. As projects now have foundations in 30 m water depth and up to 45 km distance to shore, costs have increased substantially to over $6 million /MW in some cases. Cost data was compiled from NREL’s data base used in the Offshore Barriers and Opportunities report and from published data for a total of 36 projects that had been built and commissioned for operation [11] [12].

Data on future projects was collected but not used in the analysis. The projects and their announced capital costs are listed in **Table 4-3**. In examining this data, it appears clear that there are significant cost trends associated with increasing water depth and distance from shore. Four cases are highlighted on the Table where similar size projects showed cost impact of an additional 16 to 40% as a result of building further from shore in water up to 22 m depth. Consequently, later in this report a 30% cost increase was assumed for offshore tower foundation costs along with increased operations and maintenance costs compared to bay applications. See **Section 6** and **Section 7** of this report.

Cost trends were analyzed by country, project size, water depth and distance from shore and date of construction. Results are shown in **Figure 4-6** and **Figure 4-7**. Projects built between 1990 and 2006 were less costly regardless of plant size since most were in sheltered waters less than 15 m deep and less than 10 km from shore. These initial projects, both large and small had similar cost per MW and were successful. This is considered to be an important lesson that can be drawn from European experience.

More recent European projects were primarily in exposed sites in the North Sea where construction and operating conditions are more difficult. These sites are still considered to be substantially less challenging conditions than what can be expected at offshore BOEM lease sites in the U.S. where foundations are typically in 30 m of water depth and are exposed to severe conditions in the North Atlantic Ocean. Clearly foundations and turbines can be built for these conditions but the added costs are included in the economic analysis later in this report.

Table 4-3. The future projects and their announced capital costs (data collected, but not used in the analysis)

	Country	Commissioned (Year)	Rated Capacity (MW)	Average Dist. Offshore (km)	Average Depth(m)	Announced Capital Cost ($2010 millions)	$/MW
Vindeby	DK	1991	4.95	2.5	4	12.8	2.59
Lely	NL	1994	2	1	7.5	5.5	2.75
Tunø Knob	DK	1995	5	6	3	12.8	2.56
Irene Vorrink	NL	1996	16.8	0.1	2	28.6	1.70
Dronten	NL	1997	41	0.4			
Bockstigen	Sweden	1998	2.75	3	7	6.1	2.22
Middelgrunden	DK	2000	40	2	4	62.3	1.56
Blyth	UK	2000	4	1	6	7.9	1.98
Utgrunden	Sweden	2000	10.5	7	7	17.1	1.63
Yttre Stengrund	Sweden	2001	10	4	10	18.5	1.85
Horns Rev	DK	2002	160	16	10	401.2	2.51
Samsø	DK	2002	23	3.5	14.5	48.9	2.13
Scroby Sands	UK	2003	60	2.5	6	150.6	2.51
Nysted	DK	2003	165.6	8	6	359.8	2.17
North Hoyle	UK	2003	60	6.5	9	152.8	2.55
Arklow Bank	Ireland	2004	25.2	10	5	67.5	2.68
Kentish Flats	UK	2005	90	8.5	5	204.9	2.28
Egmond aan Zee	NL	2006	108	10	20	303.0	2.81
Barrow-in-Furness	UK	2006	90	7	22	196.2	2.18
Lillgrund	Sweden	2007	110.4	10	6	283.1	2.56
Burbo Bank	UK	2007	90	5	10	220.0	2.44
Dronten 2 and 3	NL	2007	24				-
Thornton Bank I	Belgium	2008	30	29	20	202.6	6.75
Prinses Amalia	NL	2008	120	23	22	571.7	4.76
Robin Rigg	UK	2009	180	9.5	5	727.6	4.04
Sproge	DK	2009	21	93	6	50.2	2.39
Rhyl Flats	UK	2009	90	8	9.5	361.8	4.02
Inner Dowsing	UK	2009	97.2	5	10	275.8	2.84
Lynn	UK	2009	97.2	5	10	275.8	2.84
Horns Rev 2	DK	2009	209.3	30	13	717.6	3.43
Alpha Ventus	Germany	2009	60	45	30	350.4	5.84
Hywind	Norway	2009	2.3	12		70.7	30.74
Vindpark Vanern	Sweden	2010	30	4	3	129.8	4.33
Rodsand	DK	2010	207	8.8	4	573.0	2.77
Donghai Bridge	China	2010	102	9	7	361.4	3.54
Gunfleet Sands	UK	2010	172.8	7	8.5	749.1	4.34
Belwind I	Belgium	2011	165	48.5	26	877.0	5.32
BARD Offshore I*	Germany	2011	400	101	40	2,150	5.38
Nysted II	DK		207	23	9	681.3	3.29
Cape Wind	US		468	9.5	11	2,620	5.60
Atlantic City I	US		20	5	11.5	100	5.00
Galveston Offshore I	US		150	8.5	16	450	3.00
Galveston Offshore II	US		150	8.5	16	450	3.00
Block Island I	US		28.8	4.5	22.5	205	7.12
Thanet	UK		300	8	22.5	1,258.2	4.19
Delaware's Offshore Wind Park	US		450	20.9	23	1,500	3.33
Garden State Offshore Energy	US		346	31	27	1,070	3.09
Talisman Energy	Canada		10	25	45	72.1	7.21
Deepwater Wind Energy Center	US		1000	35	~40	6,000	6.00
Aegir Offshore Wind Farm	US		50	10	<80	4,000 to 5,000	8 to 10
Great Lakes Wind Energy Center	US		20	5 to 10	3 to 5	100	5.00
LI-NYC Offshore Wind I	US		350	22.5		1,500	4.29
LI-NYC Offshore Wind II	US		350	22.5		1,500	4.29

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2. 4C Offshore, http://www.4coffshore.com/windfarms/vindpark-vanern-gasslingegrund-sweden-se06.html

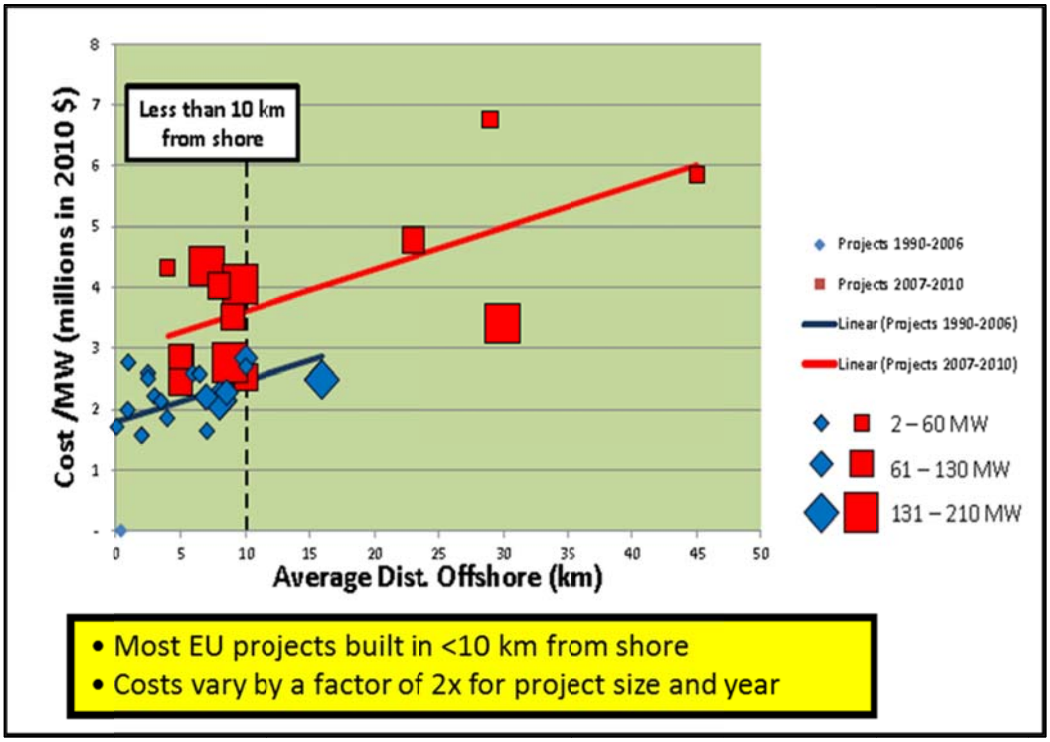

Figure 4-6. Offshore EU Wind Plant Cost vs. Distance from Shore and Date of Construction

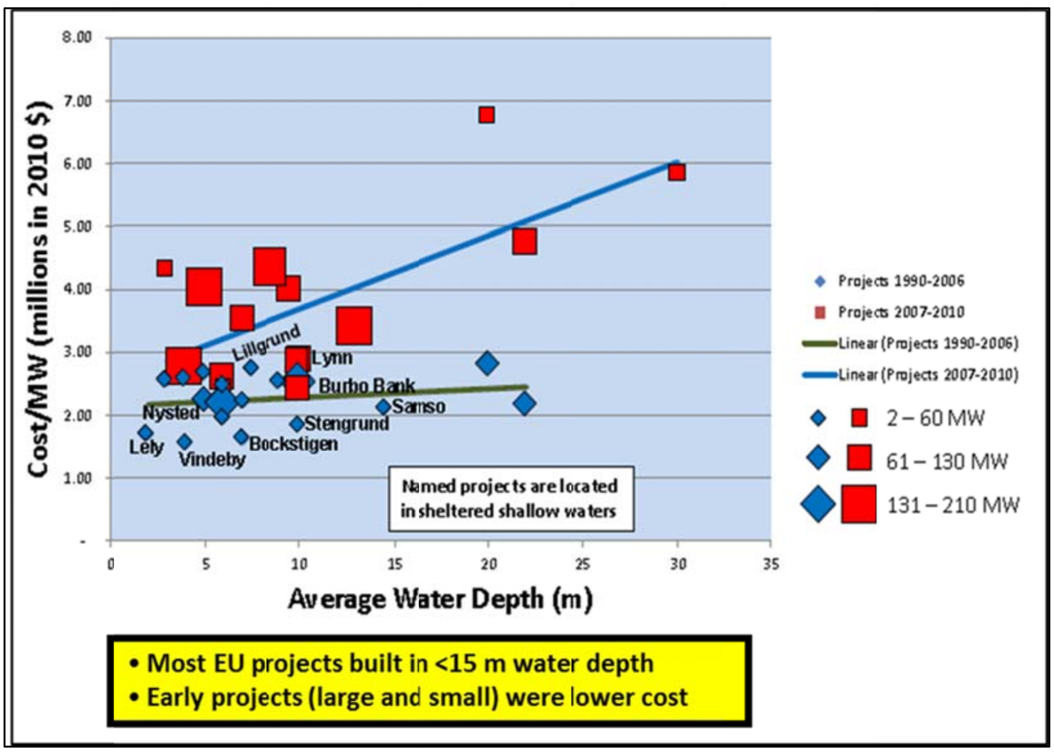

Figure 4-7. Offshore EU Wind Plant Cost vs. Water Depth in Sheltered vs. Open Water

Some EU studies attribute the cost increases for recent offshore plants to increasing costs for raw materials (steel, copper, cement, etc.) and the increased demand for land-based machines plus other macro-economic conditions [13]. These studies also project that stronger winds and larger turbines double the hours of full power operation offsetting some of the added cost. Because of the uncertainty regarding these estimates and the wide range of costs projected for U.S. offshore wind projects, only costs for complete projects are used in this study.

Analysis of European experience suggests that significant cost savings are possible in the U.S. with deployment in the large areas of sheltered, shallow state controlled waters in the Mid-Atlantic bays and sounds. These sites avoid extreme structural loads resulting from ocean winds and waves and would be far less risky to develop and maintain than ocean-based applications. Engineering and economics are primarily important, but unique wind resources, simplified regulations and environmental issues can often be addressed or mitigated more easily at the State and local level than at the Federal level.

All this presents a unique opportunity for the Mid-Atlantic States to introduce wind plants in sheltered shallow at a lower cost and there by establish the supply chain and infrastructure leading to the subsequent larger deployments in the ocean lease blocks.

4.4 Inertia toward Ocean Applications in U.S.

The BOEM offshore wind lease program has created substantial inertia toward initial U.S. deployments located in the ocean. Environmental studies have been completed on many of the lease areas with findings of no significant negative impact. There has been extensive promotion of these applications and both states and DOI can expect use revenues and jobs to result. Also the projects would be largely out of sight from shore and away from bird migratory routes. Some would say, “Out of sight and out of mind.”

But there are considerable uncertainties and major risk on this path. Specific areas of concern are: lack of wind measurements and metocean data, lack of construction and operating experience in the U.S. and uncertainties regarding cost. One way to reduce these risks could be to fund wind measurements using met towers to at least hub height or preferably the top of the turbine rotor (say 200 m height). See **Figure 4-8** of a tall met tower near a turbine in Denmark. If the data is publically available all potential developers will benefit.

Barrier – Federal and Mid-Atlantic State program emphasis is on offshore, drawing attention away from coastal and sheltered shallow water applications that will be less costly.

Mitigation Option – State and Federal programs can be expanded to include wind resource measurements, economic/regulatory analysis and environmental assessments for coastal plains, bays and sounds.

The offshore wind demonstration projects planned by DOE will be very helpful except the emphasis is aimed at ocean applications. During the design phase it is possible to add emphasis on potential cost savings in sheltered waters. The large areas on the bays and sounds of the Mid- Atlantic States provide a unique opportunity to acquire manufacturing, construction and operating experience. This could serve to quantify costs and dramatically reduce the technical and financial uncertainties.

In **Figure 4-8**, a tall met tower stands to the right of the wind turbine. Wind measurements need to be taken at hub height and at or above the top of the swept area to accurately define wind shear.

Figure 4-8. Tall met tower near a turbine in Denmark.

5.0 Power Transmission and Pricing

Pennsylvania-Jersey-Maryland (PJM) is the Regional Transmission Organizations (RTO) with jurisdiction over much of the power system in the Mid-Atlantic region covered in this study. Consequently this report is focused on their operating and power pricing policies. Another RTO, Grid South was planned to include much of North Carolina and several other Southern States. It was provisionally approved by the Federal Energy Regulatory Commission (FERC) but the involved utilities decided to continue to operate their own power systems [14]. In addition a small portion of the regional grid is operated by the federally controlled Tennessee Valley Authority (TVA).

PJM coordinates the movement and pricing of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

Figure 5-1. PJM regional operation area

Although PJM has no direct influence in the deployment and development of wind power in the region, it does provide a platform for participation of wind plants and is not a direct barrier to the connection of renewable energy to the grid. PJM training materials defines its role as, "An entity that is independent from all generation and power marketing interests and has exclusive responsibility for grid operations, short-term reliability, and transmission service within a region." There is no mention of sustainable growth or power supply source diversity although wind and solar are allowed into the queue for connection to the PJM system.

Having operational authority for all regional transmission facilities under PJM's control emphasizes the opportunity to encourage long term use of renewables. PJM intends to remain technology neutral, independent and un-biased toward the use of one type of energy technology or another. PJM's perceived role is not to bring resources to market. Consequently PJM focuses on maintaining system reliability, managing congestion and employing a transmission pricing system that will promote efficient use and expansion of transmission and generation facilities today, not necessarily in the long term, in ways that are consistent with State energy plans and goals. In fulfilling its role, PJM coordinates the continuous buying, selling and delivery of short term wholesale electricity administered through Day Ahead and Real Time markets. This short term view hinders introduction of new technologies like wind that are more costly initially but are lower cost in the long term. Although this can be an impediment short-term, the PJM policies are changing and it is not considered to be a barrier to wind energy development.

5.1 Regional Wholesale Power Pricing

The PJM market uses locational marginal pricing (LMP) that reflects the value of the energy at the specific location and time it is delivered. If the lowest-priced electricity can reach all locations, prices are the same across the entire grid. When there is transmission congestion, energy cannot flow freely to certain locations. In that case, more-expensive electricity is ordered to meet that demand. As a result, the locational marginal price is higher in those “constrained” locations.

The PJM Energy Market consists of Day-Ahead and Real-Time markets. The Day-Ahead Market is a forward market in which hourly LMPs are calculated for the next operating day based on generation offers, demand bids and scheduled bilateral transactions.

The Real-Time Market is a spot market in which current LMPs are calculated at five-minute intervals based on actual grid operating conditions. Integrated hourly real-time prices are publically available. PJM settles transactions hourly and issues invoices to market participants monthly.

PJM is the independent centralized market operator for the Mid-Atlantic region. Based on data from the PJM web site the operational decisions can be characterized as follows:

- PJM's staff monitors the high-voltage transmission grid 24 hours a day, seven days a week. PJM keeps the electricity supply and demand in balance by telling power producers how much energy should be generated and by adjusting import and export transactions.
- In managing the grid, the company dispatches about 185,600 megawatts (MW) of generating capacity over 65,441 miles of transmission lines. More than 60 million people live in the PJM region.
- PJM’s staff analyze hundreds of "what if" scenarios and prepare to deal with typical load and fault events. Each variable that might affect supply and demand for electricity is considered – from extreme weather conditions, emergency situations and equipment failures to the more easily anticipated cycles of hours, days, weeks and seasons.
- PJM exercises a broader reliability role than that of a local electric utility. PJM system operators conduct dispatch operations and monitor the status of the grid over a wide area, using telemetered data from nearly 74,000 points on the grid.

This gives PJM a big-picture view of regional conditions and reliability issues, including those in neighboring systems.

5.1.1 Power Pricing Model – Methodology

Due to the location and separation of supply recourses from the location of load centers, and the limitations on transfer capability of the transmission system, not all locations in the Mid-Atlantic region have the same wholesale energy value.

Typically the more economical generation located in western regions is not able to fully support the higher demand centers (i.e. eastern coast/I-95 corridor) due to transmission system constraints. When the system cannot transfer additional “economic” electricity to meet demand, then more expensive generation has to be dispatched. This maintains the protection and reliability of the system, but at an increased price, as shown in **Figure 5-2**. Consequently the transmission constrained areas of the Mid-Atlantic region have a higher energy value then the un-constrained areas.

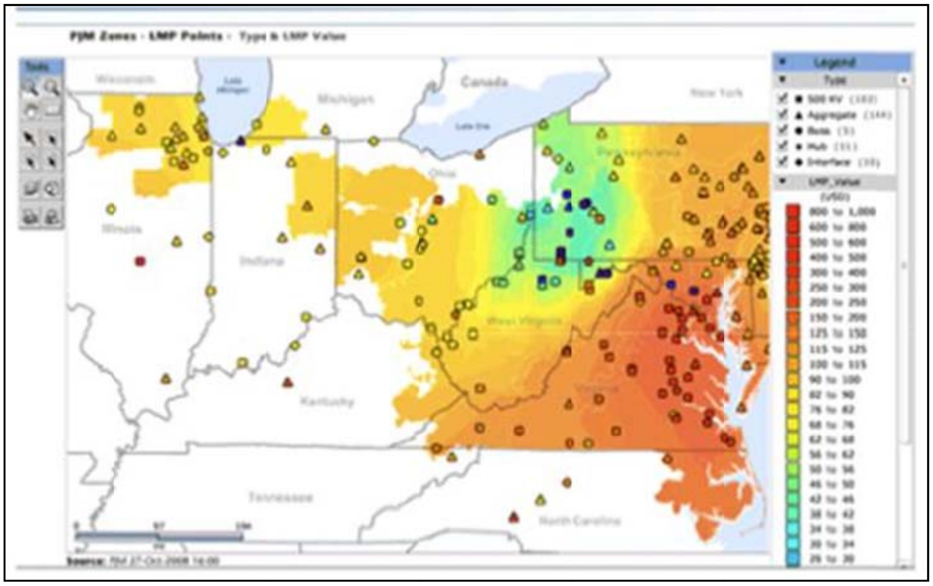

Figure 5-2. Example PJM contour map with locational marginal price (LMP) differential on typical day.

One set of questions for this study was to determine if power prices in selected areas of the Mid-Atlantic region were economic barriers to entry or if development efforts were occurring in the "better" locations. It is helpful to developers to focus on areas where the energy value of the system, as manifested by higher wholesale power prices, will support development efforts.

There are a variety of econometric computer models that are recognized by the Mid-Atlantic utility industry as tools for performing cost-benefit analyses, valuations, market structure assessments and market power studies. The Optimum Powerflow analysis is one of the better types of modeling tools for this type of study. Unfortunately access to and utilization of these types of analysis was beyond the scope and budget for this project, so the authors of this report had to develop a simplified version to perform power flow value assessment on a limited set of nodes.

Powerflow analysis is a production cost model for detailed, chronological simulation that calculates hour-by-hour production costs while recognizing the constraints on generation dispatch imposed by the transmission system. The models perform a transmission-constrained production simulation, which uses a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved AC load flow, to calculate the real power flows for each generation unit dispatched. This makes it possible to capture the economic penalties of re-dispatching the generation to satisfy transmission line flow limits and security constraints and produces forecasted market values for the nodal locations on a system.

To examine these regional value differences in this study, four PJM nodes in wind power areas representing each of the four market sectors were selected. PJM operates a transparent nodal system as shown on **Figure 5-2**: and nodes were selected for analysis to determine the economic value of energy in the four regional wind market sectors: coastal plains; ridgeline; sheltered water, as shallow bays and sounds; and ocean.

Following are the selected PJM nodes and their characteristics. Their locations are shown on **Figure 5-3**:

Cloverdale – 500KV node to represent ridgeline wind sites,

Calvert Cliffs – 500KV node – robust transmission capacity node located near potential sites in the Chesapeake in the proximity of two urban load centers Washington , DC and Baltimore, MD

Eastern Shore – DPL_ODEC[7] - an area node on the Delmarva Peninsula as a proxy pricing point for either Coastal Plains, Shallow waters, as well as, Offshore interconnection point. PJM also used Indian River for interconnection node, in their offshore wind study [15]; however the price data base, available to our study, did not contain Indian River node.

Fentress – a node adjacent to the Virginia Offshore ocean lease block site. PJM also used this pricing node as another point of potential interconnection in their baseline Offshore Wind study [15].

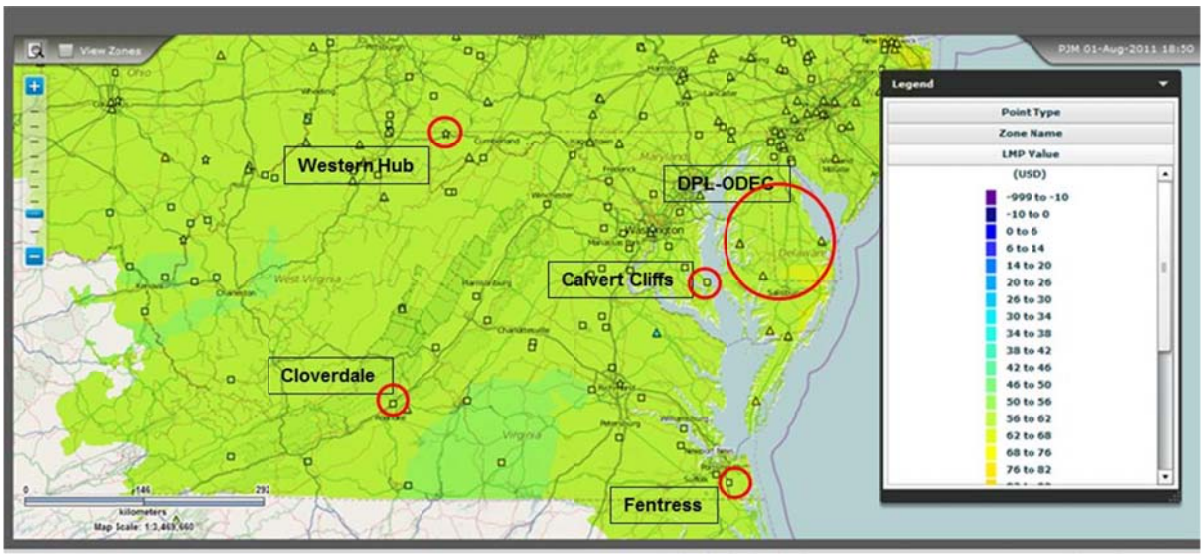

Figure 5-3. PJM interconnection node locations selected for the four wind market applications.
Source: PJM 01-August-2011

In the absence of forward pricing from PJM, the power market consultant chose PJM's Western Hub as the reference point for comparison of prices at the other four nodal sites as a means of providing an indicative forward pricing curve value of each locational node in this development study. Electricity prices at the Western Hub are considered to be the most liquid in the eastern interconnection and are traded on the NYMEX commodity exchange.

[7] Delmarva Power and Light and rural electric cooperative Old Dominion Electric Company.

5.1.2 Energy Pricing

To provide a basis for the value analysis, four years of historical data was used. Actual PJM cleared RT LMP data from 2007 to 2011 for the PJM Western Hub were compared with the four selected nodes, where RT LMP is Real-Time Locational Marginal Pricing,. Hourly data means there are about 8.760 data points per year per node, with adjustments for leap years and the start and stop of daylight savings time. The difference in value reflects the competing sources of available generation and local congestion. As can be seen in **Table 5-1** the value at some nodes is less than the Hub prices. For example, Cloverdale has low values; others are substantially higher.

These value differentials are added or subtracted from the Western Hub price. Four years of actual NYMEX commodity exchange trades for the PJM Western hub were obtained on the trade date of March 24, 2011. As is well-known, NYMEX is the New York Mercantile Exchange, a futures exchange, which trades mostly energy contracts (e.g., crude oil and refined petroleum products, natural gas, electricity), plus some contracts for agriculture and metals, which is now owned by CME Group of Chicago.

The trading data then was extrapolated for 25 years to develop a forward energy curve using the following sources and assumptions:

1. Qualitative analysis performed on potential impacts of factors effecting forward Energy pricing,
2. EPA's proposed transport rule [16] [17] [18]
3. Qualitative analysis using best case vs. worst case to come up with curves for 2015 and beyond for:

   Best case – No impacts – use only the 2.5% inflation adder, and
   Worst case – full impact – take financial impact in first couple of years, then 2.5% adder for all years after that,
4. Various traders and developers were interviewed for input on future power curves,
5. PJM Off-peak and On-peak pricing with separate curves to reflect pricing differentials. On-Peak hours are defined by PJM as Monday – Friday, with hours ending 08 to 23 (7:01 am through 11:00 pm). Off peak hours are Monday – Friday, those hours ending 01 to 07 and the hour ending 24 (11:01 pm through 7:00 am) plus all hours Saturday, Sunday and Holidays.
6. Seasonal approach to energy pricing in four markets categories to capture the seasonal effects on energy pricing, while maintain the ability to operate within budget of this report.

   Four seasons are: Winter – Dec, Jan & Feb
   Spring – Mar, Apr & May
   Summer – June, July & Aug
   Fall – Sep, Oct & Nov.

Since the study team did not have funding to utilize Optimized Power flow analysis software, we had to assume for this study that historical congestion patterns would remain the same. We understand that such would not actually occur nor is it a preferred method, but it would provide us with enough information to demonstrate the different values of energy on the system by providing these indicative values. To take into account effects of congestion, historical pricing information was used to develop a "basis" or differential for impact experienced between the Western Hub and each of the four pricing points (e.g., Calvert Cliffs vs. Western Hub).

As discussed with note 3 above, in order to best account for the effects of the potential future impacts to energy pricing for this report, it was determined to represent these risks, by two sets of forward prices. The two sets of prices would show a range of indicative outcomes.

For the lower case, for 2014 – 2015, our power market consultant assumed 2.5% for the inflationary adder. This is conservative based on recent respected economic forecasts In particular, the US Energy Information Administration projects the Wholesale Price Index for Fuel and Power to increase by 3.1% per year over the next 25 years (2010 to 2035), according to the 2012 Annual Energy Outlook (AEO), early release version [19]. The rate was 2.8% per the 2011 AEO.[8]

For the high case, termed “2015 Adder Prices,” for 2014 – 2015, our power market consultant utilized the Monthly RT LMP Swap for both on-peak and off-peak NYMEX trades and data from publically available study analysis on EPA Utility Maximum Achievable Control Technology (MACT) standards. Then, for 2016 – 2037, 2.5% was used for the inflationary adder. Project analysis runs 25 years, from 2013 through 2037.

It is noted, regarding MACT, that EPA issued rules regulating hazardous air pollutants (HAPs) emitted by electric generators, but the more significant rule is the air transport rule discussed previously. Most in industry conceded that the Utility MACT is not causing the shut downs, natural gas prices are. In the long term Clean Air Act (CAA) [23] provisions will likely impact coal-generating units in particular, causing some units to install pollution control equipment and others to retire.

Each of the four individual historical, “basis” congestion costs was used as a “differential adder” to the Western Hub forward price curve, described above, to develop indicative forward pricing at each of the four pricing nodes for the study. The four curves were utilized for the indicative forward energy market values for each location. Below, in **Table 5-1**, are the differential energy price adders for the four nodes.

[8] Annual Energy Outlook 2012, Early Release Report, DOE/EIA-0383ER(2012), US Energy Information Administration, Washington DC; January 23, 2012; Macroeconomic Indicators table.

Table 5-1. Differential Energy Price Adders for Four Nodes Relative to Western Hub ($/MWh)

Historical PJM Congestion (Basis) - 2007 thru 2010			
	Price relative to Western Hub ($/MWh)	Off-Peak	On-Peak
Fall	Western Hub - Clavert Cliffs	$ 4.53	$ 7.39
	Western Hub - Cloverdale (Moutains)	$ (6.89)	$ (9.07)
	Western Hub - DPL_ODEC (Eastern Shore)	$ 4.49	$ 7.80
	Western Hub - Fentress (Southern VA + Ocean)	$ 2.42	$ 2.23
Spring	Western Hub - Clavert Cliffs	$ 4.33	$ 4.39
	Western Hub - Cloverdale (Moutains)	$ (8.07)	$ (8.40)
	Western Hub - DPL_ODEC (Eastern Shore)	$ 5.05	$ 6.49
	Western Hub - Fentress (Southern VA + Ocean)	$ 1.99	$ (0.47)
Summer	Western Hub - Clavert Cliffs	$ 9.37	$ 10.44
	Western Hub - Cloverdale (Moutains)	$ (12.74)	$ (10.39)
	Western Hub - DPL_ODEC (Eastern Shore)	$ 7.03	$ 11.74
	Western Hub - Fentress (Southern VA + Ocean)	$ 7.38	$ 6.88
Winter	Western Hub - Clavert Cliffs	$ 6.80	$ 5.95
	Western Hub - Cloverdale (Moutains)	$ (6.21)	$ (7.01)
	Western Hub - DPL_ODEC (Eastern Shore)	$ 6.05	$ 9.00
	Western Hub - Fentress (Southern VA + Ocean)	$ 4.22	$ 1.20

Key:
Highest — Seasonal price relative to PJM Western Hub Wholesale Price ($/MWh)

The four curves were utilized for the indicative forward energy market values for each location. Below, in **Table 5-2**, are sample results from the Forward Pricing model. These results are for the Calvert Cliffs node. They show on-peak and off-peak energy prices, at 2.5% escalation, for years 2012 through 2014. For example, for January 2013, the on-peak price is $61.97 per MWh and off-peak is $41.80.

Table 5-2 further shows on-peak and off-peak power capacity and number of hours per month in each class. For January 2013, these are 43.58 MW on-peak and 45.33 MW off-peak, as well as 320 hours on-peak and 424 hours off-peak. Additional information on the four nodes is presented in **Appendix C**.

Table 5-2 PJM Forward Pricing Model Sample Output – Calvert Cliffs node, showing monthly wind energy valuation estimation, between 2012 and 2014, with the full data extending to 2037

Farm Size (MW)	Capacity Factors							
	On - Peak				Off - Peak			
	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
100	0.44	0.36	0.24	0.34	0.45	0.42	0.24	0.34

		Calvert Cliffs - Shallow Bays								
		Wholesale Energy Prices		Capacity Adjusted MW		Monthly Hours		Energy Value		
YEAR	MONTH	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	Total
2012	1	$ 60.69	$ 39.80	43.58	45.33	336	408	$ 888,668	$ 736,080	$ 1,624,748
2012	2	$ 60.69	$ 39.80	43.58	45.33	336	360	$ 888,668	$ 649,482	$ 1,538,150
2012	3	$ 55.06	$ 30.33	36.44	41.50	352	391	$ 706,289	$ 492,182	$ 1,198,471
2012	4	$ 55.06	$ 30.33	36.44	41.50	336	384	$ 674,185	$ 483,370	$ 1,157,555
2012	5	$ 55.06	$ 30.33	36.44	41.50	352	392	$ 706,289	$ 493,441	$ 1,199,730
2012	6	$ 73.10	$ 40.37	23.74	24.26	336	384	$ 583,054	$ 376,075	$ 959,128
2012	7	$ 73.10	$ 40.37	23.74	24.26	336	408	$ 583,054	$ 399,579	$ 982,633
2012	8	$ 73.10	$ 40.37	23.74	24.26	368	376	$ 638,583	$ 368,240	$ 1,006,823
2012	9	$ 58.73	$ 33.54	33.64	34.13	304	416	$ 600,651	$ 476,155	$ 1,076,806
2012	10	$ 58.73	$ 33.54	33.64	34.13	368	376	$ 727,104	$ 430,371	$ 1,157,475
2012	11	$ 58.73	$ 33.54	33.64	34.13	336	385	$ 663,877	$ 440,672	$ 1,104,550
2012	12	$ 61.97	$ 41.80	43.58	45.33	320	424	$ 864,154	$ 803,386	$ 1,667,540
2013	1	$ 61.97	$ 41.80	43.58	45.33	352	392	$ 950,570	$ 742,753	$ 1,693,323
2013	2	$ 61.97	$ 41.80	43.58	45.33	320	352	$ 864,154	$ 666,962	$ 1,531,116
2013	3	$ 57.24	$ 32.33	36.44	41.50	336	407	$ 700,836	$ 546,103	$ 1,246,939
2013	4	$ 57.24	$ 32.33	36.44	41.50	352	368	$ 734,209	$ 493,774	$ 1,227,983
2013	5	$ 57.24	$ 32.33	36.44	41.50	352	392	$ 734,209	$ 525,977	$ 1,260,186
2013	6	$ 75.69	$ 42.37	23.74	24.26	320	400	$ 574,990	$ 411,152	$ 986,143
2013	7	$ 75.69	$ 42.37	23.74	24.26	352	392	$ 632,489	$ 402,929	$ 1,035,419
2013	8	$ 75.69	$ 42.37	23.74	24.26	352	392	$ 632,489	$ 402,929	$ 1,035,419
2013	9	$ 60.34	$ 34.53	33.64	34.13	320	400	$ 649,595	$ 471,460	$ 1,121,056
2013	10	$ 60.34	$ 34.53	33.64	34.13	368	376	$ 747,035	$ 443,173	$ 1,190,207
2013	11	$ 60.34	$ 34.53	33.64	34.13	320	401	$ 649,595	$ 472,639	$ 1,122,234
2013	12	$ 63.48	$ 42.80	43.58	45.33	336	408	$ 929,570	$ 791,564	$ 1,721,134
2014	1	$ 63.48	$ 42.80	43.58	45.33	352	392	$ 973,836	$ 760,522	$ 1,734,358
2014	2	$ 63.48	$ 42.80	43.58	45.33	320	352	$ 885,305	$ 682,918	$ 1,568,223
2014	3	$ 55.12	$ 35.33	36.44	41.50	336	407	$ 674,920	$ 596,775	$ 1,271,694
2014	4	$ 55.12	$ 35.33	36.44	41.50	352	368	$ 707,059	$ 539,590	$ 1,246,649
2014	5	$ 55.12	$ 35.33	36.44	41.50	336	408	$ 674,920	$ 598,241	$ 1,273,161
2014	6	$ 70.81	$ 43.37	23.74	24.26	336	384	$ 564,814	$ 404,022	$ 968,836
2014	7	$ 70.81	$ 43.37	23.74	24.26	352	392	$ 591,710	$ 412,439	$ 1,004,149
2014	8	$ 70.81	$ 43.37	23.74	24.26	336	408	$ 564,814	$ 429,274	$ 994,087
2014	9	$ 55.47	$ 34.53	33.64	34.13	336	384	$ 627,029	$ 452,602	$ 1,079,631
2014	10	$ 55.47	$ 34.53	33.64	34.13	368	376	$ 686,746	$ 443,173	$ 1,129,919
2014	11	$ 55.47	$ 34.53	33.64	34.13	304	417	$ 567,312	$ 491,497	$ 1,058,810
2014	12	$ 64.92	$ 43.70	43.58	45.33	352	392	$ 995,899	$ 776,515	$ 1,772,413

5.1.3 Capacity Pricing

PJM Capacity Value assigned by market administers is a forward looking capacity product (at auction) to promote/maintain reliability of the system. For wind assets, PJM will allow project owners to offer 13% of name plate capacity or a demonstrated annual average of unforced capacity into the auction. Most developers interviewed for this study, stated that they would be willing to participate initially at the 13% level. This value is based on average performance of similar technology during system peak demand that occurs during summer months. Although project owners can bid a higher value, the initial level is a deterrent to wind development. See **Table 5-3** which compares actual capacity factors for several early and consequently lower efficiency wind plants.

Table 5-3. Monthly Average Capacity Factors

PJM Capacity Value for Wind and Solar

Projects:	Somerset	Mill Run	Mountaineer	Waymart	Peak Summer Capacity Values
Averaging Period:	2002-2008	2002-2008	2003-2008	2004-2008	
January	38%	44%	41%	38%	
February	34%	40%	41%	40%	
March	32%	37%	36%	36%	
April	28%	35%	33%	30%	
May	21%	25%	23%	22%	
June	14%	28%	18%	18%	17%
July	13%	13%	16%	14%	14%
August	10%	12%	12%	14%	12%-14%
September	14%	18%	19%	18%	PJM uses 13% for Wind
October	23%	27%	29%	30%	
November	32%	35%	36%	32%	
December	42%	44%	43%	37%	
Annual Avergae Over Period	25%	29%	29%	27%	

Color Denotes Summer Months Peak Capacity Factor

Notes:

1. Based on 5 to 8 year old turbine technology - New machines average
2. Installations in 2007 avaerage capacity factor was 35%; range 26% to 40%, some mos. to 55%; based on Lawrence Berkeley National Lab - US 2008 Market Report
3. No data available from newer Mid-Atlantic plants built in 2008
4. Does not account for banking of wind energy
5. Hydropower can be used as supplement during low wind periods
6. Wind can be used as supplement during drought periods

Pricing for capacity is the basis used by PJM to procure a target capacity reserve level for the RTO in a near term least cost manner while recognizing locational constraints and minimum "must-run" requirements of some generating units. Locational constraints are established by setting up Locational Deliverability Areas (LDAs) with each LDA having a separate target capacity reserve level and a maximum limit on the amount of capacity that it can import from resources located outside of the LDA. For this study, for the PJM forward pricing method, a 13% name plate capacity times the LDA market clearing price was used.

Forward forecasted LDA prices were extrapolated using historical clearing prices, eliminating significant outlying prices. Since capacity pricing is only incremental to total project revenue, to simplify, capacity pricing was escalated at 1% per year. This rate is low, because utilities replace plant and equipment slowly.

Capacity factors for sites in each of the four market areas were calculated on both a seasonal and a diurnal basis. Measured wind data were adjusted to hub height (100 m), compensated for altitude (e.g., lower air density at ridgeline site), and for ambient temperature. These seasonal capacity factors served as the basis for energy production estimates for each of the four 100 MW plant locations. Diurnal wind pattern differences for day and night times were used to develop capacity factors for on-peak /off-peak as well as the four seasons.

5.1.4 Pricing Summary

Ancillary service values and in-plant parasitic losses are quite small and were ignored for this study. Results were combined to provide comprehensive approach to developing indicative forward market values for each node. Factors included were that:

- Capacity factors were used to develop total energy production for each season (both on peak/off peak),
- Total wind plant energy production was multiplied by applicable seasonal on/off peak curve to produce revenue from seasonal energy production for each set of turbines comprising a 100 MW plant,
- All on/off peak values per seasons were summed to produce a total annual revenue stream for forecasted energy production at each location,
- Capacity revenues were then added to the total annual revenue stream for energy production producing total anticipated revenue for each location, taking into account the effects of on/off peak, seasonal and wind patterns to produce an indicatively expected market value of electricity at each location.

These annual energy production estimates and prices were then input to the energy project finance models that are discussed in **Sections 6** and **Section 7** of this report. In the economic analysis of projects, many factors are included in determining project economic viability. However the pricing differentials between different injection points are very important.

Due to the value difference alone it appears that the Delmarva coastal sites and offshore would have a price advantage over Fentress. However Delmarva transmission line capacity will quickly become a limiting factor, although moving power in a westward direction is helpful in reducing congestion.

The price differential is even more dramatic when comparing coastal to ridgeline sites. There is a $22.13 per MWh difference between DPL and Cloverdale nodes during the summer on-peak periods, as shown in **Table 5-1** (as $11.74 – 10.39). It is important to keep in mind there are other factors to consider in evaluating project economic barriers as will be discussed in **Section 6** and **Section 7** of this report.

Barrier – Transmission line capacity is not a barrier for initial projects, but can become a barrier as wind market penetration increases, leading to higher costs.

Mitigation Options – The approach used in Europe and in some states in the U.S. is to clearly commit to build the line to the projects with costs being shared by the grid system.

Table 5-4. Energy Production Estimates and Capacity Factors (assume 100m hub height)

Season			Winter				Spring				Summer				Fall				Av. Ann. Capacity Factor
Months			DJF				MAM				JJA				SON				
Application	Time of Day	Standard Plant Losses (1)	Average Wind Speed	Temp/Air Density Adj	Single Turbine Prod W/o Losses	100 MW Plant	Average Wind Speed	Temp/Air Density Adj	Single Turbine Prod w/o losses	100 MW Plant	Average Wind Speed	Temp/Air Density Adj	Single Turbine Prod w/o Losses	100 MW Plant	Average Wind Speed	Temp/Air Density Adj	Single Turbine Prod	100 MW Plant	
		(%)	(m/s)	(%)	(Hourly kWh)	(Hourly kWh)	(m/s)	(%)	(Hourly kWh)	(Hourly kWh)	(m/s)	(%)	(Hourly kWh)	(Hourly kWh)	(m/s)	(%)	(Hourly kWh)	(Hourly kWh)	
Coastal	Capacity Factor					0.38				0.37				0.14				0.25	0.28
	Day	-7.0	7.1	4.9	555.2	36,414	7.2	1.2	568.6	35,887	4.7	-3.0	214.7	12,949	5.8	1.1	370.2	23,342	
	Night	-7.0	7.8	4.9	645.9	42,367	7.6	1.2	620.8	39,183	5.1	-3.0	269.4	16,245	6.4	0.1	457.3	28,527	
Ridgeline	Capacity Factor					0.47				0.33				0.22				0.33	0.34
	Day	-16.6	9.2	5.0	799.6	47,356	7.3	1.8	581.9	33,217	5.9	-0.2	384.8	21,452	7.2	1.8	568.6	32,458	
	Night	-16.6	9.3	5.0	809.0	47,913	7.4	1.8	595.0	33,967	6.2	-0.2	428.5	23,885	7.6	1.8	620.8	35,439	
Bay	Capacity Factor					0.45				0.39				0.24				0.34	0.35
	Day	-9.0	8.3	3.7	2300.8	43,577	7.5	1.2	1976.2	36,441	6.1	-2.6	1342.8	23,741	7.2	0.1	1846.2	33,637	
	Night	-9.0	8.7	3.7	2449.7	46,398	8.6	1.2	2413.4	44,503	6.2	-2.6	1389.6	24,568	7.3	0.1	1890.0	34,435	
Ocean	Capacity Factor					0.46				0.41				0.24				0.34	0.36
	Day	-10.0	8.6	3.5	2413.4	45,130	8.1	1.1	2222.9	40,501	6.1	-2.5	1342.8	23,499	7.2	0.1	1846.2	33,268	
	Night	-10.0	9.1	3.5	2589.2	48,418	8.5	1.1	2376.4	43,298	6.4	-2.5	1482.9	25,950	7.3	0.1	1890.0	34,057	

1. Land-based turbine is GE 1.5/77sle on 100 m tower
2. Offshore turbine is REPower 5 MW on 100m tower
3. Day 0700 - 2300; Night 2301-0659 daily, weekends and holidays
4. Theoretical AEP calculated using Rayleigh Wind Distribution and Turbine Power Curves from EMD 2011 database
5. Std. Losses include: Availability, electrical (in-plant), blade contamination, and altitude.

6.0 Project Economic Results and Conclusions - Financial Results of the Cash Flow Analysis and What they Mean

One of the questions to be addressed in this study was whether economic issues would be a barrier to wind energy development in the Mid-Atlantic States. To address this question, the authors performed proforma financial analysis. We assumed a 100 MW wind farm, utilizing measured winds in the range of Class 4, that is owned and financed by an Independent Power Producer (IPP) on a limited recourse Project Finance basis. Two types of financing are examined – the current strong standard, as of first-half 2012, which tends to involve non-investment-grade-rated debt, and favorable financing, which assumes better terms. As discussed previously, the Mid-Atlantic region includes Delaware, Maryland, Virginia, North Carolina, and the District of Columbia. The specific plant capacity factor will be adjusted based on wind regime at the location and equipment type.

Across the Mid-Atlantic region, four classifications of wind farm were studied. These are: Coastal Plains, Ridgeline (mountainous land), Sheltered Water (shallow bays and sounds), and Ocean (offshore on continental shelf).

As is well known, wind energy plants are capital intensive to build, but then operate with "free fuel," over a project life running 25 years or longer. While Ridge Line and Ocean plants are more expensive to construct, the wind regime in the mountains and far offshore is stronger and steady, which may offset the added cost. Another option is Sheltered Water plants, where the wind regime may be nearly as strong and steady as for Ocean, but where construction costs are lower. To investigate these trade-offs and effects, in the Mid-Atlantic region of the United States, is the purpose of this report.

This section will discuss:

- 6.1 Methodology, Cost and Performance Estimates, and Financial Assumptions;
- 6.2 Economic Analysis Results, under Current, Likely Financing, for 2012 Wind Energy Plants, located in the Mid-Atlantic region (in 2013 dollars);
- 6.3 Economics Analysis Results, under Favorable Financing, for 2012 Wind Energy Plants, located in the Mid-Atlantic region (in 2013 dollars); and
- 6.4 Findings and Comments.

6.1 Methodology, Cost and Performance Estimates, and Financial Assumptions

The reader is encouraged to review **Section 7**, "Project Economic Inputs and Assumptions – Financial Methodology, Plant Capital Costs, Operating Expenses, and Financial Assumptions." **Section 7** sets forth inputs, assumptions, and methodology for the cash flow modeling. The model inputs include PJM forward pricing revenue forecasts, plant capital costs, and sources of project funds (debt and equity). They include performance (plant capacity factor) estimates, projected operating expenses, and financial assumptions.

6.1.1 Forward Pricing vs. Calculated COE

By way of summary, two types of financial analysis were performed – termed “Forward Pricing” and “Calculated COE.” By the first method, PJM forward power prices are forecast, so the model calculates equity and debt returns, as after-tax IRR and debt coverage. The project developer decides if returns are adequate and either proceeds, revamps, or rejects the proposed project.

By the second method, a Calculated Cost of Energy (COE) is figured, after reasonably attractive equity and debt returns are entered into the cash flow model as constraints, so the model calculates and outputs the pro forma 25-year revenue stream that is necessary. The project developer compares the plant’s COE to market prices, and will proceed, revamp, or reject the proposed project.

As is well known, PJM refers to the Penn-Jersey-Maryland Interconnection, which is the Regional Transmission Organization (RTO) for the Mid-Atlantic States and certain nearby areas. Under the first method, two sets of forward prices were prepared: 2.5% escalation, which is a conservative estimate given recent fuel and power forecasts [19], and a high case, termed “2015 Adder Prices,” which assumes EPA Utility MACT (Maximum Achievable Control Technology) standards are implemented, affecting many existing coal power plants, as discussed in **Section 5**.

6.1.2 Four Wind Market Segments and Four Plants

Wind speeds were measured and proposed 100 MW wind energy power plants were broadly defined with capital costs and operating expenses projected, for each of the four wind market segments. These locations were matched against PJM nodes; comprising substations, aggregate locations, and other; to prepare four sets of PJM forward pricing schedules.

The four proposed plants, located close to PJM nodes are mapped in **Section 5**, with **Figure 5.3**. They are:

1. DPL-ODEC, Coastal Plains;
2. Cloverdale, Ridgeline;
3. Calvert Cliffs, Shallow Water Bay; and
4. Fentress, Ocean.

6.1.3 A Merchant Power Financial Case with BB-Rated Debt.

Cash flow analysis was performed for each of the four plants, assuming a 25-year project life. The plants are assumed to sell power on a merchant basis, meaning power is sold on the competitive wholesale market at rates that fluctuate. The developer will investigate projected demand for power, looking for sites with strong demand and high prices.

As discussed with **Section 7.7**, selling merchant power is riskier than selling under a long-term power purchase agreement (PPA). Accordingly, some merchant plants are financed “on balance sheet” by strong, established developers.

When they are financed by limited recourse project finance, where debt and equity investors are secured by (have recourse to) only the project and not the developer’s other assets, the merchant power plant’s investors seek assurance they will be repaid, by evidence of a well-structured project and by guarantees from the developer. For a merchant plant utilizing limited recourse project finance, in today’s market (first half 2012), current, likely debt is unlikely to be rated higher than BB, which is one level below investment-grade.

6.1.4 50% Debt Fraction

Because debt coverage is the limiting or tight constraint, under conservative, "plain vanilla" financing-ownership, the debt fraction is limited to 50%.

By current, likely financing, the capital fraction of the project was estimated at a conservative ratio of 50% debt to 50% equity. Because the 10-year Section 45 Production Tax Credit (PTC) is utilized, and because most of the equipment is depreciated as five-year property (under MACRS, the Modified Accelerated Cost Recovery System), the projects show significant tax benefits as well as a cash return. It is assumed the developer seeks to find outside equity investors, who are in a positive earnings mode and can fully utilize the project's tax benefits. The PTC is assumed to be "monetized," or converted to cash and used to assist with debt repayment over the first ten years of project life. Limits for debt coverage for BB-rated debt, with coverage calculated as annual operating income over the annual debt payment, are estimated as 3.0 times average and 1.8 times minimum.

If a complex ownership-financing structure, with Tax Investors and "flips" were assumed, where flips are changes in allocations of cash and tax benefits over time to different ownership classes, then the debt fraction might be set higher. However, for a "plain vanilla" ownership structure, where the equity investors take both cash and tax benefits, debt coverage becomes the limiting or tight constraint in modeling project cash flows. The debt fraction must be set at 50% of total capital. If the developer wished to examine a project with 70% debt, for example, assuming interest rates did not rise due to increased risk, IRR would increase significantly, but the developer would need a higher revenue stream to meet the debt coverage limits set by lenders.

Consequently, current (first half 2012), likely IPP project finance of the 100 MW wind projects assumes 50% BB-rated, 20-year debt at 7.5% to 50% equity. Target equity returns are 17% for land-based plants. They are 22% for Bay, and 25% for Ocean, reflecting greater risk. The favorable financing set of cases, with improved debt terms, is described later, with **Section 6.3**.

6.1.5 Financial Figures of Merit to Evaluate a Project

Cost of Energy (COE), debt coverage, and IRR are important measures in evaluating a wind energy plant or other project finance or business opportunity. That three measures of COE are prepared is described in **Section 7.1.4**. Year one COE is a simple measure; it is the project's bid price for its first year, from which future prices will be escalated or otherwise calculated.

The two other measures are levelized nominal-dollar COE and levelized constant-dollar COE. These are calculated based upon the project's nominal revenue stream over its 25 year life, where the analyst first figures the Net Present Value (NPV) of revenues using the nominal-dollar discount rate and then levelizes the NPV into one level payment per year. If levelization is performed using the nominal discount rate, it produces a levelized nominal-dollar COE. If performed using the constant-dollar discount rate, it produces a levelized constant-dollar COE, which excludes inflation. When contractually-specified or nominal debt is repaid and income tax is calculated as a percentage of nominal profits, then it is necessary to inflate and figure the nominal revenues that cover project expenses, costs and returns and to then deflate these revenues.

Debt coverage and IRR are discussed fully in **Section 7**. Debt coverage compares each year's operating income against the annual debt payment (interest plus principal). One calculates the average ratio and the minimum (worst year).

IRR (Internal Rate of Return) is calculated by considering the after-tax cash flow of the project, which flows to equity investors, over all the years of project life. IRR is defined as that discount rate at which the present value of the stream of after-tax cash flows equals the present value of the initial equity investment. IRR is the rate where NPV (described below) becomes zero. As a simple percentage, IRR allows projects of different sizes to be compared.

Other measures to evaluate a project also may be considered. After discounting the after-tax cash flows of the project, by the weighted average cost of capital, Net Present Value is the discounted sum of the after-tax cash flows less initial equity investment. Projects with a positive NPV are attractive. One disadvantage of IRR is that it assumes all cash flows are reinvested at the IRR rate, which may be high. By contrast, the NPV calculation assumes cash flows are reinvested at the cost of capital discount rate.

The other measure of project value is payback, which measures the number of years until initial equity investment is paid back by the project's after-tax cash flows. Payback ignores time value of money and whether the later years of project return are fat or lean. Nonetheless, for the risk-adverse investor, this measure provides a quick means to learn when he or she will recover the initial investment.

6.2 Economic Analysis Results, under Current, Likely Financing, for Mid-Atlantic Wind Energy Plants

Results of cash flow modeling for all four wind energy plants, selling merchant power; under current, likely financing at 50% debt to 50% equity, including BB-rated, 20-year debt at a 7.50% interest rate; are presented below, with **Table 6-1**. For each of the four plants, three sets of financial analysis were performed, including 1) PJM Forward Pricing at conservative 2.5% escalation; 2) PJM Forward Pricing with 2015 Adder Prices; and 3) Calculated COE. For the first two cases, revenues are given, so the model outputs debt coverage and the after-tax IRR. For the third case, attractive debt coverage and IRR are assumed as given parameters into the model, so the model outputs a revenue stream, from which is calculated the project's COE.

6.2.1 DPL-ODEC Coastal Plains

As shown, cases 1-3 concern the DPL-ODEC Coastal Plains Wind Energy Plant. For the first case, with PJM forward pricing at 2.5%, revenues are given, but it is interesting to note that year one COE is \$0.0540 per kWh, nominal levelized COE is \$0.0661, and constant-dollar levelized COE is \$0.0513. The developer sees that debt coverage is 2.18 times average and 1.70 times minimum, which are a bit disappointing because they are below the targets of 3.0 times and 1.8 times. IRR is 12.48%, which is below the target of 17%.

For the second case, with PJM forward pricing using 2015 Adder prices, revenues again are given. Here, the year one COE is \$0.0559 per kWh, nominal levelized COE is \$0.0786, and constant-dollar levelized COE is \$0.0611. Debt coverage is better, at 2.69 times average and 1.79 times minimum, but these remain below target. IRR is better at 15.72%, but this remains below 17%.

For the third case, which is Calculated COE, debt coverage is the tight constraint, and it is 3.00 times average and 2.21 times minimum, which meet the targets of 3.0 times and 1.8 times. IRR is 18.42%, which beats the 17% target. If cash flows were run to achieve 17% IRR exactly, then debt coverage would fall slightly below target.

The COEs are the key points of interest. The year one COE is $0.0739 per kWh. Nominal levelized COE is $0.0859, which is about 2.0 cents higher than for PJM forward pricing at 2.5% and 0.7 cent higher than with 2015 Adder Prices. The constant-dollar levelized COE is $0.0667 per kWh, which is about 1.6 cent higher than PJM prices at 2.5% and 0.6 cent higher than PJM with 2015 Adder Prices.

6.2.2 *Cloverdale Ridgeline*

For the Cloverdale Ridgeline Wind Energy Plant, results are presented with cases 4-6. For case 4, with PJM forward pricing at 2.5% and revenues given, COEs might be considered low. The PJM forward prices for Cloverdale are low. The year one COE is $0.0367 per kWh, nominal levelized COE is $0.0473, and constant-dollar levelized COE is $0.0368. Debt coverage is 1.86 times average and 1.42 times minimum, which are below the BB-rated debt targets of 3.0 times and 1.8 times. IRR is 10.33%, which is below the target of 17%.

For the second case, which is case 5, with PJM forward pricing using 2015 Adder prices, revenues again are given. The year one COE is $0.0375 per kWh, nominal levelized COE is $0.0585, and constant-dollar levelized COE is $0.0455. Debt coverage improves because it is 2.39 times average and 1.55 times minimum, but these are below target. IRR is better at 14.02%, but it is still below 17%.

For the third case, case 6, which is Calculated COE, debt coverage is the tight constraint. Debt coverage is 3.02 times average and 2.29 times minimum, which meet the targets of 3.0 and 1.8 times. IRR is 19.69%, to surpass the 17% target for land-based wind energy plants. For Calculated COE, the COEs are critical. The year one COE is $0.0629 per kWh. Nominal levelized COE is $0.0743, and constant-dollar levelized COE is $0.0577 per kWh.

All three Cloverdale Ridgeline COEs, when calculated, are about 1.0 cent lower than the calculated COEs for Coastal Plains. However, market prices at Cloverdale, near Roanoke Virginia, are low, as revealed by the PJM forward prices with cases 4 and 5. The calculated nominal levelized COE at US$0.0743 is just over 2.5 cents higher than PJM prices at 2.5% and 1.5 cents higher than PJM with 2015 Adder Prices. The calculated constant-dollar levelized COE at US$0.0577 is 2.0 cents higher than PJM prices at 2.5% and 1.0 cent higher than PJM 2015 Adder Prices.

Nearby, it is noted that the 50 MW Roth Rock wind energy plant, which features 20 Nordex 2.5 MW turbines and is located on the ridgeline in Garrett County Maryland, which was financed and developed by Synergics and started up in December 2010 [20], transmits and sells much of its power to more distant power purchasers, who pay higher prices. That is, under two 20-year Power Purchase Agreements, the 50 MW Roth Rock plant sells 40 MW power and renewable energy credits to Delmarva Power & Light (Newark, DE) and 10 MW power to Maryland’s Department of General Services and the Maryland State University system, under the Generating Clean Horizons program [21,22]. In 2011, the Roth Rock plant was sold to Gestamp Wind North America, a business subsidiary of the large Spanish industrial company Gestamp [21], and its tax equity share was sold to US Bancorp [23].

Table 6-1. Cash Flow Analysis Results for Current Likely Financing for 2012 Mid-Atlantic 100 MW Wind Energy Plants (in 2013 dollars)

	Ownership/Financing Structure		COE as Year One Price (US$/kWh)	Nominal COE over contract life (US$/kWh)	Constant dollar COE over contract life (US$/kWh)	Average Debt Coverage (times). Target 3.0 X	Minimum Debt Coverage (times). Target 1.80 X	After-tax, leveraged. Targets: 17.0% land, 22% Bay, 25% Ocean.	Pre-tax, unleveraged
1	DPL-ODEC Coastal Plains - PJM Forward Pricing at 2.5% increase per year; 50% debt/50% equity								
	COE & Debt Coverage		0.0540	0.0661	0.0513	2.18	1.70		
	IRR (%)							12.48%	4.47%
	NPV at 9%							$13.899 mil	($57.783 mil)
	Payback (years)							5	17
2	DPL-ODEC Coastal Plains – PJM Forward Pricing using 2015 Adder Prices; 50% debt/50% equity								
	COE & Debt Coverage		0.0559	0.0786	0.0611	2.69	1.79		
	IRR (%)							15.72%	6.77%
	NPV at 9%							$30.251 mil	($30.530 mil)
	Payback (years)							5	13
3	DPL-ODEC Coastal Plains – COEs calculated to meet target IRR and debt coverage; 50% debt/50% equity								
	COE & Debt Coverage		0.0739	0.0859	0.0667	3.00	2.21		
	IRR (%)							18.42%	8.05%
	NPV at 9%							$41.000 mil	($12.606 mil)
	Payback (years)							4	12
4	Cloverdale Ridge Line - PJM Forward Pricing at 2.5% increase per year; 50% debt/50% equity								
	COE & Debt Coverage		0.0367	0.0473	0.0368	1.86	1.42		
	IRR (%)							10.33%	2.29%
	NPV at 9%							$5.167 mil	($86.651 mil)
	Payback (years)							6	20
5	Cloverdale Ridge Line - PJM Forward Pricing using 2015 Adder Prices; 50% debt/50% equity								
	COE & Debt Coverage		0.0375	0.0585	0.0455	2.39	1.55		
	IRR (%)							14.02%	4.92%
	NPV at 9%							$22.577 mil	($57.634 mil)
	Payback (years)							5	16
6	Cloverdale Ridge Line - COEs calculated to meet target IRR and debt coverage; 50% debt/50% equity								
	COE & Debt Coverage		0.0629	0.0743	0.0577	3.02	2.29		
	IRR (%)							19.69%	8.04%
	NPV at 9%							$48.967 mil	($13.586 mil)
	Payback (years)							4	12

	Ownership/Financing Structure		COE as Year One Price (US$/kWh)	Nominal COE over contract life (US$/kWh)	Constant dollar COE over contract life (US$/kWh)	Average Debt Coverage (times). Target 3.0 X	Minimum Debt Coverage (times). Target 1.80 X	After-tax, leveraged. Targets: 17.0% land, 22% Bay, 25% Ocean.	Pre-tax, unleveraged
7	Calvert Cliffs Shallow Bay - PJM Forward Pricing at 2.5% increase per year; 50% debt/50% equity								
	COE & Debt Coverage		0.0531	0.0659	0.0512	2.00	1.56		
	IRR (%)							10.29%	4.05%
	NPV at 9%							$7.453 mil	($91.268 mil)
	Payback (years)							6	17
8	Calvert Cliffs Shallow Bay - PJM Forward Pricing using 2015 Adder Prices; 50% debt/50% equity								
	COE & Debt Coverage		0.0546	0.0784	0.0609	2.43	1.64		
	IRR (%)							13.26%	6.08%
	NPV at 9%							$27.597 mil	($57.694 mil)
	Payback (years)							5	14
9	Calvert Cliffs Shallow Bay - COEs calculated to meet target IRR and debt coverage; 50% debt/50% equity								
	COE & Debt Coverage		0.1004	0.1167	0.0907	3.70	2.58		
	IRR (%)							22.04%	11.45%
	NPV at 9%							$92.404 mil	$50.324 mil
	Payback (years)							4	9
10	Fentress Ocean - PJM Forward Pricing at 2.5% increase per year; 50% debt/50% equity								
	COE & Debt Coverage		0.0472	0.0579	0.0450	1.00	0.80		
	IRR (%)							-2.97%	-1.76%
	NPV at 9%							($78.608 mil)	($246.308 mil)
	Payback (years)							n/a	n/a
11	Fentress Ocean - PJM Forward Pricing using 2015 Adder Prices; 50% debt/50% equity								
	COE & Debt Coverage		0.0479	0.0689	0.0535	1.26	0.90		
	IRR (%)							1.05%	0.30%
	NPV at 9%							($60.432 mil)	($216.015 mil)
	Payback (years)							24	25
12	Fentress Ocean - COEs calculated to meet target IRR and debt coverage; 50% debt/50% equity								
	COE & Debt Coverage		0.1821	0.2154	0.1674	4.53	2.96		
	IRR (%)							25.01%	15.10%
	NPV at 9%							$188.060 mil	$198.180 mil
	Payback (years)							4	7

6.2.3 Calvert Cliffs Shallow Bay

In **Table 6.1**, cases 7-9 concern the Calvert Cliffs Shallow Bay Wind Energy Plant. The first case, case 7, PJM forward pricing at 2.5%, shows year one COE is $0.0531 per kWh, nominal levelized COE is $0.0659, and constant-dollar levelized COE is $0.0512. These prices, which are given, are very close to those for DPL-ODEC, for the Coastal Plains case. For Calvert Cliffs Shallow Bay, debt coverage is 2.00 times average and 1.56 times minimum, which are low, against targets of 3.0 times and 1.8 times. IRR is 10.29%, which is significantly below the shallow bay target of 22%.

For case 8, with PJM forward pricing using 2015 Adder prices, revenues are given. Here, year one COE is $0.0546 per kWh, nominal levelized COE is $0.0784, and constant-dollar levelized COE is $0.0609. Again, these revenues are very close to those for DPL-ODEC. Debt coverage is 2.43 times average and 1.64 times minimum, which are below target. IRR is 13.26%, which is below 22%.

For case 9, with Calculated COE, IRR, the equity return, is the limiting constraint, and it is 22.04%, which meets the Sheltered Bay target of 22%. Debt coverage is 3.70 times average and 2.58 times minimum, which beat the targets of 3.0 times and 1.8 times. Regarding COEs, the year one COE is $0.1004 per kWh, the nominal levelized COE is $0.1167, and the constant-dollar levelized COE is $0.0907 per kWh. The nominal COE is 5.0 to 4.0 cents higher than the PJM prices at 2.5% escalation and with 2015 Adder prices. The constant-dollar COE is 4.0 to 3.0 cents higher than the PJM prices at 2.5% escalation and with 2015 Adder Prices.

6.2.4 Fentress, Ocean

The last set of entries in **Table 6.1** are cases 10-12, for the Fentress Ocean Wind Energy Plant. For case 10, PJM forward pricing at 2.5%, the year one COE is $0.472 per kWh, nominal levelized COE is $0.0579, and constant-dollar levelized COE is $0.0450. These prices, which are given, are lower than the others, except for Cloverdale Ridgeline. For Fentress Ocean, debt coverage is very low at 1.00 times average and 0.80 times minimum. When debt coverage is less than 1.0 times, it means the plant's operating income is too low for the project to pay its full debt payment. Likewise, IRR is very low, at -2.97%. A negative return means the equity investors lose money on their investment. They do not recover their initial investment, much less make any return.

Case 11, with PJM forward pricing using 2015 Adder prices, shows a slight improvement in results, but they still would be judged very negative. Year one COE is $0.0479 per kWh, nominal levelized COE is $0.0689, and constant-dollar levelized COE is $0.0535. Debt coverage is 1.26 times average and 0.90 times minimum, which are very low. IRR is barely positive, at 1.05%.

For case 12, the last case, with Calculated COE, IRR, the equity return, is the limiting constraint. It is 25.01%, which meets the Ocean target of 25%. For Fentress Ocean, debt coverage is 4.53 times average and 2.96 times minimum, which exceed the targets of 3.0 times and 1.8 times. For Fentress, the year one COE is $0.1821 per kWh, the nominal levelized COE is $0.2154, and the constant-dollar levelized COE is $0.1674 per kWh. The nominal COE is 15.7 to 14.6 cents higher than the PJM prices at 2.5% escalation and with 2015 Adder prices. The constant-dollar COE is 12.0 to 11.0 cents higher than the PJM prices at 2.5% escalation and with 2015 Adder Prices. When Calculated COEs are figured, the Fentress COEs greatly exceed market prices.

6.2.5 Summary of Findings

The charts below show the wind energy plant COEs described above. **Figure 6-1** shows PJM forward pricing COEs for each of the four plants. **Figure 6-2** shows Calculated COE for each of the four plants.

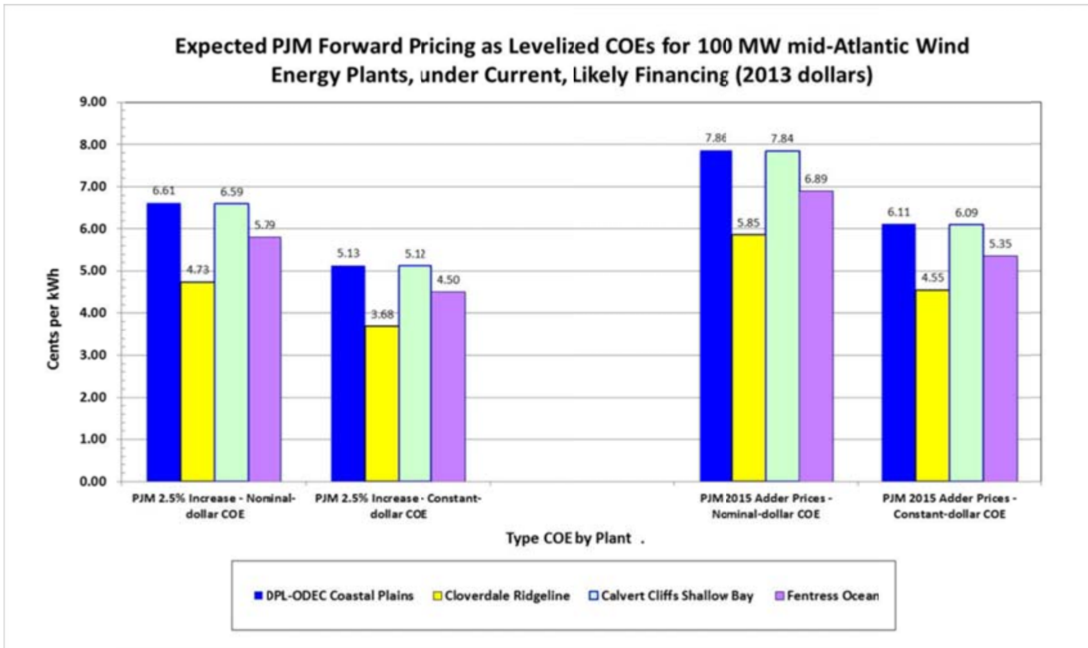

Figure 6-1. COEs for Four Plants with Current, Likely Financing using PJM Forward Prices (2013 Dollars).

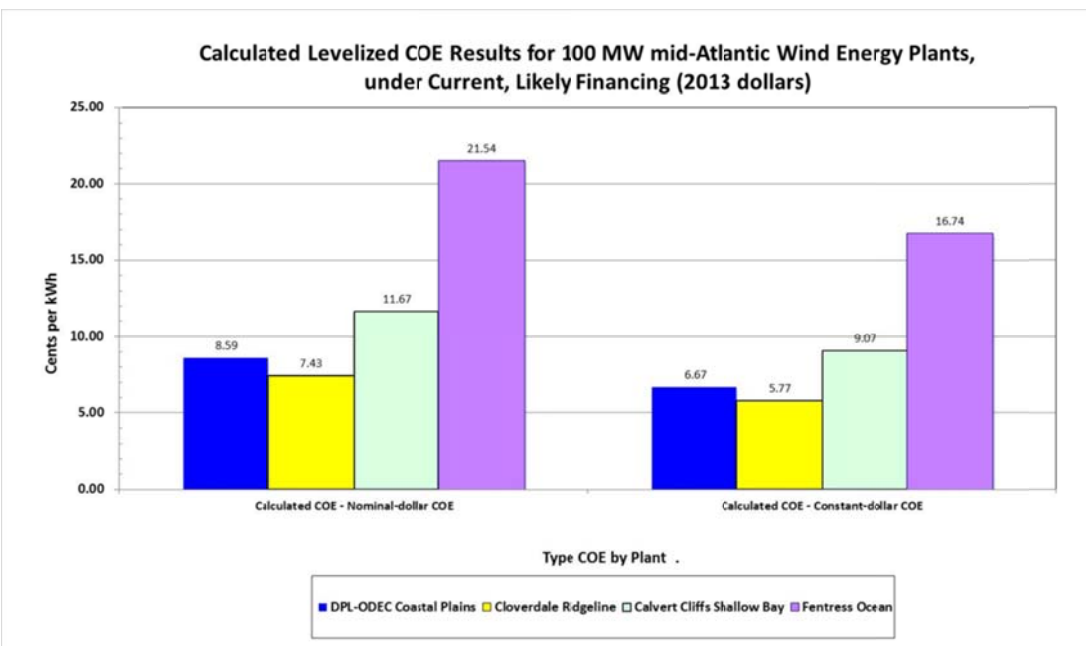

Figure 6-2. COE Results for Four Plants with Current, Likely Financing using Calculated COE (2013 Dollars)

Figure 6-1, for current likely financing, shows COEs that are given, as a result of PJM forward pricing. Reference to **Table 6-1** shows that none of these plants meet debt coverage requirements for lenders of 3.0 times average and 1.8 times worst year. None of the plants meet IRR targets for equity investors of 17% land-based, 22% Bay, or 25% Ocean.

Figure 6-2, for current likely financing, shows COEs that result when debt coverage and IRR targets are assumed to be met. For example, for Cloverdale Ridgeline, the nominal-dollar levelized COE is 7.43 cents per kWh and the constant-dollar levelized COE is 5.77 cents. Some of the results are close to market prices in a broad sense. However, they are all higher than respective PJM wholesale prices at their nodes, as shown in **Figure 6-1**.

6.3 Economic Analysis Results, under Favorable Financing, for Mid-Atlantic Wind Energy Plants.

Results of cash flow modeling for all four wind energy plants under favorable financing are set forth below, in **Table 6-2**. Favorable financing is possible when the plants sell power under a long-term Power Purchase Agreement (PPA) at somewhat fixed rates or when owners offer lenders strong guarantees. Favorable financing, at this point in time (first half 2012) assumes 60% debt to 40% equity, and includes BBB-rated, 20-year debt at a 4.00% interest rate, where the Section 45 PTC is monetized to assist with debt repayment. As discussed in **Section 7**, BBB-rated debt is the lowest level of investment-grade debt. For this lower risk, BBB-rated debt, debt coverage targets are 1.50 times average and 1.30 times minimum. The target equity returns are 17% for land-based plants, 22% for Bay and 25% for Ocean.

As done earlier, for each of the four plants, three sets of financial analysis were performed, including 1) PJM Forward Pricing at conservative 2.5% escalation; 2) PJM Forward Pricing with 2015 Adder Prices; and 3) Calculated COE. For the first two cases, revenues are given, so the model outputs debt coverage and the after-tax IRR. For the third case, attractive debt coverage and IRR are assumed as given parameters into the model, so the model outputs a revenue stream, from which is calculated the project's COE.

In reviewing cash flow results, methodology is identical to that used with **Section 6.2**. However, results are improved. The reader is encouraged to review **Table 6-2** carefully. For summarized results, however, one may refer to **Figure 6-3** and **Figure 6-4** below.

Table 6-2. Cash Flow Analysis Results Assuming Favorable Financing for 2012 Mid-Atlantic 100 MW Wind Energy Plants (in 2013 dollars).

	Ownership/Financing Structure		COE as Year One Price ($/kWh)	Nominal COE over contract life ($/kWh)	Constant dollar COE over contract life ($/kWh)	Average Debt Coverage (times). Target 1.50 X	Minimum Debt Coverage (times). Target 1.30 X	After-tax, leveraged. Targets: 17.0% land, 22% Bay, 25% Ocean.	Pre-tax, unleveraged
1	DPL-ODEC Coastal Plains - PJM Forward Pricing at 2.5% increase per year; 60% debt/40% equity								
	COE & Debt Coverage		0.0540	0.0661	0.0513	2.21	1.73		
	IRR (%)							19.61%	4.48%
	NPV at 9%							$30.540 mil	($57.385 mil)
	Payback (years)							4	16
2	DPL-ODEC Coastal Plains – PJM Forward Pricing using 2015 Adder Prices; 60% debt/40% equity								
	COE & Debt Coverage		0.0559	0.0786	0.0611	2.72	2.05		
	IRR (%)							23.11%	6.80%
	NPV at 9%							$46.891 mil	($30.133 mil)
	Payback (years)							4	13
3	DPL-ODEC Coastal Plains – COEs calculated to meet target IRR and debt coverage; 60% debt/40% equity								
	COE & Debt Coverage		0.0499	0.0579	0.0450	1.93	1.56		
	IRR (%)							17.06%	2.56%
	NPV at 9%							$20.151 mil	($74.692 mil)
	Payback (years)							4	19
4	Cloverdale Ridge Line - PJM Forward Pricing at 2.5% increase per year; 60% debt/40% equity								
	COE & Debt Coverage		0.0367	0.0473	0.0368	1.89	1.47		
	IRR (%)							17.17%	2.29%
	NPV at 9%							$22.483 mil	($86.253 mil)
	Payback (years)							4	20
5	Cloverdale Ridge Line - PJM Forward Pricing using 2015 Adder Prices; 60% debt/40% equity								
	COE & Debt Coverage		0.0375	0.0585	0.0455	2.41	1.90		
	IRR (%)							21.09%	4.94%
	NPV at 9%							$39.893 mil	($57.237 mil)
	Payback (years)							4	16
6	Cloverdale Ridge Line - COEs calculated to meet target IRR and debt coverage; 60% debt/40% equity								
	COE & Debt Coverage		0.0389	0.0451	0.0351	1.78	1.35		
	IRR (%)							17.14%	1.24%
	NPV at 9%							$19.753 mil	($90.740 mil)
	Payback (years)							4	22

	Ownership/Financing Structure		COE as Year One Price ($/kWh)	Nominal COE over contract life ($/kWh)	Constant dollar COE over contract life ($/kWh)	Average Debt Coverage (times). Target 1.50 X	Minimum Debt Coverage (times). Target 1.30 X	After-tax, leveraged. Targets: 17.0% land, 22% Bay, 25% Ocean.	Pre-tax, unleveraged
7	Calvert Cliffs Shallow Bay - PJM Forward Pricing at 2.5% increase per year; 60% debt/40% equity								
	COE & Debt Coverage		0.0531	0.0659	0.0512	2.03	1.57		
	IRR (%)							16.84%	4.06%
	NPV at 9%							$32.248 mil	($90.712 mil)
	Payback (years)							4	17
8	Calvert Cliffs Shallow Bay - PJM Forward Pricing using 2015 Adder Prices; 60% debt/40% equity								
	COE & Debt Coverage		0.0546	0.0784	0.0609	2.45	1.84		
	IRR (%)							20.10%	6.10%
	NPV at 9%							$52.393 mil	($57.138 mil)
	Payback (years)							4	14
9	Calvert Cliffs Shallow Bay - COEs calculated to meet target IRR and debt coverage; 60% debt/40% equity								
	COE & Debt Coverage		0.0699	0.0807	0.0627	2.57	1.90		
	IRR (%)							22.09%	6.40%
	NPV at 9%							$57.713 mil	($48.266 mil)
	Payback (years)							3	13
10	Fentress Ocean - PJM Forward Pricing at 2.5% increase per year; 60% debt/40% equity								
	COE & Debt Coverage		0.0472	0.0579	0.0450	1.02	0.81		
	IRR (%)							-1.17%	-1.77%
	NPV at 9%							($41.956 mil)	($245.466 mil)
	Payback (years)							n/a	n/a
11	Fentress Ocean - PJM Forward Pricing using 2015 Adder Prices; 60% debt/40% equity								
	COE & Debt Coverage		0.0479	0.0689	0.0535	1.28	1.02		
	IRR (%)							4.29%	0.30%
	NPV at 9%							($23.780 mil)	($215.173 mil)
	Payback (years)							18	25
12	Fentress Ocean - COEs calculated to meet target IRR and debt coverage; 60% debt/40% equity								
	COE & Debt Coverage		0.1319	0.1538	0.1195	3.22	2.19		
	IRR (%)							25.02%	10.67%
	NPV at 9%							$121.411 mil	$26.853 mil
	Payback (years)							3	10

6.3.1 Summary of Findings

The charts below show the wind energy plant COEs that were presented with **Table 6-2**. **Figure 6-3** shows PJM forward pricing COEs, under favorable financing, for each of the four plants. **Figure 6-4** shows Calculated COE, under favorable financing, for each of the four plants.

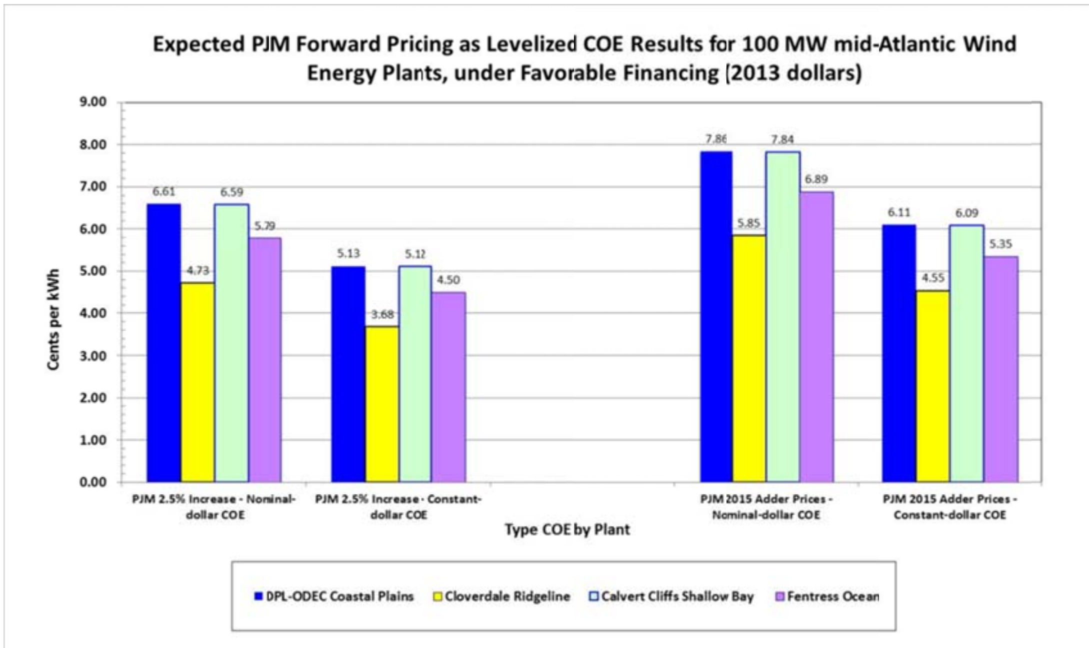

Figure 6-3. COEs of Four Plants with Favorable Financing using PJM Forward Prices (2013 Dollars).

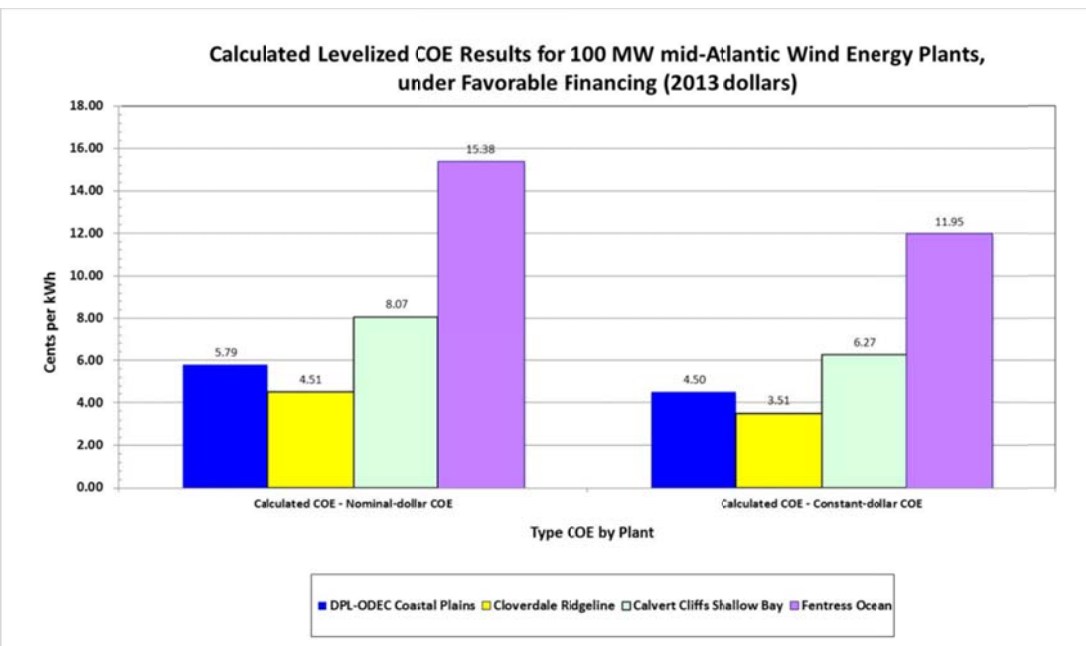

Figure 6-4. COE Results of Four Plants with Favorable Financing using Calculated COE (2013 Dollars)

Figure 6-3, for favorable financing, shows COEs that are given under PJM forward pricing. Reference to **Table 6-2** shows that several of these plants meet debt coverage requirements for lenders and IRR targets for equity investors. Specifically, the two DPL-ODEC Coastal Plains cases (cases 1 and 2 in **Table 6-2**) meet debt coverage targets and show IRRs over 17%. The two Cloverdale Ridgeline cases (cases 4 and 5) meet debt coverage and IRR targets.

Both Calvert Cliffs Shallow Bay plants meet debt coverage requirements, but they are both a little shy in hitting the equity target levels of 22% Bay. Case 7, with a 2.5% price increase, has an IRR of 16.84% and case 8, with 2015 Adder Prices, has an IRR of 20.10%, where the latter is fairly close. Both Fentress Ocean cases (cases 10 and 11) are severely deficient, with very low debt coverage rations and very low IRR returns.

Barrier – Risk premiums for both debt and equity investors, are high. Under current (first half 2012), likely financing, the best debt for most developers (with rare exceptions) is rated BB, one level below investment-grade, which carries a long-term interest rate 0f 7.5% and debt coverage targets of 3.0 times average and 1.8 times minimum. For Shallow Water Bay and Ocean plants, target equity returns are 22% and 25%

Mitigation Option – Power Purchase Agreements, where credit-worthy, large power purchasers assume some project risk, will assist with wind energy development. If initial purchase risk can be spread over a large group of buyers, individual risk is reduced. If a large developer, teaming with a large group of equity investors, can share some of the initial risk, initial, individual risk is reduced further.

With time, as developers, power purchasers and end customers, and debt and equity investors become more comfortable and experienced with offshore wind energy plants, risk is reduced. Planned DOE offshore demonstration projects will be helpful, but only if they are located in this region. Favorable financing rates for debt, with lower interest rates and with target debt coverage on the order of 1.5 times average and 1.3 times minimum, will become available. Equity target returns, estimated at 22% and 25%, for Bay and Ocean, will decline to near those of land-based plants, at about 17%.

6.4 Findings and Comments

Earlier, it was noted that wind energy plants are capital-intensive to build, but then operate with "free fuel." Their annual operating expenses are low, composed only of O&M, land rental fees, property tax, insurance and major maintenance and overhauls. For the Mid-Atlantic states of Maryland, Delaware, Virginia, the District of Columbia, and Washington DC; it was postulated that while Ridgeline, Sheltered Water Bay and Ocean plants were more expensive to build, that the wind regime in the mountains and off-shore was stronger, to produce more power, which might overcome the costs.

6.4.1 Land-Based Plants

Land-Based Plants are Financially Feasible with Favorable Financing. They "come close" with Current, Likely Financing.

As the subsequent analysis showed, under favorable financing with BBB-rated debt, the two land-based plants, for Coastal Plains and Ridgeline, met financial targets for debt coverage and equity rate of return. They appear economically feasible. From **Table 6.2**, looking at PJM forward pricing, cases 1 and 2 for Coastal Plains and cases 4 and 5 for Ridgeline meet debt coverage targets of 1.5 times average and 1.3 times minimum and the IRR target of 17%.

From **Table 6.2**, looking at Calculated COE, case 3 for Coastal Plains and case 6 for Ridgeline show nominal-dollar and constant-dollar levelized COEs that are within market prices. As discussed, the constant dollar COE excludes inflation. The Coastal Plains COEs are 5.79 cents per kWh nominal and 4.50 constant, which are less than their respective PJM forward pricing values (cases 1 and 2) by about 1 cent to 2 cents nominal and 0.5 cent to 1.5 cents constant. The Ridgeline COEs are 4.51 cents per kWh nominal and 3.51 constant, in 2013 dollars, which are less than their respective PJM forward pricing values (cases 4 and 5) by about 0.2 cent to 1.3 cents nominal and 0.2 cent to 1.0 cents constant. The wind energy plants, assuming favorable financing, produce power at COEs that are less than the PJM forward prices, which is obviously attractive to power purchasers.

If one “stresses” the plants, by assuming current, likely financing, with riskier BB-rated debt at a higher interest rate, then their economic performance slips some. From **Table 6.1**, looking at PJM forward pricing at 2015 Adder Prices, which is higher revenue, case 2 for Coastal Plains and case 5 for Ridgeline come partway to meeting the average 3.0 times debt coverage target, at 2.69 times and 2.39 times. They both come close to meeting the minimum 1.8 times debt coverage target, at 1.79 times and 1.55 times. They are both close to the equity return 17% target, with IRRs of 15.72% and 14.02%.

From **Table 6.1**, looking at Calculated COE, case 3 for Coastal Plains and case 6 for Ridgeline show nominal-dollar and constant-dollar levelized COEs that are close to market prices. The Coastal Plains COEs are 8.59 cents per kWh nominal and 6.67 constant, which exceed PJM forward pricing for DPL-ODEC (cases 1 and 2) by about 2 to 1 cents per kWh nominal and 1.5 to 0.5 cents per kWh constant. The Ridgeline COEs are 7.43 cents per kWh nominal and 5.77 constant, in 2013 dollars. They compare to PJM forward prices for Ridgeline (cases 4 and 5), which are the lowest prices for all nodes, as in excess by 2.7 to 1.5 cents nominal and 2.1 to 1.2 cents constant.

6.4.2 Ridgeline Plants Show the Best Economics

The Ridgeline plant shows only a modest increase in capital cost over the Coastal Plains plant, due to its mountain location, at $1,600 per kW vs. $1,530 for overnight capital cost (See Table 7-4 and Table 7-5). But it enjoys better performance, with a capacity factor of 34.2% vs. 28.4% (see Table 7-8).

Under favorable financing, from **Table 6-2**, the Calculated COE case 6 for Ridgeline shows a nominal levelized COE of 4.51 cents per kWh and a constant-dollar COE of 3.51 cents per kWh. These are under COEs from both sets of PJM forward pricing (at 2.5% escalation or with 2015 Adders). The Calculated COEs for Ridgeline are slightly less than the prices of 4.73 cents nominal and 3.68 cents constant for the local neighborhood of Cloverdale Ridgeline under PJM forward pricing (case 4), with case 5 higher.

Under current likely financing, from **Table 6-1**, results are less dramatic, but the trend still holds. The Calculated COE case 6 for Ridgeline shows a nominal levelized COE of 7.43 cents per kWh and a constant-dollar COE of 5.77 cents per kWh. These are over the COEs for both sets of PJM forward prices at Cloverdale Ridgeline, but they are in the general range of market prices for the broader PJM wholesale region.

6.4.3 Shallow Water Bay Plants

Under Favorable Financing, the Shallow Water Bay plant meets debt coverage and “comes close” to meeting equity return targets. It is within 0.3 cents per kWh of meeting the higher set of PJM forward prices, those with 2015 Adders. Under current likely financing, a gap to market prices, of 3 to 4 cents per kWh, exists, which is not insurmountable.

Specifically, the Shallow Water Bay plant shows increased capital cost against the Coastal Plains plant, because of its tougher, water location, at $2,300 per kW vs. $1,530 for overnight capital cost (See **Table 7-4** and **Table 7-5**). Its capacity factor is 35.4% vs. 28.4% (see **Table 7-8**).

Under favorable financing, from **Table 6-2**, looking at PJM forward pricing with 2.5% escalation and with 2015 Adder Prices, which are cases 7 and 8, the projects meet debt coverage targets of 1.5 times average and 1.3 times minimum easily, with average coverage of 2.03 and 2.45 times and with minimums of 1.57 and 1.84 times. However, they are both shy in meeting the 22% Bay return, with IRRs of 16.8% and 20.1%.

For Calvert Cliffs Shallow Water Bay, the Calculated COE case 9 shows a nominal levelized COE of 8.07 cents per kWh and a constant-dollar COE of 6.27 cents per kWh. These are very close, at 0.2 cents to 0.3 cents per kWh, to the COEs from PJM forward pricing with 2015 Adders for DPL-ODEC and for Calvert Cliffs. Specifically, the Calvert Cliffs Bay COEs compare to prices of 7.86 cents nominal and 6.11 cents constant for DPL-ODEC Coastal Plains (case 2). They compare to prices of 7.84 cents nominal and 6.09 cents constant for Calvert Cliffs Bay (case 8). The Bay prices are only a penny difference, at 1.5 cents per kWh nominal and 1.1 cents constant, above PJM prices at 2.5% increase, which are 6.59 cents nominal and 5.12 cents constant (case 7).

Under current likely financing, from **Table 6-1**, results for the Shallow Water Bay case are not so close to market prices. The PJM forward pricing cases (cases 7 and 8) do not meet debt coverage or equity return targets. The Calculated COE case 9 for Shallow Water Bay shows a nominal levelized COE of 11.67 cents per kWh and a constant-dollar COE of 9.07 cents per kWh. These are over, for PJM forward pricing with 2015 Adders, the prices of 7.84 cents nominal and 6.09 cents constant for Calvert Cliffs (case 8), by about 3.8 and 3.0 cents.

6.4.4 Ocean Plants

The Offshore Ocean plant fails to meet debt coverage and equity return targets by a significant margin, under both favorable financing and current likely financing. Calculated COEs range from 15. to 21.5 cent per kWh nominal and 12 to 16.7 cents per kWh constant.

Compared to the other wind energy plants, the Offshore Ocean plant shows the highest overnight capital cost, partly due to the need for massive foundations needed in severe ocean water conditions, at $3,390 per kW, which is nearly double the $1,530 Coastal Plains cost (See **Table 7-4** and **Table 7-5**). Its capacity factor is 36.2% vs. 28.4% for Coastal (see **Table 7-8**).

Under favorable financing, from **Table 6-2**, the two PJM forward pricing cases are 10 and 11. As shown, for both projects, debt coverage is extremely low at about 1.0 to 1.2 times, which leaves no margin of safety to meet the payment, and could fail to be adequate with a slight shift in circumstances. The equity returns are slightly negative for case 10 and only 4% for case 11, at great risk. Payback is never reached for case 10 and is 18 years for case 11.

For Fentress Ocean, the Calculated COE case 12 shows a nominal levelized COE of 15.38 cents per kWh and a constant-dollar COE of 11.95 cents per kWh. These exceed the Fentress PJM forward pricing COEs (cases 10 and 11) by 8.5 cents to 9.5 cents per kWh nominal and by 6.5 cents to 7.5 cents per kWh constant. These represent a significant gap to current market prices.

Under current likely financing, from **Table 6-1**, results for the Fentress Ocean cases (cases 10 and 11) are slightly weaker. All debt coverage is under 1.25 times, IRRs are no better than 1.05%, and the better payback is 24 years. The Fentress Calculated COE case 12 shows a nominal levelized COE of 21.54 cents per kWh and a constant-dollar COE of 16.74 cents per kWh. These greatly exceed current market prices, by 11 to 16 cents.

6.4.5 Final Comments

The authors of this report used budget pricing estimates to project capital costs and operating expenses for four different wind energy plants, located two on land and two in the water. We likewise projected PJM forward pricing curves for four nodes. Financing assumptions are based on first half 2012 conditions. Variability to our estimates exists, so our equity return percentages and COE results are not exact. They might be considered "ball park" numbers that show a trend or direction. From this basis, a developer should investigate further, working with prospective power purchasers, landowners, community and state officials and others.

In addition, the PJM forward pricing estimates match hourly wind plant capacity factors against hourly energy prices, and acknowledge that some Mid-Atlantic winds blow strong at night and during winter they fetch low off-peak power payments from a market that pays top dollar for summer day time peaks. The Calculated COE estimates assume one capacity factor for the year and one energy payment that holds constant, which approach does not distinguish seasonal and time-of-day differences. However, distance to load centers and associated transmission cost, and environmental concerns must be addressed for Ridgeline plants.

That said, what do financial results of the cash flow analysis show? First, the land-based wind energy plants in the Mid-Atlantic States are "about ready to go."

Under favorable financing, both Coastal Plains and Ridgeline plants can be built to produce power at market prices. Under current likely (higher-priced) financing conditions, the developer must look for an offset to the slightly higher financial costs, such as a site with stronger winds and a higher capacity factor, or slightly reduced costs and/or operating expenses, or a power purchaser who will pay a small premium. However, even though the Ridgeline plants pay the lowest market prices of the four nodes, they show attractive COEs that meet market prices. With only a modest increase in capital cost over the Coastal Plains plant, due to its mountain location, at $1,600 per kW for overnight capital cost, as seen in **Table 7-4** and **Table 7-5**, but with an improved capacity factor of 34.2%, as shown in **Table 7-8**, the Ridgeline plant produces power efficiently. When power from the Ridgeline plants is sold into PJM's wholesale network, the COEs often will be attractive to various buyers.

Second, shallow water bay and sound plants show much better financial results than do the off-shore ocean plants. Bay plants enjoy nearly as good a wind regime, as shown by their high capacity factor (35.4%), as do the offshore Ocean plants (36.2%), as stated in **Table 7-8**. But the capital cost of Bay plants is likely to be lower with less costly foundations than for offshore Ocean. Overnight capital cost is $2,300 vs. $3,390 for Ocean, per kW-capacity.

Under favorable financing, the Calvert Cliffs Shallow Water Bay plant COE estimates "come close" to producing power at market rates. With favorable financing, the Bay plant COEs, at 8.07 cents per kWh nominal and 6.27 cents per kWh constant (case 9, **Table 6-2**), are only slightly above PJM market prices, by 0.3 cents per kWh and by 1.5 to 1.1 cents, for PJM forward pricing with 2015 Adders and with the 2.5% price increase. These increases are not very large. They may be overcome if wind capacity factor increases, if capital costs decline with greater operating experience and/or economies of scale, or if market prices increase.

Under current, likely financing, the Calvert Cliffs Bay plant COEs, exceed market prices by a greater gap, on the order of 3 to 5 cents. Specifically, the Bay COEs are 11.67 cents per kWh nominal and 9.07 cents per kWh constant (case 9, **Table 6-1**), which exceed PJM market prices, by 3.8 to 3.0 cents per kWh and by 5 to 4 cents, for PJM forward pricing with 2015 Adders and with the 2.5% price increase. This gap may be overcome with time, as the technology improves, so the capacity factor increases and capital costs decline by learning curve effects and scale economies.

However, the Fentress Ocean COEs do not appear economically viable for the foreseeable future. The Ocean plants offer vast area potential, but bridging such a large economic gap will be challenging. If Shallow Bay wind energy plants were built, the field experience gained in doing so would benefit the future development of both Bay and Ocean plants.

One final note is that PJM must be recognized as a spot market. Spot market prices tend to reflect marginal, variable cost, so during any period of oversupply or glut, spot prices will fall. During a shortage, spot prices will rise. Power plants selling at PJM wholesale prices "ride along" with whatever the trend is. For an "old, mature" small power plant, that has repaid its debt, this represents a great opportunity, especially as fuel prices rise.

However, for the new capital-intensive plant, having prices follow a variable path is upsetting to debt and equity investors. A capital intensive power plant tends to be priced better under long-term contracts which reflect both fixed and variable costs. The wind energy plant's tariff would not fall to meet the spot market low, but it will not rise to meet spot market highs. The tariff pattern for a profitable wind energy plant might show a long, steady, revenue stream that increases slower than inflation and dips down after debt is repaid, against which spot prices rise and fall like waves against a wall. The long, steady tariff pattern can be cheaper to customers in the long run.

7.0 Project Economic Inputs and Assumptions – Financial Methodology, Plant Capital Costs, Operating Expenses, and Financial Assumptions

For the Mid-Atlantic Wind energy report, results of the cash flow analysis were set forth in the previous **Section 6**. As discussed, the authors assume a 100 MW wind farm, utilizing measured winds in the range of Class 4, which is owned and financed by an Independent Power Producer (IPP) on a limited recourse Project Finance basis. Two types of financing are examined – the current strong standard, as of first-half 2012, which tends to involve non-investment-grade-rated debt, and favorable financing, which assumes better terms. As discussed, the Mid-Atlantic region includes Delaware, Maryland, Virginia, North Carolina, and the District of Columbia. The specific plant capacity factor will be adjusted based on location and equipment type.

Across the Mid-Atlantic region, four classifications of wind farm will be studied. These are: Coastal Plains (land), Ridge Line (mountainous land), Sheltered Water (shallow bays and sounds), and Ocean (offshore on continental shelf).

As is well known, wind energy plants are capital intensive to build, but then operate with "free fuel," over a project life running 25 years or longer. While Ridge Line and Ocean plants are more expensive to construct, the wind regime in the mountains and far offshore is stronger and steady, which may offset the cost. Another option is Sheltered Water plants, where the wind regime may be nearly as strong and steady as for Ocean, but where construction cost is lower than for Ocean plants. To investigate these trade-offs and effects, in the Mid-Atlantic region of the United States, is the purpose of this report.

This chapter will discuss:

7.1 Project Finance Discounted Cash Flow – Return On Investment Methodology,

7.2 PJM Forward Pricing Forecasts – Energy and Capacity Payments

7.3 Capital Costs for the Wind Energy Plants,

7.4 Sources of Funds for the Wind Energy Plants,

7.5 Performance (Plant Capacity Factors) for the Wind Energy Plants,

7.6 Operating Expenses for the Wind Energy Plants, and

7.7 Financial Assumptions for Current, Likely and for Favorable Financing of the Wind Energy Plants.

7.1 Power Plant Project Discounted Cash Flow – Return on Investment Methodology

The **Section 6** results were obtained by reviewing the projects using Discounted Cash Flow – Return on Investment (DCF-ROI) analysis. Financing and ownership for each of the 100 MW wind energy plants assume limited recourse project finance, where debt and equity investors are secured only by assets for the one project, not by the balance sheets of the project developer or other equity investors. An Independent Power Producer, acting as developer, raises debt at 60% to 50% of capital cost and raises the balance, as 40% to 50% of cost, as equity. The project has a 25-year contract life, although useful life may be much longer, so debt term is 20 years.

Plant performance and capital cost to build the plant are estimated, with forward projections for 25 years of revenues, operating expenses, and other charges. After-tax cash flow is calculated.

Two methods of performing cash flow financial analysis were utilized. The first is where forward power prices are forecast; so the model calculates return on equity investment, as after-tax IRR, and debt coverage. The second is where an attractive equity return and adequate debt coverage are assumed, so the model calculates the associated revenue stream or Cost of Energy (COE) necessary.

7.1.1 PJM Forward Pricing

As discussed, PJM is the Penn-Jersey-Maryland Interconnection, which is the Regional Transmission Organization (RTO) that operates the power grid and wholesale electric market of the Mid-Atlantic States. PJM nodes are representative of substations, aggregated locations, generators and other locations on the network.

For this report, four PJM nodes plus PJM's Western Hub base node were examined, as mapped with **Figure 5.3**. Western Hub, which is an aggregation of about 100 underlying physical nodes, is PJM's central trading hub and is located virtually near Pittsburgh, PA. As the most liquid point and PJM's central trading hub, Western Hub's prices serve as reference electric prices against which all other nodes are derived . Prices at nodes reflect local supply and demand. When there is congestion in supplying power, prices at nodes can run high. The four nodes are described in **Section 5**.

PJM forward prices are forecast, based on regression analysis of four years of historic hourly nodal prices, so as to develop a "basis" or differential for impact experienced between the Western Hub and each of the four pricing points (e.g., Calvert Cliffs vs. Western Hub); three years of actual Commodities futures pricing data from NYMEX; and Qualitative Analysis performed on potential impacts of factors affecting forward energy pricing. See **Section 5** for details.

In order to best account for the effects of the potential future impacts to energy pricing for this report, it was determined to represent these risks by two sets of forward prices. The lower case assumed 2.5% for the inflationary adder, which is conservative based on recent respected economic forecasts for fuel and power escalation [19].[9] The high case, termed "2015 Adder Prices," assumed price escalation associated with implementation of EPA Utility standards, as discussed in **Section 5**. Project analysis runs 25 years, from 2013 through 2037.

When forward prices were prepared and entered into the cash flow analysis, the model calculates return on equity investment, as after-tax IRR, and debt coverage. If IRR and debt coverage look attractive, the developer proceeds with the project. If IRR and debt coverage are slightly low, the developer looks to improve the project, by reducing capital cost if this can be done safely, by reducing operating charges, or by increasing revenues by negotiating with the power purchaser or by possibly relocating to another site with a better wind regime. If IRR and debt coverage are very low, the developer and other project participants may reject the project, believing that project economics cannot be sufficiently improved.

7.1.2 Calculated COE

By contrast, methodology for the calculated COE approach is to estimate the plant's costs plus a reasonable return (to debt and equity investors), and enter this data as the model's inputs. A revenue stream from which to figure Cost of Energy (COE), which meets minimum IRR requirements (the hurdle rate) and minimum debt coverage requirements, is the output of cash flow modeling.

[9] The US Energy Information Administration projects the Wholesale Price Index for Fuel and Power to increase by 3.1% per year over the next 25 years (2010 – 2035), per the 2012 Annual Energy Outlook (AEO), early release version, dated January 2012. The rate was 2.8% per the 2011 AEO.

From this analysis, the analyst compares the plant's COE to what the market is paying. If the plant's COE is at or below market prices, the developer will proceed with the project. If the COE is close to a range of market prices, then the developer will negotiate project details and terms, as described above. If the COE is relatively high, the developer may reject the project.

It is useful to note that PJM forward pricing estimates match hourly wind plant capacity factors (e.g., that some Mid-Atlantic winds blow stronger at night and during winter) against hourly energy prices showing differences in pricing, by hourly on-peak/off-peak rates and by season (e.g., summer peak). The calculated COE approach is simplified, assuming one capacity factor for the year and one energy payment that holds constant.

7.1.3 Three Sets of Analysis per Node/Plant Location

Consequently, for each of the four nodes, three sets of analysis are performed. These are listed in **Table 7-1** below. Furthermore, assuming a 25-year project life, two types of financing are examined – conservative, current-day 50% BB-rated 20-year debt at 7.5% to 50% equity and favorable financing, comprising 60% BBB-rated 20-year debt at 4.0% to 40% equity. These are described later, with **Section 7.7**. As shown, six cases are examined for each project/plant site.

Table 7-1. Analysis Method per Node/Plant Site

	Analysis Method	Model Output
conservative 50% debt to 50% equity		
1	Revenues Given, as PJM Forward Pricing with 2.5% Escalation.	After-tax Equity IRR and Debt Coverage Level.
2	Revenues Given, as PJM Forward Pricing with 2015 Adder Prices.	After-tax Equity IRR and Debt Coverage Level.
3	Revenue Pricing by Calculated COE, which assumes attractive debt coverage and after-tax equity return are given.	Revenue Stream, from which is calculated the Project's COE.
favorable financing with 60% BBB-rated debt at a lower interest rate to 40% equity		
4	Revenues Given, as PJM Forward Pricing with 2.5% Escalation.	After-tax Equity IRR and Debt Coverage Level.
5	Revenues Given, as PJM Forward Pricing with 2015 Adder Prices.	After-tax Equity IRR and Debt Coverage Level.
6	Revenue Pricing by Calculated COE, which assumes attractive debt coverage and after-tax equity return are given.	Revenue Stream, from which is calculated the Project's COE.

7.1.4 Three Measures of COE

For each analysis, whether it reflects PJM forward pricing or a calculated COE, three measures of COE are prepared. These include year one COE, which is the combined energy and capacity revenues for year one, on a unit basis, or per kWh. Because future revenues often are projected to escalate by a pattern, such as inflation or inflation less one half percent, the year one figure serves as an easy rule of thumb.

The other two measures are levelized nominal-dollar COE and levelized constant-dollar COE. They each reflect 25 years of project revenues, but time value of money means that early years are counted more heavily. To figure nominal COE, the analyst calculates 25 years of project cash flows, showing revenues less operating expenses, interest, and non-cash charges, to figure before-tax income, and income taxes. The analyst then figures annual cash flows as before-tax income plus depreciation and amortization less non-deductible payments like principal on debt and any reserve fund payments, to figure before-tax cash. The analyst then deducts income tax payable and adds back any tax credits, such as wind energy's 10-year Section 45 Production Tax Credit. This gives after-tax cash. Against initial equity investment, the years of after-tax cash are used to figure the project's IRR (Internal Rate of Return). Debt coverage is figured by comparing each year's operating income against the debt payment (interest plus principal), and recording the average and minimum (worst year).

To figure COE, the analyst returns to his cash flow analysis and lists the project's annual revenues, by year, combining energy and capacity payments. For his discount rate, he or she might use the weighted average cost of capital of a traditional utility, because the utility either buys wholesale power or is an alternate source of power to end customers, and the utility's rate will standardize the analysis. This is preferable to introducing a mix of rates reflecting different developers. From the stream of nominal revenues, the analyst calculates a Net Present Value. He or she then levelizes the Net Present Value, to calculate one level payment per year over the years of project life that is equivalent to the Net Present Value. The analyst divides by annual power produced to figure a unit COE, per kWh.

If the analyst uses a nominal discount rate to levelize the nominal NPV, he or she calculates a nominal COE. If a constant-dollar rate, excluding inflation, is used, then the analyst figures a constant-dollar COE, also termed a real COE. Constant-dollar levelized COEs are lower, because they exclude inflation. For example, if the nominal discount rate is 7.00% and inflation is 2.50%, then the constant discount rate is 4.39% (as $(1 + 0.07)/(1 + 0.025) – 1$). Constant-dollar COEs are useful to government and industry policy makers for setting metrics and goals and for preparing R&D budgets, which look out many years into the future.

Note that when financing a power plant project or other business venture involves repayment of contractually-specific or nominal debt and payment of income tax (calculated on inflated nominal profits), then the analyst must prepare nominal inflated cash flows, which are deflated to figure a net present value, from which to calculate the levelized constant-dollar COE. Performing a constant-dollar analysis may yield a different answer. The US Internal Revenue Service does not recognize constant-dollar inflation-free taxable income.

When running a cash flow analysis, either with a revenue stream given or to calculate COE, the analyst tends to balance three objectives. These are: 1) a low Cost of Energy (COE) from the revenues (tariff) charged to customers; 2) adequate debt coverage for lenders or other debt investors; and 3) an attractive after-tax internal rate of return (IRR) on investment, composed of cash and tax benefits, for equity investors. As new information is developed, the cash flows are rerun in what tends to be an iterative process.

7.2 PJM Forward Pricing Forecasts – Energy and Capacity Payments

Energy comprises the larger share of PJM wholesale power prices. For this analysis, the PJM Forward Pricing forecasts are based on four years of historical PJM power prices, collected by hour, for each of four nodes plus the Western Hub and three years of actual NYMEX data extrapolated out 25 years as described in **Section 5.1.2**. Average on-peak and off-peak energy prices, were broken out by season and are set forth in **Table 7-2**.

Table 7-2. PJM Power Prices (Cents/kWh) by Season and by Node

	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak
	Fall		Winter		Spring		Summer	
Calvert Cliffs	4.42	6.34	5.60	6.66	4.53	6.33	5.67	8.43
Cloverdale	3.28	4.70	4.29	5.36	3.29	5.05	3.46	6.35
DPL-OPEC	4.42	6.38	5.52	6.96	4.61	6.54	5.44	8.56
Fentress	4.21	5.83	5.34	6.18	4.30	5.85	5.47	8.07
Western Hub	3.97	5.60	4.92	6.06	4.10	5.89	4.73	7.38

Prices may be illustrated as the group of node prices by each of four seasons, as shown in **Figure 7-1**. The price data covers January 01, 2007 through March 24, 2011. The seasons are defined as Autumn: September through November, Winter: December through February, Spring: March through May, and Summer: June through August This chart shows that PJM's summer on-peak prices are highest. Autumn and Spring prices, for both on-peak and off-peak, are low. In addition, Cloverdale Ridgeline prices are the lowest node prices in all groups.

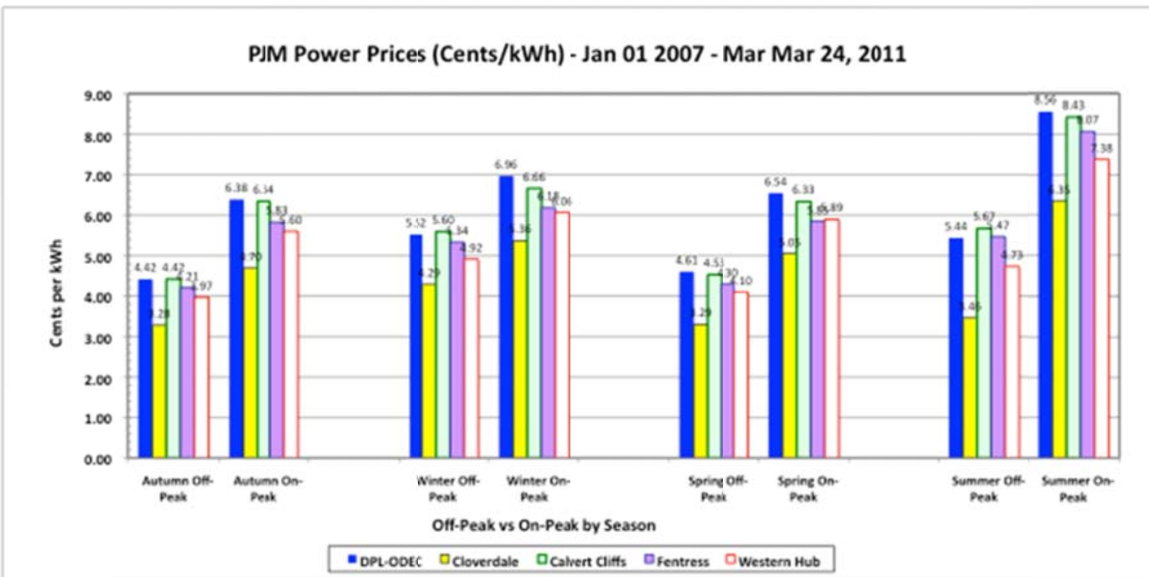

Figure 7-1 Average PJM Energy Prices by Season

For capacity, in the PJM forward pricing forecasts, prices are estimated as shown below, in **Table 7-3**. To calculate annual revenues, one multiplies the payment ($/MW-day) by plant capacity by capacity factor by 365 days. Although the current factor is 13%, it was assumed that PJM would estimate a wind energy capacity factor of 20% for the first two years. If the plant proves it has a better capacity factor over time, the 20% is raised to actual.

Table 7-3. PJM Capacity Payments

	Straight 2.5% Escalation ($/MW-day)	2015 Adder Prices ($/MW-day)
Unconstrained RTO Zone	60.00	90.00
MAAC (Mid-Atlantic Area Council)	175.00	240.00

The Unconstrained RTO (Regional Transmission Organization) areas are Western Hub, Cloverdale, and Fentress. The MAAC areas are DPL-ODEC and Calvert Cliffs. MAAC is the Mid-Atlantic Area Council, established in 1994. PJM states the MAAC region includes the transmission zones of Baltimore Gas and Electric Company, Metropolitan Edison Company, Pennsylvania Electric Company, and PPL Electric Utilities. The escalation rate for capacity is estimated at a rate of 1% per year, because utilities replace plant slowly, over many years.

By contrast, for the "Calculated COE" cases, one capacity payment of $165.00 per MW-day, escalating at a rate of 1.0% per year, is used for all cases. The actual annual capacity factor is used, with no reduced assumption of 20% for the first two years.

7.3 Capital Costs for the Wind Energy Plants

Wind power plant equipment and support facility construction and installation costs used in this study are set forth below. For land-based projects, on Coastal Plains and on Ridgelines, 1.5 MW turbines were selected, so total plant size is 100.5 MW. For water-based projects, in Bays and Ocean, 5 MW wind turbines were selected, so total plant size is 100.0 MW.

For the Coastal Plains plant, plant and equipment costs and business conditions were updated and revised to the site, but are similar to those used by DOE and NREL, as set forth in NREL's January 2008 COE Primer report [24]. Baseline costs were updated for inflation and converted to 2012 dollars. For the other plants, capital costs were estimated by an experienced engineer after reviewing the literature and talking with industry and government sources.

The largest difference between land and sea based projects is attributed to the cost of foundations and maintenance. Sea based tower foundation designs differ according to the depth of water in which the wind turbine is to be located, as shown in **Figure 7.2**.

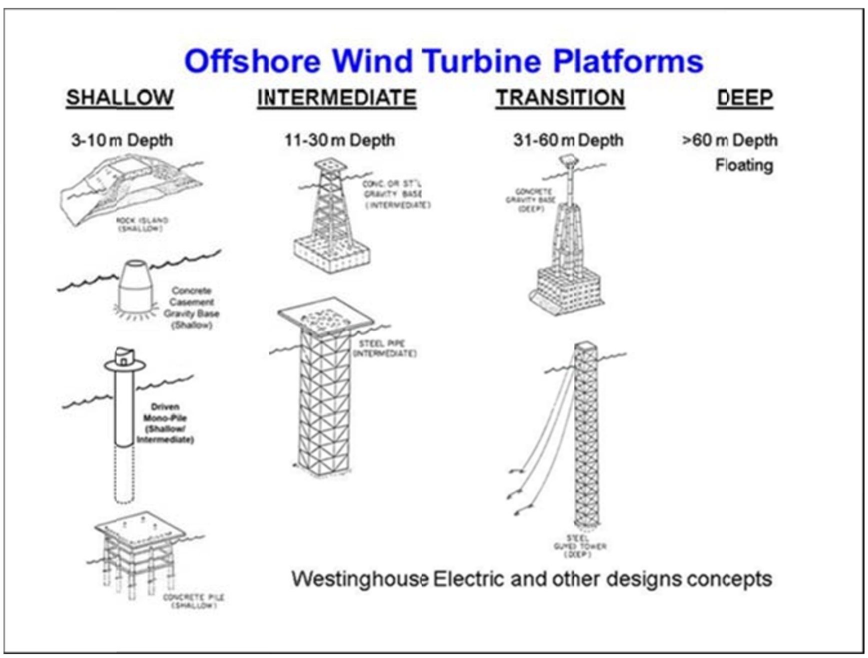

Figure 7-2. Offshore wind turbine platform designs for shallow bays and ocean applications.

Foundation costs in shallow, 3 to 10 m, water depth in bays and sounds are assumed to be similar to land-based ridgeline applications. On water, cranes and heavy construction equipment can be easily moved site to site on barges and so overall construction costs for shallow water sites may not be significantly greater than land-based projects.

For ocean applications the foundations become much heavier and more costly[10]. Data on European project cost from the engineering firm Moffatt and Nicho[11] showed that foundations can amount to 24% of the project cost and 30-40% of capital equipment cost. This is because of the need to support and protect the turbine in extreme weather conditions and because larger, 5MW turbines are anticipated for offshore applications, while use of the larger 5 MW turbine components is unlikely in land based applications due to weight, height and length transportation restrictions. In addition, offshore applications are assumed to have higher maintenance costs than land-based projects due to access limitations caused by conditions at sea and distance from shore.

For this report, costs are expressed in 2012 dollars, because the plants are assumed to be built during 2012 and to start operating in 2013.

Below is **Table 7-4** which shows plant capital costs. As shown, the turbine capital cost includes turbine, tower, and step-up transformer and controls. Turbine costs run $1,100/kW for Coastal Plains and Ridgeline, to just over $1,600/kW for Shallow Bay, to just over $1,700/kW for Ocean.

[10] The 4-leg platforms for 48 of the 6 MW REPower turbines being installed in Thornton Bank in Belgium each weigh over 300 tons. These are installed in the North Sea in water up to 26 m deep. Source: McNeilan, T., Presentation “European Offshore Wind Supply Chain Example”, at Virginia Offshore Wind Development Authority meeting, 12 January 2012.

[11] Heffron, Ron, et al, “Reducing the Cost of Offshore Wind Turbine Foundations”, AWEA Offshore Conference, Baltimore, Maryland, September 2011.

Table 7-4. Fully Loaded Capital Costs (Uses of Funds) for the 2012 100 MW Wind Energy Plants. Assuming IPP Ownership and Project Finance, located in the Mid-Atlantic region (in 2012 dollars).

Component	Coastal Plains – DPL-ODEC 67 1.5 MW turbines		Ridgeline - Cloverdale 67 1.5 MW turbines		Shallow Bays – Calvert Cliffs 20 5.0 MW turbines		Offshore Ocean - Fentress 20 5.0 MW turbines	
	Cost ($/kW)	**Cost ($1,000)**	**Cost ($/kW)**	**Cost ($1,000)**	**Cost ($/kW)**	**Cost ($1,000)**	**Cost ($/kW)**	**Cost ($1,000)**
Plant Size (MW)		100.5		100.5		100		100
Turbine	956.0	96,078	956.0	96,078	0.0		0.0	
Tower	130.7	13,132	130.7	13,132	1,610.0	161,000	1,709.7	170,970
Step-up Transformer and Controls	13.3	1,340	13.3	1,340	0.0		0.0	
TURBINE CAPITAL COST	1,100.0	110,550	1,100.0	110,550	1,610.0	161,000	1,709.7	170,970
Foundation	52.7	5,293	60.7	6,097	115.0	11,500	460.0	46,000
Transportation	54.7	5,494	63.3	6,365	115.0	11,500	230.0	23,000
Civil Works & Roads	85.3	8,576	98.0	9,849	0.0	0	0.0	0
Assembly & Installation	54.7	5,494	63.3	6,365	92.0	9,200	200.0	20,000
System Control & Data (SCADA)	13.3	1,340	13.3	1,340	23.0	2,300	41.7	4,170
Plant Substations & Intraconnection	136.7	13,735	157.3	15,812	0.0		0.0	
Step-up Transformer and Intraplant Interconnection	0.0		0.0		253.0	25,300	583.8	58,380
Transmission Lines	0.0	0	0.0	0	0.0		0.0	
Substation and Transmission Lines	0.0		0.0		0.0	0	0.0	0
Engineering, Permits, and Approval	35.3	3,551	40.7	4,087	92.0	9,200	166.8	16,680

Component	Coastal Plains – DPL-ODEC 67 1.5 MW turbines		Ridgeline - Cloverdale 67 1.5 MW turbines		Shallow Bays – Calvert Cliffs 20 5.0 MW turbines		Offshore Ocean - Fentress 20 5.0 MW turbines	
	Cost ($/kW)	Cost ($1,000)	Cost ($/kW)	Cost ($1,000)	Cost ($/kW)	Cost ($1,000)	Cost ($/kW)	Cost ($1,000)
BALANCE OF STATION COST	432.7	43,483	496.7	49,915	690.0	69,000	1,682.3	168,230
INITIAL OVERNIGHT CAPITAL COST	1,532.7	154,033	1,596.7	160,465	2,300.0	230,000	3,392.0	339,200
Assume plant financing is 50% Debt to 50% equity.								
Construction Financing (8% * subtotal * 1 year * 50% level drawdown)		6,000		6,200		8,800		13,200
Construction Insurance (0.36% to 0.50% of depreciable base, from a recent quote)		580		600		1,000		1,780
Debt Financing Fees (1% * 50% capital fraction)		840		870		1,250		1,850
Equity Financing Fees (2% * 50% capital fraction)		1,680		1,750		2,500		3,700
Debt Financing Reserve (6 months payment, given 7.50% interest over 20 years)		4,100		4,250		6,090		9,000
Working Capital Reserve (O&M * 1 year * 25%, which is 3 months.)		520		540		550		1,000
TOTAL LOADED COST	1,669.2	167,753	1,738.1	174,675	2,501.9	250,190	3,697.3	369,730

Balance of Station (BOS) costs include foundation, transportation, civil works and roads, and assembly of parts and installation. BOS costs further include SCADA equipment, plant substations and interconnection for the land-based plants or step-up transformer and Interplant Interconnection for water-based plants, plus engineering designs, permits, and approvals. As shown, BOS costs run $430 to $500 per kW for Coastal Plains and Ridgeline, to $690 per kW for Shallow Bay, and to $1,680 per kW for Ocean, which requires substantial foundations.

Note that for the land-based plants, transmission lines are not included with plant cost. In addition for the water-based plants, a substation and transmission lines are not included as part of the plant cost. Cost of transmission can vary widely and will be high for a Ridgeline or Ocean plant that is located far from the grid.

The Southwest Power Pool and others are looking at cost-sharing methods and, in early 2012, SPP approved some new projects.[12] In July 2011, FERC addressed transmission planning and cost allocation by approving Order 1000.[13] In May 2012, FERC upheld Order 1000.[14]Accordingly, because transmission prices can vary widely and because it is unclear when transmission is allocated to a project or to regional system wide electric market participants, so as not to confuse project economics, the authors of this report opted not to include transmission costs here.

Also note the Atlantic Wind Connection (AWC). The AWC is a proposed large transmission system to connect offshore power generation to the onshore electrical grid of the Mid Atlantic and New England States.[15] While it has yet to be determined how the cost will be paid, in Europe it is common practice to treat the transmission lines and a plant substation as part of the grid and their costs are allocated accordingly. The wires are brought to the project.

Looking at **Table 7- 4**, one sees that to the overnight plant cost, certain costs to get the plant financed and constructed are added. These include construction financing and a small working capital reserve. Construction insurance was added, based on a spring 2011 quote for property damage and liability. A six-month debt service reserve was added, as well as financing fees to raise debt and equity, to produce a fully loaded project capital cost. As shown, the fully loaded project cost runs $1,670 to $1,740/kW for Coastal Plains and Ridgeline, to $2,500/kW for Shallow Bay, to $3,697/kW for Ocean. These plants assume current, likely (first half 2012) financing, with 50% debt rated BB, which is non-investment-grade, and 50% equity, where the equity investors are assumed to be in a positive earnings mode and able to fully utilize the Section 45 Production Tax Credit (PTC).

For favorable financing, plant capital costs are set forth in **Table 7-5** below. As shown, for all four plants. The overnight capital cost is identical by the two financing methods. The construction financing, construction insurance, and working capital are the same. Only the financing fees, which are percentages of the debt and equity raised, and the debt service reserve change. As shown, the fully loaded project cost runs $1,660 to $1,730 per kW for Coastal Plains and Ridgeline, to $2,490 per kW for Shallow Bay, and to $3,680 per kW for Ocean. It is interesting that the total loaded costs under favorable financing are just slightly less than those listed earlier.

[12] "SPP Proposes New Cost Sharing Method for Expanding the Regional Electric Transmission Grid," Transmission & Distribution World, Penton Media Inc.; New York, NY; April 19 2010.
[13] DiMugno, Laura, "FERC Final Rule Reforms Transmission Planning, Cost Allocation," North American Windpower, Zackin Publications, Waterbury CT; July 26, 2011.
[14] NAW Staff, "FERC Denies Rehearing on Transmission Planning and Cost Allocation Order," North American Windpower, Zackin Publications, Waterbury CT; May 18, 2012.
[15] On March 31, 2011, Atlantic Grid Holdings submitted a request for right-of-way to the Bureau of Ocean Management, Regulation and Enforcement (BOEMRE). See http://www.boemre.gov/offshore/RenewableEnergy/StateActivities-RegionalProposals.htm . On December 20, 2010, AWC filed with FERC, in a petition for declaratory order. See the press release at http://www.atlanticwindconnection.com/ferc/2010-12-filingsummary/.

Table 7-5. Fully Loaded Capital Costs (Uses of Funds) with Favorable Financing. for the 2012 100 MW Wind Energy Plants.

Assuming IPP Ownership and Project Finance, located in the Mid-Atlantic region (in 2012 dollars).Component	Coastal Plains – DPL-ODEC 67 1.5 MW turbines		Ridgeline - Cloverdale 67 1.5 MW turbines		Shallow Bays – Calvert Cliffs 20 5.0 MW turbines		Offshore Ocean - Fentress 20 5.0 MW turbines	
	Cost ($/kW)	Cost ($1,000)	Cost ($/kW)	Cost ($1,000)	Cost ($/kW)	Cost ($1,000)	Cost ($/kW)	Cost ($1,000)
Plant Size (MW)		100.5		100.5		100		100
Turbine	956.0	96,078	956.0	96,078	0.0		0.0	
Tower	130.7	13,132	130.7	13,132	1,610.0	161,000	1,709.7	170,970
Step-up Transformer and Controls	13.3	1,340	13.3	1,340	0.0		0.0	
TURBINE CAPITAL COST	1,100.0	110,550	1,100.0	110,550	1,610.0	161,000	1,709.7	170,970
Foundation	52.7	5,293	60.7	6,097	115.0	11,500	460.0	46,000
Transportation	54.7	5,494	63.3	6,365	115.0	11,500	230.0	23,000
Civil Works & Roads	85.3	8,576	98.0	9,849	0.0	0	0.0	0
Assembly & Installation	54.7	5,494	63.3	6,365	92.0	9,200	200.0	20,000
System Control & Data (SCADA)	13.3	1,340	13.3	1,340	23.0	2,300	41.7	4,170
Plant Substations & Intraconnection	136.7	13,735	157.3	15,812	0.0		0.0	
Step-up Transformer and Intraplant Interconnection	0.0		0.0		253.0	25,300	583.8	58,380
Transmission Lines	0.0	0	0.0	0	0.0		0.0	
Substation and Transmission Lines	0.0		0.0		0.0	0	0.0	0

Assuming IPP Ownership and Project Finance, located in the Mid-Atlantic region (in 2012 dollars).Component	**Coastal Plains – DPL-ODEC 67 1.5 MW turbines**		**Ridgeline - Cloverdale 67 1.5 MW turbines**		**Shallow Bays – Calvert Cliffs 20 5.0 MW turbines**		**Offshore Ocean - Fentress 20 5.0 MW turbines**	
	Cost ($/kW)	**Cost ($1,000)**	**Cost ($/kW)**	**Cost ($1,000)**	**Cost ($/kW)**	**Cost ($1,000)**	**Cost ($/kW)**	**Cost ($1,000)**
Engineering, Permits, and Approval	35.3	3,551	40.7	4,087	92.0	9,200	166.8	16,680
BALANCE OF STATION COST	432.7	43,483	496.7	49,915	690.0	69,000	1,682.3	168,230
INITIAL OVERNIGHT CAPITAL COST	1,532.7	154,033	1,596.7	160,465	2,300.0	230,000	3,392.0	339,200
Assume plant financing is 60% Debt to 40% equity.								
Construction Financing (8% * subtotal * 1 year * 50% level drawdown)		6,000		6,200		8,800		13,200
Construction Insurance (0.36% to 0.42% of depreciable base, from a recent quote)		580		600		1,000		1,780
Debt Financing Fees (1% * 60% capital fraction)		1,000		1,040		1,500		2,200
Equity Financing Fees (2% * 40% capital fraction)		1,340		1,400		2,000		2,950
Debt Financing Reserve (6 months payment, given 4.00% interest over 20 years)		3,670		3,820		5,470		8,100
Working Capital Reserve (O&M * 1 year * 25%, which is 3 months.)		520		540		550		1,000
TOTAL LOADED COST	1,663.1	167,143	1,732.0	174,065	2,493.2	249,320	3,684.3	368,430

7.4 Sources of Funds

For the Mid-Atlantic Wind Energy study, it is assumed that wind energy plant ownership will be by an Independent Power Producer using limited recourse Project Finance. For a wind energy plant sized at 100 MW, this is the more likely ownership/financing option for about the next ten years, although a regulated or municipal utility might pursue wind energy plant ownership.

Given Uses of Funds, as shown in **Table 7-4** and **Table 7-5**, then Source of Funds could be prepared, as shown in **Table 7-6** and **Table 7-7**, for the different cases for 2012.

Table 7-6. Sources of Funds for 2012 100 MW Wind Energy Plants.
Assuming 50% Debt to 50% Equity (in 2012 dollars).

Funds	DPL-ODEC Coastal Plains	Cloverdale Ridgeline	Calvert Cliffs Shallow Bay	Fentress Ocean	Comments
Debt	83,877	87,338	125,095	184,865	at 7.5% for 20 years, paid on a customized schedule with monetized Section 45 PTC
Second Loan	0	0	0	0	
Equity	83,877	87,338	125,095	184,865	receiving cash and tax benefits, over 25-year contract life, plus remainder value
Total	167,754	174,676	250,190	369,730	

Table 7-7. Sources of Funds Under Favorable Financing for 2012 100 MW Wind Energy Plants.
Assuming 60% Debt to 40% Equity (in 2012 dollars).

Funds	DPL-ODEC Coastal Plains	Cloverdale Ridgeline	Calvert Cliffs Shallow Bay	Fentress Ocean	Comments
Debt	100,286	104,439	149,592	221,058	at 4.0% for 20 years, paid on a customized schedule with monetized Section 45 PTC
Second Loan	0	0	0	0	
Equity	66,857	69,626	99,728	147,372	receiving cash and tax benefits, over 25-year contract life, plus remainder value
Total	167,143	174,065	249,320	368,430	

As will be discussed later, under Financial Assumptions, to make better use of the Section 45 Production Tax Credit (PTC), which offers a tax benefit but not cash with which to repay debt, under the current, likely financing approach, the fraction of debt is reduced to 50%. For example, debt is $83.877 million for DPL-ODEC Coastal Plains and $125.095 million for Calvert Cliffs Shallow Bay. With favorable financing, the debt fraction increases to 60%, which is $100.286 million for DPL-ODEC Coastal Plains and $149.592 million for Calvert Cliffs Shallow Bay.

Because contracted plant life is 25 years, the debt term is 20 years. For current (first half 2012), likely financing, fixed rate interest is estimated at a rate of 7.50%, for BB-rated debt, assuming 10-year Treasuries at 1.75% and a spread of 5.70%, rounded up slightly. Debt repayment is twice per year, by customized payment of principal.

By favorable financing, against 10-year Treasuries at 1.75%, the spread for BBB-rated debt, which is the lowest investment-grade, is smaller, at 2.25%. Therefore, the project's interest rate, under favorable financing, for 20-year debt is 4.00%. When future economic conditions improve, Treasury rates are expected to increase, but spreads for corporate, project, and other debt and especially for riskier debt, will probably decline, so the energy project's nominal current likely interest rate is not expected to rise and might decline slightly.

As **Table 7-6** and **Table 7-7** show, for these wind energy projects, the balance of funding is equity, which is 50% or 40% of the project cost. For example, by current financing, equity is $83.877 million for DPL-ODEC Coastal Plains and $125.095 million for Calvert Cliffs Shallow Bay. With favorable financing, the equity fraction is reduced to 40%, which is $66.857 million for DPL-ODEC Coastal Plains and $99.728 million for Calvert Cliffs Shallow Bay. Equity owners receive all the project's cash and tax benefits over its 25-year contract life, plus remaining value.

Note that it is assumed that outside equity investors will be sought, who can fully utilize the project's tax benefits (i.e., from five-year rapid depreciation and ten years of Section 45 PTC), as well as its cash benefits. It has been common practice, over about the past decade, for wind energy plant developers to "monetize" the Section 45 PTC and use it to repay debt. As will be described later with Financing Assumptions, the PTC was extended in 2009 for three years, for plants placed in service before January 1, 2013. Industry observers are hopeful this credit for wind energy will be extended again because, unlike the ITC (Investment Tax Credit), which rewards high cost, the PTC rewards efficiency, in the form of high power production, regardless of cost. The Section 45 PTC for wind is $0.022 per kWh in 2012.

When it is "monetized," the PTC is "counted" with operating profits against the debt payment, to pay debt and calculate the debt coverage ratio. This practice was used here.

Furthermore, this analysis represents a basic case over which a developer may place a more complicated ownership pattern involving various classes of equity investors, including Tax Investors. If no complicated ownership strategy is desired, the basic project will stand on its own. Consequently, for the basic case, the after-tax return on equity, including all cash and tax benefits, is project-wide.

7.5 Performance (Plant Capacity Factors) for the Wind Energy Plants

To show how much power would be produced at each plant location, plant capacity factors were calculated. Capacity factor is defined as annual power produced by the plant over capacity at full rated hourly capacity and assuming 8,760 hours of operation. **Table 5-4** shows capacity factors, by season, for the four plant locations. **Table 7-8** below shows plant capacity factors by season, further broken out for on-peak and for off-peak hours.

Table 7-8. Plant Capacity Factors by Node, by Season.

	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Average
	Fall		Winter		Spring		Summer		Annual
Calvert Cliffs - Bay	34.13%	33.64%	45.33%	43.58%	41.50%	36.44%	24.26%	23.74%	35.35%
Cloverdale – Ridgeline	33.42%	30.13%	48.46%	48.46%	35.62%	34.71%	22.08%	19.01%	34.20%
DPL-OPEC – Coastal Plains	26.55%	23.34%	40.11%	36.41%	37.96%	35.89%	15.02%	12.95%	28.43%
Fentress – Ocean	33.76%	33.27%	47.17%	45.13%	42.26%	40.50%	25.04%	23.50%	36.20%

These capacity factors are also shown in **Figure 7- 3** below. The Calvert Cliffs data label is printed on the chart, for each season, to orient a reader. As **Figure 7- 3** shows, for all plants, that capacity factors are highest in winter, both for on-peak and off-peak hours. Capacity factors are second highest in spring. They are lowest in summer. The capacity factor estimates are all based on measured data at sites that are considered to be representative of each wind market sector and are used in the Forward pricing models in **Section 5**. Wind resources estimates and assumptions are discussed in detail in **Section 9** of this report.

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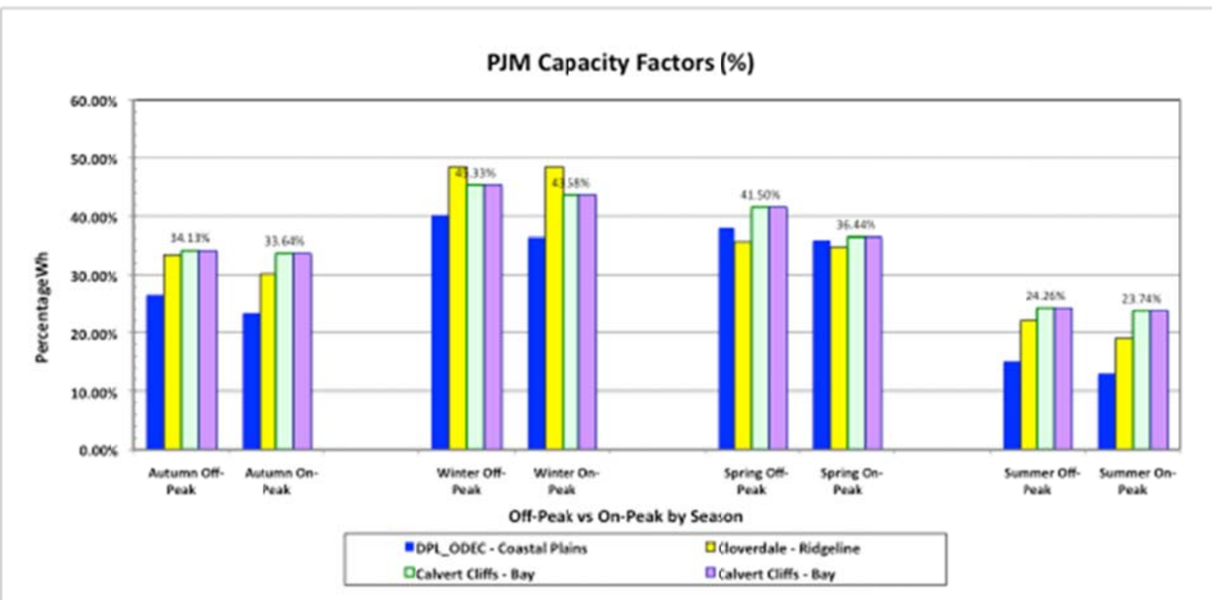

Figure 7-3. Plant Capacity Factors by Node

7.6 Operating Expenses for the Wind Energy Plants

The methodology to estimate annual operating expenses, ranging from O&M to land rent and insurance, for the wind energy plants is described below in **Table 7-9**.

Table 7-9. Methodology for Estimating Wind Energy Plant Operating Expenses

Expense	Comments
Operations and Maintenance	For Coastal Plains, estimated as $31,000 per 1.5 MW turbine or $20.67/kW. For Ridgeline, $32,000 per 1.5 MW turbine or $21.33/kW. For Shallow Bay and Ocean, $110,000 and $200,000 per 5.0 MW turbine or $22.00/kW and $40.00/kW.
Major Maintenance and Overhauls	For Coastal Plains, estimated as $9,000 per 1.5 MW turbine per year. For Ridgeline, as $9,180. For Shallow Bay and Ocean, as $35,000 and $45,000 per 5.0 MW turbine.
Site Owner Land Rent (or Royalty)	For Coastal and Ridgeline, assume rent is $5,000 per 1.5 MW turbine or $3.33/kW. For Shallow Bay and Ocean, assume rent is $4,000 per 5.0 MW turbine or $0.80/kW.
Property Tax	Estimated as 1.10% of depreciable base, at $160.6 million for Coastal and $167.3 million for Ridgeline. Assume the assessment increases by inflation, which is 2.5% here. Assume no property tax for Bay or Ocean. Assume equipment life is 25 years, so annual straight-line depreciation of 4.0% [1.0/25] is deducted, till one reaches a minimum level of 30%.
Property, Casualty and Business Interruption Insurance	Estimated as 0.311% of depreciable base, at $160.6 million for Coastal Plains and $167.3 million for Ridgeline, in spring 2011. Insurance cost is calculated based on replacement cost, annual revenues, deductibles, and so forth, which works out to this percentage. For Shallow Bay and Ocean, assume percentages are 0.44% and 0.45% on $239.8 and $354.2 million.

For each plant, operating expenses and performance are shown in **Table 7-10** below. For example, for DPL-ODEC Coastal Plains, the plant capacity factor is 28.4%. O&M is estimated as $2.077 million. Land rent is $0.335 million. Property tax, insurance, and major maintenance and overhauls are added. Operating expenses are the same, whether the plant is financed by current methods or by favorable financing.

Note that the wind energy plant is built during 2012, so it is considered a 2012 plant and costs are expressed in 2012 US dollars. Capital costs will be paid as the plant is constructed during 2012. However, the plant does not start up till January 1, 2013, so operating expenses for the cash flow projections are escalated one year to 2013, to be "year one" expenses.

For property tax, rates and methods of assessment vary by state and, within a state, by county and local jurisdiction. See **Table 7-14**, at the end of this chapter, for detailed property tax information for wind energy plants for Delaware, Maryland, North Carolina, Virginia, and the District of Columbia.

Table 7-10. Performance and Annual Operating Expenses for 2012 Wind Energy Plants.

Located in the Mid-Atlantic region (in 2013 dollars, except first column. Plant is constructed in 2012 and begins operating in 2013.)

	Coastal Plains - DPL-ODEC				**Ridgeline – Cloverdale**				**Shallow Bays - Calvert Cliffs**				**Offshore Ocean - Fentress**			
Component	**Year Zero Cost (2012 $1,000)**	**Escalation (%)**	**Year One Cost (2013 $1,000)**	**2013 $Cost/ kW**	**Year Zero Cost (2012 $1,000)**	**Escalation (%)**	**Year One Cost (2013 $1,000)**	**2013 $Cost/ kW**	**Year Zero Cost (2012 $1,000)**	**Escalation (%)**	**Year One Cost (2013 $1,000)**	**2013 $Cost/ kW**	**Year Zero Cost (2012 $1,000)**	**Escalation (%)**	**Year One Cost (2013 $1,000)**	**2013 $Cost/ kW**
Performance	28.43% capacity factor, for Class 4 winds				34.20% capacity factor, for Class 4 winds				35.35% capacity factor, for Class 4 winds				36.2% capacity factor, for Class 4 winds			
Inflation	2.50%				2.50%				2.50%				2.50%			
Operations and Maintenance	2,026	Inflation	2,077	20.67	2,092	Inflation	2,144	21.33	2,146	Inflation	2,200	22.00	3,902	Inflation	4,000	40.00
Major Maintenance & Overhauls	585	Inflation	600	5.97	600	Inflation	615	6.12	683	Inflation	700	7.00	878	Inflation	900	9.00
Site Owner Land Rent (or Royalty)	327	Inflation	335	3.33	327	Inflation	335	3.33	78	Inflation	80	0.80	78	Inflation	80	0.80
Property Tax	1,724	inflation, offset by depreciation	1,767	17.58	1,795	inflation, offset by depreciation	1,840	18.31	-	--	0	0.00	-	--	0	0.00
Property, Casualty and Business Interruption Insurance	488	Inflation	500	4.98	508	Inflation	521	5.18	1,029	Inflation	1,055	10.55	1,555	Inflation	1,594	15.94
Total First Year Expense			5,279				5,455				4,035				6,574	
** Exact plant size is 100.5 MW for Coastal Plains and Ridgeline. It is 100.0 MW for Shallow Bay and Ocean.*																

Regarding major maintenance, some wind energy projects will deposit money to a reserve fund, to be drawn down every fifth or tenth year, to perform major overhauls. Another approach is to assume an annual expense, estimated here as $6/ to $9/kW-capacity, that escalates with inflation. If funds are not needed, they may be saved for the next year. Although a major maintenance expense is tax-deductible each year and a deposit to a reserve fund is not, once the overhaul is performed, repair depreciation can be taken to shelter income. The tax savings from expensing major maintenance does not have a significant impact on COE.

7.7 Financial Assumptions for current likely and favorable financing of the Wind Energy Plants

Finance and project ownership assumptions represent an important area for cash flow modeling. For this Mid-Atlantic Wind study, inflation is estimated at 2.50% and project life is assumed to be contract life, at 25 years. Because the plants are selling merchant power, which is riskier to the lender seeking certainty of repayment and because the Section 45 PTC is taken and no complicated structure with Tax Investors or ownership flips is assumed, therefore, the project's capital fraction is set at 50% debt to 50% equity. The alternate, favorable financing scenario, which assumes either a strong Power Purchase Agreement (PPA) or iron-clad guarantees from an established, credible developer if selling merchant, and again with no Tax Investors or flips, is 60% debt to 40% equity. Both financing scenarios utilize a monetized PTC and assume equity investors are in a positive earnings mode, so they may fully utilize all tax benefits, including five-year depreciation and the PTC.

7.7.1 Project Finance

For the past 20 to 30 years, many independent power projects (IPPs), whether fossil-fueled or using renewable energy, were structured and financed utilizing limited recourse project financing. In contrast to balance-sheet corporate finance, Project Finance gives its debt and equity investors' security or recourse to, as collateral, only the assets of the project. Debt and equity investors do not have recourse to the cash and other assets of the developer and they do not have recourse to assets or earnings of the developer's other projects. Because IPP Project Finance is riskier than balance sheet corporate finance and certain other lending, debt and equity investors require a higher rate of return.

7.7.2 Debt Features, including Rating and Interest Rate

Because project life is 25 years, debt term is 20 years. This offers a short period of five years, where any problem in debt payment may be "worked out." If there are no debt repayment problems, then equity investors enjoy an outsized return, which they may share partly with the power purchaser, by a slight tariff reduction beginning in year 21.

As described earlier, current, likely, long-term project debt for a large wind energy plant, selling merchant power, sized at 100 MW or more, tends to be rated BB, which is one grade below investment grade. See **Table 7-11** below. Non-investment grade debt is termed high-yield or "junk" debt, into which certain institutional investors (as required by their bylaws) and other investors (as a matter of choice) will not invest. High-yield interest rates are much higher than those for investment grade, with rates sometimes said to have "fallen off a cliff" and spreads of about 300 to 900 basis points or higher, for debt rated BB+ to CCC, over comparable Treasuries.

Table 7-11. Classic Long-Term Senior Debt Ratings
As described in the 1994 Federal Reserve Bank of New York Quarterly Review.[16]

Investment Grade Ratings			Speculative Grade Ratings		
S&P and others	**Moody's**	**Interpretation**	**S&P and others**	**Moody's**	**Interpretation**
AAA	Aaa	Highest quality.	BB+	Ba1	Likely to fulfill obligations; ongoing uncertainty.
			BB	Ba2	
			BB-	Ba3	
AA+	Aa1	High quality.	B+	B1	High risk obligations.
AA	Aa2		B	B2	
AA-	Aa3		B-	B3	
A+	A1	Strong payment capacity.	CCC+		Current vulnerability to default, or in default (Moody's).
A	A2		CCC	Caa	
A-	A3		CCC-		
BBB+	Baa1	Adequate payment capacity.	C	Ca	In bankruptcy or default, or other marked shortcoming.
BBB	Baa2		D	D	
BBB-	Baa3				

At the present time, in mid-May 2012, the 1.75% estimated rate for 10-year Treasuries is correct, with a quote of 1.74% from Bloomberg at the close on May 25, 2012.[17] Ten-year Treasuries traded within a range of about 3.50% to 5.20% from 2005 through mid-2008, before falling to 2.10% during the financial crisis in late 2008. Over the past two and a half years, ten-year Treasury rates ranged from about 1.70% to 4.00%, before trading from a high of about 3.70%, during the first half of 2011, down to 1.72% on September 22, 2011, with a bounce and a fall to a historical low of 1.57% on May 31, 2012.

Ten-year Treasuries lately range from about 1.70% to 2.40%, from September 2011 through late-May 2012, given the "easy money" policies of the Federal Reserve and the perceived safety of US Treasuries among global investments. See **Figure 7-4** below, which presents an approximate 13-year history of Treasury rates.

[16] Richard Cantor and Frank Packer, "The Credit Rating Industry," FRBNY Quarterly Review: Federal Reserve Bank of New York; New York, NY; Summer-Fall 1994, page 3.
[17] Bloomberg Government Bonds: 10-year Treasury Notes; New York, NY; internet site: http://www.bloomberg.com/markets/rates-bonds/government-bonds/us/ ; May 15, 2012 and May 25, 2012.

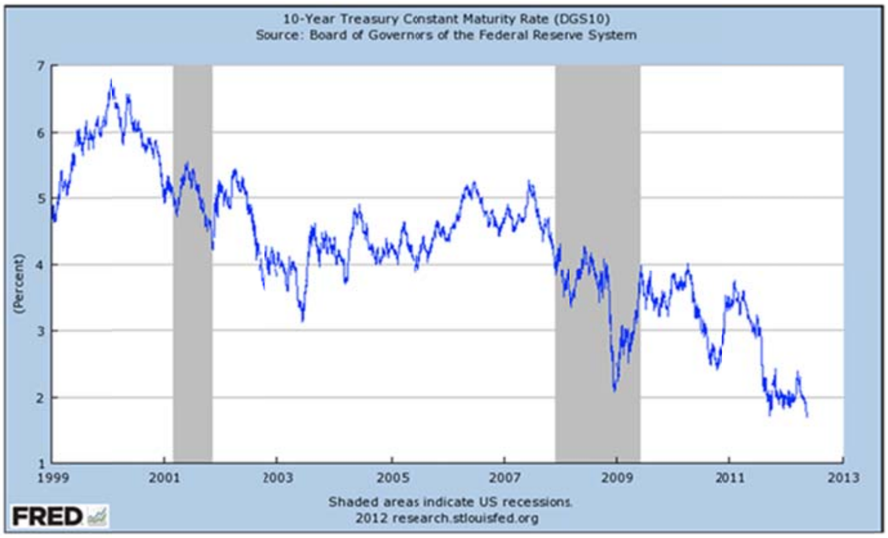

Figure 7-4. 10-Year Treasury Note Interest Rates: Jan 1999 – May 2012.

Source: Federal Reserve Bank of St. Louis, Fred Graph Observations, St. Louis MO; internet site: 10-Year Treasury Constant Maturity Rate: 01/02/1999 – 05/21/2012; prepared May 23, 2012.

Current market conditions suggest that against 10-year Treasuries at 1.75%, the spread for BB-rated debt is 5.70%. The spread may be cited as 570 basis points, where one basis point (bp) is one one-hundredth of one percent. Consequently, the wind energy project's interest rate for 20-year, BB-rated debt is 7.50%.

Limits for debt coverage for BB-rated debt, by current market conditions, with coverage calculated as annual operating income over the annual debt payment, are estimated as 3.0 times average and 1.8 times minimum.

For favorable financing, against 10-year Treasuries at 1.75%, the spread for BBB-rated debt, under current market conditions, is 2.25% or 225 basis points. Spreads are markedly lower for less risky, investment-grade debt. The project's interest rate, under favorable financing, for 20-year, BBB-rated debt is 4.00%. Limits for debt coverage for BBB-rated debt, by current market conditions, are estimated as 1.5 times average and 1.3 times minimum. The debt fraction is estimated as 60%, against 40% equity.

Debt repayment is assumed to be twice per year, by customized payment of principal, that follows operating cash flow and ten-year receipt of the Section 45 Production Tax Credit. For example, for Cloverdale – Ridgeline, under current, likely financing, the principal payment schedule, at six-month intervals, by five-year increments, is: years 1-5: 1%, 1%, 1.5%, 1.5%, 1.8%, 1.8%, 2%, 2%, 2.4%, 2.4%; years 6-10: 2.7%, 2.7%, 3.1%, 3.1%, 3.5%, 3.5%, 4%, 4%, 4.2%, 4.2%; years 11-15: 2.2%, 2.2%, 2.5%, 2.5%, 2.5%, 2.5%, 2.5%, 2.5%, 2.5%, 2.5%; and years 16:20: 2.5%, 2.5%, 2.5%, 2.5%, 2.5%, 2.5%, 2.1%, 2.1%, 2%, and 2%.

7.7.3 Equity Features

As described earlier, under current, likely long-term financing, capital raised is expected to include 50% equity. With favorable financing, the equity fraction is reduced to 40%. Equity owners receive all the project's cash and tax benefits over its 25-year contract life, plus remaining value. As discussed it is assumed that outside equity investors will be sought, who can fully utilize the project's tax benefits (i.e., from five-year rapid depreciation and ten years of Section 45 PTC), as well as its cash benefits. Projected targets for after tax IRR are 17% for land based wind energy plants, 22% for shallow water bay, and 25% for ocean. Rates are high because risk exists and the cash flows are only estimates.

For this analysis, an underlying assumption is that the Section 45 PTC will be "monetized" and used to repay debt. When it is "monetized," the PTC is "counted" with operating profits against the debt payment, to calculate the debt coverage ratio and it is used to repay debt.

When complex ownership-financing structures involving Tax Investors are employed, the project's debt fraction may be increased. However, as stated earlier, this analysis is the basic case over which the developer may place a more complicated ownership pattern, with various classes of equity investors who receive different percentages of cash and tax benefits, that "flip" or change over time. Should no complicated ownership strategy be proposed, the basic project will stand on its own. Consequently, for the basic case, the after-tax return on equity, composed of both cash and tax benefits, is project-wide.

Financial assumptions for the Mid-Atlantic wind energy project are shown below in **Table 7-12**. Summary descriptions of how and why certain values were selected are included also**.**

Section 45 Production Tax Credit (PTC): Note that in contrast to some formal estimates at DOE and NREL, where the Section 45 PTC was not included because it is not a permanent part of the Tax Code, it is assumed for this report that the PTC is included. Including the Section 45 PTC is common industry practice.

Beyond the Section 45 PTC, no other recent incentives or subsidies, such as cash grants or Bonus Depreciation, were included in this analysis. For example, the Section 1603 cash grants in lieu of tax credits provided under 2009 ARRA, which can run 30% of capital cost for qualified wind energy plants; if construction is begun during 2011 and is completed by December 31, 2012; are not included. Because they are not a permanent part of the US Tax Code, it is difficult to predict whether or not these special incentives will be extended, and because there is a certain "lag time" to plan and build a large wind energy plant of 100 MW or more, it was decided not to include special incentives.

Financial assumptions for the cash flow analysis of Mid-Atlantic wind energy plants are summarized below in **Table 7-12**.

Table 7-12. Financial Assumptions for 2012 100 MW Wind Energy Plants.

Assuming IPP Ownership and Project Finance, located in the Mid-Atlantic region (in 2012 dollars)

Parameter	Current (2012), Likely Conditions for IPP Project Finance	Favorable Conditions for IPP Project Finance
Lifetime	25 years.	same
Inflation	2.50%	same
Start Year	2013	same
Construction Period (years)	1.0	same
Debt/Equity	50/50 with PTC.	60/40 with PTC.
Debt Rate	7.50%, assuming 10-year Treasuries at 1.75% and a spread of 5.70%, rounded.	4.00%, assuming 10-year Treasuries at 1.75% and a spread of 2.25%.
Debt Term	20 years.	same
Debt Rating Level (project must meet this level, whether actually rated or not)	BB, first level below investment-grade, which is also termed high-yield or “junk” debt. For current, likely 2012 financing, if the wind energy plant sells power on a merchant basis, its debt will probably be rated BB, at the highest	BBB, lowest level of investment-grade debt. Under favorable financing, a BBB-rated project requires a strong Power Purchase Agreement. Alternatively, it requires that a Merchant Plant be located to receive attractive prices and that it have extremely strong, contracted guarantees from the developer’s parent corporation or other credit-worthy entity, which is probably a rare event.
After-tax Leveraged Equity Return	17.00% target for Land-based plants; 22% target for Bay; and 25% target for Ocean.	same
Income Tax Rate	40.0% combined, as an “average” federal/state rate, assuming 35% federal and 7.69% deductible state. For .the Mid-Atlantic states, maximum corporate rates are Delaware = 8.7%, Maryland = 8.25%, North Carolina = 6.9%, Virginia = 6.0%, and Washington DC = 9.975%.[18]	same
Debt Coverage (defined as operating income over the debt payment, composed of interest and principal)	Average of 3.00 times; minimum of 1.80 times, assuming a BB-rating, where the project sells power on a merchant basis.	Average of 1.80 times; minimum of 1.30 times, assuming a BBB-rating. The investment-grade rating is achieved either by a strong PPA, or possibly by iron-clad guarantees from a large, credit-worthy developer.
Cost Of Energy (COE)	Cost Of Energy is presented by three measures, as: a) a raw year-one bid price, b) a discounted nominal levelized charge, and c) a discounted, constant-dollar, levelized charge, where the latter excludes inflation.	same
IOU Cost of Capital Discount Rate for COE	7.00% nominal; 4.39% constant = [1.070/1.025-1]	same

18 “Range of State Corporate Income Tax Rates (For tax year 2011…)”; Federation of Tax Administrators; Washington DC; February 2011.

Parameter	Current (2012), Likely Conditions for IPP Project Finance	Favorable Conditions for IPP Project Finance
Merchant Plant Methodology vs. Power Purchase Agreement (PPA)	The project is assumed to sell power on a merchant basis, to the competitive wholesale market, where rates fluctuate, but may be estimated with a forward pricing curve, as can be estimated for PJM (Penn-Jersey-Maryland) RTO. Because merchant sales are risker, debt is probably rated BB, despite a capable developer and other project participants.	A 25-year Power Purchase Agreement (PPA) is assumed to be signed with a large, established, credit-worthy utility. This contract reduces risk for the project, such that debt is rated BBB. In a rare instance, a merchant plant might be rated BBB, if the developer provides iron-clad guarantees.
Energy Payment	The energy component of the tariff payment is a variable payment, paid as $per kWh, that is based on marginal fuel, operating expense, and other components. This is historically the larger share of the tariff payment. For this analysis, the energy payment is figured by a PJM Forward Pricing forecast, customized by PJM node, and utilizing either 2.5% escalation or 2015 Adder prices. Otherwise, by the “Calculated COE” method, the energy payment is the revenue required to meet projected cost and return requirements.	same
Capacity Payment	Capacity is a fixed payment, paid as $ per kW-capacity, that is based on PJM administered forward looking auction. For the Mid-Atlantic states, the PJM capacity auctions have paid wind energy plants an as-delivered capacity payment, estimated at [$rate/MW-day] * plant MW size * 365 days/year * capacity factor. For unconstrained RTO regions, the rate is $60/MW-day at 2.50% escalation and $90/MW-day with 2015 environment adder prices. For MAAC regions, the rate is $175/MW-day at 2.50% and $240/MW-day with 2015 adders. PJM now allows units to use a capacity factor of 13% or actual performance once historic data is available. For this analysis, it was assumed the rate would be adjusted to 20% for the first two years, with the actual capacity factor used thereafter. By the “Calculated COE” method, the actual capacity factor is always used. . As a measure of proportion, the capacity payment here ranges from the equivalent of about $0.001 to $0.007 per kWh, so it is less than one cent. Assume 1.0% escalation because utilities replace plant slowly, over many years.	same
Energy Payment Escalation Rate	The PJM Forward Pricing forecasts assume customized initial escalation based on four years of historical prices, plus NYMEX futures prices, and with longer-term escalation projected, One variable in forecasting is inflation, estimated at 2.5%. The 2.5% rate is conservative because sources like EIA’s Annual Energy Outlook 2012 project faster energy inflation [19]. The “Calculated COE” method assumes 2.0% escalation, which is 2.5% inflation less 0.5%. This revenue pattern allows, conservatively, for the pattern where power prices increase slower than inflation.	Same.

Parameter	Current (2012), Likely Conditions for IPP Project Finance	Favorable Conditions for IPP Project Finance
Renewable Energy Certificate (REC) Price	$0.003/kWh or $3.00/MWh, escalating by 2.0% per year (which is one half percent slower than inflation). Assume RECs are sold separately and not bundled into the tariff price. Renewable Energy Certificates (RECs), sometimes termed Renewable Energy Credits or "green tags", represent the environmental and social benefits from power produced by a renewable energy plant. RECs may be sold bundled with or separate from the electricity produced by the plant. One REC is the environmental and social benefits from 1,000 kWh from a renewable energy plant. If RECs are sold separately from the plant's power, then that power is no longer considered to be green. In those states with Renewable Portfolio Standards (RPS), which require their utilities to sell a certain percentage of green power, utilities often meet their requirements by buying RECs. A few socially-conscious customers (e.g., certain commercial and industrial companies, certain schools, a few residential homeowners) voluntarily buy RECs, but they are mostly bought by utilities. If the utility can meet its obligation only by buying in-state or near-regional RECs, then prices tend to be higher, on the order of $40/REC. If the utility can buy from far out-of-state, then prices are lower, on the order of $3/REC. Here, RECs are assumed to be sold at $3/MWh or $0.003/kWh, which is a recent 2011 price in Maryland. Prices are assumed to escalate at one half percent less than inflation, which is 2.0%.	same
Energy Production as Percentage of Expected Production.	100%. It is assumed that energy production will be at 100% of its projected value (i.e., what is termed P50 – 50% probability of occurring). Therefore, this approach to accounting for energy production is more aggressive than the conservative P90 (90% probability of occurring) approach that rating agencies and financial investors might impose when evaluating wind project financing.	same
Section 45 Production Tax Credit	Included in this analysis. Paid to the project's owners, who are probably some mix of outside equity investors plus the developer. For 2012, the value is $ 0.022 per kWh. See http://www.irs.gov/irb/2012-21_IRB/ar07.html with Internal Revenue Bulletin: 2012-21, dated May 21, 2012.	same
Principal Repayment of Debt	Customized repayment schedule, where the payment is adjusted to follow operating income. When the PTC is monetized, payments are higher during the first 10 years, than otherwise.	same

Parameter	Current (2012), Likely Conditions for IPP Project Finance	Favorable Conditions for IPP Project Finance
"Monetized" PTC	When the developer structures the project so that the Section 45 Production Tax Credit "counts" as money with which to repay debt. Either the developer obtains an ironclad guarantee, to provide cash equivalent to the PTC to project owners, so they, in turn, can pay the lender or lenders structure the debt financing so that equity investors, who are the project's owners will pay a portion of the debt payment from their tax savings from the PTC. An example is that FPL Group Capital unconditionally guaranteed payment of the PTC to FPL Energy National Wind LLC, in connection with the Operating Company's March 2005 wind portfolio finance offering, covering nine operating wind farms of $365 million of "BBB-" -rated notes and the Holding Company's related offering of $100 million of "BB-"-rated notes. [19] [20] Note that in 2009, FPL Energy was renamed NextEra Energy Resources. In January 2012, Fitch Ratings downgraded the OpCo Senior Secured notes to BB+ and HoldCo notes to B, because of lower than projected wind resources and increased levels of O&M, following an intermediate downgrade in 2011.[21] [22]	same
Depreciation	5-year MACRS using half-year convention. Section 168 of the tax code states that wind (and solar) energy plants are considered alternative energy property that can be treated as five-year property under the General Depreciation System of MACRS, the Modified Accelerated Cost Recovery System. Further, Tax Regulations Section 1.48-1(e)(1) permits "closely related" structures or other components to be considered as part of the original plant and thus eligible for the same tax treatment. It is assumed all the Wind Energy Plant is 5-year property, but Tax Counsel might research whether some components (e.g., fencing) must take longer depreciation. Applying the half-year convention to 5-year MACRS depreciation means that the annual fractions are: 20.0%, 32.0%, 19.2%, 11.52%, 11.52%, and 5.76%. With 50% Bonus Depreciation, half is depreciated in year one and the other half according to the given schedule, but Bonus Depreciation is not used here.	same
Unleveraged Pretax Equity Return	The cash flow model used here runs a pretax, unleveraged case as a point of comparison. With no PTC and no debt, the pretax, unleveraged IRR tends to be much lower than the leveraged equity return. The minimum acceptable rate of return for this case formerly was about 4%, as would be earned on a passboook savings account, but lately is more like 2.0% to 1.0%, as would be earned on a money market account at a bank. Most cases easily exceed this requirement, but occasionally it can become the tight constraint.	same

[19] FPL Energy, "FPL Energy announces completion of subsidiary bond offerings," FPL Energy press release, Miami FL, February 23, 2005.
[20] Doug Harvin and Ben Cooper, "FPL Energy National Wind, LLC;" Fitch Ratings; New York; March 9, 2005.
[21] Fitch Ratings, "Fitch Downgrades FPL Energy Nat'l Wind to 'BBB-'and …;" Fitch Ratings; New York; January 25, 2011.
[22] Fitch Ratings, "Fitch Downgrades FPL Energy National Wind OpCo Sr. Secured …;" Fitch Ratings; New York; January 06, 2012.

Parameter	Current (2012), Likely Conditions for IPP Project Finance	Favorable Conditions for IPP Project Finance
Positive Before-Tax Cash Flow	In similar fashion, it is required that each year of Before Tax cash flow be positive. It must exceed zero. For IPP projects taking the PTC, this can become the tight constraint.	same
Phantom Income, defined as negative after-tax cash flow.	Prevent phantom income or hold it very low. In the latter years of debt principal repayment, debt payments are composed mostly of principal and less of interest, profits are high and taxes are high, and at the same time non-deductible debt principal payments are high, so therefore the owner must pay one or the other out of his or her pocket. Phantom income can be "cured" if the project takes on less debt. Note that if phantom income is onerous, equity investors will refuse to make payments and will “mail in the keys,” causing the project to default to the lender. .	same

One may comment upon a couple points in **Table 7-12**. For its discount rate, this analysis employs the weighted average cost of capital of a typical Investor Owned Utility that would buy power or would produce competitive power. Given 2.50% inflation, the discount rate is estimated to be 7.00%, assuming an IOU with 55% debt at 5.50%, 1% preferred stock at 5.30%, and 44% common stock at 9.0%. The constant-dollar discount rate is 4.39% [1.070/1.025 -1]. The discount rate is before-tax, because the cash flow analysis separately sets out income taxes.

Debt coverage standards for BBB-rated debt financing are not high. For the IPP using Project Finance, because of the Power Purchase Agreement, which guarantees a price for all the plant's output, debt coverage can be somewhat low, at 1.5 times average and 1.3 times minimum. If the plant sold power on a merchant basis, which is riskier, then as discussed, its debt lately would be rated BB, which is one level below investment grade. To reduce risk, a merchant plant's owners may put together a synthetic PPA, to hedge power prices against commodity fuel prices for example, or they may investigate other financial risk management.

Lastly, as described previously, it is assumed that the developer "monetizes the PTC" or considers that the PTC can be converted to cash and used to pay the debt payment. Monetizing the PTC means converting a tax credit to cash. That is, the developer and his or her lender accept a guarantee that, come hell or high water, a large, established guarantor will provide cash equivalent to the PTC to the project owners, so that the project owners can pay the lender. This guarantor may be a utility holding company, if a non-regulated utility affiliate is acting as a developer of wind energy projects. This guarantor must be credit-worthy. If there is no guarantor, then the equity investors must agree to pay debt from cash saved through their tax credits, and they must provide adequate reassurance that the lender or debt investors are satisfied.

7.7.4 Property Taxes

State property taxes are set out in **Table 7-13**. Information is provided on how Delaware, Maryland, North Carolina, Virginia and The District of Columbia figure assessments and rates. Property taxes apply to land-based wind energy plants, but are sometimes reduced by state law for such plants. See **Section 8** for a discussion of state and local programs benefiting wind power generators.

Table 7-13. Property Taxes for Wind Energy Plants in the Mid-Atlantic States.

State	Assessment	Rates
Delaware	Delaware is composed of three counties. Property taxes are levied at the local level and tax rates. They are generally the same for all types of property, including residential, commercial, and industrial, except for certain state property tax incentives. The three counties base their assessments on market value at different dates in time and employ different assessment ratios. Certain cities and towns use more recent dates and different ratios. For example, Kent County taxes at 60% of the 1987 market value; New Castle County at 100% of the 1983 market value; and Sussex County at 50% of the 1974 market value. However, the town of Milford in Kent County taxes at 100% of the 2002 assessment; the town of Lewes in Sussex County taxes at 50% of the 2000 assessment. There are over 20 distinct School Districts in Cities or unincorporated areas within each of the three counties. [23, 24]	About four to five property tax rates are charged by Delaware counties. These include the County rate, School rate, City rate, Library or Crossing Guard rate, and Vo-Tech rate. For example, in Lewes in Sussex County, the County rate is $0.3983/$100 assessment, the School rate is $2.567, the City rate is $0.49, the Library rate is $0.0467, and the Vo-Tech rate is $0.2666, for a total tax rate of $3.7686 per $100 assessment. Rates vary by school distract and location. The proposed business owner must investigate his or her location.[25]
Maryland	Business property in Maryland is classified in three ways: as real property, which are buildings and heavy fixed equipment that are not moveable; as personal property, which is equipment that is movable; and as utility property. Personal property and utility property are often taxed at higher rates, but sometimes a fractional multiplier is applied to the assessment. Assessments are calculated by the state Department of Assessments and Taxation, from Baltimore or at field offices. Assessments are calculated based on: 1) cost, which is replacement cost less accrued depreciation; 2) market which is the recent sales price of a similar property, and 3) capitalized income, where a multiplier that is similar to a stock market P/E ratio is applied to earnings. At one wind energy plant in Garrett County in western Maryland, land owned by the site owner and storage buildings owned by the NUG (Non-Utility Generator) are classed as real property. The wind turbines and interconnect equipment owned by the NUG are classed as non-utility personal property.[26, 27]	The real property tax in Maryland includes a small state component and larger County and City/Town/Special District components. For example, in the City of Gaithersburg in Montgomery County, the state rate is $0.112/$100 assessment, the County rate is $0.699, and the City rate is $0.262, for a total of $1.073 per $100 assessment. In Baltimore City, the state rate is $0.112 and the City rate is $2.268, for a total of $2.380/$100 assessment. In Garrett County, the state rate is $0.112 and the County rate for Non-Utility Generators is $0.990, for a total of $1.102/$100 assessment. The non-utility personal property tax in Maryland includes County and City/Town/District components, but there is no state personal property tax. In Maryland, a 50% exemption applies to most but not all of the wind turbine and interconnect equipment. In Gaithersburg in Montgomery County, the County rate is $1.747/$100 assessment and the City rate is $0.530, for a total of $2.277 per $100 assessment or about $1.14 after the 50% exemption. In Baltimore City, the City rate is $5.67, for a total of

23 "State Tax Roundup: Delaware;" Bankrate.com; February 2, 2009.
24 "Delaware Property Tax Rates: 2010-2011;" Delaware Economic Development Office, Industry Research & Analysis Center; Dover DE; September 2010.
25 Ibid.
26 "Report of the Maryland Business Tax Reform Commission," Chairman Raymond S. Wacks; Annapolis MD; December 15, 2010.

State	Assessment	Rates
		$5.67/$100 assessment or $2.84 after the 50% exemption. In Garrett County, the County rate for Non-Utility Generators is $2.475, for a total of $2.475/$100 assessment or $1.24 after the 50% exemption. For all locations in Maryland, with time, taxable base is reduced by 5% depreciation per year till it hits a minimum level of 25%.[28, 29, 30, 31]
North Carolina	In North Carolina, power plants that sell power to end use customers are defined as public utilities and are assessed by the NC Department of Revenue. Power plants that sell power to a utility are not public utilities and are assessed locally, as real property, according to a standard schedule. That schedule is the "2011 Cost Index and Depreciation Schedules," prepared by the North Carolina Department of Revenue, which seeks to estimate replacement cost new (RCN) less depreciation. Here, for electric generating equipment, North Carolina categorizes the types of plant equipment as hydroelectric (50-year life), natural gas-fired (18-year life), steam powered (28-year life), and solar photovoltaic electric (18-year life). The assessment tends to be based on cost less accrued straight-line depreciation, but adjusted slightly for trending factors. Since 2008, North Carolina has applied an 80% reduction to the assessment for solar electric, but no taxpayers have yet built wind energy plants or lobbied for tax benefits.[32, 33]	In North Carolina, both counties and municipalities charge a property tax rate. To obtain current market prices, a sales assessment ratio will increase or decrease the latest assessment, to obtain the effective combined rate. For example, in Wake County, in Wake Forest, the County rate is $0.5340/$100 assessment, the Municipal rate is $0.5100/$100 assessment, and the 2010 ratio is 1.0346 times, so the effective combined rate is $1.0801/$100 assessment. North Carolina has over 500 locations with different property tax rates. The proposed business owner must investigate his or her location.[34, 35]

27 March 25, 2011 phone conversation: PERI and Maryland State Department of Assessments and Taxation (SDAT) Supervisor (Garrett Co, MD).
28 Ibid.
29 "2010-2011 County Tax Rates;" Maryland State Department of Assessments and Taxation; Baltimore MD; February 18, 2011.
30 "Report of the Maryland Business Tax Reform Commission," Chairman Raymond S. Wacks; Annapolis MD; December 15, 2010, pages 8-9.
31 March 30, 2011 phone conversation: PERI and Maryland State Department of Assessments and Taxation (SDAT) Administrator (Baltimore, MD).
32 "2011 Cost Index and Depreciation Schedules," North Carolina Department of Revenue, Local Government Division, Property Tax Section; Raleigh NC; effective January 1, 2011.
33 March 25, 2011 phone conversation: PERI and North Carolina Department of Revenue manager (Raleigh NC).
34 Ibid.
35 "North Carolina 2010-2011 Tax Rates and Effective Tax Rates;" North Carolina Department of Revenue, Policy Analysis and Statistics Division; Raleigh NC; about early 2011.

State	Assessment	Rates
Virginia	For Virginia, the State Corporation Commission (SCC) performs the real property tax assessment for public service corporations, which includes all electricity generating plants over 25 MW. All entity property is assessed by the SCC except autos and trucks. There is no separate personal property rate for property assessed by the SCC. The SCC prepares its assessment based strictly on cost, adjusted by a percentage good factor. Depreciation is calculated, reflecting plant life of 20 to 25 years. An equalization ratio is applied, to equalize the utility property assessment with that of the region, based on recent sales in that region.[36]	Virginia charges no state property tax. The Virginia SCC sends its assessment to the counties which apply commercial real property tax rates. Tax rates vary by county. An additional tax may be charged based on town or special district. For example, in Loudon County, the real commercial property tax rate is $1.30/$100 assessment. In Rockingham County, the real commercial property tax rate for 2012 is $0.64/$100 assessment.[37] The proposed business owner must investigate his or her location.
The District of Columbia	For The District of Columbia, the Office of Tax and Revenue states that "uniform and accurate assessments are the foundation of fair property taxation." At this point in time, until a possible site for a large wind energy plant is proposed, the authors of this report did not seek further clarification beyond this general goal.[38]	For The District of Columbia, commercial real property assessed at $3 million and less is taxed at $1.65/$100. The residual value over $3 million is taxed at $1.85/$100.[39]

[36] March 24, 2011 and May 31, 2012 phone conversation: PERI and Virginia SCC manager (Richmond VA).
[37] May 22, 2012 phone conversation: PERI and Rockingham County VA representative.
[38] "Real Property Assessment Process," The District of Columbia Office of Tax and Revenue, Washington DC, internet download March 25, 2011.
[39] Ibid.

8.0 Regulatory and Policy Issues

With the very substantial assistance of the Database of State Incentives for Renewable Energy (DSIRE**),**[40] environmental groups, and industry and government representatives, team members set out to identify those regulatory and policy issues that had substantial adverse impact on the potential for development of new wind projects in the region. Complaints and concerns raised by parties were investigated to determine the extent to which perceived barriers actually drove decisions to build, defer or abandon projects. Where possible, primary sources, such as the actual printed decisions of regulatory agencies and the ordinances and statutes themselves, were reviewed in addition to media and other accounts of ongoing activities and debates. In general there is a substantial difference in the perception of many parties of the degree to which the policies and actions of the different states[41] in the region are supportive of wind power. This perception alone is likely to be a driver of future development as no state in the region has superior wind resources. Accordingly, developers are likely to initially select locations with good wind resources and positive support from the public and state and local governments. In addition to this difference in general perception of state policy, several key issues were identified that are likely to impact the rate and extent of wind power development in the region.

Ridgeline wind resources are, for the most part, more concentrated in Maryland, Virginia and North Carolina than in neighboring states of West Virginia and Pennsylvania. For this reason, potential view shed and noise issues are likely be of more concern and the actions of only a few counties regarding these concerns will likely determine whether ridge line resources will be developed. In addition, as explained below, action at the state level in North Carolina has effectively curtailed development of ridge line resources in the state.

Coastal wind resources are not well understood and overly broad state studies have suggested that opportunities for developing wind power in North Carolina and Virginia state waters are extremely limited. Each state in the region has adopted a RPS or RPG that is nominally intended to encourage the development of renewable resources, but in most of the states in the region, the design of these programs ensures that they will be ineffective. What follows is a more detailed discussion of the more relevant issues examined by the PERI team and its consultants.

8.1 Virginia

Virginia provides for a voluntary RPG that provides financial incentives for the purchase of renewable energy to the Commonwealth's regulated utilities. This program has been criticized because it provides financial incentives in lieu of a mandate, [25] but the incentives provided by the program are so much greater than the cost of the RPG that to date Virginia's largest utilities, Dominion Electric Power (Dominion) and Appalachian Power Company (APCO) have chosen to participate. Accordingly, at least for the foreseeable future, this aspect of Virginia's program does not appear to be a barrier to development of wind power by investor owned utilities (IOUs). However, the program provides no direct incentive for independent power producers (IPPs) and, as discussed below, the program merely provides an additional revenue stream to sources of renewable energy that have been in existence for decades, and does not provide an incentive for the development of new sources of renewable energy in the Commonwealth or elsewhere.

[40] DSIRE is a comprehensive source of information on state, local, utility and federal incentives and policies that promote renewable energy and energy efficiency. Established in 1995 and funded by the U.S. Department of Energy, DSIRE is an ongoing project of the N.C. Solar Center and the Interstate Renewable Energy Council. www.dsireusa.org

[41] In this discussion we refer to the District of Columbia as a state.

Virginia law also provides for a potential[42] Clean Energy Manufacturing Incentive grant, capped at $36 million for wind and solar equipment manufacturers and biomass producers, over the six-year life of the program. This incentive is available to wind power equipment manufacturers who invest $10 million and create 30 jobs in the Commonwealth. The investment and job thresholds for biomass producers and solar generation equipment manufacturers are substantially greater than for wind equipment manufacturers. It should be noted, however, that the incentive applies to the "producers" of biomass, not merely to those who manufacture equipment used to produce energy from biomass. The Virginia Resources Authority also has the legal authority to arrange for low-interest state bond-backed loans to local authorities for a variety of projects that theoretically could include wind generation of power by the local government. However, to our knowledge, this fund has never been employed for this purpose and is too small to be of much practical assistance to a utility-scale project.

Virginia does not provide personal, corporate or sales tax relief for wind power projects and does not have a public benefit fund to support wind power projects. The Tennessee Valley Authority (TVA) provides power to two electric co-operatives, the Powell Valley Electric Co-operative and the Appalachian Electric Co-operative, that service very small areas in southwest Virginia. These entities provide access to their customers to TVA's "Generation Partners Program" and "Mid-Sized Renewable Standard Offer Program." The former program would pay small generators (up to 50 kW) retail electric rates plus $0.03 per kWh; while the latter program offers larger generators (up to 20 MW) an average price of $0.055 per kWh for energy that can be resold to TVA's customers as "green energy" and the associated Renewable Energy Certificates (RECs). In addition, Virginia provides for a modest program of net metering of residential and non-residential renewable on a "first-come, first-served" basis, of up to 1 percent of the maximum generation of the affected utility[43] and mandates that utilities provide consumers the option of purchasing 100 percent renewable energy. Virginia has also promulgated reasonable interconnection standards and a model zoning ordinance to assist localities in permitting wind power facilities.

Virginia's "Commonwealth Energy Policy" codified in 2006, is an "all of the above" plan that promotes the use of coal, natural gas, oil, nuclear energy as well as renewable energy and energy conservation. The Plan specifically establishes a policy for the Commonwealth to

> "[s]upport research and development of, and promote the use of, renewable energy sources" and to "[p]romote the generation of electricity through technologies that do not contribute to greenhouse gases and global warming." [26]

The 2006 Virginia law further provided that

> "[a]ll agencies and political subdivisions of the Commonwealth, in taking discretionary action with regard to energy issues, shall recognize the elements of the Commonwealth Energy Policy and where appropriate, shall act in a manner consistent therewith"

and

> "[t]he Commonwealth Energy Policy is intended to provide guidance to the agencies and political subdivisions of the Commonwealth in taking discretionary action with regard to energy issues, and shall not be construed to amend, repeal, or override any contrary provision of applicable law."

[42] The program is subject to the further discretionary provision of funds by the Legislature.
[43] Not available to customers of municipally owned utilities. Residential customers with a generating capacity of greater than 10 kW are charged transmission and distribution system fees. Net excess generation is sold to the utility on an "avoided cost" basis.

The Commonwealth has taken a number of useful and potentially important steps to implement this policy; including establishing a streamlined permitting mechanism. The permit regulation, known as "permit by rule" applies to wind energy projects less than 100 MW. The rule places no environmental permitting requirement on projects of less than 500 kW; for projects more than 500 kW and up to 5 MW, the permit by rule calls for notifying the Virginia Department of Environmental Quality and imposes other minimal requirements. For projects exceeding 5 MW and up to 100MW, the permit regulation establishes reasonable requirements for potential environmental impact analysis, mitigation plans, facility site planning, public participation, permit fees, inter-agency consultations, compliance and enforcement. The permit by rule includes projects located in state waters for wind farms less than 100 MW, and streamlines the process for addressing those issues.

However, notwithstanding Virginia's codified policy of supporting and facilitating new wind power generation and the adoption of an efficient permitting mechanism, several sets of discretionary actions; one by the State Corporation Commission, the other by several political subdivisions of the state that subsequently adopted proscriptive zoning regulations, have created substantial barriers to the development of wind power in Virginia.

8.1.1 Renewable Portfolio Goal (RPG) Program Design

The RPG goal through 2016 is set at 4 percent of the non-nuclear[44] 2007 sales of electricity in the state. In 2017 the goal increases to 7 percent and in 2025 to 12 percent of non-nuclear 2007 sales. For Dominion, which owns substantial nuclear resources, the target through 2016 translates to 2.7 percent of total 2007 sales. Under the statute, all costs, including Rec and administrative expenses are reimbursed and IOUs such as Dominion are entitled to recover all of their costs of participation in the program and an additional 0.5 percent rate of return on equity. For Dominion, the "bonus" for participating has been estimated by the Virginia State Corporation Commission staff[45] to amount to nominally $39 million per year[46] and a net present value of $330 million through 2025. The SCC staff also pointed out that the statute provides performance bonuses and penalties that could either eliminate the bonus or increase it to a net present value of 987 through 2025. As the Dominion system grows over the next 13 years, the amount of the bonus will rise with the increase in equity held by the company, even though the "baseline" generation (to which the increasing goals are applied) is fixed at 2007 generation levels.

In its application [27] to participate in the program, Dominion acknowledged that it would meet the goal largely through existing[47] in-state hydropower resources, supplemented as necessary by the purchase of Tier II RECs. Tier II RECs are generated by sources that are generally considered less environmentally beneficial that Tier I sources and their use is constrained or prohibited in a number of Renewable Portfolio programs. It should be noted, that while there is a difference between the value of Tier I and Tier II RECs, the value of even Tier I RECs is insufficient to incentivize new renewable development if pre-existing Tier I RECS are allowed for compliance with the RPS or RPG. Dominion indicated that, while it might construct new renewable generation if market conditions warranted doing so, the company intended to purchase Tier II RECs throughout the life of the RPG program to fill any shortfall from existing hydropower generation. Dominion estimated that the net present value of the use of Tier II RECs through 2025 was $7.9 million, compared to $221 million for Tier I RECs[48]. Thus, the flaw in the design

[44] It should be noted that because a substantial portion of the electricity sold in Virginia is generated by nuclear power, Virginia's goals are more modest than it otherwise might appear.
[45] Estimates provided in State Corporation Commission staff review of Dominion's application; Case No. PUE-2009-00082 (Nov 20, 2009) and in Dominion's application.
[46] Based on 2005 data respecting Dominion's capital base.
[47] Virginia's hydropower generation has an average age of approximately 70 years.
[48] Tier 1 REC prices are substantially less today than at the time of Dominion's application.
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of Virginia's RPG program is not the fact that it is voluntary, but the fact that it not only allows, but prioritizes the use of what are known in emissions trading circles as "anyway credits" – credit for actions that have occurred decades earlier. As a consequence, Virginia's RPG program will transfer many millions of dollars from ratepayers to operators of existing renewable generating facilities that do not need an incentive to operate and an even larger amount to the participating IOUs in the form of bonus return on equity, but is unlikely to incentivize new wind or other renewable power projects in Virginia.

8.1.2 Appalachian Power Company (APCO) State Corporation Commission Decision

At about the same time the State Corporation Commission was reviewing Dominion's application to participate in the RPG program, APCO submitted its application to the Commission for a determination that two power purchase agreements (PPA) for new wind power generation were "reasonable and prudent" means of complying with the RPG (as required by the statute for new renewable energy as well as other generation sources). The Commission rejected APCO's request and determined that the goals of the RPG were not minimums to be met and exceeded, but caps on the amount of renewable energy that would be considered "reasonable and prudent" under the Commission's rules [28].[49] Thus any new renewable generation that was not needed to meet the currently applicable goal[50] was not prudent, even if it would be needed to meet the goal established for later years. The Commission also noted Dominion's use of Tier II RECs, holding that where a lower cost method of compliance is available, it must be utilized [28]. Notably, the Commission did not find that the cost of energy in the proposed PPAs was unreasonable, but held that this question was not dispositive.

> "For example, even if a utility shows that the cost of its proposed renewable resource is low when compared to other high cost renewable resources, the statute does not require the Commission to find that such cost is reasonable or that it is prudent for a utility to take actions incurring such cost."

This decision may be one where "bad facts make bad law" as APCO had recently requested and received large rate increases needed to install pollution control equipment and resolve the company's ongoing violations of the Clean Air Act, a fact noted by the Commission in its Order.[51] The Commission asserted that "… we do not, by this Order, indicate that wind power cannot be part of a portfolio of energy sources to serve customers" and the Commission has approved proposals from IPPs to build wind power projects in Virginia. However, given the large price differential between the market value of Tier II RECs and the cost of any new source of renewable energy, it is hard to imagine the Commission will find any new renewable energy generation compatible with the RPG program unfortunately. The Commission did not release the terms of the APCO PPA, and therefore, wind power developers do not even know what price level was determined to be imprudent. It should be noted that the Commission did not review a Cost of Energy (COE) for wind power compared to fossil-fueled or nuclear generation and did not determine what the rate increase for the consumer would be. It merely decided that the cost of the PPA was substantially higher than that of Tier II RECs.

A bill was introduced in the Virginia legislature to correct this situation by specifically requiring the State Corporation Commission to consider the codified Virginia Energy Policy when considering such matters.

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[49] http://www.scc.virginia.gov/pue/renew/apco_renew_09.pdf
[50] "The Company's evidence shows that these PPAs are not needed at this time to achieve those goals under the time frame reflected in the statute." "Here, however, the new proposals would exacerbate an already difficult rate environment for customers without significant offsetting benefits and, furthermore, are not needed **at this time** to meet voluntary RPS goals under the statute." Order, p. 11 (emphasis added)

[51] Here, however, the new proposals would exacerbate an already difficult rate environment for customers without significant offsetting benefits and, furthermore, are not needed at this time to meet voluntary RPS goals under the statute.

> "*In determining the reasonableness or prudence of a utility providing energy and capacity to its customers from renewable energy resources, the Commission shall consider the extent to which such renewable energy resources, whether utility-owned or by contract, further the objectives of the Commonwealth Energy Policy set forth in §§67-101 and 67-102.*"

However, this bill was amended to also require the Commission to consider "*whether the costs of such resources is likely to result in unreasonable increases in rates paid by consumers*" and passed as amended.

Several state observers and developers believe that, because of this amendment, the revised legislation is not adequate to address the problem, especially since under the 2006 statute the State Corporation Commission was already obligated to consider the Commonwealth Energy Policy. However, the addition of one or more 100 MW wind farms to Virginia's energy pool of 25,000 MW of capacity will not lead to a noticeable increase in utility rates and so, this amended language may be sufficient to signal to the Commission that where the cost of a proposed project is consistent with similar renewable projects elsewhere in the country, that project should be approved, even though the cost of electricity may be higher than fossil-fueled generation or the purchase of RECs. If, however, the Commission continues to employ the price of Tier II RECs from existing sources (or Tier I RECs from such sources) as the standard for what costs may be considered reasonable and prudent, Virginia's Energy Policy will be frustrated and millions of dollars of ratepayer's money will be wasted.

8.1.3 Zoning Ordinances

Local opposition to new wind power projects can be a significant barrier to the development of wind power in the Mid-Atlantic area. Even if local opposition is unable to stop a project as a matter of law, the time and cost of addressing challenges raised by opponents can significantly increase the cost of generation and render a project economically unviable. Moreover, when a developer fails to properly evaluate or address environmental issues, the event is widely publicized and becomes grist for the mill of those who oppose wind power generally. If wind power is to gain public acceptance in the Mid-Atlantic region, early projects, in particular, must be good neighbors. Developers should understand that a commercial-scale wind farm is an industrial enterprise that often must be located in a pastoral or rural setting. Toward this end wind power developers (and early wind power developers in particular) should welcome sensible siting and noise regulation and should adopt conservative designs that minimize any adverse impact on the community and the environment.

Almost all of the lower elevation property in Virginia, except along the coast, does not have sufficiently strong wind resources, and so this issue does not affect most of Virginia's counties. Over the past 10 years developers have expressed interest in a number of potential ridge line and a few coastal locations in Virginia. In response to this expression of interest, a number of Virginia counties have enacted zoning ordinances. Virginia's ridgeline and coastal wind power resources are not nearly as dispersed as those in Pennsylvania, West Virginia or other states. In Virginia, high value ridgeline sites are concentrated in a fairly narrow band and developable sites are further constrained by National Park land, the Appalachian Trail and National Forests. Coastal resources are available only in those counties that are adjacent to the lower Chesapeake Bay or Atlantic Ocean. Thus, the future of much of Virginia's wind power will be decided by a relatively small number of counties. Some ordinances, such as that enacted by Roanoke County, provide for sensible setback and noise controls that regulate, but nonetheless permit, development of wind power [29]. Other ordinances, such as the ordinance adopted by Tazewell County, effectively bar commercial wind power development.

Historically, the Virginia state government has been highly deferential to local zoning determinations in almost all situations, including the siting of fossil fuel-fired power plants. However, in 2011, the Commonwealth passed a statute [30] requiring that any local ordinance addressing the siting of renewable energy facilities that generate electricity from wind or solar resources be consistent with the provisions of the Commonwealth Energy Policy, provide reasonable criteria to be addressed in the siting of any wind or solar facility while providing for the protection of the locality in a manner consistent with the goals of the Commonwealth to promote the generation of energy from wind and solar resources; and include provisions establishing reasonable requirements upon the siting of any such renewable energy facility, including provisions limiting noise, requiring buffer areas and setbacks, and addressing generation facility decommissioning. In April of 2012, the Commonwealth, working with local governments published a model zoning ordinance to assist local governments in addressing these issues [31]. However, the statute appears to exempt those zoning ordinances that have already been adopted even if they contravene the Commonwealth's 2006 Energy Policy.[52]

Floyd County likely has greater wind energy resources than any other ridgeline county. The County has proposed, and is currently contemplating, a zoning ordinance that would ignore both the 2006 and 2011 statutes and effectively bar any commercial scale wind power development. The decision of the County Commissioners on this issue will have a significant impact on the prospects of ridgeline wind power in Virginia. In contrast, Accomack County, one of the two Virginia eastern shore counties likely to have the greatest coastal resources, has been supportive of the development of wind power.

While local zoning ordinances have clearly blocked several wind power projects in Virginia from going forward, it is still premature to state that this issue will be a significant barrier over the long term. As yet, there are no commercial scale wind farms in the Commonwealth and, with the amount of misinformation that is generated by opponents of wind energy; some degree of skepticism is to be anticipated. The state government has attempted to address the concerns of opponents by working with local governments in a collaborative fashion to develop a reasonable model ordinance to address local siting issues, and there are many Virginia counties that are willing to accept wind power. Therefore, once economic conditions improve, there will likely be some wind power development. Done properly, this development can show that wind power can be a good neighbor that contributes to economic growth in the region and thereby gain acceptance in counties that currently do not permit commercial scale wind power.

8.1.4 Virginia Marine Resources Commission Report

As noted earlier, much of central Virginia does not possess developable wind resources. Other than the ridge line sites in western Virginia, only the lower Chesapeake Bay and adjacent lands have potentially economically viable wind resources. In 2009, the Virginia legislature directed the Virginia Marine Resources Commission (VMRC) to determine the feasibility of leasing state-owned bottomlands in the Chesapeake Bay and its environs. In a widely disseminated and quoted report [32] published in 2010, the Commission determined that existing competing uses ruled out any commercial scale wind farms in the Chesapeake Bay. The publication of this report effectively ended any consideration of the use of this resource. However, a detailed review of this report reveals that, while this conclusion is stated in the report; the analysis does not support this conclusion. Indeed, the report identifies a number of areas that, according to the report, may prove to be appropriate locations for the development of wind power in the Chesapeake on further review. The study was not sufficiently funded by the legislature to attempt a comprehensive review of the underlying issues and so it is not surprising that the report concludes that additional studies would need to be conducted before large areas of the Chesapeake could be declared suitable for development. For the most part, the VMRC Report provides only a superficial examination of

[52] Id."Any measures required by the ordinance shall be consistent with the locality's existing ordinances."

potential issues and conflicts that would need to be addressed as any project proposed for these areas and a tiering of areas where more extensive review would be required. Examination of several of the report's illustrations most clearly reveals the short comings of the report.

The Report identifies "Excluded Areas" (**Figure 8-1**), which it defines as:

> "[a]reas for which there is a legally defined use or protection such as navigation channels and anchorages, military security and training areas, FAA restriction areas, the NASA Wallops Flight Facility range, Baylor Grounds (public oyster grounds) and private shellfish leases".

The Commission's map of these areas identifies a large number of what it styles "shipping lanes" that run in an East-West direction between the Bay's eastern and western shores and eastward into the Atlantic Ocean from the back bays of the eastern shore. A review of the nautical charts for the area reveals that most of the claimed "shipping lanes" are unmarked open waters that are too shallow for ships to enter. The harbors that are served by these "shipping lanes" are often less than six or eight feet in depth and are used by recreational boaters and small fishing craft, not "ships." The only significant harbor on the Virginia portion of the Eastern Shore is at Cape Charles Town, while a couple of creeks, such as the Onancock and Puncoteague Creek are deep enough to support occasional barge traffic. Similarly, the "shipping lanes" identified on Virginia's Atlantic coast are generally small ocean inlets, guarded by sand bars and shifting channels that can be navigated by small, shallow draft, boats, not ships. Here, it should be understood that the individual turbines in a wind farm are typically spaced approximately 1000 yards apart and pose no threat to the navigation of smaller vessels such as those capable of using the small harbors of the lower Bay. The main north/south shipping channel of the Bay is clearly marked and often more than 100 feet deep. The main shipping channel would not be considered for a wind farm where shallower waters are readily available.

The VMRC Report also excludes large areas under the heading of "Military" and, indeed, there is unexploded ordinance in some areas of the Bay. There also are areas where the potential for interference with military, FAA and weather radar signals can be disrupted by reflected signals from wind turbines. These areas include the approaches to Norfolk and Patuxent Naval Air Station further north in Maryland. But the U.S. military, with its own renewable energy goals [33] has been generally cooperative with state and local governments in addressing such issues, and there is no indication in the Report that the U.S. military would object to the siting of any wind farm in Chesapeake Bay bottomlands, except in areas where turbines can interfere with radar. In contrast, within the State of Maryland, military and weather radar interference areas are clearly defined and their basis is explained in a report by University of Maryland, Center for Integrative Research [34]. That report suggests potential mitigation measures.

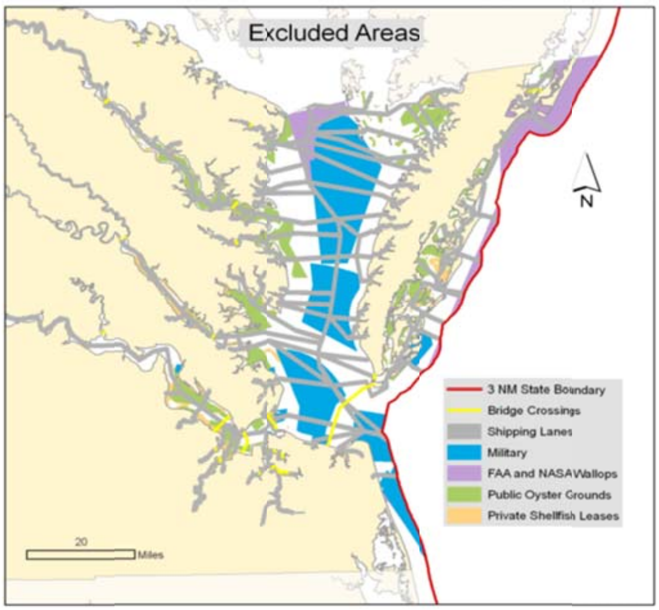

Figure 8-1. VMRC Report Excluded Areas

The VMRC Report then identifies an additional broad swath of the lower Chesapeake Bay that contains "major conflicts." Major conflict (**Figure 8-2**) areas are defined by the Report as those areas

> "where there are significant use or resources conflicts that would appear to preclude wind energy development. Examples of areas suggested for this category include sensitive shallow water areas with depths less than 2 meters,[53] including the Eastern Shore lagoon system behind Virginia's barrier islands, and areas along the coast that are of continental and global importance to birds due to the large number of species and individuals that migrate through this corridor and overwinter in the area. This area includes much of the Bay mouth that overlaps or is near blue crab spawning and nursery areas and fishery, marine mammal and turtle migratory corridors as well as high commercial shipping and recreational use areas including those near recreational beaches."

There is likely to be some conflict with migratory bird flyways along the coastline, but as studies in North Carolina, New Jersey and elsewhere have shown, such conflicts are unlikely to extend as broadly as portrayed in the VMRC report. The policy expert also notes that the VMRC Report asserts that this area is conflicted both because it is environmentally sensitive and because there is high commercial shipping and recreational use.

[53] Actually, the VMRC designates all waters less than two meters deep as major conflicts.

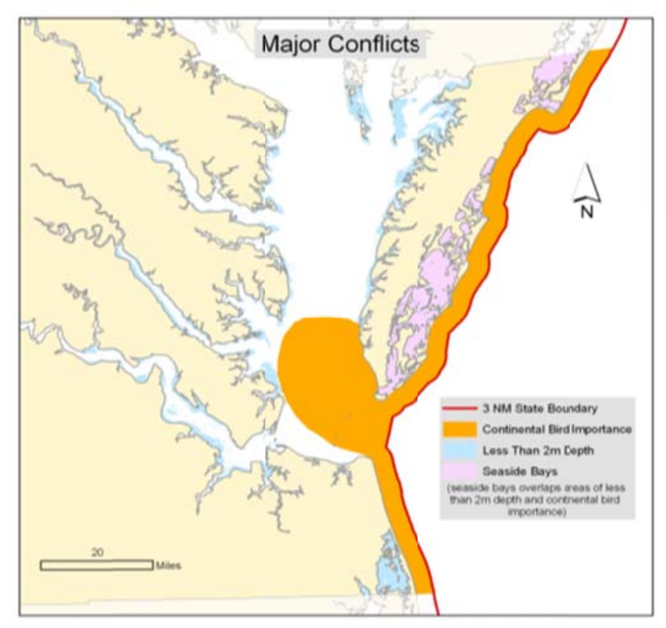

Figure 8-2. VMRC "Major Conflicts"

Next, the Report identifies areas that it deems to have "moderate conflicts" (**Figure 8-3**). These areas are defined as "areas where there appears to be some use or resource conflict, but with further analysis might possibly be considered suitable for leasing." These areas include "blue crab spawning and nursery areas" that are also dredged to provide sand and that include the Chesapeake Bay Bridge Tunnel, a structure that is far more substantial than a typical wind farm. The Report does not provide a statement of whether the Commission believes that a wind farm would pose a significant post-construction conflict with the finfish and bluefish management areas that it identifies or how it determined that a wind farm south of Tangier Island would pose a conflict with regional birds. We note that wind farms have a relatively small footprint per square mile of bottomland and that a number of studies from European offshore wind farms and other foundation based structures that turbine and similar foundations and scour reducing riprap provide beneficial havens for fish and crustaceans.

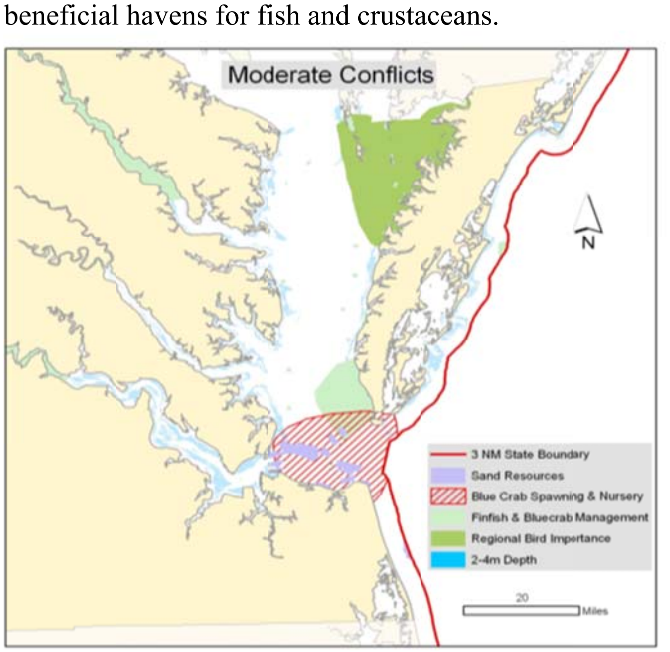

Figure 8-3. VMRC "Moderate Conflicts"

After these exclusions, there remains what the VMRC identifies as "lesser conflict areas" (**Figure 8-4**). The Report defines "lesser conflict areas" as "areas that may be suitable for leasing recognizing that detailed environmental and use analysis will be needed before permits and leases can be issued." Thus, in fact, these areas are deemed by the Commission to be potentially suitable. Located on the Western shore of the Chesapeake Bay (south of Smith Point in the vicinity of the Rappahannock River and Mobjack Bay), these areas are large enough to support commercial scale wind development[54] and are projected to have Class 4 wind resources. However, having identified these areas as potentially suitable, the Report simply dismisses these sites:

> "[w]hile there may very well be areas in state waters that are potentially suitable for development of wind projects it is unlikely there will be large areas with suitable wind resources for large industrial scale projects, nor does it appear the electrical distribution system is adequate for large projects except in the Virginia Beach area."[55]

This conclusion ignores the potential for development of the much larger areas, designated as having "some" conflict, but found by the Commission as potentially suitable for leasing on further analysis. As a result, the reported conclusion of the VMRC is that there is no potential for development of commercial scale wind generation in state-owned bottomlands in the Chesapeake Bay.

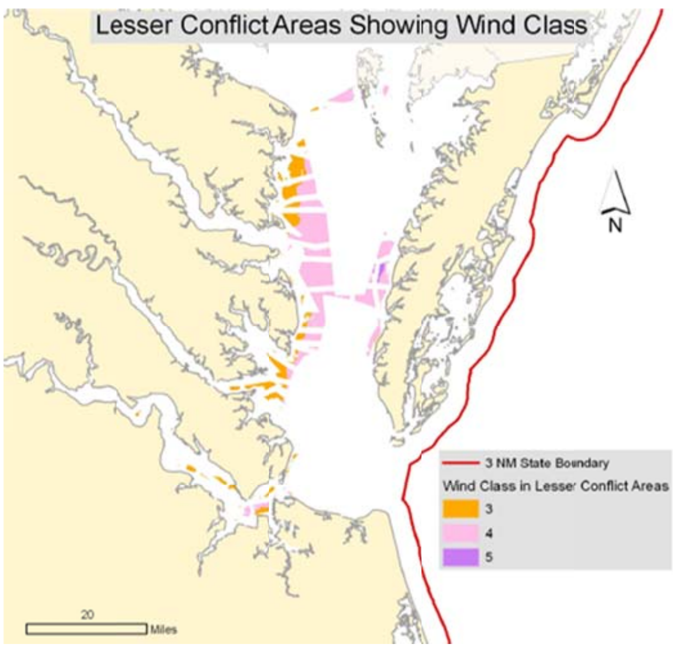

Figure 8-4. VMRC "Lesser Conflict Areas"

Attempting to resolve the policy issue of whether to exploit the available resource is beyond the scope of this review. However, the potential value of the resource is too significant to be dismissed on the basis of the limited review of the issues afforded by the 2010 VMRC Study and the unsupported "finding" that is generally quoted as the conclusion of the Commission. Among its other attributes, wind energy reduces airborne deposition of nitrogen in the Bay and reduces runoff to the Chesapeake Bay watershed from coal mining, processing and transportation activities. There is a significant difference between identifying

[54] This is particularly true if one properly scales the marked navigation channels for small boats that bisect the identified areas.
[55] The report also errs in failing to identify other options for transmission of electricity generated in state waters, such as a 220 kV line near the "lesser conflict" areas on the western shore of the Bay and the transmission capacity available at Calvert Cliffs, MD and Yorktown, VA.

areas where further work is needed to resolve potentially competing interests, and determining that an area must be excluded because the competing interests are irreconcilable and the earlier use is a priority. The VMRC Report accomplishes the former task, but not the latter. The legislature asked the VMRC to identify areas for potential development of wind power on state-owned bottomlands and the user-community has accepted the judgment of the Commission, thus ending any discussion of the potential for wind power development in the lower Bay. Significant additional resources should be provided to the VMRC to conduct a far more thorough and balanced evaluation of the issues so that the issues may be more fairly framed for Virginia's residents and their elected representatives.

8.2 North Carolina

The lack of wind development in North Carolina is in marked contrast to the abundant amount of wind resources that exist at both ends of the state. The North Carolina State Energy Office estimates that there is approximately 2400 megawatts (MW) of potential wind capacity in North Carolina. These figures include 970 MW on the mountain ridges and 1430 MW on-shore and in sound waters. North Carolina has invested substantial funds to evaluate the available wind resources and the barriers to development of wind power. It also has provided technical resources to assist local governments in addressing siting and land use issues. However, the interpretation of the 1983 Mountain Ridge Protection Act advanced by the Attorney General in 2002 has effectively stopped all development of commercial wind power in western North Carolina, and the General Assembly has left this interpretation intact by declining to reinstate the authority of local governments that was taken away by the 2002 interpretation.

However, wind power projects have been proposed, and are proceeding in several coastal counties. Several of these projects involve wildlife protection issues that are still being worked through. North Carolina has identified a potential wind power resource in its coastal bays and sounds, but apparently has not yet identified a procedure for resolving the permitting authority of the various agencies.

North Carolina has established a mandatory "Renewable Energy and Energy Efficiency Portfolio Standard" (RPS) that obliges the three major investor-owned utilities (IOUs) in the state to purchase up to 12.5 percent of 2020 retail electricity sales in North Carolina from eligible sources by 2021. Eligible sources include energy efficiency and new renewables. Municipal utilities and electric cooperatives must meet a target of 10 percent renewables by 2018. State law also provides a corporate tax credit of 35 percent, up to $2.5 million per installation, for wind power used for a business purpose as well as an individual tax credit, up to $10,500, for wind power used for non-business purposes. The state also grants a tax credit for renewable energy equipment manufacturers of up to 25 percent, with no limit on the amount of the credit. It also has established a local option[56] for Property-Assessed Clean Energy (PACE) financing for energy improvements, including distributed generation wind power projects. North Carolina has also promulgated reasonable interconnection standards and a model zoning ordinance to assist localities in permitting wind power facilities.

Duke Power has a standing offer to purchase wind power generated RECs at $5 per MWh. This level of support represents a subsidy of 5-10 percent of the cost of new wind generation. Together with the Federal Production Tax Credit (if available) would appear to be of some meaningful value in stimulating new wind projects in the state. However, the total purchase under this program is limited to 5,000 MWh per year[57] from any one source. Thus, while this offer would not be of much use to the developer of a 100 MW wind farm, it may provide a useful incentive to distributed wind power generation in North Carolina for those sources for which net metering is less optimal. In addition, customers who elect to pay a premium for "green" electricity support the North Carolina Green Power program which, for larger

[56] As of this date, no county has adopted a PACE financing program.
[57] Nominally, 2MW of capacity.

sources of renewable electricity, contracts with renewable energy sources based on a bidding process and retires the RECs generated by those sources. Smaller wind-energy systems can receive a payment of $0.09 per kWh from the program plus approximately $0.04 per kWh from participating utilities. The TVA "Generation Partners Program," discussed above, is also available to TVA-supplied electric cooperatives serving North Carolina customers.

One more point, this study focused on the PJM area since pricing was transparent and that the PJM system provides more opportunities than the traditional control area of North Carolina operated by vertically integrated utilities. In the latter, the economics will likely be discounted compared to the PJM Fentress case since there is not the opportunity for developer to sell merchant power - only PPA from utilities or to imbedded muni's.

North Carolina law requires its three in-state IOUs to offer net metering for systems up to 1 MW capacity with no limit on the aggregate capacity that must be accommodated. Residential systems up to 20 kW and industrial systems up to 100 kW have the right to net metering without standby charges; larger systems may be assessed standby charges at the same rate as for fossil fuel-fired customer owned generation. Under this program, net excess generation is surrendered to the utility on an annual basis.

8.2.1 North Carolina RPS Design

North Carolina's RPS was adopted in 2007 based on a comprehensive analysis by a consulting firm experienced in the design of such programs. This firm considered the parallel goals of encouraging development of new renewable energy, while avoiding significant increases in retail electricity rates [35].[58] The consultant's report concluded that most new renewable energy would come from wind energy. It further concluded that although a goal of 5 percent new wind energy was readily achievable, North Carolina would experience difficulty meeting a 10 percent new renewable standard unless large hydropower was included in the mix of available resources. Rather than pursuing new large hydropower projects or relying on "anyway credits" from existing renewable generation, the consulting firm recommended the inclusion of new energy efficiency measures as part of the standard. New energy efficiency measures, while not directly promoting the installation of new wind power, do further the stated legislative goal of encouraging private investment in renewable energy and energy efficiency. As the first general compliance date is 2012, the source of the RECs used for compliance is not yet available, but of the 8,600 MW of new renewable generation that has registered to provide RECs to NC utilities, approximately 8,000 MW is represented by wind power projects across the U.S. that have come on line since the program was adopted.[59]

While the percentages in North Carolina's RPS program are lower than those found elsewhere in the region, North Carolina's program is likely to be more effective in facilitating new renewable development, including new wind development in North Carolina, because the North Carolina program generally focuses on new sources,[60] requires that a minimum of 75 percent of the RECs used for compliance be "in-state" RECs and excludes both new and existing large hydropower sources. Moreover, the required REC percentages are based on generation in the year prior to the compliance year, and so will grow as system demand increases. Energy efficiency measures may only be used to meet 25 percent of the standard through 2021.[61] Small percentages of the overall standard are reserved for solar and swine waste (0.2 percent each) and poultry waste powered energy supplies (900,000 MWh). In their annual

[58] The program provides for caps on the amount of the incremental program cost that the utilities may recover from customers. Thus far, program costs have been well below the allowed caps.
[59] http://www.ncuc.commerce.state.nc.us/reps/RegistrationSpreadsheet2008-2012.xls
[60] Small hydro power (less than 10 MW) does not need to be new.
[61] Thereafter, energy efficiency may be used to meet up to 40 percent of the standard.

reports, two utilities have indicated that they anticipate difficulty in meeting the swine waste set asides, but not otherwise.

Barrier - RECs need to be structured to emphasize in-state projects involving, new renewable energy plants

Mitigation Options – Restructure RPS/RPG

8.2.2 North Carolina Mountain Ridge Protection Act

As in many other states, local zoning and land use decisions have traditionally been the province of local governments in North Carolina. However, in response to public opposition to a high-rise condominium resort that was built on Sugar Top Mountain in Avery County, the North Carolina General Assembly partially withdrew the delegation of zoning authority to counties when it adopted the 1983 Mountain Ridge Protection Act (MRPA). While the major public opposition to the resort was based on arguments that the "modernistic" design of the resort was ugly; the legislature did not attempt to ban "ugly" structures, as such a provision would be difficult to enforce. Rather, the legislative findings for the MRPA also cited potential difficulties in providing sanitation and fire protection for these ten-story high rise condominiums and the potential infringement of water rights of those living at lower elevations. The MRPA exempts water, radio and television towers and any equipment for the transmission of electricity or communications or both.[62] It also exempts "structures of a relatively slender nature." In 1978, under U.S. DOE funding, what was then the largest windmill (2 MW) in the world had been installed at a "ridgeline" location (Howard Knob) at Appalachian State University[63] (**Figure 8-5**) – and the MPRA explicitly listed "windmills" as among the "structures of a relatively slender nature" that are exempt from the MPRA. It should be noted that the turbines in use today no longer have heavy truss towers of the Howard Knob wind mill as shown in **Figure 8.5**. These designs have been superseded by even more slender and less costly tubular towers.

Figure 8-5. Boone N.C. DOE/NASA 2 MW Experimental Windmill Built in 1979

Some have argued that the term "windmill" refers to something different than the type of structure at Howard Knob. However, at that time the legislature was developing the MRPA, "windmill" was a common term for what we now also refer to as windmills, wind turbines or wind power generating facilities. Moreover, the Boone, NC, windmill was frequently in the news when the MRPA was being considered and was consistently referred to as a windmill in the news accounts of the day.[64] In contrast, there is no evidence to suggest that any consideration was given by the NC legislature of a need to exempt farm-based windmills used to irrigate fields or provide water for livestock on high ridge tops. There is no specific reference to such structures in the statute, and for technical reasons, it is unlikely that mechanical farm

[62] Wind turbine towers are similar in size to the other exempt structures and entirely dissimilar in shape to the "Sugar Cube" (the nickname applied to the Sugar Top Resort). Moreover, a wind farm is used for the transmission of electricity and is not dissimilar in impact to a transmission line that will necessarily have a number of associated supporting structures.
[63] Appalachian State University in Boone, NC.
[64] http://www.time.com/time/magazine/article/0,9171,924182,00.html; http://tvnews.vanderbilt.edu/program.pl?ID=290721 http://www.carolinacorner.com/attractions/boone-becomes-windmill-city.htm

windmills would commonly be placed on high elevation ridge lines. A "turbine" is a rotary mechanical device that extracts energy from a fluid flow (a gas, steam or water) and turns it into useful mechanical work. Thus, a windmill is a turbine, irrespective of whether the mechanical work provided by the rotation of the windmill's blades is turning the shaft of a water pump or the shaft of a generator. Finally, given the specificity of the Sugar Top Resort issue, it is reasonable to assume that, if the Legislature had meant to exempt only single tower farm windmills, it could have found the specific language to do so.

However, in a 2002 letter to Tennessee officials, the North Carolina Attorney General interpreted the MPRA exemption as only applying to "the traditional, solitary farm windmill which has long been in use in rural communities." The 2002 letter did not cite any additional reasoning or authority for its conclusion. There is no administrative record to examine as the Attorney General's view was merely expressed in a letter and was not published as a formal interpretation. It is not clear what legal deference this statement is entitled to, and reportedly, the Attorney General's conclusion differed from that of the North Carolina Department of Justice.[65]

However, the NC State Utilities Commission has relied on this view to oppose at least one application for a proposed wind farm in North Carolina.[66] In 2009, a State Commission identified the 2002 letter of the Attorney General as a significant barrier to the development of wind power in the state, and a bill was introduced in the State Senate to clarify and correct the matter. The bill would have allowed local governments to opt out of the MRPA ban once local zoning and other regulation of wind farms had been adopted by those governments. However, as it proceeded through the legislative process the "pro-wind" bill was amended to override the preference of local governments on the issue and clarify that commercial-scale ridge line wind power was, indeed, banned as interpreted by the Attorney General. The amended bill passed the State Senate by a wide margin, but was not taken up by the NC House of Representatives.

As a consequence of the NC PUC's reliance on the informal conclusion of the Attorney General, much[67] of the wind resource of western North Carolina is excluded from commercial wind development and may remain so for the foreseeable future. A developer could challenge the 2002 letter from the Attorney General and the PUC's reliance on that letter in a court proceeding, but the developer would then risk prompting a reintroduction of the 2009 Senate Bill explicitly banning commercial wind farms in ridgeline areas. While a landowner whose property value is reduced by the inability to develop wind power might well adopt such a course of action at some point, it is reasonable to assume that commercial wind farm developers will simply look elsewhere for viable projects. However, some western counties that favor development of available wind resources have taken actions (discussed later) that may directly limit the impact of the MRPA or prompt judicial resolution of the issue.

8.2.3 Zoning Ordinances

The MRPA is an exception to North Carolina land use law that generally defers land use decisions to county and city officials. North Carolina has developed a model zoning ordinance that provides for reasonable setback, flicker, noise and other regulation of small (< 20 kW); medium (20-100 kW) and large (>100 kW) wind energy facilities. Ashe County, in Western North Carolina, has adopted zoning ordinances that incorporate the provisions of the MRPA for "protected areas" under that statute and impose a 199-foot height restriction for other areas in the county to bar construction of turbines that would need to be lighted under Federal Aviation Administration (FAA) regulations. In contrast,

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[65] The Tennessee Attorney General also reached the opposite conclusion when evaluating an identical Tennessee ridge line protection statute.
[66] *http://www.windaction.org/news/c88/?sort=title*
[67] There are some sites that may be outside of the protected areas of the MRPA, but it is not clear if any of those sites are suitable for commercial wind development.

neighboring Madison County has adopted an ordinance that treats commercial wind farms as conditional uses. Watauga County (which includes Boone, NC; the home of the original DOE wind turbine) also has determined that wind power is in the public interest, that "single wind power turbines" (of any size) are exempt from the MRPA and that large wind energy systems comprised of such "single wind power turbines" may be permitted by the County. It is unclear how, when or whether these conflicting interpretations of the MRPA will be resolved.

A number of coastal counties have adopted zoning ordinances that are generally patterned on the North Carolina Model Zoning regulation, although some counties provide for a more stringent 55 decibels (db) noise limitation rather than the 60 db more commonly found. Carteret County provides for a substantially more stringent setback requirement; six times the height of the tower plus rotor tip. At the maximum allowed height (550 feet) this requires a setback of more than one-half mile. Notwithstanding this limit, a developer has proposed to build 100 MW wind farm in Carteret County.

8.2.4 The North Carolina Utilities Commission

As in Virginia, the North Carolina Utilities Commission (NCUC) is constrained by law to approve those future generation resource options "that can be obtained at the least cost to ratepayers consistent with adequate reliable electric service and other legal obligation." At this time, the NCUC does not consider externalized costs, such as environmental or public health costs that may be associated with fossil fuel-fired generation or the potential for very high disposal costs associated with nuclear power. Accordingly, unless and until new wind power generation is lower in direct costs than new generation from these sources, there is a substantial risk that all or part of the cost of new generation will be disallowed in cost recovery – unless it is otherwise required by law. Thus, for the near term, the mandatory requirements of the North Carolina REPS serve as the de facto ceiling for new wind power generation owned or sponsored by North Carolina regulated utilities.

However, unlike the situation in Virginia, because most of the RECs used for compliance must be from new, in-state renewable sources, this limitation does not appear to be a significant barrier. Energy use forecasts for North Carolina call for energy supplied by the three IOUs to increase from 120,000 GWh per year to 140,000 GWh per year from 2012 to 2021; while North Carolina electricity from municipal generators is projected to increase from 35,000 GWh per year to 40,000 GWh per year. During this period the RPS increases from 4 percent to 12.5 percent (10 percent by 2018 for municipal generators).[68] Thus, approximately 7,500 GWh per year of electric generation must be from renewable generation or energy efficiency programs in 2021. Energy efficiency programs are likely to be the lowest cost option, and so are assumed to occur up to the maximum allowed under the program (25 percent in 2021). Adding biomass fuels to existing coal-fired plants is likely to be the next lowest cost option, but the amount of available fuel is likely to be constrained, as is the ability of coal-fired plants to use biomass. If one assumes that biomass and wind power are employed equally to meet the RPS, slightly more than 2,500 MW of new wind powered generation would be needed, 75 percent of which would need to be from in-state sources.[69] This figure is reasonably close to the current estimates of land-based wind power economically available in North Carolina – including western North Carolina resources and, while the RPS provides a cap on the amount of compliance costs that may be passed on to the utility's customers, the utility's obligation to comply is not limited by cost.

8.2.5 North Carolina Studies

[68] Electric cooperatives and municipal utilities may meet their entire obligation by energy efficiency and demand side management and may use large hydropower to meet up to 30 percent of their obligation.
[69] Qualifying out of state sources of RECs are limited to small hydropower and new renewables.

As in Virginia, the North Carolina legislature commissioned a study to examine the potential for development of wind power in state-owned waters in Pamlico and Albemarle Sounds [36]. However, substantially more resources were applied to this effort, conducted by the University of North Carolina, than were employed in the Virginia review of the issue and the scope of the study was expanded to include offshore wind power development in Federal waters. The UNC Coastal Wind Study involved input from 24 named contributors and generated a 368 page final report, which included detailed geologic, wind resource and constraint mapping and identification of potential areas for development (**Figure 8-6**). As in the Virginia study, areas with competing military uses were simply eliminated from consideration rather than being identified as areas warranting further investigation. However, in contrast to the Virginia review, the UNC Coastal Wind Study recommended that the remaining areas in Pamlico Sound be utilized for a wind power demonstration project and considered for commercial scale wind power development. The UNC Coastal Wind Study identified only modest cost savings associated with development of wind power in the Pamlico Sound when compared to offshore wind power, a conclusion not supported by this review.

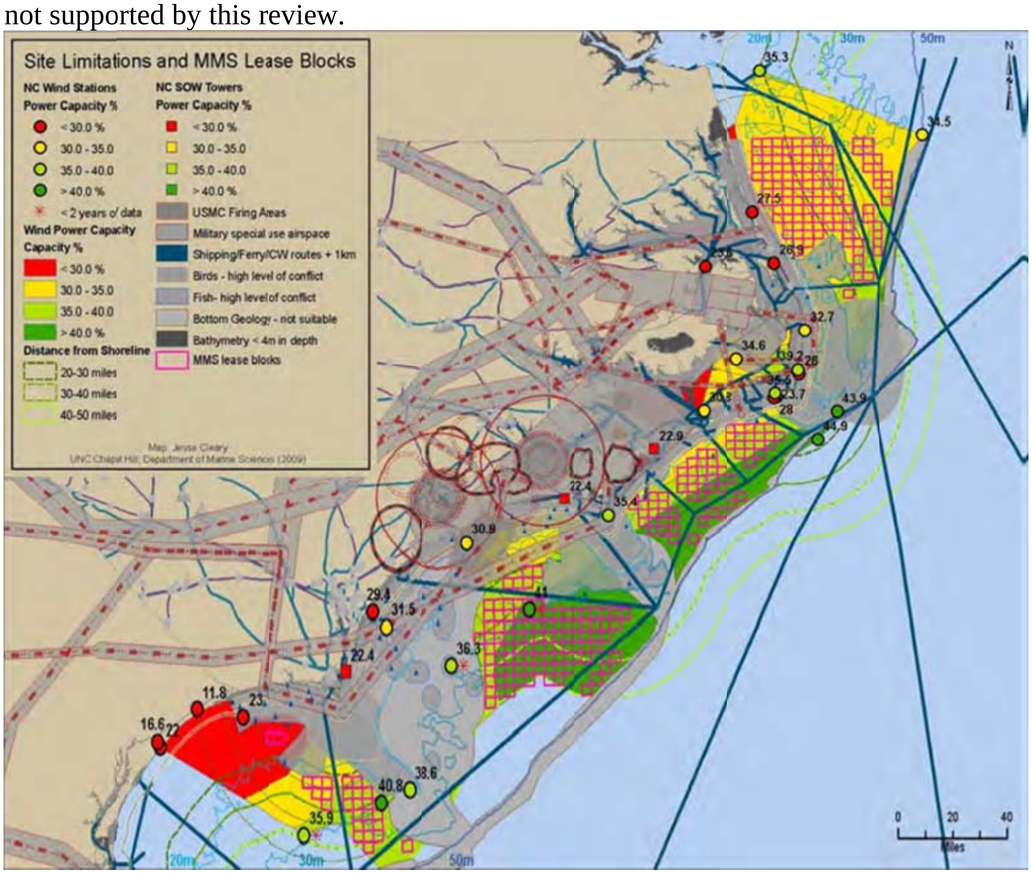

Figure 8-6. UNC Review of Coastal and Offshore Wind Power Development Potential

8.2.6 Other Potential Barriers

It is not uncommon for those who oppose a commercial or industrial enterprise for other reasons to seek to delay or prevent the project by filing a lawsuit alleging a violation of federal or state environmental statutes, and indeed, there have been a number of proposed wind farms in the United States that have been delayed by lawsuits alleging such violations. These lawsuits often allege violations of the Endangered Species Act, failure to conduct environmental assessments or violation of noise ordinances. There have been a number of occasions where a court has determined that the plaintiffs were correct in their assertions. However, the remedy commonly ordered by the courts is to obtain the necessary permit (often an Incidental Take Permit under the Endangered Species Act), implement measures to mitigate the adverse impact, or conduct a more thorough assessment of impacts – rather than a prohibition on the development of the resource. Developers occasionally complain that the prospect of such lawsuits is a barrier to development of wind power. However, closely examined, those complaints are rarely premised on the content of the underlying environmental statute or permit obligation. Rather, the developers objection is to the use of frivolous lawsuits to interpose environmental objections as a tactic to achieve other goals and on what they claim are unnecessary delays in processing permits.

There is little one can do to constrain the litigious tendency of our culture or the creativity of the bar. This issue is far broader than environmental law and beyond the scope of this review. The risk of a frivolous lawsuit and associated permitting delays can be minimized by proper up front attention to environmental requirements and a candid assessment of the environmental suitability of a proposed site early in the process - before significant costs are invested in a particular location. As with any other industrial enterprise, compliance with applicable environmental laws should be considered a normal part of the business, in the same manner as compliance with the tax code. Early consultation with permitting authorities and local environmental organizations can go a long way towards minimizing the extent to which compliance with environmental requirements is a true barrier. Indeed, wind power developers should recognize that much of societies' willingness to pay a premium price for renewable energy is rooted in concern over environmental interests.

Several wind power projects are under development in coastal North Carolina, and in at least two of these proposed projects, issues related to protection of birds - bald eagles[70] and migrating snowbirds[71]- from windmill strikes have been raised. This should not be an unexpected development in a coastal area and reports thus far indicate that the issues are being addressed. Neither of these reports suggests that environmental obligations pose a significant barrier to the development of wind power in North Carolina.

8.3 Maryland

Maryland possesses developable wind resources in its western and north central ridgeline areas and potentially in coastal areas on the Eastern Shore of the state near the Chesapeake Bay and Atlantic Ocean. As discussed elsewhere in this report, there also is a potentially developable resource in state waters of the Chesapeake Bay. Two wind farms are currently operating in western Maryland, and a number of others are being pursued by developers. The State of Maryland is providing significant technical and financial support for development of wind power although much of that effort is focused on offshore wind development. Maryland is a participant in the Regional Greenhouse Gas Initiative (RGGI), a ten state cap-and-trade program meant to reduce CO_2 emissions from electric generating units (EGUs). RGGI is designed to reduce CO_2 emissions from the electricity generation in the participating states by approximately 10 percent by 2019.

Maryland has established an RPS that requires that a portion of the electricity sold to residential and commercial customers be from renewable sources. The portion that must be from renewable sources increases annually until it reaches 20 percent by 2022. The program includes a separate solar RPS that increases over time to reach 2 percent by 2020 with balance allocated to wind and other Tier I technologies. State law also provides a personal and corporate tax credit of $0.0085 per kWh, up to $2.5 million over a five-year period and a 100 percent exemption for wind power equipment and generation from real property, personal property and sales taxes. Maryland also has a PACE financing program and a clean energy grant program of up to 50 percent of the cost of installing residential-scale wind power systems. Maryland has promulgated reasonable interconnection standards and mandates net metering of power for individual systems up to 2 MW, with a 1,500 MW aggregate capacity limit, but has not adopted model zoning or noise ordinances for wind power systems.

[70] http://www.newsobserver.com/2012/05/22/v-print/2083181/wind-farm-could-harm-the-states.html
[71] http://www.newsobserver.com/2011/12/03/1686603/environmental-groups-fight-wind.html

8.3.1 Maryland RPS Design

Maryland's RPS provides for three separate categories of RECs – Tier I, Tier I Solar and Tier II. Tier I RECs include electricity generated from solar, wind, qualifying biomass, landfill gas (methane), geothermal, small hydropower, and poultry litter and waste-to-energy electric generating facilities. The Tier I RPS for 2012 is 6.4 percent of electricity sold at retail in the state and rises to 20 percent by 2022.[72] The Tier II REC obligation is 2.5 percent in 2012 and remains at that level until the obligation expires in 2018. Tier II sources are limited to large hydroelectric plants of greater than 30 MW, but the Tier II obligation may also be satisfied by Tier I RECs. Tier I Solar RECs may be generated from photovoltaic cells of any vintage and residential solar hot water heating systems commissioned in fiscal 2012 or later. Maryland accepts RECs generated by sources located in the PJM service area, which extends as far west as parts of Michigan. Maryland provides for an Alternate Compliance Penalty (ACP) for sources that fail to acquire the required RECs in a compliance period. ACP receipts are used to fund renewable projects in the state. The ACP for Tier I RECs is $40 per MWh ($0.04 per kWh). This amount is larger than the cost differential for wind and biomass generated electricity and should provide a reasonable incentive for compliance.[73] For Tier I Solar RECs the ACP is currently $400 per MWh ($0.40 per kWh); declining to $350 per MWh in 2015. These levels also should be sufficient during this time frame. However, commencing in 2017 the program provides for a significant increases in the Solar REC obligation, increasing annually thereafter from 0.55 percent to 0.9, 1.2, 1.5, 1.85, and 2.0 percent. During this time, the ACP declines from $350 to $200, $150, $100 and finally (post 2022) to $50 per MWh. Installed prices for new solar generation have been falling in recent years. However, there is a reasonable probability that, the ACP will no longer serve as a credible incentive for new solar installations at some point. Given the multi-year planning and permitting horizon for new commercial-scale solar installations, Maryland should revisit the 2017 ACP before the end of 2015 to determine if the level that has been set will serve its intended purpose.

The ACP for Tier II RECs is $15 per MWh ($0.015 per kWh). At this level, the Tier II REC price will not likely serve as a significant incentive for the construction of new large hydropower generation. However, it is substantially larger than current REC prices from existing large hydropower sources and should be sufficient to provide an incentive for utilities to acquire the necessary Tier II RECs for the period until the category is phased out in 2018. The ACP for small industrial process load (IPL) customers is set at $4 per MWh ($0.004 per kWh); declining to $2 per MWh ($0.002 per kWh) for both solar and non-solar Tier I REC obligations. These levels are clearly insufficient to ensure compliance, especially with solar REC obligations, and essentially amount to a legislative determination to exempt those IPL sales from the RPS.

Maryland does not establish the preference for "anyway" credits - RECs generated by pre-existing sources – found in the Virginia program, but the Maryland RPS does not require that RECs be additional. Instead, Maryland accepts RECs generated by existing sources that have no need of any incentive. As a result, the Maryland RPS is met at very low cost. The average cost of compliance with the Maryland RPS was $2.13 per MWh ($0.00213 per kWh); but at an even lower cost effectiveness. The Maryland Public Service Commission recently published its *Renewable Energy Portfolio Standard Report of 2012,* [37] which included an identification of the sources of the RECs that were used for compliance in 2010. That list includes only a relatively small percentage of "new" renewable electricity where the Maryland RPS can be said to have influenced the decision to employ the renewable resource. A review of the five sources that generated more than 100,000 RECs in Maryland highlights the issue.[74] Two of the sources

[72] Electricity sold to large industrial process load customers (> 300 million Kwh/yr) is exempt. This is a relatively narrow exemption. There were approximately 65.6 million MWh of total retail electricity sales in Maryland for 2010: 64.1 million MWh were subject to RPS compliance, and 1.5 million MWh were exempt.
[73] While these payments do not increase with inflation, the price differential between fossil-fueled electricity and renewables can be expected to be reduced over time.
[74] These five sources provided 47 percent of the RECs needed for Tier I compliance in 2010.

were hydropower plants. The Blewett hydropower plant in North Carolina commenced operations in 1912; while the Trenton, NY hydropower plant commenced operations in 1901 and was refurbished in 1984.

With no fuel costs and with the major capital costs amortized long ago, these hydropower plants are likely to have extremely low variable operating costs. Existing hydropower plants are routinely among the first sources to be dispatched and have no need for the subsidy provided by the RPS.

Pulp and paper mills generate substantial quantities of the residues from the pulping process. These residues, commonly known as black liquor, are highly toxic to aquatic life and so the discharge of this waste material to public waters is highly restricted under Federal and state environmental laws. However, black liquor contains more than half of the energy content of the wood fed into the digester of a kraft pulp mill. Accordingly, since 1935 pulp and paper mills have been combusting black liquor[75]to generate steam for industrial processes and electricity, and to recover the chemicals employed in the pulping process. Today, nearly all black liquor generated in pulp and paper mills is concentrated and burned for energy recovery. Since black liquor is derived from woody materials it is technically considered a “renewable” energy source. Because substantial quantities of this waste are generated at pulp and paper mills across the country it is not surprising that the other three very large sources of Maryland’s RECs are pre-existing pulp and paper mills. These mills, two in Virginia and one in Pennsylvania, date back to the 1930s and 1940s and would be burning these mill wastes for energy as they have for years, whether or not Maryland provided an additional revenue stream from its RPS.

The issue we raise here is not whether hydropower or black liquor-fired generation should be considered “renewable” energy, but whether RPS programs should permit the use of “anyway” credits. Allowing pre-existing sources, such as 100-year old hydropower facilities or 50-year old paper mills, to generate RECs is a waste of the rate payers’ money, since, as the Maryland Report shows, almost all of the money goes to provide a windfall revenue stream that does not incentivize new investment. Moreover, this practice actually undermines the value of the program. Since these pre-existing sources generate RECs at no cost, they serve to drive the market price of RECs down to the point (currently $0.002 per kWh) where the REC market is of no use in stimulating new renewable energy development.

It has been argued that this problem may be self-correcting, since at some point all of the pre-existing renewable generation will be absorbed into the system and new renewable generation will be needed. However, there is no way to know whether this saturation will occur at levels below a state’s RPS maximum, and if so, when the RPS will begin to serve a positive purpose. Since not all states have an RPS and not all states allow pre-existing generation to be used, the available pool of “anyway credits” is unknown and may be a large percentage of the target for those states that have an RPS and allow pre-existing renewable sources to participate. If it chooses to address this problem, Maryland could revise its program to exclude pre-existing sources from generating saleable RECs and thereby improve the cost-effectiveness of its program, while continuing to count the pre-existing renewable energy in Maryland in determining whether it had met its goal for renewable generation. Maryland could also include any new generation from existing sources that was “additional” to that occurring at the start of its program.

8.3.2 State Approval Process

Maryland’s electricity market is deregulated, and so there is no requirement that the PSC approve the terms of a PPA in Maryland. However, State law specifies that a wind-generating facility greater than 70 MW must obtain a Certificate of Public Convenience and Necessity (CPCN) from the PSC. The issuance

[75] http://www.babcock.com/about/history.html

of a CPCN is a formal adjudicatory process that includes public participation and addresses all relevant issues, including environmental and noise related issues. The Maryland PSC has issued a CPCN for one wind farm and has not denied any applications. However, subsequent to the amendment to the Maryland statute exempting wind farms of less than 70 MW from the CPCN formal adjudicative process, two wind farms received PSC approval and have been constructed in Maryland. It can be reasonably anticipated that will be the path commonly pursued by Maryland wind farm developers.

8.3.3 Zoning Ordinances

Many of Maryland's counties have adopted wind power zoning ordinances, most of which only apply to residential-scale system. Allegany and Garrett Counties are the two westernmost counties in the state and have most of Maryland's ridgeline wind resource. For this reason, zoning constraints in those counties will have a significant impact on the likely development of mountain wind resources in Maryland. After a wind farm was proposed to be located in Allegany County, county authorities adopted a zoning ordinance that required a minimum setback of 2,000 feet from the nearest residence and 5,000 feet from schools and properties on the National Registry of Historic Places. The developer has received a CPCN from the PSC, but has determined that the project was not viable under the County's restrictions and has suspended the project. A majority of the elected commission officials have since been replaced and the developer is pursuing a modification of the restriction. Garrett County does not currently have zoning ordinances applicable to unincorporated areas. In order to install wind turbines, developers need only grid authorization and a building permit. Garrett County is home to the Backbone Mountain wind farm and three additional wind farms are proposed in the county. Garrett County officials are currently[76] soliciting comment on a proposed zoning ordinance that would establish a 5:1 setback requirement (2,000 feet for a 400 foot high turbine) for new wind farms in the County. It is not clear whether, given the layout of the proposed projects, such a requirement would preclude development, but this is likely to be the result if the ordinance is adopted as proposed.

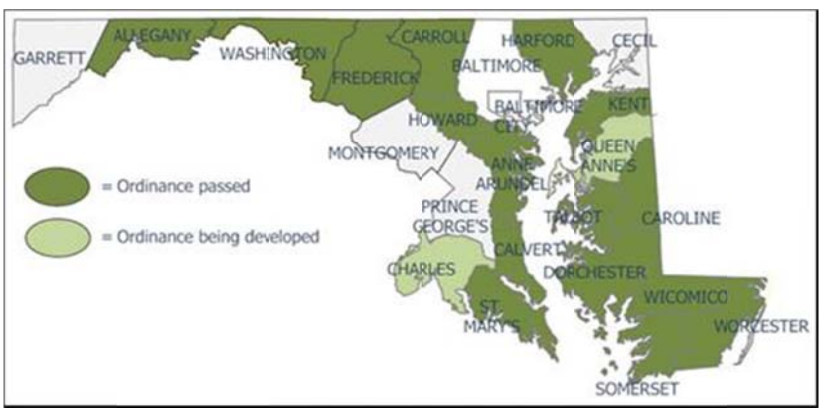

Figure 8-7. Maryland Energy Administration: Counties with Wind Ordinances

There may be greater local acceptance for commercial scale wind power in Maryland's coastal communities. Somerset County, the southernmost county on Maryland's eastern shore has adopted a zoning ordinance that specifies a 750 foot setback[77] and the City of Crisfield in Somerset County, with a $4.1million grant from the Maryland Department of Energy, is preparing to construct a 300 foot tall, 750 kW wind turbine.

[76] Comments are due on June 15, 2012
[77] The county is considering a proposal to increase the requirement to 1,000 feet.

8.4 Delaware

Delaware has a long coastline along the Atlantic Ocean and the Delaware Bay and relatively undeveloped areas within a reasonable distance of the coast and in the Delaware Bay itself. While the offshore wind resource has been the subject of significant discussion, there has been relatively limited interest to date in Delaware's modest, but still potentially valuable coastal resources. However, his may change with the development of wind turbines designed to operate in lower wind ranges.

Delaware has provided significant political, technical and economic support for the development of wind resources in Federal waters off the Delaware coast. The University of Delaware is one of the nation's leading wind power research institutions and is deeply involved in efforts to advance offshore wind power generation. Based on specific direction from the Delaware legislature and with the support of the Governor, the Delaware PSC approved the first PPA for offshore wind power substantially greater than current prices.[78] Delaware is also a member of RGGI and has adopted a hybridized RPS that should be effective in encouraging the development of new renewables.

Delaware's utilities offer small wind rebate programs of $0.30 to $1.25 per watt of installed capacity for generators larger than 500 watts, up to maximum incentive of $2,500 per installation. The state mandates net metering with excess generation compensated at the retail rate for the generator, who retains ownership of the associated REC. Individual system limits are set at 25 kW for residential customers, 100kW for farm customers on residential rates and 2 MW for commercial or industrial customers. The authorized aggregate capacity limit for this program is five percent of peak demand. The state has adopted standard interconnection requirements and has promulgated mandatory setback and noise standards for residential wind turbines, but has not addressed large scale installations. Delaware does not offer tax incentives for wind power generation or equipment purchases.

8.4.1 State Approval Process

Delaware's electricity market is regulated and therefore contracts for the purchase of renewable energy are subject to review by the Delaware Public Service Commission (PSC). The Delaware PSC did approve a PPA between NRG Bluewater and Delmarva Power for offshore wind power at prices substantially higher than for fossil fuel-fired generation. However, this decision was effectively made by the legislature. The PSC has approved purchases of wind power by Delmarva Power from facilities in other states (e.g., Pennsylvania, Maryland) as needed to meet Delaware RPS requirements. Delaware has promulgated reasonable siting and noise requirements for residential wind power units.[79] The Delaware statute specifically precludes local governments from adopting more restrictive requirements. Requirements for larger systems have not yet been developed. When the University of Delaware sought to install a single large (2 MW) turbine at its campus in Lewes, city officials treated the application as one for the most analogous structure in the city's code – an electric transmission line support structure – for which no height restriction was authorized.

8.4.2 Delaware RPS Design

Delaware's RPS is complex and has been modified a number of times since its initial adoption in 2005. The design of the RPS recognizes the anyway credit issue and provides a complicated resolution of competing interests.

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[78] Development of this project is currently suspended because of the pending expiration of the Section 45 Production Tax Credits (PTC) and the DOE Renewable Energy and Energy Efficiency Loan Guarantee Program (LGP).

[79] Under the Delaware statute the minimum setback is 1.0 times the height of the turbine (base to tip of a blade) from property lines and the noise limit is no more than 5 decibels above average existing noise level up to a maximum of 60 decibels at any location along the property line.

At this time all IOUs, retail electric suppliers, municipal utilities and rural electric cooperatives must comply with the RPS or, for the latter suppliers, a comparable RPS commencing in 2013.[80]
Sales to industrial customers with a peak load of more than 1,500 kW are exempt. The RPS establishes an escalating scale similar to other states in the region. The current requirement is 8.5 percent and the 2020 requirement is 20 percent. Recent revisions extend the program out to 2025-2026[81] and increase the obligation to 25 percent in 2025. Within those percentages are minimum "carve outs" for solar PV that currently are set at 0.40 percent and rise over time to 3.50 percent in 2025.[82]

The statute provides that, commencing with the 2014 schedule; the PSC may accelerate or decelerate the schedule given certain market conditions. The statute authorizes a discretionary freeze in the compliance schedule if program costs exceed three percent of retail electricity costs in a year and a mandatory freeze in the schedule if program costs result in an increase of four percent or more in the average customer's monthly bill. The program includes compliance multipliers for in-state wind turbines installed before 2013, for in-state installations where 50 percent of the equipment is manufactured in Delaware and for in-state installations with a 75 percent in-state work force. While RECs can generally be supplied by renewable energy generators within PJM and adjoining service areas, energy sold or displaced by a customer-sited wind generator can also generate RECs, but only if the system is sited in Delaware.

While ACPs serve little purpose in several state programs, they are a key component of the Delaware RPS. The Delaware ACP is intended to strongly incentivize compliance and to serve as an indicator that the schedule has become too stringent. Suppliers who fail to secure sufficient RECs for compliance must initially pay $25 per MWh of shortfall into Delaware's renewable energy fund. After the first year of use, the ACP for that supplier increases to $50 per MWh and after the second year it increases to $80 per MWh ($0.08 per kWh). However, if, notwithstanding these high ACPs, there is widespread (greater than 30 percent) use of ACPs for compliance for a period of three years and a showing of adequate planning by retail electric suppliers, the PSC may relax the RPS schedule. Additionally concerns are addressed by the requirement that no more than one percent of each year's retail sales may be met by resources placed in service before January 1, 1998. For 2012, this means that no more than 12 percent of the RECs needed for compliance can be generated by sources that were placed in service prior to 1998; for 2020 no more than 5 percent of RECs may be generated by such older sources.

8.5 District of Columbia

The District of Columbia does not have sufficient wind resources or available land to support development of commercial scale wind power and the area is too densely populated for significant residential wind power development. Accordingly, most of the District's renewable energy programs, such as its PACE program, PSC incentives, and business energy rebate programs are limited to solar energy. The District's interconnection standards theoretically apply to wind power installations. The D.C. program includes electric and natural gas bill surcharges that fund a sustainable energy trust fund. This fund, intended to raise approximately $20 million per year commencing in 2012, focuses on energy-saving measures in low income homes and commercial buildings in the District rather than investing in wind projects in remote locations.

The District does enforce a RPS that is similar in many respects to the "standard" RPS design. The D.C. RPS has separate schedules for Tier I, Tier II and solar RPS. As in Virginia and other states, the Tier I and solar REC schedules escalate over time. The Tier I requirement is 5.0 percent for 2012 and increases annually until it reaches 20 percent in 2020. Tier II includes municipal solid waste and large hydropower

[80] Early versions of the RPS had allowed these suppliers to opt out of the program.
[81] The requirements apply on a mid-year (June 30) basis rather than on a calendar year basis.
[82] These requirements are part of, not in addition to, the basic requirement.

sources. The Tier II REC obligation is currently 2.5 percent of sales and is reduced each year until the category is phased out by 2020. A solar REC requirement, currently 0.50 percent of sales, increases annually until it reaches 2.50 percent in 2023. The solar REC carve out is part of the overall RPS obligation of 20 percent renewable and not in addition to that requirement. The ACP provided by the D.C. RPS for the Tier I obligation is $50 per MWh ($0.05 per kWh), a level that should be sufficient to motivate compliance with the standard. For Tier II obligations the ACP is $10 per MWh, a level that should encourage compliance with the standard but will not serve to incentivize new large hydropower generation. As in the Maryland RPS, the solar ACP is initially high ($0.50 per kWh), but then declines to levels ($0.05 per kWh) that may not be sufficient to support new solar generation.

The D.C. RPS, like some others discussed herein, does not attempt to address the issue of anyway credits. The program provides no limitation on the age of the sources of the renewables and incorporates a broad definition of renewables that include source categories discussed earlier. Accordingly, while program costs are low, most of the payments by District ratepayers under the D.C. RPS program are simply providing additional revenues to existing sources rather than providing an incentive to the development of new renewables.

9.0 Mid-Atlantic Wind Resource

The complexity of the Mid-Atlantic shoreline and local features such as the Chesapeake and Delaware Bays, Pamlico sound and other small inlets results in small scale local wind circulations driven by land-sea thermal contrasts and abrupt changes in surface roughness. The Appalachian mountains to the west are oriented nearly perpendicular to the prevailing cool season westerly wind direction, however the warm season wind direction is more southerly and local topographic features such as valleys likely play a more prominent warm season role.

The Mid-Atlantic geographic variability introduces complex seasonal and diurnal variations in the wind resource across the region. A warm season phenomenon known as the nocturnal low level jet (LLJ) is due to surface cooling of the elevated western region after sunset [38]. Superimposed on these regional and local wind features are the large scale winds due to the prevailing synoptic weather systems and climatic features such as the Bermuda High.

The wind resource analysis here is based partly on the model results from the Eastern Wind Integration Study (EWITS) [1] and partly on wind observations from tall towers, rawinsondes and buoys. There are few long-term anemometer measurements at hub height and little information about the spatial and temporal variations in atmospheric stability and their impact on the vertical wind profile. There is little, if any, data on the vertical wind profile at fixed offshore locations. Several recent estimates of the offshore wind resource [39] [40] have been made by extrapolating buoy data to hub height using a log-law relation. This may be valid under neutrally stable conditions that are common in the marine boundary layer, but it could be a poor approximation in the bays and sounds and likely underestimates the wind resource in the stable nocturnal boundary layer over both land and sea.

The occurrence of very high wind velocities associated with weather events such as nor'easters or tropical cyclones in the Mid-Atlantic are also important considerations for wind development, but it is beyond the scope of this report to estimate risks for offshore wind turbines associated with these events. A recent study [41] of near-coastal east coast tropical cyclones was based on the Hurricane Database (HURDAT) maintained by the National Hurricane Center covering the years 1899-2004. The study found winds in excess of 115 kt (59 m/s) in only 4 out of 106 years, and using an extreme value analysis they estimated that the East Coast can expect 103 kt hurricane winds once every 10 years. Wind turbines installed offshore must survive worst case events so it is prudent to design them to survive 100-year storm characteristics shown previously in **Table 4.1**.

In this report we distinguish 4 main geographic regions: 1) the western, elevated region; 2) the coastal plain; 3) shallow bays and sound and 4) offshore ocean. There is a lack of wind measurements for the region as a whole, thus we focus on the shallow bays and sounds where tall tower data is available. In addition, emphasis in Mid-Atlantic wind has thus far been on ridgeline and offshore regions, while inland shallow bays and sounds and coastal regions are largely unexplored as a potential wind resource. The extent to which the lower capital costs are offset by weaker winds is investigated elsewhere in this report. A summary of the wind resource assessment and locations of wind measurements used is given in **Table 9-1**.

9.1 Eastern Wind Integration Study (EWITS)

This section presents an overview of the Mid-Atlantic wind resource using the recent NREL Eastern Wind Integration Study (EWITS) [1] for the three-year period 2004-2006. The study used a data assimilation system that combines a high resolution mesoscale model with wind measurements to assess the wind resource at selected onshore and coastal locations and several thousand offshore locations. The onshore sites chosen for detailed analysis in that study were those that were free from conflict with other interests (navigation, military, etc.), and in this sense EWITS gives a realistic evaluation of the available wind resource. The study provides a baseline estimate of the wind resource in the Mid-Atlantic western highlands, along the coast, and offshore. EWITS did not evaluate the wind resource in the Mid-Atlantic coastal plain, nor in other possible high resource locations along the coast and in the bays and sounds.

Table 9-1. Summary of the Wind Resource Assessment and Locations of Wind Measurements

Mid-Atlantic Winds										
Measured Data	**Dates**	**Height (m)[1]**	**DJF**		**MAM**		**JJA**		**SON**	
			On-Peak[2]	Off-Peak[2]	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Aberdeen[3]	Jan08-Jun10	50m	D4.9[4]	-	D4.7	-	D3.8	-	D5.3	-
		100m	D5.8	-	D5.7	-	D4.7	-	D6.2	-
		150m	D6.5	-	D6.6	-	D5.3	-	D6.8	-
Crisfield	Oct08-Oct09	76m	D8.2	N8.6	D7.4	N8.1	D5.9	N6.1	D7.2	N7.1
Bay Application Scaled (alpha = 0.08)[5]	Extrapolated	100m	D8.3	N8.7	D7.5	N8.6	D6.1	D6.2	D7.2	N7.3
Eastville	Jun06-May08	49m	D5.5	N5.8	D5.8	N5.6	D3.9	N3.8	D4.5	N4.6
		75m	D6.0	N6.5	D6.2	N6.3	D4.3	N4.3	D5.1	N5.3
		110m	D7.2	N8.0	D7.3	N7.7	D4.8	N5.2	D5.9	N6.5
Newport News	Aug06-Dec07	51m	D6.1	N6.4	D6.5	N5.9	D5.5	N4.8	D5.5	N5.3
		85m	D6.7	N7.2	D6.9	N6.6	D5.6	N5.2	D5.9	N5.9
		97m	D6.9	N7.6	D7.0	N6.9	D5.1	N5.0	D5.3	N5.5
Wallops	Sep09-Feb10	46m	D7.3	N7.3	-	-	-	-	D6.7	N6.4
		76m	D9.1	N9.1	-	-	-	-	D8.3	N6.4
		91m	D9.8	N9.8	-	-	-	-	D9.0	N8.8
Coastal Plain Applicatior	Interpolated	100m	D7.1	N7.8	D7.2	N7.6	D4.7	N5.1	D5.8	N6.4
Chesapeake Light	1985-2010	43m	D8.1	N8.5	D7.6	N7.9	D5.8	N6.0	D6.9	N7.3
Ocean Application Scaled (alpha = 0.08)[5]		100m	D8.6	N9.1	D8.1	N8.5	D6.2	N6.4	D7.4	N7.8
Ridgeline	Dec09-Nov10	80m	D8.7	N8.8	D6.9	N7.0	D5.6	N5.9	D7.1	N7.2
Ridgeline Application Scaled (alpha = 0.25)[6]		100m	D9.2	N9.3	D7.3	N7.4	D5.9	N6.2	D7.5	N7.6
Model Data EWITS										
Ridge	2004-2006	100m	D9.4	N9.4	D7.5	N7.7	D5.6	N6.2	D6.9	N7.6
Coastal			D7.4	N8.0	D6.6	N7.5	D5.1	N6.5	D6.0	N7.0
Ocean			D9.9	N9.9	D9.6	N9.9	D7.6	N8.1	D8.3	N8.4

Notes:
1. Height Above Ground (meters)
2. PJM - Day On-Peak = 0700 - 2300; Night Off-Peak 2301-0659
3. Aberdeen data collect from sondes between 6-7 am EST
4. Wind Shear: $U_2 = U_1 * (z_2 / z_1)^{Alpha}$
5. Scaled per ASME with Alpha = 0.04 to 0.08 over open sea with light - moderate Class 3 winds
6. Alpha = 0.25; Hilly, Forested Terrain [1]

References:

[1] Giovanni Gualtier and Sauro Secci, "Wind Shear Coefficients, roughness length and energy yields over coastal locations in Southern Italy," Renewable Energy, vol. 36, pp. 1081-1094, 2011.

EWITS wind resource estimates were provided only at 80 and 100m AGL (above ground level) heights.

Figure 9-1 shows the EWITS locations, the location symbols are colored according to the mean wind at 100m for the years 2004-2006. Also shown in the figure is a subset of EWITS locations, numbered 1-25, that are representative of the range of geographic conditions in the mountains, along the coast/bays/sounds, and offshore that have been selected for further detailed study in this report. The

EWITS offshore wind resource evaluation indicates wind speeds of 8-9m/s, with capacity factors in the range 0.40-0.45, for the offshore locations.

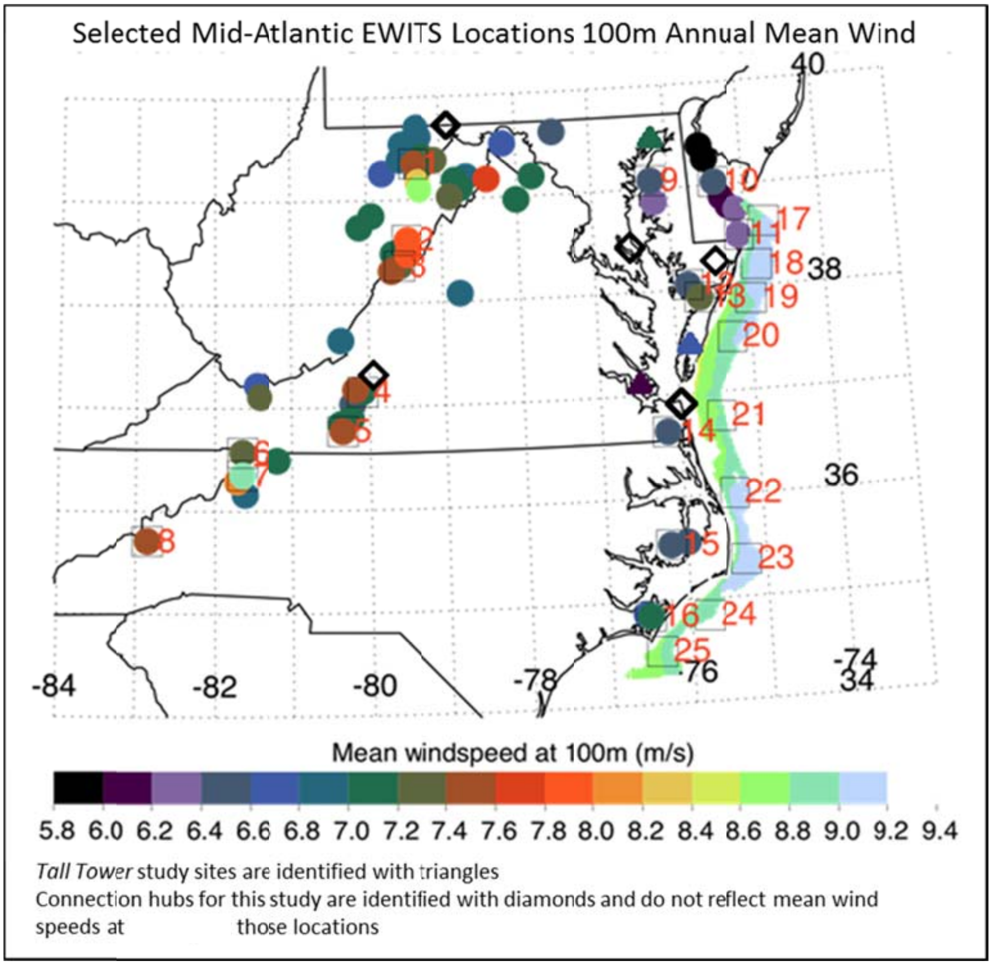

Figure 9-1. Measurement sites for selected PJM nodes.
The numbered sites are a subset chosen to represent the range of conditions along the Appalachians, coastline and offshore. Mountain: 1-8, Coast: 9-16 Offshore: 17-25. Sites are colored according to 100m annual mean wind speed from the EWITS study. Additional offshore measurements are not shown individually. There are no locations in the Delaware, Chesapeake Bays and the Sounds in North Carolina.

Figure 9-2 summarizes the seasonal and diurnal variability in the wind speed at 100 m for the 3 years combined, and for the separate mountain, coastal and offshore subsets defined in Figure 1. All times shown are local time (EST). The area between wind contours, as a fraction of the total area of the plot, is equal to the fraction of time that the wind has a value in the range bounded by the contours. Wind speeds > about 7 m/s for example occur about 1/3 of the time for the coastal sites. The lowest wind speeds occur during the summer in the early to mid-morning in all regions but at slightly different times, and increase in late afternoon. For the mountain sites, cool season (DJFMA) winds decrease in the afternoon and pick up after sunset. Offshore winds > 9 m/s occurs about half the time. Overall, the diurnal variations are on the order of 1-2 m/s. The results from the EWITS study indicate annual mean wind speeds at 100m of about 6-7 m/s in the coastal and bay/sound regions (class 3), 7-8 m/s (class 4-5) in the elevated region to the west and 8.5-9 m/s (class 6-7) offshore (beyond 3 nm).

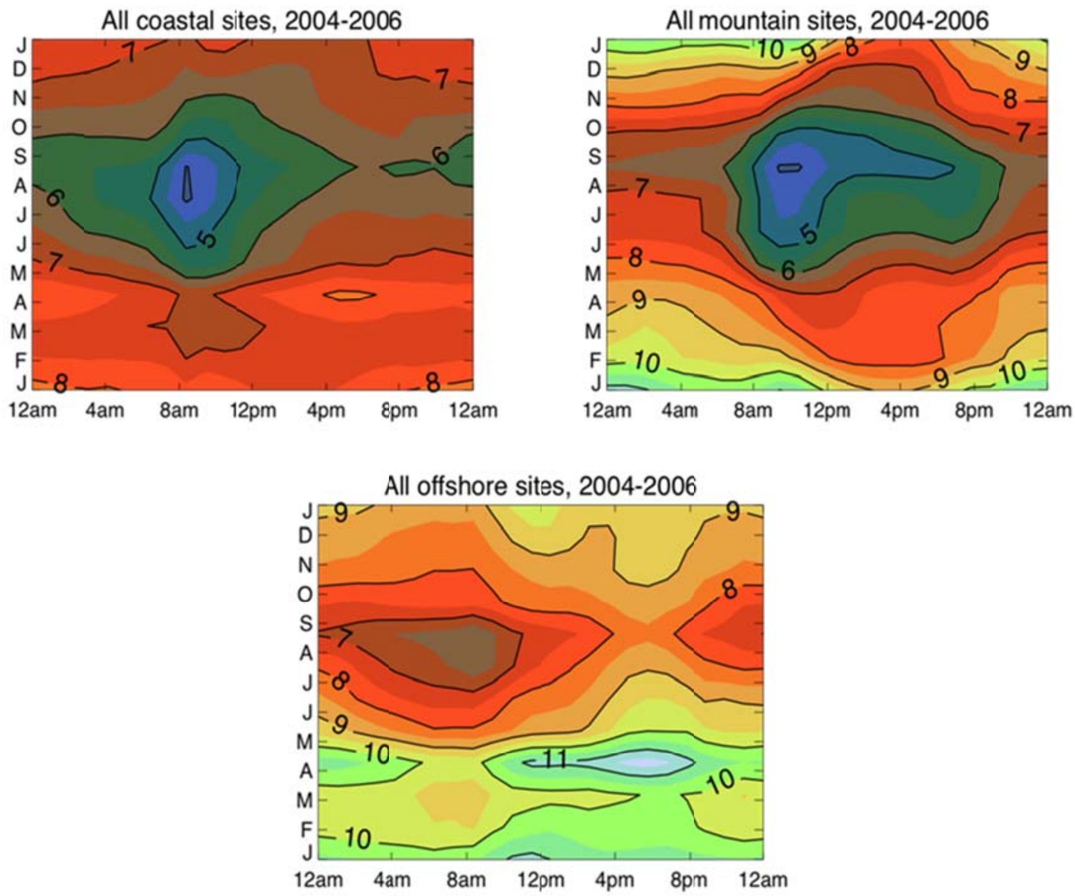

Figure 9-2. Seasonal and Diurnal Characteristics of the 100m Wind from the EWITS.
Study for 2004-2006. All years and all numbered locations for each of the geographic subsets defined in Figure 1 are combined. Contours are wind speed in m/s, colored contour spacing is every 0.5 m/s.

A detailed view of the seasonal and diurnal variability in the wind power density (WPD) for the year 2004 is shown in **Figure 9-3**. This shows the variability from site to site within each geographical subset (mountain, coast, offshore) and the variability across the subsets. ("Bays/sounds" in the figure legend = "coastal"). The other years are similar. Each plot is the mean WPD at each site for each hour of day, averaged over each month. The thick black line is the mean WPD (total WPD per site), and shows the reduction in intermittency of the WPD for the region as a whole. The diurnal variability in the available WPD varies substantially across these 25 sites, but is clearly reduced when the total power is considered. The midday minimum survives the averaging because it is a broad regional characteristic. These results indicate substantial variations in the hourly WPD, which varies also with location, even when averaged over a month.

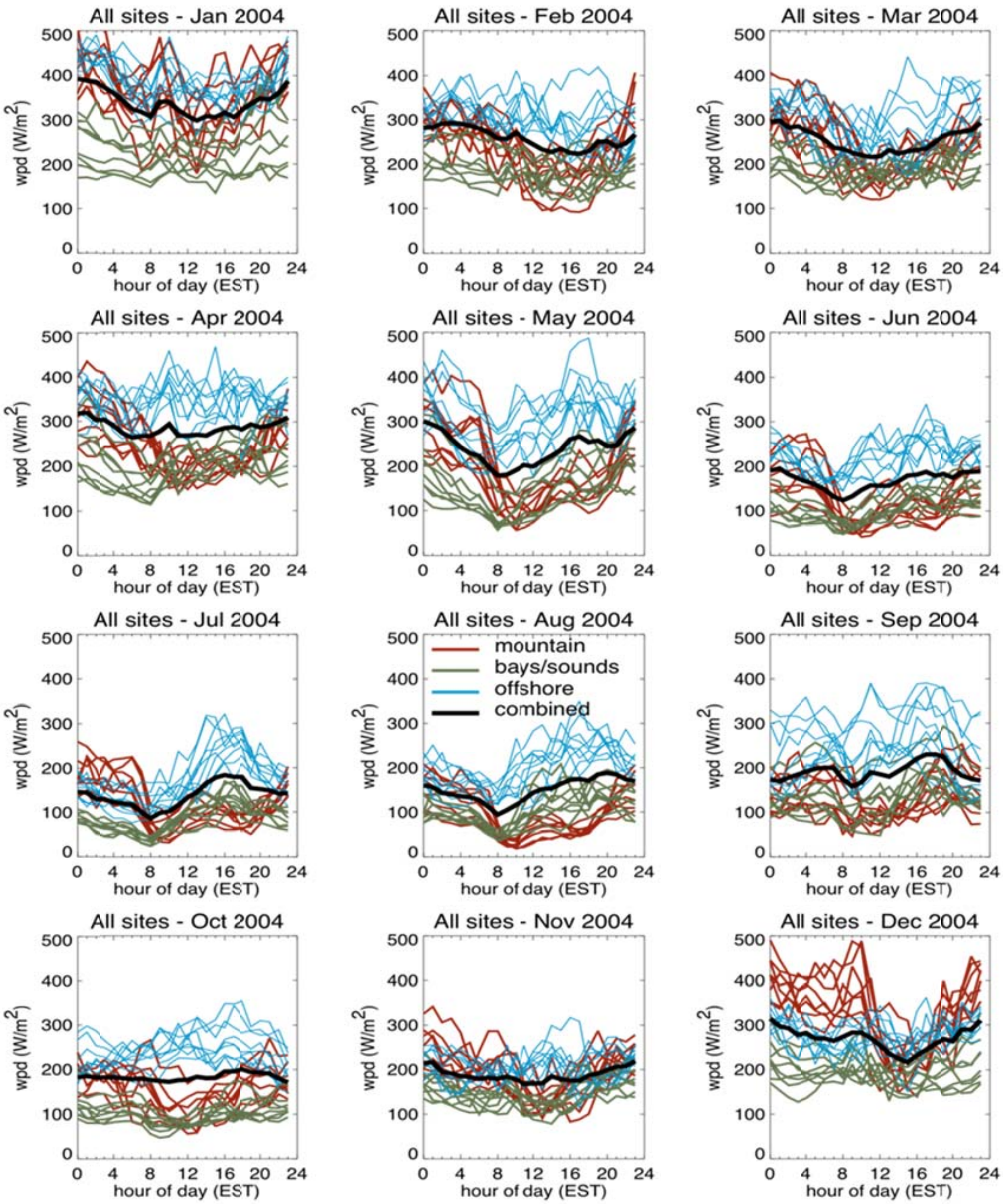

Figure 9-3. Diurnal variability in Wind Power density (WPD) for each month of 2004.
Each graph corresponds to one of the numbered locations shown in Figure 1. Model output taken from EWITS.

9.2 Wind measurements and comparisons with EWITS

The left panels in **Figure 9-4** show the seasonal/diurnal variability at 100m for individual EWITS locations for the most recent year (2006) that are closest to wind measurements. The right panels show Anemometer data for available years between 2006-2009. The on-peak and off-peak time periods for the measurements are shown in **Table 9.1**. With the exception of the Chesapeake Light Tower data, the model/data comparisons are not time-coincident, but they nevertheless give an idea of the actual measured winds and their variability. The two middle left panels correspond to EWITS locations on the

Eastern Shore (numbers 12 & 13 in **Figure 9-1**) that are close to the Crisfield (CRSF) tower (76m), but show overall weaker winds. This is partly due to interannual variability, or to the influence of the local terrain. The winds on the Eastern Shore are stronger relative to the wind at Newport News (NPTN). This is most likely due to the larger open water fetch of the Chesapeake Bay to the west; the smaller surface roughness of the Bay allows the westerly or southerly winds to accelerate as they traverse the Bay.

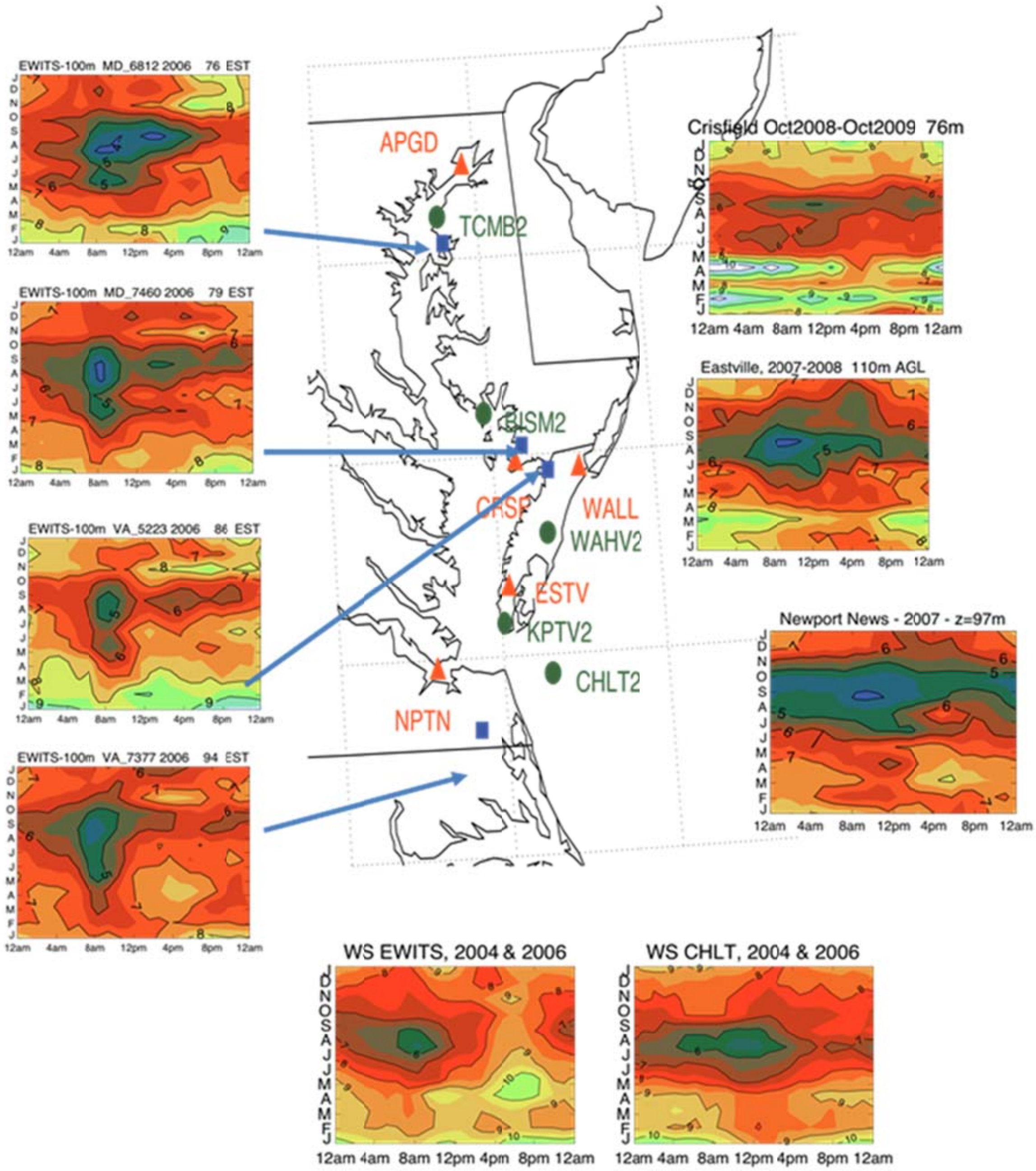

Figure 9-4. Seasonal and diurnal variability in wind speed at EWITS.
Locations (left panel), that are closest to buoys and available tall tower data (right panel) and a comparison of EWITS and anemometer data at Chesapeake Light Tower (two bottom panels). The data time periods are given in Table__. CRSF=Crisfield, MD, NPTN=Newport News, VA, WALL=Wallops, VA. NBDC stations: BISM2, TCBM2(10m), WAHV2, KPTV2(6.4m), CHLT2=Chesapeake Light Tower(43m). Blue squares: EWITS locations; green dots: buoys; orange triangles: tall tower anemometers.

It is not clear whether the differences in the measured winds at Eastville (ESTV) and Crisfield (CRSF) are due to interannual variations, or to differences in the local terrain. The bottom two panels compare measured and EWITS winds at Chesapeake Light Tower (CHLT2) for the years 2004 and 2006 (some wind measurements were missing in 2005, so this year has been excluded in this plot). The CHLT anemometer is at 43m, and the data has been scaled to 100m using a wind shear exponent of 0.08, which is appropriate for open sea, for purposes of comparison .These plots show several model/data differences in the diurnal cycle. The measurements show a prominent wind maximum from 4-8 pm during late spring/early summer, a mid-afternoon decrease in the wind and an extended period of weak winds during mid-summer that are not reproduced in the model. These differences in the phasing of the diurnal cycle could perhaps be due to real differences in the wind that are not taken into account with the uniform logarithmic rescaling of the wind speed from 43 to 100m. Eastville tower data (not shown) also indicate that the diurnal cycle can vary significantly from 50-100m.

As previously mentioned, there exists at present little information anywhere in the Mid-Atlantic about the vertical wind profile at heights 50-150 m that are important for wind turbines. Extrapolations from 10m buoy or 50m winds commonly use a power law model, but this approximation is strictly valid for the neutral boundary layer and likely underestimates the wind, especially in the stably stratified nocturnal boundary layer. Model simulations continue to have difficulty accurately simulating the stable boundary layer because the intermittency of the turbulence is not easily parameterized. Under some conditions, the assumption of neutral stratification is reasonable; examples are the marine boundary layer during times for example when cooler continental air moves over the warmer ocean water or under convective conditions over land. The change in wind speed with height is also strongly dependent on time of day, with larger increases at night relative to day, and is likely to be highly variable at coastal locations.
A plot of the annual mean wind at the anemometer vertical levels shown in **Figure 9-5** gives a sense of how rapidly the wind increases with height on average and how that differs between the sites. Sea breeze circulations could be contributing to the dramatic increase with height at Wallops, VA (WALL) and Eastville, MD (ESTV) relative to Newport News, VA (NPTN). More relevant, however, for turbine operation is the instantaneous wind shear.

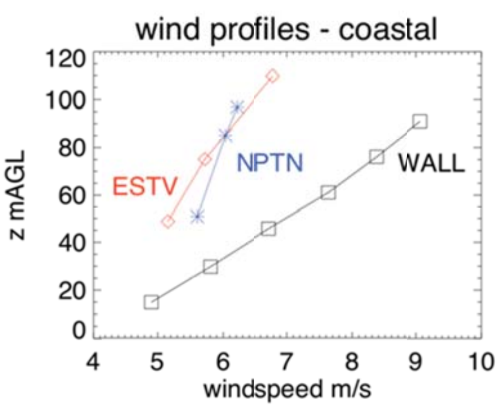

Figure 9-5. Annual Mean Wind Speed at Each Anemometer Level.
Eastville (ESTV), Newport News (NPTN) and Wallops (WALL) locations shown.

Figure 9-6 is a contour plot of the difference in the wind between heights 110 and 49 m at Eastville. The strong seasonal and diurnal variability in the wind shear is apparent and this underscores the uncertainty in simplified estimates of higher level winds from near surface measurements, especially near land/sea boundaries.

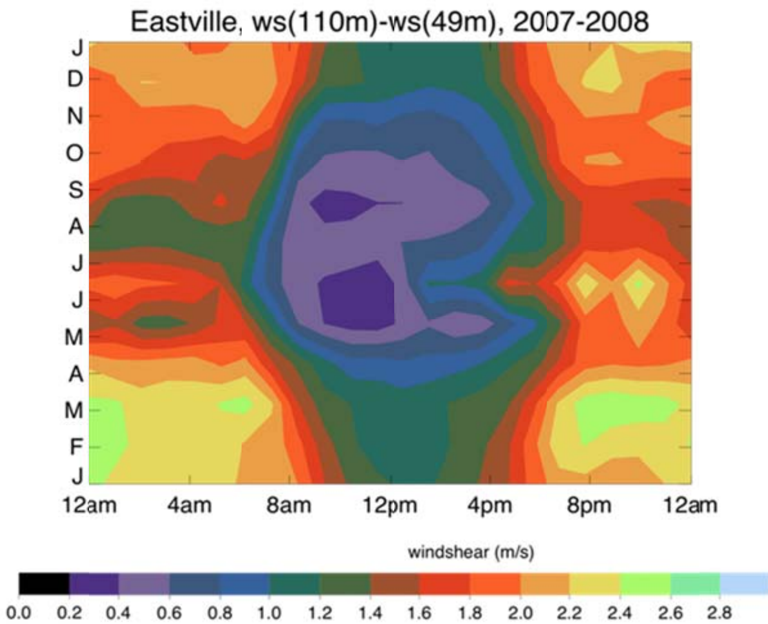

Figure 9-6. Seasonal and Diurnal Variability of the Difference in Wind Speed between 110 and 49 m.
Data based on anemometer data at Eastville, MD.

Another view of the vertical wind profile and its seasonal dependence can be seen in **Figure 9-7**. The measurements used for this plot are high vertical resolution (sampling roughly every 3 m above ground level) rawinsondes launched at Aberdeen Proving Ground (APGD) located along the northern reaches of the Chesapeake Bay during the years 2008-2010[83]. This data allows an estimate of the change in wind speed across the rotor. With the exception of the months of August and September, 50 m winds are in the range 5-7 m/s and increase to 7-9 m/s at rotor top (150m). The disadvantage in using the rawinsonde data is that the standard NWS launch times are 0 UTC (7pm EST) and 12 UTC (7am EST), which could bias the results as these are typically transition periods. Although data is very limited it is possible that wind strengths at typical hub height could be underestimated by a full wind power class.

[83] Wind measurement data from Eastville and New Port News, Virginia and Aberdeen, Maryland are discussed in detail in the Mid-Atlantic Tall Tower Report [2]

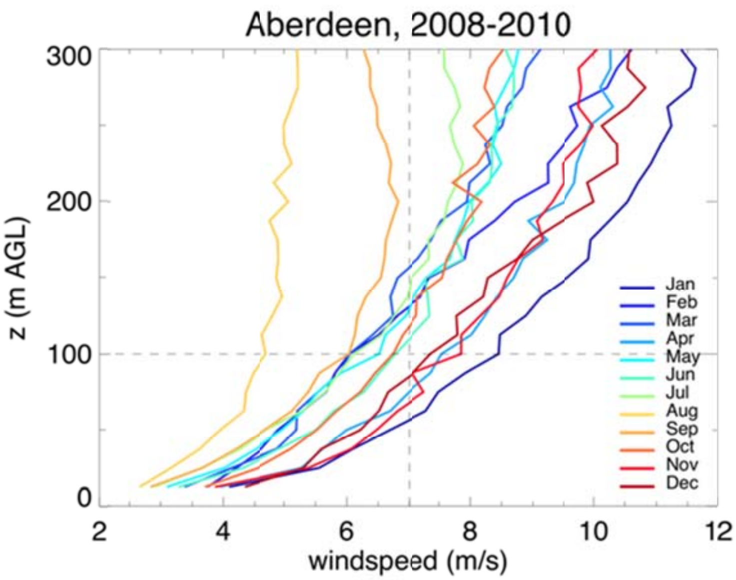

Figure 9-7. Vertical profiles of wind speed at Aberdeen, MD.
High vertical resolution rawinsondes used. Standard launch times are 0 and 12 UTC (7am and 7pm local).

In order to put these non-time-coincident comparisons in perspective, in **Figure 9-8** we look at the interannual variability for the years 2006-2011 using NBDC NOS (National Ocean Service) buoy data at station BISM2, which is close to the EWITS and Eastville locations. The 10m winds typically range from about 4-6 m/s and the years considered for this analysis appear similar with respect to the annual mean. If the increase in wind speed with height at Eastville for the available year 2007-2008 is representative for other years, then this suggests that the wind resource at locations such as Eastville could be significantly underestimated for wind energy production. **Figure 9-9** shows the interannual variability in the annual mean wind speed at other buoy locations; annual mean wind speeds similar to BISM2 are also found at the tip of the Delmarva Peninsula; winds over land in the central region of the Delmarva are much weaker relative to the coastal locations.

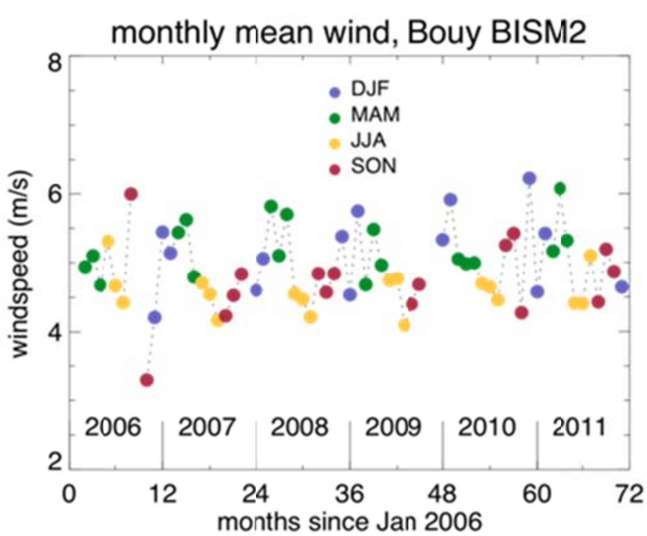

Figure 9-8. Monthly mean wind at NOAA/NOS Buoy BISM2 (Bishop's Head, MD).
Anemometer height is 10m.

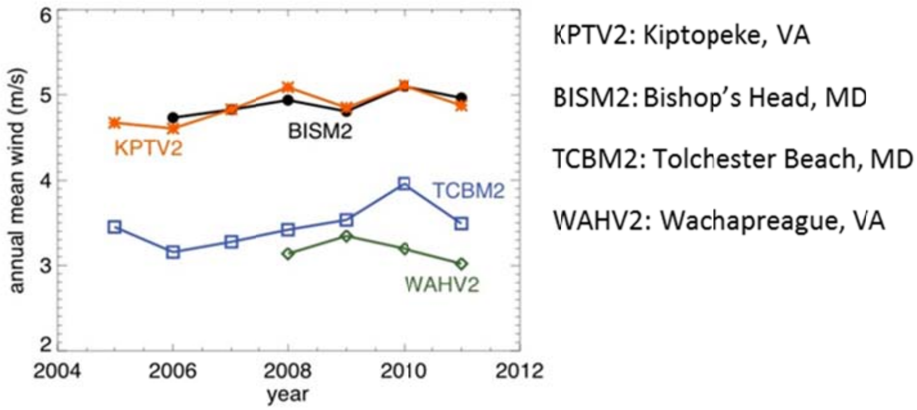

Figure 9-9. Annual mean wind at several NOS locations in Delmarva.

9.3 The Mid-Atlantic low level jet as a potential wind resource

The Mid-Atlantic coastal plain is generally not considered as an important wind resource region. There are however some potential wind resources that arise from large scale topographic/thermal forcing due to surface cooling of the elevated western region during the warm season that could significantly increase wind energy potential. This forcing often gives rise to a nocturnal low level jet (LLJ) [42]in the coastal plain. The LLJ is a strong band of fast wind that occurs under stable PBL conditions at night during the summer months. It begins after sunset, persists for most of the night, and is strongest at about 1am [43]. To illustrate the spatial characteristics of the LLJ, **Figure 9-10** shows a model simulation on August 2, 2007 using the state-of-the-art Weather Research and Forecast WRF model [44] at resolution 9km. The left panels show the LLJ as it begins to form at about 7pm local time; the right panels show the fully developed LLJ pattern at 11pm EST. The top, middle and bottom panels show the wind across a typical rotor span at heights 140, 99 and 60m AGL. The LLJ covers a significant portion of the coastal plain, extending west to approximately the 350m elevation contour (not shown), and east to the coast and offshore. In this example, winds at 7pm are greater than 13 m/s in the Chesapeake and Delaware Bays and further north off the coast of New Jersey.

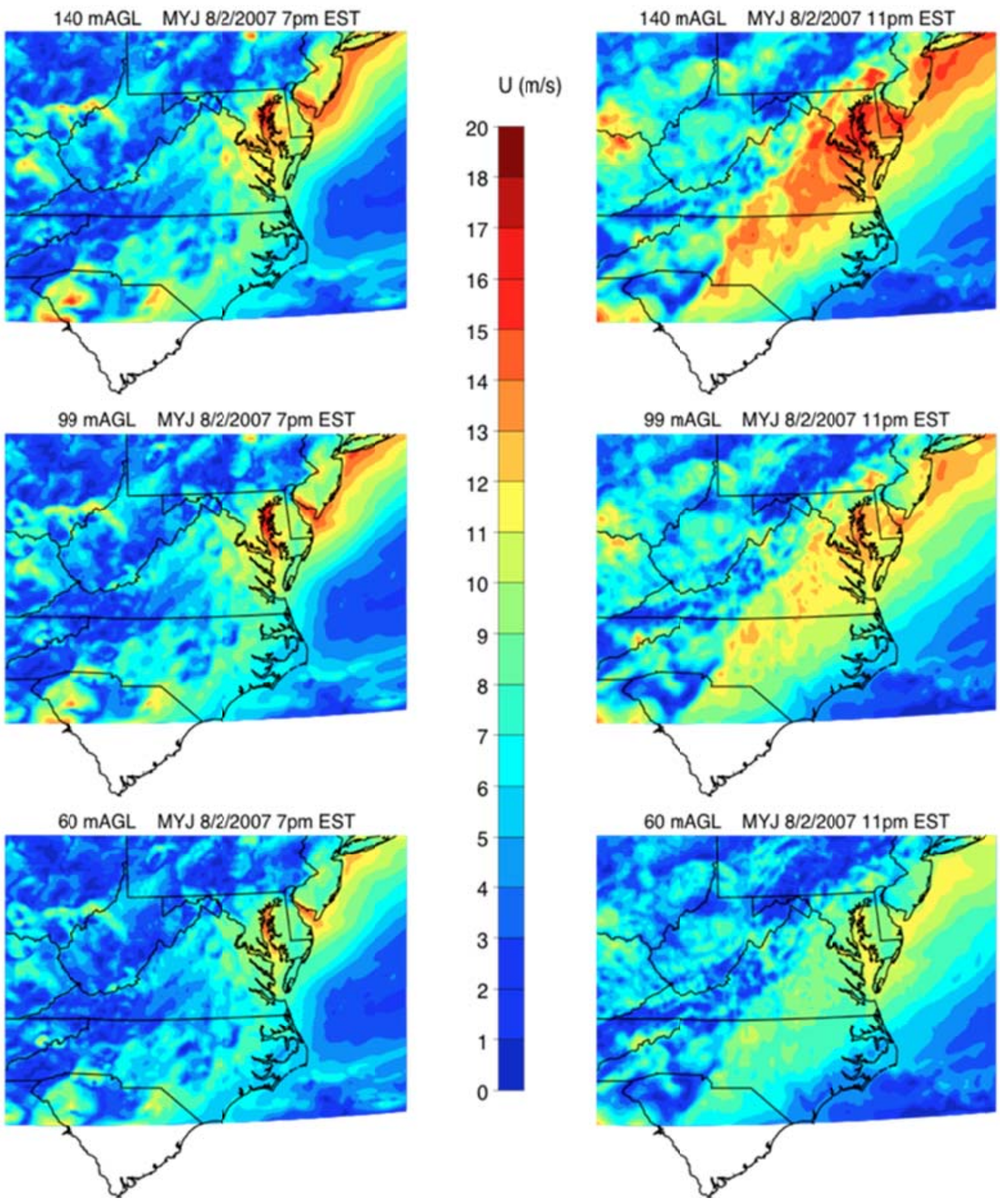

Figure 9-10. The Aug 2, 2007 low level jet at across-rotor heights 60, 99 and 140m AGL
Left panels: 7pm, EST; Right panels: 11pm EST. Winds were computed with the Weather Research Forecast Model at a 9km horizontal resolution, using the MYJ boundary layer scheme. Results were validated with measurements at Beltsville, MD and other stations.

The Mid-Atlantic LLJ as a potential wind resource is not yet clear. There are indications that it is a fairly common occurrence during the warm season [43] [42], however the climatology of the LLJ is uncertain due to the lack of suitable multi-decadal wind data that sample the jet at the time and height at which it occurs. NWS rawinsondes, for example, are launched at the standard times 00 and 12 UTC (7am and 7pm local time) and so are out of phase with the nighttime jet maximum.

9.4 Wind Resource Potential and Uncertainties

The analysis presented here has used a multi-platform wind observation analysis that we recognize is by no means comprehensive due to the lack of suitable wind observations, the sparse spatial sampling, and non-temporally coincident data records. Each data source clearly has its own problems and advantages. **Table 9.1** presents a summary of seasonal/diurnal variability for the coastal, mountain and offshore EWITS locations shown in **Figure 9.1**, and for the wind measurements discussed in **section 9.2**. The table entries are the mean wind speeds (in m/s) averaged separately for day (8am-8pm which is considered to be a reasonable approximation for the PJM 7am-11pm day used in **Section 5** of this report), night, and season. The available model and observational data is unfortunately not time-coincident and spans the years 2004-2010. Analysis of wind measurements from the few available tall towers, rawinsondes and buoys and for limited time periods suggest that the wind resource may be underestimated by models in coastal regions. The challenges in a robust resource assessment in these regions derive from the variability of the land-sea boundary, the sparse sampling and the cost of tall tower platforms that can measure the wind across the nominal rotor span, from 50-150 m. There is substantial interannual variability in the Mid-Atlantic wind, and it is difficult to draw conclusions about the wind resource at a given location from limited time (i.e. single year) sampling. Comparisons of the EWITS data with anemometer data reveal some significant differences with respect to the overall resource and its diurnal variability and highlight the need for more extensive tall tower and offshore wind measurements.

The extent to which the LLJ is an important resource for the coastal plains during the summer, its eastward extent, and in particular whether the onset of the LLJ coincides with the high load period in the summer is uncertain. The standard WMO launch times of 0UTC and 12 UTC correspond, on the east coast, to sunrise and sunset transition periods where atmospheric stability is changing. This temporal sampling is also coincidentally out of phase with the time of occurrence of the warm season nocturnal LLJ. But the jets do occur over large areas in the Mid-Atlantic and are energetic and could increase average wind speed estimates to a higher wind power class.

Barrier - Wind resource measurement data is severely lacking for the Mid-Atlantic region, and consequently there is a high degree of uncertainty. However, limited data at turbine hub height and across the rotor suggests that wind resources may be underestimated by at least one wind power classes over the coastal areas including Delmarva and the bays and sounds. Offshore wind resources could be overestimated.

Mitigation Option – A coordinated regional wind measurement campaign could provide needed spatial, temporal, seasonal and vertical (shear) wind characteristics.

10.0 Environmental Considerations

In order to form a complete picture of barriers to wind energy PERI not only partnered with both the Maryland Department of Natural Resources (DNR) and the Chesapeake Bay Foundation (CBF) in considering environmental issues surrounding wind energy, but also took into consideration concerns from regional environmental groups. A workshop, hosted by the CBF, was held to obtain insights and ideas for addressing environmental issues that could be barriers to wind development. Through this meeting and numerous one-to-one discussions, environmental topics of prime importance emerged. These include: turbine effects on bird and bat populations; greenhouse gases (GHG), nitrogen oxides (NO_x), and sulfur oxides (SO_x) displacement; eutrophication of regional waters; noise; aesthetics and public attitude towards wind power; and radar interference. Discussion also focused on the importance of looking at broader environmental issues, i.e. comparing wind energy to damage from mountain top coal mining, resulting water and air pollution from burning fossil fuels and uranium mining for making electricity.

10.1 Non-Governmental Organization Workshop

A key stakeholder meeting was conducted with representatives from regional and national environmental groups. The meeting was hosted by CBF, on March 1, 2011, at their office in Richmond, VA with representatives from seven Non-Governmental Organizations (NGOs) to obtain information on environmental issues relating to wind and other energy sources. Barriers to wind project development were discussed along with mitigation measures and offsetting benefits compared to other energy options. The sixteen participants participated in an exercise by placing 100 MW wind plant blocks on regional 1: 100,000 scale topographic maps and on marine navigation charts. The agenda for the meeting is shown in **Figures 10-1**. A list of participating organizations is included in **Appendix A**.

Mid-Atlantic Wind: Overcoming the Challenges
PERI-NGO Workshop Agenda
March 1, 2011, 9:30 am – 4:00 pm

MORNING SESSION: IDENTIFICATION AND DISCUSSION OF BARRIERS

GREETINGS, INTRODUCTION AND PROJECT OVERVIEW (Gerel/Ancona) –15 min

OPEN DISCUSSION OF NGO PERCEPTIONS OF BARRIERS TO THE DEVELOPMENT OF WIND IN THE MID-ATLANTIC STATES (all NGO participants - primary focus on Virginia) – 45 min

TECHNICAL ISSUES: (Ancona) (30 min)
- Review of VA wind maps
- Projects forecast for region
- Resources needed to reach 20% goal
- DOE State data
- MD RPS example
- Perception of available resources (slides 9-12)
- Cost issues
  - Onshore vs. coastal vs. offshore vs. ridgeline
  - Recent coal and gas prices
  - Production tax credit status

POLICY/REGULATORY ISSUES: (Buckheit) (30 min)
- Support for climate change regulation
- Federal budget cuts
- Existing coal plant retirements

VIRGINIA
- VA RPS "goal" structure
- Imported RECs
- Tier II RECs
- Effect of multipliers
- Industry plans
- Regulatory actions
- Zoning restrictions
- VA MRC Report

MARYLAND and DELAWARE
- RPS structure
- Effect of multipliers
- Imported RECs
- Apparent overlooking of the Bay(s)
- Public interest

NORTH CAROLINA
- RPS Structure
- Energy study
- NC Ridge Protection Act
- Zoning restrictions
- Abandonment of Pamlico Sound demonstration project
- Elizabeth City Project

CHART/MAP REVIEW OF POTENTIAL WIND ENERGY SITES (30 min)

AVIAN/BAY AND OTHER ENVIRONMENTAL ISSUES NOT EXPLORED EARLIER (NGOs – 1 hour)

AFTERNOON SESSION: DEVELOPMENT OF POTENTIAL SOLUTIONS/ACTION ITEMS

(Open discussion - specifics to be developed based on morning session)

Figure 10-1. NGO Meeting Agenda

10.2 Risks to Birds and Bats Relative to Alternatives

Collisions involving birds and bats into turbines are a common public concern when observing potential environmental risks with wind turbines. Wind turbines create an obstacle for migrating birds flying in the path of the wind farm. However, the data shows that bird collisions are not a major concern when compared to other energy sources and only create a relatively small risk for migrating species which can be mitigated by avoiding sites on migratory routes. A study done at Nysted wind farm in Denmark, an offshore site in sheltered water, concluded that only 0.9 percent of night migrating and 0.6 percent of day migrating birds were in danger of collision, defined as flying < 50 m to a turbine [45]. **Figure 10-2** illustrates the radar imagery obtained during the study and shows that a majority of migrating birds fly around the wind farm, those that fly through the wind farm are over-inflated since **Figure 10-2** does not show those birds that fly over or under the sweep area of the turbines.

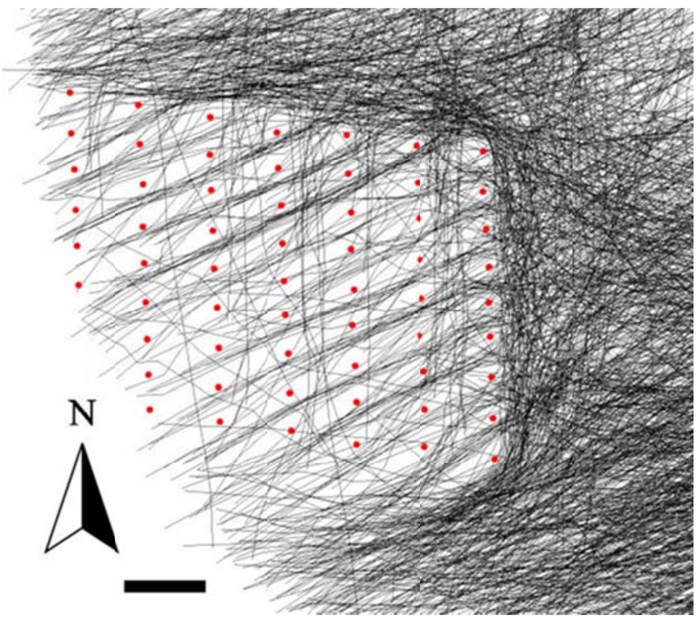

Figure 10-2. Bird Flight Path Mapping at Nysted Wind Farm, Denmark

The additional flight distance needed to detour these wind farms is approximately 0.5 km, a very small portion compared to the total migration episode experienced by many species, which can reach up to 1,400 km. At such a low risk of collision, models for proposed U.S. offshore projects like Cape Wind in Massachusetts estimated 260 bird fatalities annually across all species. This has been deemed to pose no ecologically significant threat to bird species relative to the benefits received from said species from increased use of the renewable energy in the area by the Massachusetts Audubon Society [46]. There does exist concern with the Mid-Atlantic region being at the heart of the Atlantic flyway (see **Figure 10-3)** which has the possibility to result in a higher number of collisions during the migration season. Consequently estuaries along the shores of the Delmarva Peninsula should be excluded from wind plant development.

Although collision risk for bird species is minimal, further mitigation can theoretically be achieved through proper wind farm design and placement. The greater risk comes from nocturnal collisions, due to the birds becoming attracted to the lighting used on the turbines at night, similar to the current observations of nocturnal birds circling brightly lighted offshore oil platforms in the Gulf of Mexico[84]. Studies have shown that this circling behavior increases the risk of collision [47]. By switching from

[84] A single oil platform in the Gulf of Mexico causes approximately 50 bird deaths for collisions annually [47]

continuous illumination on oil rigs to intermittent flash of strobe lights marking a wind farm, the circling phenomenon could be avoided and reduce the risk of nocturnal collisions. Other risk mitigation recommendations include allowing for migration corridors between wind farms and turning off turbines at night when high migration intensity is forecasted.

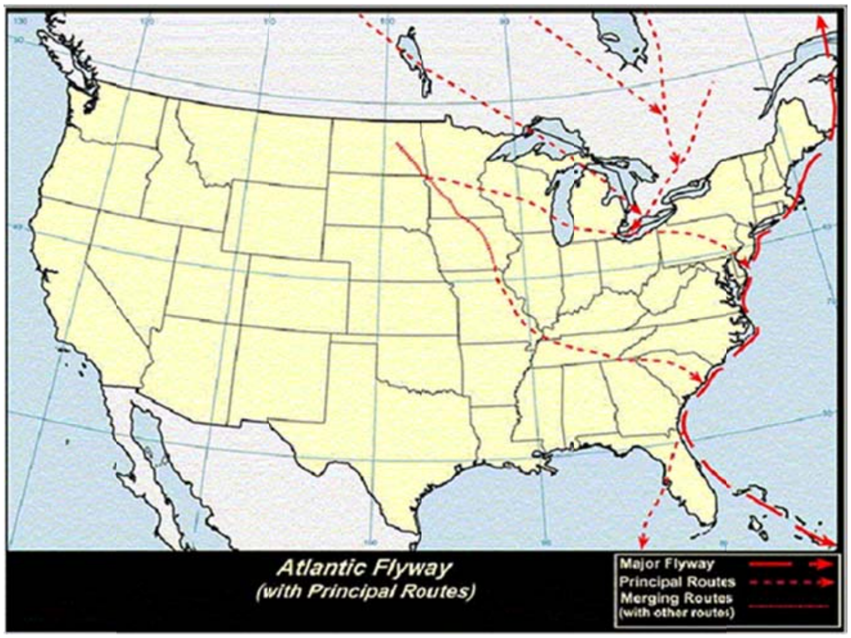

Figure 10-3. Atlantic Flyway

Bird collisions have been well documented and provide a general idea about the risks associated with wind turbines and birds. Bat collisions, however, have not been as highly documented, but current research is ongoing. Bat carcasses have been found at the base of all U.S. land-based wind farms, but these findings have occurred sporadically and even at turbines which are not in operation.

Since bats feed primarily at night on flying insects when the wind speed is less than 6 m/s, raising the turbine startup wind speed slightly can dramatically reduce bat mortality. Raising the turbine speed means the turbine is idle during times of low wind speed. One study estimated this mitigation measure reduced risk to bats by 85 percent with only 2.6 percent loss in energy output [5]. It is understood that some bats migrate over water at times, but it is not conclusive as to the exact cause of bat interaction with turbines. This needs further study [48] but should not be a blocking issue.

10.3 Atmospheric Emission Displacement

Displacement of Greenhouse Gas emissions (GHG), nitrogen oxides (NO_X), and sulfur oxides (SO_X) are an inevitable benefit from wind power. According to NREL, a single 1.5 MW turbine displaces 2,700 metric tons of CO_2 annually relative to the current average U.S. fuel mix. Since these turbines have a lifespan of around 20 years, one such turbine could displace as much as 54,000 metric tons of CO_2 emissions or more during its lifespan. Under 20% Wind by 2030, 825 million metric tons of CO_2 emissions are estimated to be avoided. Under the DOE 2030 scenario, the Mid-Atlantic States could install 24.4 GW and consequently displace 66 million tons or 8.02 percent of the US CO_2 emissions.

If offshore capacity is included, the emission reduction share increases to 12.1 percent. The emission displacement would actually be higher since the DOE national scenario is based on 18 percent of electricity from coal and coal is the primary fuel for generation in North Carolina and Maryland and second behind nuclear in Virginia.

A reduction of power plant emissions is paramount in solving numerous problems including eutrophication of regional rivers, bays and sounds; respiratory health issues like asthma, acid rain and climate change. Besides reductions in CO_2 emissions, displacement of coal-fire powered electricity yields reduction in atmospheric emissions of lead, mercury, arsenic, chromium and selenium produced by such power plants.

In addition some reduction is likely in the demand for natural gas as a viable energy alternative to coal. This saving will be diminished as the penetration of wind power increases the need for additional quick start natural gas fired turbine generators to balance the variations in wind plant output. Reduced natural gas consumption decreases the need for fracking, for which long term environmental impacts are still relative unknown, but have been suggested to poison aquifers and cause earthquakes. France and Bulgaria have banned fracking due to similar concerns.

Low cost fossil fuels are sometimes considered a barrier to accruing the environmental benefits of wind energy. However, prices for conventional fossil fuels tend to rise and fall in cycles, so today's glut is followed by tomorrow's shortage. Wind offers a hedge against oscillating fossil fuel prices.

Wind energy is eligible to sell carbon credits for renewable energy power production if a carbon market can be found. Prices for carbon credits at markets like the Chicago Climate Exchange increased until 2007, but have done poorly in recent years due to an excess of carbon credits. In fact the Carbon Cap and Trade market at the Chicago Climate Exchange closed in late 2010.

However the Regional Greenhouse Gas Initiative (RGGI) currently manages carbon trading among some states on the East Coast including the Mid-Atlantic region. Comprised of nine states; Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont, RGGI operates carbon trading auctions quarterly for these states based on each state's individual CO_2 limits and the cycles a portion of the revenue generated from the auction back to the states to be invested in consumer programs and clean energy development. In participation of these auctions each state maintains a revenue stream to invest into further CO_2 reductions and therefore has a direct incentive to regulate emissions properly. Only Delaware and Maryland participate in these auctions in the Mid-Atlantic region. Those states that do not participate lose the direct incentive to manage CO_2 emissions in order to receive the revenue stream. To date 15 auctions have been held. Maryland has received $188,828,931 and Delaware $25,412,511 in cumulative proceeds.

10.4 Eutrophication of Regional Waters

Eutrophication is the process where a body of fresh water acquires a high concentration of inorganic nutrients, namely nitrates and phosphorous, which causes excessive algae growth which then in turn removes large amounts of oxygen from the body of water. The problem is compounded when the algae decomposes and inputs more nutrients into the ecosystem. This process has plagued the Chesapeake Bay over the past 40 + years, leading to large portions of the bay becoming dead zones which inhibit aquatic life and destroy the aquatic ecosystem. Eutrophication has both immense negative ecological and economic impacts, namely "fish-kills" that are created in dead-zone which then hurt local fishing economies and make shellfish from those areas toxic for human consumption.

The three largest sources of excessive nitrogen loading are chemical fertilizers from farm, urban and suburban lands; second is agriculture run-off laden with animal waste; and third is Municipal and industrial waste water including dumping of raw sewage and human waste. There are a range of programs to limit these sources.

Atmospheric sources contribute about one-third of the nitrogen loading and include vehicles, gases from livestock and fertilized soil, and electric power plant emissions. EIA reported that power plants located in the five study states emitted 136,297 metric tons of nitrogen oxides during 2010. In addition there is nitrogen loading from power plants in surrounding states, mining operations (including mountain top coal removal) and fuel transport. One option could be to add a carbon tax on electricity generated from carbonaceous fuels, regardless of its source.

Similar to the displacement of Greenhouse Gases (GHGs), the displacement of nitrogen discharge into the bay will come as a direct result of wind energy taking the place of combustion of fossil fuel fired plants and mobile sources. Although, nitrogen run-off from agriculture continues to be the primary issue, organizations like the Chesapeake Bay Foundation and Sierra Club are making strides in fighting for more stringent regulations on all sources of nitrogen run-off into the bay. Wind turbines would attack a different aspect of the eutrophication problem that has previously been lower priority.

Eutrophication has caused large dead zones in the bay area (seen in **Figure 10-4**) that happen to be near good wind resources. These dead zones provide the ideal location for turbine installation without worry of disturbing currently existing ecosystems, and also are located in some of the more feasible locations for wind farms (see wind resource map in **Figure 4-5**) These locations would serve as installation ground for the turbines which would in turn be part of the solution to solve the issue of dead-zones. As efforts continue to reduce nitrogen run-off and the size of dead zones in the bay decrease, these submerged turbine platforms can act as artificial reefs and benefit the ecosystem, all without the initial negative impact of disturbing the ecosystem during installation.

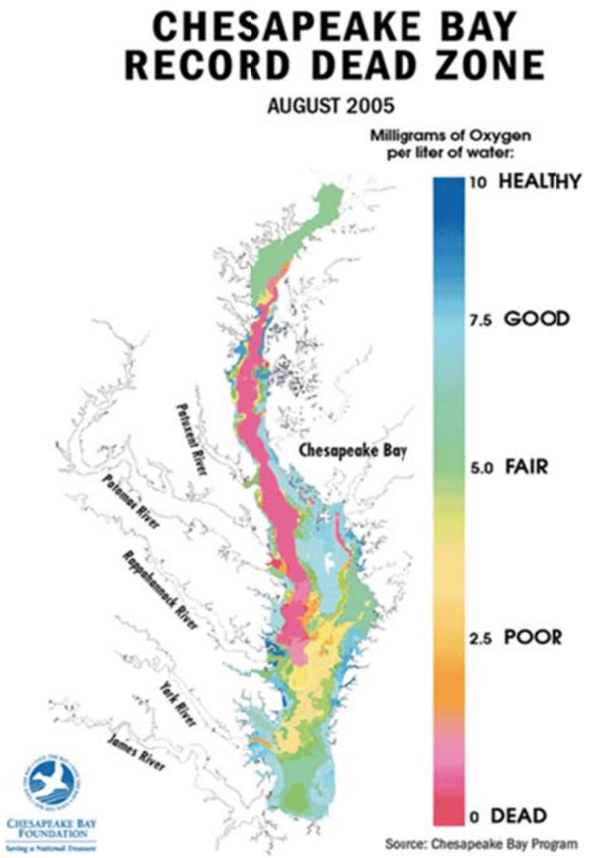

Figure 10-4. Chesapeake Bay Dead Zones

10.5 Aesthetics and Public Attitude

Visual impacts produced by wind turbines are important considerations in project planning and siting. The higher visibility of ridgeline and offshore increases initial concerns but these tend to diminish as more wind plants are built. Aerodynamic and machinery sounds from turbines can be annoying to nearby homes and can become barriers to projects. One solution is using model ordinances with reasonable set back requirements and noise limits that communities can use to minimize these issues. These are discussed in the **Section 8** of this report.

Despite these mitigation measures, ridgeline sites have encountered serious opposition in Maryland, Virginia and North Carolina. Public media, law suits and regulatory processes have delayed projects for years. These delays and associated legal costs become economic barriers for developers and consequently they choose sites elsewhere. For example in nearby Pennsylvania wind development is proceeding with 790 MW of wind plants located mainly on ridgelines with another 131 MW beginning installation in Mehoopany in June 2012.. In some cases the initial projects were placed on mountains that had already been damaged by strip mining. Also the coal business has been declining, so the local jobs associated with the wind plants are perceived as beneficial. Seeing wind plants operating, along with their economic benefits, has helped to open markets in Pennsylvania. Public education through stakeholder groups has also been helpful in reducing opposition.

Beach and mountain tourism plays a major role in many local economies of the Mid-Atlantic region. Since the proposed offshore wind project in Massachusetts, there has existed a strong concern that the installation of turbines would have a negative effect on tourism as the sight of turbines off the coast would take away from the aesthetic beauty of the horizon [49]. Although no negative effects on tourism have been observed at European beaches that installed offshore wind farms, current public opinion of both residents of Mid-Atlantic States and out-of-state tourists poses a barrier to the most cost-effective implementation of offshore wind turbines. Studies were conducted by the University of Delaware for both Maryland and Delaware to determine public opinion and feasibility of offshore wind turbines [50] [51].

The study conducted for Delaware produced mixed results. The study concluded that there is favorable support for offshore wind farms, but the support was stronger for wind farms that are not visible from the shore. Those surveyed greatly supported offshore turbine projects 22 km and further out. They showed decreasing support the closer the hypothetical wind farm got to shore, as illustrated by **Figure 10-5** [50].

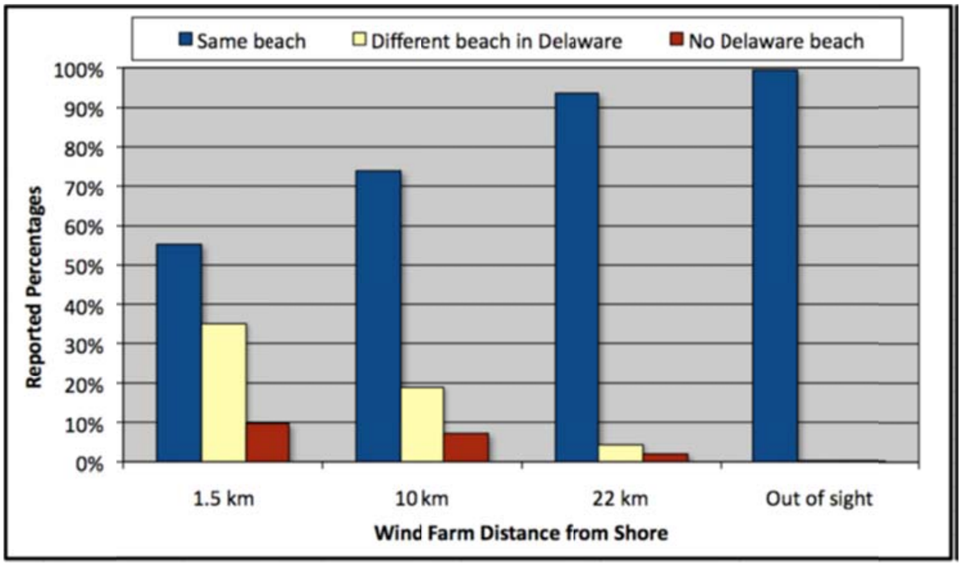

Figure 10-5. Survey of Anticipated Tourist Reaction to a Hypothetical Wind Farm

Differences were noted in response from local vs. out-of-state tourist groups. The study also concluded that 66 percent of out-of-state beachgoers surveyed and 84 percent of Delaware resident beachgoers surveyed claimed that they were likely to visit a beach with turbines 10 km offshore at least once, which leaves the option for sequential trips after the first. This is consistent with evidence in Europe that offshore wind power actually boosts local economies in terms of tourism. These boosts in tourism are also in addition to local economy boosts seen from the additional jobs created for turbine installation. A proposed 600 MW offshore project in Maryland would create 500 jobs initially in the first two years for construction and manufacturing and then maintain 80 jobs on an ongoing basis [51].

Public perception of wind farms improved with increased outreach to stakeholder groups. In a separate study, University of Delaware researchers found that in the State supporters significantly out number opponents. Depending on where they live, respondents with an impacted view favored a project 2:1, ocean area residents' favored 3:1 and inland residents' favored 5:1, that is five favors offshore plants for every one opposed [52]. These results are dramatically more favorable than similar surveys done for the Cape Wind Project in Massachusetts although attitudes in New England seem to be improving. The actually effects of offshore wind installations on local residents and tourism is still ambiguous. Public opinion must be taken into account in considering installation projects, and open communication with local stakeholders is critical, but it cannot be the sole deciding factor. The offshore wind demonstration projects planned by the U.S. DOE in 2014–2017 will help address these uncertainties and seeing actual turbines will likely serve to reduce these concerns as was the case on earlier DOE demonstration programs.

Aesthetics can become barriers especially for high visibility ridgeline projects in tourist areas. Offshore plants can also encounter barriers based mainly on cost and “Not-in-my-beach-view” issues. Data shows that careful attention to early and open communication can frequently mitigate these issues. Reasonable model ordinances and demonstration projects can reduce these obstacles.

10.6 Radar

There are significant concerns that wind turbines can interfere with surveillance, navigation, and Doppler weather radars. This is especially important for the Navy, Coast Guard, and Federal Aviation Administration (FAA). The national security implications of radar interference are obvious, especially along the Mid-Atlantic coast. Although mitigation measures have been used successfully in Europe, like techniques involving the use of signal processing techniques to reduce ground-clutter, these have not been sufficiently tested under operational conditions on the U.S. with full-scale turbines in an operational multi-radar environment.

Radar has been studied and FAA has conducted field tests to determine effects of operating turbines on radar signals. Results show that wind power plants interfere with the radar tracking of aircraft and weather. A wind farm located close to a border could create a blind zone for detecting intruding aircraft; current weather radar software could misinterpret the high turbulence at the blade tips as a possible tornado; current air traffic control software could temporarily lose the tracks of aircraft flying over wind farms.

Despite these difficulties, there is no fundamental physical constraint preventing detection and mitigation of wind turbine interference. A study for US Department of Homeland Security [53] concluded that, “The technologies of wind turbines and radar can coexist.” A variety of mitigation measures were suggested but also acknowledged that our aging radar system may not be able to use the most promising mitigation measures that are based on digital signal processing capabilities.

The United Kingdom conducted several years of study and initiated collaboration between the military and other stakeholders regarding potential effects on radar systems and mitigation strategies. These studies found that some level of the interference from wind turbines can be mitigated with improved radar hardware, filtering software, or gap-filling radar systems [54]. Most recently, some land-based projects in the Western U.S. have experienced siting delays as the result of concerns regarding potential radar interference to civilian aircraft and nearby military installations.

Radar issues have been well documented in Mid-Atlantic regional studies. University of Maryland did a detailed and thorough analysis of issues [55]. University of North Carolina did a parallel study on the feasibility of wind energy in the Pamlico and Albemarle Sounds considering extensive military operations in the vicinity [36]. In both studies conflicting uses were cited. However, little attention was given to possible changes to traditional or preexisting operations and to what could be curtailed, relocated or equipment modified to accommodate both the wind turbines and other uses.

Wind turbines also have national security implications that are often overlooked. Reducing our dependence on energy imports can reduce the need for some security operations. We need to revise current thinking and usage of air and sea space to find compatible operation of wind turbines alongside preexisting operations.

The national importance of wind energy was expressed recently by Iowa Governor, Terry Branstad, “The PTC and Iowa's renewable-power commitments have brought in billions of dollars of investment, generated jobs and helped wind-related businesses prosper in the state.” Branstad added, those policies have turned the wind power industry into “an American success story that is helping us build our manufacturing base, create jobs, lower energy costs and strengthen **our energy security,**” [*emphasis added*].

11.0 Conclusions

Throughout this report, numerous issues, impediments and barriers to the development of wind energy in the Mid-Atlantic have been identified. Individually, many of these issues alone are not enough to derail wind energy development, but in combination they become barriers preventing the utilization of both known and potential wind resources in the region. There also exist several major barriers to wind energy development which, unless overcome, will continue to constrain wind energy development in the Mid-Atlantic. The Executive Summary in this report describes the technical approach used to define the most important barriers and options for their resolution or mitigation.

There is potential for over 4,000 MW of land-based wind energy plants throughout the Mid-Atlantic region and several times that offshore. All states have significant wind energy potential yet there are only two utility scale projects installed in Maryland and none elsewhere in the region to date. The absence of wind energy projects for bulk power generation continues, despite a growing demand for electricity that is among the highest in the nation, increasing up to 3.2 percent annually. Ample wind resources are available at Appalachian mountain ridgeline sites, on the coastal plains, at shallow sheltered water sites in Delaware and Chesapeake Bays, Albemarle and Pamlico Sounds, and at deeper water sites off the Atlantic coast.

The primary barriers to wind development outlined in this report can be grouped into three categorical types; Policy-Regulatory Issues, Wind Resource Technical Uncertainty, Economic Viability and Public Interest. The properties of these typologies are not mutually independent and do interact.

11.1 Policy and Regulatory Issues

Although all Mid-Atlantic States acknowledge the importance of wind in their energy plans and have Renewable Energy Portfolio Standards or Goals (RPS/RPG) in place, there have been only two projects built. Several issues were identified as critical shortcomings in the Mid-Atlantic State RPS/RPG programs. First, in most cases fulfillment is allowed from facilities that predated the portfolio laws and Renewable Energy Certificates (RECs) may be generated anywhere in the PJM system. Maryland provided just over 3 percent of the Tier 1 RECs retired in 2010. The rest of the RECs came from Pennsylvania, Virginia and 11 other States as far away as Michigan. Second, REC requirements are being fulfilled largely with “anyway” credits. Many credits are generated from facilities that were built long ago and would operate anyway. These include large hydropower plants and plants burning paper plant black liquor wastes in facilities installed in the early 1900s. Both types of facilities would operate anyway regardless of RPS/RPG. North Carolina is an exception, requiring that RECs be generated from new activities deployed after the RPS law was passed and that 75 percent must come from in-state sources. Despite these enlightened RPS provisions, no wind plants have been deployed as the escalating requirements are not yet sufficient.

An issue in Virginia is that the goals have been met largely through existing in-state hydropower resources, supplemented as necessary by the purchase of Tier II RECs from pre-existing facilities and operation. Tier II RECs are generated by sources that are generally considered less environmentally beneficial than Tier I sources and their use is constrained or prohibited in a number of Renewable Portfolio programs.

Another issue in Virginia is that portfolio goals are treated as ceilings rather than minimum targets to be met or exceeded. The State Corporation Commission was asked to determination if two power purchase agreements (PPA) for new wind power generation were “reasonable and prudent”, as required by the RPG statute. The Commission determined that the goals of the RPG were not minimums, but caps and that any new renewable generation that was not needed to meet the currently applicable goal was not prudent, even if it would be needed to meet the goal established for later years. The Commission also noted that

Tier II RECs, where they are available as a lower cost method of compliance, they must be used. Several legislative efforts in Virginia to increase and strengthen the RPG have failed in favor of least-cost-power-today, disregarding energy plans to increase use of wind and other renewables in the Commonwealth. In North Carolina, the current interpretation of the state's Mountain Ridge Protection Act has served to rule much of the state's ridgeline resources "off limits" to development.

All of the Mid-Atlantic State energy plans mention policies favoring renewable energy and reducing energy imports by developing indigenous resources. There are also a variety of grant programs aimed mainly at residential applications along with property and sales tax and property wavers available in some states but not in others. In Delaware and Maryland money is available for renewable energy programs from the Regional Greenhouse Gas Initiative (RGGI), the ten-state cap-and-trade program meant to reduce CO_2 emissions.

Delaware has an effective RPS program and the University of Delaware has implemented a strong and effective offshore wind energy research, teaching and public education program. There are opportunities for coastal and bay wind resources that could be developed while offshore research continues. In addition, the local utility, Delmarva Power and Light, owned by Pepco Holdings, and the Delaware Public Service Commission are receptive to wind and renewable energy.

11.2 Federal Emphasis on Offshore Projects

In recent years the attention in the Mid-Atlantic States has shifted from land-based applications to offshore in Federal waters. The U.S. Department of Interior, Bureau of Ocean Energy Management (BOEM) and U.S. Department of Energy (DOE) have kindled much of this interest from the states and potential project developers. BOEM has identified lease blocks for offshore three of which are in the Atlantic Ocean off the coast of Delaware, Maryland, Virginia and possibly later North Carolina. Project proposals have been solicited and an environmental assessment completed with favorable results showing "no significant impact." DOE has solicited major research and technology demonstration projects for offshore applications. All this effort has created substantial interest for projects beyond the 12 nm limit in federal waters.

This large emphasis on offshore ocean applications has drawn attention and resources away from consideration of possible sites in Delaware and Chesapeake Bays, Albemarle and Pamlico Sounds, and from land-based sites along the coast. Consequently offshore wind development has created a barrier to onshore and bay wind development.

Our study team attempted to reexamine the applications on the coastal plain and in the shallow sheltered waters of bays and sounds. Based on analysis of tall tower (>70 m height) wind data, we concluded that wind resources appear to be marginally better offshore compared to bays, but the platform cost in the ocean for deeper water and survival in hurricane generated waves of up to 30 m height plus added operation and maintenance expense, favored application in the bays. Based on detailed economic analysis, the levelized cost of energy (in 2013 constant dollars) was estimated at $0.091 per kWh for bay installation vs. $0.167 per kWh for ocean installations. These estimates appear to be consistent with offshore project cost trends in Europe and with detailed engineering studies completed by DOE early in the Federal Wind Program. Of course there are issues associated with deploying turbines in the bays and sounds. Environmental issues, such as birds, bats and view shed concerns, must be addressed and balanced against the benefits to bay water and air quality from reduced coal mining and thermal power plant emissions.

11.3 Economic Assessment Results

This study looked at the economic viability of four different applications of wind plants; ridgeline, coastal plains, shallow bays and sounds, and offshore oceans. Three of these markets appear to be economically viable today. The levelized cost of energy from potential coastal sites appears to be attractive for near-term development in the Mid-Atlantic. Next most attractive potential sites are in sheltered shallow waters of bays and sounds due to proximity to load and because the wind resources are probably underestimated.

Ridgeline sites are lowest cost. However, the distance to load centers and associated transmission and environmental factors must be cost must be considered The Ocean project is more challenging and would require significant reductions in risks, more confidence in wind resources, reductions in risk premiums and/or an attractive long-term Power Purchase Agreement (PPA) to be viable. These findings are based on analysis of modeled PJM forward pricing and cash-flow model results comparing 100 MW plants using 1.5 MW turbines on land and 5 MW turbines in Bay and Ocean applications. Underlying assumptions for costs, performance, and financing, are detailed in the report for eight different cases.

11.4 Technical Uncertainties

A barrier is the uncertainty about wind resources. There is a paucity of wind resource data suitable for planning utility-scale wind plant. There is substantial data available at or below 50 m height but research using measurement from seven sites showed that wind resource increased substantially at large turbine hub height (100 m) and above. Result from the multi-year wind velocity and shear measurements indicates that existing wind maps underestimate the wind resource over the coastal plains by one wind power class and may overestimate the wind offshore.

Significant differences were noted in comparing the actual wind measurements with model results from the DOE, Eastern Wind Integration Study (EWITS). The Ridgeline data wind speeds and capacity factors were similar. But looking at the high wind shear measured at 100 m hub height and above on the Delmarva at Wallops and Eastville leads to the conclusion that average coastal plain wind speeds may be underestimated by at least one wind power class. The reverse is true on the ocean. The analysis showed that the EWITS estimates for average seasonal wind speed offshore were about 15% higher than estimates in this study. These differences are considered to be very significant and resulting uncertainty would be a barrier to any developer.

An additional uncertainty and potentially valuable finding is evidence of the presence of Low Level Jets (LLJ) across the Mid-Atlantic region. LLJ may significantly increase wind plant production during spring and summer months. These jets are powerful winds that arise from large scale topographic/thermal forcing due to surface cooling of the elevated western region during the warm season. Unfortunately the jets begin around sunset and are highest during the PJM off-peak period at night.

Lack of good wind characteristics data is considered to be a major barrier to wind development. Many factors contribute to uncertainty regarding the regional wind resource. These include the lack of long-term, hub height or above wind measurements, the atmospheric complexity and variability at the land-sea boundary, extreme events (hurricanes) and the presence of low level jets. This uncertainty is a barrier for developers and for their debt and equity investors.

One other technical barrier could be limitations on the existing transmission grid. This study assumed that required transmission lines will be available when needed to handle the energy from the 100 MW plants. Transmission line projects like the Mid-Atlantic Power Pathway (MAPP) are assumed to be available. Further, we did not evaluate the potential impact from the proposed offshore backbone.

11.5 Public Interest

Public opinion of wind energy and environmental issues are important but are not considered to be barriers at this time. These can become block issues if they are not addressed properly in the project planning process as is the case in North Carolina. There a judicial interpretation of the Ridgeline Protection Act has effectively blocked all wind development in the western part of the state. However reasonable zoning ordinances can go a long way to prevent issues before they start. Model zoning policies are available and in use except in a few communities where projects began before model ordinances were ready.

Generally environmental issues can be defined, avoided or mitigated. These can preclude the use of environmentally sensitive sites but are not considered a barrier to development. Bird sanctuaries and fly ways should be avoided. Bats issues can largely be avoided by raising the turbine cut-in wind speed. Noise and aesthetics are issues that can generally be handled through open dialog citing the value and benefits from wind power that result from reducing coal and other fossil fuel burning and shrinking the “dead zones” in the bay and ocean. Public opinion is generally favorable toward wind in the Mid-Atlantic. Because of this, currently public interest and environmental issues are considered critically important but are not a barrier to wind energy development.

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Appendix A: Interview and Discussion Meetings (ground rules, questions, contacts and NGO meeting participants)

Interviews - with numerous industry stakeholders at conferences and meetings **–** see following ground rules, questions and interview form.

Program Progress Review Presentations

James Madison University, Virginia Wind Collaborative, Harrisonburg, VA, 17 June 2010 – "Mid-Atlantic Wind: Overcoming the Barriers"

Southern Application Regional Wind Institute Meeting, Washington, DC, 26 October 2011, "Mid-Atlantic Wind – overcoming the Challenges – Economic Issues"

American Wind Energy Association, Offshore Wind Conference, Baltimore, MD, 15 August 2011 – Paper title: Redefining Offshore – Mid-Atlantic Bays and Sounds an Overlooked Opportunity?

James Madison University, Virginia Wind Energy Symposium, Harrisonburg, VA, 20-21 June 2012 – Presentations B. Buckheit, "Policy and Regulatory Barriers – Next Steps"
L. Sparling, "Variability in Mid-Atlantic Wind from Measurements"
D. Ancona, "Offshore Wind – Value in Shallow Sheltered Waters."

Information Exchange meeting with Non-Governmental Organizations (NGOs)
NGO meeting hosted by Chesapeake Bay Foundation, Richmond, VA, 1 March 2011 – see meeting agenda and meeting participants.

Mid-Atlantic Wind – Overcoming the Challenges
Defining and Overcoming the Technical, Economic and Legal Issues

Background
The mid-Atlantic region, including Delaware, Maryland, North Carolina, Virginia, and District of Columbia, has excellent wind energy potential but no utility scale projects have been installed to date. The absence of wind energy projects continues despite a growing demand for electricity that is among the highest in the nation. Ample wind resources are available at sites in four distinct application areas: 1) Appalachian mountain ridgelines, 2) Coastal planes, i.e. Delmarva Peninsula, 3) Sheltered shallow waters of Delaware and Chesapeake Bays, Albemarle and Pamlico Sounds, and 4)Deeper water sites on the continental shelf off the Atlantic coast.

Princeton Energy Resources International (PERI) was selected by United States Department of Energy (DOE), through an open competitive process, to lead a study to identify barriers to wind energy development in this region and to determined barrier reduction mechanisms or mitigation measures. The DOE grant, DE-EE0000315.000, included a cost share supported by the Maryland Department of Natural Resources (DNR), for wind resource assessment through University of Maryland Baltimore County. Chesapeake Bay Foundation agreed to assist in the analysis of environmental issues.

Following are interview starter questions but others may get to root causes for stalled development. Where possible provide documentation to illustrate specific barriers. We can insure anonymity if necessary

Issue Questions:
General

1. What comes to mind as the primary barrier to mid-Atlantic wind?
2. What are the primary administrative/legal barriers to project development:
   a. In Delaware?
   b. In District of Columbia?
   c. In Maryland?
   d. In North Carolina?
   e. In Virginia?
   f. What are the primary reasons for slow wind energy development in the region?
3. What barriers do you see for the distinct markets:
   a. Appalachian mountain ridgelines?
   b. Coastal planes, i.e. Delmarva Peninsula?
   c. Sheltered shallow waters of Delaware and Chesapeake Bays, Albemarle and Pamlico Sounds?
   d. Deeper water sites off the Atlantic coast?
4. Powerful low level wind jets have been identified in coastal areas. How should this information be verified and documented for the wind industry and other stakeholders?
5. The DOE supported anemometer loan programs have been at 50 – 60 meter heights above ground level. How should additional measurements up to 200 m AGL be obtained to validate recent 80 m wind resource maps?

Project Approval Process

1. What are the reasons that wind installations in the Atlantic Ocean appear to be favored over shallow water sites in protected waters of regional bays and sounds.
2. What parts of the approval process take the most time to complete and/or ultimately stops projects? How can the process be changed to streamline approvals and accept more projects?
3. What is your experience with community education and acceptance of wind projects? What type of community education programs would reduce barriers in communities?

Cost or Price

4. Residential electricity prices increased significantly in 2009, averaging 14.16 cents/kWh in DE, 15.12 in MD, 9.99 in NC, 10.66 in VA and 13.50 in DC, among the highest in the nation behind New England, Alaska and Hawaii. These prices could be stabilized and reduced with local large scale wind development. What are the reasons that these options are not yet aggressively pursued by public utility commissions?
5. How could transportation cost of renewable energy be factored into credits/certificates needed to meet state portfolio standards?
6. How could local job creation, along with state and local tax revenues be factored into the energy policy decision making?
7. PJM pegs the capacity value at 13% while actual capacity factors for WV plants average 25-29% (with old style turbines). How could the true value be factored into the price for power? Including carbon reduction, health benefits, dead zones due reduced nitrogen loading on bays, etc.?
8. How can Renewable Energy Certificates (RECs) for wind be best used?

Interconnection

9. Have grid connection approvals been an obstacle? Example?
10. How could existing dams (i.e. 548 MW Conowingo or dams in TVA) or pumped storage be used to enhance the value of wind energy?
11. In Germany, the cost of transmission lines bringing the grid to a project is borne by the power system, not the project. How could the this be done in US for land-based plants? For offshore plants?

Environmental

12. How should environmental issues be balanced and compared. For example:
    a. Mountain top removal coal mining vs. ridgeline wind mining?
    b. Dead zones in the bays vs. view shed concerns?
    c. Impacts on birds and bats from acid rain vs. blade strikes?
    d. Not-In-My Back-Yard (NIMBY) concerns for ridgeline vs. farmlands vs. shallow water bays/sounds vs. more expensive deep water sites?
13. Others

Other Issues?

Mid-Atlantic Wind – Overcoming the Challenges
Notes – Interviewer ____________________

Interviewee: ___________________________ **Business Card:**
Date/Place: ___________________________
Name: ______________________________
Company: ____________________________
Address: _____________________________
____
Phone: ______________________________

Issue Questions:
General

1. Primary barrier?
2. Administrative/legal:
   a. In Delaware?
   b. In District of Columbia?
   c. In Maryland?
   d. In North Carolina?
   e. In Virginia?
   f. Regional?
3. Market specific:
   a. Mountain ridgelines?
   b. Coastal planes?
   c. Sheltered shallow waters?
   d. Ocean?
4. Wind resources and low level jets?
5. Value of anemometer loan programs?
6. Other?

Mid-Atlantic Wind – Overcoming the Challenges (Cont.)
Notes – Interviewer ______________________

Project Approval Process

1. Public Service Commission level? Local level?
2. Atlantic Ocean vs. bay and sounds?
3. Streamlining approvals?
4. Community acceptance?
5. Others?

Cost or Price

6. Power pricing? Wheeling cost?
7. Job creation?
8. PJM capacity value vs. capacity factor?
9. Renewable Energy Certificates (REC) value?
10. Others?

Interconnection

11. Transmission line connection cost?
12. Grid connection approvals?
13. Hydro storage?
14. Other?

Environmental

15. Balancing environmental issues?
16. Others

Other Issues?

Meeting on Mid-Atlantic Wind Energy
With
Regional Environmental Groups and Non-Government Organizations (NGOs)
Hosted by Chesapeake Bay Foundation and Princeton Energy Resources International, LLC
Richmond, Virginia
1 March 2011

Participants:

Appalachian Voices
Mike McCoy
Tom Cormons
Phone 434.293.6373
Appalachian Voices is an environmental non-profit focusing on reducing coal's impact on the central and southern Appalachian region.

Chesapeake Bay Foundation
Mike Gerel
Capitol Place
1108 E. Main Street
Suite 1600
Richmond, Virginia 23219-3539
Phone 804.780.1392
*Chesapeake Bay Foundation*s sets agenda and speaks on behalf of the bay while fighting for strong and effective laws and regulations while working in partnership with government, businesses, and citizens.

Chesapeake Climate Action Network
Chelsea Harnish
Beth Kempler
Phone 804.767.8983 (C. Harnish)
Phone 804.335.0915 (B. Kemplar)
Chesapeake Climate Action Network fights global warming in Maryland, Virginia, and Washington D.C. through mobilization of grassroots movements.

Macaulay & Burtch, PC
Hunter W. Jamerson
The Branch Building
1015 East Main Street
Richmond, Virginia 23219-3527
Phone: 804.649.0985
Macaulay & Burtch is a Richmond law firm that focuses on employment and labor law, government affairs and regulatory litigation.

Piedmont Environmental Council
Daniel Holmes
Robert Marmet
45 Horner Street
Warrenton, Virginia 20186
Phone 540.347.2334 (D. Holmes)
Phone 571.213.4250 (R. Marmet)
Piedmont Environmental Council is an organization with over 40 years of strategic planning in environmental issues including but not limited to renewable energy and land use.

Sierra Club
Glen Besa (Chair, Virginia Chapter)
Ivy Main Vice-Chair Virginia Chapter)
422 East Franklin Street
Suite 302
Richmond, Virginia 23219
Phone 804.387.6001 (G. Besa)
Phone 703.448.7618 (I. Main)

Eileen Levandoski
Virginia Beach, Virginia
Phone 757.277.8537
Sierra Club is a grassroots environmental organization which works to protect communities, wild places, and the planet itself.

Virginia Conservation Network
Nathan Lott
422 East Franklin Street
Suite 303
Richmond, Virginia 23219
Phone 804.644.0283
Virginia Conservation Network represents more than 100 nonprofits and community groups through public policy research, advocacy, education, and capacity building for its member organizations.

Appendix B: Economic Model Run Examples

Two cases are presented. The first is, under current (first half 2012), likely financing, case number 8, Calvert Cliffs Shallow Bay, with PJM Forward Pricing using 2015 Adder Prices, at 50% debt to 50% equity. The second is, under current (first half 2012), likely financing, case number 6, Cloverdale Ridgeline, using Calculated COEs that meet target IRR and debt coverage limits, at 50% debt to 50% equity.

For each case, included are two pages of summary and input information, three pages of earnings, three pages of cash flows, and a one-page graph.

First Case
Under current (first half 2012), likely financing, case number 8, Calvert Cliffs Shallow Bay, with PJM Forward Pricing using 2015 Adder Prices, at 50% debt to 50% equity.

SUMMARY PAGE Calvert Cliffs Shallow Bays 100 MW IPP - PJM frwd Pricing 50% debt, with Monetized PTC 05/19/12 10:36 PM

File: 0517_50.50_shortBayCalvertCliffs_IPPWind2012_Adder.xlsx

Construction and Development Assumptions and Operating Results

All figures are in thousands of U.S. dollars.

Capital					
Total Project Cost		250,190			
Start Date		2013	at 100% for year 1		
Project Description		100 MW Wind Farm, owned by taxable IPP, using Project Finance, selling merchant power, by on/off-peak PJM Forward Pricing Curves. Calvert Cliffs Shallow Bays using 2015 Adder Prices.			
Finance					
Debt		125,095	at 7.500%	for 20 years	
Secondary Debt		0	at 7.500%	for 7 years	
Equity		125,095			

Total		250,190			
Operations					
Net Rated Capacity		100,000	kW, using	5,000	kW-rated turbines
Actual Hours/Year		8,760	hours/year	20	turbines
Wind Resource		Class 4 Winds			
Net Capacity Factor		35.35%			
Plant Annual Electricity		309,666	thou kWh/year		
Contract Term		25	years	31	max years
Operations & Maintenance - fixed		$22.00	/kW or	$110,000	/turbine - year
escalating at		2.50%	/year	equiv to 0.710 c/kWh	
Operations & Maintenance - var.		$0.000	/kWh		
escalating at		2.50%	/year		
For land payment, select 1 = percentage revenues, 2 = fixed rent				2	ok
Site Owner Royalty	not used	0.00%	of revenues		
Site Owner Land Rent	used	$80.00	thous/year or	$4,000	/turbine - year
escalating at		2.50%	/year	equiv to 0.026 c/kWh	
Property Tax		0.000%	of depreciable base		
escalating at		2.50%	/year		
where base depreciates		4.00%	/year, till hits	30.0%	
Insurance	1,055	0.440%	of depreciable base esc. at	2.50%	/year
Major Maintenance & Overhauls		$700.00	thous/year or	$35,000	/turbine - year
escalating at		2.50%	/year	equiv to 0.226 c/kWh or $7.00/kW	
				--	
Inflation		2.50%	/year		
Interest Earned on Reserves		2.70%	/year; Interest on Work. Cap	0.50%	/year

Loaded Capital Cost per kW Capacity		2,502	[250190 / 100]		
Cost per Annual kWh		$0.81	[250190 / 309666]		
--	--		--		
RETURNS					
using a discount rate of		9.00%			
1 Pre-tax Unleveraged IRR		6.078%	over 25 years		
Net Present Value		(57,694)	using 9%		
Payback		14	years		
2 After-tax Leveraged IRR		13.258%	over 25 years	Target 17%	
Net Present Value		27,597	using 9%		
Payback		5	years		
2a Cash-on-Cash Return, excluding PTC		10.781%	average		
(before-tax cash on equity, non-discounted)		1.042%	minimum		
COST OF UTILITY ENERGY	+---- -->	$0.0546	/kWh - first year		
in currency of 2013	+---- -->	$0.0784	/kWh - nominal levelized		
	+---- -->	$0.0609	/kWh - constant$ levelized		
in currency of the year	+---- -->	$0.0800	/kWh - year 21		
in currency of 2012	+---- -->	$0.0765	/kWh - nominal levelized		
	+---- -->	$0.0594	/kWh - constant$ levelized		
using a discount rate of	7.00% nominal				
	4.39% constant (with no inflation)				
				BB-rated Merchant	BBB-rated PPA
DEBT COVERAGE	*** PTC is monetized to cover debt payment. ***			Min Target	Min Target
Senior Debt Coverage ratio:		2.428	average	3.00 times	1.50 times
		1.644	minimum	1.80 times	1.30 times
Secondary Debt Coverage ratio:		--	average		
--		--	minimum		
Equipment Overhaul Reserve & Drawdown?	no, not undertaken		ok		
Every 10 years, at 0 %, 0%, 0% and 0% of plant cost.					

05/14/2012 note: This Excel spreadsheet model shows cash flow financials for wind energy projects. Enter data in cells with blue lettering as: pg 1: project cost & performance;
pg 2 (Sources): capital costs & selected financial, pg 4 (Revenues): Rev. case (some on pg 31); pg 13 (Cash Flow): COE disc rate; pg 15 (LP): LP pct shares; pg 17 (Debt): PTC details;
pg 19 (Work Sheet #1): depreciation; pg 21 (Work Sheet #2): senior debt; pg 23 (Work Sheet #3): secondary debt; pg 29: graph title.
By trial and error, a user seeks low COE, an attractive equity return, and good debt coverage, which results are summarized on page 1.

This particular Project is 100 MW, using Class 4 Winds winds with a 35.35% capacity factor. Contract term is 25 years.
Capital Cost is $2300 /kW. O&M is $22 /kW and $0 /kWh and $700 thousand per year.

This Project TAKES the 10-year Section 45 Production Tax Credit. Revenues use on-peak/off-peak PJM Forward Pricing Curves.
Financing is 50% senior debt at 7.5% for 20 years and 0% secondary debt and 50% equity.
Sales Tax is $ 0 thousands. Property tax is 0 % of depreciable base, escalating at inflation, but with base depreciating at 4% per year till hits 30%.
To print, hit File, Print, Entire Workbook. Printout is 30 pages for 20 years and 39 pages for 30 years. With all Revenue data, prinout is 73 or 82 pages.

06/07/2012 page 1

Sources and Uses of Funds — **Calvert Cliffs Shallow Bays 100 MW IPP - PJM frwd Pricing 50% debt, with Monetized PTC** — **05/19/12** **10:36 PM**

Uses of Funds *in thousands of mixed-year dollars*

Turbine }		0	
Tower }		161,000	
Step-up Transformer & Controls }		0	
Foundation		11,500	
Transportation		11,500	
Civil Works & Roads		0	
Assembly & Installation		9,200	
System Control & Data (SCADA)		2,300	
Stepup Transformer & Intraplant Interconr		25,300	
Substation & Transmission Lines		0	
Engineering, Permits, and Approval		9,200	
SubTotal	2,300 /kW		
Home Office Overhead		0	
Total	2,300 /kW		230,000
Sales Tax	0		0 *
Construction Financing	8,800		8,800 *
(estimated as $220 mil * 8% * 12 mos * 50% for level draw)			
Construction Insurance	(0.42%)		1,000 *
Land			0
Initial Working Capital: First Year			0
Debt Financing Fees	1,251		1,250 --
(Debt Closing [lawyers,accountants], Commitment Fee; all amortized over the life of the debt)			
Equity Financing Fees	2,502		2,500 --
(Tax Advice, Equity Organizational Costs, etc.; part amortized in 1 year, part in 5 years, part excluded)			--
Debt Service Reserve Fund	6,087		6,090 --
Working Capital, Operating Reserve	550		550
Equipment Repair Reserve Initial Pmt			0

			250,190

Misc.

Start Year	2013
Year 1 Calendar Fraction	100.00%
Factor w/ 2 debt pmts/yr	100.00%

Depreciation Rate #1: 20%, 32%, 19.2%, 11.52%, 11.52%, 5.76%, 0%
0%, 0%, 0%, 0%, 0%, 0%, 0%
0%, 0%, 0%, 0%, 0%, 0%, 0%

Depreciation Rate #2: 3.75%, 7.219%, 6.677%, 6.177%, 5.713%, 5.285%, 4.888%
4.522%, 4.462%, 4.461%, 4.462%, 4.461%, 4.462%, 4.461%
4.462%, 4.461%, 4.462%, 4.461%, 4.462%, 4.461%, 2.231%

Equity Amortization: 40% @ 5 years, 40% @ 1 year, and 20% @ no write-off

Sources of Funds

50.00%	Debt	125,095	at 7.500%	for 20 years	customized principal repayment
0.00%	Second Loan	0	at 7.500%	for 7 years	level mortgage
50.00%	Equity	125,095			
----------		----------			
100.00%		250,190			

Customized debt repayment is 1%, 1%, 1.5%, 1.5%, 1.8%, 1.8%, 2%, 2%, 2.4%, 2.4% and 2.7%, 2.7%, 3.1%, 3.1%, 3.5%, 35%, 4%, 4%, 4.2%, 4.2% and 2.2%, 2.2%, 2.5%, 25%, 2.5%, 2.5%, 2.5%, 2.5% and 2.5%, 2.5%, 2.5%, 25%, 2.5%, 2.5%, 2.5%, 2.5% and 2.1%, 2.1%, 2%, 2%, 0%, 0%, 0%, 0%, 0%, 0% and 0%, 0%, 0%, 0%,

Taxes

Marginal Tax Rate: Federal	35.00%	corporate federal rate is 35%,
State	7.69%	corporate "average" state is 7.69%,
Combined	40.00%	
Investment Tax Credit	0.00%	

Depreciation *Select 3, 5, 7, 10, 15, or 20 years; using macrs deprec.*

Depreciation Class Life #1	5	years; Percent at Life #1		100.00% ok
Depreciation Class Life #2	20	years; Percent at Life #2		0.00% ok
Amortization for Equity Finc'g Fees		40.00%	40.00%	20.00% (See B275 on Sheet3.)

Tax Treatment

Sum of Depreciable Items		239,800 including sales tax		
Primary System Depreciable Base			239,800	5 years
less Tax Credit Adjustmt	50.00%	0		
Primary System Depreciable Base		239,800		
Other Depreciable Base			0	20 years
Amortization over Sr Debt's Life			1,250	20 years
Amortization over Second Debt's Life			0	7 years
5 years' Amortization			1,000	
1 years' Amortization			1,000	
No Write-Off			500	
Land			0	
First Year Start-Up (expensed in yr 1)			0	
Reserve Funds			6,640	

			250,190	ok

06/07/2012 page 2

Earnings — **Calvert Cliffs Shallow Bays 100 MW IPP - PJM frwd Pricing 50% debt, with Monetized PTC** — **05/19/12** — **10:36 PM**

All figures in $thousands.

			0	1	2	3	4	5	6	7	8	9	10
			2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	Power (thou kWh)			309,591	309,644	309,655	310,698	309,638	309,610	309,591	310,715	309,582	309,610
	Revenues												
	Energy Payment	5 Adder Prices		15,171	15,432	18,298	18,750	19,094	19,537	19,981	20,527	20,907	21,364
	Capacity Payment			1,752	1,770	3,159	3,210	3,222	3,254	3,286	3,340	3,352	3,386
	REC			929	948	966	989	1,005	1,026	1,046	1,071	1,088	1,110
	Interest on Reserves			167	167	167	167	167	167	167	167	167	167
	Total Revenues			18,019	18,316	22,590	23,116	23,489	23,984	24,480	25,105	25,514	26,027
	Operating Costs												
	Operations & Maintenance - fixed			2,200	2,255	2,311	2,369	2,428	2,489	2,551	2,615	2,680	2,747
	Operations & Maintenance - var.			0	0	0	0	0	0	0	0	0	0
	Site Owner Land Rent			80	82	84	86	88	91	93	95	97	100
	Property Tax			0	0	0	0	0	0	0	0	0	0
	Insurance			1,055	1,081	1,109	1,136	1,165	1,194	1,224	1,254	1,286	1,318
	Major Maintenance & Overhauls			700	718	735	754	773	792	812	832	853	874
	Total Operating Costs			4,035	4,136	4,239	4,345	4,454	4,565	4,680	4,796	4,916	5,039
	Operating Income			13,984	14,180	18,351	18,771	19,035	19,419	19,801	20,308	20,598	20,988
	Other Expenses												
	Interest on Loan #1			9,335	9,124	8,829	8,481	8,087	7,623	7,098	6,497	5,817	5,057
	Interest on Loan #2			0	0	0	0	0	0	0	0	0	0
	Loan Guarantee Fee			0	0	0	0	0	0	0	0	0	0
	Depreciation			47,960	76,736	46,042	27,625	27,625	13,812	0	0	0	0
	Repair Depreciation			0	0	0	0	0	0	0	0	0	0
	Amortization			1,263	263	263	263	263	63	63	63	63	63
	Total Other Expenses			58,558	86,123	55,133	36,369	35,975	21,498	7,160	6,560	5,879	5,119
	Before-Tax Profits			(44,574)	(71,942)	(36,782)	(17,598)	(16,940)	(2,079)	12,640	13,749	14,718	15,868
40.00%	Income Tax Paid (Benefit Rec'd)			(17,829)	(28,777)	(14,713)	(7,039)	(6,776)	(832)	5,056	5,500	5,887	6,347
	Investment Tax Credit Received			0	0								
	Production Tax Credits Received			6,813	6,983	7,158	7,336	7,520	7,708	7,901	8,098	8,301	8,508
	After-Tax Profits			(19,932)	(36,182)	(14,911)	(3,222)	(2,644)	6,460	15,485	16,347	17,132	18,029

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Earnings		Calvert Cliffs Shallow Bays 100 MW IFP - PJM frwd Pricing 50% debt, with Monetized PTC								05/19/12	10:36 PM	
All figures in $thousands.												
		11	12	13	14	15	16	17	18	19	20	21
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Power (thou kWh)		309,638	310,651	309,644	309,655	309,582	310,698	309,610	309,591	309,644	310,642	309,582
Revenues												
Energy Payment	5 Adder Prices	21,832	22,438	22,867	23,400	23,934	24,541	25,026	25,608	26,208	26,929	27,444
Capacity Payment		3,420	3,475	3,489	3,524	3,559	3,617	3,630	3,666	3,704	3,763	3,777
REC		1,132	1,159	1,178	1,202	1,225	1,254	1,275	1,301	1,327	1,358	1,380
Interest on Reserves		167	167	167	167	167	167	167	167	167	167	3
Total Revenues		26,552	27,239	27,702	28,293	28,885	29,580	30,099	30,742	31,405	32,217	32,605
Operating Costs												
Operations & Maintenance - fixed		2,816	2,887	2,959	3,033	3,109	3,186	3,266	3,348	3,431	3,517	3,605
Operations & Maintenance - var.		0	0	0	0	0	0	0	0	0	0	0
Site Owner Land Rent		102	105	108	110	113	116	119	122	125	128	131
Property Tax		0	0	0	0	0	0	0	0	0	0	0
Insurance		1,351	1,384	1,419	1,454	1,491	1,528	1,566	1,605	1,646	1,687	1,729
Major Maintenance & Overhauls		896	918	941	965	989	1,014	1,039	1,065	1,092	1,119	1,147
Total Operating Costs		5,165	5,294	5,427	5,562	5,702	5,844	5,990	6,140	6,293	6,451	6,612
Operating Income		21,387	21,945	22,275	22,731	23,184	23,736	24,109	24,602	25,112	25,766	25,993
Other Expenses												
Interest on Loan #1		4,363	3,936	3,467	2,998	2,528	2,059	1,590	1,121	671	281	0
Interest on Loan #2		0	0	0	0	0	0	0	0	0	0	0
Loan Guarantee Fee		0	0	0	0	0	0	0	0	0	0	0
Depreciation		0	0	0	0	0	0	0	0	0	0	0
Repair Depreciation		0	0	0	0	0	0	0	0	0	0	0
Amortization		63	63	63	63	63	63	63	63	63	63	0
Total Other Expenses		4,425	3,998	3,529	3,060	2,591	2,122	1,653	1,184	733	344	0
Before-Tax Profits		16,961	17,947	18,746	19,671	20,593	21,614	22,456	23,419	24,379	25,422	25,993
Income Tax Paid (Benefit Rec'd)	40.00%	6,785	7,179	7,498	7,868	8,237	8,645	8,982	9,367	9,751	10,169	10,397
Investment Tax Credit Received												
Production Tax Credits Received		0	0	0	0	0	0	0	0	0	0	0
After-Tax Profits		10,177	10,768	11,247	11,802	12,356	12,968	13,474	14,051	14,627	15,253	15,596

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Earnings Calvert Cliffs Shallow Bays 100 MW IPP - PJM frwd Pricing 50% debt, with Monetized PTC 05/19/12 10:36 PM

All figures in $thousands.

			22	23	24	25	26	27	28	29	30	31	32
			2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
	Power (thou kWh)		309,666	309,666	309,666	309,666	0	0	0	0	0	0	0
	Revenues												
	Energy Payment	5 Adder Prices	28,001	28,561	29,132	29,715	0	0	0	0	0	0	0
	Capacity Payment		3,854	3,893	3,932	3,971	0	0	0	0	0	0	0
	REC		1,436	1,465	1,494	1,524	0	0	0	0	0	0	0
	Interest on Reserves		3	3	3	3	0	0	0	0	0	0	0
	Total Revenues		33,294	33,922	34,561	35,213	0	0	0	0	0	0	0
	Operating Costs												
	Operations & Maintenance - fixed		3,695	3,787	3,882	3,979	0	0	0	0	0	0	0
	Operations & Maintenance - var.		0	0	0	0	0	0	0	0	0	0	0
	Site Owner Land Rent		134	138	141	145	0	0	0	0	0	0	0
	Property Tax		0	0	0	0	0	0	0	0	0	0	0
	Insurance		1,772	1,816	1,862	1,908	0	0	0	0	0	0	0
	Major Maintenance & Overhauls		1,176	1,205	1,235	1,266	0	0	0	0	0	0	0
	Total Operating Costs		6,777	6,947	7,120	7,298	0	0	0	0	0	0	0
	Operating Income		26,517	26,975	27,441	27,914	0	0	0	0	0	0	0
	Other Expenses												
	Interest on Loan #1		0	0	0	0	0	0	0	0	0	0	0
	Interest on Loan #2		0	0	0	0	0	0	0	0	0	0	0
	Loan Guarantee Fee		0	0	0	0	0	0	0	0	0	0	0
	Depreciation		0	0	0	0	0	0	0	0	0	0	0
	Repair Depreciation		0	0	0	0	0	0	0	0	0	0	0
	Amortization		0	0	0	0	0	0	0	0	0	0	0
	Total Other Expenses		0	0	0	0	0	0	0	0	0	0	0
	Before-Tax Profits		26,517	26,975	27,441	27,914	0	0	0	0	0	0	0
40.00%	Income Tax Paid (Benefit Rec'd)		10,607	10,790	10,976	11,166	0	0	0	0	0	0	0
	Investment Tax Credit Received												
	Production Tax Credits Received		0	0	0	0	0	0	0	0	0	0	0
	After-Tax Profits		15,910	16,185	16,464	16,749	0	0	0	0	0	0	0

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Cash Flow & COE — Calvert Cliffs Shallow Bays 100 MW IPP - PJM frwd Pricing 50% debt, with Monetized PTC — 05/19/12 10:36 PM

All figures in $thousands.	0 2012	1 2013	2 2014	3 2015	4 2016	5 2017	6 2018	7 2019	8 2020	9 2021	10 2022
Before-Tax Profits		(44,574)	(71,942)	(36,782)	(17,598)	(16,940)	(2,079)	12,640	13,749	14,718	15,868
Add Back:											
Year 1 Cash from Financing		0									
Depreciation & Repair Deprec.		47,960	76,736	46,042	27,625	27,625	13,812	0	0	0	0
Amortization		1,263	263	263	263	263	63	63	63	63	63
Released from Reserve		0	0	0	0	0	0	0	0	0	0
Total Additions		49,223	76,999	46,304	27,887	27,887	13,875	63	63	63	63
Subtract Off:											
Loan #1 Principal		2,502	3,753	4,503	5,004	6,005	6,755	7,756	8,757	10,008	10,508
Loan #2 Principal		0	0	0	0	0	0	0	0	0	0
Other (e.g., Reserve Deposit)		0	0	0	0	0	0	0	0	0	0
Total Subtractions		2,502	3,753	4,503	5,004	6,005	6,755	7,756	8,757	10,008	10,508
Before-Tax Cash		2,147	1,304	5,019	5,285	4,943	5,041	4,947	5,055	4,773	5,423
Taxes Payable (Benefit Received)		(17,829)	(28,777)	(14,713)	(7,039)	(6,776)	(832)	5,056	5,500	5,887	6,347
Investment Tax Credit		0	0								
Production Tax Credit		6,813	6,983	7,158	7,336	7,520	7,708	7,901	8,098	8,301	8,508
After-Tax Cash	(125,095)	26,789	37,063	26,889	19,661	19,239	13,580	7,791	7,653	7,187	7,584

After-tax IRR 13.258%
using starting estimate of 12.000%
Net Present Value 27,597 , using 9.00% as discount rate for developer

	0 2012	1 2013	2 2014	3 2015	4 2016	5 2017	6 2018	7 2019	8 2020	9 2021	10 2022
Payback		5									
		1	1	1	1	1	0	0	0	0	0

Cash-on-Cash Return (before-tax cash vs. equity investment, ignoring time value of money [and discount factor] and excluding tax credits, tax losses, tax payments)
Minimum 1.04% <-- -- Reset both as years of project l
Average 10.78%

	0 2012	1 2013	2 2014	3 2015	4 2016	5 2017	6 2018	7 2019	8 2020	9 2021	10 2022
Before-Tax Cash and Equity Investment	(125,095)	2,147	1,304	5,019	5,285	4,943	5,041	4,947	5,055	4,773	5,423
BT Cash to Equity Investment (not discounted)		1.72%	1.04%	4.01%	4.23%	3.95%	4.03%	3.95%	4.04%	3.82%	4.33%

		1 2013	2 2014	3 2015	4 2016	5 2017	6 2018	7 2019	8 2020	9 2021	10 2022
COST OF ENERGY	Cal fraction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Electric Revenues:	Energy	15,171	15,432	18,298	18,750	19,094	19,537	19,981	20,527	20,907	21,364
	Capacity	1,752	1,770	3,159	3,210	3,222	3,254	3,286	3,340	3,352	3,386
Total (thousands)		16,923	17,202	21,457	21,960	22,316	22,791	23,267	23,867	24,259	24,750

Net Present Value 282,986 , using 7.000% <--- SET THIS! Before-tax rate, from utility's cost of capital
Current $ Levelized 24,283 as Rate * NPV/(1-(1+Rate)^(-n)) (e.g., 4.50% for tax-free coop; 7.05% for IOU) *

lev COE/kWh $0.0784 in nominal terms of 2013
lev COE/kWh $0.0765 in nominal terms of 2012

04/30/01 note: NPV boosts year 1 to 100% and cuts any N+1 last year to zero.

1st-yr Cost $0.0546
Constant $ NPV 282,986 , as nominal
Constant $ levelized 18,869 , using 4.390% = (1 + 0.07)/(1 + 0.025) - 1
lev COE/kWh $0.0609 in constant terms of 2013
lev COE/kWh $0.0594 in constant terms of 2012

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Cash Flow & COE

Calvert Cliffs Shallow Bays 100 MW IPP - PJM frwd Pricing 50% debt, with Monetized PTC 05/19/12 10:36 PM

All figures in $thousands.	11 2023	12 2024	13 2025	14 2026	15 2027	16 2028	17 2029	18 2030	19 2031	20 2032	21 2033
Before-Tax Profits	16,961	17,947	18,746	19,671	20,593	21,614	22,456	23,419	24,379	25,422	25,993
Add Back:											
Year 1 Cash from Financing											
Depreciation & Repair Deprec.	0	0	0	0	0	0	0	0	0	0	0
Amortization	63	63	63	63	63	63	63	63	63	63	0
Released from Reserve	0	0	0	0	0	0	0	0	0	6,090	0
Total Additions	63	63	63	63	63	63	63	63	63	6,153	0
Subtract Off:											
Loan #1 Principal	5,504	6,255	6,255	6,255	6,255	6,255	6,255	6,255	5,254	5,004	0
Loan #2 Principal	0	0	0	0	0	0	0	0	0	0	0
Other (e.g., Reserve Deposit)	0	0	0	0	0	0	0	0	0	0	0
Total Subtractions	5,504	6,255	6,255	6,255	6,255	6,255	6,255	6,255	5,254	5,004	0
Before-Tax Cash	11,520	11,754	12,553	13,478	14,400	15,421	16,264	17,226	19,187	26,571	25,993
Taxes Payable (Benefit Received)	6,785	7,179	7,498	7,868	8,237	8,645	8,982	9,367	9,751	10,169	10,397
Investment Tax Credit											
Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0
After-Tax Cash	4,735	4,576	5,055	5,610	6,163	6,776	7,281	7,859	9,436	16,402	15,596
	0	0	0	0	0	0	0	0	0	0	0
life varies.											
Before-Tax Cash and Equity Investment	11,520	11,754	12,553	13,478	14,400	15,421	16,264	17,226	19,187	26,571	25,993
BT Cash to Equity Investment (not discour	9.21%	9.40%	10.04%	10.77%	11.51%	12.33%	13.00%	13.77%	15.34%	21.24%	20.78%

		11	12	13	14	15	16	17	18	19	20	21
COST OF ENERGY	Cal fraction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Electric Revenues:	Energy	21,832	22,438	22,867	23,400	23,934	24,541	25,026	25,608	26,208	26,929	27,444
	Capacity	3,420	3,475	3,489	3,524	3,559	3,617	3,630	3,666	3,704	3,763	3,777
Total (thousands)		25,252	25,913	26,356	26,924	27,493	28,158	28,657	29,275	29,912	30,692	31,222

*To figure Discount rate:

Utility debt	55.00%	5.50%
preferred	1.00%	5.30%
common	44.00%	9.00%
weighted average cost of capit		7.04%

fraction energy vs. capacity			2013 year 1 bid	2013 nominal	2013 constant
Energy sum	574,696	87.11%	$0.0476	$0.0683	$0.0531
Capac sum	85,008	12.89%	$0.0070	$0.0101	$0.0079
Total	659,704	100.00%	$0.0546	$0.0784	$0.0609

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Cash Flow & COE — Calvert Cliffs Shallow Bays 100 MW IPP - PJM frwd Pricing 50% debt, with Monetized PTC — 05/19/12 10:36 PM

All figures in $thousands.	22 2034	23 2035	24 2036	25 2037	26 2038	27 2039	28 2040	29 2041	30 2042	31 2043	32 2044
Before-Tax Profits	26,517	26,975	27,441	27,914	0	0	0	0	0	0	0
Add Back:											
Year 1 Cash from Financing											
Depreciation & Repair Deprec.	0	0	0	0	0	0	0	0	0	0	0
Amortization	0	0	0	0	0	0	0	0	0	0	0
Released from Reserve	0	0	0	0	0	0	0	0	0	0	0
Total Additions	0	0	0	0	0	0	0	0	0	0	0
Subtract Off:											
Loan #1 Principal	0	0	0	0	0	0	0	0	0	0	0
Loan #2 Principal	0	0	0	0	0	0	0	0	0	0	0
Other (e.g., Reserve Deposit)	0	0	0	0	0	0	0	0	0	0	0
Total Subtractions	0	0	0	0	0	0	0	0	0	0	0
Before-Tax Cash	26,517	26,975	27,441	27,914	0	0	0	0	0	0	0
Taxes Payable (Benefit Received)	10,607	10,790	10,976	11,166	0	0	0	0	0	0	0
Investment Tax Credit											
Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0
After-Tax Cash	15,910	16,185	16,464	16,749	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
Before-Tax Cash and Equity Investment	26,517	26,975	27,441	27,914	0	0	0	0	0	0	0
BT Cash to Equity Investment (not discou	21.20%	21.56%	21.94%	22.31%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
COST OF ENERGY Cal fraction	100%	100%	100%	100%	0%	100%	100%	100%	100%	100%	100%
Electric Revenues: Energy	28,001	28,561	29,132	29,715	0	0	0	0	0	0	0
Capacity	3,854	3,893	3,932	3,971	0	0	0	0	0	0	0
Total (thousands)	31,855	32,454	33,064	33,686	0	0	0	0	0	0	

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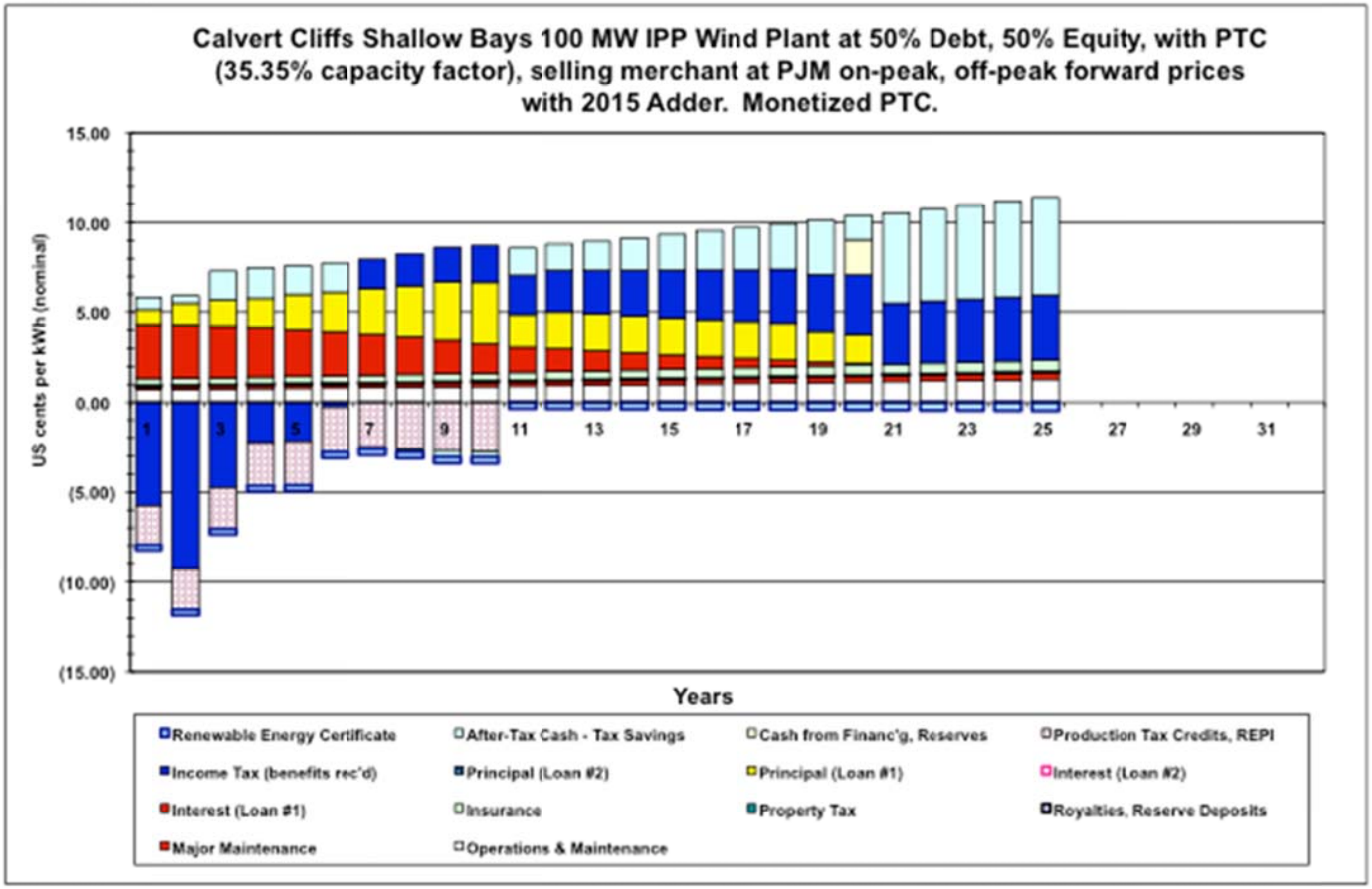

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Appendix B – Second Case

Under current (first half 2012), likely financing, case number 6, Cloverdale Ridgeline, using Calculated COEs that meet target IRR and debt coverage limits, at 50% debt to 50% equity.

SUMMARY PAGE | **Cloverdale Ridgeline 100 MW IPP - calculated COE; 50% debt, with Monetized PTC** | **05/16/12** | **7:11 PM**

File: 0516_50.50_shortRidgeline_IPPWind2012_CalcCOE.xlsx

Construction and Development Assumptions and Operating Results
All figures are in thousands of U.S. dollars.

Capital

Total Project Cost		174,675			
Start Date		2013	at 100% for year 1		
Project Description		100 MW Wind Farm, owned by taxable IPP, using Project Finance, selling merchant power, with COE calculated to give target IRR and debt coverage Cloverdale Ridgeline.			

Finance

Debt	87,338	at 7.500%	for 20 years
Secondary Debt	0	at 7.500%	for 7 years
Equity	87,338		

Total	174,675		

Operations

Net Rated Capacity		100,500	kW, using		1,500	kW-rated turbines
Actual Hours/Year		8,760	hours/year		67	turbines
Wind Resource		Class 4 Winds				
Net Capacity Factor		34.20%				
Plant Annual Electricity		301,090	thou kWh/year			
Contract Term		25	years		31	max years
Operations & Maintenance - fixed		21.33	/kW or	$31,995	/turbine - year	
escalating at		2.50%	/year	equiv to 0.712 c/kWh		
Operations & Maintenance - var.		$0.000	/kWh			
escalating at		2.50%	/year			
For land payment, select 1 = percentage revenues, 2 = fixed rent					2	ok
Site Owner Royalty	*not used*	0.00%	of revenues			
Site Owner Land Rent	*used*	$335.00	thous/year or	$5,000	/turbine - year	
escalating at		2.50%	/year	equiv to 0.111 c/kWh		
Property Tax		1.100%	of depreciable base			
escalating at		2.50%	/year			
where base depreciates		4.00%	/year, till hits		30.0%	
Insurance	521	0.311%	of depreciable base esc. at		2.50%	/year
Major Maintenance & Overhauls		$615.00	thous/year or	$9,179	/turbine - year	
escalating at		2.50%	/year	equiv to 0.204 c/kWh or $6.12/kW		
				--		
Inflation		2.50%	/year			
Interest Earned on Reserves		2.70%	/year; Interest on Work. Cap		0.50%	/year

Loaded Capital Cost per kW Capacity		1,738	[174675 / 100.5]
Cost per Annual kWh		$0.58	[174675 / 301089.96]
--	--		--

RETURNS

	using a discount rate of	9.00%		
1	Pre-tax Unleveraged IRR	8.035%	over 25 years	
	Net Present Value	(13,586)	using 9%	
	Payback	12	years	
2	After-tax Leveraged IRR	19.685%	over 25 years	Target 17%
	Net Present Value	48,967	using 9%	
	Payback	4	years	
2a	Cash-on-Cash Return, excluding PTC	14.509%	average	
	(before-tax cash on equity, non-discounted)	6.666%	minimum	

COST OF UTILITY ENERGY	+---- -->	$0.0629	/kWh - first year
in currency of 2013	+---- -->	$0.0743	/kWh - nominal levelized
	+---- -->	$0.0577	/kWh - constant$ levelized
in currency of the year	+---- -->	$0.0800	/kWh - year 21
in currency of 2012	+---- -->	$0.0725	/kWh - nominal levelized
	+---- -->	$0.0563	/kWh - constant$ levelized
using a discount rate of	7.00%	nominal	
	4.39%	constant (with no inflation)	

				BB-rated Merchant	BBB-rated PPA
DEBT COVERAGE	*** PTC is monetized to cover debt payment. ***			Min Target	Min Target
Senior Debt Coverage ratio:		3.018	average	3.00 times	1.50 times
		2.291	minimum	1.80 times	1.30 times
Secondary Debt Coverage ratio:		--	average		
--		--	minimum		

Equipment Overhaul Reserve & Drawdown?	no, not undertaken	ok
Every 10 years, at 0 %, 0%, 0% and 0% of plant cost.		

05/14/2012 note: This Excel spreadsheet model shows cash flow financials for wind energy projects. Enter data in cells with blue lettering as: pg 1: project cost & performance;
pg 2 (Sources): capital costs & selected financial, pg 4 (Revenues): Rev. case (some on pg 31); pg 13 (Cash Flow): COE disc rate; pg 15 (LP): LP pct shares; pg 17 (Debt): PTC details;
pg 19 (Work Sheet #1): depreciation; pg 21 (Work Sheet #2): senior debt; pg 23 (Work Sheet #3): secondary debt; pg 29: graph title.
By trial and error, a user seeks low COE, an attractive equity return, and good debt coverage, which results are summarized on page 1.

This particular Project is 100.5 MW, using Class 4 Winds winds with a 34.2% capacty factor. Contract term is 25 years.
Capital Cost is $1596.67 /kW. O&M is $21.33 /kW and $0 /kWh and $615 thousand per year.

This Project TAKES the 10-year Section 45 Production Tax Credit. Revenues are those where COE is calculated to give target IRR and debt coverage.
Financing is 50% senior debt at 7.5% for 20 years and 0% secondary debt and 50% equity.
Sales Tax is $ 0 thousands. Property tax is 1.1 % of depreciable base, escalating at inflation, but with base depreciating at 4% per year till hits 30%.
To print, hit File, Print, Entire Workbook. Printout is 30 pages for 20 years and 39 pages for 30 years. With all Revenue data, prinout is 73 or 82 pages.

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Sources and Uses of Funds — **Cloverdale Ridgeline 100 MW IPP - calculated COE; 50% debt, with Monetized PTC** — **05/16/12** **7:11 PM**

Uses of Funds *in thousands of mixed-year dollars*

Turbine		96,078		
Tower		13,132		
Step-up Transformer & Controls		1,340		
Foundation		6,097		
Transportation		6,365		
Civil Works & Roads		9,849		
Assembly & Installation		6,365		
System Control & Data (SCADA)		1,340		
Plant Substations & Intraconnection		15,812		
Transmission Lines		0		
Engineering, Permits, and Approval		4,087		
SubTotal	1,597 /kW			
Home Office Overhead		0		
Total	1,597 /kW		160,465	
Sales Tax	0		0	*
Construction Financing	6,200		6,200	*
(estimated as $155 mil * 8% * 12 mos * 50% for level draw)				
Construction Insurance	(0.36%)		600	*
Land			0	
Initial Working Capital: First Year			0	
Debt Financing Fees	873		870	--
(Debt Closing [lawyers,accountants], Commitment Fee; all amortized over the life of the debt)				
Equity Financing Fees	1,747		1,750	--
(Tax Advice, Equity Organizational Costs, etc.; part amortized in 1 year, part in 5 years, part excluded)				--
Debt Service Reserve Fund	4,250		4,250	--
Working Capital, Operating Reserve	536		540	
Equipment Repair Reserve Initial Pmt			0	

			174,675	

Misc.

Start Year	2013
Year 1 Calendar Fraction	100.00%
Factor w/ 2 debt pmts/yr	100.00%

Depreciation Rate #1: 20%, 32%, 19.2%, 11.52%, 11.52%, 5.76%, 0%
0%, 0%, 0%, 0%, 0%, 0%, 0%
0%, 0%, 0%, 0%, 0%, 0%, 0%

Depreciation Rate #2: 3.75%, 7.219%, 6.677%, 6.177%, 5.713%, 5.285%, 4.888%
4.522%, 4.462%, 4.461%, 4.462%, 4.461%, 4.462%, 4.461%
4.462%, 4.461%, 4.462%, 4.461%, 4.462%, 4.461%, 2.231%

Equity Amortization: 40% @ 5 years, 40% @ 1 year, and 20% @ no write-off

Sources of Funds

50.00%	Debt	87,338	at 7.500%	for 20 years	customized principal repayment
0.00%	Second Loan	0	at 7.500%	for 7 years	level mortgage
50.00%	Equity	87,338			
----------		----------			
100.00%		174,675			

Customized debt repayment is 1%, 1%, 1.5%, 1.5%, 1.8%, 1.8%, 2%, 2%, 2.4%, 2.4% and 2.7%, 2.7%, 3.1%, 3.1%, 3.5%, 3.5%, 4%, 4%, 4.2%, 4.2% and 2.2%, 2.2%, 2.5%, 2.5%, 2.5%, 2.5%, 2.5%, 2.5% and 2.5%, 2.5%, 2.5%, 2.5%, 2.5%, 2.5%, 2.5% and 2.1%, 2.1%, 2%, 2%, 0%, 0%, 0%, 0%, 0%, 0% and 0%, 0%, 0%, 0%,

Taxes

Marginal Tax Rate: Federal	35.00%	corporate federal rate is 35%,
State	7.69%	corporate "average" state is 7.69%,
Combined	40.00%	
Investment Tax Credit	0.00%	

Depreciation *Select 3, 5, 7, 10, 15, or 20 years; using macrs deprec.*

Depreciation Class Life #1	5	years; Percent at Life #1		100.00%	ok
Depreciation Class Life #2	20	years; Percent at Life #2		0.00%	ok
Amortization for Equity Finc'g Fees		40.00%	40.00%	20.00%	(See B275 on Sheet3.)

Tax Treatment

Sum of Depreciable Items		167,265 including sales tax		
Primary System Depreciable Base			167,265	5 years
less Tax Credit Adjustmt	50.00%	0		
Primary System Depreciable Base		167,265		
Other Depreciable Base			0	20 years
Amortization over Sr Debt's Life			870	20 years
Amortization over Second Debt's Life			0	7 years
5 years' Amortization			700	
1 years' Amortization			700	
No Write-Off			350	
Land			0	
First Year Start-Up (expensed in yr 1)			0	
Reserve Funds			4,790	

			174,675	ok

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Earnings — Cloverdale Ridgeline 100 MW IPP - calculated COE; 50% debt, with Monetized PTC — 05/16/12 — 7:11 PM

All figures in $thousands.

	0	1	2	3	4	5	6	7	8	9	10
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Power (thou kWh)		301,090	301,090	301,090	301,090	301,090	301,090	301,090	301,090	301,090	301,090
Revenues											
Energy Payment --		16,861	17,198	17,542	17,893	18,251	18,616	18,988	19,368	19,755	20,151
Capacity Payment		2,070	2,091	2,112	2,139	2,154	2,176	2,197	2,225	2,242	2,264
REC		903	921	940	959	978	997	1,017	1,038	1,058	1,079
Interest on Reserves		117	117	117	117	117	117	117	117	117	117
Total Revenues		19,952	20,328	20,711	21,108	21,500	21,906	22,320	22,748	23,173	23,611
Operating Costs											
Operations & Maintenance - fixed		2,144	2,197	2,252	2,308	2,366	2,425	2,486	2,548	2,612	2,677
Operations & Maintenance - var.		0	0	0	0	0	0	0	0	0	0
Site Owner Land Rent		335	343	352	361	370	379	388	398	408	418
Property Tax		1,840	1,810	1,778	1,744	1,706	1,665	1,622	1,575	1,524	1,471
Insurance		521	534	547	561	575	589	604	619	634	650
Major Maintenance & Overhauls		615	630	646	662	679	696	713	731	749	768
Total Operating Costs		5,454	5,515	5,576	5,636	5,696	5,755	5,813	5,871	5,928	5,984
Operating Income		14,497	14,813	15,135	15,472	15,805	16,152	16,507	16,877	17,245	17,627
Other Expenses											
Interest on Loan #1		6,518	6,370	6,164	5,921	5,646	5,322	4,955	4,536	4,061	3,531
Interest on Loan #2		0	0	0	0	0	0	0	0	0	0
Loan Guarantee Fee		0	0	0	0	0	0	0	0	0	0
Depreciation		33,453	53,525	32,115	19,269	19,269	9,634	0	0	0	0
Repair Depreciation		0	0	0	0	0	0	0	0	0	0
Amortization		884	184	184	184	184	44	44	44	44	44
Total Other Expenses		40,854	60,078	38,462	25,374	25,099	15,000	4,999	4,580	4,105	3,574
Before-Tax Profits		(26,357)	(45,266)	(23,327)	(9,902)	(9,294)	1,151	11,508	12,298	13,140	14,053
40.00% Income Tax Paid (Benefit Rec'd)		(10,543)	(18,106)	(9,331)	(3,961)	(3,718)	461	4,603	4,919	5,256	5,621
Investment Tax Credit Received		0	0								
Production Tax Credits Received		6,624	6,790	6,959	7,133	7,312	7,494	7,682	7,874	8,071	8,272
After-Tax Profits		(9,190)	(20,370)	(7,037)	1,192	1,735	8,185	14,587	15,253	15,955	16,704

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Earnings | **Cloverdale Ridgeline 100 MW IPP - calculated COE; 50% debt, with Monetized PTC** | **05/16/12** | **7:11 PM**

All figures in $thousands.

		11	12	13	14	15	16	17	18	19	20	21
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	Power (thou kWh)	301,090	301,090	301,090	301,090	301,090	301,090	301,090	301,090	301,090	301,090	301,090
	Revenues											
	Energy Payment --	20,554	20,965	21,384	21,812	22,248	22,693	23,147	23,610	24,082	24,563	24,087
	Capacity Payment	2,287	2,316	2,333	2,356	2,379	2,410	2,427	2,452	2,476	2,508	2,526
	REC	1,101	1,123	1,146	1,168	1,192	1,216	1,240	1,265	1,290	1,316	1,342
	Interest on Reserves	117	117	117	117	117	117	117	117	117	117	3
	Total Revenues	24,059	24,521	24,979	25,453	25,936	26,436	26,931	27,443	27,965	28,504	27,958
	Operating Costs											
	Operations & Maintenance - fixed	2,744	2,813	2,883	2,955	3,029	3,105	3,182	3,262	3,343	3,427	3,513
	Operations & Maintenance - var.	0	0	0	0	0	0	0	0	0	0	0
	Site Owner Land Rent	429	440	451	462	473	485	497	510	522	536	549
	Property Tax	1,413	1,352	1,287	1,217	1,144	1,066	983	896	861	882	904
	Insurance	667	683	700	718	736	754	773	792	812	832	853
	Major Maintenance & Overhauls	787	807	827	848	869	891	913	936	959	983	1,008
	Total Operating Costs	6,040	6,094	6,148	6,200	6,251	6,301	6,349	6,396	6,498	6,661	6,827
	Operating Income	18,019	18,427	18,832	19,253	19,686	20,135	20,582	21,048	21,467	21,844	21,131
	Other Expenses											
	Interest on Loan #1	3,046	2,748	2,420	2,093	1,765	1,438	1,110	783	468	197	0
	Interest on Loan #2	0	0	0	0	0	0	0	0	0	0	0
	Loan Guarantee Fee	0	0	0	0	0	0	0	0	0	0	0
	Depreciation	0	0	0	0	0	0	0	0	0	0	0
	Repair Depreciation	0	0	0	0	0	0	0	0	0	0	0
	Amortization	44	44	44	44	44	44	44	44	44	44	0
	Total Other Expenses	3,089	2,791	2,464	2,136	1,809	1,481	1,154	826	512	240	0
	Before-Tax Profits	14,929	15,635	16,368	17,117	17,877	18,654	19,429	20,221	20,955	21,604	21,131
40.00%	Income Tax Paid (Benefit Rec'd)	5,972	6,254	6,547	6,847	7,151	7,462	7,771	8,089	8,382	8,642	8,452
	Investment Tax Credit Received											
	Production Tax Credits Received	0	0	0	0	0	0	0	0	0	0	0
	After-Tax Profits	8,958	9,381	9,821	10,270	10,726	11,192	11,657	12,133	12,573	12,962	12,679

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Earnings — **Cloverdale Ridgeline 100 MW IPP - calculated COE; 50% debt, with Monetized PTC** — **05/16/12** — **7:11 PM**

All figures in $thousands.

	22	23	24	25	26	27	28	29	30	31	32
	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Power (thou kWh)	301,090	301,090	301,090	301,090	0	0	0	0	0	0	0
Revenues											
Energy Payment --	24,569	25,060	25,562	26,073	0	0	0	0	0	0	0
Capacity Payment	2,577	2,602	2,628	2,655	0	0	0	0	0	0	0
REC	1,396	1,424	1,453	1,482	0	0	0	0	0	0	0
Interest on Reserves	3	3	3	3	0	0	0	0	0	0	0
Total Revenues	28,545	29,090	29,645	30,212	0	0	0	0	0	0	0
Operating Costs											
Operations & Maintenance - fixed	3,600	3,690	3,783	3,877	0	0	0	0	0	0	0
Operations & Maintenance - var.	0	0	0	0	0	0	0	0	0	0	0
Site Owner Land Rent	563	577	591	606	0	0	0	0	0	0	0
Property Tax	927	950	974	998	0	0	0	0	0	0	0
Insurance	875	896	919	942	0	0	0	0	0	0	0
Major Maintenance & Overhauls	1,033	1,059	1,085	1,112	0	0	0	0	0	0	0
Total Operating Costs	6,998	7,173	7,352	7,536	0	0	0	0	0	0	0
Operating Income	21,547	21,917	22,293	22,676	0	0	0	0	0	0	0
Other Expenses											
Interest on Loan #1	0	0	0	0	0	0	0	0	0	0	0
Interest on Loan #2	0	0	0	0	0	0	0	0	0	0	0
Loan Guarantee Fee	0	0	0	0	0	0	0	0	0	0	0
Depreciation	0	0	0	0	0	0	0	0	0	0	0
Repair Depreciation	0	0	0	0	0	0	0	0	0	0	0
Amortization	0	0	0	0	0	0	0	0	0	0	0
Total Other Expenses	0	0	0	0	0	0	0	0	0	0	0
Before-Tax Profits	21,547	21,917	22,293	22,676	0	0	0	0	0	0	0
40.00% Income Tax Paid (Benefit Rec'd)	8,619	8,767	8,917	9,070	0	0	0	0	0	0	0
Investment Tax Credit Received											
Production Tax Credits Received	0	0	0	0	0	0	0	0	0	0	0
After-Tax Profits	12,928	13,150	13,376	13,606	0	0	0	0	0	0	0

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Cash Flow & COE — Cloverdale Ridgeline 100 MW IPP - calculated COE; 50% debt, with Monetized PTC — 05/16/12 — 7:11 PM

All figures in $thousands.	0 2012	1 2013	2 2014	3 2015	4 2016	5 2017	6 2018	7 2019	8 2020	9 2021	10 2022
Before-Tax Profits		(26,357)	(45,266)	(23,327)	(9,902)	(9,294)	1,151	11,508	12,298	13,140	14,053
Add Back:											
Year 1 Cash from Financing		0									
Depreciation & Repair Deprec.		33,453	53,525	32,115	19,269	19,269	9,634	0	0	0	0
Amortization		884	184	184	184	184	44	44	44	44	44
Released from Reserve		0	0	0	0	0	0	0	0	0	0
Total Additions		34,337	53,708	32,298	19,452	19,452	9,678	44	44	44	44
Subtract Off:											
Loan #1 Principal		1,747	2,620	3,144	3,494	4,192	4,716	5,415	6,114	6,987	7,336
Loan #2 Principal		0	0	0	0	0	0	0	0	0	0
Other (e.g., Reserve Deposit)		0	0	0	0	0	0	0	0	0	0
Total Subtractions		1,747	2,620	3,144	3,494	4,192	4,716	5,415	6,114	6,987	7,336
Before-Tax Cash		6,233	5,822	5,827	6,057	5,966	6,113	6,137	6,228	6,196	6,760
Taxes Payable (Benefit Received)		(10,543)	(18,106)	(9,331)	(3,961)	(3,718)	461	4,603	4,919	5,256	5,621
Investment Tax Credit		0	0								
Production Tax Credit		6,624	6,790	6,959	7,133	7,312	7,494	7,682	7,874	8,071	8,272
After-Tax Cash	(87,338)	23,400	30,718	22,117	17,151	16,995	13,147	9,215	9,182	9,011	9,411

After-tax IRR 19.685%
using starting estimate of 12.000%
Net Present Value 48,967 , using 9.00% as discount rate for developer

	0	1	2	3	4	5	6	7	8	9	10
Payback		4									
		1	1	1	1	0	0	0	0	0	0

Cash-on-Cash Return (before-tax cash vs. equity investment, ignoring time value of money [and discount factor] and excluding tax credits, tax losses, tax payments) — Minimum 6.67% <-- -- Reset both as years of project l — Average 14.51%

	0	1	2	3	4	5	6	7	8	9	10
Before-Tax Cash and Equity Investment	(87,338)	6,233	5,822	5,827	6,057	5,966	6,113	6,137	6,228	6,196	6,760
BT Cash to Equity Investment (not discounted)		7.14%	6.67%	6.67%	6.93%	6.83%	7.00%	7.03%	7.13%	7.09%	7.74%

		1	2	3	4	5	6	7	8	9	10
COST OF ENERGY	Cal fraction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Electric Revenues:	Energy	16,861	17,198	17,542	17,893	18,251	18,616	18,988	19,368	19,755	20,151
	Capacity	2,070	2,091	2,112	2,139	2,154	2,176	2,197	2,225	2,242	2,264
Total (thousands)		18,931	19,289	19,654	20,032	20,405	20,792	21,186	21,593	21,997	22,414

Net Present Value 260,606 , using 7.000% <--- SET THIS! Before-tax rate, from utility's cost of capital
Current $ Levelized 22,363 as Rate * NPV/(1-(1+Rate)^(-n)) (e.g., 4.50% for tax-free coop; 7.05% for IOU) *

lev COE/kWh $0.0743 in nominal terms of 2013
lev COE/kWh $0.0725 in nominal terms of 2012

04/30/01 note: NPV boosts year 1 to 100% and cuts any N+1 last year to zero.

1st-yr Cost $0.0629
Constant $ NPV 260,606 , as nominal
Constant $ levelized 17,377 , using 4.390% = (1 + 0.07)/(1 + 0.025) - 1
lev COE/kWh $0.0577 in constant terms of 2013
lev COE/kWh $0.0563 in constant terms of 2012

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Cash Flow & COE — Cloverdale Ridgeline 100 MW IPP - calculated COE; 50% debt, with Monetized PTC — 05/16/12 — 7:11 PM

All figures in $thousands.	11 2023	12 2024	13 2025	14 2026	15 2027	16 2028	17 2029	18 2030	19 2031	20 2032	21 2033
Before-Tax Profits	14,929	15,635	16,368	17,117	17,877	18,654	19,429	20,221	20,955	21,604	21,131
Add Back:											
Year 1 Cash from Financing											
Depreciation & Repair Deprec.	0	0	0	0	0	0	0	0	0	0	0
Amortization	44	44	44	44	44	44	44	44	44	44	0
Released from Reserve	0	0	0	0	0	0	0	0	0	4,250	0
Total Additions	44	44	44	44	44	44	44	44	44	4,294	0
Subtract Off:											
Loan #1 Principal	3,843	4,367	4,367	4,367	4,367	4,367	4,367	4,367	3,668	3,493	0
Loan #2 Principal	0	0	0	0	0	0	0	0	0	0	0
Other (e.g., Reserve Deposit)	0	0	0	0	0	0	0	0	0	0	0
Total Subtractions	3,843	4,367	4,367	4,367	4,367	4,367	4,367	4,367	3,668	3,493	0
Before-Tax Cash	11,130	11,312	12,045	12,794	13,553	14,330	15,105	15,898	17,331	22,404	21,131
Taxes Payable (Benefit Received)	5,972	6,254	6,547	6,847	7,151	7,462	7,771	8,089	8,382	8,642	8,452
Investment Tax Credit											
Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0
After-Tax Cash	5,158	5,058	5,497	5,947	6,403	6,869	7,334	7,809	8,949	13,762	12,679
	0	0	0	0	0	0	0	0	0	0	0
life varies.											
Before-Tax Cash and Equity Investment	11,130	11,312	12,045	12,794	13,553	14,330	15,105	15,898	17,331	22,404	21,131
BT Cash to Equity Investment (not discour	12.74%	12.95%	13.79%	14.65%	15.52%	16.41%	17.30%	18.20%	19.84%	25.65%	24.19%

COST OF ENERGY	Cal fraction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Electric Revenues:	Energy	20,554	20,965	21,384	21,812	22,248	22,693	23,147	23,610	24,082	24,563	24,087
	Capacity	2,287	2,316	2,333	2,356	2,379	2,410	2,427	2,452	2,476	2,508	2,526
Total (thousands)		22,840	23,280	23,716	24,167	24,627	25,103	25,574	26,061	26,558	27,071	26,613

						2013 year 1 bid	2013 nominal	2013 constant
*To figure Discount rate:			fraction energy vs. capacity					
Utility debt	55.00%	5.50%	Energy sum	535,030	90.13%	$0.0567	$0.0669	$0.0520
preferred	1.00%	5.30%	Capac sum	58,599	9.87%	$0.0062	$0.0073	$0.0057
common	44.00%	9.00%						
			Total	593,628	100.00%	$0.0629	$0.0743	$0.0577
weighted average cost of capit		7.04%						

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Cash Flow & COE Cloverdale Ridgeline 100 MW IPP - calculated COE; 50% debt, with Monetized PTC 05/16/12 7:11 PM

All figures in $thousands.		22 2034	23 2035	24 2036	25 2037	26 2038	27 2039	28 2040	29 2041	30 2042	31 2043	32 2044
Before-Tax Profits		21,547	21,917	22,293	22,676	0	0	0	0	0	0	0
Add Back:												
Year 1 Cash from Financing												
Depreciation & Repair Deprec.		0	0	0	0	0	0	0	0	0	0	0
Amortization		0	0	0	0	0	0	0	0	0	0	0
Released from Reserve		0	0	0	0	0	0	0	0	0	0	0
Total Additions		0	0	0	0	0	0	0	0	0	0	0
Subtract Off:												
Loan #1 Principal		0	0	0	0	0	0	0	0	0	0	0
Loan #2 Principal		0	0	0	0	0	0	0	0	0	0	0
Other (e.g., Reserve Deposit)		0	0	0	0	0	0	0	0	0	0	0
Total Subtractions		0	0	0	0	0	0	0	0	0	0	0
Before-Tax Cash		21,547	21,917	22,293	22,676	0	0	0	0	0	0	0
Taxes Payable (Benefit Received)		8,619	8,767	8,917	9,070	0	0	0	0	0	0	0
Investment Tax Credit												
Production Tax Credit		0	0	0	0	0	0	0	0	0	0	0
After-Tax Cash		12,928	13,150	13,376	13,606	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0
Before-Tax Cash and Equity Investment		21,547	21,917	22,293	22,676	0	0	0	0	0	0	0
BT Cash to Equity Investment (not discou		24.67%	25.09%	25.53%	25.96%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
COST OF ENERGY	Cal fraction	100%	100%	100%	100%	0%	100%	100%	100%	100%	100%	100%
Electric Revenues:	Energy	24,569	25,060	25,562	26,073	0	0	0	0	0	0	0
	Capacity	2,577	2,602	2,628	2,655	0	0	0	0	0	0	0
Total (thousands)		27,145	27,663	28,190	28,727	0	0	0	0	0	0	

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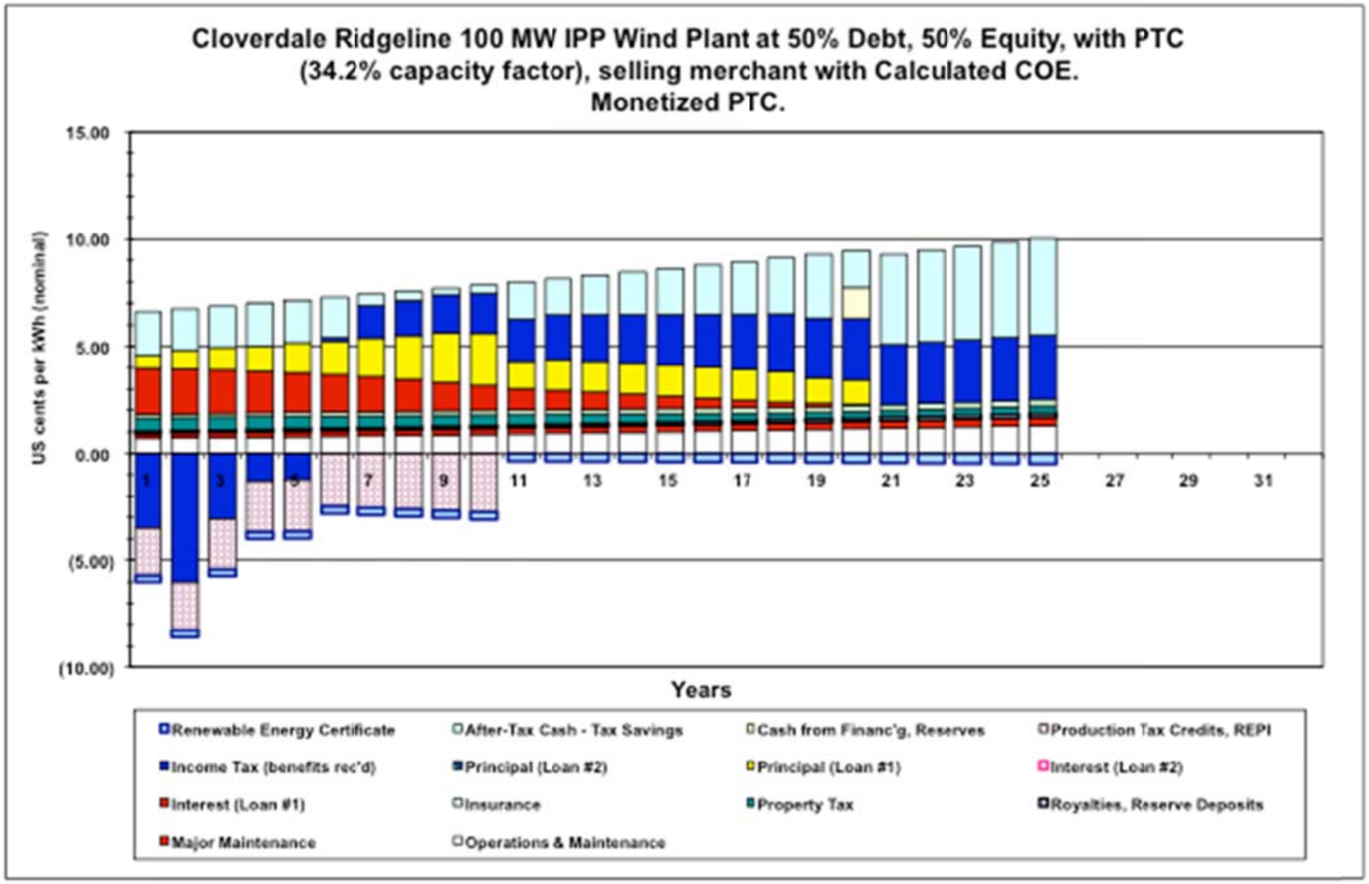

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Appendix C: Power Market Trading Model Results for the 2012 Mid-Atlantic Wind Energy Plants

Four cases are presented. These are DPL-ODEC Coastal Plains, Cloverdale Ridgeline, Calvert Cliffs Shallow Bay, and Fentress Ocean. Pricing, capacity factor, and hours are presented on a monthly basis for the years 2012 through 2035. Five pages of data are presented for each case.

In organizing the trading model results, the following definitions were employed.

1. Seasons are defined as: Fall: Sept-Nov, Winter: Dec-Feb, Spring: Mar-May, and Summer: June-Aug.

2. On-Peak vs. Off-Peak Hours, are defined by PJM, on a wholesale basis, as:

   Mon-Fri: Hours ending 0100 through 0700 and the hour ending 2400 are off-peak (11:01 pm through 7:00 am);

   Mon-Fri: Hours ending 0800 to the hour ending 23:00 are on-peak (7:01 am through 11:00 pm);

   Sat-Sun and holidays are off-peak.

3. Holidays are: New Year's Day - Jan 1*; Memorial Day - last Mon, May; Independence - July 4*; Labor Day - first Mon, Sept; Thanksgiving - fourth Thurs, Nov; Christmas - Dec 25*.

   *= if this holiday date is Sunday, then take Monday.

4. In the USA, Daylight Savings Time begins in March, on the second Sunday, when the clock "springs forward" to lose one hour. Daylight Savings Time ends in November, on the first Sunday, when the clock "falls back" to add one hour.

Farm Size (MW)
100

Capacity Factors							
On - Peak				Off - Peak			
Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
0.3641	0.3589	0.1295	0.2334	0.4011	0.3796	0.1502	0.2655

DPL_ODEC - Coastal Plains

		Wholesale Energy Prices		Capacity Adjusted MW		Monthly Hours		Energy Value		
YEAR	MONTH	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	Total
2012	1	$ 63.74	$ 39.05	0.00	0.00	336	408	$ 779,789	$ 639,088	$ 1,418,876
2012	2	$ 63.74	$ 39.05	0.00	0.00	336	360	$ 779,789	$ 563,901	$ 1,343,690
2012	3	$ 57.16	$ 31.05	0.00	0.00	352	391	$ 722,158	$ 460,834	$ 1,182,992
2012	4	$ 57.16	$ 31.05	0.00	0.00	336	384	$ 689,332	$ 452,584	$ 1,141,916
2012	5	$ 57.16	$ 31.05	0.00	0.00	352	392	$ 722,158	$ 462,013	$ 1,184,171
2012	6	$ 74.40	$ 38.03	0.00	0.00	336	384	$ 323,728	$ 219,348	$ 543,076
2012	7	$ 74.40	$ 38.03	0.00	0.00	336	408	$ 323,728	$ 233,057	$ 556,786
2012	8	$ 74.40	$ 38.03	0.00	0.00	368	376	$ 354,560	$ 214,778	$ 569,338
2012	9	$ 59.14	$ 33.49	0.00	0.00	304	416	$ 419,630	$ 369,920	$ 789,549
2012	10	$ 59.14	$ 33.49	0.00	0.00	368	376	$ 507,973	$ 334,350	$ 842,323
2012	11	$ 59.14	$ 33.49	0.00	0.00	336	385	$ 463,801	$ 342,353	$ 806,155
2012	12	$ 65.02	$ 41.05	0.00	0.00	320	424	$ 757,531	$ 698,163	$ 1,455,694
2013	1	$ 65.02	$ 41.05	0.00	0.00	352	392	$ 833,284	$ 645,472	$ 1,478,755
2013	2	$ 65.02	$ 41.05	0.00	0.00	320	352	$ 757,531	$ 579,607	$ 1,337,138
2013	3	$ 59.34	$ 33.05	0.00	0.00	336	407	$ 715,581	$ 510,591	$ 1,226,172
2013	4	$ 59.34	$ 33.05	0.00	0.00	352	368	$ 749,656	$ 461,665	$ 1,211,321
2013	5	$ 59.34	$ 33.05	0.00	0.00	352	392	$ 749,656	$ 491,773	$ 1,241,430
2013	6	$ 76.99	$ 40.03	0.00	0.00	320	400	$ 319,059	$ 240,504	$ 559,563
2013	7	$ 76.99	$ 40.03	0.00	0.00	352	392	$ 350,965	$ 235,694	$ 586,659
2013	8	$ 76.99	$ 40.03	0.00	0.00	352	392	$ 350,965	$ 235,694	$ 586,659
2013	9	$ 60.75	$ 34.49	0.00	0.00	320	400	$ 453,740	$ 366,286	$ 820,026
2013	10	$ 60.75	$ 34.49	0.00	0.00	368	376	$ 521,801	$ 344,309	$ 866,110
2013	11	$ 60.75	$ 34.49	0.00	0.00	320	401	$ 453,740	$ 367,202	$ 820,942
2013	12	$ 66.53	$ 42.05	0.00	0.00	336	408	$ 813,962	$ 688,182	$ 1,502,144
2014	1	$ 66.53	$ 42.05	0.00	0.00	352	392	$ 852,722	$ 661,195	$ 1,513,917
2014	2	$ 66.53	$ 42.05	0.00	0.00	320	352	$ 775,202	$ 593,726	$ 1,368,928
2014	3	$ 57.22	$ 36.05	0.00	0.00	336	407	$ 690,056	$ 556,940	$ 1,246,996
2014	4	$ 57.22	$ 36.05	0.00	0.00	352	368	$ 722,916	$ 503,573	$ 1,226,488
2014	5	$ 57.22	$ 36.05	0.00	0.00	336	408	$ 690,056	$ 558,309	$ 1,248,365
2014	6	$ 72.11	$ 41.03	0.00	0.00	336	384	$ 313,779	$ 236,651	$ 550,430
2014	7	$ 72.11	$ 41.03	0.00	0.00	352	392	$ 328,720	$ 241,581	$ 570,302
2014	8	$ 72.11	$ 41.03	0.00	0.00	336	408	$ 313,779	$ 251,442	$ 565,220
2014	9	$ 55.88	$ 34.49	0.00	0.00	336	384	$ 438,235	$ 351,635	$ 789,870
2014	10	$ 55.88	$ 34.49	0.00	0.00	368	376	$ 479,972	$ 344,309	$ 824,281
2014	11	$ 55.88	$ 34.49	0.00	0.00	304	417	$ 396,499	$ 381,853	$ 778,352
2014	12	$ 67.97	$ 42.95	0.00	0.00	352	392	$ 871,155	$ 675,346	$ 1,546,500
2015	1	$ 67.97	$ 42.95	0.00	0.00	336	408	$ 831,557	$ 702,911	$ 1,534,468
2015	2	$ 67.97	$ 42.95	0.00	0.00	320	352	$ 791,959	$ 606,433	$ 1,398,392
2015	3	$ 58.49	$ 36.82	0.00	0.00	352	391	$ 738,938	$ 546,549	$ 1,285,487
2015	4	$ 58.49	$ 36.82	0.00	0.00	352	368	$ 738,938	$ 514,399	$ 1,253,337
2015	5	$ 58.49	$ 36.82	0.00	0.00	320	424	$ 671,762	$ 592,677	$ 1,264,439
2015	6	$ 73.62	$ 41.88	0.00	0.00	352	368	$ 335,600	$ 231,489	$ 567,089
2015	7	$ 73.62	$ 41.88	0.00	0.00	368	376	$ 350,855	$ 236,521	$ 587,376
2015	8	$ 73.62	$ 41.88	0.00	0.00	336	408	$ 320,346	$ 256,651	$ 576,996
2015	9	$ 57.08	$ 35.24	0.00	0.00	336	384	$ 447,662	$ 359,281	$ 806,943
2015	10	$ 57.08	$ 35.24	0.00	0.00	352	392	$ 468,979	$ 366,766	$ 835,745
2015	11	$ 57.08	$ 35.24	0.00	0.00	320	401	$ 426,345	$ 375,187	$ 801,531
2015	12	$ 69.45	$ 43.87	0.00	0.00	352	392	$ 890,049	$ 689,850	$ 1,579,899
2016	1	$ 69.45	$ 43.87	0.00	0.00	320	424	$ 809,135	$ 746,164	$ 1,555,300
2016	2	$ 69.45	$ 43.87	0.00	0.00	336	360	$ 849,592	$ 633,536	$ 1,483,128
2016	3	$ 59.79	$ 37.62	0.00	0.00	368	375	$ 789,695	$ 535,492	$ 1,325,187
2016	4	$ 59.79	$ 37.62	0.00	0.00	336	384	$ 721,026	$ 548,343	$ 1,269,369
2016	5	$ 59.79	$ 37.62	0.00	0.00	336	408	$ 721,026	$ 582,615	$ 1,303,641
2016	6	$ 75.17	$ 42.75	0.00	0.00	352	368	$ 342,652	$ 236,305	$ 578,957
2016	7	$ 75.17	$ 42.75	0.00	0.00	320	424	$ 311,502	$ 272,264	$ 583,766
2016	8	$ 75.17	$ 42.75	0.00	0.00	368	376	$ 358,227	$ 241,442	$ 599,669
2016	9	$ 58.32	$ 36.01	0.00	0.00	336	384	$ 457,324	$ 367,119	$ 824,442
2016	10	$ 58.32	$ 36.01	0.00	0.00	336	408	$ 457,324	$ 390,063	$ 847,387
2016	11	$ 58.32	$ 36.01	0.00	0.00	336	385	$ 457,324	$ 368,075	$ 825,398
2016	12	$ 70.96	$ 44.82	0.00	0.00	336	408	$ 868,078	$ 733,481	$ 1,601,559
2017	1	$ 70.96	$ 44.82	0.00	0.00	336	408	$ 868,078	$ 733,481	$ 1,601,559
2017	2	$ 70.96	$ 44.82	0.00	0.00	320	352	$ 826,741	$ 632,807	$ 1,459,548
2017	3	$ 61.12	$ 38.43	0.00	0.00	368	375	$ 807,294	$ 547,082	$ 1,354,376
2017	4	$ 61.12	$ 38.43	0.00	0.00	320	400	$ 701,994	$ 583,554	$ 1,285,549
2017	5	$ 61.12	$ 38.43	0.00	0.00	352	392	$ 772,194	$ 571,883	$ 1,344,077
2017	6	$ 76.75	$ 43.64	0.00	0.00	352	368	$ 349,880	$ 241,241	$ 591,121
2017	7	$ 76.75	$ 43.64	0.00	0.00	320	424	$ 318,073	$ 277,951	$ 596,024
2017	8	$ 76.75	$ 43.64	0.00	0.00	368	376	$ 365,784	$ 246,485	$ 612,269

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Farm Size (MW)
100

Capacity Factors							
On - Peak				Off - Peak			
Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
0.3641	0.3589	0.1295	0.2334	0.4011	0.3796	0.1502	0.2655

DPL_ODEC - Coastal Plains

		Wholesale Energy Prices		Capacity Adjusted MW		Monthly Hours		Energy Value		
YEAR	MONTH	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	Total
2017	9	$ 59.58	$ 36.80	0.00	0.00	320	400	$ 444,979	$ 390,783	$ 835,762
2017	10	$ 59.58	$ 36.80	0.00	0.00	352	392	$ 489,476	$ 382,968	$ 872,444
2017	11	$ 59.58	$ 36.80	0.00	0.00	336	385	$ 467,227	$ 376,129	$ 843,356
2017	12	$ 72.51	$ 45.79	0.00	0.00	320	424	$ 844,787	$ 778,728	$ 1,623,515
2018	1	$ 72.51	$ 45.79	0.00	0.00	352	392	$ 929,265	$ 719,956	$ 1,649,222
2018	2	$ 72.51	$ 45.79	0.00	0.00	320	352	$ 844,787	$ 646,491	$ 1,491,278
2018	3	$ 62.49	$ 39.27	0.00	0.00	352	391	$ 789,448	$ 582,812	$ 1,372,260
2018	4	$ 62.49	$ 39.27	0.00	0.00	336	384	$ 753,564	$ 572,378	$ 1,325,942
2018	5	$ 62.49	$ 39.27	0.00	0.00	352	392	$ 789,448	$ 584,302	$ 1,373,750
2018	6	$ 78.38	$ 44.56	0.00	0.00	336	384	$ 341,048	$ 257,009	$ 598,057
2018	7	$ 78.38	$ 44.56	0.00	0.00	336	408	$ 341,048	$ 273,072	$ 614,120
2018	8	$ 78.38	$ 44.56	0.00	0.00	368	376	$ 373,529	$ 251,655	$ 625,184
2018	9	$ 60.87	$ 37.60	0.00	0.00	304	416	$ 431,914	$ 415,335	$ 847,249
2018	10	$ 60.87	$ 37.60	0.00	0.00	368	376	$ 522,843	$ 375,399	$ 898,242
2018	11	$ 60.87	$ 37.60	0.00	0.00	336	385	$ 477,379	$ 384,385	$ 861,763
2018	12	$ 74.09	$ 46.78	0.00	0.00	320	424	$ 863,284	$ 795,623	$ 1,658,907
2019	1	$ 74.09	$ 46.78	0.00	0.00	352	392	$ 949,612	$ 735,576	$ 1,685,188
2019	2	$ 74.09	$ 46.78	0.00	0.00	320	352	$ 863,284	$ 660,517	$ 1,523,801
2019	3	$ 63.89	$ 40.12	0.00	0.00	336	407	$ 770,446	$ 619,877	$ 1,390,323
2019	4	$ 63.89	$ 40.12	0.00	0.00	352	368	$ 807,133	$ 560,479	$ 1,367,612
2019	5	$ 63.89	$ 40.12	0.00	0.00	352	392	$ 807,133	$ 597,032	$ 1,404,165
2019	6	$ 80.05	$ 45.50	0.00	0.00	320	400	$ 331,712	$ 273,355	$ 605,066
2019	7	$ 80.05	$ 45.50	0.00	0.00	352	392	$ 364,883	$ 267,888	$ 632,770
2019	8	$ 80.05	$ 45.50	0.00	0.00	352	392	$ 364,883	$ 267,888	$ 632,770
2019	9	$ 62.20	$ 38.43	0.00	0.00	320	400	$ 464,556	$ 408,153	$ 872,708
2019	10	$ 62.20	$ 38.43	0.00	0.00	368	376	$ 534,239	$ 383,664	$ 917,903
2019	11	$ 62.20	$ 38.43	0.00	0.00	320	401	$ 464,556	$ 409,173	$ 873,729
2019	12	$ 75.72	$ 47.80	0.00	0.00	336	408	$ 926,355	$ 782,263	$ 1,708,619
2020	1	$ 75.72	$ 47.80	0.00	0.00	352	392	$ 970,467	$ 751,586	$ 1,722,054
2020	2	$ 75.72	$ 47.80	0.00	0.00	320	376	$ 882,243	$ 720,909	$ 1,603,152
2020	3	$ 65.32	$ 41.00	0.00	0.00	352	391	$ 825,261	$ 608,523	$ 1,433,784
2020	4	$ 65.32	$ 41.00	0.00	0.00	352	368	$ 825,261	$ 572,728	$ 1,397,989
2020	5	$ 65.32	$ 41.00	0.00	0.00	320	424	$ 750,237	$ 659,882	$ 1,410,119
2020	6	$ 81.75	$ 46.46	0.00	0.00	352	368	$ 372,666	$ 256,802	$ 629,468
2020	7	$ 81.75	$ 46.46	0.00	0.00	368	376	$ 389,606	$ 262,385	$ 651,991
2020	8	$ 81.75	$ 46.46	0.00	0.00	336	408	$ 355,727	$ 284,715	$ 640,442
2020	9	$ 63.56	$ 39.28	0.00	0.00	336	384	$ 498,449	$ 400,478	$ 898,926
2020	10	$ 63.56	$ 39.28	0.00	0.00	352	392	$ 522,184	$ 408,821	$ 931,005
2020	11	$ 63.56	$ 39.28	0.00	0.00	320	401	$ 474,713	$ 418,207	$ 892,920
2020	12	$ 77.39	$ 48.85	0.00	0.00	352	392	$ 991,844	$ 767,997	$ 1,759,841
2021	1	$ 77.39	$ 48.85	0.00	0.00	320	424	$ 901,676	$ 830,691	$ 1,732,367
2021	2	$ 77.39	$ 48.85	0.00	0.00	320	352	$ 901,676	$ 689,630	$ 1,591,306
2021	3	$ 66.80	$ 41.90	0.00	0.00	368	375	$ 882,198	$ 596,416	$ 1,478,614
2021	4	$ 66.80	$ 41.90	0.00	0.00	352	368	$ 843,842	$ 585,283	$ 1,429,125
2021	5	$ 66.80	$ 41.90	0.00	0.00	320	424	$ 767,129	$ 674,347	$ 1,441,476
2021	6	$ 83.50	$ 47.45	0.00	0.00	352	368	$ 380,645	$ 262,251	$ 642,895
2021	7	$ 83.50	$ 47.45	0.00	0.00	336	408	$ 363,343	$ 290,756	$ 654,099
2021	8	$ 83.50	$ 47.45	0.00	0.00	352	392	$ 380,645	$ 279,354	$ 659,999
2021	9	$ 64.95	$ 40.15	0.00	0.00	336	384	$ 509,380	$ 409,345	$ 918,726
2021	10	$ 64.95	$ 40.15	0.00	0.00	336	408	$ 509,380	$ 434,929	$ 944,310
2021	11	$ 64.95	$ 40.15	0.00	0.00	336	385	$ 509,380	$ 410,411	$ 919,792
2021	12	$ 79.10	$ 49.91	0.00	0.00	368	376	$ 1,059,835	$ 752,785	$ 1,812,619
2022	1	$ 79.10	$ 49.91	0.00	0.00	336	408	$ 967,675	$ 816,851	$ 1,784,527
2022	2	$ 79.10	$ 49.91	0.00	0.00	320	352	$ 921,596	$ 704,734	$ 1,626,330
2022	3	$ 68.30	$ 42.82	0.00	0.00	368	375	$ 902,109	$ 609,529	$ 1,511,639
2022	4	$ 68.30	$ 42.82	0.00	0.00	336	384	$ 823,665	$ 624,158	$ 1,447,823
2022	5	$ 68.30	$ 42.82	0.00	0.00	336	408	$ 823,665	$ 663,168	$ 1,486,833
2022	6	$ 85.30	$ 48.46	0.00	0.00	352	368	$ 388,823	$ 267,835	$ 656,658
2022	7	$ 85.30	$ 48.46	0.00	0.00	320	424	$ 353,475	$ 308,593	$ 662,068
2022	8	$ 85.30	$ 48.46	0.00	0.00	368	376	$ 406,497	$ 273,658	$ 680,154
2022	9	$ 66.38	$ 41.04	0.00	0.00	336	384	$ 520,585	$ 418,434	$ 939,020
2022	10	$ 66.38	$ 41.04	0.00	0.00	336	408	$ 520,585	$ 444,587	$ 965,172
2022	11	$ 66.38	$ 41.04	0.00	0.00	336	385	$ 520,585	$ 419,524	$ 940,109
2022	12	$ 80.85	$ 51.01	0.00	0.00	336	408	$ 989,113	$ 834,796	$ 1,823,910
2023	1	$ 80.85	$ 51.01	0.00	0.00	336	408	$ 989,113	$ 834,796	$ 1,823,910
2023	2	$ 80.85	$ 51.01	0.00	0.00	320	352	$ 942,013	$ 720,217	$ 1,662,229
2023	3	$ 69.85	$ 43.76	0.00	0.00	368	375	$ 922,518	$ 622,971	$ 1,545,489
2023	4	$ 69.85	$ 43.76	0.00	0.00	320	400	$ 802,190	$ 664,502	$ 1,466,692

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Farm Size (MW)
100

Capacity Factors							
On - Peak				Off - Peak			
Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
0.3641	0.3589	0.1295	0.2334	0.4011	0.3796	0.1502	0.2655

DPL_ODEC - Coastal Plains

		Wholesale Energy Prices		Capacity Adjusted MW		Monthly Hours		Energy Value		
YEAR	MONTH	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	Total
2023	5	$ 69.85	$ 43.76	0.00	0.00	352	392	$ 882,409	$ 651,212	$ 1,533,621
2023	6	$ 87.14	$ 49.49	0.00	0.00	352	368	$ 397,205	$ 273,560	$ 670,765
2023	7	$ 87.14	$ 49.49	0.00	0.00	320	424	$ 361,096	$ 315,188	$ 676,284
2023	8	$ 87.14	$ 49.49	0.00	0.00	368	376	$ 415,260	$ 279,507	$ 694,766
2023	9	$ 67.85	$ 41.96	0.00	0.00	320	400	$ 506,734	$ 445,574	$ 952,308
2023	10	$ 67.85	$ 41.96	0.00	0.00	352	392	$ 557,407	$ 436,662	$ 994,069
2023	11	$ 67.85	$ 41.96	0.00	0.00	336	385	$ 532,070	$ 428,865	$ 960,935
2023	12	$ 82.65	$ 52.14	0.00	0.00	320	424	$ 962,940	$ 886,649	$ 1,849,589
2024	1	$ 82.65	$ 52.14	0.00	0.00	352	392	$ 1,059,234	$ 819,732	$ 1,878,966
2024	2	$ 82.65	$ 52.14	0.00	0.00	336	360	$ 1,011,087	$ 752,815	$ 1,763,902
2024	3	$ 71.43	$ 44.73	0.00	0.00	336	407	$ 861,399	$ 691,085	$ 1,552,484
2024	4	$ 71.43	$ 44.73	0.00	0.00	352	368	$ 902,418	$ 624,863	$ 1,527,281
2024	5	$ 71.43	$ 44.73	0.00	0.00	352	392	$ 902,418	$ 665,615	$ 1,568,033
2024	6	$ 89.02	$ 50.55	0.00	0.00	320	400	$ 368,906	$ 303,725	$ 672,632
2024	7	$ 89.02	$ 50.55	0.00	0.00	352	392	$ 405,797	$ 297,651	$ 703,448
2024	8	$ 89.02	$ 50.55	0.00	0.00	352	392	$ 405,797	$ 297,651	$ 703,448
2024	9	$ 69.35	$ 42.89	0.00	0.00	320	400	$ 517,945	$ 455,521	$ 973,466
2024	10	$ 69.35	$ 42.89	0.00	0.00	368	376	$ 595,637	$ 428,190	$ 1,023,827
2024	11	$ 69.35	$ 42.89	0.00	0.00	320	401	$ 517,945	$ 456,660	$ 974,605
2024	12	$ 84.49	$ 53.29	0.00	0.00	336	408	$ 1,033,611	$ 872,044	$ 1,905,655
2025	1	$ 84.49	$ 53.29	0.00	0.00	352	392	$ 1,082,830	$ 837,846	$ 1,920,676
2025	2	$ 84.49	$ 53.29	0.00	0.00	320	352	$ 984,391	$ 752,351	$ 1,736,743
2025	3	$ 73.06	$ 45.72	0.00	0.00	336	407	$ 880,977	$ 706,412	$ 1,587,388
2025	4	$ 73.06	$ 45.72	0.00	0.00	352	368	$ 922,928	$ 638,721	$ 1,561,649
2025	5	$ 73.06	$ 45.72	0.00	0.00	336	408	$ 880,977	$ 708,147	$ 1,589,124
2025	6	$ 90.95	$ 51.64	0.00	0.00	336	384	$ 395,758	$ 297,852	$ 693,610
2025	7	$ 90.95	$ 51.64	0.00	0.00	352	392	$ 414,604	$ 304,057	$ 718,661
2025	8	$ 90.95	$ 51.64	0.00	0.00	336	408	$ 395,758	$ 316,468	$ 712,226
2025	9	$ 70.89	$ 43.85	0.00	0.00	336	384	$ 555,909	$ 447,088	$ 1,002,997
2025	10	$ 70.89	$ 43.85	0.00	0.00	368	376	$ 608,853	$ 437,774	$ 1,046,627
2025	11	$ 70.89	$ 43.85	0.00	0.00	304	417	$ 502,966	$ 485,510	$ 988,475
2025	12	$ 86.38	$ 54.47	0.00	0.00	352	392	$ 1,107,016	$ 856,413	$ 1,963,429
2026	1	$ 86.38	$ 54.47	0.00	0.00	336	408	$ 1,056,697	$ 891,369	$ 1,948,066
2026	2	$ 86.38	$ 54.47	0.00	0.00	320	352	$ 1,006,378	$ 769,024	$ 1,775,402
2026	3	$ 74.72	$ 46.74	0.00	0.00	352	391	$ 943,950	$ 693,734	$ 1,637,684
2026	4	$ 74.72	$ 46.74	0.00	0.00	352	368	$ 943,950	$ 652,926	$ 1,596,876
2026	5	$ 74.72	$ 46.74	0.00	0.00	320	424	$ 858,137	$ 752,284	$ 1,610,421
2026	6	$ 92.93	$ 52.76	0.00	0.00	352	368	$ 423,631	$ 291,606	$ 715,236
2026	7	$ 92.93	$ 52.76	0.00	0.00	368	376	$ 442,886	$ 297,945	$ 740,832
2026	8	$ 92.93	$ 52.76	0.00	0.00	336	408	$ 404,375	$ 323,302	$ 727,677
2026	9	$ 72.46	$ 44.84	0.00	0.00	336	384	$ 568,278	$ 457,121	$ 1,025,398
2026	10	$ 72.46	$ 44.84	0.00	0.00	352	392	$ 595,338	$ 466,644	$ 1,061,983
2026	11	$ 72.46	$ 44.84	0.00	0.00	320	401	$ 541,217	$ 477,358	$ 1,018,575
2026	12	$ 88.31	$ 55.68	0.00	0.00	352	392	$ 1,131,807	$ 875,444	$ 2,007,251
2027	1	$ 88.31	$ 55.68	0.00	0.00	320	424	$ 1,028,915	$ 946,909	$ 1,975,824
2027	2	$ 88.31	$ 55.68	0.00	0.00	320	352	$ 1,028,915	$ 786,113	$ 1,815,028
2027	3	$ 76.42	$ 47.78	0.00	0.00	368	375	$ 1,009,385	$ 680,183	$ 1,689,567
2027	4	$ 76.42	$ 47.78	0.00	0.00	352	368	$ 965,498	$ 667,486	$ 1,632,984
2027	5	$ 76.42	$ 47.78	0.00	0.00	320	424	$ 877,726	$ 769,060	$ 1,646,786
2027	6	$ 94.96	$ 53.90	0.00	0.00	352	368	$ 432,883	$ 297,924	$ 730,807
2027	7	$ 94.96	$ 53.90	0.00	0.00	336	408	$ 413,207	$ 330,308	$ 743,514
2027	8	$ 94.96	$ 53.90	0.00	0.00	352	392	$ 432,883	$ 317,354	$ 750,237
2027	9	$ 74.08	$ 45.85	0.00	0.00	336	384	$ 580,955	$ 467,404	$ 1,048,359
2027	10	$ 74.08	$ 45.85	0.00	0.00	336	408	$ 580,955	$ 496,617	$ 1,077,572
2027	11	$ 74.08	$ 45.85	0.00	0.00	336	385	$ 580,955	$ 468,622	$ 1,049,577
2027	12	$ 90.29	$ 56.92	0.00	0.00	368	376	$ 1,209,818	$ 858,423	$ 2,068,240
2028	1	$ 90.29	$ 56.92	0.00	0.00	336	408	$ 1,104,616	$ 931,480	$ 2,036,096
2028	2	$ 90.29	$ 56.92	0.00	0.00	336	360	$ 1,104,616	$ 821,894	$ 1,926,510
2028	3	$ 78.17	$ 48.85	0.00	0.00	368	375	$ 1,032,475	$ 695,391	$ 1,727,866
2028	4	$ 78.17	$ 48.85	0.00	0.00	320	400	$ 897,805	$ 741,750	$ 1,639,555
2028	5	$ 78.17	$ 48.85	0.00	0.00	352	392	$ 987,585	$ 726,915	$ 1,714,500
2028	6	$ 97.04	$ 55.07	0.00	0.00	352	368	$ 442,367	$ 304,401	$ 746,768
2028	7	$ 97.04	$ 55.07	0.00	0.00	320	424	$ 402,152	$ 350,723	$ 752,875
2028	8	$ 97.04	$ 55.07	0.00	0.00	368	376	$ 462,474	$ 311,018	$ 773,493
2028	9	$ 75.74	$ 46.88	0.00	0.00	320	400	$ 565,666	$ 497,859	$ 1,063,525
2028	10	$ 75.74	$ 46.88	0.00	0.00	352	392	$ 622,233	$ 487,902	$ 1,110,135
2028	11	$ 75.74	$ 46.88	0.00	0.00	336	385	$ 593,949	$ 479,190	$ 1,073,139
2028	12	$ 92.32	$ 58.19	0.00	0.00	320	424	$ 1,075,693	$ 989,636	$ 2,065,328

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Farm Size (MW)
100

Capacity Factors							
On - Peak				Off - Peak			
Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
0.3641	0.3589	0.1295	0.2334	0.4011	0.3796	0.1502	0.2655

DPL_ODEC - Coastal Plains

		Wholesale Energy Prices		Capacity Adjusted MW		Monthly Hours		Energy Value		
YEAR	MONTH	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	Total
2029	1	$ 92.32	$ 58.19	0.00	0.00	352	392	$ 1,183,262	$ 914,946	$ 2,098,208
2029	2	$ 92.32	$ 58.19	0.00	0.00	320	352	$ 1,075,693	$ 821,584	$ 1,897,277
2029	3	$ 79.97	$ 49.95	0.00	0.00	352	391	$ 1,010,224	$ 741,314	$ 1,751,538
2029	4	$ 79.97	$ 49.95	0.00	0.00	336	384	$ 964,305	$ 728,042	$ 1,692,347
2029	5	$ 79.97	$ 49.95	0.00	0.00	352	392	$ 1,010,224	$ 743,210	$ 1,753,434
2029	6	$ 99.18	$ 56.27	0.00	0.00	336	384	$ 431,538	$ 324,563	$ 756,101
2029	7	$ 99.18	$ 56.27	0.00	0.00	336	408	$ 431,538	$ 344,848	$ 776,387
2029	8	$ 99.18	$ 56.27	0.00	0.00	368	376	$ 472,637	$ 317,801	$ 790,439
2029	9	$ 77.44	$ 47.94	0.00	0.00	304	416	$ 549,433	$ 529,478	$ 1,078,912
2029	10	$ 77.44	$ 47.94	0.00	0.00	368	376	$ 665,104	$ 478,567	$ 1,143,671
2029	11	$ 77.44	$ 47.94	0.00	0.00	336	385	$ 607,269	$ 490,022	$ 1,097,291
2029	12	$ 94.41	$ 59.49	0.00	0.00	320	424	$ 1,099,963	$ 1,011,803	$ 2,111,766
2030	1	$ 94.41	$ 59.49	0.00	0.00	352	392	$ 1,209,959	$ 935,441	$ 2,145,399
2030	2	$ 94.41	$ 59.49	0.00	0.00	320	352	$ 1,099,963	$ 839,988	$ 1,939,950
2030	3	$ 81.80	$ 51.07	0.00	0.00	336	407	$ 986,455	$ 788,990	$ 1,775,445
2030	4	$ 81.80	$ 51.07	0.00	0.00	352	368	$ 1,033,429	$ 713,387	$ 1,746,816
2030	5	$ 81.80	$ 51.07	0.00	0.00	352	392	$ 1,033,429	$ 759,912	$ 1,793,341
2030	6	$ 101.36	$ 57.50	0.00	0.00	320	400	$ 420,047	$ 345,483	$ 765,530
2030	7	$ 101.36	$ 57.50	0.00	0.00	352	392	$ 462,052	$ 338,573	$ 800,625
2030	8	$ 101.36	$ 57.50	0.00	0.00	352	392	$ 462,052	$ 338,573	$ 800,625
2030	9	$ 79.18	$ 49.03	0.00	0.00	320	400	$ 591,353	$ 520,649	$ 1,112,003
2030	10	$ 79.18	$ 49.03	0.00	0.00	368	376	$ 680,056	$ 489,411	$ 1,169,467
2030	11	$ 79.18	$ 49.03	0.00	0.00	320	401	$ 591,353	$ 521,951	$ 1,113,304
2030	12	$ 96.54	$ 60.83	0.00	0.00	336	408	$ 1,181,081	$ 995,486	$ 2,176,567
2031	1	$ 96.54	$ 60.83	0.00	0.00	352	392	$ 1,237,323	$ 956,448	$ 2,193,770
2031	2	$ 96.54	$ 60.83	0.00	0.00	320	352	$ 1,124,839	$ 858,851	$ 1,983,690
2031	3	$ 83.68	$ 52.22	0.00	0.00	336	407	$ 1,009,159	$ 806,765	$ 1,815,924
2031	4	$ 83.68	$ 52.22	0.00	0.00	352	368	$ 1,057,214	$ 729,458	$ 1,786,672
2031	5	$ 83.68	$ 52.22	0.00	0.00	336	408	$ 1,009,159	$ 808,747	$ 1,817,906
2031	6	$ 103.60	$ 58.77	0.00	0.00	336	384	$ 450,798	$ 338,941	$ 789,739
2031	7	$ 103.60	$ 58.77	0.00	0.00	352	392	$ 472,265	$ 346,002	$ 818,267
2031	8	$ 103.60	$ 58.77	0.00	0.00	336	408	$ 450,798	$ 360,125	$ 810,923
2031	9	$ 80.96	$ 50.14	0.00	0.00	336	384	$ 634,914	$ 511,175	$ 1,146,089
2031	10	$ 80.96	$ 50.14	0.00	0.00	368	376	$ 695,382	$ 500,525	$ 1,195,907
2031	11	$ 80.96	$ 50.14	0.00	0.00	304	417	$ 574,446	$ 555,104	$ 1,129,550
2031	12	$ 98.73	$ 62.20	0.00	0.00	352	392	$ 1,265,371	$ 977,980	$ 2,243,351
2032	1	$ 98.73	$ 62.20	0.00	0.00	336	408	$ 1,207,854	$ 1,017,897	$ 2,225,751
2032	2	$ 98.73	$ 62.20	0.00	0.00	320	376	$ 1,150,337	$ 938,062	$ 2,088,399
2032	3	$ 85.61	$ 53.40	0.00	0.00	368	375	$ 1,130,757	$ 760,121	$ 1,890,877
2032	4	$ 85.61	$ 53.40	0.00	0.00	352	368	$ 1,081,593	$ 745,932	$ 1,827,525
2032	5	$ 85.61	$ 53.40	0.00	0.00	320	424	$ 983,267	$ 859,443	$ 1,842,710
2032	6	$ 105.90	$ 60.06	0.00	0.00	352	368	$ 482,733	$ 331,968	$ 814,701
2032	7	$ 105.90	$ 60.06	0.00	0.00	336	408	$ 460,791	$ 368,051	$ 828,842
2032	8	$ 105.90	$ 60.06	0.00	0.00	352	392	$ 482,733	$ 353,618	$ 836,351
2032	9	$ 82.79	$ 51.28	0.00	0.00	336	384	$ 649,258	$ 522,810	$ 1,172,067
2032	10	$ 82.79	$ 51.28	0.00	0.00	336	408	$ 649,258	$ 555,485	$ 1,204,743
2032	11	$ 82.79	$ 51.28	0.00	0.00	336	385	$ 649,258	$ 524,171	$ 1,173,429
2032	12	$ 100.97	$ 63.60	0.00	0.00	368	376	$ 1,352,944	$ 959,232	$ 2,312,176
2033	1	$ 100.97	$ 63.60	0.00	0.00	336	408	$ 1,235,297	$ 1,040,869	$ 2,276,165
2033	2	$ 100.97	$ 63.60	0.00	0.00	320	352	$ 1,176,473	$ 898,004	$ 2,074,477
2033	3	$ 87.59	$ 54.61	0.00	0.00	368	375	$ 1,156,882	$ 777,327	$ 1,934,209
2033	4	$ 87.59	$ 54.61	0.00	0.00	336	384	$ 1,056,283	$ 795,983	$ 1,852,266
2033	5	$ 87.59	$ 54.61	0.00	0.00	336	408	$ 1,056,283	$ 845,732	$ 1,902,015
2033	6	$ 108.25	$ 61.38	0.00	0.00	352	368	$ 493,463	$ 339,295	$ 832,759
2033	7	$ 108.25	$ 61.38	0.00	0.00	320	424	$ 448,603	$ 390,927	$ 839,530
2033	8	$ 108.25	$ 61.38	0.00	0.00	368	376	$ 515,893	$ 346,671	$ 862,565
2033	9	$ 84.66	$ 52.45	0.00	0.00	336	384	$ 663,959	$ 534,735	$ 1,198,695
2033	10	$ 84.66	$ 52.45	0.00	0.00	336	408	$ 663,959	$ 568,156	$ 1,232,116
2033	11	$ 84.66	$ 52.45	0.00	0.00	336	385	$ 663,959	$ 536,128	$ 1,200,087
2033	12	$ 103.27	$ 65.04	0.00	0.00	352	392	$ 1,323,588	$ 1,022,672	$ 2,346,261
2034	1	$ 103.27	$ 65.04	0.00	0.00	336	408	$ 1,263,425	$ 1,064,414	$ 2,327,839
2034	2	$ 103.27	$ 65.04	0.00	0.00	320	352	$ 1,203,262	$ 918,318	$ 2,121,580
2034	3	$ 89.62	$ 55.85	0.00	0.00	368	375	$ 1,183,660	$ 794,963	$ 1,978,623
2034	4	$ 89.62	$ 55.85	0.00	0.00	320	400	$ 1,029,269	$ 847,961	$ 1,877,230
2034	5	$ 89.62	$ 55.85	0.00	0.00	352	392	$ 1,132,196	$ 831,002	$ 1,963,198
2034	6	$ 110.67	$ 62.74	0.00	0.00	352	368	$ 504,462	$ 346,806	$ 851,268
2034	7	$ 110.67	$ 62.74	0.00	0.00	320	424	$ 458,601	$ 399,581	$ 858,182
2034	8	$ 110.67	$ 62.74	0.00	0.00	368	376	$ 527,392	$ 354,345	$ 881,737

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Farm Size (MW)
100

Capacity Factors							
On - Peak				Off - Peak			
Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
0.3641	0.3589	0.1295	0.2334	0.4011	0.3796	0.1502	0.2655

DPL_ODEC - Coastal Plains

		Wholesale Energy Prices		Capacity Adjusted MW		Monthly Hours		Energy Value		
YEAR	MONTH	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	Total
2034	9	$ 86.59	$ 53.65	0.00	0.00	320	400	$ 646,694	$ 569,749	$ 1,216,443
2034	10	$ 86.59	$ 53.65	0.00	0.00	352	392	$ 711,364	$ 558,354	$ 1,269,718
2034	11	$ 86.59	$ 53.65	0.00	0.00	336	385	$ 679,029	$ 548,384	$ 1,227,413
2034	12	$ 105.63	$ 66.52	0.00	0.00	320	424	$ 1,230,721	$ 1,131,236	$ 2,361,957
2035	1	$ 105.63	$ 66.52	0.00	0.00	352	392	$ 1,353,793	$ 1,045,860	$ 2,399,653
2035	2	$ 105.63	$ 66.52	0.00	0.00	320	352	$ 1,230,721	$ 939,140	$ 2,169,861
2035	3	$ 91.70	$ 57.12	0.00	0.00	352	391	$ 1,158,450	$ 847,731	$ 2,006,181
2035	4	$ 91.70	$ 57.12	0.00	0.00	336	384	$ 1,105,794	$ 832,554	$ 1,938,347
2035	5	$ 91.70	$ 57.12	0.00	0.00	352	392	$ 1,158,450	$ 849,899	$ 2,008,349
2035	6	$ 113.14	$ 64.14	0.00	0.00	336	384	$ 492,292	$ 369,918	$ 862,210
2035	7	$ 113.14	$ 64.14	0.00	0.00	336	408	$ 492,292	$ 393,038	$ 885,330
2035	8	$ 113.14	$ 64.14	0.00	0.00	368	376	$ 539,177	$ 362,211	$ 901,389
2035	9	$ 88.56	$ 54.88	0.00	0.00	304	416	$ 628,335	$ 606,113	$ 1,234,447
2035	10	$ 88.56	$ 54.88	0.00	0.00	368	376	$ 760,616	$ 547,833	$ 1,308,448
2035	11	$ 88.56	$ 54.88	0.00	0.00	336	385	$ 694,475	$ 560,946	$ 1,255,421
2035	12	$ 88.56	$ 54.88	0.00	0.00	320	424	$ 1,031,780	$ 933,285	$ 1,965,065

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Farm Size (MW)
100

Capacity Factors							
On - Peak				Off - Peak			
Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
0.4846	0.3471	0.1901	0.3013	0.4846	0.3562	0.2208	0.3342

Cloverdale - Ridgeline

		Wholesale Energy Prices		Capacity Adjusted MW		Monthly Hours		Energy Value		
YEAR	MONTH	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	Total
2012	1	$ 47.73	$ 26.79	48.46	48.46	336	408	$ 777,187	$ 529,673	$ 1,306,860
2012	2	$ 47.73	$ 26.79	48.46	48.46	336	360	$ 777,187	$ 467,358	$ 1,244,545
2012	3	$ 42.27	$ 17.93	34.71	35.62	352	391	$ 516,485	$ 249,737	$ 766,221
2012	4	$ 42.27	$ 17.93	34.71	35.62	336	384	$ 493,008	$ 245,266	$ 738,274
2012	5	$ 42.27	$ 17.93	34.71	35.62	352	392	$ 516,485	$ 250,375	$ 766,860
2012	6	$ 52.27	$ 18.26	19.01	22.08	336	384	$ 333,858	$ 154,817	$ 488,676
2012	7	$ 52.27	$ 18.26	34.71	22.08	336	408	$ 609,586	$ 164,493	$ 774,079
2012	8	$ 52.27	$ 18.26	19.01	22.08	368	376	$ 365,654	$ 151,592	$ 517,246
2012	9	$ 42.27	$ 22.11	30.13	33.42	304	416	$ 387,166	$ 307,373	$ 694,539
2012	10	$ 42.27	$ 22.11	30.13	33.42	368	376	$ 468,675	$ 277,818	$ 746,493
2012	11	$ 42.27	$ 22.11	30.13	33.42	336	385	$ 427,920	$ 284,468	$ 712,388
2012	12	$ 49.01	$ 28.79	48.46	48.46	320	424	$ 759,976	$ 591,538	$ 1,351,514
2013	1	$ 49.01	$ 28.79	48.46	48.46	352	392	$ 835,973	$ 546,894	$ 1,382,867
2013	2	$ 49.01	$ 28.79	48.46	48.46	320	352	$ 759,976	$ 491,088	$ 1,251,064
2013	3	$ 44.45	$ 19.93	34.71	35.62	336	407	$ 518,394	$ 288,951	$ 807,344
2013	4	$ 44.45	$ 19.93	34.71	35.62	352	368	$ 543,079	$ 261,263	$ 804,342
2013	5	$ 44.45	$ 19.93	34.71	35.62	352	392	$ 543,079	$ 278,301	$ 821,380
2013	6	$ 54.86	$ 20.26	19.01	22.08	320	400	$ 333,736	$ 178,932	$ 512,668
2013	7	$ 54.86	$ 20.26	34.71	22.08	352	392	$ 670,299	$ 175,353	$ 845,652
2013	8	$ 54.86	$ 20.26	19.01	22.08	352	392	$ 367,110	$ 175,353	$ 542,463
2013	9	$ 43.88	$ 23.11	30.13	33.42	320	400	$ 423,066	$ 308,886	$ 731,953
2013	10	$ 43.88	$ 23.11	30.13	33.42	368	376	$ 486,526	$ 290,353	$ 776,879
2013	11	$ 43.88	$ 23.11	30.13	33.42	320	401	$ 423,066	$ 309,659	$ 732,725
2013	12	$ 50.52	$ 29.79	48.46	48.46	336	408	$ 822,670	$ 588,988	$ 1,411,657
2014	1	$ 50.52	$ 29.79	48.46	48.46	352	392	$ 861,845	$ 565,890	$ 1,427,735
2014	2	$ 50.52	$ 29.79	48.46	48.46	320	352	$ 783,495	$ 508,146	$ 1,291,641
2014	3	$ 42.33	$ 22.93	34.71	35.62	336	407	$ 493,708	$ 332,443	$ 826,151
2014	4	$ 42.33	$ 22.93	34.71	35.62	352	368	$ 517,218	$ 300,587	$ 817,805
2014	5	$ 42.33	$ 22.93	34.71	35.62	336	408	$ 493,708	$ 333,260	$ 826,967
2014	6	$ 49.98	$ 21.26	19.01	22.08	336	384	$ 319,253	$ 180,253	$ 499,506
2014	7	$ 49.98	$ 21.26	34.71	22.08	352	392	$ 610,675	$ 184,009	$ 794,684
2014	8	$ 49.98	$ 21.26	19.01	22.08	336	408	$ 319,253	$ 191,519	$ 510,772
2014	9	$ 39.01	$ 23.11	30.13	33.42	336	384	$ 394,917	$ 296,531	$ 691,448
2014	10	$ 39.01	$ 23.11	30.13	33.42	368	376	$ 432,528	$ 290,353	$ 722,882
2014	11	$ 39.01	$ 23.11	30.13	33.42	304	417	$ 357,306	$ 322,014	$ 679,320
2014	12	$ 51.96	$ 30.69	48.46	48.46	352	392	$ 886,378	$ 582,987	$ 1,469,365
2015	1	$ 51.96	$ 30.69	48.46	48.46	336	408	$ 846,088	$ 606,782	$ 1,452,870
2015	2	$ 51.96	$ 30.69	48.46	48.46	320	352	$ 805,798	$ 523,498	$ 1,329,297
2015	3	$ 43.60	$ 23.71	34.71	35.62	352	391	$ 532,713	$ 330,168	$ 862,881
2015	4	$ 43.60	$ 23.71	34.71	35.62	352	368	$ 532,713	$ 310,746	$ 843,459
2015	5	$ 43.60	$ 23.71	34.71	35.62	320	424	$ 484,285	$ 358,033	$ 842,318
2015	6	$ 51.49	$ 22.11	19.01	22.08	352	368	$ 344,554	$ 179,650	$ 524,204
2015	7	$ 51.49	$ 22.11	34.71	22.08	368	376	$ 657,711	$ 183,555	$ 841,266
2015	8	$ 51.49	$ 22.11	19.01	22.08	336	408	$ 328,893	$ 199,177	$ 528,069
2015	9	$ 40.21	$ 23.86	30.13	33.42	336	384	$ 407,086	$ 306,156	$ 713,242
2015	10	$ 40.21	$ 23.86	30.13	33.42	352	392	$ 426,471	$ 312,534	$ 739,005
2015	11	$ 40.21	$ 23.86	30.13	33.42	320	401	$ 387,701	$ 319,710	$ 707,410
2015	12	$ 53.44	$ 31.61	48.46	48.46	352	392	$ 911,525	$ 600,511	$ 1,512,036
2016	1	$ 53.44	$ 31.61	48.46	48.46	320	424	$ 828,659	$ 649,532	$ 1,478,191
2016	2	$ 53.44	$ 31.61	48.46	48.46	336	360	$ 870,092	$ 551,490	$ 1,421,582
2016	3	$ 44.90	$ 24.50	34.71	35.62	368	375	$ 573,532	$ 327,268	$ 900,800
2016	4	$ 44.90	$ 24.50	34.71	35.62	336	384	$ 523,660	$ 335,122	$ 858,782
2016	5	$ 44.90	$ 24.50	34.71	35.62	336	408	$ 523,660	$ 356,067	$ 879,727
2016	6	$ 53.04	$ 22.98	19.01	22.08	352	368	$ 354,906	$ 186,729	$ 541,635
2016	7	$ 53.04	$ 22.98	34.71	22.08	320	424	$ 589,105	$ 215,144	$ 804,249
2016	8	$ 53.04	$ 22.98	19.01	22.08	368	376	$ 371,038	$ 190,788	$ 561,826
2016	9	$ 41.44	$ 24.63	30.13	33.42	336	384	$ 419,559	$ 316,022	$ 735,580
2016	10	$ 41.44	$ 24.63	30.13	33.42	336	408	$ 419,559	$ 335,773	$ 755,332
2016	11	$ 41.44	$ 24.63	30.13	33.42	336	385	$ 419,559	$ 316,845	$ 736,403
2016	12	$ 54.95	$ 32.56	48.46	48.46	336	408	$ 894,696	$ 643,717	$ 1,538,413
2017	1	$ 54.95	$ 32.56	48.46	48.46	336	408	$ 894,696	$ 643,717	$ 1,538,413
2017	2	$ 54.95	$ 32.56	48.46	48.46	320	352	$ 852,091	$ 555,364	$ 1,407,455
2017	3	$ 46.23	$ 25.31	34.71	35.62	368	375	$ 590,552	$ 338,144	$ 928,696
2017	4	$ 46.23	$ 25.31	34.71	35.62	320	400	$ 513,523	$ 360,687	$ 874,210
2017	5	$ 46.23	$ 25.31	34.71	35.62	352	392	$ 564,876	$ 353,473	$ 918,349
2017	6	$ 54.62	$ 23.87	19.01	22.08	352	368	$ 365,516	$ 193,985	$ 559,501
2017	7	$ 54.62	$ 23.87	34.71	22.08	320	424	$ 606,718	$ 223,505	$ 830,222
2017	8	$ 54.62	$ 23.87	19.01	22.08	368	376	$ 382,131	$ 198,202	$ 580,333

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Farm Size (MW)
100

Capacity Factors							
On - Peak				Off - Peak			
Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
0.4846	0.3471	0.1901	0.3013	0.4846	0.3562	0.2208	0.3342

Cloverdale - Ridgeline

		Wholesale Energy Prices		Capacity Adjusted MW		Monthly Hours		Energy Value		
YEAR	MONTH	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	Total
2017	9	$ 42.71	$ 25.41	30.13	33.42	320	400	$ 411,756	$ 339,723	$ 751,478
2017	10	$ 42.71	$ 25.41	30.13	33.42	352	392	$ 452,931	$ 332,928	$ 785,859
2017	11	$ 42.71	$ 25.41	30.13	33.42	336	385	$ 432,343	$ 326,983	$ 759,326
2017	12	$ 56.50	$ 33.53	48.46	48.46	320	424	$ 876,110	$ 688,875	$ 1,564,984
2018	1	$ 56.50	$ 33.53	48.46	48.46	352	392	$ 963,721	$ 636,884	$ 1,600,605
2018	2	$ 56.50	$ 33.53	48.46	48.46	320	352	$ 876,110	$ 571,896	$ 1,448,006
2018	3	$ 47.60	$ 26.15	34.71	35.62	352	391	$ 581,563	$ 364,195	$ 945,758
2018	4	$ 47.60	$ 26.15	34.71	35.62	336	384	$ 555,128	$ 357,675	$ 912,803
2018	5	$ 47.60	$ 26.15	34.71	35.62	352	392	$ 581,563	$ 365,126	$ 946,689
2018	6	$ 56.25	$ 24.79	19.01	22.08	336	384	$ 359,283	$ 210,180	$ 569,464
2018	7	$ 56.25	$ 24.79	34.71	22.08	336	408	$ 656,009	$ 223,317	$ 879,325
2018	8	$ 56.25	$ 24.79	19.01	22.08	368	376	$ 393,501	$ 205,802	$ 599,302
2018	9	$ 44.00	$ 26.22	30.13	33.42	304	416	$ 403,024	$ 364,540	$ 767,564
2018	10	$ 44.00	$ 26.22	30.13	33.42	368	376	$ 487,871	$ 329,488	$ 817,360
2018	11	$ 44.00	$ 26.22	30.13	33.42	336	385	$ 445,448	$ 337,375	$ 782,823
2018	12	$ 58.08	$ 34.52	48.46	48.46	320	424	$ 900,728	$ 709,287	$ 1,610,015
2019	1	$ 58.08	$ 34.52	48.46	48.46	352	392	$ 990,801	$ 655,756	$ 1,646,557
2019	2	$ 58.08	$ 34.52	48.46	48.46	320	352	$ 900,728	$ 588,842	$ 1,489,570
2019	3	$ 49.00	$ 27.00	34.71	35.62	336	407	$ 571,454	$ 391,500	$ 962,954
2019	4	$ 49.00	$ 27.00	34.71	35.62	352	368	$ 598,667	$ 353,985	$ 952,652
2019	5	$ 49.00	$ 27.00	34.71	35.62	352	392	$ 598,667	$ 377,071	$ 975,738
2019	6	$ 57.92	$ 25.73	19.01	22.08	320	400	$ 352,309	$ 227,224	$ 579,533
2019	7	$ 57.92	$ 25.73	34.71	22.08	352	392	$ 707,601	$ 222,680	$ 930,281
2019	8	$ 57.92	$ 25.73	19.01	22.08	352	392	$ 387,540	$ 222,680	$ 610,220
2019	9	$ 45.33	$ 27.05	30.13	33.42	320	400	$ 437,028	$ 361,586	$ 798,615
2019	10	$ 45.33	$ 27.05	30.13	33.42	368	376	$ 502,582	$ 339,891	$ 842,474
2019	11	$ 45.33	$ 27.05	30.13	33.42	320	401	$ 437,028	$ 362,490	$ 799,519
2019	12	$ 59.71	$ 35.54	48.46	48.46	336	408	$ 972,260	$ 702,654	$ 1,674,915
2020	1	$ 59.71	$ 35.54	48.46	48.46	352	392	$ 1,018,558	$ 675,099	$ 1,693,658
2020	2	$ 59.71	$ 35.54	48.46	48.46	320	376	$ 925,962	$ 647,544	$ 1,573,506
2020	3	$ 50.43	$ 27.88	34.71	35.62	352	391	$ 616,198	$ 388,321	$ 1,004,520
2020	4	$ 50.43	$ 27.88	34.71	35.62	352	368	$ 616,198	$ 365,479	$ 981,677
2020	5	$ 50.43	$ 27.88	34.71	35.62	320	424	$ 560,180	$ 421,095	$ 981,275
2020	6	$ 59.62	$ 26.69	19.01	22.08	352	368	$ 398,966	$ 216,861	$ 615,827
2020	7	$ 59.62	$ 26.69	34.71	22.08	368	376	$ 761,576	$ 221,575	$ 983,151
2020	8	$ 59.62	$ 26.69	19.01	22.08	336	408	$ 380,831	$ 240,432	$ 621,264
2020	9	$ 46.69	$ 27.90	30.13	33.42	336	384	$ 472,647	$ 358,013	$ 830,660
2020	10	$ 46.69	$ 27.90	30.13	33.42	352	392	$ 495,154	$ 365,471	$ 860,626
2020	11	$ 46.69	$ 27.90	30.13	33.42	320	401	$ 450,140	$ 373,862	$ 824,003
2020	12	$ 61.38	$ 36.58	48.46	48.46	352	392	$ 1,047,010	$ 694,926	$ 1,741,936
2021	1	$ 61.38	$ 36.58	48.46	48.46	320	424	$ 951,827	$ 751,655	$ 1,703,482
2021	2	$ 61.38	$ 36.58	48.46	48.46	320	352	$ 951,827	$ 624,015	$ 1,575,842
2021	3	$ 51.90	$ 28.78	34.71	35.62	368	375	$ 662,994	$ 384,436	$ 1,047,430
2021	4	$ 51.90	$ 28.78	34.71	35.62	352	368	$ 634,168	$ 377,260	$ 1,011,428
2021	5	$ 51.90	$ 28.78	34.71	35.62	320	424	$ 576,516	$ 434,669	$ 1,011,186
2021	6	$ 61.37	$ 27.67	19.01	22.08	352	368	$ 410,678	$ 224,870	$ 635,548
2021	7	$ 61.37	$ 27.67	34.71	22.08	336	408	$ 715,765	$ 249,313	$ 965,078
2021	8	$ 61.37	$ 27.67	19.01	22.08	352	392	$ 410,678	$ 239,536	$ 650,214
2021	9	$ 48.08	$ 28.77	30.13	33.42	336	384	$ 486,759	$ 369,175	$ 855,934
2021	10	$ 48.08	$ 28.77	30.13	33.42	336	408	$ 486,759	$ 392,248	$ 879,007
2021	11	$ 48.08	$ 28.77	30.13	33.42	336	385	$ 486,759	$ 370,136	$ 856,895
2021	12	$ 63.09	$ 37.65	48.46	48.46	368	376	$ 1,125,089	$ 686,055	$ 1,811,144
2022	1	$ 63.09	$ 37.65	48.46	48.46	336	408	$ 1,027,256	$ 744,443	$ 1,771,698
2022	2	$ 63.09	$ 37.65	48.46	48.46	320	352	$ 978,339	$ 642,264	$ 1,620,603
2022	3	$ 53.41	$ 29.70	34.71	35.62	368	375	$ 682,250	$ 396,742	$ 1,078,992
2022	4	$ 53.41	$ 29.70	34.71	35.62	336	384	$ 622,924	$ 406,263	$ 1,029,187
2022	5	$ 53.41	$ 29.70	34.71	35.62	336	408	$ 622,924	$ 431,655	$ 1,054,579
2022	6	$ 63.17	$ 28.69	19.01	22.08	352	368	$ 422,683	$ 233,080	$ 655,763
2022	7	$ 63.17	$ 28.69	34.71	22.08	320	424	$ 701,607	$ 268,549	$ 970,156
2022	8	$ 63.17	$ 28.69	19.01	22.08	368	376	$ 441,895	$ 238,147	$ 680,042
2022	9	$ 49.51	$ 29.66	30.13	33.42	336	384	$ 501,224	$ 380,616	$ 881,840
2022	10	$ 49.51	$ 29.66	30.13	33.42	336	408	$ 501,224	$ 404,404	$ 905,628
2022	11	$ 49.51	$ 29.66	30.13	33.42	336	385	$ 501,224	$ 381,607	$ 882,831
2022	12	$ 64.84	$ 38.75	48.46	48.46	336	408	$ 1,055,789	$ 766,123	$ 1,821,912
2023	1	$ 64.84	$ 38.75	48.46	48.46	336	408	$ 1,055,789	$ 766,123	$ 1,821,912
2023	2	$ 64.84	$ 38.75	48.46	48.46	320	352	$ 1,005,513	$ 660,969	$ 1,666,482
2023	3	$ 54.96	$ 30.65	34.71	35.62	368	375	$ 701,988	$ 409,355	$ 1,111,343
2023	4	$ 54.96	$ 30.65	34.71	35.62	320	400	$ 610,424	$ 436,645	$ 1,047,069

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Farm Size (MW)
100

Capacity Factors							
On - Peak				Off - Peak			
Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
0.4846	0.3471	0.1901	0.3013	0.4846	0.3562	0.2208	0.3342

Cloverdale - Ridgeline

		Wholesale Energy Prices		Capacity Adjusted MW		Monthly Hours		Energy Value		
YEAR	MONTH	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	Total
2023	5	$ 54.96	$ 30.65	34.71	35.62	352	392	$ 671,467	$ 427,912	$ 1,099,379
2023	6	$ 65.01	$ 29.72	19.01	22.08	352	368	$ 434,987	$ 241,495	$ 676,483
2023	7	$ 65.01	$ 29.72	34.71	22.08	320	424	$ 722,032	$ 278,244	$ 1,000,277
2023	8	$ 65.01	$ 29.72	19.01	22.08	368	376	$ 454,760	$ 246,745	$ 701,505
2023	9	$ 50.97	$ 30.57	30.13	33.42	320	400	$ 491,476	$ 408,690	$ 900,167
2023	10	$ 50.97	$ 30.57	30.13	33.42	352	392	$ 540,624	$ 400,517	$ 941,141
2023	11	$ 50.97	$ 30.57	30.13	33.42	336	385	$ 516,050	$ 393,365	$ 909,415
2023	12	$ 66.64	$ 39.87	48.46	48.46	320	424	$ 1,033,367	$ 819,262	$ 1,852,629
2024	1	$ 66.64	$ 39.87	48.46	48.46	352	392	$ 1,136,703	$ 757,431	$ 1,894,134
2024	2	$ 66.64	$ 39.87	48.46	48.46	336	360	$ 1,085,035	$ 695,600	$ 1,780,635
2024	3	$ 56.54	$ 31.61	34.71	35.62	336	407	$ 659,418	$ 458,318	$ 1,117,735
2024	4	$ 56.54	$ 31.61	34.71	35.62	352	368	$ 690,818	$ 414,400	$ 1,105,219
2024	5	$ 56.54	$ 31.61	34.71	35.62	352	392	$ 690,818	$ 441,426	$ 1,132,245
2024	6	$ 66.89	$ 30.78	19.01	22.08	320	400	$ 406,909	$ 271,870	$ 678,779
2024	7	$ 66.89	$ 30.78	34.71	22.08	352	392	$ 817,264	$ 266,433	$ 1,083,697
2024	8	$ 66.89	$ 30.78	19.01	22.08	352	392	$ 447,600	$ 266,433	$ 714,033
2024	9	$ 52.48	$ 31.51	30.13	33.42	320	400	$ 505,950	$ 421,212	$ 927,161
2024	10	$ 52.48	$ 31.51	30.13	33.42	368	376	$ 581,842	$ 395,939	$ 977,781
2024	11	$ 52.48	$ 31.51	30.13	33.42	320	401	$ 505,950	$ 422,265	$ 928,214
2024	12	$ 68.48	$ 41.02	48.46	48.46	336	408	$ 1,115,012	$ 811,125	$ 1,926,137
2025	1	$ 68.48	$ 41.02	48.46	48.46	352	392	$ 1,168,108	$ 779,316	$ 1,947,424
2025	2	$ 68.48	$ 41.02	48.46	48.46	320	352	$ 1,061,917	$ 699,794	$ 1,761,711
2025	3	$ 58.16	$ 32.61	34.71	35.62	336	407	$ 678,351	$ 472,700	$ 1,151,051
2025	4	$ 58.16	$ 32.61	34.71	35.62	352	368	$ 710,654	$ 427,404	$ 1,138,058
2025	5	$ 58.16	$ 32.61	34.71	35.62	336	408	$ 678,351	$ 473,861	$ 1,152,213
2025	6	$ 68.82	$ 31.87	19.01	22.08	336	384	$ 439,595	$ 270,221	$ 709,815
2025	7	$ 68.82	$ 31.87	34.71	22.08	352	392	$ 840,869	$ 275,850	$ 1,116,719
2025	8	$ 68.82	$ 31.87	19.01	22.08	336	408	$ 439,595	$ 287,110	$ 726,704
2025	9	$ 54.01	$ 32.47	30.13	33.42	336	384	$ 546,824	$ 416,684	$ 963,508
2025	10	$ 54.01	$ 32.47	30.13	33.42	368	376	$ 598,903	$ 408,003	$ 1,006,906
2025	11	$ 54.01	$ 32.47	30.13	33.42	304	417	$ 494,746	$ 452,493	$ 947,238
2025	12	$ 70.37	$ 42.21	48.46	48.46	352	392	$ 1,200,298	$ 801,748	$ 2,002,047
2026	1	$ 70.37	$ 42.21	48.46	48.46	336	408	$ 1,145,739	$ 834,473	$ 1,980,212
2026	2	$ 70.37	$ 42.21	48.46	48.46	320	352	$ 1,091,180	$ 719,937	$ 1,811,118
2026	3	$ 59.83	$ 33.62	34.71	35.62	352	391	$ 730,985	$ 468,280	$ 1,199,265
2026	4	$ 59.83	$ 33.62	34.71	35.62	352	368	$ 730,985	$ 440,734	$ 1,171,719
2026	5	$ 59.83	$ 33.62	34.71	35.62	320	424	$ 664,532	$ 507,802	$ 1,172,334
2026	6	$ 70.80	$ 32.99	19.01	22.08	352	368	$ 473,779	$ 268,024	$ 741,802
2026	7	$ 70.80	$ 32.99	34.71	22.08	368	376	$ 904,385	$ 273,850	$ 1,178,235
2026	8	$ 70.80	$ 32.99	19.01	22.08	336	408	$ 452,243	$ 297,157	$ 749,400
2026	9	$ 55.59	$ 33.45	30.13	33.42	336	384	$ 562,791	$ 429,313	$ 992,103
2026	10	$ 55.59	$ 33.45	30.13	33.42	352	392	$ 589,590	$ 438,257	$ 1,027,847
2026	11	$ 55.59	$ 33.45	30.13	33.42	320	401	$ 535,991	$ 448,319	$ 984,310
2026	12	$ 72.30	$ 43.42	48.46	48.46	352	392	$ 1,233,293	$ 824,741	$ 2,058,035
2027	1	$ 72.30	$ 43.42	48.46	48.46	320	424	$ 1,121,176	$ 892,067	$ 2,013,243
2027	2	$ 72.30	$ 43.42	48.46	48.46	320	352	$ 1,121,176	$ 740,584	$ 1,861,760
2027	3	$ 61.53	$ 34.67	34.71	35.62	368	375	$ 785,998	$ 463,040	$ 1,249,038
2027	4	$ 61.53	$ 34.67	34.71	35.62	352	368	$ 751,825	$ 454,396	$ 1,206,221
2027	5	$ 61.53	$ 34.67	34.71	35.62	320	424	$ 683,477	$ 523,543	$ 1,207,020
2027	6	$ 72.83	$ 34.13	19.01	22.08	352	368	$ 487,361	$ 277,312	$ 764,673
2027	7	$ 72.83	$ 34.13	34.71	22.08	336	408	$ 849,415	$ 307,455	$ 1,156,870
2027	8	$ 72.83	$ 34.13	19.01	22.08	352	392	$ 487,361	$ 295,398	$ 782,759
2027	9	$ 57.21	$ 34.46	30.13	33.42	336	384	$ 579,156	$ 442,257	$ 1,021,413
2027	10	$ 57.21	$ 34.46	30.13	33.42	336	408	$ 579,156	$ 469,898	$ 1,049,054
2027	11	$ 57.21	$ 34.46	30.13	33.42	336	385	$ 579,156	$ 443,409	$ 1,022,565
2027	12	$ 74.28	$ 44.66	48.46	48.46	368	376	$ 1,324,709	$ 813,685	$ 2,138,394
2028	1	$ 74.28	$ 44.66	48.46	48.46	336	408	$ 1,209,517	$ 882,934	$ 2,092,451
2028	2	$ 74.28	$ 44.66	48.46	48.46	336	360	$ 1,209,517	$ 779,060	$ 1,988,577
2028	3	$ 63.28	$ 35.73	34.71	35.62	368	375	$ 808,330	$ 477,310	$ 1,285,640
2028	4	$ 63.28	$ 35.73	34.71	35.62	320	400	$ 702,896	$ 509,131	$ 1,212,026
2028	5	$ 63.28	$ 35.73	34.71	35.62	352	392	$ 773,185	$ 498,948	$ 1,272,133
2028	6	$ 74.91	$ 35.30	19.01	22.08	352	368	$ 501,283	$ 286,833	$ 788,116
2028	7	$ 74.91	$ 35.30	34.71	22.08	320	424	$ 832,075	$ 330,482	$ 1,162,557
2028	8	$ 74.91	$ 35.30	19.01	22.08	368	376	$ 524,068	$ 293,069	$ 817,137
2028	9	$ 58.87	$ 35.50	30.13	33.42	320	400	$ 567,553	$ 474,505	$ 1,042,058
2028	10	$ 58.87	$ 35.50	30.13	33.42	352	392	$ 624,308	$ 465,015	$ 1,089,324
2028	11	$ 58.87	$ 35.50	30.13	33.42	336	385	$ 595,931	$ 456,712	$ 1,052,642
2028	12	$ 76.32	$ 45.93	48.46	48.46	320	424	$ 1,183,435	$ 943,688	$ 2,127,123

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Farm Size (MW)
100

Capacity Factors							
On - Peak				Off - Peak			
Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
0.4846	0.3471	0.1901	0.3013	0.4846	0.3562	0.2208	0.3342

Cloverdale - Ridgeline

		Wholesale Energy Prices		Capacity Adjusted MW		Monthly Hours		Energy Value		
YEAR	MONTH	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	Total
2029	1	$ 76.32	$ 45.93	48.46	48.46	352	392	$ 1,301,778	$ 872,467	$ 2,174,245
2029	2	$ 76.32	$ 45.93	48.46	48.46	320	352	$ 1,183,435	$ 783,439	$ 1,966,874
2029	3	$ 65.07	$ 36.83	34.71	35.62	352	391	$ 795,080	$ 512,927	$ 1,308,006
2029	4	$ 65.07	$ 36.83	34.71	35.62	336	384	$ 758,940	$ 503,744	$ 1,262,683
2029	5	$ 65.07	$ 36.83	34.71	35.62	352	392	$ 795,080	$ 514,238	$ 1,309,318
2029	6	$ 77.05	$ 36.50	19.01	22.08	336	384	$ 492,119	$ 309,487	$ 801,606
2029	7	$ 77.05	$ 36.50	34.71	22.08	336	408	$ 898,550	$ 328,830	$ 1,227,380
2029	8	$ 77.05	$ 36.50	19.01	22.08	368	376	$ 538,987	$ 303,040	$ 842,027
2029	9	$ 60.56	$ 36.56	30.13	33.42	304	416	$ 554,732	$ 508,219	$ 1,062,951
2029	10	$ 60.56	$ 36.56	30.13	33.42	368	376	$ 671,517	$ 459,352	$ 1,130,869
2029	11	$ 60.56	$ 36.56	30.13	33.42	336	385	$ 613,125	$ 470,347	$ 1,083,471
2029	12	$ 78.40	$ 47.23	48.46	48.46	320	424	$ 1,215,737	$ 970,471	$ 2,186,207
2030	1	$ 78.40	$ 47.23	48.46	48.46	352	392	$ 1,337,310	$ 897,228	$ 2,234,538
2030	2	$ 78.40	$ 47.23	48.46	48.46	320	352	$ 1,215,737	$ 805,674	$ 2,021,411
2030	3	$ 66.91	$ 37.95	34.71	35.62	336	407	$ 780,362	$ 550,188	$ 1,330,550
2030	4	$ 66.91	$ 37.95	34.71	35.62	352	368	$ 817,522	$ 497,467	$ 1,314,989
2030	5	$ 66.91	$ 37.95	34.71	35.62	352	392	$ 817,522	$ 529,911	$ 1,347,433
2030	6	$ 79.23	$ 37.73	19.01	22.08	320	400	$ 481,981	$ 333,255	$ 815,237
2030	7	$ 79.23	$ 37.73	34.71	22.08	352	392	$ 968,044	$ 326,590	$ 1,294,635
2030	8	$ 79.23	$ 37.73	19.01	22.08	352	392	$ 530,179	$ 326,590	$ 856,770
2030	9	$ 62.30	$ 37.64	30.13	33.42	320	400	$ 600,713	$ 503,193	$ 1,103,905
2030	10	$ 62.30	$ 37.64	30.13	33.42	368	376	$ 690,820	$ 473,001	$ 1,163,821
2030	11	$ 62.30	$ 37.64	30.13	33.42	320	401	$ 600,713	$ 504,451	$ 1,105,163
2030	12	$ 80.53	$ 48.57	48.46	48.46	336	408	$ 1,311,288	$ 960,265	$ 2,271,554
2031	1	$ 80.53	$ 48.57	48.46	48.46	352	392	$ 1,373,731	$ 922,608	$ 2,296,338
2031	2	$ 80.53	$ 48.57	48.46	48.46	320	352	$ 1,248,846	$ 828,464	$ 2,077,310
2031	3	$ 68.79	$ 39.10	34.71	35.62	336	407	$ 802,319	$ 566,867	$ 1,369,186
2031	4	$ 68.79	$ 39.10	34.71	35.62	352	368	$ 840,525	$ 512,548	$ 1,353,073
2031	5	$ 68.79	$ 39.10	34.71	35.62	336	408	$ 802,319	$ 568,260	$ 1,370,579
2031	6	$ 81.47	$ 38.99	19.01	22.08	336	384	$ 520,391	$ 330,624	$ 851,015
2031	7	$ 81.47	$ 38.99	34.71	22.08	352	392	$ 995,419	$ 337,512	$ 1,332,930
2031	8	$ 81.47	$ 38.99	19.01	22.08	336	408	$ 520,391	$ 351,288	$ 871,679
2031	9	$ 64.09	$ 38.75	30.13	33.42	336	384	$ 648,813	$ 497,353	$ 1,146,166
2031	10	$ 64.09	$ 38.75	30.13	33.42	368	376	$ 710,605	$ 486,992	$ 1,197,596
2031	11	$ 64.09	$ 38.75	30.13	33.42	304	417	$ 587,021	$ 540,094	$ 1,127,116
2031	12	$ 82.72	$ 49.94	48.46	48.46	352	392	$ 1,411,061	$ 948,622	$ 2,359,684
2032	1	$ 82.72	$ 49.94	48.46	48.46	336	408	$ 1,346,922	$ 987,342	$ 2,334,264
2032	2	$ 82.72	$ 49.94	48.46	48.46	320	376	$ 1,282,783	$ 909,903	$ 2,192,686
2032	3	$ 70.72	$ 40.28	34.71	35.62	368	375	$ 903,380	$ 538,050	$ 1,441,430
2032	4	$ 70.72	$ 40.28	34.71	35.62	352	368	$ 864,103	$ 528,006	$ 1,392,109
2032	5	$ 70.72	$ 40.28	34.71	35.62	320	424	$ 785,548	$ 608,355	$ 1,393,903
2032	6	$ 83.77	$ 40.29	19.01	22.08	352	368	$ 560,539	$ 327,357	$ 887,896
2032	7	$ 83.77	$ 40.29	34.71	22.08	336	408	$ 976,955	$ 362,939	$ 1,339,895
2032	8	$ 83.77	$ 40.29	19.01	22.08	352	392	$ 560,539	$ 348,706	$ 909,245
2032	9	$ 65.92	$ 39.90	30.13	33.42	336	384	$ 667,329	$ 511,999	$ 1,179,328
2032	10	$ 65.92	$ 39.90	30.13	33.42	336	408	$ 667,329	$ 543,999	$ 1,211,328
2032	11	$ 65.92	$ 39.90	30.13	33.42	336	385	$ 667,329	$ 513,332	$ 1,180,661
2032	12	$ 84.96	$ 51.34	48.46	48.46	368	376	$ 1,515,204	$ 935,480	$ 2,450,683
2033	1	$ 84.96	$ 51.34	48.46	48.46	336	408	$ 1,383,447	$ 1,015,095	$ 2,398,542
2033	2	$ 84.96	$ 51.34	48.46	48.46	320	352	$ 1,317,568	$ 875,768	$ 2,193,337
2033	3	$ 72.70	$ 41.49	34.71	35.62	368	375	$ 928,646	$ 554,195	$ 1,482,841
2033	4	$ 72.70	$ 41.49	34.71	35.62	336	384	$ 847,894	$ 567,496	$ 1,415,390
2033	5	$ 72.70	$ 41.49	34.71	35.62	336	408	$ 847,894	$ 602,965	$ 1,450,859
2033	6	$ 86.12	$ 41.61	19.01	22.08	352	368	$ 576,290	$ 338,129	$ 914,419
2033	7	$ 86.12	$ 41.61	34.71	22.08	320	424	$ 956,579	$ 389,583	$ 1,346,163
2033	8	$ 86.12	$ 41.61	19.01	22.08	368	376	$ 602,485	$ 345,480	$ 947,965
2033	9	$ 67.79	$ 41.07	30.13	33.42	336	384	$ 686,308	$ 527,010	$ 1,213,318
2033	10	$ 67.79	$ 41.07	30.13	33.42	336	408	$ 686,308	$ 559,949	$ 1,246,257
2033	11	$ 67.79	$ 41.07	30.13	33.42	336	385	$ 686,308	$ 528,383	$ 1,214,691
2033	12	$ 87.26	$ 52.78	48.46	48.46	352	392	$ 1,488,546	$ 1,002,619	$ 2,491,165
2034	1	$ 87.26	$ 52.78	48.46	48.46	336	408	$ 1,420,885	$ 1,043,542	$ 2,464,427
2034	2	$ 87.26	$ 52.78	48.46	48.46	320	352	$ 1,353,223	$ 900,311	$ 2,253,534
2034	3	$ 74.73	$ 42.73	34.71	35.62	368	375	$ 954,544	$ 570,745	$ 1,525,288
2034	4	$ 74.73	$ 42.73	34.71	35.62	320	400	$ 830,038	$ 608,794	$ 1,438,832
2034	5	$ 74.73	$ 42.73	34.71	35.62	352	392	$ 913,042	$ 596,618	$ 1,509,660
2034	6	$ 88.54	$ 42.97	19.01	22.08	352	368	$ 592,435	$ 349,170	$ 941,605
2034	7	$ 88.54	$ 42.97	34.71	22.08	320	424	$ 983,378	$ 402,305	$ 1,385,683
2034	8	$ 88.54	$ 42.97	19.01	22.08	368	376	$ 619,364	$ 356,761	$ 976,125

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Farm Size (MW)
100

Capacity Factors							
On - Peak				Off - Peak			
Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
0.4846	0.3471	0.1901	0.3013	0.4846	0.3562	0.2208	0.3342

Cloverdale - Ridgeline

		Wholesale Energy Prices		Capacity Adjusted MW		Monthly Hours		Energy Value		
YEAR	MONTH	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	Total
2034	9	$ 69.71	$ 42.26	30.13	33.42	320	400	$ 672,154	$ 564,997	$ 1,237,151
2034	10	$ 69.71	$ 42.26	30.13	33.42	352	392	$ 739,369	$ 553,697	$ 1,293,066
2034	11	$ 69.71	$ 42.26	30.13	33.42	336	385	$ 705,761	$ 543,810	$ 1,249,571
2034	12	$ 89.62	$ 54.25	48.46	48.46	320	424	$ 1,389,770	$ 1,114,767	$ 2,504,537
2035	1	$ 89.62	$ 54.25	48.46	48.46	352	392	$ 1,528,747	$ 1,030,634	$ 2,559,381
2035	2	$ 89.62	$ 54.25	48.46	48.46	320	352	$ 1,389,770	$ 925,467	$ 2,315,237
2035	3	$ 76.81	$ 44.00	34.71	35.62	352	391	$ 938,433	$ 612,783	$ 1,551,216
2035	4	$ 76.81	$ 44.00	34.71	35.62	336	384	$ 895,777	$ 601,813	$ 1,497,590
2035	5	$ 76.81	$ 44.00	34.71	35.62	352	392	$ 938,433	$ 614,350	$ 1,552,783
2035	6	$ 91.01	$ 44.37	19.01	22.08	336	384	$ 581,303	$ 376,161	$ 957,464
2035	7	$ 91.01	$ 44.37	34.71	22.08	336	408	$ 1,061,390	$ 399,671	$ 1,461,061
2035	8	$ 91.01	$ 44.37	19.01	22.08	368	376	$ 636,665	$ 368,324	$ 1,004,989
2035	9	$ 71.68	$ 43.49	30.13	33.42	304	416	$ 656,587	$ 604,683	$ 1,261,270
2035	10	$ 71.68	$ 43.49	30.13	33.42	368	376	$ 794,816	$ 546,540	$ 1,341,356
2035	11	$ 71.68	$ 43.49	30.13	33.42	336	385	$ 725,701	$ 559,623	$ 1,285,324
2035	12	$ 71.68	$ 43.49	48.46	48.46	320	424	$ 1,111,611	$ 893,670	$ 2,005,281

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Farm Size (MW)
100

Capacity Factors							
On - Peak				Off - Peak			
Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
0.4358	0.3644	0.2374	0.3364	0.4533	0.4150	0.2426	0.3413

Calvert Cliffs - Shallow Bays

		Wholesale Energy Prices		Capacity Adjusted MW		Monthly Hours		Energy Value		
YEAR	MONTH	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	Total
2012	1	$ 60.69	$ 39.80	43.58	45.33	336	408	$ 888,668	$ 736,080	$ 1,624,748
2012	2	$ 60.69	$ 39.80	43.58	45.33	336	360	$ 888,668	$ 649,482	$ 1,538,150
2012	3	$ 55.06	$ 30.33	36.44	41.50	352	391	$ 706,289	$ 492,182	$ 1,198,471
2012	4	$ 55.06	$ 30.33	36.44	41.50	336	384	$ 674,185	$ 483,370	$ 1,157,555
2012	5	$ 55.06	$ 30.33	36.44	41.50	352	392	$ 706,289	$ 493,441	$ 1,199,730
2012	6	$ 73.10	$ 40.37	23.74	24.26	336	384	$ 583,054	$ 376,075	$ 959,128
2012	7	$ 73.10	$ 40.37	23.74	24.26	336	408	$ 583,054	$ 399,579	$ 982,633
2012	8	$ 73.10	$ 40.37	23.74	24.26	368	376	$ 638,583	$ 368,240	$ 1,006,823
2012	9	$ 58.73	$ 33.54	33.64	34.13	304	416	$ 600,651	$ 476,155	$ 1,076,806
2012	10	$ 58.73	$ 33.54	33.64	34.13	368	376	$ 727,104	$ 430,371	$ 1,157,475
2012	11	$ 58.73	$ 33.54	33.64	34.13	336	385	$ 663,877	$ 440,672	$ 1,104,550
2012	12	$ 61.97	$ 41.80	43.58	45.33	320	424	$ 864,154	$ 803,386	$ 1,667,540
2013	1	$ 61.97	$ 41.80	43.58	45.33	352	392	$ 950,570	$ 742,753	$ 1,693,323
2013	2	$ 61.97	$ 41.80	43.58	45.33	320	352	$ 864,154	$ 666,962	$ 1,531,116
2013	3	$ 57.24	$ 32.33	36.44	41.50	336	407	$ 700,836	$ 546,103	$ 1,246,939
2013	4	$ 57.24	$ 32.33	36.44	41.50	352	368	$ 734,209	$ 493,774	$ 1,227,983
2013	5	$ 57.24	$ 32.33	36.44	41.50	352	392	$ 734,209	$ 525,977	$ 1,260,186
2013	6	$ 75.69	$ 42.37	23.74	24.26	320	400	$ 574,990	$ 411,152	$ 986,143
2013	7	$ 75.69	$ 42.37	23.74	24.26	352	392	$ 632,489	$ 402,929	$ 1,035,419
2013	8	$ 75.69	$ 42.37	23.74	24.26	352	392	$ 632,489	$ 402,929	$ 1,035,419
2013	9	$ 60.34	$ 34.53	33.64	34.13	320	400	$ 649,595	$ 471,460	$ 1,121,056
2013	10	$ 60.34	$ 34.53	33.64	34.13	368	376	$ 747,035	$ 443,173	$ 1,190,207
2013	11	$ 60.34	$ 34.53	33.64	34.13	320	401	$ 649,595	$ 472,639	$ 1,122,234
2013	12	$ 63.48	$ 42.80	43.58	45.33	336	408	$ 929,570	$ 791,564	$ 1,721,134
2014	1	$ 63.48	$ 42.80	43.58	45.33	352	392	$ 973,836	$ 760,522	$ 1,734,358
2014	2	$ 63.48	$ 42.80	43.58	45.33	320	352	$ 885,305	$ 682,918	$ 1,568,223
2014	3	$ 55.12	$ 35.33	36.44	41.50	336	407	$ 674,920	$ 596,775	$ 1,271,694
2014	4	$ 55.12	$ 35.33	36.44	41.50	352	368	$ 707,059	$ 539,590	$ 1,246,649
2014	5	$ 55.12	$ 35.33	36.44	41.50	336	408	$ 674,920	$ 598,241	$ 1,273,161
2014	6	$ 70.81	$ 43.37	23.74	24.26	336	384	$ 564,814	$ 404,022	$ 968,836
2014	7	$ 70.81	$ 43.37	23.74	24.26	352	392	$ 591,710	$ 412,439	$ 1,004,149
2014	8	$ 70.81	$ 43.37	23.74	24.26	336	408	$ 564,814	$ 429,274	$ 994,087
2014	9	$ 55.47	$ 34.53	33.64	34.13	336	384	$ 627,029	$ 452,602	$ 1,079,631
2014	10	$ 55.47	$ 34.53	33.64	34.13	368	376	$ 686,746	$ 443,173	$ 1,129,919
2014	11	$ 55.47	$ 34.53	33.64	34.13	304	417	$ 567,312	$ 491,497	$ 1,058,810
2014	12	$ 64.92	$ 43.70	43.58	45.33	352	392	$ 995,899	$ 776,515	$ 1,772,413
2015	1	$ 64.92	$ 43.70	43.58	45.33	336	408	$ 950,631	$ 808,209	$ 1,758,840
2015	2	$ 64.92	$ 43.70	43.58	45.33	320	352	$ 905,362	$ 697,278	$ 1,602,641
2015	3	$ 56.39	$ 36.11	36.44	41.50	352	391	$ 723,326	$ 585,890	$ 1,309,216
2015	4	$ 56.39	$ 36.11	36.44	41.50	352	368	$ 723,326	$ 551,426	$ 1,274,752
2015	5	$ 56.39	$ 36.11	36.44	41.50	320	424	$ 657,569	$ 635,338	$ 1,292,908
2015	6	$ 72.32	$ 44.22	23.74	24.26	352	368	$ 604,322	$ 394,776	$ 999,098
2015	7	$ 72.32	$ 44.22	23.74	24.26	368	376	$ 631,791	$ 403,359	$ 1,035,150
2015	8	$ 72.32	$ 44.22	23.74	24.26	336	408	$ 576,853	$ 437,687	$ 1,014,540
2015	9	$ 56.68	$ 35.28	33.64	34.13	336	384	$ 640,616	$ 462,431	$ 1,103,047
2015	10	$ 56.68	$ 35.28	33.64	34.13	352	392	$ 671,121	$ 472,065	$ 1,143,186
2015	11	$ 56.68	$ 35.28	33.64	34.13	320	401	$ 610,110	$ 482,904	$ 1,093,014
2015	12	$ 66.40	$ 44.62	43.58	45.33	352	392	$ 1,018,513	$ 792,907	$ 1,811,420
2016	1	$ 66.40	$ 44.62	43.58	45.33	320	424	$ 925,921	$ 857,634	$ 1,783,555
2016	2	$ 66.40	$ 44.62	43.58	45.33	336	360	$ 972,217	$ 728,180	$ 1,700,397
2016	3	$ 57.69	$ 36.90	36.44	41.50	368	375	$ 773,637	$ 574,277	$ 1,347,914
2016	4	$ 57.69	$ 36.90	36.44	41.50	336	384	$ 706,364	$ 588,060	$ 1,294,424
2016	5	$ 57.69	$ 36.90	36.44	41.50	336	408	$ 706,364	$ 624,814	$ 1,331,178
2016	6	$ 73.86	$ 45.09	23.74	24.26	352	368	$ 617,249	$ 402,555	$ 1,019,804
2016	7	$ 73.86	$ 45.09	23.74	24.26	320	424	$ 561,136	$ 463,813	$ 1,024,949
2016	8	$ 73.86	$ 45.09	23.74	24.26	368	376	$ 645,306	$ 411,306	$ 1,056,612
2016	9	$ 57.91	$ 36.05	33.64	34.13	336	384	$ 654,541	$ 472,507	$ 1,127,048
2016	10	$ 57.91	$ 36.05	33.64	34.13	336	408	$ 654,541	$ 502,038	$ 1,156,580
2016	11	$ 57.91	$ 36.05	33.64	34.13	336	385	$ 654,541	$ 473,737	$ 1,128,278
2016	12	$ 67.91	$ 45.57	43.58	45.33	336	408	$ 994,343	$ 842,758	$ 1,837,102
2017	1	$ 67.91	$ 45.57	43.58	45.33	336	408	$ 994,343	$ 842,758	$ 1,837,102
2017	2	$ 67.91	$ 45.57	43.58	45.33	320	352	$ 946,994	$ 727,086	$ 1,674,079
2017	3	$ 59.02	$ 37.72	36.44	41.50	368	375	$ 791,505	$ 586,949	$ 1,378,454
2017	4	$ 59.02	$ 37.72	36.44	41.50	320	400	$ 688,265	$ 626,079	$ 1,314,344
2017	5	$ 59.02	$ 37.72	36.44	41.50	352	392	$ 757,092	$ 613,557	$ 1,370,649
2017	6	$ 75.45	$ 45.98	23.74	24.26	352	368	$ 630,500	$ 410,527	$ 1,041,027
2017	7	$ 75.45	$ 45.98	23.74	24.26	320	424	$ 573,181	$ 472,999	$ 1,046,180
2017	8	$ 75.45	$ 45.98	23.74	24.26	368	376	$ 659,159	$ 419,452	$ 1,078,611

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Farm Size (MW)
100

Capacity Factors							
On - Peak				Off - Peak			
Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
0.4358	0.3644	0.2374	0.3364	0.4533	0.4150	0.2426	0.3413

Calvert Cliffs - Shallow Bays

		Wholesale Energy Prices		Capacity Adjusted MW		Monthly Hours		Energy Value		
YEAR	MONTH	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	Total
2017	9	$ 59.17	$ 36.84	33.64	34.13	320	400	$ 636,967	$ 502,952	$ 1,139,919
2017	10	$ 59.17	$ 36.84	33.64	34.13	352	392	$ 700,664	$ 492,893	$ 1,193,556
2017	11	$ 59.17	$ 36.84	33.64	34.13	336	385	$ 668,815	$ 484,091	$ 1,152,906
2017	12	$ 69.46	$ 46.54	43.58	45.33	320	424	$ 968,593	$ 894,436	$ 1,863,029
2018	1	$ 69.46	$ 46.54	43.58	45.33	352	392	$ 1,065,453	$ 826,931	$ 1,892,384
2018	2	$ 69.46	$ 46.54	43.58	45.33	320	352	$ 968,593	$ 742,550	$ 1,711,143
2018	3	$ 60.39	$ 38.55	36.44	41.50	352	391	$ 774,610	$ 625,535	$ 1,400,145
2018	4	$ 60.39	$ 38.55	36.44	41.50	336	384	$ 739,401	$ 614,336	$ 1,353,737
2018	5	$ 60.39	$ 38.55	36.44	41.50	352	392	$ 774,610	$ 627,134	$ 1,401,745
2018	6	$ 77.08	$ 46.90	23.74	24.26	336	384	$ 614,805	$ 436,904	$ 1,051,709
2018	7	$ 77.08	$ 46.90	23.74	24.26	336	408	$ 614,805	$ 464,210	$ 1,079,015
2018	8	$ 77.08	$ 46.90	23.74	24.26	368	376	$ 673,358	$ 427,802	$ 1,101,159
2018	9	$ 60.47	$ 37.65	33.64	34.13	304	416	$ 618,356	$ 534,537	$ 1,152,893
2018	10	$ 60.47	$ 37.65	33.64	34.13	368	376	$ 748,537	$ 483,139	$ 1,231,676
2018	11	$ 60.47	$ 37.65	33.64	34.13	336	385	$ 683,446	$ 494,704	$ 1,178,150
2018	12	$ 71.04	$ 47.53	43.58	45.33	320	424	$ 990,733	$ 913,529	$ 1,904,262
2019	1	$ 71.04	$ 47.53	43.58	45.33	352	392	$ 1,089,806	$ 844,584	$ 1,934,390
2019	2	$ 71.04	$ 47.53	43.58	45.33	320	352	$ 990,733	$ 758,402	$ 1,749,134
2019	3	$ 61.79	$ 39.41	36.44	41.50	336	407	$ 756,541	$ 665,581	$ 1,422,122
2019	4	$ 61.79	$ 39.41	36.44	41.50	352	368	$ 792,567	$ 601,803	$ 1,394,370
2019	5	$ 61.79	$ 39.41	36.44	41.50	352	392	$ 792,567	$ 641,051	$ 1,433,618
2019	6	$ 78.74	$ 47.84	23.74	24.26	320	400	$ 598,184	$ 464,213	$ 1,062,397
2019	7	$ 78.74	$ 47.84	23.74	24.26	352	392	$ 658,003	$ 454,929	$ 1,112,931
2019	8	$ 78.74	$ 47.84	23.74	24.26	352	392	$ 658,003	$ 454,929	$ 1,112,931
2019	9	$ 61.79	$ 38.48	33.64	34.13	320	400	$ 665,184	$ 525,280	$ 1,190,464
2019	10	$ 61.79	$ 38.48	33.64	34.13	368	376	$ 764,961	$ 493,763	$ 1,258,725
2019	11	$ 61.79	$ 38.48	33.64	34.13	320	401	$ 665,184	$ 526,593	$ 1,191,777
2019	12	$ 72.67	$ 48.55	43.58	45.33	336	408	$ 1,064,097	$ 897,889	$ 1,961,986
2020	1	$ 72.67	$ 48.55	43.58	45.33	352	392	$ 1,114,768	$ 862,678	$ 1,977,446
2020	2	$ 72.67	$ 48.55	43.58	45.33	320	376	$ 1,013,426	$ 827,466	$ 1,840,892
2020	3	$ 63.22	$ 40.28	36.44	41.50	352	391	$ 810,972	$ 653,644	$ 1,464,616
2020	4	$ 63.22	$ 40.28	36.44	41.50	352	368	$ 810,972	$ 615,194	$ 1,426,166
2020	5	$ 63.22	$ 40.28	36.44	41.50	320	424	$ 737,248	$ 708,811	$ 1,446,058
2020	6	$ 80.45	$ 48.80	23.74	24.26	352	368	$ 672,272	$ 435,661	$ 1,107,933
2020	7	$ 80.45	$ 48.80	23.74	24.26	368	376	$ 702,830	$ 445,132	$ 1,147,962
2020	8	$ 80.45	$ 48.80	23.74	24.26	336	408	$ 641,714	$ 483,016	$ 1,124,730
2020	9	$ 63.15	$ 39.32	33.64	34.13	336	384	$ 713,815	$ 515,390	$ 1,229,204
2020	10	$ 63.15	$ 39.32	33.64	34.13	352	392	$ 747,806	$ 526,127	$ 1,273,933
2020	11	$ 63.15	$ 39.32	33.64	34.13	320	401	$ 679,823	$ 538,207	$ 1,218,030
2020	12	$ 74.34	$ 49.59	43.58	45.33	352	392	$ 1,140,354	$ 881,224	$ 2,021,578
2021	1	$ 74.34	$ 49.59	43.58	45.33	320	424	$ 1,036,686	$ 953,161	$ 1,989,846
2021	2	$ 74.34	$ 49.59	43.58	45.33	320	352	$ 1,036,686	$ 791,303	$ 1,827,989
2021	3	$ 64.70	$ 41.18	36.44	41.50	368	375	$ 867,558	$ 640,883	$ 1,508,441
2021	4	$ 64.70	$ 41.18	36.44	41.50	352	368	$ 829,838	$ 628,920	$ 1,458,758
2021	5	$ 64.70	$ 41.18	36.44	41.50	320	424	$ 754,398	$ 724,625	$ 1,479,023
2021	6	$ 82.20	$ 49.78	23.74	24.26	352	368	$ 686,898	$ 444,462	$ 1,131,360
2021	7	$ 82.20	$ 49.78	23.74	24.26	336	408	$ 655,675	$ 492,773	$ 1,148,448
2021	8	$ 82.20	$ 49.78	23.74	24.26	352	392	$ 686,898	$ 473,448	$ 1,160,347
2021	9	$ 64.55	$ 40.19	33.64	34.13	336	384	$ 729,571	$ 526,789	$ 1,256,359
2021	10	$ 64.55	$ 40.19	33.64	34.13	336	408	$ 729,571	$ 559,713	$ 1,289,284
2021	11	$ 64.55	$ 40.19	33.64	34.13	336	385	$ 729,571	$ 528,161	$ 1,257,731
2021	12	$ 76.05	$ 50.66	43.58	45.33	368	376	$ 1,219,607	$ 863,490	$ 2,083,096
2022	1	$ 76.05	$ 50.66	43.58	45.33	336	408	$ 1,113,554	$ 936,978	$ 2,050,532
2022	2	$ 76.05	$ 50.66	43.58	45.33	320	352	$ 1,060,528	$ 808,373	$ 1,868,901
2022	3	$ 66.20	$ 42.10	36.44	41.50	368	375	$ 887,774	$ 655,220	$ 1,542,994
2022	4	$ 66.20	$ 42.10	36.44	41.50	336	384	$ 810,576	$ 670,945	$ 1,481,521
2022	5	$ 66.20	$ 42.10	36.44	41.50	336	408	$ 810,576	$ 712,879	$ 1,523,455
2022	6	$ 83.99	$ 50.80	23.74	24.26	352	368	$ 701,890	$ 453,482	$ 1,155,372
2022	7	$ 83.99	$ 50.80	23.74	24.26	320	424	$ 638,082	$ 522,490	$ 1,160,572
2022	8	$ 83.99	$ 50.80	23.74	24.26	368	376	$ 733,794	$ 463,341	$ 1,197,134
2022	9	$ 65.98	$ 41.09	33.64	34.13	336	384	$ 745,720	$ 538,473	$ 1,284,193
2022	10	$ 65.98	$ 41.09	33.64	34.13	336	408	$ 745,720	$ 572,128	$ 1,317,848
2022	11	$ 65.98	$ 41.09	33.64	34.13	336	385	$ 745,720	$ 539,875	$ 1,285,596
2022	12	$ 77.80	$ 51.76	43.58	45.33	336	408	$ 1,139,214	$ 957,259	$ 2,096,472
2023	1	$ 77.80	$ 51.76	43.58	45.33	336	408	$ 1,139,214	$ 957,259	$ 2,096,472
2023	2	$ 77.80	$ 51.76	43.58	45.33	320	352	$ 1,084,965	$ 825,870	$ 1,910,836
2023	3	$ 67.75	$ 43.05	36.44	41.50	368	375	$ 908,495	$ 669,915	$ 1,578,410
2023	4	$ 67.75	$ 43.05	36.44	41.50	320	400	$ 789,996	$ 714,576	$ 1,504,572

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Farm Size (MW)
100

Capacity Factors							
On - Peak				Off - Peak			
Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
0.4358	0.3644	0.2374	0.3364	0.4533	0.4150	0.2426	0.3413

		Calvert Cliffs - Shallow Bays								
		Wholesale Energy Prices		Capacity Adjusted MW		Monthly Hours		Energy Value		
YEAR	MONTH	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	Total
2023	5	$ 67.75	$ 43.05	36.44	41.50	352	392	$ 868,996	$ 700,284	$ 1,569,280
2023	6	$ 85.83	$ 51.83	23.74	24.26	352	368	$ 717,256	$ 462,728	$ 1,179,984
2023	7	$ 85.83	$ 51.83	23.74	24.26	320	424	$ 652,051	$ 533,143	$ 1,185,194
2023	8	$ 85.83	$ 51.83	23.74	24.26	368	376	$ 749,859	$ 472,787	$ 1,222,646
2023	9	$ 67.44	$ 42.00	33.64	34.13	320	400	$ 725,975	$ 573,385	$ 1,299,360
2023	10	$ 67.44	$ 42.00	33.64	34.13	352	392	$ 798,573	$ 561,917	$ 1,360,490
2023	11	$ 67.44	$ 42.00	33.64	34.13	336	385	$ 762,274	$ 551,883	$ 1,314,157
2023	12	$ 79.60	$ 52.88	43.58	45.33	320	424	$ 1,110,014	$ 1,016,401	$ 2,126,415
2024	1	$ 79.60	$ 52.88	43.58	45.33	352	392	$ 1,221,016	$ 939,691	$ 2,160,707
2024	2	$ 79.60	$ 52.88	43.58	45.33	336	360	$ 1,165,515	$ 862,982	$ 2,028,497
2024	3	$ 69.33	$ 44.01	36.44	41.50	336	407	$ 848,889	$ 743,429	$ 1,592,317
2024	4	$ 69.33	$ 44.01	36.44	41.50	352	368	$ 889,312	$ 672,191	$ 1,561,503
2024	5	$ 69.33	$ 44.01	36.44	41.50	352	392	$ 889,312	$ 716,030	$ 1,605,341
2024	6	$ 87.72	$ 52.89	23.74	24.26	320	400	$ 666,370	$ 513,266	$ 1,179,636
2024	7	$ 87.72	$ 52.89	23.74	24.26	352	392	$ 733,007	$ 503,001	$ 1,236,008
2024	8	$ 87.72	$ 52.89	23.74	24.26	352	392	$ 733,007	$ 503,001	$ 1,236,008
2024	9	$ 68.94	$ 42.94	33.64	34.13	320	400	$ 742,135	$ 586,172	$ 1,328,306
2024	10	$ 68.94	$ 42.94	33.64	34.13	368	376	$ 853,455	$ 551,001	$ 1,404,456
2024	11	$ 68.94	$ 42.94	33.64	34.13	320	401	$ 742,135	$ 587,637	$ 1,329,772
2024	12	$ 81.44	$ 54.03	43.58	45.33	336	408	$ 1,192,474	$ 999,353	$ 2,191,827
2025	1	$ 81.44	$ 54.03	43.58	45.33	352	392	$ 1,249,258	$ 960,163	$ 2,209,421
2025	2	$ 81.44	$ 54.03	43.58	45.33	320	352	$ 1,135,689	$ 862,187	$ 1,997,876
2025	3	$ 70.96	$ 45.01	36.44	41.50	336	407	$ 868,766	$ 760,185	$ 1,628,951
2025	4	$ 70.96	$ 45.01	36.44	41.50	352	368	$ 910,136	$ 687,342	$ 1,597,478
2025	5	$ 70.96	$ 45.01	36.44	41.50	336	408	$ 868,766	$ 762,053	$ 1,630,819
2025	6	$ 89.65	$ 53.98	23.74	24.26	336	384	$ 715,099	$ 502,872	$ 1,217,971
2025	7	$ 89.65	$ 53.98	23.74	24.26	352	392	$ 749,151	$ 513,349	$ 1,262,500
2025	8	$ 89.65	$ 53.98	23.74	24.26	336	408	$ 715,099	$ 534,302	$ 1,249,401
2025	9	$ 70.48	$ 43.90	33.64	34.13	336	384	$ 796,633	$ 575,307	$ 1,371,940
2025	10	$ 70.48	$ 43.90	33.64	34.13	368	376	$ 872,503	$ 563,322	$ 1,435,824
2025	11	$ 70.48	$ 43.90	33.64	34.13	304	417	$ 720,763	$ 624,748	$ 1,345,511
2025	12	$ 83.32	$ 55.22	43.58	45.33	352	392	$ 1,278,207	$ 981,147	$ 2,259,353
2026	1	$ 83.32	$ 55.22	43.58	45.33	336	408	$ 1,220,106	$ 1,021,193	$ 2,241,300
2026	2	$ 83.32	$ 55.22	43.58	45.33	320	352	$ 1,162,006	$ 881,030	$ 2,043,036
2026	3	$ 72.62	$ 46.02	36.44	41.50	352	391	$ 931,480	$ 746,801	$ 1,678,281
2026	4	$ 72.62	$ 46.02	36.44	41.50	352	368	$ 931,480	$ 702,871	$ 1,634,352
2026	5	$ 72.62	$ 46.02	36.44	41.50	320	424	$ 846,800	$ 809,830	$ 1,656,631
2026	6	$ 91.63	$ 55.10	23.74	24.26	352	368	$ 765,700	$ 491,876	$ 1,257,575
2026	7	$ 91.63	$ 55.10	23.74	24.26	368	376	$ 800,504	$ 502,569	$ 1,303,073
2026	8	$ 91.63	$ 55.10	23.74	24.26	336	408	$ 730,895	$ 545,341	$ 1,276,236
2026	9	$ 72.06	$ 44.88	33.64	34.13	336	384	$ 814,459	$ 588,204	$ 1,402,664
2026	10	$ 72.06	$ 44.88	33.64	34.13	352	392	$ 853,243	$ 600,459	$ 1,453,702
2026	11	$ 72.06	$ 44.88	33.64	34.13	320	401	$ 775,675	$ 614,245	$ 1,389,920
2026	12	$ 85.26	$ 56.43	43.58	45.33	352	392	$ 1,307,879	$ 1,002,655	$ 2,310,534
2027	1	$ 85.26	$ 56.43	43.58	45.33	320	424	$ 1,188,981	$ 1,084,504	$ 2,273,485
2027	2	$ 85.26	$ 56.43	43.58	45.33	320	352	$ 1,188,981	$ 900,343	$ 2,089,324
2027	3	$ 74.33	$ 47.07	36.44	41.50	368	375	$ 996,693	$ 732,462	$ 1,729,155
2027	4	$ 74.33	$ 47.07	36.44	41.50	352	368	$ 953,359	$ 718,789	$ 1,672,148
2027	5	$ 74.33	$ 47.07	36.44	41.50	320	424	$ 866,690	$ 828,170	$ 1,694,860
2027	6	$ 93.66	$ 56.24	23.74	24.26	352	368	$ 782,661	$ 502,082	$ 1,284,743
2027	7	$ 93.66	$ 56.24	23.74	24.26	336	408	$ 747,086	$ 556,656	$ 1,303,741
2027	8	$ 93.66	$ 56.24	23.74	24.26	352	392	$ 782,661	$ 534,826	$ 1,317,487
2027	9	$ 73.67	$ 45.89	33.64	34.13	336	384	$ 832,731	$ 601,424	$ 1,434,155
2027	10	$ 73.67	$ 45.89	33.64	34.13	336	408	$ 832,731	$ 639,013	$ 1,471,744
2027	11	$ 73.67	$ 45.89	33.64	34.13	336	385	$ 832,731	$ 602,990	$ 1,435,721
2027	12	$ 87.24	$ 57.67	43.58	45.33	368	376	$ 1,399,125	$ 982,876	$ 2,382,000
2028	1	$ 87.24	$ 57.67	43.58	45.33	336	408	$ 1,277,462	$ 1,066,525	$ 2,343,986
2028	2	$ 87.24	$ 57.67	43.58	45.33	336	360	$ 1,277,462	$ 941,051	$ 2,218,513
2028	3	$ 76.07	$ 48.13	36.44	41.50	368	375	$ 1,020,138	$ 749,088	$ 1,769,226
2028	4	$ 76.07	$ 48.13	36.44	41.50	320	400	$ 887,076	$ 799,027	$ 1,686,103
2028	5	$ 76.07	$ 48.13	36.44	41.50	352	392	$ 975,784	$ 783,047	$ 1,758,831
2028	6	$ 95.74	$ 57.41	23.74	24.26	352	368	$ 800,047	$ 512,542	$ 1,312,590
2028	7	$ 95.74	$ 57.41	23.74	24.26	320	424	$ 727,316	$ 590,538	$ 1,317,854
2028	8	$ 95.74	$ 57.41	23.74	24.26	368	376	$ 836,413	$ 523,685	$ 1,360,098
2028	9	$ 75.33	$ 46.92	33.64	34.13	320	400	$ 810,914	$ 640,598	$ 1,451,512
2028	10	$ 75.33	$ 46.92	33.64	34.13	352	392	$ 892,006	$ 627,786	$ 1,519,792
2028	11	$ 75.33	$ 46.92	33.64	34.13	336	385	$ 851,460	$ 616,575	$ 1,468,035
2028	12	$ 89.27	$ 58.94	43.58	45.33	320	424	$ 1,244,970	$ 1,132,791	$ 2,377,761

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Farm Size (MW)
100

Capacity Factors							
On - Peak				Off - Peak			
Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
0.4358	0.3644	0.2374	0.3364	0.4533	0.4150	0.2426	0.3413

Calvert Cliffs - Shallow Bays

		Wholesale Energy Prices		Capacity Adjusted MW		Monthly Hours		Energy Value		
YEAR	MONTH	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	Total
2029	1	$ 89.27	$ 58.94	43.58	45.33	352	392	$ 1,369,467	$ 1,047,297	$ 2,416,765
2029	2	$ 89.27	$ 58.94	43.58	45.33	320	352	$ 1,244,970	$ 940,430	$ 2,185,401
2029	3	$ 77.87	$ 49.23	36.44	41.50	352	391	$ 998,770	$ 798,818	$ 1,797,588
2029	4	$ 77.87	$ 49.23	36.44	41.50	336	384	$ 953,371	$ 784,517	$ 1,737,888
2029	5	$ 77.87	$ 49.23	36.44	41.50	352	392	$ 998,770	$ 800,861	$ 1,799,631
2029	6	$ 97.87	$ 58.61	23.74	24.26	336	384	$ 780,692	$ 546,016	$ 1,326,707
2029	7	$ 97.87	$ 58.61	23.74	24.26	336	408	$ 780,692	$ 580,141	$ 1,360,833
2029	8	$ 97.87	$ 58.61	23.74	24.26	368	376	$ 855,043	$ 534,640	$ 1,389,684
2029	9	$ 77.03	$ 47.98	33.64	34.13	304	416	$ 787,737	$ 681,268	$ 1,469,005
2029	10	$ 77.03	$ 47.98	33.64	34.13	368	376	$ 953,577	$ 615,761	$ 1,569,338
2029	11	$ 77.03	$ 47.98	33.64	34.13	336	385	$ 870,657	$ 630,500	$ 1,501,157
2029	12	$ 91.36	$ 60.24	43.58	45.33	320	424	$ 1,274,019	$ 1,157,843	$ 2,431,863
2030	1	$ 91.36	$ 60.24	43.58	45.33	352	392	$ 1,401,421	$ 1,070,459	$ 2,471,880
2030	2	$ 91.36	$ 60.24	43.58	45.33	320	352	$ 1,274,019	$ 961,228	$ 2,235,248
2030	3	$ 79.70	$ 50.35	36.44	41.50	336	407	$ 975,861	$ 850,465	$ 1,826,325
2030	4	$ 79.70	$ 50.35	36.44	41.50	352	368	$ 1,022,330	$ 768,971	$ 1,791,301
2030	5	$ 79.70	$ 50.35	36.44	41.50	352	392	$ 1,022,330	$ 819,121	$ 1,841,451
2030	6	$ 100.06	$ 59.84	23.74	24.26	320	400	$ 760,121	$ 580,712	$ 1,340,834
2030	7	$ 100.06	$ 59.84	23.74	24.26	352	392	$ 836,133	$ 569,098	$ 1,405,232
2030	8	$ 100.06	$ 59.84	23.74	24.26	352	392	$ 836,133	$ 569,098	$ 1,405,232
2030	9	$ 78.77	$ 49.07	33.64	34.13	320	400	$ 847,937	$ 669,894	$ 1,517,831
2030	10	$ 78.77	$ 49.07	33.64	34.13	368	376	$ 975,128	$ 629,701	$ 1,604,828
2030	11	$ 78.77	$ 49.07	33.64	34.13	320	401	$ 847,937	$ 671,569	$ 1,519,506
2030	12	$ 93.49	$ 61.58	43.58	45.33	336	408	$ 1,368,984	$ 1,138,861	$ 2,507,845
2031	1	$ 93.49	$ 61.58	43.58	45.33	352	392	$ 1,434,174	$ 1,094,200	$ 2,528,374
2031	2	$ 93.49	$ 61.58	43.58	45.33	320	352	$ 1,303,794	$ 982,547	$ 2,286,341
2031	3	$ 81.58	$ 51.50	36.44	41.50	336	407	$ 998,912	$ 869,897	$ 1,868,809
2031	4	$ 81.58	$ 51.50	36.44	41.50	352	368	$ 1,046,480	$ 786,541	$ 1,833,020
2031	5	$ 81.58	$ 51.50	36.44	41.50	336	408	$ 998,912	$ 872,034	$ 1,870,947
2031	6	$ 102.30	$ 61.10	23.74	24.26	336	384	$ 815,999	$ 569,239	$ 1,385,238
2031	7	$ 102.30	$ 61.10	23.74	24.26	352	392	$ 854,856	$ 581,098	$ 1,435,954
2031	8	$ 102.30	$ 61.10	23.74	24.26	336	408	$ 815,999	$ 604,816	$ 1,420,815
2031	9	$ 80.55	$ 50.18	33.64	34.13	336	384	$ 910,503	$ 657,691	$ 1,568,193
2031	10	$ 80.55	$ 50.18	33.64	34.13	368	376	$ 997,217	$ 643,989	$ 1,641,206
2031	11	$ 80.55	$ 50.18	33.64	34.13	304	417	$ 823,788	$ 714,211	$ 1,537,999
2031	12	$ 95.68	$ 62.95	43.58	45.33	352	392	$ 1,467,745	$ 1,118,534	$ 2,586,279
2032	1	$ 95.68	$ 62.95	43.58	45.33	336	408	$ 1,401,030	$ 1,164,189	$ 2,565,218
2032	2	$ 95.68	$ 62.95	43.58	45.33	320	376	$ 1,334,314	$ 1,072,880	$ 2,407,194
2032	3	$ 83.51	$ 52.68	36.44	41.50	368	375	$ 1,119,925	$ 819,854	$ 1,939,780
2032	4	$ 83.51	$ 52.68	36.44	41.50	352	368	$ 1,071,233	$ 804,550	$ 1,875,783
2032	5	$ 83.51	$ 52.68	36.44	41.50	320	424	$ 973,848	$ 926,982	$ 1,900,830
2032	6	$ 104.60	$ 62.40	23.74	24.26	352	368	$ 874,047	$ 557,067	$ 1,431,114
2032	7	$ 104.60	$ 62.40	23.74	24.26	336	408	$ 834,317	$ 617,618	$ 1,451,936
2032	8	$ 104.60	$ 62.40	23.74	24.26	352	392	$ 874,047	$ 593,398	$ 1,467,445
2032	9	$ 82.38	$ 51.32	33.64	34.13	336	384	$ 931,176	$ 672,647	$ 1,603,823
2032	10	$ 82.38	$ 51.32	33.64	34.13	336	408	$ 931,176	$ 714,688	$ 1,645,863
2032	11	$ 82.38	$ 51.32	33.64	34.13	336	385	$ 931,176	$ 674,399	$ 1,605,575
2032	12	$ 97.92	$ 64.35	43.58	45.33	368	376	$ 1,570,436	$ 1,096,804	$ 2,667,240
2033	1	$ 97.92	$ 64.35	43.58	45.33	336	408	$ 1,433,876	$ 1,190,149	$ 2,624,026
2033	2	$ 97.92	$ 64.35	43.58	45.33	320	352	$ 1,365,596	$ 1,026,796	$ 2,392,392
2033	3	$ 85.49	$ 53.89	36.44	41.50	368	375	$ 1,146,451	$ 838,665	$ 1,985,116
2033	4	$ 85.49	$ 53.89	36.44	41.50	336	384	$ 1,046,759	$ 858,793	$ 1,905,552
2033	5	$ 85.49	$ 53.89	36.44	41.50	336	408	$ 1,046,759	$ 912,468	$ 1,959,227
2033	6	$ 106.95	$ 63.72	23.74	24.26	352	368	$ 893,717	$ 568,903	$ 1,462,620
2033	7	$ 106.95	$ 63.72	23.74	24.26	320	424	$ 812,470	$ 655,475	$ 1,467,945
2033	8	$ 106.95	$ 63.72	23.74	24.26	368	376	$ 934,341	$ 581,270	$ 1,515,611
2033	9	$ 84.26	$ 52.49	33.64	34.13	336	384	$ 952,366	$ 687,978	$ 1,640,344
2033	10	$ 84.26	$ 52.49	33.64	34.13	336	408	$ 952,366	$ 730,976	$ 1,683,342
2033	11	$ 84.26	$ 52.49	33.64	34.13	336	385	$ 952,366	$ 689,769	$ 1,642,135
2033	12	$ 100.22	$ 65.79	43.58	45.33	352	392	$ 1,537,427	$ 1,169,043	$ 2,706,470
2034	1	$ 100.22	$ 65.79	43.58	45.33	336	408	$ 1,467,544	$ 1,216,759	$ 2,684,303
2034	2	$ 100.22	$ 65.79	43.58	45.33	320	352	$ 1,397,661	$ 1,049,753	$ 2,447,414
2034	3	$ 87.52	$ 55.13	36.44	41.50	368	375	$ 1,173,639	$ 857,947	$ 2,031,586
2034	4	$ 87.52	$ 55.13	36.44	41.50	320	400	$ 1,020,556	$ 915,143	$ 1,935,699
2034	5	$ 87.52	$ 55.13	36.44	41.50	352	392	$ 1,122,611	$ 896,840	$ 2,019,451
2034	6	$ 109.36	$ 65.08	23.74	24.26	352	368	$ 913,879	$ 581,034	$ 1,494,914
2034	7	$ 109.36	$ 65.08	23.74	24.26	320	424	$ 830,799	$ 669,453	$ 1,500,252
2034	8	$ 109.36	$ 65.08	23.74	24.26	368	376	$ 955,419	$ 593,665	$ 1,549,085

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Farm Size (MW)
100

Capacity Factors							
On - Peak				Off - Peak			
Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
0.4358	0.3644	0.2374	0.3364	0.4533	0.4150	0.2426	0.3413

Calvert Cliffs - Shallow Bays

		Wholesale Energy Prices		Capacity Adjusted MW		Monthly Hours		Energy Value		
YEAR	MONTH	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	Total
2034	9	$ 86.18	$ 53.69	33.64	34.13	320	400	$ 927,700	$ 733,012	$ 1,660,712
2034	10	$ 86.18	$ 53.69	33.64	34.13	352	392	$ 1,020,470	$ 718,352	$ 1,738,822
2034	11	$ 86.18	$ 53.69	33.64	34.13	336	385	$ 974,085	$ 705,524	$ 1,679,610
2034	12	$ 102.58	$ 67.26	43.58	45.33	320	424	$ 1,430,527	$ 1,292,820	$ 2,723,347
2035	1	$ 102.58	$ 67.26	43.58	45.33	352	392	$ 1,573,580	$ 1,195,249	$ 2,768,828
2035	2	$ 102.58	$ 67.26	43.58	45.33	320	352	$ 1,430,527	$ 1,073,284	$ 2,503,812
2035	3	$ 89.60	$ 56.40	36.44	41.50	352	391	$ 1,149,268	$ 915,159	$ 2,064,426
2035	4	$ 89.60	$ 56.40	36.44	41.50	336	384	$ 1,097,028	$ 898,775	$ 1,995,803
2035	5	$ 89.60	$ 56.40	36.44	41.50	352	392	$ 1,149,268	$ 917,499	$ 2,066,767
2035	6	$ 111.83	$ 66.48	23.74	24.26	336	384	$ 892,066	$ 619,272	$ 1,511,338
2035	7	$ 111.83	$ 66.48	23.74	24.26	336	408	$ 892,066	$ 657,976	$ 1,550,043
2035	8	$ 111.83	$ 66.48	23.74	24.26	368	376	$ 977,025	$ 606,370	$ 1,583,396
2035	9	$ 88.15	$ 54.92	33.64	34.13	304	416	$ 901,458	$ 779,781	$ 1,681,239
2035	10	$ 88.15	$ 54.92	33.64	34.13	368	376	$ 1,091,238	$ 704,802	$ 1,796,041
2035	11	$ 88.15	$ 54.92	33.64	34.13	336	385	$ 996,348	$ 721,673	$ 1,718,021
2035	12	$ 88.15	$ 54.92	43.58	45.33	320	424	$ 1,229,286	$ 1,055,589	$ 2,284,875

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Farm Size (MW)
100

Capacity Factors							
On - Peak				Off - Peak			
Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
0.4513	0.4050	0.2350	0.3327	0.4717	0.4226	0.2504	0.3376

		Fentress - Off Shore Ocean								
		Wholesale Energy Prices		Capacity Adjusted MW		Monthly Hours		Energy Value		
YEAR	MONTH	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	Total
2012	1	$ 55.94	$ 37.22	45.13	47.17	336	408	$ 848,192	$ 716,331	$ 1,564,523
2012	2	$ 55.94	$ 37.22	45.13	47.17	336	360	$ 848,192	$ 632,057	$ 1,480,249
2012	3	$ 50.20	$ 27.99	40.50	42.26	352	391	$ 715,656	$ 462,440	$ 1,178,096
2012	4	$ 50.20	$ 27.99	40.50	42.26	336	384	$ 683,127	$ 454,161	$ 1,137,287
2012	5	$ 50.20	$ 27.99	40.50	42.26	352	392	$ 715,656	$ 463,622	$ 1,179,279
2012	6	$ 69.53	$ 38.38	23.50	25.04	336	384	$ 549,036	$ 369,035	$ 918,072
2012	7	$ 69.53	$ 38.38	23.50	25.04	336	408	$ 549,036	$ 392,100	$ 941,136
2012	8	$ 69.53	$ 38.38	23.50	25.04	368	376	$ 601,325	$ 361,347	$ 962,672
2012	9	$ 53.57	$ 31.43	33.27	33.76	304	416	$ 541,824	$ 441,349	$ 983,173
2012	10	$ 53.57	$ 31.43	33.27	33.76	368	376	$ 655,892	$ 398,911	$ 1,054,804
2012	11	$ 53.57	$ 31.43	33.27	33.76	336	385	$ 598,858	$ 408,460	$ 1,007,318
2012	12	$ 57.21	$ 39.22	45.13	47.17	320	424	$ 826,239	$ 784,422	$ 1,610,662
2013	1	$ 57.21	$ 39.22	45.13	47.17	352	392	$ 908,863	$ 725,221	$ 1,634,084
2013	2	$ 57.21	$ 39.22	45.13	47.17	320	352	$ 826,239	$ 651,219	$ 1,477,458
2013	3	$ 52.38	$ 29.99	40.50	42.26	336	407	$ 712,747	$ 515,763	$ 1,228,509
2013	4	$ 52.38	$ 29.99	40.50	42.26	352	368	$ 746,687	$ 466,341	$ 1,213,028
2013	5	$ 52.38	$ 29.99	40.50	42.26	352	392	$ 746,687	$ 496,754	$ 1,243,441
2013	6	$ 72.13	$ 40.38	23.50	25.04	320	400	$ 542,393	$ 404,444	$ 946,837
2013	7	$ 72.13	$ 40.38	23.50	25.04	352	392	$ 596,633	$ 396,355	$ 992,988
2013	8	$ 72.13	$ 40.38	23.50	25.04	352	392	$ 596,633	$ 396,355	$ 992,988
2013	9	$ 55.18	$ 32.42	33.27	33.76	320	400	$ 587,482	$ 437,845	$ 1,025,327
2013	10	$ 55.18	$ 32.42	33.27	33.76	368	376	$ 675,604	$ 411,574	$ 1,087,178
2013	11	$ 55.18	$ 32.42	33.27	33.76	320	401	$ 587,482	$ 438,940	$ 1,026,421
2013	12	$ 58.73	$ 40.22	45.13	47.17	336	408	$ 890,550	$ 774,067	$ 1,664,617
2014	1	$ 58.73	$ 40.22	45.13	47.17	352	392	$ 932,957	$ 743,711	$ 1,676,668
2014	2	$ 58.73	$ 40.22	45.13	47.17	320	352	$ 848,143	$ 667,822	$ 1,515,965
2014	3	$ 50.26	$ 32.99	40.50	42.26	336	407	$ 683,943	$ 567,362	$ 1,251,305
2014	4	$ 50.26	$ 32.99	40.50	42.26	352	368	$ 716,512	$ 512,996	$ 1,229,508
2014	5	$ 50.26	$ 32.99	40.50	42.26	336	408	$ 683,943	$ 568,756	$ 1,252,699
2014	6	$ 67.25	$ 41.38	23.50	25.04	336	384	$ 530,981	$ 397,881	$ 928,862
2014	7	$ 67.25	$ 41.38	23.50	25.04	352	392	$ 556,265	$ 406,171	$ 962,436
2014	8	$ 67.25	$ 41.38	23.50	25.04	336	408	$ 530,981	$ 422,749	$ 953,730
2014	9	$ 50.31	$ 32.42	33.27	33.76	336	384	$ 562,415	$ 420,331	$ 982,747
2014	10	$ 50.31	$ 32.42	33.27	33.76	368	376	$ 615,979	$ 411,574	$ 1,027,553
2014	11	$ 50.31	$ 32.42	33.27	33.76	304	417	$ 508,852	$ 456,453	$ 965,305
2014	12	$ 60.17	$ 41.12	45.13	47.17	352	392	$ 955,804	$ 760,353	$ 1,716,157
2015	1	$ 60.17	$ 41.12	45.13	47.17	336	408	$ 912,359	$ 791,388	$ 1,703,747
2015	2	$ 60.17	$ 41.12	45.13	47.17	320	352	$ 868,913	$ 682,766	$ 1,551,679
2015	3	$ 51.53	$ 33.76	40.50	42.26	352	391	$ 734,592	$ 557,864	$ 1,292,456
2015	4	$ 51.53	$ 33.76	40.50	42.26	352	368	$ 734,592	$ 525,048	$ 1,259,640
2015	5	$ 51.53	$ 33.76	40.50	42.26	320	424	$ 667,811	$ 604,947	$ 1,272,758
2015	6	$ 68.76	$ 42.23	23.50	25.04	352	368	$ 568,750	$ 389,136	$ 957,886
2015	7	$ 68.76	$ 42.23	23.50	25.04	368	376	$ 594,602	$ 397,595	$ 992,197
2015	8	$ 68.76	$ 42.23	23.50	25.04	336	408	$ 542,898	$ 431,433	$ 974,331
2015	9	$ 51.51	$ 33.17	33.27	33.76	336	384	$ 575,852	$ 430,054	$ 1,005,906
2015	10	$ 51.51	$ 33.17	33.27	33.76	352	392	$ 603,274	$ 439,013	$ 1,042,287
2015	11	$ 51.51	$ 33.17	33.27	33.76	320	401	$ 548,431	$ 449,093	$ 997,524
2015	12	$ 61.64	$ 42.04	45.13	47.17	352	392	$ 979,223	$ 777,411	$ 1,756,634
2016	1	$ 61.64	$ 42.04	45.13	47.17	320	424	$ 890,203	$ 840,873	$ 1,731,076
2016	2	$ 61.64	$ 42.04	45.13	47.17	336	360	$ 934,713	$ 713,948	$ 1,648,662
2016	3	$ 52.83	$ 34.56	40.50	42.26	368	375	$ 787,357	$ 547,624	$ 1,334,982
2016	4	$ 52.83	$ 34.56	40.50	42.26	336	384	$ 718,891	$ 560,767	$ 1,279,659
2016	5	$ 52.83	$ 34.56	40.50	42.26	336	408	$ 718,891	$ 595,815	$ 1,314,707
2016	6	$ 70.30	$ 43.10	23.50	25.04	352	368	$ 581,547	$ 397,164	$ 978,710
2016	7	$ 70.30	$ 43.10	23.50	25.04	320	424	$ 528,679	$ 457,602	$ 986,281
2016	8	$ 70.30	$ 43.10	23.50	25.04	368	376	$ 607,980	$ 405,798	$ 1,013,778
2016	9	$ 52.75	$ 33.94	33.27	33.76	336	384	$ 589,625	$ 440,020	$ 1,029,645
2016	10	$ 52.75	$ 33.94	33.27	33.76	336	408	$ 589,625	$ 467,521	$ 1,057,146
2016	11	$ 52.75	$ 33.94	33.27	33.76	336	385	$ 589,625	$ 441,166	$ 1,030,791
2016	12	$ 63.15	$ 42.99	45.13	47.17	336	408	$ 957,626	$ 827,339	$ 1,784,966
2017	1	$ 63.15	$ 42.99	45.13	47.17	336	408	$ 957,626	$ 827,339	$ 1,784,966
2017	2	$ 63.15	$ 42.99	45.13	47.17	320	352	$ 912,025	$ 713,783	$ 1,625,808
2017	3	$ 54.16	$ 35.37	40.50	42.26	368	375	$ 807,216	$ 560,528	$ 1,367,744
2017	4	$ 54.16	$ 35.37	40.50	42.26	320	400	$ 701,927	$ 597,897	$ 1,299,824
2017	5	$ 54.16	$ 35.37	40.50	42.26	352	392	$ 772,120	$ 585,939	$ 1,358,058
2017	6	$ 71.89	$ 43.99	23.50	25.04	352	368	$ 594,663	$ 405,393	$ 1,000,056
2017	7	$ 71.89	$ 43.99	23.50	25.04	320	424	$ 540,603	$ 467,083	$ 1,007,686
2017	8	$ 71.89	$ 43.99	23.50	25.04	368	376	$ 621,693	$ 414,206	$ 1,035,899

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Farm Size (MW)
100

Capacity Factors							
On - Peak				Off - Peak			
Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
0.4513	0.4050	0.2350	0.3327	0.4717	0.4226	0.2504	0.3376

Fentress - Off Shore Ocean

		Wholesale Energy Prices		Capacity Adjusted MW		Monthly Hours		Energy Value		
YEAR	MONTH	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	Total
2017	9	$ 54.01	$ 34.73	33.27	33.76	320	400	$ 574,992	$ 468,995	$ 1,043,987
2017	10	$ 54.01	$ 34.73	33.27	33.76	352	392	$ 632,492	$ 459,615	$ 1,092,107
2017	11	$ 54.01	$ 34.73	33.27	33.76	336	385	$ 603,742	$ 451,408	$ 1,055,150
2017	12	$ 64.70	$ 43.96	45.13	47.17	320	424	$ 934,393	$ 879,168	$ 1,813,561
2018	1	$ 64.70	$ 43.96	45.13	47.17	352	392	$ 1,027,832	$ 812,816	$ 1,840,648
2018	2	$ 64.70	$ 43.96	45.13	47.17	320	352	$ 934,393	$ 729,875	$ 1,664,268
2018	3	$ 55.53	$ 36.20	40.50	42.26	352	391	$ 791,590	$ 598,234	$ 1,389,824
2018	4	$ 55.53	$ 36.20	40.50	42.26	336	384	$ 755,609	$ 587,524	$ 1,343,133
2018	5	$ 55.53	$ 36.20	40.50	42.26	352	392	$ 791,590	$ 599,764	$ 1,391,354
2018	6	$ 73.51	$ 44.91	23.50	25.04	336	384	$ 580,466	$ 431,820	$ 1,012,287
2018	7	$ 73.51	$ 44.91	23.50	25.04	336	408	$ 580,466	$ 458,809	$ 1,039,275
2018	8	$ 73.51	$ 44.91	23.50	25.04	368	376	$ 635,749	$ 422,824	$ 1,058,573
2018	9	$ 55.30	$ 35.54	33.27	33.76	304	416	$ 559,335	$ 499,098	$ 1,058,432
2018	10	$ 55.30	$ 35.54	33.27	33.76	368	376	$ 677,089	$ 451,107	$ 1,128,197
2018	11	$ 55.30	$ 35.54	33.27	33.76	336	385	$ 618,212	$ 461,905	$ 1,080,117
2018	12	$ 66.29	$ 44.95	45.13	47.17	320	424	$ 957,320	$ 899,037	$ 1,856,357
2019	1	$ 66.29	$ 44.95	45.13	47.17	352	392	$ 1,053,052	$ 831,185	$ 1,884,237
2019	2	$ 66.29	$ 44.95	45.13	47.17	320	352	$ 957,320	$ 746,370	$ 1,703,690
2019	3	$ 56.93	$ 37.06	40.50	42.26	336	407	$ 774,659	$ 637,428	$ 1,412,087
2019	4	$ 56.93	$ 37.06	40.50	42.26	352	368	$ 811,547	$ 576,348	$ 1,387,895
2019	5	$ 56.93	$ 37.06	40.50	42.26	352	392	$ 811,547	$ 613,936	$ 1,425,483
2019	6	$ 75.18	$ 45.85	23.50	25.04	320	400	$ 565,353	$ 459,210	$ 1,024,563
2019	7	$ 75.18	$ 45.85	23.50	25.04	352	392	$ 621,888	$ 450,026	$ 1,071,914
2019	8	$ 75.18	$ 45.85	23.50	25.04	352	392	$ 621,888	$ 450,026	$ 1,071,914
2019	9	$ 56.63	$ 36.37	33.27	33.76	320	400	$ 602,899	$ 491,081	$ 1,093,980
2019	10	$ 56.63	$ 36.37	33.27	33.76	368	376	$ 693,334	$ 461,616	$ 1,154,950
2019	11	$ 56.63	$ 36.37	33.27	33.76	320	401	$ 602,899	$ 492,309	$ 1,095,208
2019	12	$ 67.92	$ 45.97	45.13	47.17	336	408	$ 1,029,861	$ 884,708	$ 1,914,569
2020	1	$ 67.92	$ 45.97	45.13	47.17	352	392	$ 1,078,902	$ 850,013	$ 1,928,915
2020	2	$ 67.92	$ 45.97	45.13	47.17	320	376	$ 980,820	$ 815,319	$ 1,796,139
2020	3	$ 58.36	$ 37.94	40.50	42.26	352	391	$ 832,003	$ 626,858	$ 1,458,861
2020	4	$ 58.36	$ 37.94	40.50	42.26	352	368	$ 832,003	$ 589,984	$ 1,421,987
2020	5	$ 58.36	$ 37.94	40.50	42.26	320	424	$ 756,367	$ 679,764	$ 1,436,131
2020	6	$ 76.89	$ 46.81	23.50	25.04	352	368	$ 636,013	$ 431,335	$ 1,067,348
2020	7	$ 76.89	$ 46.81	23.50	25.04	368	376	$ 664,923	$ 440,712	$ 1,105,635
2020	8	$ 76.89	$ 46.81	23.50	25.04	336	408	$ 607,104	$ 478,219	$ 1,085,323
2020	9	$ 57.99	$ 37.21	33.27	33.76	336	384	$ 648,246	$ 482,438	$ 1,130,685
2020	10	$ 57.99	$ 37.21	33.27	33.76	352	392	$ 679,115	$ 492,489	$ 1,171,604
2020	11	$ 57.99	$ 37.21	33.27	33.76	320	401	$ 617,377	$ 503,796	$ 1,121,174
2020	12	$ 69.58	$ 47.01	45.13	47.17	352	392	$ 1,105,398	$ 869,312	$ 1,974,711
2021	1	$ 69.58	$ 47.01	45.13	47.17	320	424	$ 1,004,907	$ 940,277	$ 1,945,184
2021	2	$ 69.58	$ 47.01	45.13	47.17	320	352	$ 1,004,907	$ 780,607	$ 1,785,515
2021	3	$ 59.83	$ 38.84	40.50	42.26	368	375	$ 891,742	$ 615,450	$ 1,507,192
2021	4	$ 59.83	$ 38.84	40.50	42.26	352	368	$ 852,971	$ 603,962	$ 1,456,932
2021	5	$ 59.83	$ 38.84	40.50	42.26	320	424	$ 775,428	$ 695,869	$ 1,471,297
2021	6	$ 78.64	$ 47.80	23.50	25.04	352	368	$ 650,491	$ 440,418	$ 1,090,910
2021	7	$ 78.64	$ 47.80	23.50	25.04	336	408	$ 620,924	$ 488,290	$ 1,109,214
2021	8	$ 78.64	$ 47.80	23.50	25.04	352	392	$ 650,491	$ 469,141	$ 1,119,633
2021	9	$ 59.38	$ 38.08	33.27	33.76	336	384	$ 663,829	$ 493,714	$ 1,157,543
2021	10	$ 59.38	$ 38.08	33.27	33.76	336	408	$ 663,829	$ 524,571	$ 1,188,400
2021	11	$ 59.38	$ 38.08	33.27	33.76	336	385	$ 663,829	$ 495,000	$ 1,158,829
2021	12	$ 71.29	$ 48.08	45.13	47.17	368	376	$ 1,184,037	$ 852,804	$ 2,036,841
2022	1	$ 71.29	$ 48.08	45.13	47.17	336	408	$ 1,081,077	$ 925,384	$ 2,006,461
2022	2	$ 71.29	$ 48.08	45.13	47.17	320	352	$ 1,029,597	$ 798,370	$ 1,827,967
2022	3	$ 61.34	$ 39.76	40.50	42.26	368	375	$ 914,211	$ 630,049	$ 1,544,260
2022	4	$ 61.34	$ 39.76	40.50	42.26	336	384	$ 834,714	$ 645,170	$ 1,479,884
2022	5	$ 61.34	$ 39.76	40.50	42.26	336	408	$ 834,714	$ 685,493	$ 1,520,207
2022	6	$ 80.43	$ 48.81	23.50	25.04	352	368	$ 665,332	$ 449,729	$ 1,115,060
2022	7	$ 80.43	$ 48.81	23.50	25.04	320	424	$ 604,847	$ 518,166	$ 1,123,013
2022	8	$ 80.43	$ 48.81	23.50	25.04	368	376	$ 695,574	$ 459,506	$ 1,155,079
2022	9	$ 60.81	$ 38.98	33.27	33.76	336	384	$ 679,801	$ 505,271	$ 1,185,072
2022	10	$ 60.81	$ 38.98	33.27	33.76	336	408	$ 679,801	$ 536,851	$ 1,216,652
2022	11	$ 60.81	$ 38.98	33.27	33.76	336	385	$ 679,801	$ 506,587	$ 1,186,388
2022	12	$ 73.05	$ 49.18	45.13	47.17	336	408	$ 1,107,649	$ 946,487	$ 2,054,137
2023	1	$ 73.05	$ 49.18	45.13	47.17	336	408	$ 1,107,649	$ 946,487	$ 2,054,137
2023	2	$ 73.05	$ 49.18	45.13	47.17	320	352	$ 1,054,904	$ 816,577	$ 1,871,481
2023	3	$ 62.89	$ 40.70	40.50	42.26	368	375	$ 937,241	$ 645,013	$ 1,582,254
2023	4	$ 62.89	$ 40.70	40.50	42.26	320	400	$ 814,992	$ 688,014	$ 1,503,006

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Farm Size (MW)
100

Capacity Factors							
On - Peak				Off - Peak			
Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
0.4513	0.4050	0.2350	0.3327	0.4717	0.4226	0.2504	0.3376

Fentress - Off Shore Ocean

		Wholesale Energy Prices		Capacity Adjusted MW		Monthly Hours		Energy Value		
YEAR	MONTH	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	Total
2023	5	$ 62.89	$ 40.70	40.50	42.26	352	392	$ 896,491	$ 674,254	$ 1,570,745
2023	6	$ 82.27	$ 49.84	23.50	25.04	352	368	$ 680,543	$ 459,272	$ 1,139,815
2023	7	$ 82.27	$ 49.84	23.50	25.04	320	424	$ 618,675	$ 529,161	$ 1,147,836
2023	8	$ 82.27	$ 49.84	23.50	25.04	368	376	$ 711,477	$ 469,256	$ 1,180,733
2023	9	$ 62.28	$ 39.89	33.27	33.76	320	400	$ 663,021	$ 538,664	$ 1,201,686
2023	10	$ 62.28	$ 39.89	33.27	33.76	352	392	$ 729,324	$ 527,891	$ 1,257,215
2023	11	$ 62.28	$ 39.89	33.27	33.76	336	385	$ 696,173	$ 518,464	$ 1,214,637
2023	12	$ 74.84	$ 50.30	45.13	47.17	320	424	$ 1,080,844	$ 1,006,084	$ 2,086,928
2024	1	$ 74.84	$ 50.30	45.13	47.17	352	392	$ 1,188,928	$ 930,153	$ 2,119,081
2024	2	$ 74.84	$ 50.30	45.13	47.17	336	360	$ 1,134,886	$ 854,222	$ 1,989,108
2024	3	$ 64.47	$ 41.67	40.50	42.26	336	407	$ 877,295	$ 716,702	$ 1,593,997
2024	4	$ 64.47	$ 41.67	40.50	42.26	352	368	$ 919,071	$ 648,025	$ 1,567,096
2024	5	$ 64.47	$ 41.67	40.50	42.26	352	392	$ 919,071	$ 690,288	$ 1,609,358
2024	6	$ 84.16	$ 50.90	23.50	25.04	320	400	$ 632,849	$ 509,841	$ 1,142,690
2024	7	$ 84.16	$ 50.90	23.50	25.04	352	392	$ 696,134	$ 499,644	$ 1,195,778
2024	8	$ 84.16	$ 50.90	23.50	25.04	352	392	$ 696,134	$ 499,644	$ 1,195,778
2024	9	$ 63.78	$ 40.83	33.27	33.76	320	400	$ 679,003	$ 551,313	$ 1,230,316
2024	10	$ 63.78	$ 40.83	33.27	33.76	368	376	$ 780,854	$ 518,234	$ 1,299,088
2024	11	$ 63.78	$ 40.83	33.27	33.76	320	401	$ 679,003	$ 552,691	$ 1,231,694
2024	12	$ 76.68	$ 51.46	45.13	47.17	336	408	$ 1,162,804	$ 990,291	$ 2,153,094
2025	1	$ 76.68	$ 51.46	45.13	47.17	352	392	$ 1,218,175	$ 951,456	$ 2,169,631
2025	2	$ 76.68	$ 51.46	45.13	47.17	320	352	$ 1,107,432	$ 854,369	$ 1,961,801
2025	3	$ 66.09	$ 42.66	40.50	42.26	336	407	$ 899,387	$ 733,765	$ 1,633,152
2025	4	$ 66.09	$ 42.66	40.50	42.26	352	368	$ 942,215	$ 663,453	$ 1,605,668
2025	5	$ 66.09	$ 42.66	40.50	42.26	336	408	$ 899,387	$ 735,568	$ 1,634,955
2025	6	$ 86.09	$ 51.99	23.50	25.04	336	384	$ 679,747	$ 499,910	$ 1,179,656
2025	7	$ 86.09	$ 51.99	23.50	25.04	352	392	$ 712,115	$ 510,324	$ 1,222,440
2025	8	$ 86.09	$ 51.99	23.50	25.04	336	408	$ 679,747	$ 531,154	$ 1,210,900
2025	9	$ 65.32	$ 41.79	33.27	33.76	336	384	$ 730,154	$ 541,706	$ 1,271,860
2025	10	$ 65.32	$ 41.79	33.27	33.76	368	376	$ 799,692	$ 530,421	$ 1,330,113
2025	11	$ 65.32	$ 41.79	33.27	33.76	304	417	$ 660,615	$ 588,259	$ 1,248,874
2025	12	$ 78.57	$ 52.64	45.13	47.17	352	392	$ 1,248,153	$ 973,291	$ 2,221,444
2026	1	$ 78.57	$ 52.64	45.13	47.17	336	408	$ 1,191,419	$ 1,013,017	$ 2,204,436
2026	2	$ 78.57	$ 52.64	45.13	47.17	320	352	$ 1,134,685	$ 873,976	$ 2,008,661
2026	3	$ 67.76	$ 43.68	40.50	42.26	352	391	$ 965,938	$ 721,722	$ 1,687,659
2026	4	$ 67.76	$ 43.68	40.50	42.26	352	368	$ 965,938	$ 679,267	$ 1,645,205
2026	5	$ 67.76	$ 43.68	40.50	42.26	320	424	$ 878,125	$ 782,634	$ 1,660,759
2026	6	$ 88.07	$ 53.11	23.50	25.04	352	368	$ 728,496	$ 489,357	$ 1,217,853
2026	7	$ 88.07	$ 53.11	23.50	25.04	368	376	$ 761,610	$ 499,995	$ 1,261,605
2026	8	$ 88.07	$ 53.11	23.50	25.04	336	408	$ 695,383	$ 542,548	$ 1,237,931
2026	9	$ 66.89	$ 42.77	33.27	33.76	336	384	$ 747,784	$ 554,464	$ 1,302,247
2026	10	$ 66.89	$ 42.77	33.27	33.76	352	392	$ 783,393	$ 566,015	$ 1,349,408
2026	11	$ 66.89	$ 42.77	33.27	33.76	320	401	$ 712,175	$ 579,010	$ 1,291,185
2026	12	$ 80.50	$ 53.85	45.13	47.17	352	392	$ 1,278,881	$ 995,672	$ 2,274,553
2027	1	$ 80.50	$ 53.85	45.13	47.17	320	424	$ 1,162,619	$ 1,076,951	$ 2,239,571
2027	2	$ 80.50	$ 53.85	45.13	47.17	320	352	$ 1,162,619	$ 894,073	$ 2,056,692
2027	3	$ 69.46	$ 44.72	40.50	42.26	368	375	$ 1,035,265	$ 708,706	$ 1,743,971
2027	4	$ 69.46	$ 44.72	40.50	42.26	352	368	$ 990,254	$ 695,477	$ 1,685,730
2027	5	$ 69.46	$ 44.72	40.50	42.26	320	424	$ 900,231	$ 801,310	$ 1,701,541
2027	6	$ 90.10	$ 54.25	23.50	25.04	352	368	$ 745,287	$ 499,891	$ 1,245,177
2027	7	$ 90.10	$ 54.25	23.50	25.04	336	408	$ 711,410	$ 554,227	$ 1,265,637
2027	8	$ 90.10	$ 54.25	23.50	25.04	352	392	$ 745,287	$ 532,492	$ 1,277,779
2027	9	$ 68.51	$ 43.78	33.27	33.76	336	384	$ 765,855	$ 567,540	$ 1,333,395
2027	10	$ 68.51	$ 43.78	33.27	33.76	336	408	$ 765,855	$ 603,011	$ 1,368,866
2027	11	$ 68.51	$ 43.78	33.27	33.76	336	385	$ 765,855	$ 569,018	$ 1,334,873
2027	12	$ 82.49	$ 55.09	45.13	47.17	368	376	$ 1,369,939	$ 977,037	$ 2,346,976
2028	1	$ 82.49	$ 55.09	45.13	47.17	336	408	$ 1,250,814	$ 1,060,189	$ 2,311,003
2028	2	$ 82.49	$ 55.09	45.13	47.17	336	360	$ 1,250,814	$ 935,461	$ 2,186,275
2028	3	$ 71.21	$ 45.79	40.50	42.26	368	375	$ 1,061,322	$ 725,636	$ 1,786,958
2028	4	$ 71.21	$ 45.79	40.50	42.26	320	400	$ 922,888	$ 774,012	$ 1,696,901
2028	5	$ 71.21	$ 45.79	40.50	42.26	352	392	$ 1,015,177	$ 758,532	$ 1,773,709
2028	6	$ 92.18	$ 55.42	23.50	25.04	352	368	$ 762,497	$ 510,688	$ 1,273,185
2028	7	$ 92.18	$ 55.42	23.50	25.04	320	424	$ 693,179	$ 588,401	$ 1,281,580
2028	8	$ 92.18	$ 55.42	23.50	25.04	368	376	$ 797,155	$ 521,790	$ 1,318,945
2028	9	$ 70.17	$ 44.81	33.27	33.76	320	400	$ 747,026	$ 605,149	$ 1,352,175
2028	10	$ 70.17	$ 44.81	33.27	33.76	352	392	$ 821,729	$ 593,046	$ 1,414,775
2028	11	$ 70.17	$ 44.81	33.27	33.76	336	385	$ 784,378	$ 582,456	$ 1,366,833
2028	12	$ 84.52	$ 56.36	45.13	47.17	320	424	$ 1,220,600	$ 1,127,198	$ 2,347,798

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Farm Size (MW)
100

Capacity Factors							
On - Peak				Off - Peak			
Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
0.4513	0.4050	0.2350	0.3327	0.4717	0.4226	0.2504	0.3376

Fentress - Off Shore Ocean

		Wholesale Energy Prices		Capacity Adjusted MW		Monthly Hours		Energy Value		
YEAR	MONTH	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	Total
2029	1	$ 84.52	$ 56.36	45.13	47.17	352	392	$ 1,342,660	$ 1,042,127	$ 2,384,787
2029	2	$ 84.52	$ 56.36	45.13	47.17	320	352	$ 1,220,600	$ 935,787	$ 2,156,387
2029	3	$ 73.00	$ 46.88	40.50	42.26	352	391	$ 1,040,724	$ 774,691	$ 1,815,415
2029	4	$ 73.00	$ 46.88	40.50	42.26	336	384	$ 993,418	$ 760,822	$ 1,754,241
2029	5	$ 73.00	$ 46.88	40.50	42.26	352	392	$ 1,040,724	$ 776,673	$ 1,817,397
2029	6	$ 94.31	$ 56.62	23.50	25.04	336	384	$ 744,676	$ 544,440	$ 1,289,116
2029	7	$ 94.31	$ 56.62	23.50	25.04	336	408	$ 744,676	$ 578,468	$ 1,323,144
2029	8	$ 94.31	$ 56.62	23.50	25.04	368	376	$ 815,598	$ 533,098	$ 1,348,695
2029	9	$ 71.87	$ 45.87	33.27	33.76	304	416	$ 726,853	$ 644,238	$ 1,371,091
2029	10	$ 71.87	$ 45.87	33.27	33.76	368	376	$ 879,874	$ 582,292	$ 1,462,166
2029	11	$ 71.87	$ 45.87	33.27	33.76	336	385	$ 803,364	$ 596,230	$ 1,399,593
2029	12	$ 86.60	$ 57.66	45.13	47.17	320	424	$ 1,250,682	$ 1,153,268	$ 2,403,950
2030	1	$ 86.60	$ 57.66	45.13	47.17	352	392	$ 1,375,750	$ 1,066,229	$ 2,441,979
2030	2	$ 86.60	$ 57.66	45.13	47.17	320	352	$ 1,250,682	$ 957,430	$ 2,208,112
2030	3	$ 74.84	$ 48.01	40.50	42.26	336	407	$ 1,018,414	$ 825,698	$ 1,844,112
2030	4	$ 74.84	$ 48.01	40.50	42.26	352	368	$ 1,066,910	$ 746,577	$ 1,813,487
2030	5	$ 74.84	$ 48.01	40.50	42.26	352	392	$ 1,066,910	$ 795,267	$ 1,862,176
2030	6	$ 96.50	$ 57.85	23.50	25.04	320	400	$ 725,653	$ 579,455	$ 1,305,108
2030	7	$ 96.50	$ 57.85	23.50	25.04	352	392	$ 798,218	$ 567,866	$ 1,366,084
2030	8	$ 96.50	$ 57.85	23.50	25.04	352	392	$ 798,218	$ 567,866	$ 1,366,084
2030	9	$ 73.61	$ 46.96	33.27	33.76	320	400	$ 783,642	$ 634,128	$ 1,417,770
2030	10	$ 73.61	$ 46.96	33.27	33.76	368	376	$ 901,188	$ 596,080	$ 1,497,268
2030	11	$ 73.61	$ 46.96	33.27	33.76	320	401	$ 783,642	$ 635,713	$ 1,419,355
2030	12	$ 88.74	$ 59.00	45.13	47.17	336	408	$ 1,345,592	$ 1,135,461	$ 2,481,053
2031	1	$ 88.74	$ 59.00	45.13	47.17	352	392	$ 1,409,668	$ 1,090,933	$ 2,500,601
2031	2	$ 88.74	$ 59.00	45.13	47.17	320	352	$ 1,281,516	$ 979,614	$ 2,261,130
2031	3	$ 76.72	$ 49.16	40.50	42.26	336	407	$ 1,044,034	$ 845,486	$ 1,889,520
2031	4	$ 76.72	$ 49.16	40.50	42.26	352	368	$ 1,093,750	$ 764,469	$ 1,858,219
2031	5	$ 76.72	$ 49.16	40.50	42.26	336	408	$ 1,044,034	$ 847,563	$ 1,891,597
2031	6	$ 98.74	$ 59.11	23.50	25.04	336	384	$ 779,626	$ 568,410	$ 1,348,037
2031	7	$ 98.74	$ 59.11	23.50	25.04	352	392	$ 816,751	$ 580,252	$ 1,397,003
2031	8	$ 98.74	$ 59.11	23.50	25.04	336	408	$ 779,626	$ 603,936	$ 1,383,562
2031	9	$ 75.39	$ 48.07	33.27	33.76	336	384	$ 842,771	$ 623,196	$ 1,465,968
2031	10	$ 75.39	$ 48.07	33.27	33.76	368	376	$ 923,035	$ 610,213	$ 1,533,248
2031	11	$ 75.39	$ 48.07	33.27	33.76	304	417	$ 762,507	$ 676,752	$ 1,439,260
2031	12	$ 90.93	$ 60.37	45.13	47.17	352	392	$ 1,444,433	$ 1,116,255	$ 2,560,689
2032	1	$ 90.93	$ 60.37	45.13	47.17	336	408	$ 1,378,777	$ 1,161,817	$ 2,540,594
2032	2	$ 90.93	$ 60.37	45.13	47.17	320	376	$ 1,313,121	$ 1,070,694	$ 2,383,815
2032	3	$ 78.65	$ 50.34	40.50	42.26	368	375	$ 1,172,227	$ 797,699	$ 1,969,926
2032	4	$ 78.65	$ 50.34	40.50	42.26	352	368	$ 1,121,261	$ 782,808	$ 1,904,069
2032	5	$ 78.65	$ 50.34	40.50	42.26	320	424	$ 1,019,328	$ 901,931	$ 1,921,259
2032	6	$ 101.03	$ 60.41	23.50	25.04	352	368	$ 835,748	$ 556,644	$ 1,392,393
2032	7	$ 101.03	$ 60.41	23.50	25.04	336	408	$ 797,760	$ 617,149	$ 1,414,909
2032	8	$ 101.03	$ 60.41	23.50	25.04	352	392	$ 835,748	$ 592,947	$ 1,428,695
2032	9	$ 77.22	$ 49.21	33.27	33.76	336	384	$ 863,217	$ 637,991	$ 1,501,208
2032	10	$ 77.22	$ 49.21	33.27	33.76	336	408	$ 863,217	$ 677,865	$ 1,541,082
2032	11	$ 77.22	$ 49.21	33.27	33.76	336	385	$ 863,217	$ 639,652	$ 1,502,869
2032	12	$ 93.17	$ 61.77	45.13	47.17	368	376	$ 1,547,344	$ 1,095,590	$ 2,642,933
2033	1	$ 93.17	$ 61.77	45.13	47.17	336	408	$ 1,412,792	$ 1,188,831	$ 2,601,624
2033	2	$ 93.17	$ 61.77	45.13	47.17	320	352	$ 1,345,516	$ 1,025,659	$ 2,371,175
2033	3	$ 80.63	$ 51.54	40.50	42.26	368	375	$ 1,201,708	$ 816,854	$ 2,018,562
2033	4	$ 80.63	$ 51.54	40.50	42.26	336	384	$ 1,097,212	$ 836,459	$ 1,933,670
2033	5	$ 80.63	$ 51.54	40.50	42.26	336	408	$ 1,097,212	$ 888,737	$ 1,985,949
2033	6	$ 103.39	$ 61.73	23.50	25.04	352	368	$ 855,220	$ 568,860	$ 1,424,080
2033	7	$ 103.39	$ 61.73	23.50	25.04	320	424	$ 777,472	$ 655,426	$ 1,432,899
2033	8	$ 103.39	$ 61.73	23.50	25.04	368	376	$ 894,093	$ 581,227	$ 1,475,320
2033	9	$ 79.09	$ 50.38	33.27	33.76	336	384	$ 884,174	$ 653,155	$ 1,537,329
2033	10	$ 79.09	$ 50.38	33.27	33.76	336	408	$ 884,174	$ 693,977	$ 1,578,151
2033	11	$ 79.09	$ 50.38	33.27	33.76	336	385	$ 884,174	$ 654,856	$ 1,539,030
2033	12	$ 95.47	$ 63.21	45.13	47.17	352	392	$ 1,516,593	$ 1,168,815	$ 2,685,408
2034	1	$ 95.47	$ 63.21	45.13	47.17	336	408	$ 1,447,657	$ 1,216,521	$ 2,664,179
2034	2	$ 95.47	$ 63.21	45.13	47.17	320	352	$ 1,378,721	$ 1,049,548	$ 2,428,269
2034	3	$ 82.66	$ 52.78	40.50	42.26	368	375	$ 1,231,926	$ 836,488	$ 2,068,414
2034	4	$ 82.66	$ 52.78	40.50	42.26	320	400	$ 1,071,240	$ 892,254	$ 1,963,494
2034	5	$ 82.66	$ 52.78	40.50	42.26	352	392	$ 1,178,364	$ 874,409	$ 2,052,773
2034	6	$ 105.80	$ 63.09	23.50	25.04	352	368	$ 875,178	$ 581,382	$ 1,456,560
2034	7	$ 105.80	$ 63.09	23.50	25.04	320	424	$ 795,616	$ 669,853	$ 1,465,470
2034	8	$ 105.80	$ 63.09	23.50	25.04	368	376	$ 914,959	$ 594,021	$ 1,508,980

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Farm Size (MW)
100

Capacity Factors							
On - Peak				Off - Peak			
Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
0.4513	0.4050	0.2350	0.3327	0.4717	0.4226	0.2504	0.3376

Fentress - Off Shore Ocean

		Wholesale Energy Prices		Capacity Adjusted MW		Monthly Hours		Energy Value		
YEAR	MONTH	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	on-peak	off-peak	Total
2034	9	$ 81.02	$ 51.58	33.27	33.76	320	400	$ 862,528	$ 696,561	$ 1,559,089
2034	10	$ 81.02	$ 51.58	33.27	33.76	352	392	$ 948,781	$ 682,630	$ 1,631,411
2034	11	$ 81.02	$ 51.58	33.27	33.76	336	385	$ 905,654	$ 670,440	$ 1,576,095
2034	12	$ 97.83	$ 64.69	45.13	47.17	320	424	$ 1,412,756	$ 1,293,723	$ 2,706,480
2035	1	$ 97.83	$ 64.69	45.13	47.17	352	392	$ 1,554,032	$ 1,196,084	$ 2,750,116
2035	2	$ 97.83	$ 64.69	45.13	47.17	320	352	$ 1,412,756	$ 1,074,034	$ 2,486,791
2035	3	$ 84.74	$ 54.05	40.50	42.26	352	391	$ 1,207,990	$ 893,163	$ 2,101,153
2035	4	$ 84.74	$ 54.05	40.50	42.26	336	384	$ 1,153,081	$ 877,172	$ 2,030,254
2035	5	$ 84.74	$ 54.05	40.50	42.26	352	392	$ 1,207,990	$ 895,447	$ 2,103,437
2035	6	$ 108.27	$ 64.49	23.50	25.04	336	384	$ 854,925	$ 620,052	$ 1,474,977
2035	7	$ 108.27	$ 64.49	23.50	25.04	336	408	$ 854,925	$ 658,805	$ 1,513,730
2035	8	$ 108.27	$ 64.49	23.50	25.04	368	376	$ 936,346	$ 607,134	$ 1,543,480
2035	9	$ 82.99	$ 52.81	33.27	33.76	304	416	$ 839,323	$ 741,683	$ 1,581,006
2035	10	$ 82.99	$ 52.81	33.27	33.76	368	376	$ 1,016,022	$ 670,368	$ 1,686,390
2035	11	$ 82.99	$ 52.81	33.27	33.76	336	385	$ 927,672	$ 686,414	$ 1,614,086
2035	12	$ 82.99	$ 52.81	45.13	47.17	320	424	$ 1,198,444	$ 1,056,220	$ 2,254,664

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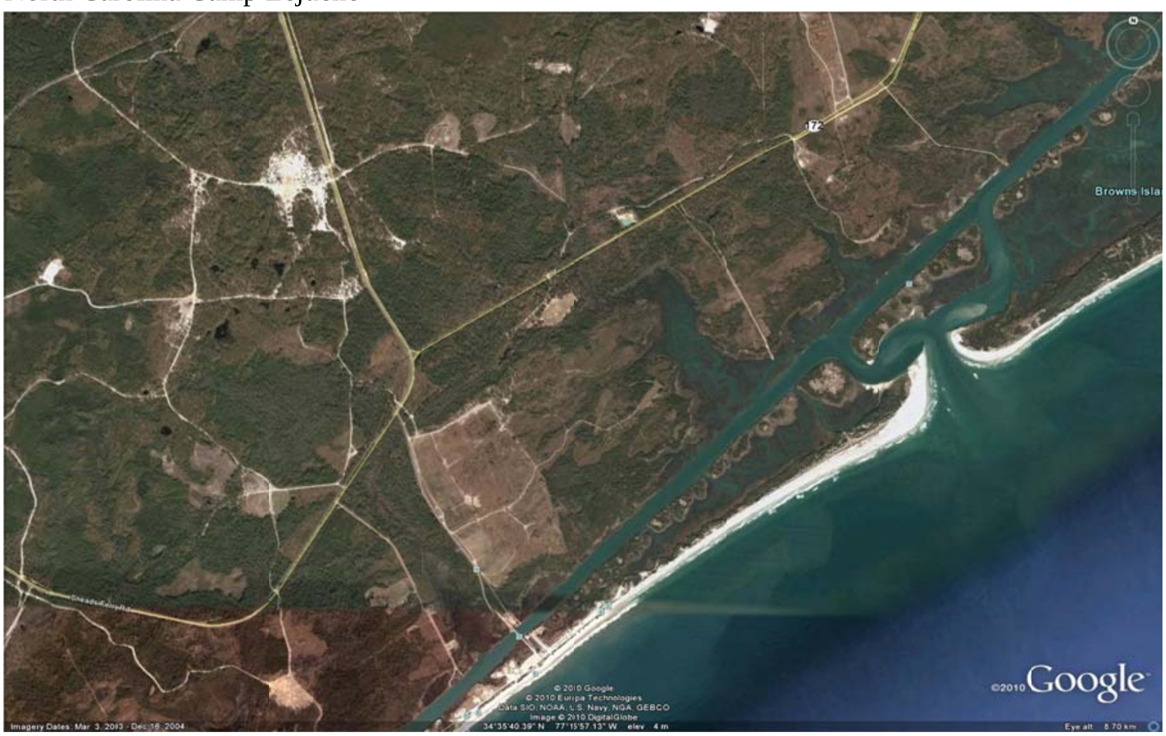
Appendix D: Examples of Coastal Sites that could be evaluated for Wind Power Generation

North Carolina phosphate mining facility on Pamlico River

North Carolina Camp Lejuene

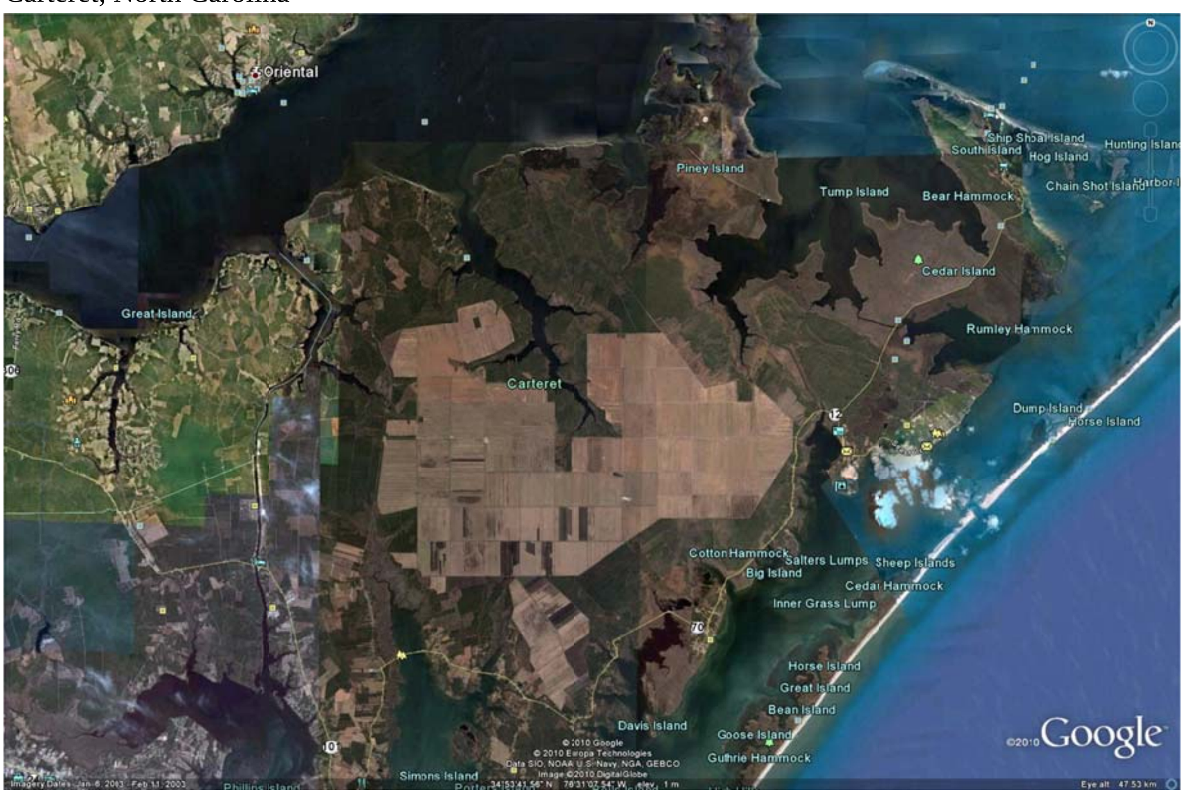


Pamlico Sound & Hyde County NC (10 mile reference line added

Marine Air Station –Cherry Hill NC

Farmland, near Currituck Sound, NC

Carteret, North Carolina

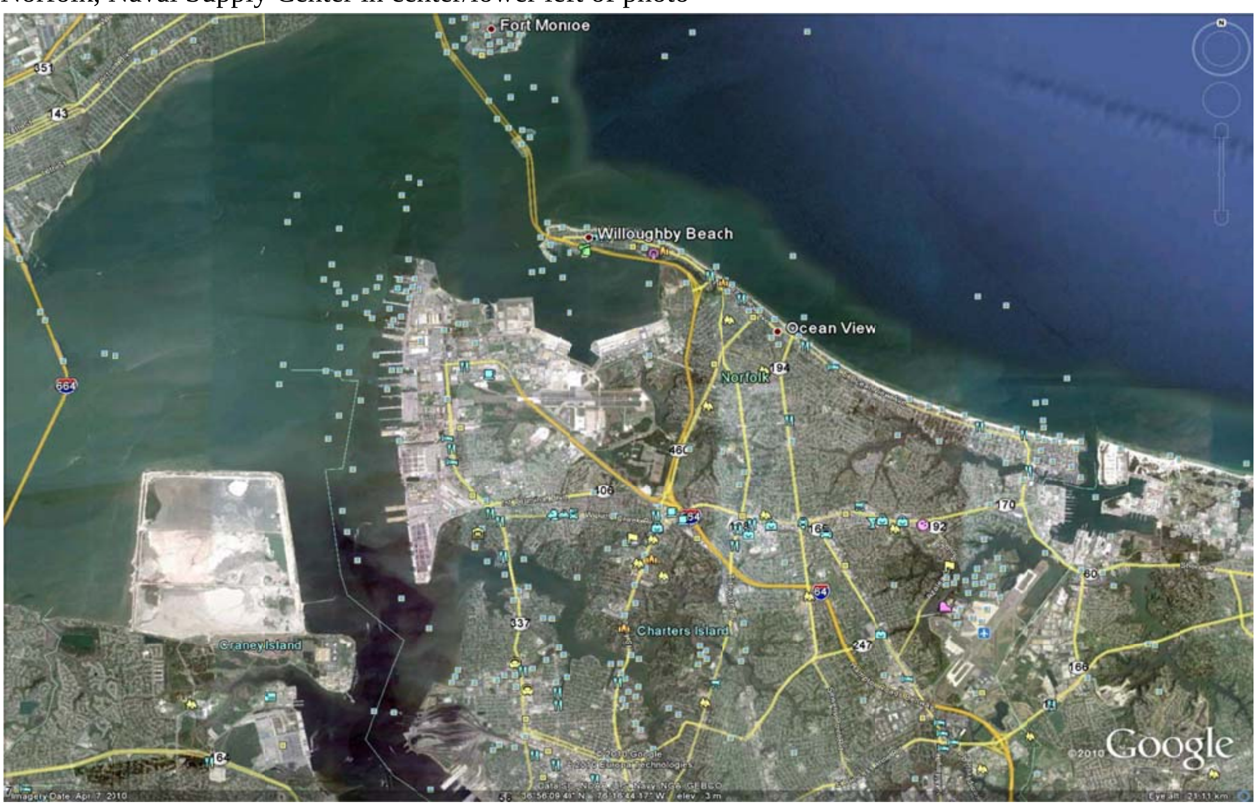


Virginia Beach farmland encroaching on wetland

Virginia Beach farmland encroaching on wetland (n. end Currituck Sound)

Mixed use area – Virginia Beach

Norfolk, Naval Supply Center in center/lower left of photo



Virginia: Chesapeake Bay Bridge Tunnel

Virginia: Chesapeake Bay Bridge Tunnel Toll Plaza

North end, Chesapeake Bay Bridge tunnel

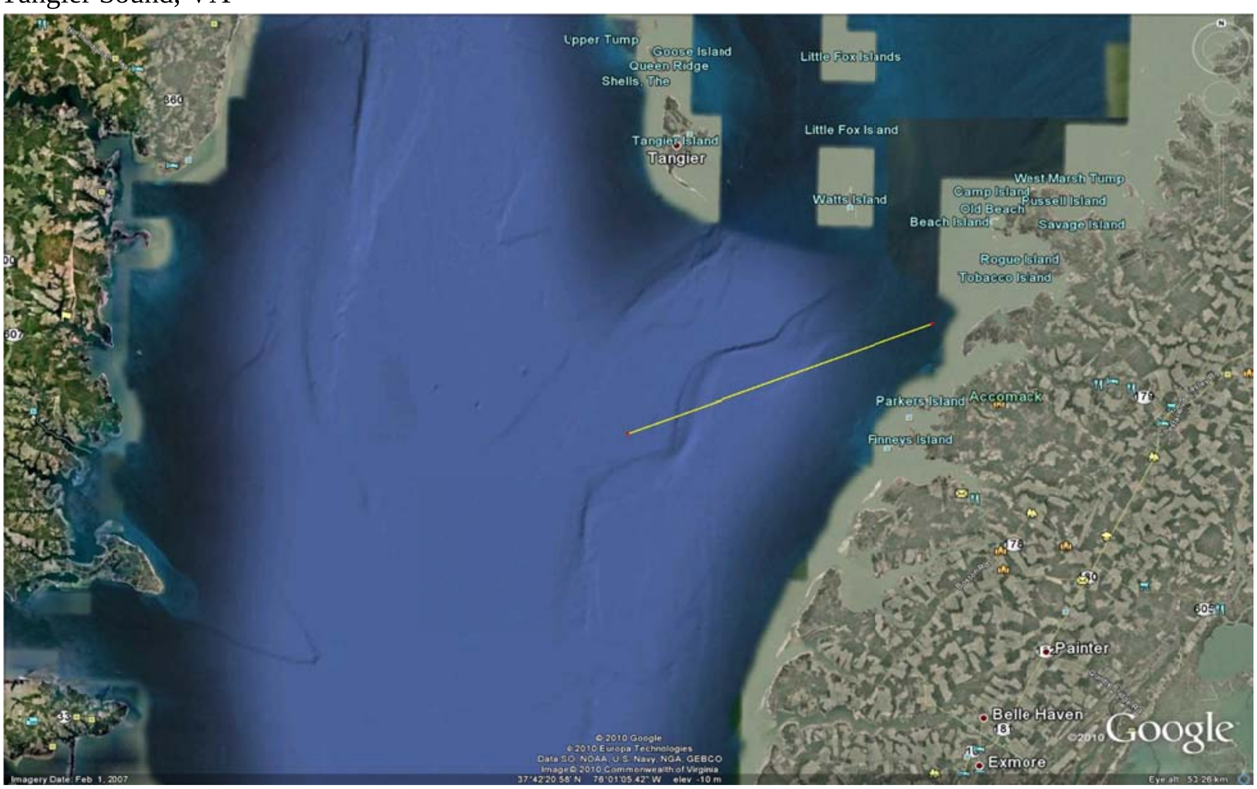
Virginia – Sunken Liberty Ships at Kiptopeke

Delmarva peninsula ocean side farmland

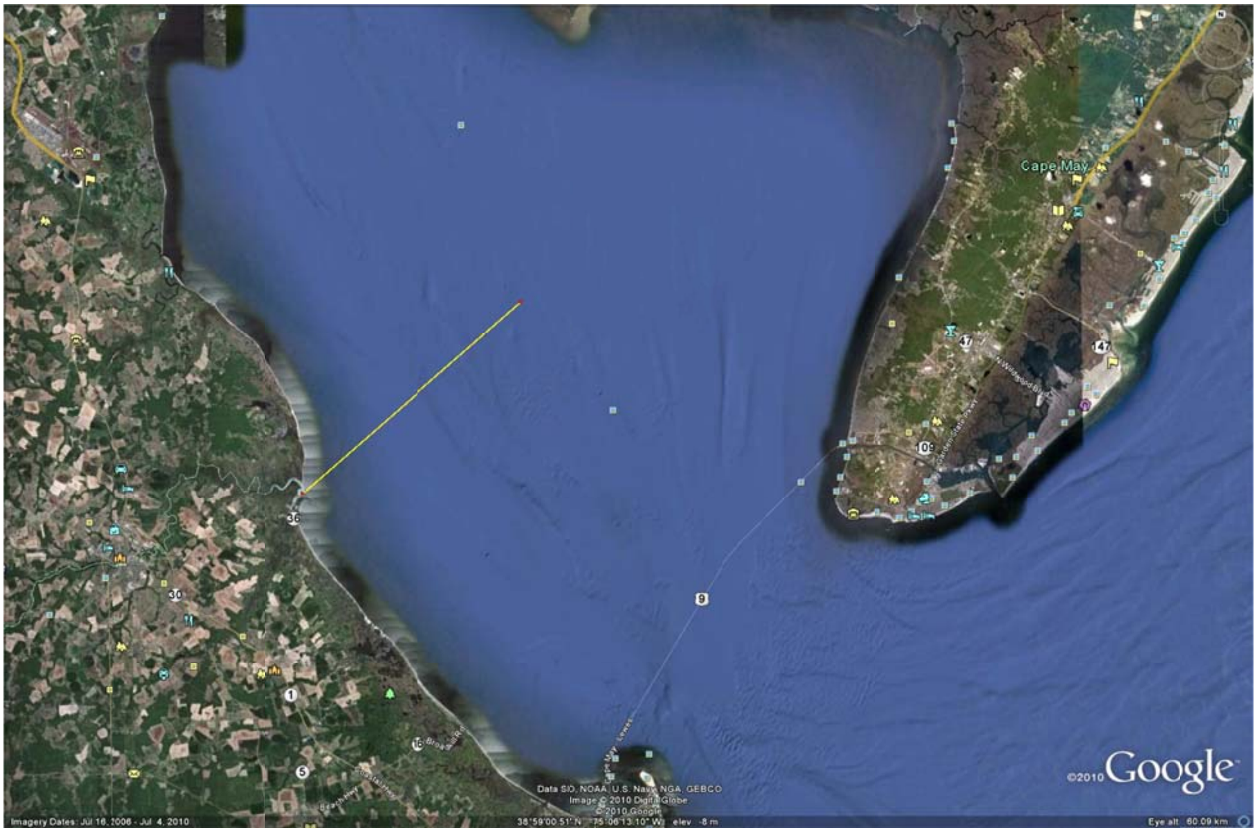
Matthews, VA

Wallops Island, VA

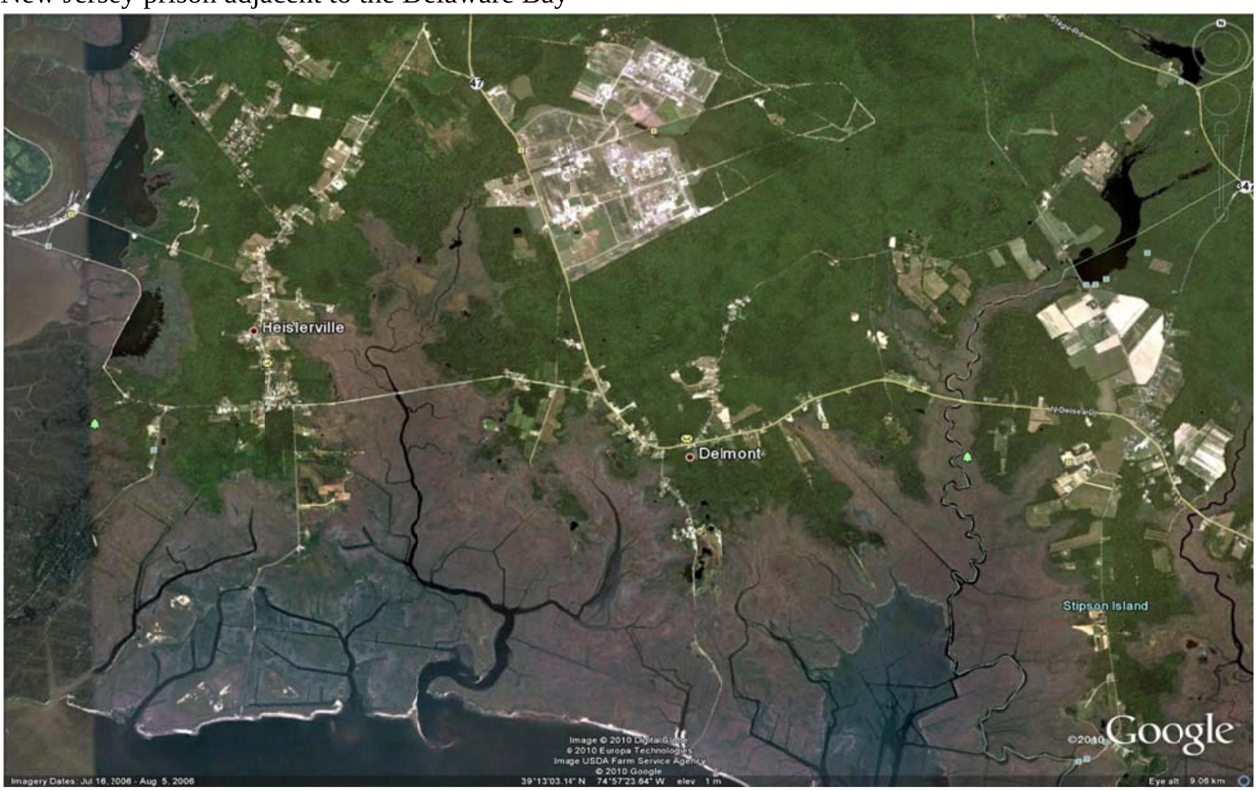
Tangier Sound, VA



Lower Delaware Bay (10 mile line added for reference

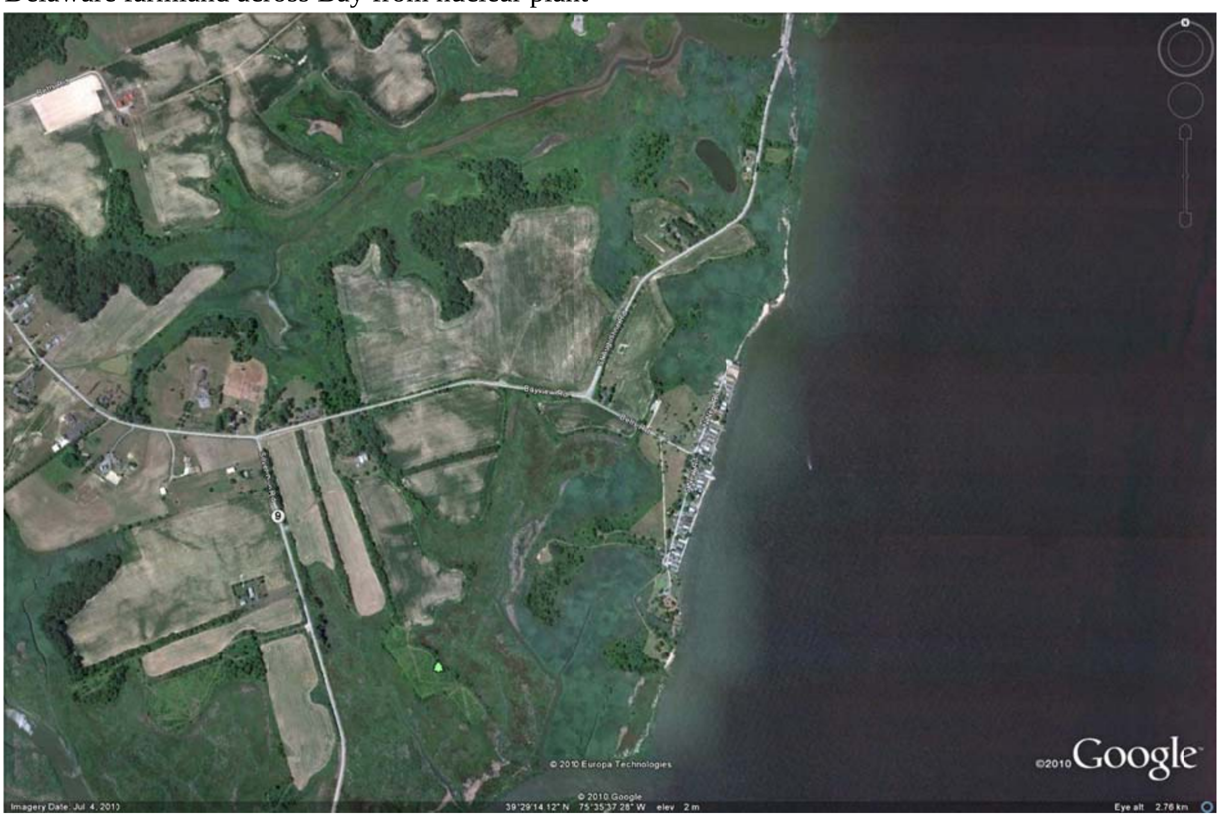


New Jersey prison adjacent to the Delaware Bay



Nuclear power plant on Delaware Bay

Delaware farmland across Bay from nuclear plant



Air Liquide Chemical Plant, DE

New Jersey property across Del. Bay from Air Liquide plant

Delaware City, entrance to C&D canal

Agricultural property on Delaware Bay, Bowers, DE