CAN WIND BE A "FIRM" RESOURCE? A NORTH CAROLINA CASE STUDY

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INTRODUCTION

Electricity generated from wind is becoming increasingly prevalent across the United States. Since 1981, installed wind capacity in the U.S. has grown from 10 megawatts ("MW") to over 6,000 MW in 2003[1], representing 0.6% of total U.S. installed capacity.[2] This rapid growth is attributed to a number of factors, including both increasing environmental awareness and decreasing economic costs.[3] Increasing awareness and concern regarding the environmental consequences of power production, most notably global climate change, have increased interest in renewable forms of power generation, primarily in wind.[4] Advances in turbine technology, coupled with a growing knowledge base surrounding wind patterns and optimal siting, have led to production costs on par with traditional forms of generation such as coal and natural gas fired power plants.[5] The Energy Information Administration ("EIA") forecasts that, due to these reasons as well as increased awareness of the environmental benefits of renewable energy, wind capacity will increase from the current 6,000 MW in 2003 to 16,000 MW in 2025.[6]

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1. American Wind Energy Association, *Wind Energy Frequently Asked Questions* (2004), at http://www.awea.org/faq/instcap.html.

2. Energy Information Administration, *Annual Energy Outlook 2004* (2004), at http://www.eia.doe.gov/oiaf/aeo/electricity.html.

3. *See, e.g.,* RONALD BINZ, IMPACT OF A RENEWABLE ENERGY PORTFOLIO STANDARD ON RETAIL ELECTRIC RATES IN COLORADO 5 (2004).

4. Business Week Online, *Global Warming* (Aug. 16, 2004), at http://www.businessweek.com/magazine/content/04_33/b3896001_mz001.htm.

5. *See, e.g.,* PROGRESS ENERGY, PROGRESS ENERGY CAROLINAS RESOURCE PLAN (2003) (North Carolina Utilities Commission, Docket No. E-100, Sub98).

6. Energy Information Administration, *supra* note 2.

Wind power presents a new type of generation, with issues quite different from traditional electricity generation sources.[7] These traditional electricity generation sources, such as coal and natural gas fired power plants, are well understood and their behavior is predictable.[8] These sources use a combustion process to burn a purchased fuel. They have a known capacity and can be turned up or down at the command of an operator (making them dispatchable).[9] Their use is generally scheduled by the electric utility up to a day ahead of time.[10] Wind power, however, does not exhibit these same characteristics. The fuel, wind, is free, but its use cannot be commanded by an operator, and the amount of power that will be produced at any one time is unknown.[11] The wind blows as it will.

Electric utilities must constantly balance electric generation with demand precisely.[12] To do this, utilities rely on the ability to control the output of their generation sources and their knowledge of how much power each source could produce.[13] The necessity for precise control means that the intermittency of wind power is a source of great concern to electric utilities.[14] Indeed, integration of wind power into a utility system creates additional costs.[15] In North Carolina, utilities have expressed this concern about integrating wind power into their systems.[16] In 2003, both Duke Power and Progress Energy disqualified wind energy from consideration in their annual plans because, according to Duke Power:

> Wind Power appears to be economical at higher capacity factors but the level of wind currents is not sufficiently high in the Carolinas to achieve those capacity factors. Also, Wind is not a dispatch-

7. J. SMITH, ET AL. WIND POWER IMPACTS ON ELECTRIC POWER SYSTEM OPERATING COSTS: SUMMARY AND PERSPECTIVE ON WORK TO DATE 2 (2004); ENERNEX CORPORATION, XCEL ENERGY, AND THE MINNESOTA DEPARTMENT OF COMMERCE, WIND INTEGRATION STUDY-FINAL REPORT 17 (2004).

8. ENERNEX CORPORATION, ET AL., *supra* note 7, at 17.

9. BRIAN PARSONS, ET AL., GRID IMPACTS OF WIND POWER: A SUMMARY OF RECENT STUDIES IN THE UNITED STATES 2 (2003).

10. *Id.*

11. *See, e.g.,* ENERNEX CORPORATION, ET AL., *supra* note 7, at 17.

12. *See, e.g., Id.* at 15; SMITH, ET AL., *supra* note 7, at 1.

13. *See, e.g.,* SMITH, ET AL. *supra* note 7 at 1.

14. DUKE POWER, THE DUKE POWER ANNUAL PLAN (2003) (North Carolina Utilities Commission, Docket No. E-100, Sub98); PROGRESS ENERGY, *supra* note 5.

15. SMITH, ET AL., *supra* note 7, at 8.

16. DUKE POWER, *supra* note 14, at 33.

> able resource. Therefore, it is not suitable in comparison to peaking duty cycle technologies.[17]

And according to Progress Energy,

> These cost comparisons illustrate that wind projects have high fixed costs but essentially no operating costs. Therefore, at high enough capacity factors they could become economically competitive with the lower-cost technologies identified. However, the geographic and atmospheric characteristics impact the ability of wind projects to achieve those capacity factors. Wind projects must be constructed in areas with high average wind speed. In general, wind resources in the southeast, are limited. The average wind speed in the southeast is below 14 miles per hour and is not sufficient for wind projects to be an economic alternative. Because a wind project would not be expected to operate above 20-25% capacity factor in the Carolinas geographic area, it is not a viable alternative for intermediate duty. Further, because wind is not dispatchable, it is not a suitable alternative for peaking duty. As a result, wind was eliminated from consideration as a potential resource to meet future generation needs.[18]

In these statements, the utilities address wind in terms of two critical aspects of any electricity generation source: capacity and energy. Capacity (kilowatts) is the reliable ability to generate a certain amount of electricity, and energy (kilowatt-hours) is the electricity that is actually generated. Both are valuable, and are generally valued separately. For example, say a natural gas combined cycle turbine is roughly 95% reliable. Therefore, a turbine with a 100 MW rated capacity would receive a capacity credit of 95 MW. If this turbine is run roughly half the time, it produces 100 MW per hour for half the hours of the year, thus roughly 438,000 megawatt-hours (MWh) in a year. The turbine would receive payments for both the 95 MW (the ability to produce 95 MW on demand) and the 438,000 MWh of energy produced.

Due to both the fast pace of research and technology development in the wind industry[19] and the forecast growth in wind capacity over the next twenty years,[20] it is critical to continually reconsider the objections to wind. Conventional wisdom holds that capacity credit is given to an individual site based on the individual site characteris-

17. *Id.*

18. PROGRESS ENERGY, *supra* note 5.

19. MICHAEL MILLIGAN, MODELING UTILITY-SCALE WIND POWER PLANTS PART 2: CAPACITY CREDIT (2002).

20. *Id*.

tics.[21] This philosophy generally leads to the assumption that wind farms have no capacity value because the degree of variability of the resource is so high at each individual site.[22]

Modern financial portfolio theory, though, presents a different way of looking at the world. A financial portfolio consists of a combination of individual stocks.[23] Developed by Harry Markowitz in 1959, mean-variance portfolio theory enables the creation of minimum-variance portfolios for a given level of expected return.[24] This theory is based on diversification—the portfolio variance (risk) will be lower, the lower the correlation between the individual assets that make up the portfolio.[25]

This idea of portfolio diversification is applied here to wind power. Due to topography and meteorology, winds in different geographic locations are often not correlated and sometimes negatively correlated.[26] By blending individual sites together into a portfolio, the overall risk, or variability, of portfolio power production should be reduced.[27] This Note uses wind data from three sites in North Carolina and Tennessee to analyze whether dispersing wind turbines geographically can provide some capacity value for wind farms.

I. WIND RESOURCES

The best sites for wind development have strong, frequent winds.[28] For the past three decades, the National Renewable Energy Laboratory ("NREL") has compiled data on wind resources around the country.[29] Wind resource maps, such as the North Carolina map,[30]

21. *Id.* at 12.

22. BRENDAN KIRBY, ET AL., CALIFORNIA RENEWABLES PORTFOLIO STANDARD RENEWABLE GENERATION INTEGRATION COST ANALYSIS, PHASE III: RECOMMENDATIONS FOR IMPLEMENTATION 17 (2004).

23. CAROL ALEXANDER, HANDBOOK OF RISK MANAGEMENT AND ANALYSIS (1996).

24. *Id.* at 172.

25. *Id*.

26. MILLIGAN, *supra* note 19, at 40.

27. *See* Kai N. Lee, *The Path Along the Ridge: Regional Planning in the Face of Uncertainty*, 58 WASH. L. REV. 317, 330 (1983) (arguing that portfolio diversification applied to Northwest power would reduce risk).

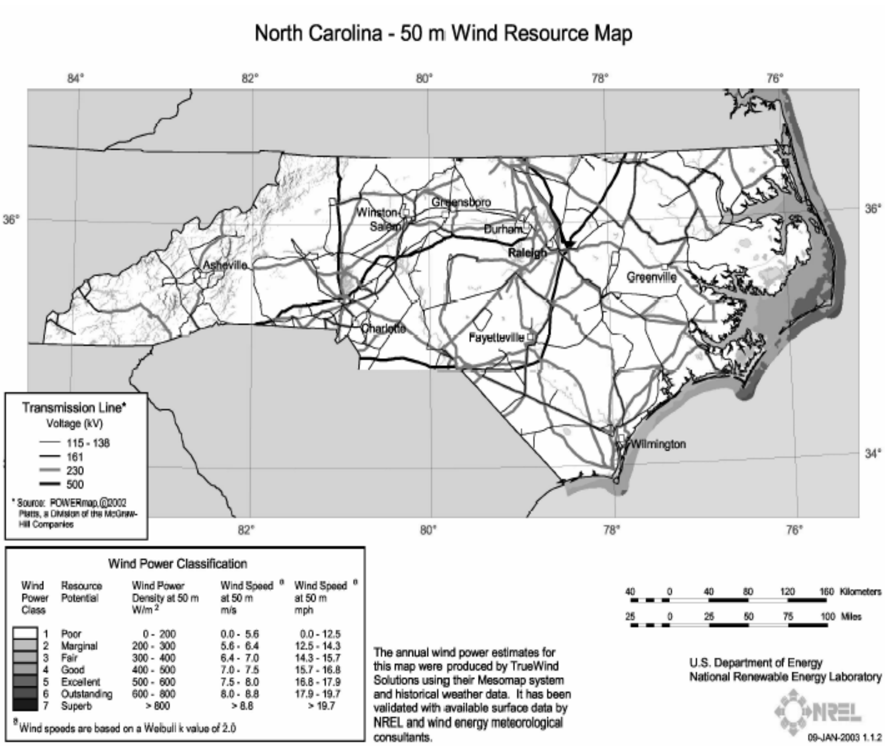
28. National Renewable Energy Laboratory, *Wind Resource: U.S. Wind Maps*, at http://www.nrel.gov/wind/wind_map.html.

29. *Id*.

30. National Renewable Energy Laboratory, *North Carolina Wind Resource Map* (2003), at http://www.eere.energy.gov/windandhydro/windpoweringamerica/maps_template.asp?stateab=nc (last visited Oct. 25, 2004).

are created based on measurements taken throughout the year at monitoring stations and on sophisticated meteorological models, and display interpolated annual average wind speeds.[31] Wind resources are classified on a scale of 1 (Poor) to 7 (Superb), with industrial scale wind generation primarily built in areas with class 3 or higher wind resources. As seen in the map below (Figure 1), North Carolina's wind resources are located primarily on the coast and along the western mountain ridges, and range from class 2 to class 6.[32]

Figure 1



While maps such as the NREL map are helpful in determining the general geographical spread of wind resources in a particular region, they do not provide sufficient data on where to plan a wind project. The wind speeds indicated on the NREL map are annual aver-

31. *Id.*
32. *Id.*

ages[33] that provide no indication of the variability of the wind resource over time, or of the average speeds during electric load peak demand. These measures are often more indicative of the potential for wind development on a particular site than merely the annual average speed. Therefore, these maps should be used to locate potential sites. Once potential sites are identified, more detailed data collection over a period of one to several years should follow to evaluate each site thoroughly.

II. North Carolina Wind Data

To explore ideas surrounding the capacity value of wind power, North Carolina was chosen as a case study. North Carolina has relatively good class 3 and 4 winds along both the eastern coast and the western mountain ridges.[34] There are currently no utility scale wind developments in the State, although at least one is being considered by a private developer. In order to analyze the impacts on wind power output of geographic distribution of wind generation, three sites in different locations were chosen for analysis: one on the coast and two in the mountains of eastern Tennessee. According to the NREL wind map, these regions should have high annual average wind speeds. Anemometer studies in the southeast are uncommon because there has thus far been little interest in developing wind projects, and because these studies are costly and time consuming (data is generally taken every few seconds for a year or more).[35] That said, these sites were originally chosen by developers for anemometer studies based on NREL wind maps and other relevant geographical information,[36] and are therefore likely reasonable sites. Sites in Tennessee were chosen because no appropriately detailed wind speed data at utility-scale height currently exists for the western North Carolina mountains.[37] Eastern Tennessee, also part of the Appalachian mountain chain, shares some topographical and meteorological characteristics with western North Carolina, and it was therefore considered a good proxy.

33. *Id.*

34. *Id*.

35. Interview with Jeff Tiller, Director, Appalachian State University Energy Center (Aug. 28, 2004).

36. *Id.*

37. *Id.*

At the request of the developers, the specific locations of these sites have been omitted.[38] Each dataset contains one year of wind speed data, taken every few seconds and then averaged by an anemometer at the height indicated to provide ten minute average and standard deviation output data. Utility scale wind turbines generally have hub heights of at least 50 meters.[39] As seen in the table below, the data collection period for each site varied.

North Carolina site information (Figure 2)

Acronym	Location	Height (m)	Start date	Start time	End date	End time
CST[40]	NC Coast	89	7/22/2003	0:00:00	7/21/2004	23:50:00
MTN1[41]	TN Mtns	50	3/24/2001	16:00:00	3/21/2002	8:20:00
MTN2[42]	TN Mtns	50	1/1/2002	0:00:00	12/31/2002	23:50:00

To allow for ease of comparison, the data was re-indexed to begin at midnight on January 1st and end at 11:50 pm on December 31st, regardless of year. While this allows for observations of seasonal variation in wind speeds, it does, admittedly, overlook unique meteorological events that could have affected wind speeds at particular times of a particular year. Ideally for this type of analysis, data would be collected at multiple sites for multiple years, with the same start and end times.

Further, the three sites contained some missing data (0.3% at the CST site, 3.1% at the MTN1 site, and 3.7% at the MTN2 site). Missing data was filled in via linear extrapolation so as to not unfairly penalize these sites by interpreting missing data as zeros. This linear ex-

38. Telephone Interview with Simon Rich, Chairman, Carolina Green Energy (Sept. 3, 2004); Telephone Interview with Rick Carson, Tennessee Valley Authority (Aug. 28, 2004).

39. GE ENERGY, GE WIND ENERGY ANNOUNCES NEW SERIES OF 2-MEGAWATT CLASS WIND TURBINES (2003) *available at* http://www.gepower.com/about/press/en/2003_press/040803a.htm (noting that GE Wind Energy, one of the largest domestic producers of wind turbines, produces turbines capable of a range of hub heights from roughly 50 to 100 meters).

40. Rich, *supra* note 38.

41. Carson, *supra* note 38.

42. *Id*.

trapolation is not seen as seriously influencing the results, since the total amount of missing data is small. Had missing data been represented as zeros instead of linear extrapolation, the average wind speeds shown in the table below would have been reduced by 0.04 m/s, 0.22 m/s, and 0.10 m/s, respectively.

The following graphs, depicting wind speeds during the month of January at each site, provide an indication of the variability of wind resources.

Figure 3

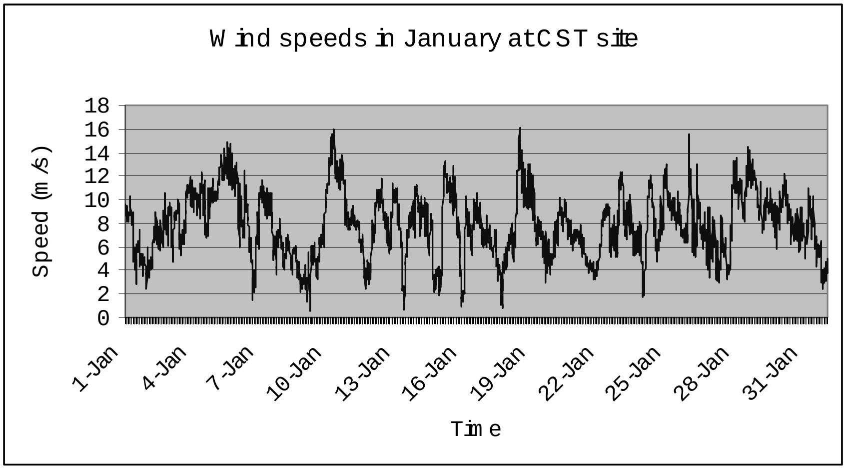


Figure 4

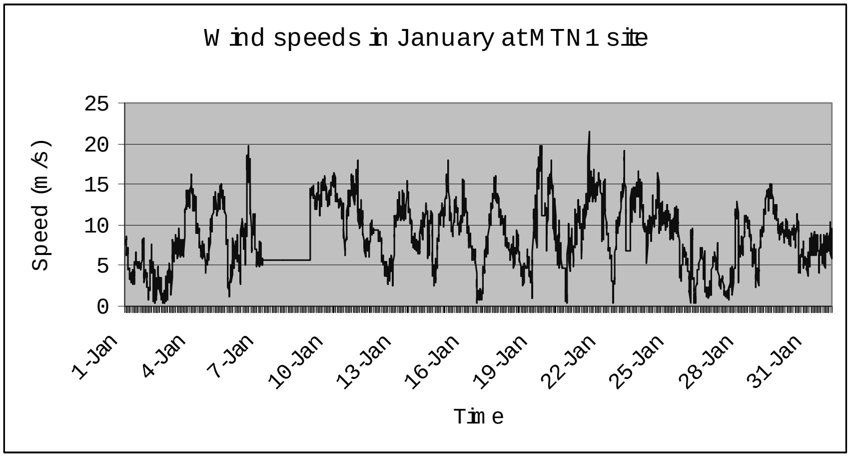
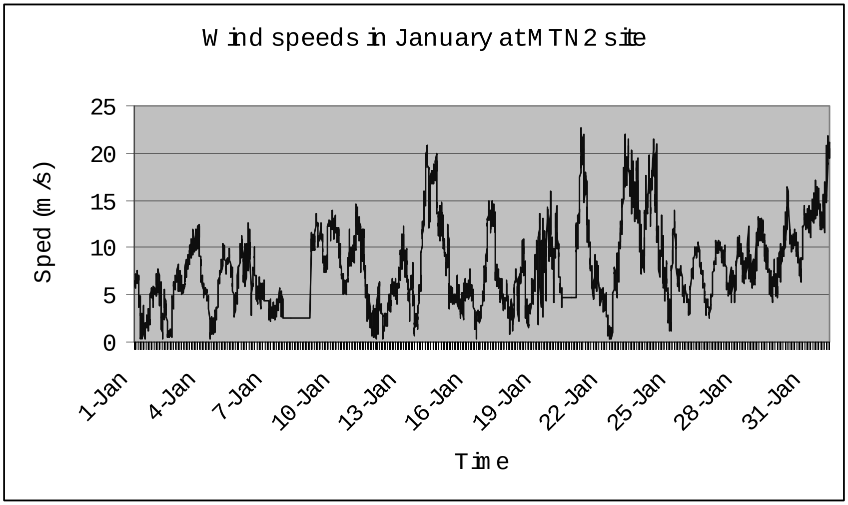


Figure 5



Site summary statistics for entire year (Figure 6)

Site	Average wind speed (m/s)	Standard deviation (m/s)	Wind speed capacity factor
CST	7.32	0.66	27%
MTN1	7.37	0.74	30%
MTN2	6.43	0.92	26%

An important metric for wind farms is the capacity factor of the facility.[43] The capacity factor is simply the average wind speed or power output during a time period divided by the maximum wind speed or power output during that same time period.[44] This metric is quite different from capacity credit/value. Capacity credit represents the amount of capacity that can reliably be counted on and is therefore of value to the utility, whereas the capacity factor simply represents the percentage of the maximum output that the wind farm will put out during some time period.[45] In other words, the capacity factor

43. *See, e.g.,* PROGRESS ENERGY, *supra* note 5 (indicating that wind power is not a viable option for intermediate duty because of low expected 20-25% capacity factor).

44. U.S. DEPARTMENT OF ENERGY, ENERGY EFFICIENCY AND RENEWABLE ENERGY OFFICE, INFORMATION RESOURCES, GLOSSARY, at http://www.eere.energy.gov/consumerinfo/energyglossary.html#C.

45. MILLIGAN, *supra* note 19.

is an indicator of energy whereas the capacity credit is an indicator of capacity.

The variability of the data was analyzed using an error components model. As previously mentioned, data was collected at each site by an anemometer that measured the wind speed every few seconds. Based on these measurements, data was recorded as a 10-minute average with an associated standard deviation. That is, a particular wind speed within a 10-minute period is represented as

$$x_{tt} = \overline{x_t} + e_{tt}$$

where

τ = ten-minute period

t = specific time within a ten-minute period

$x_{\tau t}$ = wind speed at a particular moment during a 10-minute period,

$\overline{x_t}$ = average wind speed during that 10-minute period, and

$\varepsilon_{\tau t}$ = within 10-minute idiosyncratic shock, assumed to be normally distributed.

In addition, there is variation across 10-minute periods. Therefore,

$$x_{tt} = \bar{x} + h_t + e_{tt}$$

where

$\bar{x}$ = average wind speed at a site

η_τ = cross 10-minute idiosyncratic shock.

The total variance of a site is therefore,

$$\text{var}(x_{\tau t}) = \text{var}(x_{\tau t}) + \text{var}(\varepsilon_{\tau t}) + 2*\text{cov}(\eta_\tau, \varepsilon_{\tau t})$$

While the cross 10-minute idiosyncratic shock can be calculated directly from the data, the within 10-minute shock must be empirically estimated based on the 10-minute average and standard deviation, with the assumption that the error is normally distributed. This empirical estimation is necessary because we observe the within 10-minute standard deviation, not $\varepsilon_{\tau t}$, and there is no information on the frequency of measurements within a 10-minute period. The shocks are estimated by drawing a value from a random normally distributed function with a given 10-minute average and standard deviation. This process is repeated 100 times and averaged to provide a best estimate of standard error, or idiosyncratic shock. Subsequently, this shock is combined according to the above equation to produce a total variance for a site for a specific time period. The standard deviation is calculated as the square root of the total variance.

III. NORTH CAROLINA ELECTRIC UTILITIES

North Carolina electric customers are served by a variety of utilities, as follows:

Top Five Utilities Ranked by Retail Sales, 2002[46] (Figure 7)

Name	Retail Sales (MWh)	% of NC retail sales47
Duke Power	53,983,683	44%
Progress Energy	35,327,404	39%
Virginia Electric & Power Co.	3,860,522	3%
Fayetteville Public Works Commission	2,082,850	2%
Energy United Electric Membership Corporation	1,352,171	1%

Duke Power and Progress Energy together account for 73% of North Carolina electricity sales. As such, they are the most likely to build or acquire any large scale new generation. North Carolina is a regulated state, meaning that investor-owned utilities ("IOUs") are allowed to hold monopolies in their service areas in exchange for a legal obligation to serve all their customers reliably and economically.[47] The North Carolina Utilities Commission ("NCUC") is the government body responsible for overseeing regulated utilities and setting rates that allow for a reasonable return on investment to the

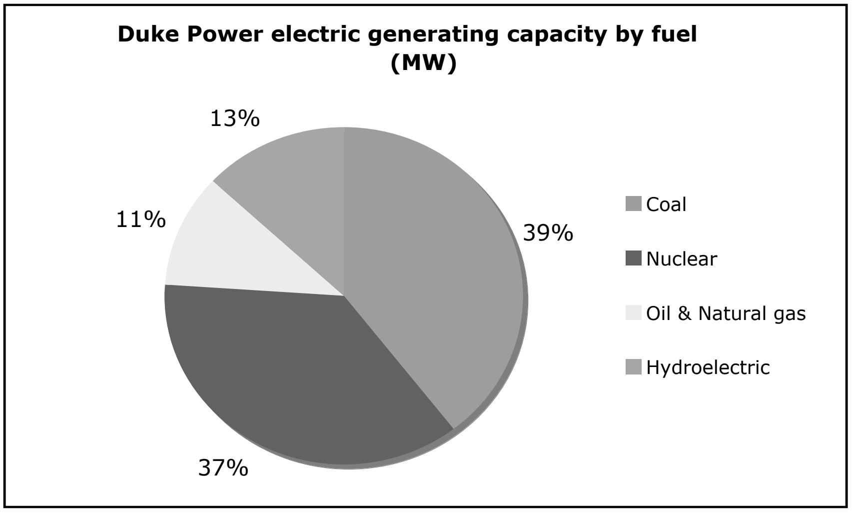
46. ENERGY INFORMATION ADMINISTRATION, NORTH CAROLINA SUMMARY STATISTICS 2002 (2002) *available at* http://www.eia.doe.gov/cneaf/electricity/st_profiles/north_carolina.pdf (last visited Nov. 1 2004).

47. Robert J. Michaels, *Electric Utility Regulation*, in THE CONCISE ENCYCLOPEDIA OF ECONOMICS, LIBRARY OF ECONOMICS AND LIBERTY (2004) *available at* http://www.econlib.org/library/Enc/ElectricUtilityRegulation.html (last visited Mar. 6, 2005).

utility at the lowest cost to customers.[48] As IOUs, the NCUC Public Staff has the obligation to assure an energy supply adequate to protect the public health and safety, and could therefore recommend to the NCUC that a more in depth study of wind power be conducted.[49] For these reasons, Duke Power and Progress Energy will be the focus of this report.

As seen in the following charts, Progress Energy and Duke Power generate electricity primarily from coal, nuclear, and natural gas, and the two have slightly different mixes of generating capacity.[50]

Figure 8

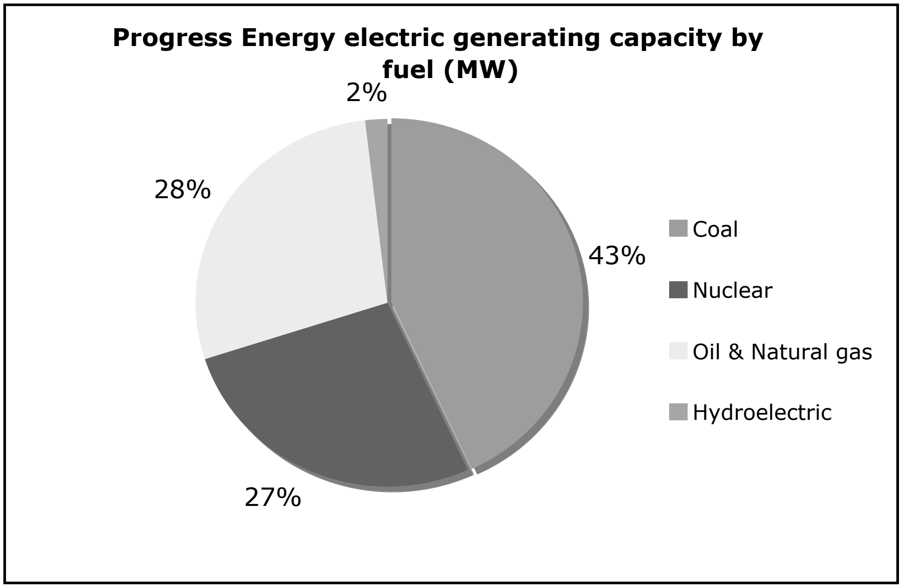


48. North Carolina Utilities Commission, *Mission Statement available at* http://www.ncuc.commerce.state.nc.us/overview/mission.htm (April 15, 2005).

49. North Carolina Utilities Commission, *North Carolina Public Staff* (1998) *available at* http://www.pubstaff.commerce.state.nc.us/psabout.htm (last visited Jul. 10, 2005).

50. North Carolina Utilities Commission, *North Carolina Electric Utilities Overview* (2003) *available at* http://ncucftp.commerce.state.nc.us/NCUC/NCUCoverview.pdf (last visited Mar. 6, 2005).

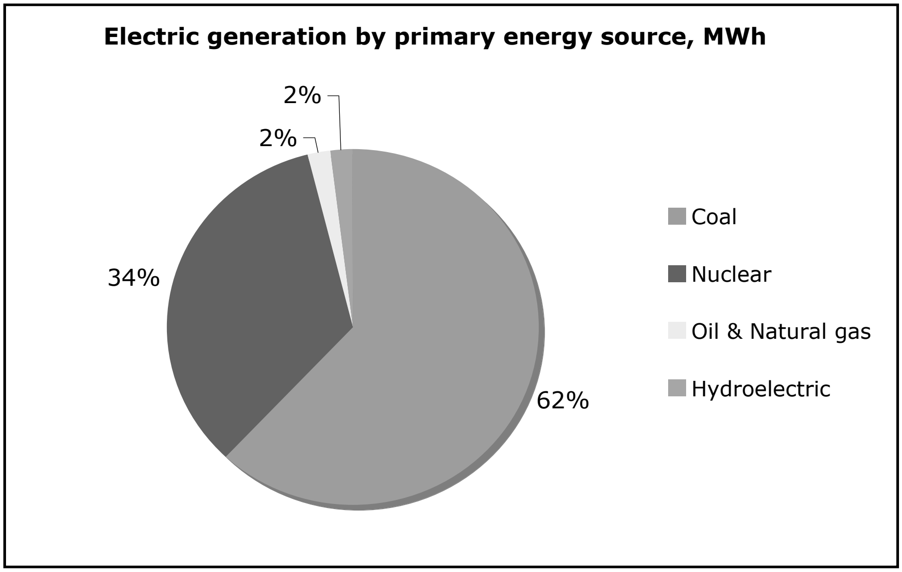
Figure 9



Electricity generation by primary energy source in North Carolina does not exactly match electric generation capacity, as seen below.[51]

51. Energy Information Administration, *North Carolina Summary Statistics* (2002), *at* http://www.eia.doe.gov/cneaf/electricity/st_profiles/north_carolina.pdf (last visited Mar. 6, 2005).

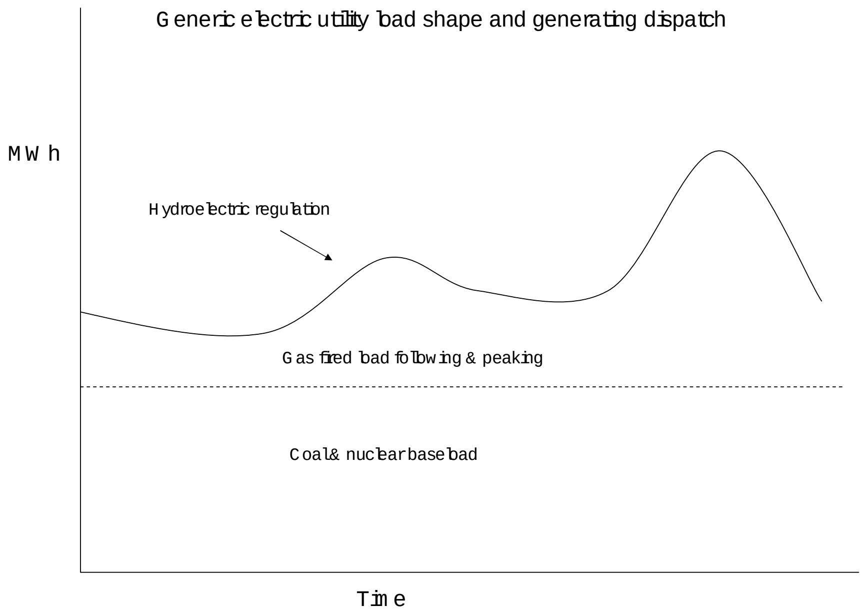
Figure 10



Coal and nuclear generation account for proportionally more MWh of electricity generation than they do for megawatts of capacity because the operating characteristics of both coal and nuclear power plants are such that it is most economical to run them continuously.[52] Specifically, it is expensive to ramp production up and down, and takes time to start the plants up.[53]

52. Duke Energy, *Energy 101: Glossary of Terms "Baseload plant"*, at http://www.duke-energy.com/company/energy101/glossary/B.asp (last visited Apr. 28, 2005).
53. *Id*.

Figure 11



Therefore, as seen in the figure above, while coal and nuclear are generally run at full capacity most of the year, the output of natural gas and petroleum power plants is ramped up and down throughout the day as electric demand varies.[54] As a rule of thumb, in most utility systems natural gas plants generally run roughly 50% of the time, and petroleum plants somewhat less.[55]

IV. Viability of Wind Power

A. *Economic vs. Physical Viability*

The question of physical viability of wind power at low penetration[56] rates has largely been addressed. While all utility systems have

54. Energy Information Administration, *supra* note 2. The EIA AEO 2004 reports that, in 2002, coal-fired generation accounted for roughly 2000 billion kWh and natural gas-fired for 685 billion kWh. The EIA EPA 2003 reports that net summer capacity in 2002 was 315,000 MW for coal and 171,000 MW for natural gas. Thus, natural gas capacity produced roughly half of possible power production, whereas coal produced substantially more. *Id*.

55. *Id*.

56. As used in this Note, "penetration" refers to the percentage of wind in a utility's portfolio of resources.

unique features that make comparisons difficult, a total of 6,300 MW of utility-scale wind generation has been installed to date at a diverse set of utilities, and 3,000 MW more is planned for the next five years, in the United States.[57] The success of these installations is a good indicator that integrating wind power is physically viable on most systems. Further, utilities routinely manage intermittent demand;[58] Wind simply represents intermittent supply.[59] The question, therefore, is not whether integrating wind power (at least at low penetration rates) is physically possible, but how expensive that integration is.

The economic viability of utility-scale wind power can be generally split into "unfavorable" and "favorable" economics. Unfavorable economics refers to the added costs to the utility system incurred by the addition of wind generation.[60] On the other hand, favorable economics refers to the economic value of that resource to the developer or utility.[61] Several studies have been conducted around the country with the goal of quantifying the unfavorable economics of wind, and the results have shown relatively low costs of integration on all systems.[62] Because these studies span a diversity of utility systems and geographic locations, it is reasonable to assume that similar costs might be found on most systems in the country. This Note discusses these costs, but focuses its analysis on favorable economics. Specifically, when is a wind farm worthy of a capacity credit, and under what circumstances is backup, either through energy storage or market purchases, in the economic best interest of the wind developer?

B. *Unfavorable Economics*

Integrating wind power into a utility system presents a unique challenge. Traditional electricity generation sources, such as coal and gas fired power plants are predictable generators.[63] These sources use a combustion process to burn a purchased fuel, can be turned on, up, or down at the command of an operator (they are dispatchable), and

57. American Wind Energy Association, *Wind Industry Statistics*, *AWEA Wind Web Tutorial* (2004), at http://www.awea.org/faq/tutorial/wwt_statistics.html (last visited Mar. 6, 2005).

58. *See, e.g.* KIRBY, ET AL., *supra* note 22, at 16.

59. PARSONS, ET AL., *supra* note 9, at 2.

60. ERIC HIRST, INTERACTIONS OF WIND FARMS WITH BULK-POWER OPERATIONS AND MARKETS 1 – 2 (Prepared for Project for Sustainable FERC Energy Policy, Sept. 2001).

61. *Id.* at 1.

62. SMITH, ET AL., *supra* note 7, at 7 – 9.

63. *Id.* at 1.

their use is generally scheduled up to a day ahead of time.[64] Wind power, however, does not exhibit these same characteristics. On the contrary, the characteristics of wind more closely resemble the characteristics of electric demand, which is also highly variable.[65]

Electric generation is managed to respond to demand on three time horizons:[66]

- Unit commitment: most vertically integrated utilities decide which resources to dispatch 12 to 24 hours ahead of when they will be needed.[67] These decisions to commit units are based on historical demand during the upcoming time period, recent trends in demand and weather, and the cost of each resource at that time.[68] Unit commitments can be made because the dispatcher has confidence that a particular resource will or will not be available to produce a certain amount of power during the upcoming day.[69] Because wind is currently so variable, utilities find it difficult to include wind in these day-ahead unit commitments. The amount of capacity committed for the upcoming day is generally the base amount that is forecast to be demanded during the entire period.[70]
- Load following: Throughout the day, demand generally trends up or down. In response, utilities add resources to the generating mix, or increase or decrease existing resource energy output about every five to ten minutes.[71] Load following is somewhat predictable based on recent trends, and patterns of customers tend to be correlated.[72] That is, demand is generally low in the middle of the night while people are asleep, rises in the morning as people and businesses begin to turn on appliances, drops slightly in the middle of the day while people are away from the home, rises again in the evening as people go

64. *Id.* at 3.

65. KIRBY, ET AL., *supra* note 22, at 14 – 15.

66. PARSONS, ET AL., *supra* note 9, at 2,

67. ERIC HIRST, INTEGRATING WIND ENERGY WITH THE BPA POWER SYSTEM: PRELIMINARY STUDY 3 (Prepared for BPA Power Business Line Sept. 2002).

68. *Id*.

69. *Id.*

70. *Id*. at 15.

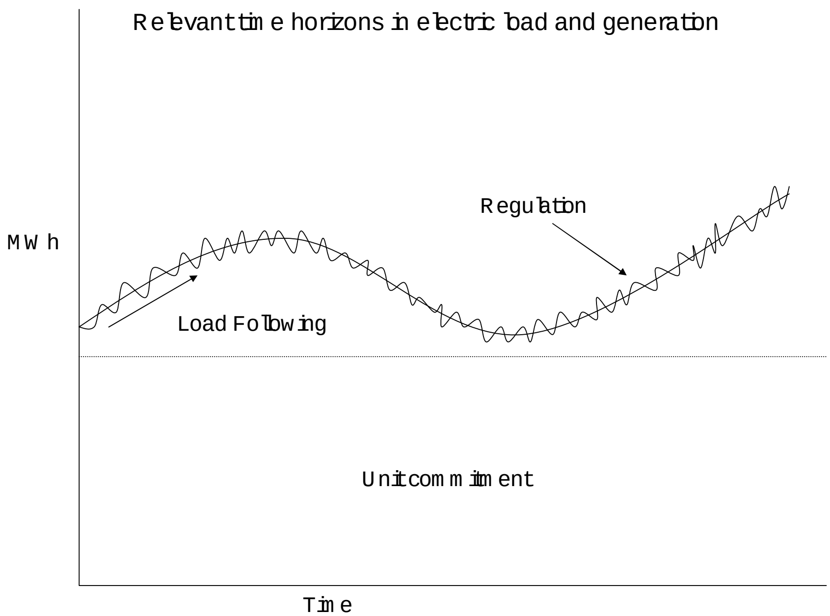
71. ERIC HIRST & BRENDAN KIRBY, ANCILLARY SERVICES: A CALL FOR FAIR PRICES 2 (1999) *available at* http://www.ornl.gov/sci/btc/apps/Restructuring/PUFRegLF.pdf (last visited Apr. 15, 2005).

72. *Id*.

home from work, and then drops as people go to bed.[73] Because this pattern is fairly reliable across days, utilities must have resources ready that can be economically turned up or down throughout the day. To meet trending demand, the dispatcher must have control over the power output of these resources.

- Regulation: Regulation deals with minute-to-minute variations in the balance between generation and load; that is, the fluctuations (+ 1 MW) around an underlying trend. These fluctuations are generally not easily forecast because they depend on individual consumer choices regarding electricity usage.

Figure 12



The impacts of wind power must be addressed on each of these three time horizons, and not unexpectedly, wind power integration represents an added cost to the system.[74] Several utilities, government agencies, and consultants have undertaken studies of wind integration

73. MICHAEL RICE, AN ANALYSIS OF PURPA AND SOLAR ENERGY (1980).
74. SMITH, ET AL., *supra* note 7, at 9.

costs on their utility systems, and the results shown in the following table can inform other states and utility systems.

Summary of integration costs from previous studies[75] (Figure 13)

Study	Relative wind penetration (%)	Regulation ($/MWh)	Load following ($/MWh)	Unit commitment ($/MWh)	Total ($/MWh)
UWIG/Xcel	3.5	0	0.41	1.44	1.85
PacifiCorp	20	0	2.50	3.00	5.50
BPA	7	0.19	0.28	1.00-1.80	1.47-2.27
Hirst	0.06-0.12	0.05-0.30	0.70-2.80	Na	Na
We Energies I	4	1.12	0.09	1.75	2.92
We Energies II	29	1.02	0.15	1.75	2.92
Great River I	4.3				3.19
Great River II	16.6				4.53
CA RPS Phase I	4	0.17	Na	Na	Na

These studies report integration costs ranging from $1.47 to $5.50/MWh. Despite the differences in these utility systems in terms of generation mix and load profile, the results of their integration cost studies are remarkably similar; the overwhelming result being that integration costs, at a range of wind penetration levels, are low.[76]

Further discussion of a few of these studies can enlighten any efforts taken by either Duke Power or Progress Energy. We Energies is a regulated utility in Wisconsin and Michigan that has a 6,000 MW peak load and an installed capacity of 5,900 MW.[77] The difference between installed capacity and peak load is made up for with purchased capacity.[78] Eighty-seven percent of WE Energies's capacity is made up

75. *Id.* at 8.
76. *Id.* at 9.
77. *Id.* at 5.
78. *Id.* at 5 – 6.

of coal and nuclear.[79] In this regard, this system is therefore quite similar to both Duke Power and Progress Energy, both of whom produce the majority of their energy from coal and nuclear. We Energies evaluated four levels of wind capacity and the economic impacts that capacity would have on regulation, load following, and unit commitment, and found the following costs[80]:

Integration costs at We Energies (Figure 14)

Wind Capacity (MW)	Total Integration Cost ($/MWh)
250	1.90
500	2.47
1000	2.82
2000	2.92

We Energies based their analysis on wind data collected at 13 sites across Wisconsin during a three year period.[81] If Duke Power and Progress Energy want to determine integration costs on their system, they should conduct a similar study. As will be seen in the following section, this type of data could also better inform any analysis of the benefits incurred from geographically distributing wind power within a utility's service area.

A related topic that will not be discussed in depth here, but deserves mention is the potential of wind forecasting. Accurate forecasting would be invaluable to electric utilities and wind developers, particularly in a competitive market, because it would allow wind power to be scheduled a day or more ahead of time, thereby making largely obsolete the issue of variability of the resource.[82] However, forecasting is not an exact science, and there is invariably some error associated with wind forecasts (of course, the same is true, as will be discussed later, of load forecasts).[83] To understand the value of wind forecasting, it is first necessary to understand the types, methods, and accuracy of current forecasting technology.

79. ELECTROTEK CONCEPTS, INC., QUANTIFYING SYSTEM OPERATION IMPACTS OF INTEGRATING BULK WIND GENERATION AT WE ENERGIES 1 (Presented at POWER-GEN Renewable Energy 2004, Las Vegas, Nevada, Mar. 2004).

80. *Id.* at 8.

81. *Id.* at 2.

82. MILLIGAN, *supra* note 19, at 4.

83. *Id.*

There are generally two time frames associated with wind forecasting, and different methods are used for each. The most desirable forecasts are longer term forecasts; that is, one to two days ahead. These forecasts make use of sophisticated meteorological models to make predictions on when and how hard the wind will be blowing several days in the future.[84] These meteorological models make use of weather data from satellites and surface measurements and are used to forecast one to two days into the future.[85] On a shorter time frame, persistence modeling techniques can be used to predict wind speeds several hours in the future.[86] Persistence models use data on wind output during the prior two to three hours to produce forecasts for the next two to three hours.[87] The longer time frame associated with meteorological modeling leads to significantly larger forecasting error.[88]

In 2001, Hirst found that a simple persistence model explained 81% of the hourly variation in wind output.[89] Day-ahead forecasts are somewhat less accurate.[90] However, this level of accuracy can significantly address the concern over variability of wind in competitive power markets where capacity and energy are bought and sold a day or two ahead of time. When evaluating wind as a potential resource in North Carolina, utilities should consider the forecasting potential of both meteorological and persistence forecasts.

C. *Favorable Economics*

Favorable economics is used to refer to the value developers receive from wind power implementation. That is, the payments received from utilities for power minus the costs associated with building and running a wind development. Payments from utilities can take two forms: capacity and energy. As discussed above, these are separate concepts and as such, receive separate payments. Wind developments always receive energy payments for some or all of the energy they produce.[91] A more controversial question is to what extent, if any, they should be given capacity payments as well.

84. HIRST, supra note 61, at 21.
85. *Id*.
86. *Id*.
87. *Id*.
88. HIRST, *supra* note 68, at 19.
89. *Id*.
90. *Id*.
91. MILLIGAN, *supra* note 19, at 11.

All generating resources are assigned a capacity value, which indicates that resource's contribution to the reliability of the overall electrical supply system.[92] That is, a resource's ability to deliver power when needed provides capacity value to the system that is separate and distinct from the energy it generates.[93] The capacity value is almost always less than that resource's rated capacity, since no resource is perfectly reliable.[94] While fossil fuel plants tend to have high capacity values (on the order of 95%),[95] wind farms are often assigned zero capacity values due to the high variability of their output.[96] If a wind farm cannot guarantee a particular capacity, other resources must be committed as back up in an amount equal to the wind farm's output. Therefore, a higher capacity value can greatly increase the economic viability of the wind farm.

D. *Geographical Dispersion of Wind Resources*

Winds sometime exhibit some degree of seasonality or diurnal variation that results in a statistically significant utility peak coincidence.[97] In this case, the wind farm contributes positively to the overall reliability of the system and deserves an associated capacity credit. Further, geographically dispersed portfolios of wind farms should exhibit less variation than do the individual wind farms, and could potentially command a higher capacity credit for the combined output.[98] Finally, in some cases, backup generation becomes economical to the wind developer.[99] That is, building energy storage on site or buying an option on backup generation to effectively "firm" the wind farm output could make economic sense.

Data from the three sites in North Carolina and eastern Tennessee were used to examine the issue of capacity credits for wind power. Ten-minute wind speeds were converted to power outputs based on the power output curve (displayed in the following graph) of a wind turbine that would likely be used at these sites, the Vestas 1.65 MW

92. *Id*. at 13.

93. KIRBY, ET AL., *supra* note 22, at 1.

94. MILLIGAN, *supra* note 19, at 12.

95. KIRBY, ET AL., *supra* note 22, at 14.

96. *Id*.

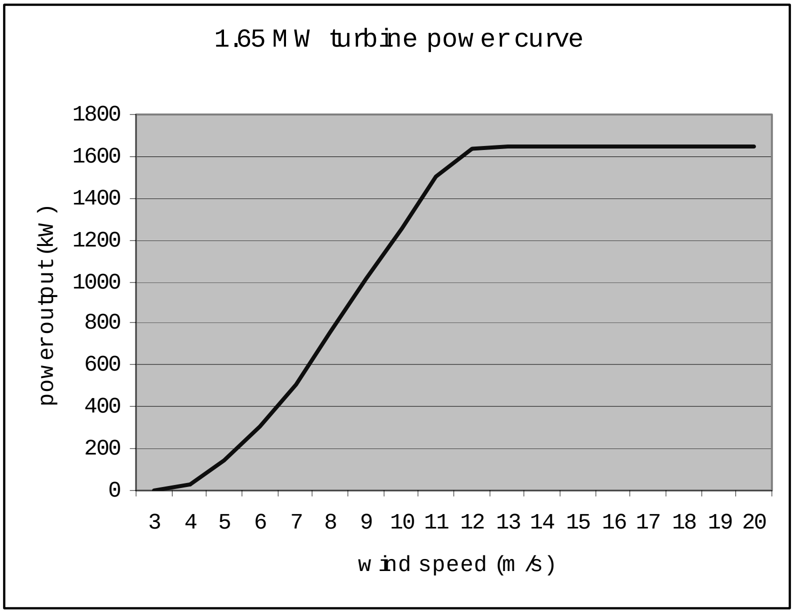
97. ENERNEX CORPORATION, CHARACTERIZATION OF THE WIND RESOURCE IN THE UPPER MIDWEST: WIND INTEGRATION STUDY 4 (2004).

98. *Id*. at 39.

99. ELECTRIC POWER RESEARCH INSTITUTE, U.S. DEPT. OF ENERGY, HANDBOOK OF ENERGY STORAGE FOR TRANSMISSION AND DISTRIBUTION APPLICATIONS 15-30, 11-17, 10-19, 8-21 (2003).

turbine. This turbine has a cut-in speed of 3.5 m/s and a cut-out speed of 20 m/s, and produces its maximum power output, 1.65 MW, starting at 13 m/s.[100] As seen in the following graph, power output increases approximately linearly with increasing wind speed until the maximum output is reached and remains constant from roughly 13 m/s to 20 m/s.

Figure 15



The following table gives average power output and power capacity factor for each 1.65 MW turbine at that site for the year.

100. VESTAS, V82-1.65 MW PITCH REGULATED WIND TURBINE WITH OPTISLIP AND OPTITIP (2004) *available at* http://www.vestas.com.

Figure 16

Site	Average power output (kW)	Average standard deviation (kW)	Capacity factor
CST	644	527	39%
MTN1	668	580	41%
MTN2	502	571	30%

As stated previously, the capacity factor, especially the power capacity factor, is important to the economic viability of a wind farm because it indicates the expected energy production at that site.[101] These sites exhibit relatively high capacity factors, in comparison to Progress Energy's statement that, "a wind project would not be expected to operate above 20-25% capacity factor in the Carolinas geographic area, [and therefore] it is not a viable alternative for intermediate duty."[102]

The North Carolina system exhibits two demand peaks: a summer peak in the evening in August and a winter peak in the morning in January.[103] These two peaks are when capacity is most in demand during the year. Utilities often find it economically inefficient to own enough capacity to meet the annual peaks, since that last bit of capacity is only used once or twice a year. Thus, these are periods when wind could contribute substantially. Therefore, when determining whether a wind farm or portfolio of wind farms is worthy of a capacity credit, the scope of this analysis was narrowed to focus on these peak periods. The January peak was modeled as the four hour period from 5:30 am to 9:30 am every day in January, and the August peak was modeled as the four hour period from 4:00 pm to 8:00 pm every day in August. A four hour period was chosen because it is broad enough to be fairly assured of capturing the peak. Wind speeds even within this narrow four-hour period exhibit high variability.

For the above mentioned peak periods, the mean and standard deviation were calculated for each of the three sites. For simplicity,

101. N.C. Utilities Comm'n, *supra* note 49.

102. *Id.*

103. Duke Power reports in personal interviews that its summer peaks have occurred on July 30, 2002, August 27, 2003, and July 14, 2004. The peak with the largest magnitude, on July 30, 2002, occurred at 5:00 pm. Duke Power also reports its winter peaks on January 3, 2001 at 8:00 am, January 24, 2003, and January 20, 2004.

these results represent one turbine at each site. For economy of scale, it is likely there would be more than one turbine at each site, but the results presented here would hold for each turbine at a particular site.

January peak (Figure 17)

Site	Mean (kW)	Standard Deviation (kW)
CST	869.26	466.35
MTN1	952.05	633.42
MTN2	651.11	565.07

Figure 18

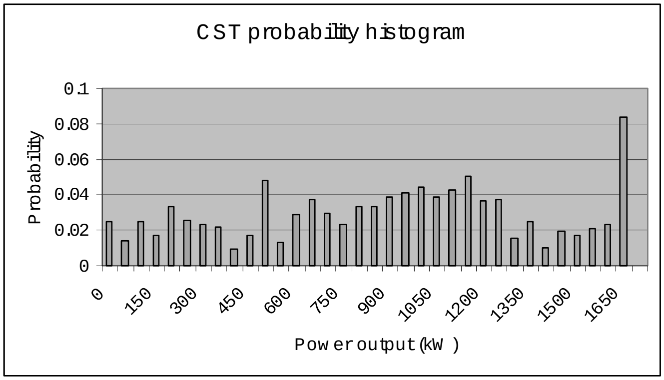


Figure 19

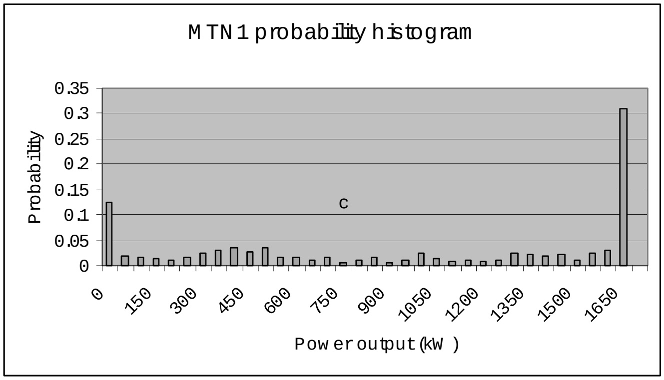
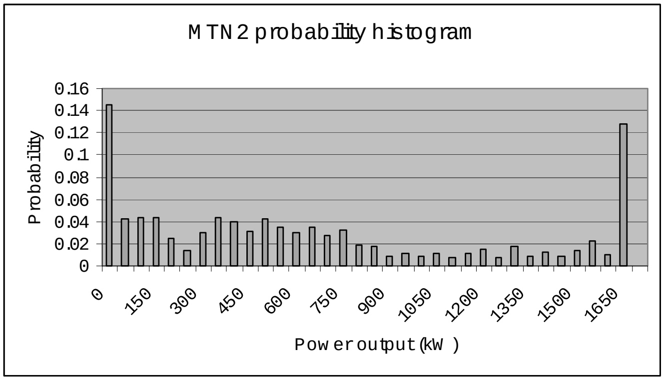


Figure 20



As is expected, the power outputs of turbines at these three sites during January exhibit extremely high variability. At each of the three sites, there is generally less than a 5% probability of getting any particular power output other than zero or the maximum. It is also clear that while wind speeds at each site appear to be approximately normally distributed, the power output at each individual site is not. This situation occurs because the transformation from wind speed to power output is based on a non-linear function, as seen in the graph of the turbine power curve.[104] The wind turbine modeled here has a cut-in wind speed of 3.5 m/s and a cut-out wind speed of 20 m/s,[105] so all wind speeds outside that range produce zero power. Similarly, for the range of wind speeds from roughly 13 m/s to 20 m/s, the turbine produces a constant 1.65 MW, hence, the higher probability of getting 1.65 MW output.

The mean, standard deviation, and power output distributions for the August peak period follow.

August peak (Figure 21)

Site	Mean (kW)	Standard Deviation (kW)
CST	684.01	481.71
MTN1	315.74	375.94
MTN2	216.01	348.71

104. Duke Power Interviews, *supra* note 104.
105. VESTAS, *supra* note 101.

Figure 22

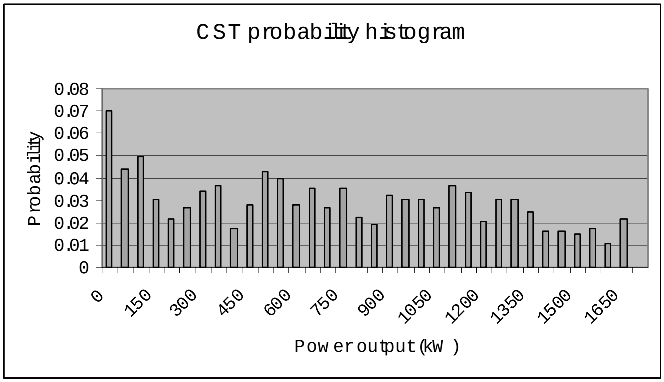


Figure 23

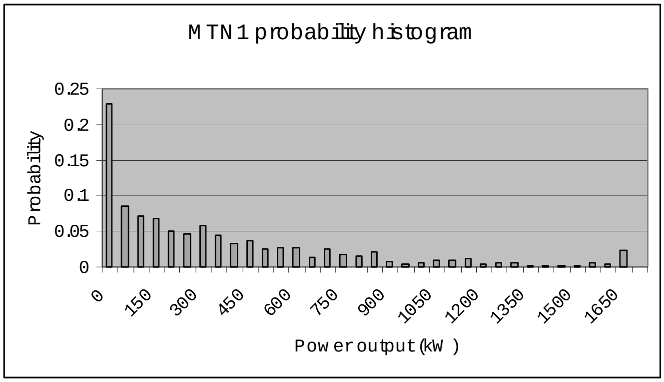
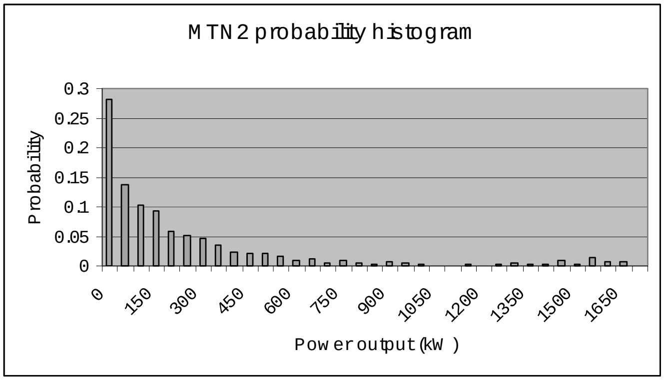


Figure 24



As in the January peak period, the power output distributions in the August peak period are highly variable. However, the MTN1 and MTN2 sites are greatly skewed toward zero in comparison to the CST site and to all the sites in January. This shape is a result of the very low wind speeds at these sites during August—the average wind speed in August is 5.4 m/s at the MTN1 site and 4.7 m/s at the MTN2 site. With a wind turbine that has a 3.5 m/s cut-in wind speed and a shallow slope to the low wind speed section of the power curve, low wind speeds result in the observed skew.

Because the power distributions are not normally distributed, the standard deviations reported here for each site are not equivalent to standard deviations in normally distributed functions. However, the standard deviation still serves as a valuable indicator of variability.

High variability, as seen here, is often the primary concern cited by electric utilities.[106] Certainly no capacity credit will be given to a wind farm exhibiting a power distribution function similar to any of the above.

The question here concerns whether geographically distributing wind generation effectively raises the capacity value of the system by decreasing this variability. Geographical distributions of wind resources have been considered in other studies, although not, as yet, in great detail. In 2002, Eric Hirst, a consultant for the Bonneville Power Administration ("BPA"), suggested that the variability of the output of wind generation at dispersed locations would be less than the vari-

106. *See, e.g.*, PROGRESS ENERGY, *supra* note 5; DUKE POWER, THE DUKE POWER ANNUAL PLAN (2003).

ability of co-located wind generation.[107] Hirst found that the standard deviation of the total output of five dispersed wind farms would have been 30% lower than the standard deviation had they been co-located.[108]

The first step in determining the value of geographical dispersion in North Carolina is to determine whether the three sites exhibit any covariance. That is, are large power output values at one site associated with large power output values at another site (positive covariance), are the power output values unrelated (covariance near zero) or are large power output values at one site associated with small power output values at another site (negative covariance).

Covariance matrices were generated for both the January and August peak periods (data points every 10 minutes within a four hour peak period every day in that month), according to the formula:

$$\mathrm{cov}(x,y) = 1/n^* \, \Sigma(x_i - \mu_x)(y_i - \mu_y)$$

Where:
x, y = data series
n = number of data points
μ = data series average
i = data point

January peak covariance matrix (Figure 25)

	CST	MTN1	MTN2
CST	211007	-24631	-18026
MTN1	-24631	387634	115744
MTN2	-18026	115744	306337

107. ERIC HIRST, BONNEVILLE POWER ADMINISTRATION, INTEGRATING WIND ENERGY WITH THE BPA POWER SYSTEM: PRELIMINARY STUDY (2002).
108. *Id*.

August peak covariance matrix(Figure 26)

	CST	MTN1	MTN2
CST	219965	-16606	-6930
MTN1	-16606	152236	-20402
MTN2	-6930	-20402	125262

As can be seen from the above matrices, there is some degree of negative covariance between the three sites. Specifically, the CST and MTN1 sites and CST and MTN2 sites exhibit negative covariance during the January peak, while the MTN1 and MTN2 sites exhibit positive covariance. Positive covariance between MTN1 and MTN2 is not particularly surprising, since they are closer to one another than to the CST site, and therefore likely share some topographical and meteorological characteristics. During the August peak, all sites exhibit negative covariance. This result indicates that large power output values at one site are associated with small power output values at another site. This negative covariance should have the effect of reducing the variability of the combined output of the three sites.

The value of this negative covariance in reducing system variability was determined by running an optimization model to determine the mix of generation at each site that would yield the collective minimum variability. This optimization problem minimizes the portfolio variability by changing the share of wind at each site, subject to several constraints, according to the following form:

$$\begin{gathered} \text{minimize: } s'\Omega\, s \\ \text{by changing: } s \\ \text{subject to: } 0 \le s \le 1 \\ s'i = 1 \\ s'\mu \ge \mu_{min} \end{gathered}$$

where:

$$\Omega = \text{covariance matrix} = \begin{bmatrix} s_1^2 & s_{12} & s_{13} \\ s_{21} & s_2^2 & s_{23} \\ s_{31} & s_{32} & s_3^2 \end{bmatrix}$$

$$s = \text{shares vector} = \begin{bmatrix} s_1 \\ s_2 \\ s_3 \end{bmatrix}$$

$$i = \begin{bmatrix} 1 \\ 1 \\ 1 \end{bmatrix}$$

$$\mu = \text{mean output vector} = \begin{bmatrix} m_1 \\ m_2 \\ m_3 \end{bmatrix}$$

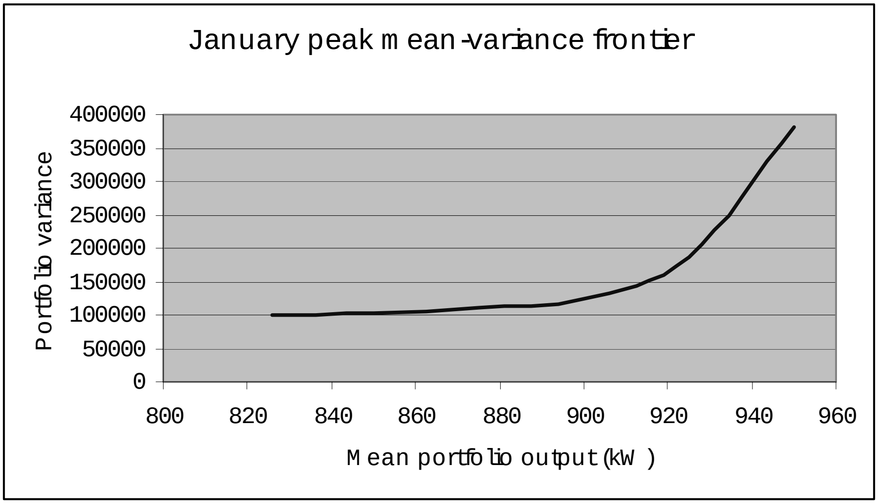
μ_{min} = specified minimum portfolio weighted power output

Variance is not independent of average—as portfolio average power output increases, variance increases.[109] While minimal variability in power output is desirable, some higher level of variability might be acceptable to achieve a higher average output. To maximize the economic value of the wind farms, this decision should be based on the individual risk preferences of the wind developer and utility, and the comparative value of energy and capacity payments. If capacity is more valuable, a developer may choose a portfolio with a lower output and accordingly lower variance. However, if energy is more valuable, a developer may choose a portfolio with a higher mean output and variance, thereby giving up possible capacity payments.

The following graph gives the mean variance frontier for the January peak period. Different mean portfolio outputs are associated with different portfolios of wind (a different percentage of the total wind capacity at each site).

109. *See* Figure 27.

Figure 27



During this period, the MTN1 site has the highest mean output of the three sites. Therefore, the point (952, 387000) represents the portfolio with 100% of the wind turbines at the MTN1 site. As wind is added at the other two sites, portfolio variance decreases, but so does mean portfolio output, according to the above mean-variance frontier.

This report is focused on the potential for capacity credit, so the portfolio that has the absolute lowest variability is shown below.

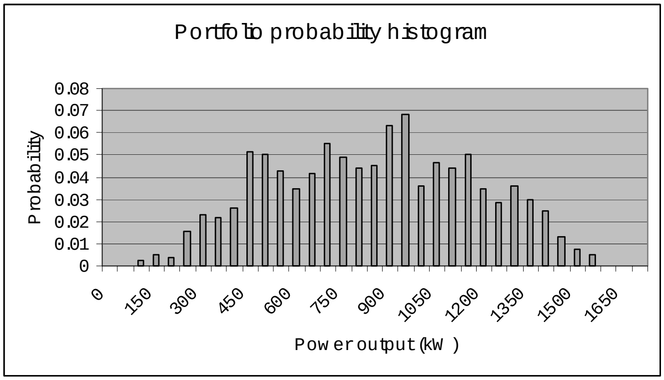
January peak portfolio (Figure 28)

CST share	MTN1 share	MTN2 share	Mean power output (kW)	Standard deviation (kW)
51.8%	20.6%	27.6%	826.07	314.89

Shares at each site are given as percentages because share is independent of total amount of wind. For example, if a developer wanted to install a total of 10 wind turbines, this portfolio would require five be installed at the CST site, two at the MTN1 site, and three at the MTN2 site. If 20 wind turbines were desired, ten would be installed at the CST site, four at the MTN1 site, and six at the MTN2 site.

The following graph gives the probability histogram for this lowest variance portfolio during the January peak period. It represents the weighted average of the probabilities of the three individual sites during this time period. Aggregation of the three individual sites results in a distribution substantially closer to normal.

Figure 29



As can be seen, the standard deviation of the combined output is substantially less than any of the three individual sites for the January peak period. This result occurs because, as shown by the largely negative covariance between sites, the sites are geographically dispersed and therefore the wind at each site is not entirely correlated. The variation at one site to some degree cancels the variation at another site.

While this smaller variability is good, the absolute magnitude of the variability is still quite large. The capacity credit given to fossil fuel power plants is on the order of 95% of rated capacity, because there is always some probability, no matter how small, that the plant will fail and therefore not be available when needed.[110] Therefore, wind should be given capacity credit for the power output generated with 95% confidence. In a normal distribution, this level is represented by the mean power output minus 1.645 standard deviations.

Because the lowest variability portfolio distributions for the January peak period is not precisely normally distributed, the 95% level was calculated by using a histogram of power output to calculate the power output level with a 0.95 cumulative probability. Based on

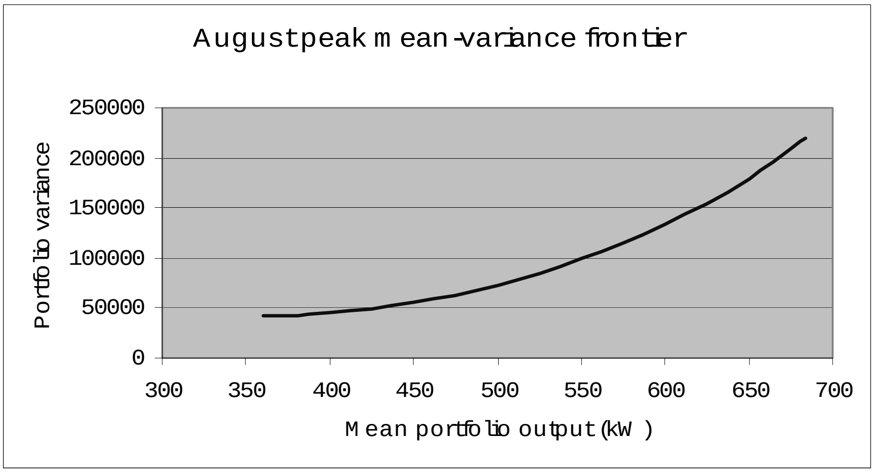
110. MILLIGAN, *supra* note 19, at 12.

this methodology, this portfolio is worthy of 340 kW of capacity credit during the January peak period.

The mean-variance frontier for January is relatively flat until roughly 900 kW mean portfolio output, at which point variance rises sharply. It is likely that a developer would prefer a portfolio at this point because while the mean portfolio output is substantially higher than the minimum, variance is only slightly higher.

Using the same methodology, the mean-variance frontier was generated for the August peak period. During this period, the CST site has the highest mean power output of the three sites, so the extreme point (684, 220000) represents the portfolio with 100% of the wind at the CST site. As wind is added at the other two sites, both variance and mean decrease along the mean-variance frontier shown below.

Figure 30

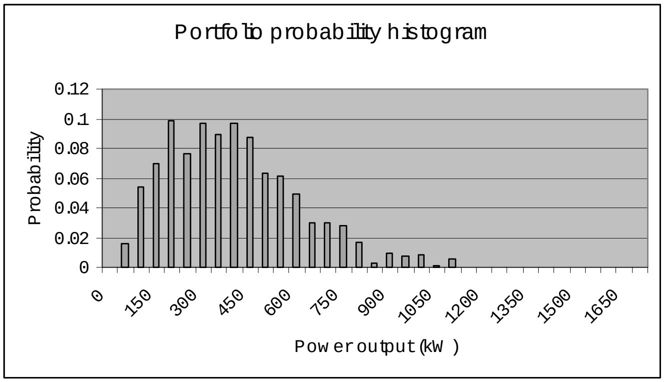


The following portfolio represents the portfolio with the lowest total variance.

August peak portfolio (Figure 31)

CST share	MTN1 share	MTN2 share	Mean power output (kW)	Standard deviation (kW)
23.2%	35.8%	40.9%	360.53	205.78

Figure 32



The MTN1 and MTN2 sites are individually largely skewed towards zero, and thus the portfolio that includes these sites, as seen above, is not normally distributed. As in January, the power output was calculated that had a 0.95 cumulative probability of occurring. Based on this method, this portfolio deserves a 110 kW capacity credit (of a maximum 1650 kW rated capacity) during the August peak period.

Because utilities are capable of, and often do purchase capacity during their peak periods, capacity credit during only one peak is still valuable to the utility.[111] This is important because the lowest variance portfolio for the January peak period does not have the same share of wind at each site as the lowest variance portfolio for the August peak period. Wind turbines are not portable, and it is therefore not possible to create both portfolios simultaneously. Rather, the developer and utility must decide in which peak period capacity is more valuable, and stick with that portfolio.

E. *Other Methods of Calculating Capacity Credit*

Other methods of calculating capacity credit have been developed by wind and utility experts around the country, and are worthy of discussion. One approach to determining a wind farm's capacity credit is to calculate its effective load carrying capability ("ELCC"), a metric created by the National Renewable Energy Laboratory ("NREL") and applied most recently by the California Energy Commission ("CEC") in its renewable generation integration cost

111. *See, e.g.*, SMITH, ET AL., *supra* note 7, at 5.

analysis.[112] This approach is useful because it can be applied to any type of generating resource, whether fossil fuel or renewable.[113] The ELCC equation says that the increase in capacity that results from adding a new generator can support x more MW of load at the same reliability level as the original load could be supplied.[114] The ELCC is based on the loss of load probability ("LOLP"), which is the probability that enough generation units are on forced outage that the utility is unable to meet its load, thereby quantifying the risk of not supplying enough generation to the system.[115] When this method was applied to existing wind farms in California, capacity credits were determined to be 22 to 26%.[116] Since these existing California wind farms were built, turbine technology has been developed to improve energy capture at low wind speeds.[117] The CEC believes, had this technology been installed at the existing sites, the capacity credits would be significantly increased.[118]

While this is a rigorous method, the CEC and others have recognized that this iterative approach is perhaps overly complicated and time consuming, and have made efforts to develop simpler methods.[119] One of these methods calculates the capacity factor of the wind farm over the top 10 to 20% of load hours and using this as an approximation for the ELCC.[120] In North Carolina, the top load hours surround the summer and winter peaks.[121] Due to lack of precise hourly data regarding the peak hours in the last few years, this approximation was modeled for North Carolina as the capacity factor during the January and August peak periods. Because the January peak period portfolio had a substantially higher average power output, the portfolio determined for the January peak was applied to this calculation of both peak periods.

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112. KIRBY, *supra* note 22.
113. *Id.* at 23.
114. *Id*.
115. *Id*.
116. *Id.* at 31.
117. *Id.* at 38.
118. *Id*.
119. *Id.* at 24.
120. *Id*.
121. DUKE POWER, *supra* note 107.

Portfolio of power output during top 10% of load hours (Figure 33)

CST share	MTN1 share	MTN2 share	Average power output (kW)	Maximum power output (kW)	Capacity factor
51%	21%	28%	638.55	1532.82	42%

Based on these results, the capacity credit of this system of wind farms should be approximated by the 42% capacity factor found during the top load hours of this representative year. This method is significantly more generous to wind power than the initial method discussed here. The discrepancy arises because, in the first method, capacity credit was only given for the amount of power the wind turbine was likely to produce with 95% confidence at any time during the peak period. Here, however, capacity credit is given for the amount of power generated in the peak period, not taking a confidence interval into account. While it is likely that this amount of power would be generated at some point during the top load hours, there is still uncertainty surrounding exactly when it will be produced.

V. Role of Physical or Market Purchased Backup

The next logical question is whether some form of backup, either physical energy storage or a purchased market option, is economically attractive as a mechanism to increase the capacity credit. This question will not be addressed analytically here, but will be discussed as a basis for future analysis. To determine whether backup makes economic sense, we must consider both the value of the capacity credit and the cost of backup. Further, the shape of the portfolio output distribution must be taken into consideration when analyzing backup, since, as seen above, a normal distribution cannot be assumed.

There are two distinct types of backup possible for wind farm generation—physical storage and a market option on capacity. Physical storage can take many forms, with different forms suited for different utility time horizons, as seen below.

Figure 34

Time horizon	Storage need	Storage types
Regulation	Seconds - minutes	• Lead acid batteries • Superconducting magnetic energy storage • Flywheels • Ultracaps
Load following	Minutes - hours	• Lead acid batteries • Nickel cadmium batteries • Sodium sulfur batteries • Zinc bromine batteries • Superconducting magnetic energy storage • Flywheels • Ultracaps • Pumped hydro
Unit commitment	Hours - days	• Compressed Air Energy Storage (“CAES”) • Regenesys • Vanadium redox batteries • Sodium sulfur batteries • Pumped hydro

For the purposes of capacity credit, energy storage technologies suited for unit commitment are most appropriate.[122] The Electric Power Research Institute (“EPRI”) recently conducted a study on

122. In terms of capacity credit, energy storage is used to create blocks of “firm” power, thus the unit commitment time scale. ELECTRIC POWER RESEARCH INSTITUTE, *supra* note 100, at 15-30, 11-17, 10-19, 8-21.

the costs and benefits of these various storage technologies, and found the following costs for unit commitment technologies.[123]

Figure 35

Technology	Capital cost ($M)	Fixed O&M cost ($/kWy)	Variable O&M cost ($/kWy)	Disposal cost ($/kW)
Compressed air energy storage	5.5-8.3	19-24.6	4.7-65	
Regenesys	75.7	80.3	11.6	1.9
Vanadium redox batteries	26.2	54.8	7	
Sodium sulfur batteries	22.7	51.2	13.4	43.2

EPRI did not analyze pumped hydro storage technology, but pumped hydro, in certain areas of the country, could prove to be an economical choice for storage of wind power. While there is no indication that new pumped hydro facilities will be constructed in North Carolina, there is one existing project that could potentially be used for the purpose of integrating wind power.[124] In a pumped hydro system, off-peak or variable power is used to pump water from a reservoir to a different reservoir at a height above the first, for instance, up a mountain. Then, when the power is needed during peak periods, the water in the upper reservoir is released through a turbine, generating reliable power.

The possibility for combined wind-hydro system is best seen with the recently developed Bonneville Power Administration wind firming service. BPA runs a 16 gigawatt (GW of BPA capacity) hydroelectric system in the Pacific Northwest region.[125] Due to the large quantity of hydro capacity at their disposal, they have been able to develop two separate wind firming products. The first is known as Networking Wind Integration Service, and through this service, BPA

123. *Id*.
124. Bonneville Power Administration, *Fast Facts*, at http://www.bpa.gov/corporate/about_BPA/Facts/FactDocs/BPA_Facts_2004.pdf (last visited Apr. 28, 2005).
125. *Id*.

uses its hydro system to integrate the output of a wind farm.[126] That is, on an hourly basis, BPA uses hydro to make up the difference between a customer's load and the wind farm's output.[127] This service costs a customer $4.50/MWh.[128] The second BPA service is known as Storage & Shaping Service, and is designed for utilities that do not want to manage the hour to hour variability of wind resources [129] Through this service, BPA uses the hourly output of a wind farm to pump water into its reservoir. A week later, BPA releases that amount of water to produce a firm block of power with zero variability. This service costs $6.00/MWh.[130]

Pumped hydro works economically in the Pacific North West because of the region's substantial hydro capacity.[131] The majority of the rest of the country does not have such a substantial hydro resource, and therefore should likely consider other storage mechanisms, as listed above.

CONCLUSIONS

Wind capacity is growing quickly in the United States as costs decrease and awareness of the environmental benefits of wind power grows.[132] With the recent ratification of the Kyoto Protocol, carbon limits are a reality in much of the world, and continue to be a possibility in the United States. Electric utilities that burn coal are especially vulnerable to carbon limitations, due to the high carbon content of coal.[133] For this reason, too, wind power is an attractive option. If carbon limits are instituted in the United States, wind power will be much more valuable.

In the absence of carbon limits, however, wind power can still be an attractive option. The viability of wind on a utility system depends on two factors: (1) the additional costs imposed on the utility system by integrating the variability inherent in wind power, and (2) the

126. *Id.* at 1.

127. *Id.*

128. *Id.*

129. *Id.* at 2.

130. *Id.* at 2.

131. *See* BONNEVILLE POWER ADMINISTRATION, THE COLUMBIA RIVER SYSTEM INSIDE STORY 5 (2001) *available at* http://www.bpa.gov/power/pg/columbia_river_inside_story.pdf.

132. AMERICA WIND ENERGY ASSOCIATION, WIND INDUSTRY STATISTICS (2004) *available at* http://www.awea.org/faq/tutorial/wwt_statistics.html.

133. *See* MARK D. JACKSON, ENERGY: THE BATTLE OF ECONOMY VS. ECOLOGY *available at* http://www.science.fau.edu/chemistry/mdj/chm3085/energy.prn.pdf.

value of the wind development to the developer, which takes the form of energy and capacity payments (in addition to the Federal Tax Credit, that provides a subsidy to wind developments in addition to payments gotten from the electric utility[134]).

Studies conducted by utilities and consultants around the country provide a range of integration costs from $1.47 to $5.50/MWh.[135] The range of costs is likely due to the differences in these utility systems, including different generating mixes, load shapes, wind regimes, and restructuring status. The utilities represented in these studies are all quite different, and as such, this range likely represents a range of costs that would be found in most systems around the country. The bottom line of these studies is that the cost of integrating wind power is generally low.

While all wind farms get payments for some or all of the energy they produce, few also receive capacity payments, due to the variability of the wind. Geographically dispersing wind farms and considering their output together rather than individually, significantly reduces the variability of the wind system. In the three site system analyzed in North Carolina, geographical dispersion during the January peak period could allow for a capacity credit of 340 kW, out of a maximum turbine capacity of 1650 kW. Geographical dispersion during the August peak period could allow for a capacity credit of 110 kW.

Several simplifications and assumptions were made in this analysis, which if this study was to be expanded, should be addressed. An expanded analysis would include more than one year of data, an analysis of time periods other than the two annual peaks, inclusion of transmission and distribution constraints, time series modeling, and further analysis of energy storage.

134. 26 U.S.C. § 45 (2000).

135. SMITH, ET AL., *supra* note 7, at 8.