Short Term Output Variations in Wind Farms — Implications for Ancillary Services in the United States

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Abstract:

This paper reviews changes in the marketplace that affect wind and other renewable energy technologies with the advent of competition in the electric power market place and discusses the role of Federal and State policies in the recent wind installations in the United States. In particular, it reviews the implications of ancillary service requirements on a wind farm and presents initial operating results of monitoring one Midwest wind farm. Under Federal energy policy, each generator must purchase, or otherwise provide for, the ancillary services, such as dispatch, regulation, operation reserve, voltage regulation and scheduling required to move power to load. As a renewable technology that depends on the forces of nature, short term output variations are inherently greater for a wind project than for a gas-fired combined cycle or a supercritical coal-fired unit.

Introduction

The wind farm phenomenon initially occurred in California in the early 1980s because of the confluence of favorable Federal and State tax policies, excellent wind resources and favorable regulatory treatment that provided, in some cases, guaranteed contract prices (inflation adjusted) for 10 years based on projections of oil prices that were as high as $32/bbl in the early 1980s. In 1985 over 485 MW were installed bringing the total capacity to over 800 MW. For several reasons, the Federal tax credits for wind energy were allowed to expire in 1985 when credits for other renewables were extended, then the price of oil fell to less than $20 per bbl, and electric utilities began to switch to natural gas. Because holders of interim standard offer contracts were given 10 years to develop them, additional construction continued at a slower pace after 1985 through the early 1990s. Today, as shown on the map in figure 1, about 1600 MW is installed in California.

The Energy Policy Act of 1992 (EPAct) was enacted largely in response to the invasion of Kuwait. It provided incentives for adoption of many energy efficient and alternative energy technologies (including a 1.5 cent per kWh production tax credit for wind and closed-loop biomass discussed below) and authorized increased research and development for all energy sectors. One provision provided for equal access to all users of electric transmission lines and required transmission owners to charge all customers what they charged themselves and to publish rates and line usage on a real time basis. This set the stage for what would later become FERC order 888 that provided that each generator either provide, or pay for, its own ancillary services.[1] In addition, two years after EPAct, the California Public Utility Commission proposed deregulation of the electric power sector and that proposal culminated several years later with legislation that changed the fundamental regulator structure in California and has been followed in many fashion in other portion of the United States. The general model is to provide for competition in generation, transmission as a common carrier operated by a regional transmission organization (as FERC would later call it, abbreviated RTO) or a independent system operator, sort of like a super power pool, and continued regulation of the distribution system. Customers would be allowed to choose their generator(s). During the transition from regulated monopoly to competition, such recovery of stranded costs of assets such as nuclear power plants are provided by a surcharge on customer bills as are promotion of certain socially-desirable causes such as renewable energy. The surcharge on customer bills is often called a System Benefit Charge (SBC) or Competitive Transition Charge and has proven important in recent deployment of wind and other renewables. Other policies are also important as discussed below.

In the United States, the market for wind energy was quiet in the early 1990s. Kenetech Windpower installed the first windfarm outside the United States in 1994, selling to Northern States Power Company. A slightly larger project for sales to

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[1]Reference order 888

the Lower Colorado River Authority was competed in 1995. A 6.6 MW DOE/EPRI turbine Verification project was installed in the Davis, Texas mountains in 1996 by Zond Systems and a similar project at Searsburg, Vermont a year later. However, in 1998 and 1999, almost 1000 MW in new projects and 200 MW in "re-powered projects", i.e. replacement of older technology by new state-of-the-art technology often by replacing 10 turbines with one 600 to 750 kW model, were installed. **What was the motivation?**

Wind turbine technology has improved substantially over the last 10 years. Without subsidy, cost of energy dropped from 9-12 cents per kWh to 5-6 cents in better wind resources. In addition, the availability of the Federal Production Tax Credit, provided by Section 1914 of EPAct, allows an inflation adjusted 1.5 cent per kWh credit to project owners for production in the first 10 years of operation for eligible projects.[2] Wind projects installed between January 1, 1994 and June 30, 1999 were eligible. In addition, repowered projects in which the value of the new equipment was 80 percent of the value of the project were included. Assuming a typical financial structure of an independent generating company, this would allow a bid price to be reduced from 5 cents per kWh to 4 cents or less.[3] Projects installed in 1994 and 1995 were bid at 5 cents per kWh, projects later in 1997 about 4 cents and recent projects are reported close to 3 cents per kWh and sometimes less. On the other hand, a green field natural gas combined cycle plant might be installed in three-years and provide firm energy at 3 to 3.5 cents per kWh. So, the point is not that the PTC makes wind competitive with natural gas, but it significantly reduces the gap.

While all projects installed in recent period have used the PTC, their motivation usually reflected a preference for wind or other renewable energy expressed through State policy and/or customers' demand. For example, as a legislative compromise to allow Northen States Power Company (NSP) to store spent fuel in dry casks on the grounds of the Prairie Island nuclear power plant, NSP agreed in 1994 to purchase energy from 425 MW of wind projects and 100 MW of biomass by 2002. This legislation has led to the 25 MW former-Kenetech plant installed in 1994, two 100 MW projects by Enron Wind installed in 1998 and 1999 respectively, and two 11.5 MW projects by Northern Alternative Energy (NAE). NAE also has a distributed wind project under development. In the neighboring State of Iowa, two major utilities eventually agreed to purchase of energy from 250 MW of wind plants. In Texas, the Lower Colorado River Authority purchased energy from the first wind plant in that state in 1995 {check). Moreover, in Texas, as a result of exploring customer preferences, Central and Southwest Services signed a contract for output of 75 MW wind plant near McCamey and TXU Electric for 44 MW near Big Spring. Both projects are located on top of mesas and operated by the end of June 1999. These mesas project several hundred feet above grade level, providing excellent wind resources that were never envisioned in the original wind atlas of the United States because the geographical detail were too coarse. Another State policy is the renewable energy portfolio standard (RPS) in which a State sets a goal for X percent of electric power in the State to be supplied from renewable energy sources by a certain time. Ten States have enacted an RPS; the largest being Texas' with 2000 MW to be supplied by 2009. States also can elect to support renewables through System Benefit Charges or Competitive Transition Charges (CTC). The CTC in California finances many programs including renewables R&D and a wind-only least cost auction. The California SBC was recently extended for 10 years, with the details of support to be determined over the next several months.

Green pricing and green marketing programs offer customers of electric utility systems the opportunity to choose suppliers. Credit must be given to Traverse City Light and Power in Traverse City , Michigan, for the pioneering effort in which 300 customers agreed to pay a premium to receive electricity from a wind turbine.[4] Example of utility programs include WindSource in Colorado in which customers sign up for 100 kWh block of wind energy for a $2.5 premium above existing rates. In that program, 20 MW have been brought on line. {need cite}. In deregulated markets a number of firms offer a blend of renewables or wind-specific products; moreover, several commercial firms, light manufacturers and even municipalities such as the City of Santa Monica have signed up for wind and /or other renewables. More than 60 green pricing programs are offered by regulated utilities, leading to over 60 MW of wind development. Green marketing programs are offered in at least seven states, providing at least 40 MW of new development.

In summary, the deregulated market place often seems weighted against wind and other renewables, but the very fact of deregulations allows for customer choice that appears to favor green energy quite strongly. Moreover, the transition from regulated to deregulated environments allows States to develop programs such as System Benefit Charges to promote renewables. The aggregate impact of these policies is shown in Figure 2 in which by the end of calendar 2001, when the initial

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[2]The PTC is now 1.7 cents per kWh.

[3] Wind Program modeling shows a 1.1 cent per kWh difference in the bid price.

[4] More info is at ????????

extension of the PTC is set to expire[5], Almost 2,000 MW of new wind energy capacity is expected to be installed in 2000 and 2001 as a result of the combined effect of energy policies and customer choice.

Table 1 compares the old and new market places {New versus old marketplace}. Under the old market, renewable generators were most often small power producers under Section 210 of PURPA who had to sell product to the local utility at avoided cost. In the new paradigm, all generators are deregulated and can seek customers throughout the service territory. The transmission system becomes a common carrier, while distribution services are regulated. The challenge for wind power is that it is a low capacity factor, intermittent source, often located remote from load. If wind transmission were to be priced on a traditional per MW-year basis, wind would be disadvantaged because of the low capacity factor and distance involved. This is why the National Wind Coordinating Committee, a multi-stakeholder group organized to support the appropriated deployment of wind energy in the United States, has issued a consensus set of principles for treatment of wind energy by the emerging Regional Transmission Organizations.[6] As part of assuring that all generators are treated fairly, FERC has rules that each must pay for, or provide, its own ancillary services, including dispatch, regulation, operating reserve, unit and transmission scheduling, etc. These were never considered under PURPA; rather costs for ancillary services were rolled into customers bills. Now, they have to be paid for explicitly when RTOs are fully implemented. The one thing we know in the United States is that the variation in output from the windfarm is likely to be greater that the variation from the gas-combined cycle and thus, the wind plant may pose a higher regulating burden on the system. Not only is the magnitude of the regulation and other ancillary service impact not well known, but because these are supplied by a competitive market, prices are unknown at this point. The next section of the paper reviews results from early measurement programs to provide more information on output variations that would affect regulation.

Wind Powering America — A New Initiative

Secretary of Energy Bill Richardson announced the Wind Powering America initiative in June 1999. It recognized that wind energy was becoming closer to cost competitive, that wind energy provides rural economic benefits and had a place in the National energy portfolio. Consequently, he established three goals: 1) provide 5 percent of the nation's electricity by 2020, 2) Double the states with 20 MW or more to 16 States by 2005, and to 24 States by 2010, and 3) Provide 5 percent of Federal electricity use by 2010 (1000 MW). The first goal corresponds to 80,000 MW. That might seem like a stretch from today's roughly 2500 MW, but the United States had lots of wind resources on-shore, the cost of the technology is expected to decline while performance increases, and wind development when properly sited is compatible with the environment and leaves much of the land spanned by turbines available for farming, ranching or other uses. The details of the program will be determined on a regional basis, not from Washington. The role of the Department is to proved resources to leverage interest, demonstrate Federal leadership through purchase of green energy and providing the proper policy environment, and to coordinate results and share success. To date, at least ten meetings have been held in locations throughout the United States, and early signs of success can be observed[7]. For example, Federal agencies in the Denver area banded together to offer a purchase of 10.7 MW in wind energy at a cost of 2.5 cents per kWh above existing costs. This is expected to lead to an equivalent amount of new wind capacity to serve this need.

Variation in Wind Power Output

Very little public domain data is available for existing wind power plants, making it difficult to draw general conclusions about how short-term wind power output affects grid operation. However, there have been no problems in this regard integrating 800 MW in CA wind farms in to a stiff grid. Curtailments in Tehachapi, CA (USA) during high winds have occurred, but many of these were primarily caused by transmission network weaknesses that have corrected. Some of these curtailments continue to occur, and are a result of nuisance under-voltage tripping. The cause of this has not yet been determined.

Several researchers have examined the effects of wind output variability on system operation. For example, Javid, Younkins, et al. (1985 IEEE/PES) found no problems at wind penetration rates in the range of 10-15%. Chan, Power, et al. (PES 1983) find that there is very low risk of a significant decrease in wind output within a 10 minute interval.

To address short-term variability of wind power plants on system operation, The National Renewable Energy Laboratory has

[5] Both the Gore and Bush campaigns support PTC extension beyond 2001.

[6] See http://www.nationalwind.org for more information

[7] See http://www.eren.doe.gov/windpoweringamerica for more information.

entered into a subcontract to collect wind power data from two locations in the Midwest region of the United States. Data includes real power, reactive power, 3-phase line-to-ground voltages, and wind speed data. The objectives of the project are to collect high quality, long-term high-frequency data from a wind power plant from several sites with different geographic characteristics and from several types of wind turbines. The goal is to obtain at least two years of data from this project, so that a detailed analysis of power fluctuations can be performed on a high-resolution time scale. This will help us obtain a better understanding of the frequency distribution of wind power, the relationship of wind power plants to ancillary services in the emerging electricity markets, spatial and temporal diversity and correlation issues, and wind capacity credit.

There are other important uses for this data. For example, we can obtain a better understanding of local micro siting effects, and examine various correlation statistics between different wind turbines. This will help us assess the smoothing effect of aggregate power from a large collection of wind turbines. If the data can also be matched with utility load, cost, and/or market data, we can obtain estimates of the value of capacity that wind power plants contribute to the grid. The data could also play a useful role in the evaluation and field testing of various wind-forecasting methods.

The data is collected and downloaded to the NWTC each day via modem. As a backup, the data is also written to a local removable disk that is replaced and sent to NREL every two weeks as a backup measure. Some data has already been collected, and preliminary analysis has been done. From these data sets it is possible to calculate various patterns of electricity production, ranging from second-to-second scales up to monthly. We can compare power and energy output of individual turbines with total wind farm output, and can calculate various coincidence factors and examine hourly production profiles.

Figure 1 (Jack's pic 1) shows an example of a daily profile, obtained from four monitoring points within the wind farm. The graph is based on 1-minute average data, and shows the power output at each of the four points, along with the total wind power output and a reference wind speed. For this 24-hour period, we can see that the total wind power is near maximum output for three distinct periods: from about 4:00-8:00, from about 9:00-12:30, and from about 17:00-23:00. The two downward spikes near the 8:00 and 9:00 hours are caused either by over-voltage problems, similar to what has occurred in Tehachapi, CA, or by transmission network problems, such as a line overload. The downward trends in the early afternoon are also most likely due to network problems. Other data that has been collected so far also shows some downward spikes during periods of extreme wind.

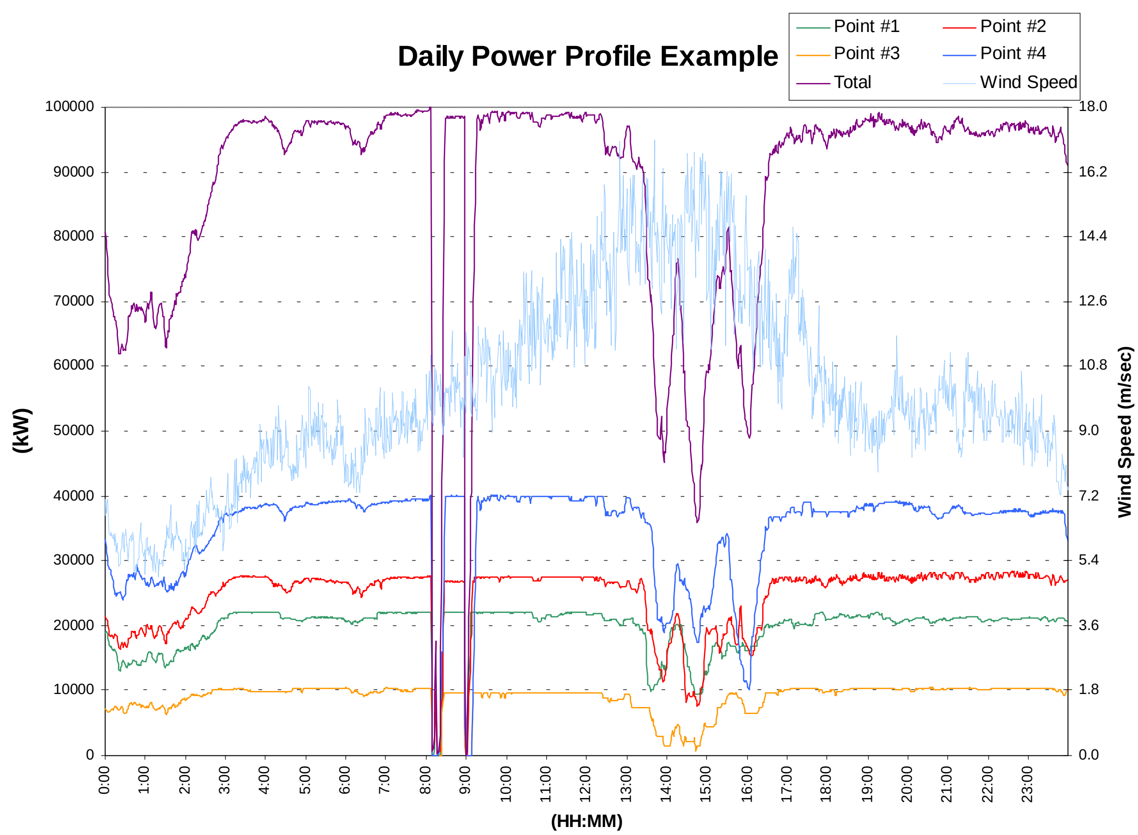

Fig 1. Daily power profile example from NREL's data monitoring project

Figure xx-2 (Figure 4.4 from Yih-huei's draft report) illustrates the propagation of a wind gust through the wind park, using 1-second data. The graph clearly shows the increase in power output at each of the four monitoring sites, and this pickup occurs with a time lag that corresponds to the passage of the gust. The total power output reaches a peak at 21:33:33, although the last interconnection point to peak does not do so until about seven minutes later. The time interval between the peak at the first site and the peak at the last site is about sixteen minutes. The graph also shows the total output of the wind park during this period, and we can see that this total output is sustained and with less variation than at the individual data collection points. The coincidental peak is 55,740 kW, which occurs just after 21:33, whereas the non-coincidental peak for this period is 69,250 kW. By calculating the ratio of the coincidental peak to the non-coincidental peak (80.5% in this case) we obtain a measure of the degree of power production diversity. The smoothing effects found in this data corroborate that found by Ernst (NREL tech report on the web...get the citation) and by Milligan and Factor (PMAPS) using hourly data.

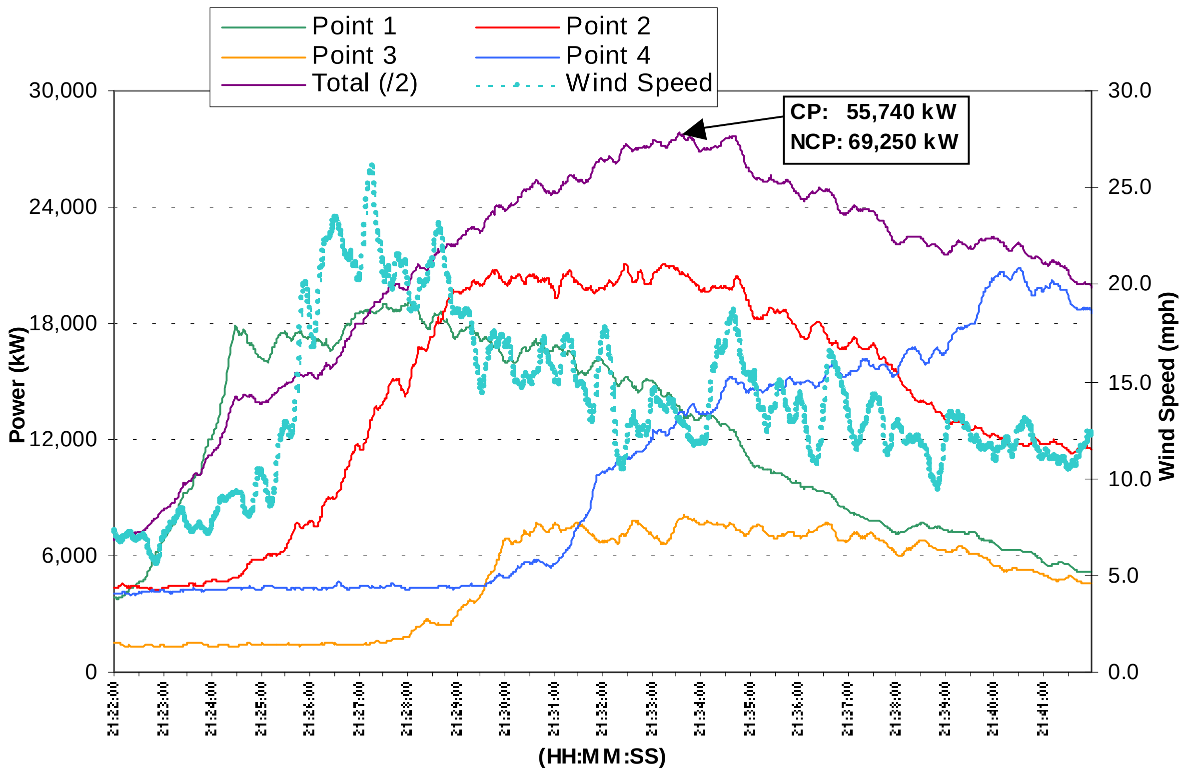

Fig. 2. Example of smoothing effect as a gust is propagated through the wind farm

Conclusions and Future Work

As the utility industry moves deeper into restructuring, knowledge of wind power variations and the role that these variations play in the provision of ancillary services will be vital. Analysis and anecdotal evidence suggest that as wind provides power to the grid with a modest penetration rate, that this variation should not pose significant problems to grid operation or impose excessive ancillary services burdens on the wind power plant. However, additional data analysis would help shed more light on these important issues, particularly because of the different characteristics found among wind sites and the correlation with local grid properties. Given these differences, it will be important to investigate mitigation strategies that can be adapted to new locations.