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The Full Cost of Renewables: Managing Wind Integration Costs in California

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LIST OF ACRONYMS

AB 32	Assembly Bill 32 (Global Warming Solutions Act of 2006)
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CCGT	Combined Cycle Gas Turbine
CPUC	California Public Utilities Commission
DAM	Day-Ahead Market
DSM	Demand Side Management
HASP	Hour-Ahead Scheduling Process
IFM	Integrated Forward Market
MAE	Mean Absolute Error
MW	Megawatt (unit of power; measures a flow)
MWh	Megawatt (unit of energy; measures a stock)
PIR(P)	Participating Intermittent Resource Program
RMSE	Root Mean Square Error
RPS	Renewable Portfolio Standard
RTED	Real-Time Economic Dispatch
SCE	Southern California Edison

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CHAPTER I: INTRODUCTION

"Warming of the climate system is unequivocal. Most of the global average warming over the past 50 years is very likely due to anthropogenic GHG increases. Unmitigated climate change would, in the long term, be likely to exceed the capacity of natural, managed and human system to adapt" (IPCC, 2007).

With these words, the International Panel on Climate Change concluded in its Fourth Assessment Report that ignoring global climate change was no longer an option. Amidst a sea of mounting evidence – rising global air and ocean temperature anomalies, thermal expansion of the world's oceans, melting Arctic sea ice, and a correspondent increase in atmospheric concentrations of greenhouse gases (GHG) – the panel confirmed that human activity is significantly altering the Earth's climate. Moreover, multiple studies have demonstrated that continued global climate change would be an environmental and economic catastrophe of unprecedented scope, threatening "the basic elements of life" (Stern, 2006).

In the past few years, much focus has shifted away from whether the mitigation of climate change is a good idea, to how it might best be accomplished. Despite some public opposition and the lack of a single sweeping climate policy, the United States has begun to pursue a number of options to reduce GHG emissions and mitigate global climate change. Five of the largest pathways to GHG reduction are improved efficiency in buildings and appliances; reducing transportation emissions through improved fuel standards and alternative fuel sources; adjusting operations in the industrial sector to reduce emissions; improving the world's stock of carbon sinks such as forests; and shifting the production of electric power to renewable sources of energy (McKinsey, 2007).

However, in the absence of comprehensive federal action, the momentum for dramatic cuts to GHG emissions has largely fallen to the states. California, in particular, has enthusiastically embraced the challenge of comprehensive reform. The state adopted AB 32, the Global Warming Solutions Act of 2006, which requires the state to reduce its GHG emissions to 1990 levels by the year 2020, an ambitious challenge illustrated below (Figure I-A). This bill authorizes a cap and trade program, a market mechanism designed to find the most cost effective way to reduce GHG emissions across the entire California economy. However, the state also has a number of performance standards, including a renewable portfolio standard (RPS), which requires that by 2020, a minimum of 33% of electricity consumed in the state be provided from renewable sources of energy (CARB, 2008).

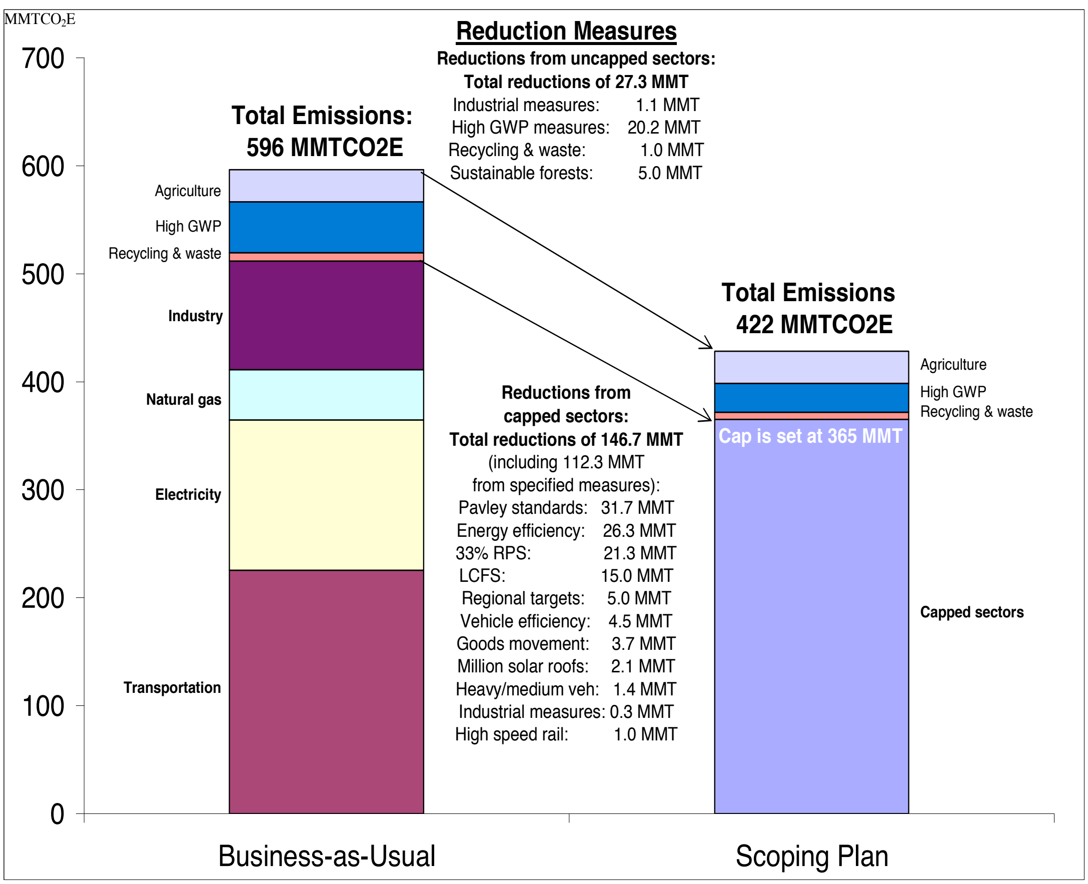

Figure I-A Planned GHG reductions under AB 32 (CARB, 2008)

Within renewable energy, a number of technologies exist that can potentially offset the combustion of fossil fuels and the associated emissions of CO_2. Electricity can be produced by harnessing power from the earth's internal heat, solar irradiance, solar heat, wind, rivers and tides. Wind power has gained particular interest, due to a combination of technological maturity, high expansion potential, and low costs. The levelized cost of energy from a wind farm is quite low, and even starting to approach cost-competitiveness with some forms of conventional generation, as shown below (EIA, 2010).

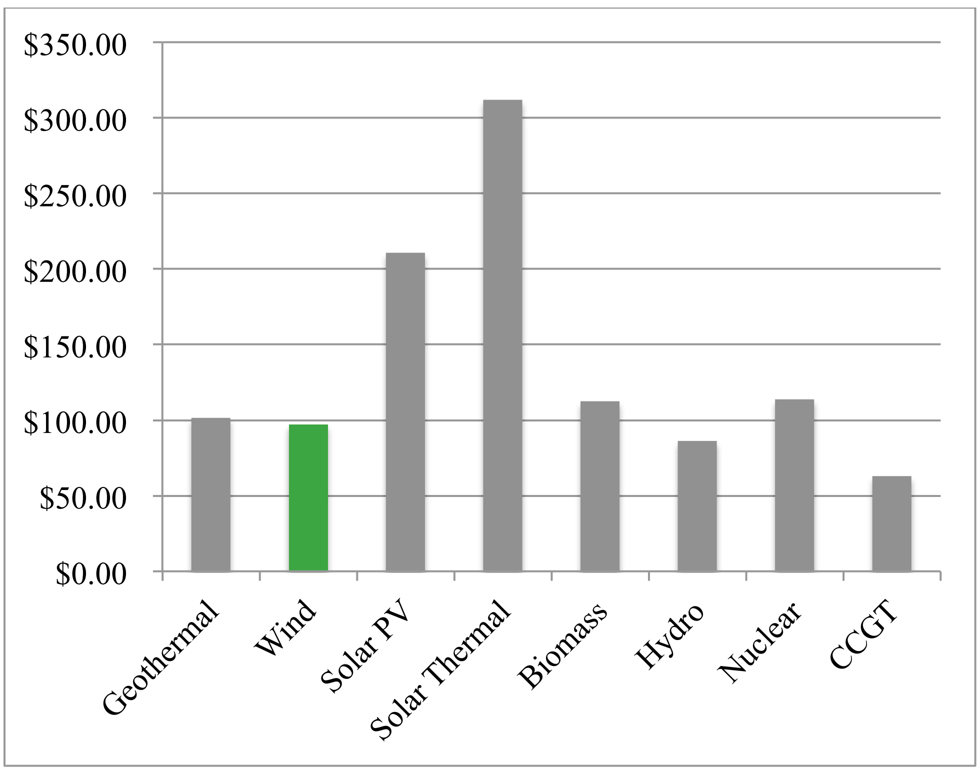

Figure I-B Levelized cost of energy comparison by technology, $/MWh (EIA, 2010)

For that reason, wind is frequently cited as a key component in reducing GHG emissions. A simple cost-effectiveness analysis takes the lifetime cost of wind energy versus the lifetime cost of providing the same amount of energy from conventional generation, calculates the difference as the "renewable premium", divides that by the quantity of GHG emissions avoided by using renewable energy, and ends with an estimate of cost per ton of CO_2 avoided by using wind power.

However, the costs of building and operating a renewable power generator do not paint a complete picture. Due to their unpredictable and variable generation profiles, renewable sources of energy such as wind impose a unique burden on the rest of the electric power system. In order to accommodate this less reliable renewable power, the remaining conventional generation units must deviate from their optimal operating profiles, increasing their costs and potentially releasing additional GHG. Although this burden is conceptually understood, it is not explicitly valued in the market today. Thus, when analysts and policymakers discuss the cost-effectiveness of renewable energy as a GHG-reduction strategy, a key element is missing from the cost side of the equation, known as wind integration costs

The goal of this paper is to understand the role of wind integration costs in the broader context of California's GHG reduction goals. Specifically, I seek to answer how integration costs can be understood, minimized, and allocated, so that GHG reductions can be as cost-effective as possible. Proper treatment of integration costs should have two effects: first, to decrease the social cost of wind power as a GHG reduction strategy, and second, to help drive the market to cost-effective mix of GHG reduction strategies.

Notably, many other benefits of renewable energy have been ignored. There may be other reasons to pursue renewable energy, even if it is not cost-effective from a GHG standpoint alone. These other benefits are frequently said to include reduced local air pollution from nitrous oxides, particulate matter and sulfur dioxide; improved national security by decreasing America's reliance on foreign sources of fuel; the alleviation of resource depletion concerns; domestic job creation through green technology infrastructure investments; and promoting price stability by hedging against swings in the price of fossil fuels, especially natural gas. While acknowledging that these other effects are potentially valuable social goals, they are beyond the scope of this paper.

Why does this question require an academic focus? Simply put, policymakers must understand the costs of GHG reduction because the market does not. A central goal of environmental economics is to achieve socially optimal levels of pollution reduction at the lowest possible cost. According to the equimarginal cost principle, when there are multiple pathways to accomplish a goal – in the case, several ways to reduce GHG – society should pursue all the options in such a way to equalize the marginal cost of all pathways. The proof of this is well understood in microeconomics.

In well-functioning markets, the equimarginal principle should be satisfied without government intervention. The ability to trade theoretically ensures that all opportunities for cost savings are found, leading to Pareto efficient outcomes. However, when economic externalities exist, private actions fail to lead to the lowest possible social cost, and society is leaving money on the table. Wind integration costs are a classic example of a negative externality.

Pro-wind advocates might argue that this negative externality is outweighed by the positive externality of avoided GHG emissions, and in many cases, this could be true. However, California's recent policies have begun to explicitly value the renewable attributes of wind power. The combination of the 33% RPS, which requires utilities to use renewable sources of energy to provide power, and the AB 32 cap and trade program, a market mechanism which puts a price on carbon, have internalized the positive externalities of wind. The negative externalities of wind, on the other hand, have been largely ignored by policy, and could distort the power of markets to find least-cost ways to reduce greenhouse gases.

Chapter 2 will review in more detail the physical impacts of including wind in California's electric generation portfolio. While the issues surrounding wind are nontrivial, they are manageable, and should be the subject of serious analysis, not hyperbole and conjuncture. I start by reviewing the basics of system operations today, which importantly, already manage significant amounts of variability and uncertainty. I then show what happens when wind increases the variability and uncertainty.

Chapter 3 shifts the focus from operations to economics, by looking at the general scope of integration costs. A substantial – but largely opaque – literature from the United States and Europe offers a decent consensus on the order of magnitude of integration costs, as well as some of the key variables and sensitivities that drive costs. Some of the key variables I discuss relate to physical characteristics of the electric grid and wind resources. These parameters are important to understanding wind integration costs, though they offer little help in the policy realm.

Chapter 4 discusses how wind integration costs can be minimized and allocated through the details of electricity market structure. After a dry but necessary review of California's electricity markets, I discuss six aspects of market design that represent feasible policy levers. By engaging some or all of these levers, California could optimize its market design to better accommodate wind, and internalize the externality of wind integration costs.

Chapter 5 offers three concluding thoughts. First, the inclusion of wind integration costs is a necessary part of policy discussions surrounding GHG emissions. Second, technical and mundane-sounding market design and policy issues can have a major impact on integration costs. Third, the importance of integration costs will only rise, so it makes sense to act now rather than deal with them later. Renewable energy has an important role to play in 21st century society, but to properly achieve its benefits, we must also recognize – and manage – its costs.

CHAPTER II: PHYSICAL MANAGEMENT OF WIND POWER

The cost of integrating renewable power can be generally defined as the cost of all actions taken to maintain the reliability of the electric grid in response to the uncertainty and variability of renewable power. This chapter will explain, from a physical operations perspective, exactly what those actions are. In order to do so, however, it is necessary to begin with the basics of electric power operations.

2.1 Traditional System Operations

The day-to-day job of electric system operators is organized around one central goal: maintaining the reliable flow of electricity to customers, or more colloquially, "keeping the lights on". In order to do this, groups known as balancing authorities maintain careful control over the electric grid at all times. Each such organization is responsible for maintaining reliability within a certain geographic region; for example, the California Independent System Operator (CAISO) is responsible for maintaining the reliable supply of power to most of California.

In order to maintain reliability, each balancing authority much match the supply and demand for power within its territory at all times. The demand for power is known as "load", and represents the sum of electricity being drawn by residential, commercial and industrial customers. This power is supplied by electric generation from power plants, such as coal-fired steam power plants, nuclear generation stations, hydroelectric dams or wind turbines. Power can also be imported or exported from one balancing authority to another.

One crucial feature of electric power is that, generally speaking, it cannot be stored. Most consumer goods are produced, put into inventory, and then sold whenever a customer wants to buy them. Electricity has no such "shelf life". When electricity is generated at a power plant, it must be consumed instantly. Therefore, balancing authorities must make sure that the amount of power being generated is equal to load, not just in the aggregate, but at any given instant. If generation exceeds load, it will increase the frequency of the alternating current power that flows through transmission lines, and vice versa. By convention, electric devices in the United States are designed to operate using an alternating current at a constant, 60-hertz frequency. Even small deviations to this frequency can cause serious damage to electrical equipment, and can trigger generator trips or load shedding to avoid a system emergency.

Even without intermittent renewable technologies, the task of instantaneously balancing load and generation is a significant challenge for system operators. As a general rule, system operators cannot control the amount of load that customers demand at any given time. Therefore, they must forecast the expected load, and then plan ahead so that enough generation will be available to meet demand.

For example, on any given morning, the CAISO will estimate the hourly load profile for the next day. The ISO might estimate a load of 16,000 MW for the hour of 12am to 1am, a load of 15,000 MW for the hour of 1am to 2am, and so forth. Then, power plants can submit bids to provide this energy. The ISO will accept as many bids as necessary to meet projected demand, starting with the lowest-cost bids and moving up the cost curve. Based on the results of this bidding process, the ISO will produce an energy schedule, which specifies which power plants will generate power, when they will generate power, how much power they will produce, and how much they will be paid. It also issues daily unit commitment instructions, so that power plants with long start-up times can turn on or off (CAISO, 2010a).

However, this process is imperfect. The actual load drawn by consumers does not follow the neat forecast assumed during the planning process. For example, the forecast of 16,000 MW for 12am to 1am is almost certainly wrong. Specifically, three types of errors are possible. First, the estimate of load could be biased. For example, during the first hour of the day, customers could use more total energy than expected. Second, the load could rise or fall during the hour, giving it an intra-hour load shape. For example, customers might use 17,0 00 MW at 12am, and decrease their usage to 15,000 MW by 1am. Third, the load could fluctuate randomly about the average of 16,000 MW, creating a sawtooth pattern. All three of these possibilities are both realistic and common in normal grid operations, and are illustrated below.

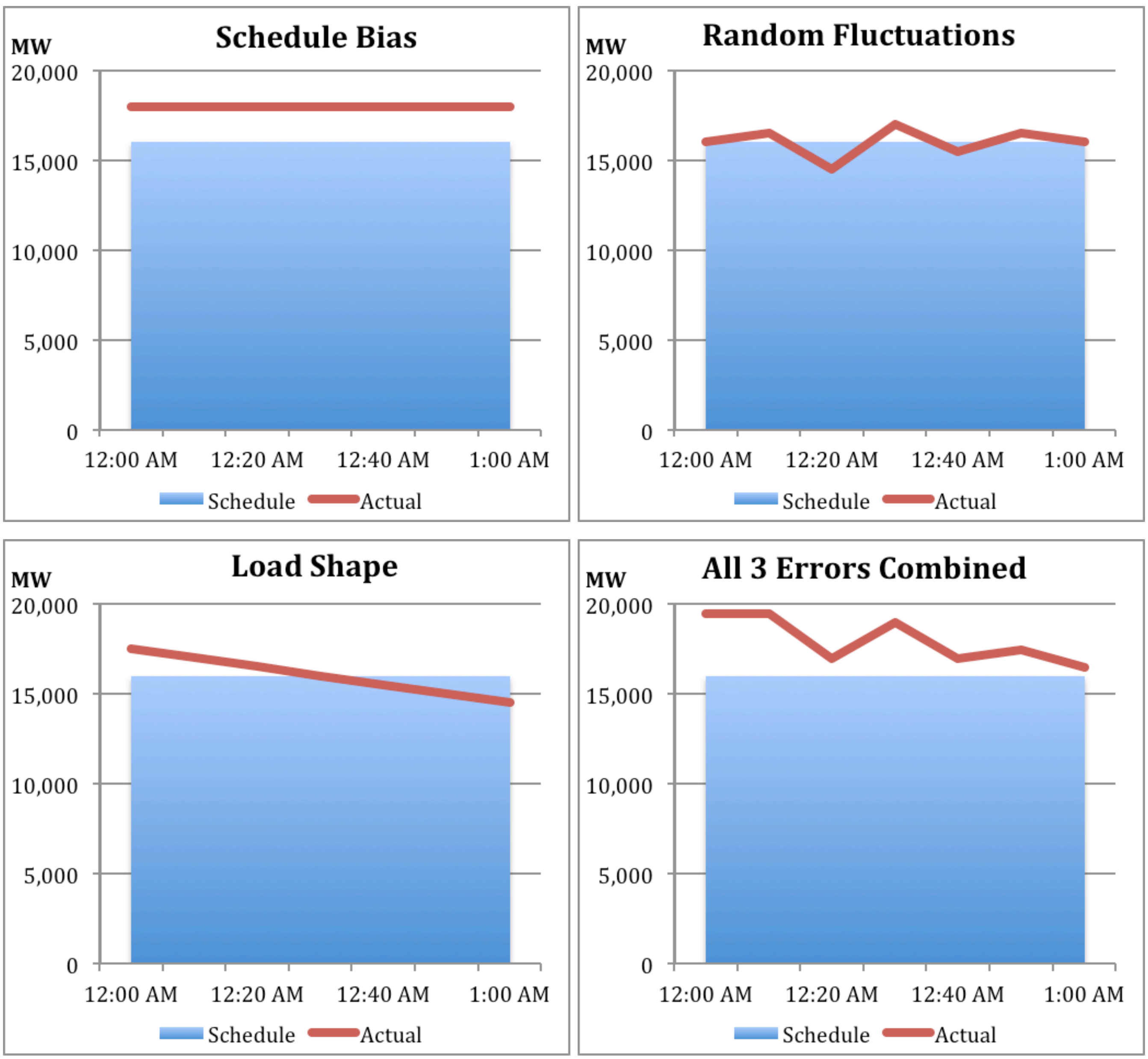

Figure II-A Different types of load error

In addition to load uncertainty, there is also a possibility that expected generation will be unavailable. For example, a fire might damage a transmission line scheduled to provide power from a distant source, or a mechanical failure could force a natural gas plant to shut down. While it is impossible to prepare for every possible contingency, grid operators include the possibility of these unexpected events in their planning process.

In short, "irrespective of current and future levels of wind generation, power systems are already required to cope with significant variability and intermittency concerns" (Fox et. al, 2007). The issues of uncertainty and variability, so often associated with renewable power, already exist in electric systems. Operators manage these issues using "ancillary services", which are used to match generation and load at a more granular level.

A power plant is said to provide ancillary services if a certain portion of its capacity is set aside to be flexible. In addition to simply providing energy, power plants can choose sell the ability to accommodate changes in demand on short notice. For example, a 100-MW gas-fired power plant might provide 80 MW of steady power, and also offer the ability to increase or decrease its generation by up to 20 MW. The capacity set aside for the purpose is known as the operating reserve.

Power plants can offer several different types of operating reserves, differentiated primarily based on how fast they can respond to a dispatch order requiring them to increase or decrease generation. Unfortunately, there is no single set of ancillary service definitions; the names and exact technical specifications vary among different balancing authorities and countries, largely as a matter of convention. However, there are a few common categories.

Almost all balancing authorities will have some kind of fast-responding ancillary service, variously known as frequency regulation or primary control. Regulation service is designed to respond on the order of seconds, and is controlled by an Automated Generation Control (AGC) system. This allows generation to automatically adjust to small fluctuations in load (Rebours et. al, 2007).

Balancing authorities also have ancillary services that allow manual adjustments to generation, which are generally slower in response time and larger in magnitude. Generally speaking, there will be different types of operating reserves for load following, imbalance energy and contingencies. Load following refers to the ability to track the shape of the day's load profile at a greater granularity than hourly schedules, and generally operates on the order of minutes. Imbalance reserves help to compensate for net schedule bias, and contingency reserves are in place to replace generation that could be lost in a system emergency, such as the loss of a major transmission line (Dragoon, 2010).

It would be economically infeasible – to say nothing of physically impractical – to have enough operating reserves to respond to every imaginable contingency. Instead, balancing authorities select a reasonable operating margin to provide a satisfactory level of reliability. The size of this operating margin is based on several factors, including the largest possible single contingency event, the availability of power plants connected to the system, and the expected error in demand forecasts (Ferris and Infield, 2008). Greater operating reserve requirements to maintain grid reliability impose a cost that is ultimately paid by electric ratepayers.

These ancillary services are the means through which system operators manage uncertainty and variability. Currently, that operating challenge is driven by the characteristics of load. The addition of variable energy sources, such as wind power, will increase the magnitude of this operating challenge; however, the challenge remains conceptually the same.

2.2 Understanding Wind Power's Impact

Therefore, our first task in evaluating the cost of wind integration is to assess the extent to which wind power increases the requirement for balancing reserves. To do so, it is helpful to think of wind as "negative load". Since wind power can generally not be controlled, its behavior is more similar to load than generation. By subtracting the amount of wind generation from load, one creates a new "net load" profile. Then, balancing authorities must operate traditional power plants so that their generation matches net load, as opposed to raw load.

Due to the inclusion of wind power, net load will be more unpredictable and more variable than raw load. However, the techniques used to balance net load are the same ancillary services that are provided in traditional systems. Kirby and Milligan (2008) note that wind has many similar characteristics to load, and that the differences in managing the two are "more of degree than kind," as wind "add[s] to aggregate variability." The crucial question is how much of each type of ancillary service is required, and then how much will it cost.

In order to determine the impact of wind power on the reserve requirements for net load, it is important to first understand the characteristics of wind power generation. The power generated by a turbine is a function of wind speed, and has 4 distinct regions. Light winds will not generate any power at all; the minimum level of wind required to generate electricity is known as the cut-in speed, often around 4 m/s. From there, the wind power increases as a cubic function of wind speed, until the turbine reaches its maximum rated power output. Within this region, the output can change dramatically in response to even small changes in the wind. Once the rated power is reached, usually at 13-14 m/s, the wind speed can continue to increase but output will remain constant. However, if the wind reaches too high of a speed, often at 25 m/s, the turbines must shut down, or “cut off”, to avoid damaging the equipment. The sudden drop-off of power is another potential source of power variability (Laughton, 2007).

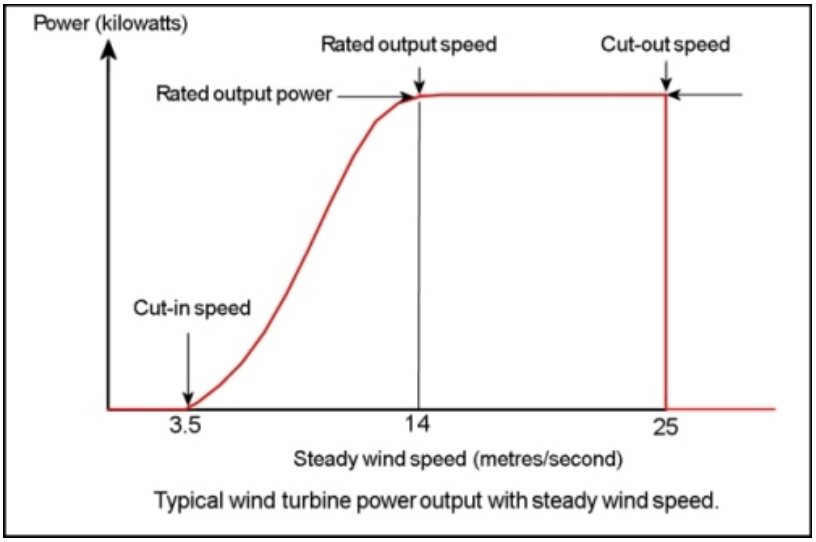

Figure II-B Wind power output as a function of wind speed

It would be easier to manage wind output if its fluctuations could be predicted. Unfortunately, despite a significant amount of investment, wind forecasting remains an inexact science. Meteorological models are available that forecast power output based on projected weather patterns and geography. For time horizons of just a few hours, though, the best predictor of future output is simply the current value of wind output. This approach, known as persistence forecasting, yields estimates that are unbiased over large samples, but are not especially precise. In other words, forecasts are accurate when averaged over many observations, but are not greatly reliable for any single data point. In fact, one study in Montana found that persistence forecasts with a look-ahead time of 60 minutes, while unbiased, had an average root mean square error of 20% (Dragoon, 2010). Forecast error can be somewhat reduced by aggregating forecasts over a larger area – for example, forecasts errors for all of Germany were 25% lower than forecast errors for one of Germany’s four balancing areas – but the problem remains substantial (Rohrig, 2005). Fox et. al (2007) find that the benefits of forecasting over a large area are greatest at short time frames, and fade with greater look-ahead times. A comparison of forecast errors between a single wind farm and 15 wind farms shows that with lead times of just a few hours, the aggregated forecast reduces error by 50%; however, day-ahead aggregated forecasts are only approximately 20% better than the single farm day-ahead forecast.

Even more than uncertainty, the variability of wind power is arguably its best-known characteristic. However, this variability follows certain recognizable patterns that are often glossed over. Specifically, the variability of wind power comes from several sources, including short, medium, and long term wind flutuations. At the most granular level, significant wind power variance can occur from second-to-second wind turbulence and gusts. This is especially true if a wind turbine is operating below its rated output, when its power will change with the cube of wind speed. If this variation is not smoothed out in some way, it can have a significant impact on power systems. However, variations on the order of 10 minutes are less significant. If the second-by-second variations are removed, the wind output during a given ten-minute period is likely to remain unchanged in the next 10-minute period, and the problem of intermittency seems much more manageable.

In the medium term, power output can follow daily patterns. For example, in California, wind power tends to be strongest at night and weakest during the middle of the day. Power output can also vary along so-called synoptic trends, following the passing of weather systems and storm fronts. Together, these medium term variations can cause significant variation in wind output. Finally, most geographic locations have some longer-term seasonal trend, such as particularly strong wind during the spring months in the Pacific Northwest (Ferris and Infield, 2008).

Similar to forecast uncertainty, variability can also be reduced if a system contains wind power from several sources. Ideally, a power system would receive wind power from several projects with uncorrelated output, so that random deviations would cancel each other out by the law of large numbers. The extent of these benefits depends on two factors: time-scale and geographic diversity. One heavily-cited study used German wind data from 230 sites over one year to quantify the correlation between different projects, and found that if output was measured at a short time scale, wind turbines tended to be uncorrelated (Ernst, 1999). 5-minute averages showed a correlation coefficient of almost zero if sited a few kilometers apart. In fact, for turbines just 170 meters apart, there was no observed significant correlation for second-by-second data; the correlation coefficient only exceeded 0.2 at a time scale of over a minute. In other words, even minimal geographic diversity can significantly decrease the second-by-second variability of aggregate wind output, and modest geographic diversity can decrease the minute-by-minute variability (Figure II-C).

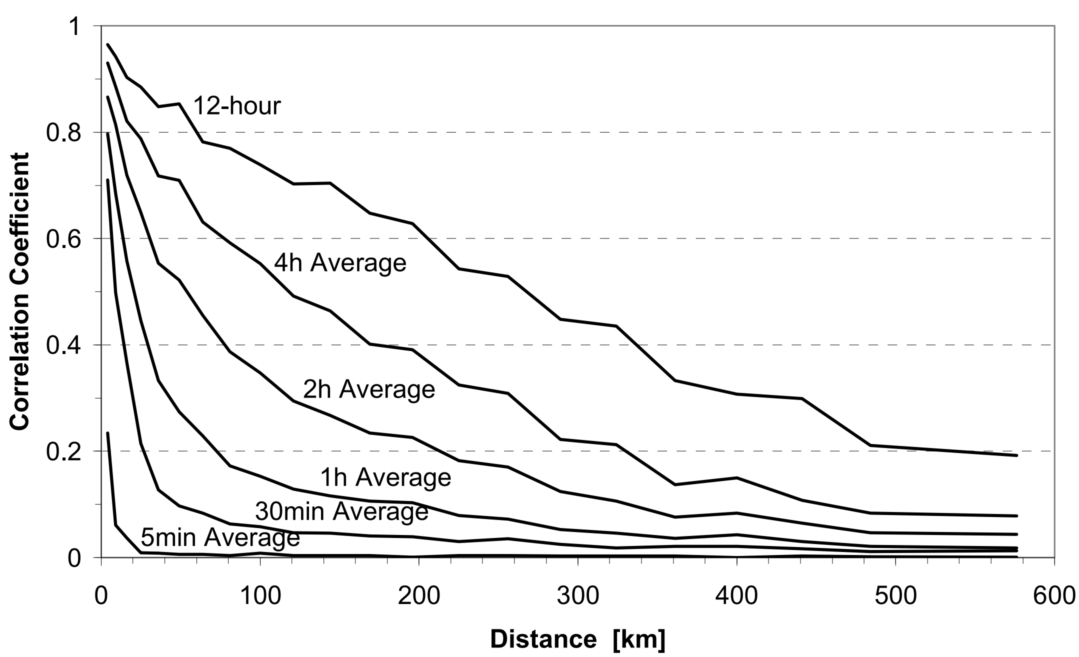

Figure II-C Correlations of wind farms related to distance, time intervals (Ernst, 1999)

However, those same benefits are less applicable to longer-term trends. Using 1-hour averages, wind project output maintains significant correlation up to 80 km apart, and 12-hour averages are significantly correlated for projects up to 500 km apart. This is an intuitively attractive result, as variations over longer time scales are caused by larger weather systems, which are more likely to affect all of the wind farms over a significant area, as opposed to more random short-term gusts.

A similar study in Western Denmark also found significant benefits of aggregation. This study examined the hourly change in wind generation as a percentage of installed capacity. For a single wind farm, changes of at least 10% of rated capacity occurred during 7% of all hours; for the aggregated wind fleet, however, changes of that magnitude only occurred during 1% of all hours. The operational implication is that geographic spacing can be a useful tool in reducing the need for impact of variability at shorter time scales; however, longer-term variability such as daily patterns will not be as easily solved.

2.3 Incremental Reserve Requirements

These trends of variability and uncertainty help determine the incremental reserve requirements; in other words, how much more balancing capacity is required to maintain reliability on a grid with wind than one without wind? One common misconception is to assume that all variability and uncertainty associated with wind power must be counter-balanced by a dedicated flexible power plant. This is simply not true. Kirby and Milligan (2008) describe how "the power system does not need respond to the variability of each individual turbine"; instead, the system must "meet the North American Reliability Corporation (NERC) reliability standards and balance aggregate load-net wind with a aggregate generation. Fortunately, wind and load tend to be uncorrelated, so they do not add linearly, greatly reducing the net flexibility required from conventional generation."

Reliability standards are typically proportional to the standard deviation of the differences between actual load and scheduled load, or the load errors. For example, NERC standards require balancing authorities to maintain sufficient reserves such that 10-minute errors can be contained within certain limits 90% of the time in each month (Dragoon, 2010). In other words, the required balancing reserves depend on magnitude of the 90th percentile error, which is directly proportional to the standard deviation for approximately normal distributions. As more wind is added to the grid, the standard deviation of net load errors will increase, requiring more incremental reserves.

However, as Kirby and Milligan explain above, the standard deviation of net load error is not simply the sum of the standard deviations of load error and wind error. Instead, the following relationship holds true:

$$\hat{\sigma}_{\text{Net Load}} \cong \sqrt{\sigma^2{}_{\text{Load}} + \sigma^2{}_{\text{Wind}}}$$

This relationship holds in equality if the distributions of wind error and load error are statistically independent. This assumption is generally reasonable, and actual data show only small deviations from the predictions of this equation (Dragoon, 2010; Kirby and Milligan, 2008).

As a result of this relationship, the incremental reserve requirements for net load are significantly less than reserve requirements would be to balance wind alone. In addition, the incremental reserve requirements are a non-linear function of wind variability. This relationship is graphed below, and shows an increasing marginal impact of wind power on system operations. The straight blue line represents the hypothetical incremental balancing requirements under perfect correlation, while the red curve assumes statistical independence. (Negative correlations, while uncommon today, might be achieved with dynamic demand response, to be discussed later).

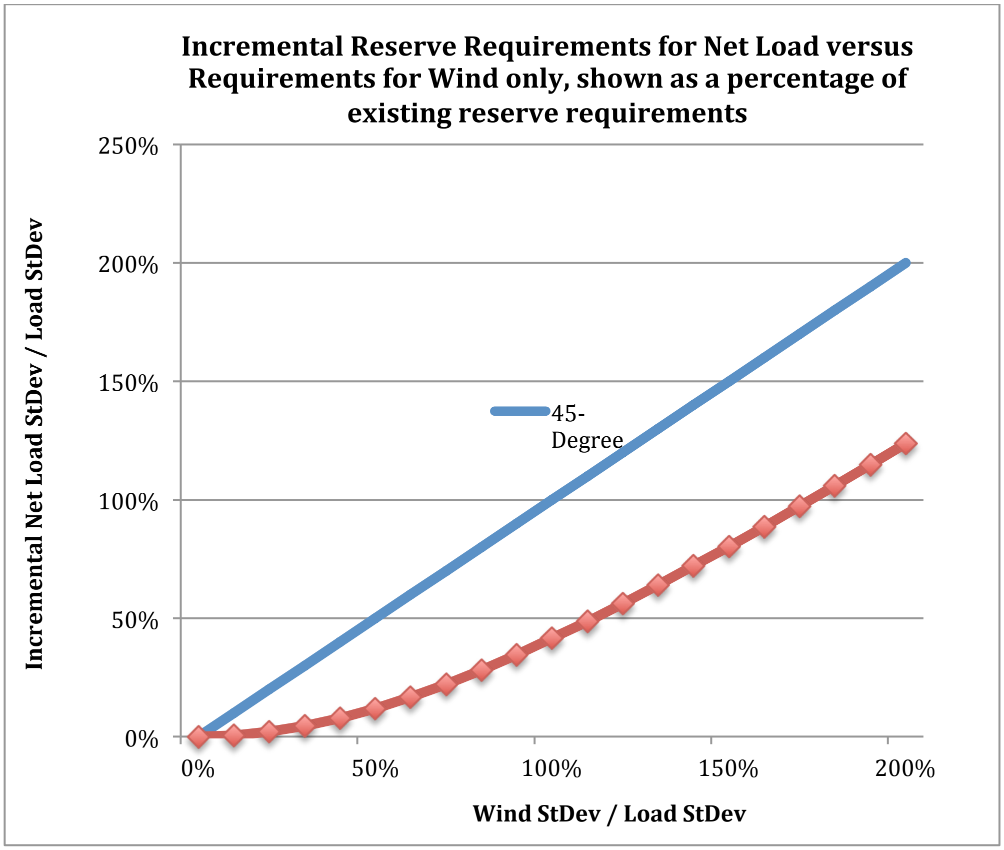

Figure II-D Incremental reserve requirements of net load as wind is added

For example, Dragoon uses data from the Bonneville Power Administration in the Pacific Northwest to illustrate how net load error is significantly lower than the sum of wind and load errors. Using one month of data, Dragoon calculates the standard deviations of wind and load errors individually, the predicted standard deviation of net load error using the equation above, and the actual net load error. As can be seen below, the equation creates very accurate predictions. Furthermore, this relationship can be applied to several different measures of variability; Dragoon separately calculates the impact of sawtooth errors, minute-by-minute load following, and schedule bias. Of course, these results are specific to the data analyzed, but the principles of incremental load requirement remain the same. Specifically, the last column finds that although wind errors had a standard deviation of 145.5 MW, the standard deviation of net load only increased by 64.5 MW when wind was added to the grid. In other words, the incremental net load reserve requirements were less than half of the requirements to balance wind power alone (Dragoon, 2010).

Standard Deviation of Errors in…	Forecast Bias	Following	Regulation	Total
Load	117.6	60.3	19.7	133.6
Wind	140.0	43.1	10.3	145.5
Net Load (Actual)	183.2	72.2	22.1	198.1
Net Load (Estimated)	182.8	74.2	22.3	184.6
Increase in Standard Deviation…	65.6	11.9	2.4	64.5
…as percent of wind stdev alone	55.8%	19.7%	12.2%	44.3%

One other key observation from this analysis is that forecast bias is the largest component of incremental balancing reserve requirements. This result is replicated throughout the literature. For example, Ferris and Infield (2008) calculate the incremental reserve requirements due to wind power with and without forecast errors. With a wind penetration level of 20% scheduled using persistence forecasts, the grid would require 7% of wind capacity to be set aside as operating reserves. If forecasts were perfect, however, that number would drop to 2%.

Several other estimates exist of the impact of wind on reserve requirements. Millborrow (2007) estimates that if wind supplies 10% of electricity, the incremental reserve requirements would equal 3-6% of the wind's rated capacity; that number grows to 4-8% at 20% penetration levels. Milligan (2003) estimates that with 17% of energy coming from wind, incremental reserve requirements equal 6-11% of rated wind capacity, depending largely on forecast quality. Gross et al. (2006) find similar results in a review of several studies, with 5-10% reserve requirements at 20% wind. Most studies find that reliability can be achieved by procuring balancing reserves of approximately three times the standard deviation of net load error

(Holttinen et. al, 2008), and are all consistent with the statistical approach described in Dragoon (2010).

It is clear that the physical challenge of managing wind is not as extreme as some misconceptions make it out to be, but that it also cannot be assumed away. Additional balancing reserves are required as the variability and unpredictability of net load grows. I now shift gears to discuss the cost of this managing this physical impact, and what can be done about it.

CHAPTER III: EXOGENOUS WIND INTEGRATION COSTS

In this chapter, I explore the general scope of wind integration costs. By comparing a number of studies, it is possible to understand the order of magnitude for integration costs. I found that it is impractical, and even disingenuous, to try and specify the wind integration costs to an exact dollar-and-cent value. The number of varying assumptions, both hidden and explicit, within the literature is astounding, and without access to proprietary simulation software, it is impossible to isolate the effects of any given assumption. However, it is clear that several exogenous factors affect the wind integration cost, within a consensus range.

3.1 Scope of Wind Integration Costs

Within the United States, there have been a number of production simulation studies that attempt to quantify the cost of maintaining reliability with various wind levels. These studies use proprietary models to simulate the results of electricity market activity. First, they start with historical load patterns, possibly scaled up to account for growth in electric consumption. Then, the models mimic the natural market bid process by finding the most cost-effective way to dispatch available generation to meet load, given a set of generating units, transmission lines, market rules, expected forecast accuracy, and reliability constraints.

To estimate the cost of wind integration, the studies will simulate the same period with and without wind. Wind is typically modeled as a "must-take" resource, meaning the other resources must work around it. Studies will include observed or simulated wind power output levels, as well as synthetic forecasts. These synthetic forecasts are used when the models simulate the unit scheduling process. Then, the models must redispatch units to make up the difference between expected and actual wind in simulated real-time.

By comparing model runs with and without wind, it is possible to back out the costs of managing the uncertainty and variability of wind generation. The overall system costs generally decrease due to fuel savings from avoided thermal generation, but these savings are partially offset by integration costs. The studies provide integration cost estimates, which typically reflect the sum of costs from additional regulation reserves, additional load following reserves, and cost of scheduling units to meet the altered load shape. Furthermore, these numbers can be determined with different assumptions about the accuracy of the synthetic forecasts used, geographic diversity of the wind fleet, or other key parameters.

The actual models used to simulate the results of market transactions are, unfortunately, generally presented as "black boxes"; that is, the inner workings of the model are not revealed. It is therefore impossible to verify if wind power is being properly incorporated into the models. Furthermore, details about how future wind profiles are generated and how reliability standards are maintained are typically not disclosed.

Fortunately, however, there is a broad consensus among multiple studies about the order of magnitude for wind integration costs. Over 10 different system operators have conducted production simulation studies, often with several wind penetration level cases. The results are displayed below in Figure III-A (Dragoon 2010; Electrotek Concepts 2003; Enernex 2004, 2006, 2007 and 2008; Idaho Power 2007; Northern Arizona University 2007). Generally speaking, they suggest that for moderate levels of wind power – between 10% and 20% penetration levels – integration costs fall on the order of $4 to $8 per MWh. In other words, for each MWh of wind energy on the grid, the resultant actions required to maintain reliability cost an additional $4 to $8.

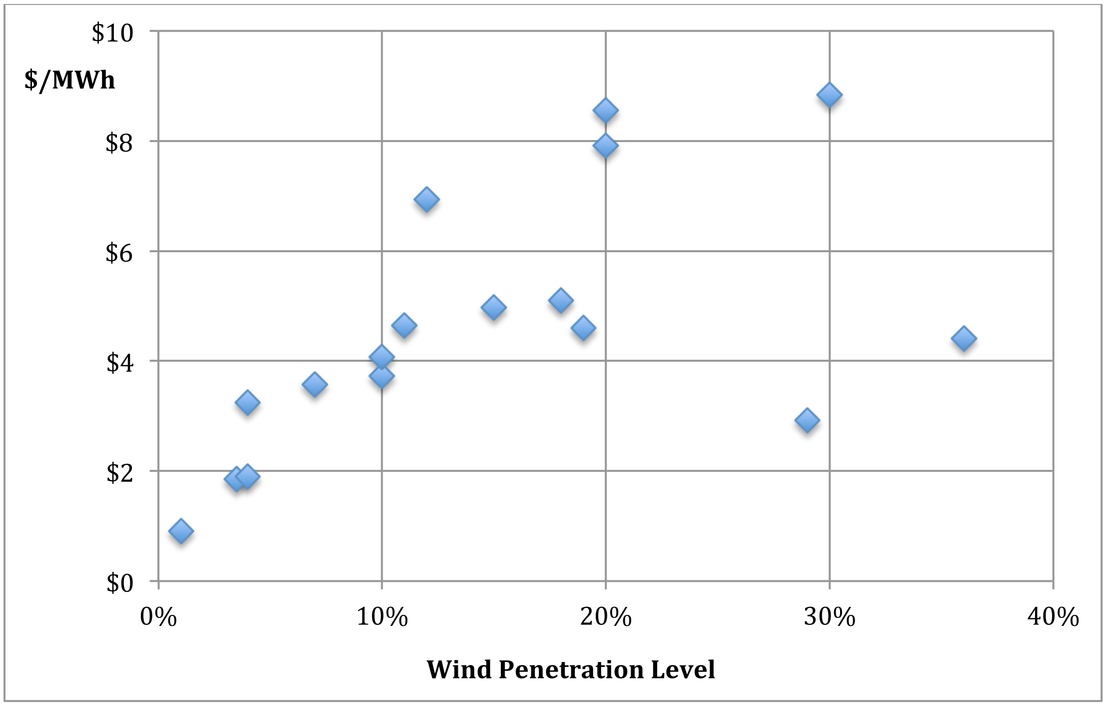

Figure III-A Wind integration cost estimates from several studies

Gross et al. (2006) conduct a similar meta-analysis of European and British studies. Despite an exhaustive review of studies divergent in methodologies and assumptions, the authors find that "over 80% of studies concluded that the cost of providing additional reserves would be less (and in many cases substantially less) than £5 per MWh of intermittent generation penetration levels up to, and in some cases exceeding, 20%."

The question of exactly how much CO_2 is saved by using 1 MWh of wind power is the subject of some debate; there is no definitive answer to the counterfactual question of how much CO_2 would have been emitted in the absence of that wind power. In California, a reasonable proxy value is the emissions from an equivalent amount of natural gas-fired generation, which is approximately .65 tons per MWh (EIA, 2010). On that assumption, every $1 in integration cost per MWh corresponds to an extra cost of $1.50 per ton of CO_2 reduction. Therefore, the range of $4 - $8 / MWh in integration costs implies an extra cost of $6 - $12 / ton CO_2 reduced that is not normally included in standard analyses.

3.2 Common Trends in Integration Cost Results

Several additional results are common across the studies, and are consistent with the physical principles of wind management discussed in chapter 2. First, most studies found that forecast uncertainty was by far the largest contributor to wind integration costs. When models were run with perfect foresight – i.e. using the actual wind values as the forecasts – costs fell dramatically (Northern Arizona University, 2007; GE Energy, 2010). Even the inclusion of more realistic state-of-the art forecasts in the scheduling process was a significant improvement over managing all wind power in real-time without the benefit of planning with forecasts.

Second, the studies confirmed that costs of additional ultra-fast regulation reserves were minimal. This is consistent with the idea that, aggregated across an entire system, very large swings in power output simply do not happen within seconds, or even a few minutes. The bulk of costs came from unit commitment and load following reserves.

Third, many studies find that costs of integration increase non-linearly as a function of wind penetration level. There are several intuitive reasons for this result. First, as demonstrated in the previous chapter, there are increasing marginal quantities of balancing reserves required to deal with increasing levels of wind. At low levels of wind, the variability of net load only increases by a small fraction of the variability in wind alone. At higher levels of wind, the variability of net load increases at an almost 1:1 rate with the variability of wind alone. Second, the marginal costs of providing these balancing reserves also increase as more wind is added to the grid. In well-functioning markets, economic dispatch systems are used to find the most cost-effective way to balance wind power. This means that highly flexible units that can easily provide ancillary services are used first, and more expensive balancing services come later. Third, earlier projects are likely to use the geographic areas with the highest wind speeds and capacity factors, which tend to have a more stable energy output. The addition of inferior project sites can cause integration costs to rise.

Many studies find a key point of inflection in wind integration costs to be on the order of 20% penetration. One academic study found that "fuel savings increase linearly up to a penetration level of 20%, after which, the rate of increase decreases continuously because of the decrease in the fuel costs of marginal units, the execution of the wind curtailment option and the increase spinning reserve requirements associated with wind uncertainty" (Albadi and El-Saadany, 2011). Denny and O'Malley (2007) model the Irish system and find that fuel savings significantly decrease after a "critical point" of wind generation at 21% of electric generation, after which more expensive baseload units begin to bear responsibility for managing wind output. Millborrow (2007) reviews several more theoretical studies on high wind penetrations, and finds that double-digit integration costs are likely to begin when wind reaches 20-30% of electric generation on a standard system.

In most cases, the black box software used to run production simulation studies provides integration cost estimates to exact dollars-and-cents values. However, achieving a high degree of certainty around such precise estimates is difficult, if not impossible, without knowing exactly how the simulations work and how accurate the hidden assumptions are. The range of cost estimates and consensus over certain trends provides a good understanding of the order of magnitude of cost estimates; for our purposes, it is not necessary to reach any potentially false precision beyond that level. Instead, it is more prudent to examine the drivers of these costs.

In their comprehensive review of integration cost studies, Gross et al. (2006) find that "the difference between individual studies is typically larger than the increase in costs within each study resulting from increased penetration levels. This suggests that the reserve cost is particularly sensitive to assumptions about system characteristics". In other words, while the order of magnitude of integration costs has been well established, the specifics depend on the host system. Chapter 4 will address the impact of market structure on integration costs; for now, I will briefly discuss some of the physical characteristics that affect integration costs in California.

3.3 Exogenous Cost Drivers

One of the most commonly cited factors that determines integration costs is the penetration level of wind, and its relationship to other renewables. Fortunately, in this area, California has an advantage. Although California has an aggressive RPS, its current and projected mix of renewable projects is relatively well balanced. Forecasts for the year 2020 shown below suggest that wind will only comprise approximately 30% of California's RPS goals; solar power will comprise another 35%, geothermal another 20%, and the remaining 15% will come from biomass, biogas and small hydro (CPUC). The existence of legacy contracts in geothermal power from the days of the Public Utility Regulatory Policy Act and excellent solar resources have helped achieve this balance. Generally speaking, geothermal provides baseload power, and solar's fluctuations are independent of wind. Therefore, it seems that for the time being, wind's penetration within the entire electric grid will remain below 15%, sparing California from the significantly higher integration costs that seem to begin at around 20%.

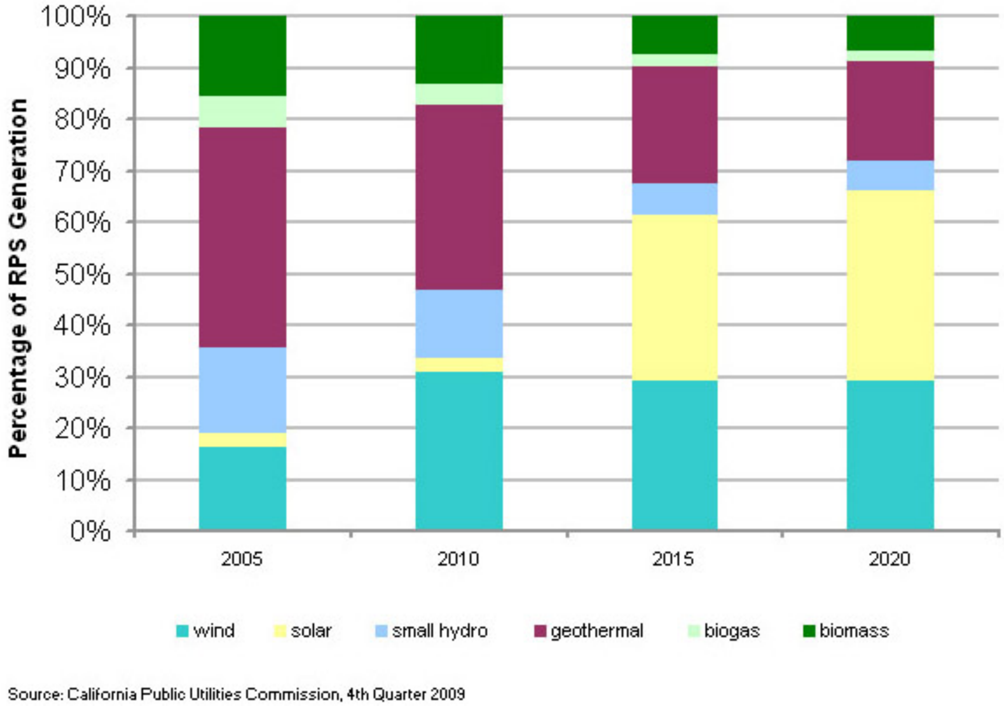

Figure III-B Projections of RPS energy by technology type (CPUC)

Geographic diversity in California is decent, but not great. California's on-shore wind resources are clustered in three main areas: Altamont Pass which is east of San Francisco, Tehachapi Pass which is south of Bakersfield, and San Gorgonio Pass outside of Palm Springs; together, these three areas produce over 95% of California's wind power from over 13,000 turbines (California Energy Commission). Within each area, geographic diversity is limited, as the best resources are tightly clustered. However, the fact that all three areas work under the same ISO is good for costs, because they are far enough apart to achieve low cross-correlations.

Another relevant factor to integration costs is overall grid flexibility, which is influenced by the type and cost of other generating units available to provide balancing services. In 2010, just over 70% of energy was generated inside of California, as opposed to imports; for reasons discussed in Chapter 4, in-state generation is generally used for renewables integration. Of in-state generation, over half comes from natural gas, which is a decently flexible resource.

Combined-cycle gas turbines that are already on, as well as gas turbines, provide an important source of flexibility for the grid. Approximately 20% of energy comes from “baseload” sources, such as coal, geothermal and nuclear power, which have difficulty with fast cycling. Hydroelectric power, which is physically the most flexible resource when not subject to policy constraints, provides 15% of in-state generation, and the remainder comes from variable renewable sources (CEC 2010). The figure below shows one example of how these resource were combined in a sample spring day from May, 2011:

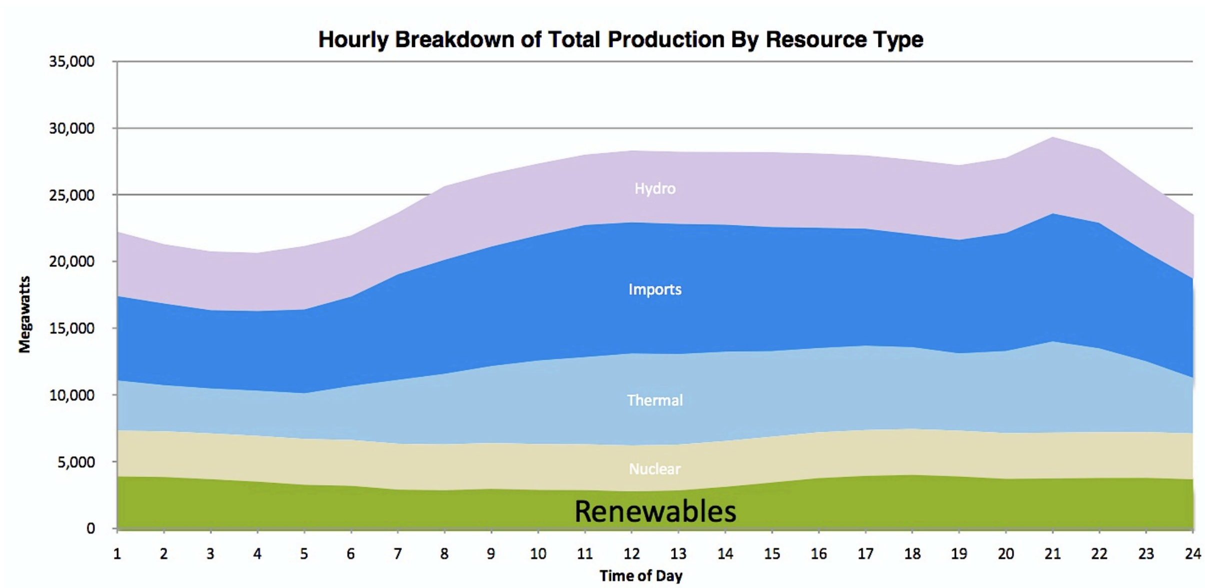

Figure III-C Mix of different resources throughout a sample day in California (CAISO Renewables Watch, 2011)

The physical flexibility of California’s resources is quite good, especially the mix of natural gas and hydroelectric power. This, along with the geographic distance between major wind farms and the fact that wind levels are relatively low, indicates that integration costs have the potential to be comparatively low in California. Whether or not these physical advantages will actually be helpful largely depends on policy and market structure, the details of which determine how efficiently CAISO can use its resources to integrate wind.

CHAPTER IV: CREATING A BETTER MARKET FOR WIND

Most existing wind integration studies have focused on precisely quantifying the costs. Often, they do so with production simulation models that operate under the assumption that the structure of electricity markets will remain the same. However, the academic literature points to the critical importance of electricity market design as one way that costs can be affected through policy levers. There are a great number of nuances in market structure that, despite sounding rather technical and mundane, have significant impacts on both the quantity and cost of balancing reserves required to integrate wind power. In this chapter, I discuss a number of these details, including how they affect integration costs and how California can optimize its market structure to minimize and allocate costs. First, though, it is prudent to begin with the dry, but important, details of California's current market instruments for scheduling energy.

4.1 California's Market Design

It is worth understanding the conventions, terminology and market processes used in California's electric markets to avoid potential confusion. While most modern electric system operators follow the same principles, specific details vary from region to region. Within California, CAISO is responsible for making sure that generation and load are always equal, and it does so in several stages.

The first stage is the day-ahead market (DAM), also known as the integrated forward market (IFM), and is the "first cut" at scheduling energy generation to match demand. The process to schedule energy for any given operating day begins with the submissions of energy bids. Generating units submit bid curves for each operating hour, containing several important characteristics. All generators have minimum and maximum physical operating levels; for example, a gas-fired plant may be able to operate between 20 MW and 100 MW. Then, bids may include a portion of capacity that is "self-scheduled", meaning that the generator is willing to supply that quantity regardless of price. The bid curve then includes minimum prices that the generator is willing to accept for various quantities of energy.

Continuing in the example, the gas generator may be willing to supply between 20 and 40 MW at any price, so it would submit a self-schedule bid up to 40 MW. Then, it might offer to provide between 40 MW and 70 MW for a minimum price of $20 / MWh, and up to 100 MW for a minimum price of $30 / MWh. Generators may use up to 10 different price-quantity combinations in their bid curves, and may submit different bids for different operating hours. Note, however, that all accepted bids to supply energy are paid the cost of the marginal clearing bid, so generators have little incentive to game the market; it generally makes sense to bid at cost. Self-schedules, low-cost bids and high-cost bids are all paid the same price.

Finally, every bid contains operational details, including the cost and time required to startup the plant, information about whether the plant is already online, and how quickly the plant can move ("ramp") from one power level to another. Bids may come from generators within the CAISO or anyone wishing to import power from a neighboring balancing authority.

Simultaneously, generation units may also submit bids to provide ancillary services. Specifically, the ISO explicitly procures four types of ancillary services: regulation up, regulation down, spinning reserves, and non-spinning reserves. (Load-following services are not an explicit ancillary service in CAISO, and will be discussed shortly). Regulation up and down are the capacity to adjust output in response to an automatic signal on a near-instantaneous basis, while spinning and non-spinning reserves are reserves that can provide power within 10 minutes in the event of a system contingency. Generators wishing to participate must include, for each hour, the quantity of each ancillary service they wish to provide, their minimum price for doing so, and operational information about their ramp rates. These generators may submit mutually exclusive bids for energy and ancillary services.

Thirdly, in the DAM, load-serving entities submit bids to purchase energy. Similar to supply bids, demand bids can either come as self-schedules (i.e. willing to buy a certain quantity of energy at any price) or as price-quantity curves. These demand bids can be used to serve load within CAISO or to export power to a neighboring balancing authority. Finally, based on these load forecasts, CAISO will determine the desired quantity of ancillary services to meet its reliability obligations.

The DAM closes at 10:00 AM on the day before any given operating day. For each operating hour, CAISO uses a co-optimization model to take the energy supply bids, energy demand bids, ancillary service supply bids, ancillary service demand requirements, and any available information such as transmission constraints, and find the least-cost way to dispatch generation units to meet load and ancillary service requirements. Later in the afternoon, the results are published, and generation units can see their schedules for the next day. This DAM process is where the bulk of the work happens: the bulk of energy, non-spinning reserves and spinning reserves are scheduled through the DAM, and all regulation reserves are procured in this time. However, wind power almost never uses the DAM.

After the DAM comes the hour-ahead scheduling process (HASP). The HASP market is almost an exact replica of the DAM conducted for each individual operating hour. Leading up to each hour, the HASP is used to adjust bids to reflect more current information, with the exception that bids for regulation reserves may not be changed. Generators may revise their bids, though this rarely happens unless there is some unexpected change, such an unplanned maintenance emergency. Base-load generators, if not awarded a bid during the DAM, may choose not to participate in HASP, due to the impracticality of starting up on such short notice. However, most supply bids will stay the same as they were in the DAM. More commonly, load-serving utilities will adjust their demand bids to reflect the latest information on expected load. Import and export schedules may also be adjusted.

The HASP market is where the bulk of wind scheduling comes into play. Currently, California uses a program known as PIRP, the Participating Intermittent Resource Program. Under PIRP, CAISO contracts with an external vendor to create generation forecasts for all wind farms under the program. These forecasts are released 105 minutes prior to the start of each operating hour, and participating generators use that forecast as a self-scheduled supply bid quantity during the HASP. Using the officially sanctioned forecast has economic benefits for wind forecasters that will be discussed later.

New bids and adjustments for the HASP market must be submitted by no later than 75 minutes prior to the start of any given operating hour. CAISO re-runs its optimization software, and publishes the results no later than 45 minutes before the start of the operating hour. By this point, the "baseline" hourly energy schedule is fixed, the energy schedules on the interties between CAISO and other balancing authorities are fixed, and the quantities of available ancillary services are fixed.

The third and final stage involves real-time operations. This stage uses two tools, real-time economic dispatch and regulation reserve, to match generation to the intra-hour variations in load. Real-time economic dispatch (RTED) is how the CAISO provides load-following (LF) services. Suppose that the final hourly energy schedule was 5,000 MW, but load quickly increased to 5,100 MW. In this situation, CAISO would look back at the economic energy supply bids it had received, and award an additional 100 MW to the cheapest available generation, subject to operational and locational constraints. Alternatively, if fell to be 4,900 MW, the CAISO would reduce the most expensive 100 MW of generation that could feasibly make that adjustment. In real-time, CAISO makes these adjustments to its economic dispatch every 5 minutes to provide load-following. The other tool, regulation reserve, is automatically dispatched on a 4-second basis to counter fluctuations within each 5-minute period. At the end of every 5-minute period, CAISO uses its real-time economic dispatch to compensate for the net change that has occurred since the last adjustment. This way, regulation reserves can be "reset" to their base point, so that this ultra-fast capacity will be fully available in the next 5-minute period.

The figure below illustrates this process. The lowest purple line represents the hourly energy schedule from the DAM, while the green line shows its adjustment from the HASP. The red line adds in the effects of RTED, which accounts for the difference between the hourly schedule and the 5-minute schedules. Finally, the blue line adds in regulation reserves, which account for the difference between 5-minute schedules and actual instantaneous output. Together, these various tools create a generation profile that can match load at a high enough level of granularity to ensure reliability and power quality.

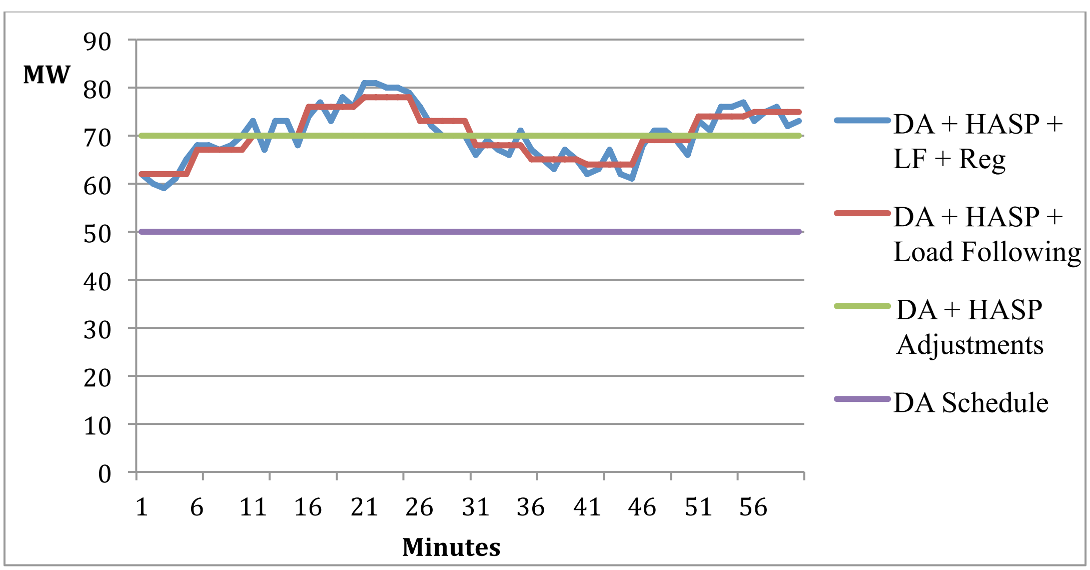

Figure IV-A Contribution of each market function to meeting actual load

For operational reasons, real-time economic dispatch is not nearly as flexible or economically efficient as dispatch from the DAM or HASP processes. Adjustments at this stage may only come from generators that are already online. These units can vary their generation between their maximum rated output, and the greater of their minimum rated output or their self-schedule quantity. In addition, real-time economic dispatch cannot use resources outside of the CAISO because intertie schedules are fixed during the HASP market, and even within CAISO, transmission constraints may lead to uneconomical results.

Returning to our previous example, the gas plant may have been awarded a bid to provide 70 MW of power at a price somewhere between \$20 and \$30 / MWh. The plant could provide 30 MW of load following up capacity, reaching its maximum rated output of 100 MW, subject to its ramp rate limit. Alternatively, it could provide 30 MW of load following down capacity, going to 40 MW, which is the quantity that was self-scheduled. Note that RTED will not reduce the unit down to 20 MW, even though it is physically possible. It is important to recognize the role of ramp rate limits and of self-scheduling; both of these factors constrain the pool of flexible capacity available for load following.

Now that we have established the details of CAISO's markets, we can examine the potential of several reforms to manage integration costs within this framework. The integration costs come in several forms: from energy imbalance met by load following, from increased requirements for regulation reserve, and from less efficient use of conventional plants. A number of policy levers exist that can help manage these costs. I discuss each policy lever in detail throughout this chapter; the following table provides a brief summary for the reader's reference.

Policy Lever:	Reduce Costs?	Allocate Costs?
(1) Shorten market intervals and gate closure times.	Yes – reduces reserve requirements with more accurate forecasts	No
(2) Energy imbalance charges	Yes – reduces reserve requirements with incentives for better forecasts	Yes – uses "causer-pays" principle to recover costs
(3) Improved balancing area cooperation	Yes – reduces reserve requirements by aggregating load and wind, and reduces balancing cost by pooling flexible resources	No
(4) Increased participation in redispatch markets	Yes – increases availability of flexible resources within CAISO	No
(5) Energy storage and demand side management	Yes – reduces reserve requirements by inducing negative correlation between load and wind	No
(6) Renewable integration charges	No	Yes – imposes per-MW charge on generators

4.2. Market Intervals and Gate Closure Times

It has been consistently shown that forecast error is a key driver of integration costs. In CAISO, inaccurate HASP forecasts cause the use of load following reserves to solve the energy imbalance, which costs significantly more than using the HASP bidding process to find the most economical way to serve load. One California study found that over 80% of incremental load following requirements due to wind generation are from forecast errors, as opposed to the inherent variability of wind (CAISO 2010). Therefore, it is prudent to examine ways in which forecast error can be reduced.

One possibility is to adjust market intervals and gate closure times. As mentioned before, CAISO requires HASP schedules to be submitted 75 minutes in advance, and schedules wind in 1-hour blocks. Both of these practices, while not altogether unusual, may contribute to unnecessarily high forecast error.

Doherty and O'Malley (2005) analyze the relationship between forecast error and look-ahead time. In time frames of just a few hours, the most accurate predictor of future wind generation is current wind generation. Unfortunately, this means that forecast error increases quickly as a function of look-ahead time (Figure IV-B). Their paper shows that the standard deviation of forecast error roughly doubles from 6% of installed wind capacity with a 60-minute look-ahead time to 12% of installed wind capacity with a 120-minute look-ahead time. Although approximate, this analysis shows that over short time horizons, a given percent decrease in forecast horizon time will yield the same percent decrease in forecast error.

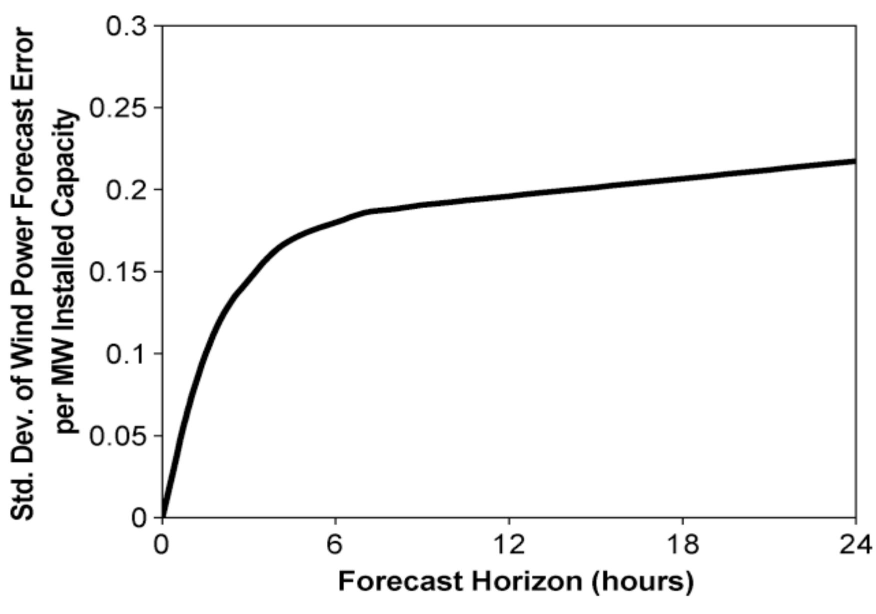

Figure IV-B Increasing wind forecast error as a function of look-ahead time (Doherty and O'Malley, 2005)

Dragoon (2010) finds similar results in his analysis. Figure IV-C shows simulated incremental reserve requirements of a wind farm as a function of two variables: gate closure time and scheduling interval (Figure IV-C). Within each individual curve, Dragoon adjusts the length of the scheduling period, and finds that the benefits of shorter operating periods are real but modest. On the other hand, decreasing the lead time for forecasts has a major impact. Persistence forecasts taken 60 minutes before the operating period yield reserve requirements 30% lower than a base level of forecasts taken 120 minutes in advance; if 30-minute forecasts can be attained, the reserve requirements are cut in half from the base case (Dragoon, 2010).

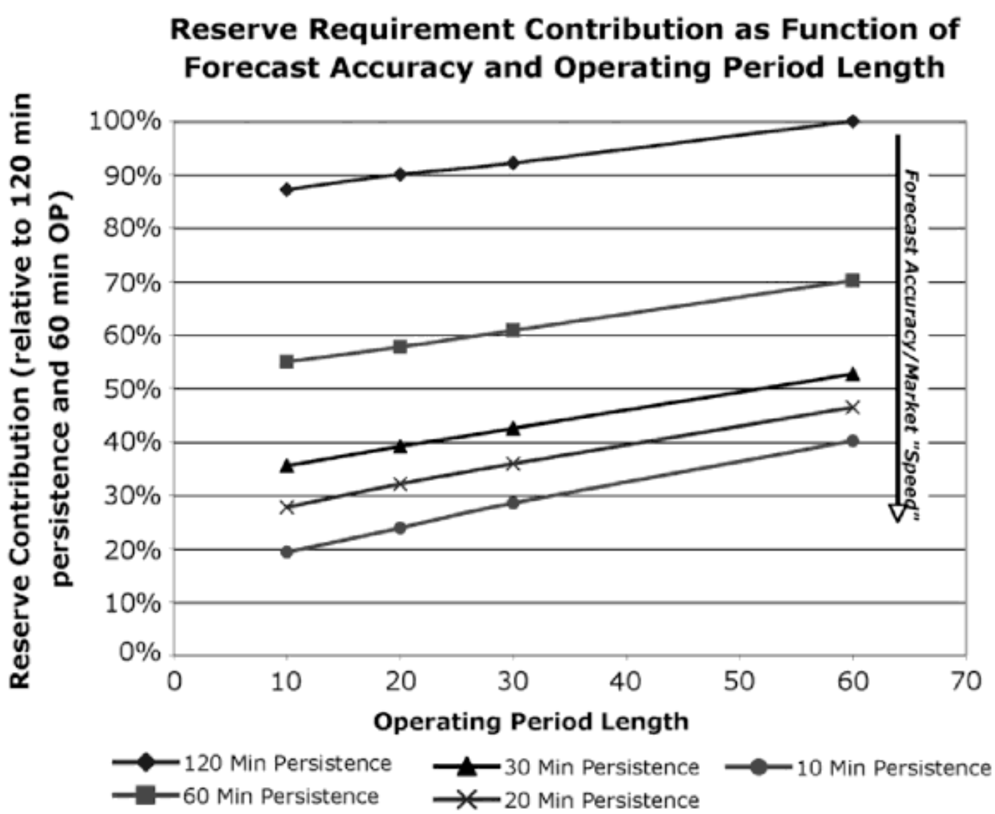

Figure IV-C Incremental reserve requirements versus market interval, gate closure time (Dragoon, 2010)

I found a similar trend using published data from the Bonneville Power Administration (BPA), which serves as the balancing authority for much of the Pacific Northwest. One virtue of the BPA over CAISO is that, possibly because it is a public agency, its system operations data is much easier to use. BPA publishes actual wind generation and wind schedules at 5-minute intervals, so I was able to see how forecast error varied within each hour. Similarly to the literature, I found that forecast errors were greater in later parts of each hour (Figure IV-D)

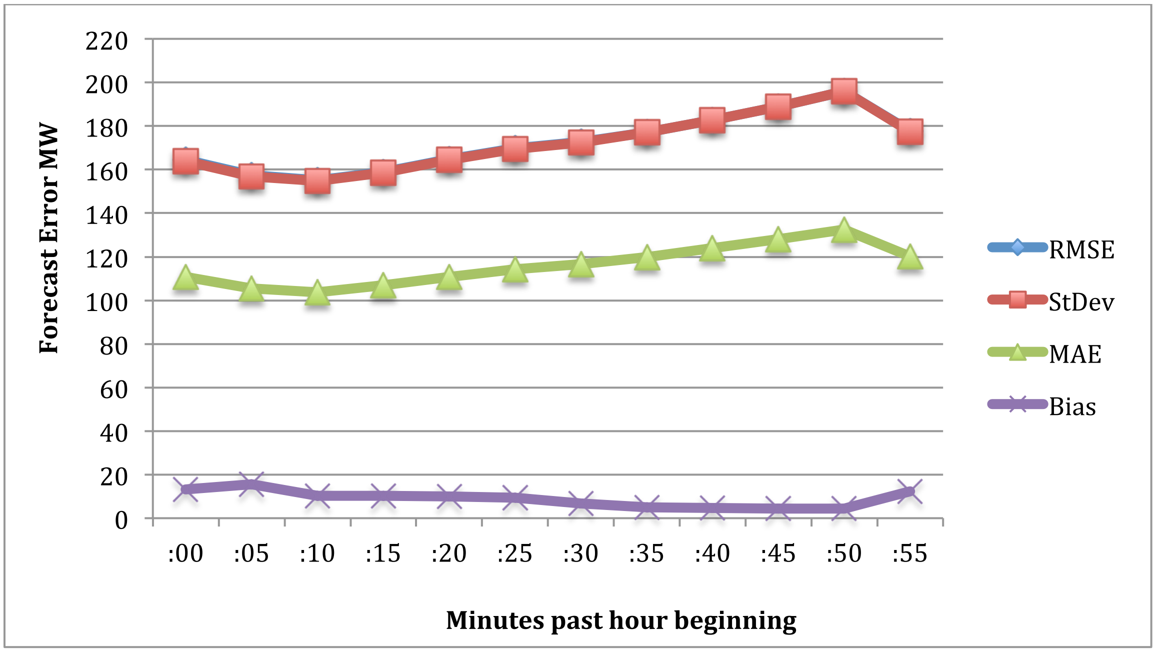

Figure IV-D Increasing wind forecast error throughout the hour in BPA

Each data point on the x-axis represents the forecast error at a certain point in the hour, and each line represents a different measure of forecast error. For example, the first data point on the middle green line represents the mean absolute forecast error, measured at the top of every hour for all 8,760 hours in the year 2010. The next point on that line represents the same measure of forecast error, with data drawn from snapshots taken 5 minutes into every hour. Note that the snapshots at the top of every hour, 5 minutes into every hour, and 55 minutes into every hour are not relevant, as the scheduled amount of wind power is ramping between one hour's forecast and the next hour's forecast. The relevant time period ranges from the snapshots 10 minutes into each hour to 50 minutes into each hour, inclusive.

For each 5-minute interval, several forecast error measures are calculated. The bottom line represents forecast bias, or the simple average of forecast error. The next line up represents mean absolute forecast error. The top line is actually made of two lines that are nearly identical: root mean square forecast error, and standard deviation of forecast error. These two measures converge on each other as forecast bias approaches zero.

Notably, the MAE, RMSE and standard deviation of error all increase throughout the hour. The MAE increases from 104 MW 10 minutes into every hour, up to 133 MW 50 minutes into every hour. The standard deviation of errors, which provides a greater penalty for large errors, increases from 155 MW at the 10 minute mark to 196 MW at the 50 minute mark. The good news is that these errors are relatively small compared to the size of BPA's wind fleet, which averaged 787 MW throughout the year, and had a capacity of nearly 3,000 MW. This supports the idea that forecast errors aggregated over a balancing area will be relatively modest. However, this also shows that real data, not just market simulations, confirm the idea that shorter forecasting lead times can reduce error.

California's 75-minute look-ahead time in HASP is higher than in many other areas. Dragoon (2010) cites a range of 75 minutes to 20 minutes of lead times prior to the operating period for schedule submissions in various balancing authorities. In Texas, an adjustment period allows adjustments to schedules until 60 minutes prior to the operating hour (ERCOT, 2005). The Southwest Power Pool does not lock schedules until 45 minutes prior to the beginning of the operating hour (SPP, 2011). In the Bonneville Power Administration, there is no central bid clearing house, but energy is typically traded and scheduled 45 minutes prior to an operating hour, and schedulers have until 20 minutes prior to the operating hour to submit schedules. BPA has also begun to experiment with intra-hour trading, which allows half-hour schedules to be submitted no less than 15 minutes before a half-hour period (BPA, 2011a). These examples illustrate the possibility of using scheduling practices that could lead to greater forecast accuracy than those currently employed by CAISO.

Furthermore, even if CAISO did not make any changes to the 75 minute gate closure time, there is still room for improvement in the forecasting lead time. The forecasts provided under by the ISO under the Participating Intermittent Resource Program (PIRP) – which are used in HASP market – are provided 105 minutes before the start of the operating hour (CAISO 2010). This means that there is a gap of at least 30 minutes between the forecast creation time and the closure of hour-ahead markets, a gap which unnecessarily exacerbates forecast error.

It is worth remembering that, in this case, there is no real benefit to having the forecasts earlier than required. The CAISO's optimization model does not run until the market closes at 75 minutes before the operating hour, and does not benefit from having information before this time. Bidding strategies for other generators should be independent of expected wind power; recalling that all accepted bids are paid the marginal bid price, the optimal bid price strategy has little relation to other units' strategies. Therefore, this 30-minute gap is an unnecessary cause of inaccuracy.

A combination of these two reforms would be helpful for reducing forecast accuracy. First, it would be best for the CAISO to reduce the gate closure time, from its current point of 75 minutes prior to the operating hour to a closer time, perhaps 50-60 minutes. Then, the gap between gate closure time and forecast issuance should be decreased, as larger gaps provide no real operational benefit. Together, these could decrease forecast error, and therefore, reduce expensive load following requirements in real-time.

4.3 Energy Imbalance Charges

Another aspect of CAISO's markets that could use improvement is the financial treatment of forecast error and imbalance. Under PIRP, the status quo provides what is essentially a free pass to wind generators for the difference between scheduled energy and forecast energy. This has two main problems: first, that it removes any economic incentive to improve forecasting technology, and second that it externalizes the cost of energy imbalance. In many ways, PIRP is a classic microeconomic moral hazard problem.

The details of PIRP are relatively straightforward. The conditions for participation are twofold: first, generators must submit the PIRP forecast as their HASP schedule, and second, there is a nominal fee of $0.10 per MWh for the forecasting services. Through a competitive bidding process, CAISO selected the company AWS TrueWind as the external vendor to provide PIRP forecasts. In exchange for participation, CAISO essentially waives any imbalance penalties. Specifically, CAISO will calculate each generator's net forecast error at the end of every month. At the end of the month, CAISO will either pay or charge generators in accordance with the net bias. If the plant output provided more energy to the grid than it was scheduled to, it has essentially provided "free energy", and will be compensated at that month's weighted average marginal energy price for the imbalance quantity. Conversely, if the plant delivered less energy than its schedules, it was paid for energy it did not deliver, so CAISO charges it the monthly price for this difference. These energy charges are mostly free of associated imbalance penalties, penalties that are applied to non-participating resources (CAISO, 2010c). In other words, wind generators enrolled in PIRP use load following reserves without paying their cost.

The effect of netting forecast errors over the month is significant. Recall that forecasts are accurate over large samples, but pose considerable operational difficulty because of the lack of precision. One study found that, over a year, the sum of the absolute values of forecast errors in PIRP exceeded 500,000 MWh. However, the net error over that same time period was only 3,000 MW (Blatchford et al., 2007). Even if substantial imbalance penalties were imposed on the net forecast error, the quantity would still be miniscule; netting the forecast errors masks a very large energy imbalance issue.

As a result, there is no economic incentive to improve performance. A recent analysis found that the statewide root mean square hour-ahead forecast error was approximately 10% of installed wind capacity (CAISO 2010c). While not outrageously high, this number is significantly higher than the preceding analysis from BPA, which had an average RMSE of approximately 5% of capacity. Furthermore, there are several ways in which forecasts might be improved. First, energy schedulers could contract with other forecast vendors, apart from the one chosen by CAISO, who might have a better understanding of the specific geography or technology of a given wind farm; there are at least 6 alternatives to the vendor chosen by CAISO (Dragoon, 2010). Second, during the half hour between the release of PIRP forecasts and the HASP market closure, the quality of forecasts could improve given new information. Finally, traders who work with the same wind farms may be able to exercise judgment superior to meteorological models and algorithms. Unfortunately, in the current system, schedulers who deviate from PIRP lose preferential settlements treatment, even if it improves their forecast accuracy.

Furthermore, even if forecast accuracy could not be improved, the current practices of PIRP mean that energy imbalance will continue to be a negative externality imposed by wind generators. CAISO's market settlements provide the same energy price to wind as any other generator, in spite of the operational difficulty. As long as this problem remains an external cost, markets will not find the most cost-effective blend of GHG reduction strategies. Fox et. al (2007) argue that it is "not good practice" to socialize costs; instead, "costs should be allocated to those who can control them, thus encouraging them to invest in solutions to reduce them." In addition to lower costs, "proper allocation of the costs of wind power will optimize the amount of wind generation."

Fortunately, alternatives exist to make wind generators pay for the extra energy imbalance that they cause, in keeping with a "causer-pays" principle. BPA has been something of a leader in this regard, and has adopted a sophisticated set of tiered imbalance payments for the numerous wind generators in its area. First, it does not allow monthly imbalance netting, but instead, settles accounts based on hourly imbalances. Within each hour, a small tolerance band is allowed for penalty-free reimbursement. Specifically, energy imbalances up to the greater of 2 MW or 1.5% of the scheduled amount of energy are considered "band 1." Within this band, energy produced in excess of the schedule is compensated at the full market price, and energy deficiencies are charged the full market rate, similar to the PIRP system. Beyond that band, though, BPA imposes a 10% haircut penalty; excess energy only receives a 90% payment, and a deficiency in energy quantities is charged at 110% of the market rate. Finally, a "persistent deviation penalty" applies if generators are consistently over-scheduling or under-scheduling energy over the course of several consecutive hours. When a persistent deviation penalty is assessed, any energy produced in excess of the schedule is not compensated at all, and any energy deficiencies are charged the greater $100 / MWh or 125% of the market rate (BPA, 2011a).

Although there is little empirical research on the incentive effects of these charges, informal conversations with officials from Southern California Edison who manage wind resources in the area suggest that traders are "pulling out all the stops" to avoid these penalties whenever possible. Furthermore, the existence of these charges ensures that the wind generators, and not ratepayers, compensate the grid proportionally to the operational challenges they impose. To create incentives for lower energy imbalances, and to properly allocate costs, CAISO should consider replacing PIRP with these sorts of strategies.

4.4. Balancing Area Cooperation

The importance of geographic diversity has been referenced several times, indicating its importance for keeping integration costs low. Unfortunately, as mentioned in Chapter 3, there is little that can be done to increase the geographic diversity of wind resource in California; high-quality wind projects are essentially limited to the three small geographic areas with sufficiently high wind speeds to support viable projects. However, cooperation between neighboring balancing authorities can provide many of the same benefits of geographic diversity, without requiring a physical change in the location of wind projects.

The literature abounds with examples of how balancing area cooperation can reduce integration costs. By aggregating load, aggregating wind fluctuations, aggregating forecast error, and aggregating the pool of flexible generation resources, cooperating initiatives can reduce both the price and quantity of required incremental balancing reserves.

In the Nordic countries – Norway, Finland, Sweden, Denmark and Estonia – the NordPool spot market has allowed the countries to pool their resources as one. Denmark's famously high levels of wind penetration are, in many ways, thanks to its ability to use NordPool to balance its wind power in a larger market. Holttien (2007) estimates that without NordPool, the reserve requirements would be twice as high as they are today, and more wind power would have to be curtailed for reliability purposes.

The Western Wind and Solar Integration Study by GE Energy (2010) found similarly strong support for balancing area cooperation in its analysis. The figure below shows how the standard deviation of net load hourly changes increases as a function of wind penetration. With individual states treated separately, variability increases significantly with wind power; for example, adding 20% wind power increases the standard deviation of net load variations by 70% in Western Colorado, 40% in Wyoming, 25% in New Mexico, and to a lesser extent in Arizona, Eastern Colorado in Nevada. However, when all the regions are combined, the increase in variability is almost insignificant. Along the same lines, the study found billions of dollars in potential savings from pooling spinning reserves across the larger regions.

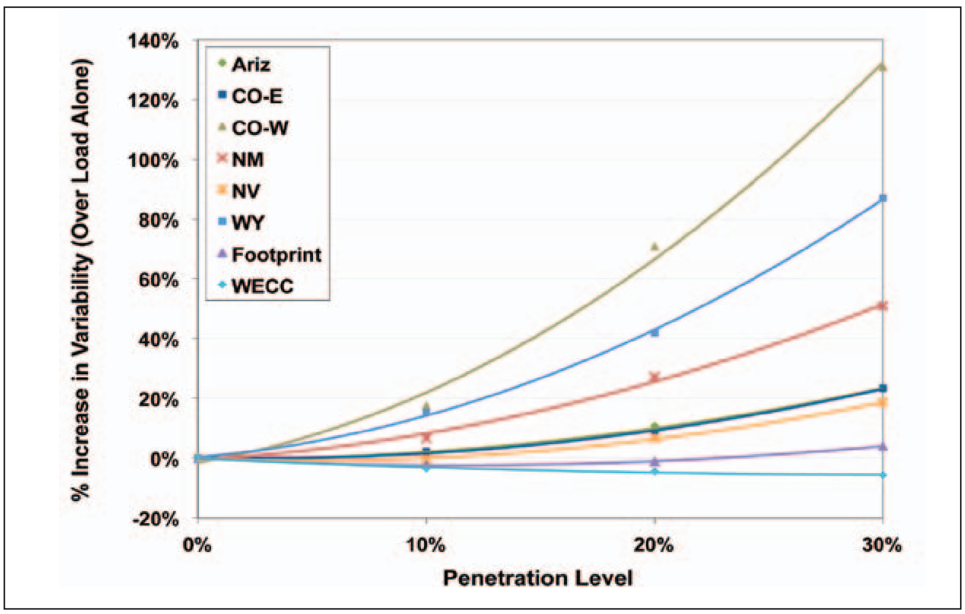

Figure IV-E Wind's contribution to variability, depending on balancing area size (GE Energy, 2010)

These are simply two examples of many studies that support the conclusions that balancing area cooperation reduces integration costs. Compared to many balancing areas, CAISO already encompasses quite a large market; however, there are still ways that its cooperation with neighbors could be improved.

The key barrier to increasing cooperation is that intertie schedules are currently locked when the HASP market closes. Therefore, imports and exports can only be used to balance expected shifts in wind and load. For imbalances between HASP-scheduled energy and actual production, CAISO can only depend on its own resources to balance these imbalances, even if there is available transmission to neighboring balancing areas. The one exception to this rule is a pilot program between CAISO and BPA, which allows 200 MW of wind generation to submit half-hour schedules over the California-Oregon intertie; however, this pilot only includes wind from BPA to adjust its schedules exports into CAISO, and does not increase California's access to out-of-state balancing resources (BPA, 2011b). Expanding the scope of these sorts of programs to allow real-time adjustments to intertie schedules would allow naturally independent fluctuations to reduce the quantity of net balancing requirements between two areas, and would also allow the least-cost dispatch of balancing services over the pooled area to deal with the imbalance that does remain.

4.5. Participation in Redispatch Markets

The existence of 5-minute economic dispatch periods is a helpful feature in California's markets that should not be taken for granted. Adjusting the schedule on a 5-minute basis – even given numerous operational constraints – allows significant cost savings compared to using regulation reserves to match all intra-hour variability. In order to be as effective as possible, CAISO should work to ensure it has access to the broadest possible pool of resources to provide 5-minute dispatch services. The section on balancing area cooperation discussed one way to do that, but another approach is to encourage greater participation in these markets from CAISO's own resources.

Recall that the capacity available for 5-minute dispatch is constrained by several factors. Load-following (LF) up services can be provided when dispatchable units have been awarded a bid less than their maximum operating capacity. LF down services come from dispatchable units that are generating more than their minimum power output; however, real-time dispatch will not decrease generation below self-scheduled quantities. Therefore, market participants can to some extent limit their participation in LF down. In addition, load following is limited in speed to the collective sum of ramp rates from participating units. A single plant providing 100 MW of LF up will not be able to increase its output as quickly as two plants simultaneously providing 50 MW each. Finally, load following capacity is limited by transmission constraints within CAISO, as well as rules against adjusting intertie schedules in real-time.

A CAISO study designed to examine the operational impacts of a 20% RPS tried to determine whether current scheduling practices provided sufficient load following capacity to manage the variability associated with this level of intermittent output. The required LF capacity to manage intermittency is represented by the maximum difference between a 5-minute schedule and its associated hourly schedule, taking into account natural variability and simulated forecast error. The study simulation found that the system's LF up capacity was more than sufficient to meet operational requirements from renewable output. However, under very conservative assumptions about the grid's flexibility, there were occasional instances of overgeneration, when LF down capacity would be unable to accommodate increases in wind power (CAISO 2010b).

These instances of overgeneration were expected to be quite rare, accounting for only 0.2% of the wind's energy. However, given that the study only modeled a 20% RPS, it is naturally concerning for 33% RPS implications. The hours with a high risk for overgeneration are typically characterized by fast increases in wind power, large amounts of must-run hydroelectric power, low load, and little-to-no thermal generation available for economic dispatch. These conditions are most likely to occur during early morning hours during the spring runoff season; indeed, BPA recently experienced similar problems with its wind and hydro plants, where an overgeneration condition required “environmental redispatch", a mandatory curtailment of wind power to avoid system emergencies.

A shortage of LF down capacity has operational impacts, but also indicates the broader need for CAISO to make real-time markets as robust as possible. The problems projected in the CAISO report are not caused by a physical lack of dispatchable generation, but instead, the failure of current market systems to properly forecast and prepare for these conditions. By achieving greater participation in redispatch markets, CAISO could lower the operational burden of renewable energy, and three strategies could help do this.

The first strategy is to let wind power participate in RTED. It may seem counterintuitive to use wind power to balance its own fluctuations; however, modern wind turbine design allows for substantial amounts of control. By making adjustments to various technical parameters, such as blade pitch and generator torque, wind operators can adjust the power produced by a wind turbine, subject the limits of wind speed and rated output (Lackner 2009). Currently in CAISO, wind turbines have no economic incentive to use these capabilities; the more energy they produce, the more they are paid. Furthermore, current practices are not well suited to wind’s more dynamic approach to balancing.

However, there is no technical reason why wind generators could not provide some degree of flexibility in the market, given the right price. In order for this to happen, it might be necessary for CAISO to create a new product type for balancing services. Rather than offering load following services, wind generators could more feasibly provide the ability to limit generation to a certain quantity. Generators would demand a price at least as high as the expected market value of lost energy; in exchange, the CAISO would gain added flexibility to help manage overgeneration situations without sacrificing market principles.

A second strategy would be to encourage more generating units to offer economic bids instead of self-schedules. The 20% RPS operational analysis from CAISO (2010b) found that self-schedules currently play a large role in limiting the robustness of real-time markets. If all thermal plants could provide LF down services to their minimum safe output level, without the constraint of self-schedules, LF down capacity would be doubled. Not only would this decrease the likelihood of operational emergencies, but it would also provide more economic choices for CAISO to provide LF at minimal cost. It would be wise for CAISO to explore various incentives to encourage participation in these markets. Possibilities might include paying self-scheduled units a slightly lower rate than the market-clearing price, or providing a premium above market prices to units that provide load following.

Finally, rather than encouraging more units to bid in economic schedules instead of self-schedules, the CAISO could reform the way it selects winning bids in the day-ahead market. One flaw in the current system is that day-ahead awards are made without regard to the expected behavior of wind power. As a result, hours in which greater variability is expected are treated no differently than hours with more stable wind speeds.

A more sophisticated system would allow the units selected in day-ahead markets to partially depend on the forecasted load following need. A few simple rules could improve this process. For example, LF up requirements will be greater when forecasted wind is low, while LF down requirements will be greater when expected wind is high. Certain seasonal and diurnal patterns could be incorporated as well; for example, wind makes the largest contribution to LF requirements during the spring, and each season has certain hours where the greatest LF challenges are expected (CAISO 2010b). By incorporating this knowledge into the DA scheduling practices, along with wind forecasts, CAISO could ensure sufficient flexibility for challenging hours. For example, CAISO could identify "priority" hours where it sets a maximum percentage of energy awarded to self-schedules, limiting non-dispatchable resources such as imports or geothermal power. The more accurately CAISO could incorporate forecasts of load-following requirements, the more it could target key hours for increased flexibility without negatively impacting economic dispatch the rest of the time.

4.6. Energy Storage and Demand Side Management

Most strategies to manage intermittency focus on flexible generation. However, it is also possible to manage variable and unpredictable output using the demand side of electric markets. Energy storage and demand-side management (DSM) offer additional sources of variability that the CAISO could pursue to potentially lower integration costs. While many technological options exist, the basic idea is the same: to create a negative correlation between changes in wind output and changes in load. Thus, wind's contribution to incremental reserve requirements could be minimized.

One commonly mentioned solution to the integration challenge is dedicated energy storage technologies. Proponents argue that energy storage devices, such as large battery arrays, can store excess energy when the wind is producing large amounts of power, and discharge that energy to the grid when the wind stops blowing. Popular media often portrays storage technologies as a "silver bullet" solution, and technology vendors are not shy about echoing that idea. For example, A123 Systems, a manufacturer of lithium ion batteries, published a white paper that showcases how the company's technology can manage fluctuations in renewable energy, help reduce CO_2 emissions, and promote grid reliability (Vartanian). Somewhat amusingly, this paper cited similar research performed by Beacon Power, a flywheel manufacturer that also promoted its technology for renewable power integration and famously filed for Chapter 11 bankruptcy in November, 2011.

The technical claims that energy storage can solve integration issues are generally true. However, they misrepresent both the purpose and economics of energy storage. First, energy storage technology could have a substantial impact on the grid today; there is a reason why it has not already been deployed. Claims that energy storage will be needed specifically to balance the wind suffer from the same logical fallacy as claims that that ancillary services are needed specifically to balance the wind. To the contrary, system operators use a number of tools to balance the variability and unpredictability of load today, and have done so largely without dedicated energy storage. Renewable generation does not present a new category of need in energy markets, and "if cheap and effective energy storage were to become available, it would be widely used in electricity generation systems…irrespective of renewable generation systems" (Infield and Watson, 2009).

This leads to the second issue: despite the appeal of energy storage, the economics simply do not add up for its use in renewables integration. Rittershausen and McDonagh (2010) examine the use of energy storage for intermittent energy smoothing and shaping, an application that could potentially reduce load following requirements, and find that costs exceed benefits by two orders of magnitude. Other potential uses of energy storage, such as providing ancillary services or shifting load from off-peak to on-peak are (1) also not cost effective, and (2) are not linked to renewables integration nearly as directly as industry insiders would argue.

However, there are other ways to induce a negative correlation between changes in load and wind generation, apart from dedicated energy storage devices. Demand-side management (DSM) uses devices that are already deployed on the grid, and as a result, can achieve many of the same benefits of storage at considerably lower cost.

Electric vehicles are often cited as a way to manage intermittency without impacting generation units. Specifically, large-scale deployment of electric vehicles has two main benefits. First, assuming most people charge vehicles during off-peak hours, they provide a significant source of load during the hours when the risk of overgeneration is greatest. Therefore, having electric vehicles decreases the need to de-commit baseload plants in order to maintain reliability. Second, if electric vehicles can use "smart" charging habits, they could be used for load following. Modern smart-grid technology is beginning to enable individual devices to respond to signals and adjust their electric load accordingly. With a fleet of batteries plugged into the grid, the CAISO could substantially increase or decrease load in response to fluctuations in wind, without relying on generating units to provide that load-following capability. Even more impressive, "vehicle-to-grid" technology can allow electric vehicle batteries to reverse power flow and supply energy to the grid during periods of generation shortfall.

Of course, electric vehicles are an expensive way to provide this technology. However, if consumers plan to buy them anyway – and SCE estimates that 400,000 vehicles will be purchased in its service territory by 2020 (Minick, 2011) – then grid operators should look into using this opportunity. Lund and Kempton (2008) study the Danish system and find that the use of electric vehicles can substantially decrease the risk of excess renewable energy, increase CO_2 savings from wind, and enable higher wind penetrations with fewer operational difficulties.

However, electric vehicles are only one example of a technology that can vary its load to provide integration services and lower the need for generation-based balancing. Everett (2009) discusses the potential of several everyday technologies whose electric load could be varied without significant impacts to performance, if they could respond to signals from the grid. In the UK system – which is larger than California's grid, but on the same order of magnitude – Everett estimates 400 MW of available flexible load from domestic refrigeration, 300 MW from commercial refrigeration, 300 MW from large-scale water pumping and 4,000 MW from off-peak domestic electric resistance heating. Dragoon (2010) adds that building HVAC and irrigation pump load could also be varied in response to centralized signals. Within limits, these loads could be adjusted to help integrate wind power and minimize incremental reserve requirements.

Most DSM requires some sort of smart grid, which can communicate dispatch orders to specific types of load. However, Infield and Watson (2009) discuss a proposal for "dynamic demand", which can respond to grid fluctuations without any central control. In refrigeration applications, compressors can be programmed to respond to small fluctuations in grid frequency. If the grid AC frequency rises above the standard of 60 Hz, it means that generation is exceeding load, so compressors can be programmed to detect that change and increase the power of their compressor. Similarly, if the grid frequency drops, compressors can turn off without any direct order from the ISO. This kind of technology can facilitate the spread of DSM even without a smart grid.

The vast majority of renewables integration studies take load as a given, and discuss integration costs based on the assumption that the pool of generation resources is exclusively responsible for managing the variability in wind output. Such an approach, if practiced in reality, would lead to unnecessarily high integration costs. Unfortunately, the exclusion of DSM practices from these studies makes it difficult to quantitatively assess the potential cost savings by using DSM. However, it is qualitatively clear that these measures can play an important role.

Fortunately, CAISO already contains an infrastructure for DSM. However, most programs are centered around reducing non-critical load during peak summertime hours, such as air condition cycling or agriculture and pumping interruptible programs. With relatively modest market reforms, the same kinds of programs could be used to help manage renewable output, for example by reducing load if wind power decreases faster than expected. Economic incentives for participation in these programs already exist; the focus simply needs to expand from peak load management to include renewables integration.

Unlike some other market reforms, DSM programs require the active involvement of utilities, as opposed to simply their consent. CAISO can directly control its interactions with generators and utilities; however, it does not have that same level of direct access to individual customers who might sign up for a flexible load program. Nonetheless, with the right economic incentives, DSM could be a helpful tool to minimize integration costs.

4.7 Wind Integration Charges

Finally, one proposal that could help internalize the costs of intermittency is a simple integration charge. BPA, in addition to its performance-based imbalance charges, also has a flat rate known as a Variable Energy Resource Balancing Supplement. This fee is currently set at \$1.23 / kw-month of installed wind capacity, which roughly translates to \$5.70 / MWh with a 30% capacity factor (BPA, 2011a).

Compared to imbalance charges, this approach lacks the advantage of creating incentives for improved performance. In addition, this kind of approach in an ISO may face legal challenges, since the Federal Energy Regulatory Commission could potentially consider this a violation of ISO's obligation to provide non-discriminatory open access to transmission. It is an open question if this would be seen as reasonable cost-recovery along the lines of interconnection fees, or a subsidy for specific technologies.

On the other hand, this approach provides the benefits of administrative ease and financial certainty. Having a flat fee structure makes it much easier for utilities to incorporate integration costs into their decision making process; forecasting imbalance payments would be a much harder task. It also allows CAISO to be certain it will recover a certain quantity of revenue and properly internalize costs. Finally, a flat rate helps to avoid politically difficult questions about defining the scope of a single wind farm for purposes of netting energy imbalance. For example, some might argue that imbalance charges should be imposed on each schedule submitted, while other suggest that companies should be charged for the imbalance of their entire net wind fleet. Thus, even though imbalance payments more accurately follow the "causer pays" principle, a simple rule might be the easiest.

CHAPTER V: CONCLUSIONS

Renewable energy is a popular and exciting topic, and it deserves no less. Unfortunately, because the stakes of energy policy are so high, there is hyperbole from wind power's supporters and its detractors in the public sphere. Hopefully, the preceding analysis has shown how integration issues are manageable but nontrivial. Three concluding remarks follow.

First, integration costs matter. In the discussion of cost-effective greenhouse gas reductions, it is important to be honest about the true costs of every strategy. The GHG abatement cost curves constructed by McKinsey (2007) show an enormous array of strategies to reduce greenhouse gases, many of them with similar marginal costs. With wind integration costs in California ranging between \$4 and \$8 per MWh – and consequently, \$6 to \$12 per ton of CO_2 avoided – the impacts of this analysis on the optimal mix of GHG reduction policies is potentially significant.

The whole purpose of a cap and trade system, like the one being developed under AB 32, is to find the most cost-effective way to reduce emissions. Internalizing the cost of pollution is one key step that allows this to happen. However, accurately representing the costs of each potential strategy is just as important. Individual players in a cap and trade system will seek to maximize their private benefit, which only corresponds to maximum social benefit if all external costs are included. The issue of wind integration costs should not be treated as an insult to the industry or its technology; instead, it is simply a technical reality.

Second, market structure and policy issues can have a major impact on integration costs. The realistic policy levers to manage integration costs may not be the ones with the most popular appeal. Giant energy storage projects are not cost-effective, and CAISO can not simply "spread out” wind generators. The inherent flexibility of generating resources is largely fixed, and policymakers have only limited control over the mix of renewable technologies.

On the other hand, issues that sound very mundane can play a major role in driving integration costs to the lower end of the range. Policies should be designed to minimize and allocate wind integration costs. Cost minimization means that GHG emissions from wind will be cheaper. Cost allocation means that the market will accurately find the optimal mix of GHG reduction strategies, and has the side benefit of creating an incentive for even further cost reduction.

Specifically, some combination of the six policy levers from Chapter 4 could go a long way to meeting these goals. CAISO could look into shortening market intervals and gate closure times; introducing imbalance charges; expanding balancing area cooperation; increasing the robustness of economic redispatch; using more demand-side management or storage; and integration fees. Each of these has either empirical or theoretical support for its role in minimizing and.or allocating integration costs.

Finally, wind integration costs will only increase with time. Thanks to a diverse resource mix, California should see modest integration costs for the time being. However, as policymakers consider moving beyond the 33% RPS standard to even more ambitious goals, they are more likely to encounter the non-linearities found in most studies. Furthermore, if California truly wants to be a national leader, it needs to demonstrate that its solutions can be replicated at the national scale, not just in areas whose wind resources are balanced by significant solar, geothermal and hydroelectric potential. California will have to address the issue of integration costs at some point; it might as well do so now, when the costs are still modest and controversy might be less heated.

In the 20th century, when renewable energy was still something of a novelty, integration costs would not have seemed like a major consideration. The solar panels on the roof of Jimmy Carter's White House would have had an infinitesimal impact on the electric grid, and renewable energy plants subsidized by the Public Utilities Regulatory Policy Act of 1978 generated a truly miniscule amount of energy. However, policies as aggressive as California's 33% RPS and cap-and-trade program mean that the days of viewing renewable energy as a technological curiosity are well on their way out. As the quantity of renewable energy increases, and as the urgency to achieve cost-effective GHG solutions grows, it is no longer acceptable to ignore the hard operational details of renewable power. Significant help from state and federal policy has allowed wind power to earn the premium it rightly deserves for reducing CO_2 emissions; however, enlightened and efficient markets must consider costs as well as benefits. California has long been a national leader in promoting environmental awareness and stewardship, and its current policy regime is solidifying that reputation. Prudent action to understand, minimize and allocate wind integration costs can ensure that this reputation will not be for simple idealism, but for smart and economically efficient planning as well.

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