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The Impact of Balancing Area Size, Obligation Sharing, and Energy Markets on Mitigating Ramping Requirements in Systems with Wind Energy¹

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ABSTRACT

Balancing area reserve sharing² holds the promise of significantly reducing wind integration costs. In a companion paper³ we examine wind integration costs as a function of balancing area size to determine if the larger system size helps mitigate wind integration cost increases. In this paper we turn to an examination of the NYISO sub-hourly energy market to understand how it incentivizes generators to respond to ramping signals without having to explicitly pay for the service. Because markets appear to have the ability of bringing out supply response in sub-hourly energy markets, and because existing thermal resources appear to have significant untapped ramping capability, we believe that a combination of fast energy markets and combined balancing area operations can increase the grid's ability to absorb higher wind penetrations without experiencing significant operational problems or costs.

INTRODUCTION: POWER SYSTEMS OPERATION AND WIND

During the past several years, the use of wind energy has expanded around the world. In the United States, there were nearly 17 GW of wind capacity online at the end of 2007 (<http://www.awea.org/projects/>) and an additional 3 GW of wind under construction. The growth in actual and prospective wind energy facilities has in part stimulated a number of analyses of power system operations at the same time as additional experience with wind has helped grid operators become familiar with this relatively new energy source.

A significant focus of several wind integration analyses has been on the operational impact that wind has on the grid. These impacts arise from the variable nature of the wind resource and from the difficulty in accurately predicting wind energy hours or days in advance. Wind integration studies prior to 2006 have generally focused on the impact of wind on power system operations within existing balancing area boundaries. A recent study carried out for the Minnesota Public Utilities Commission by EnerNex (2006) examined the

¹This work is based on a paper presented at WindPower 2007 by the authors.

²Balancing area obligation sharing involves the continuous sharing of ACE and imbalance obligations among two or more balancing areas in order to reduce regulation and load following requirements in meeting CPS 1 and 2. It is the continuous analogy to the current practice of sharing contingency response obligations within reserve sharing groups.

³The Impact of Balancing Area Size and Ramping Requirements on Wind Integration, to appear, *Wind Engineering*.

impact of a 20% wind penetration (based on energy) statewide, and recognized the interconnection benefits to the MISO energy markets. Miller and Jordon (2006) illustrated the benefits of balancing area consolidation using data from GE Energy (2005) for the New York State Energy Research Development Authority.

Because wind energy is primarily an energy source used for saving fuel, and not as a capacity resource used for meeting peak loads, the capacity value of wind will be a fraction of its rated nameplate capacity. In the extreme (and highly unlikely) event that wind has no capacity value, any system that is capable of operating in the absence of wind can continue to operate with wind. The installed non-wind generation would be capable of supplying needed capacity and energy during the times that it is needed. Although operational changes would be expected to arise with the addition of wind energy, the sufficiency of the pre-existing system would clearly still be adequate.

However, there has been recent concern about whether sufficient ramping capability exists to help manage the increasing variability that results from significant wind penetrations. Bonneville Power Administration (BPA) recently embarked on a study to determine the extent to which wind forecasts could help reduce wind integration costs. BPA also raised concern about the increased cost of dealing with wind ramp requirements at the Northwest Wind Integration Action Plan Technical Work Group Meeting, Aug 14, 2006. This concern has also been raised by other utilities and grid operators.

To help address the issue of ramping, we obtained data that could be used to calculate system ramping requirements both for individual balancing areas (formerly called control areas) and a combined, integrated balancing area. We used wind data from the Minnesota PUC's 20% Wind Integration Study (EnerNex, 2006), which was simulated by WindLogics to represent a geographically dispersed wind scenario for the study. Because of proprietary concerns, we were unable to secure load data from the utilities, nor were we able to obtain data for the non-wind generation. Instead, we used data from Platts' Basecase to extract hourly load data by balancing authority, and thermal generation data.

In some of our previous work we utilized Platts' hourly thermal generation data to estimate the ability of a balancing authority to provide ramping (Kirby & Milligan, 2005). The Platts data is derived from EPA filings that detail hourly emissions of all thermal power plants in the U.S. The data set shows actual thermal generation on an hourly basis for all thermal units in the footprint. Because this is actual data from 2004, our study year, it is important to note that the thermal units were committed and dispatched for a system with limited wind generation, and caution must be used in interpreting these data. However, our approach was to calculate the actual ramping capability of each thermal unit in MN, based on *actual, observed* data. Specific ramping capability for each generator are very likely to be larger, perhaps significantly so, than what we were able to observe in our data. In addition, any non-thermal generating source, such as hydro and nuclear, were not part of the database. Although nuclear units do not provide any significant ramping capability, hydro generation does.

Because our work was limited to an analysis of hourly data, we are confident that we significantly understate the benefits of combined reserve sharing or balancing area operations. Miller and Jordan (2006) showed that, as measured by standard deviation of load and wind variability, the benefits of combined operations were greater for the 5-minute time slice as compared to the hourly period. The penetration of wind in the NY study was 10%, based on wind rated capacity to system peak load. In contrast, our MN data set is a much higher penetration. To accentuate wind's impact on the system, we used the Platts load data, as reported in 2004, without scaling to the higher load level that was used as the basis of the MN study. Our wind penetration is therefore approximately 30% based on energy, and

approximately 50% based on capacity. Our system representation shows an annual combined peak load of 11,378 MW with rated wind capacity of 5,688 MW.

Our analysis in a previous paper (Wind Engineering part 1) examined the impact that wind has on balancing area ramp requirements, and compared the need for ramping under two scenarios: (1) balancing areas continue with separate operation, obtaining all needed ramping from within the area, and (2) the state of MN operates as a single balancing area. This second scenario was the basis for the MN 20% Wind Integration Study. Contrary to the MN study, we ignored any interaction with the MISO energy market or with generating units that are outside the MN footprint. This puts the entire ramping burden on generators that are within the balancing area. Using the same data set, augmented by the Platts generation data, we provide an analysis of the supply of existing ramping capability, compare it to the demand, and discuss how sub-hourly energy markets provide and price ramping services. We also use data from the NYISO as an example of this phenomenon.

BALANCING AREA RAMPING CAPABILITY

In (Wind Engineering Part 1) we showed how balancing area size influences the ramping requirements of the aggregated wind fleet; geographic diversity greatly reduces the wind ramping impact. We also showed how aggregating wind with load further reduces the ramping requirements of the aggregation. These are genuine physical reductions in integration requirements. We now look at the supply of ramping capability. The work offered here extends previous work we presented at WindPower 2005 and 2006 (Kirby and Milligan, 2005 and 2006) where we introduced a method for determining a balancing authority's ramping capability for every hour of the year. We also discussed how ramping can be either a very low-cost byproduct of fast energy markets, or it can be a very expensive additional service, depending on the characteristics of the balancing area's generation fleet.

Ramping: Low-Cost Energy Market Byproduct or Expensive Service?

We are going to argue that in many cases there is an abundance of ramping capability inherently available from the conventional generation fleet. Market rules may or may not provide access to that capability, but it is physically there. This can be quantified on an hourly basis for any given balancing authority. The reason that ramping (or load following) is often essentially costless can be seen through the example presented in Figure 1. This typical daily load curve shows four classes of generators serving the load. Nearly 20,000 MW can be served from the lowest cost baseload generators that can run continuously and need no maneuvering capability to meet their energy obligations.

The remaining generators (Intermediate 1, Intermediate 2, and Peaking) must have maneuvering capability simply to be in the energy market. Their output is not needed all day, so they must have the ability to cycle on and off in order to sell into the hourly energy market. If they could not cycle or follow load, they would not be selected to supply energy at all. They would have to compete with the baseload generators that do not cycle, but which have lower costs. These last generators must be flexible concerning their output levels and run times, not because of load following requirements, but simply to be able to sell energy into a variable market. Flexibility would be needed even if the load was known in advance (it is still different from day to day). Flexibility would be needed even if the load made perfect step changes hourly (both run time and level would still vary). Inflexible units such as nuclear plants simply could not serve this part of the load or sell energy into this market.

When a utility or an IPP considers building a generator, it has to decide which part of the market it wishes to serve. If it wants to serve the baseload market, it will build a generator with

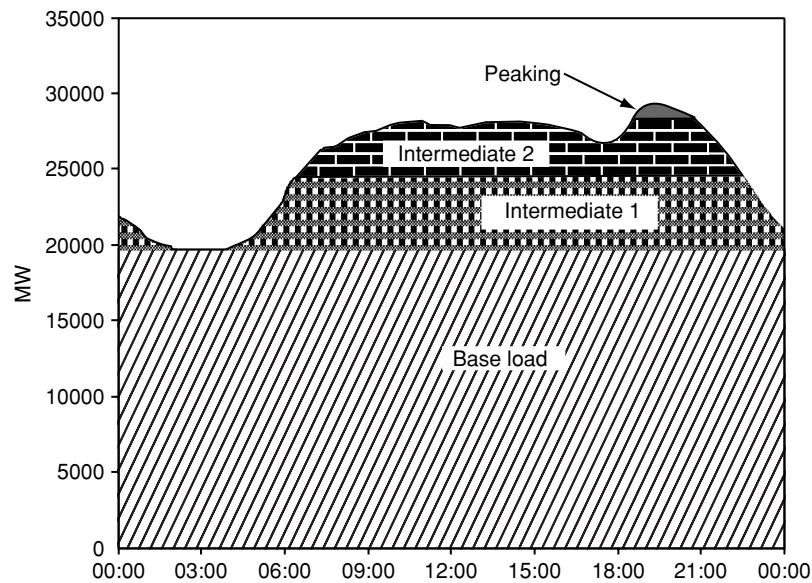


Figure 1: Participation in energy markets requires maneuverability for all but base load units.

low operating cost so that it is always on. It will have high efficiency and low fuel costs. Capital cost can be higher because the cost is spread over many hours. The generator need not have much maneuvering capability. If the utility or IPP decides it can't compete with existing baseload generators, and wants to serve the intermediate or peaking market instead, the generator will have to be lower capital cost because there are fewer hours to spread that cost over. It can have a lower efficiency or a higher fuel cost because power prices will be higher. It must be maneuverable to be able to enter and leave the energy market as prices rise and fall with rising and falling load.

The basic question of whether we need a ramping service or just fast energy markets can be looked at somewhat differently now. Do the generators that are built to meet the intermediate and peaking energy markets (higher operating cost, lower capital cost) inherently have enough response capability to meet the system's ramping needs? If so, there is little point in creating or paying for a ramping service, or dispatching specific generators to provide it. Integrating wind generation, with its increased ramping requirements, may not be too expensive.

First we will examine the opposite case. What if the marginal generators do not have sufficient ramping capability? Figure 2 presents a hypothetical example where a fast energy market, which normally provides load following as a byproduct, may have difficulty providing ramp capacity under some conditions. Prior to 8:00 a.m., this example system is serving the 2,550 MW load with over 3,000 MW of base-load generation and therefore clearing all energy at \$10/MWh. At 8:00 a.m., a 300 MW ramp starts which the base load generation can not follow. There is ample base load capacity; it simply can not ramp fast enough. Peaking generation (the only other generation in this example system) is started to meet the ramp needs. The peak generator stays on until the base load generation can ramp up. With no explicit ramping service, the price rises for the *entire* energy market (all 2,850 MW) from \$10/MWh to \$90/MWh for 5 hours just to follow a 30-minute 300-MW ramp. In this case, it might be better to create a separate ramping or load following service and pay the peak generator for its response, rather than distorting the price of the entire energy market.

It is very important to determine if ramping requirements can be served at a low cost as a byproduct of the sub-hourly energy market, or if ramping requirements impose a high cost

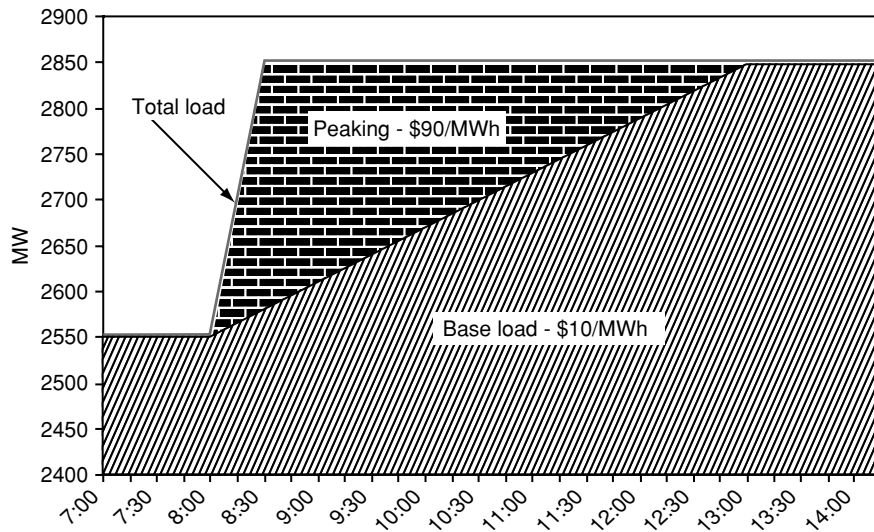


Figure 2: In this simple example load following is required from an expensive peaking generator but energy is only an incidental product.

because dedicated resources must be used. Wind integration studies that *assume* the need for dedicated ramping resources will calculate much higher integration costs than ones that tap actual system ramping capability. We analyzed demonstrated thermal ramping capability from a public database and compared it to the system balancing requirements for alternative balancing area configurations.

Individual Generator and Fleet Ramping Capability in Minnesota

We used the method we first developed in 2005 to determine individual thermal generator and aggregate ramping capability that was available each hour of the analysis year.⁴ Because generator ramping capability is not publicly available, we derived both the unit capability and the hourly availability from hourly public generator output data using the methods described in Kirby and Milligan (2005). For each generator, we analyzed a year of hourly generator output data to determine the maximum output, minimum non-zero operating output, and MW/min ramping capability. We were careful to avoid hours immediately before or after startup or shutdown, when false ramp rates and minimum loads are in the data. These estimates of generator capability are conservative. They only consider capability that was used during the year, and they can not detect faster ramp rates that are not sustained for a full hour. Only thermal generators are considered, so ramping capability from hydro is ignored. Generators that are located outside of the four control areas (Great River Energy, Minnesota Power Company, Northern States Power, and Otter Tail Power) were also not considered. Individual generator capabilities were summed each hour to determine the total balancing area thermal fleet capability.

Figure 3 presents a histogram of the fleet ramping capability compared with the ramping requirements of the load, and the load aggregated with wind generation. Two things are immediately obvious. First, thermal ramping capability generally greatly exceeds load and wind requirements. Second, load and wind up and down ramping requirements are largely

⁴Hourly generator output data is published as an EPA requirement. It is only available for fossil-fuel burning generators.

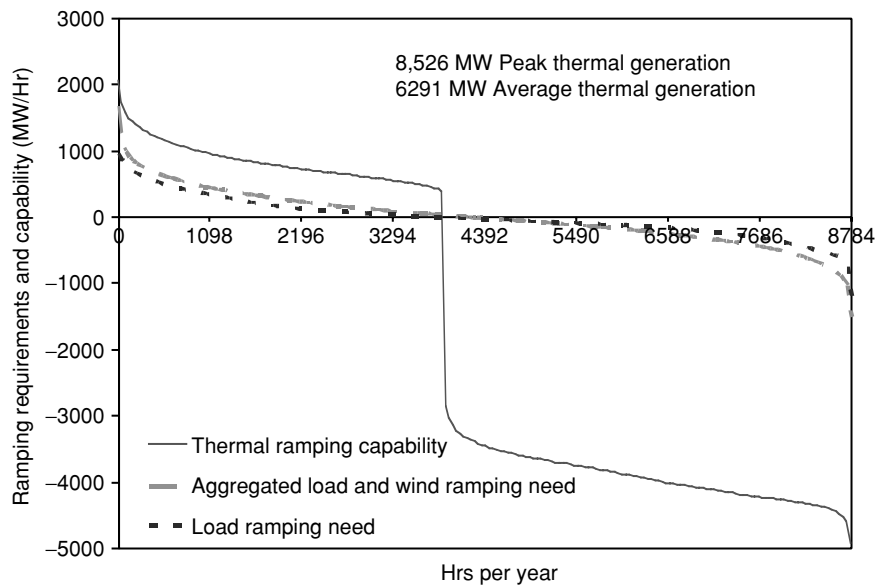


Figure 3: Thermal ramping capabilities exceed load and wind ramping requirements.

symmetric, but the generator ramping capability is not. There is much more down ramp capability than up ramp capability. This is not surprising. Most generators tend to get dispatched near full load so they have more capability to move down than up in normal operations.

The daily pattern of thermal generating fleet ramping-capability is shown in Figure 4. The daily load shape is perceptible, but it does not dominate. That is, average up ramp capability is greater during the night than during the day, but it never approaches zero. Down ramping capability is always large. The thermal generation fleet always has the capability to respond to nearly 3,000 MW/hour of wind increase.

Implications for Wind Integration

Thermal units in this system have ample ramping capacity to accommodate load and wind for the vast majority of hours. This does not disagree with operator recollections of specific instances when wind ramping caused problems. Instead, it suggests that ramping is not normally an economic problem. The lack of symmetry indicates that wind up-ramps are much less of a concern than wind down ramps. Of course, if the wind is already blowing, it has freed up generating capacity that is in theory available if the wind stops. This does not guarantee that there will be sufficient ramping capability, or that the generation is even on line and available to respond.

Access to the sub-hourly ramping capability of the generators that are in the energy market is critical. Market structures that artificially limit generator movement artificially deny the system a vital reliability resource, and force the expensive procurement of alternative maneuverability. This greatly increases wind integration costs and provides no benefits. Though available generator ramping capability adds linearly as larger groups are aggregated together, the load and wind ramping requirements do not. Consequently, the probability that excess ramping capacity is available increases as the balancing region increases in size. This can be accomplished by combining Balancing Areas or by facilitating sub-hourly transactions between individual Balancing Areas.

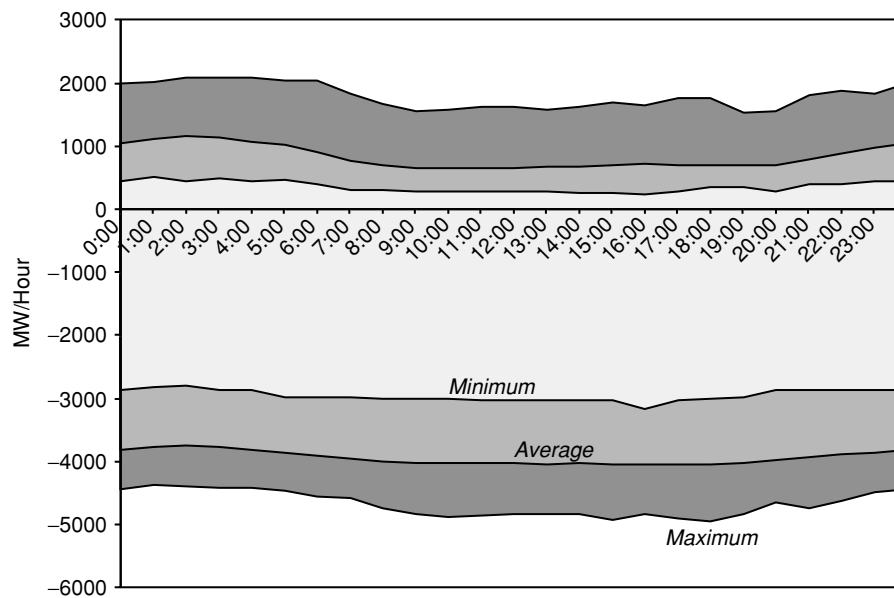


Figure 4: Hourly system ramping capability reflects the daily load pattern, but the daily pattern does not dominate. The plot reflects a full year of hourly data.

Physical access to the generation is critical as well. Transmission constraints complicate the situation by subdividing the generation pool and disaggregating the ramping resource. We made no attempt in this analysis to account for transmission constraints.

Obtaining Load Following From Real-Time Energy Markets: NYISO Example

The fact that excess ramping capability exists within the generation fleet does not itself guarantee that generators are willing to maneuver without significant compensation. An examination of sub-hourly energy markets shows that the energy markets themselves do provide such an incentive, and they do it without incurring costs to customers. ERCOT, PJM, NYISO, ISONE, MISO, and CAISO all operate sub-hourly energy markets which are capable of responding to wind variability and forecast error. We examined a year of sub-hourly price data from the NYISO.

Examination of price data from the NYISO 5-minute real-time market provides insights into how load following can be extracted from sub-hourly energy markets at little or no cost. NYISO 5-minute real-time energy market price-data was examined for all of 2006 to determine if there is a cost associated with obtaining sub-hourly response from generators. Clearly, obtaining minute-to-minute response is costly since regulation is always the most expensive ancillary service, with prices that remain high even at night. Presumably, then, 5-minute response would be more expensive than hourly response. NYISO data provides some surprising results.⁵

Regulation markets specifically procure maneuvering capacity from generators. When a generator sells a MW of capacity to the regulation market for an hour the generator gives the system operator the right to move the generator's real-power output anywhere within the sold range in whatever manner the system operator desires. Generators participating in sub hourly energy markets, on the other hand, do not sell control; they simply respond to energy

⁵Price data is for NYISO 2006 reference bus. Actual locations incur costs (or payments) for losses and congestion. Examining locational prices in the 11 NYISO zones produced similar results.

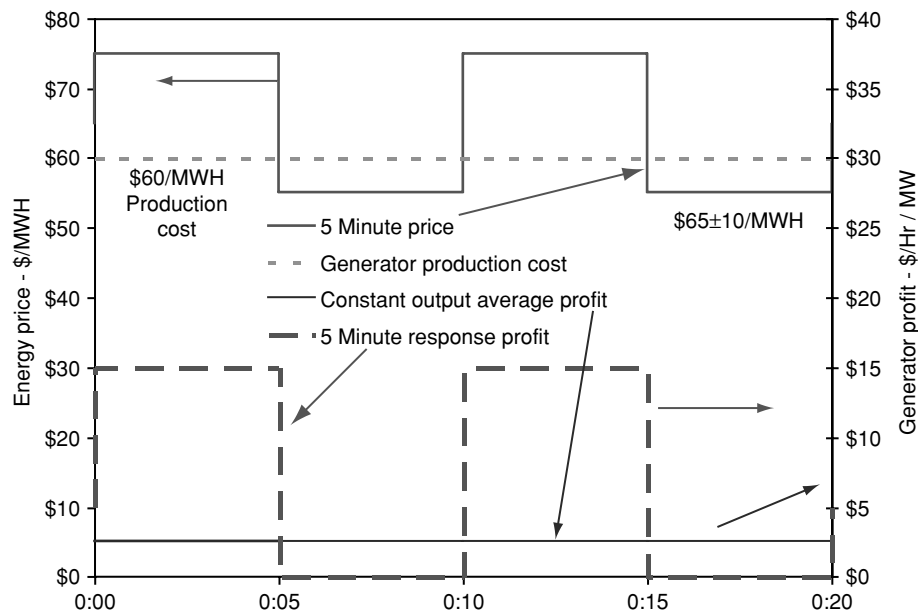


Figure 5: A simplified one-hour example shows there is an incentive for some generators to respond to 5-minute price signals.

price signals. Further, prices seldom got to zero or negative. This means that a generator's response incentive in any given sub-hourly interval depends on the generator's production cost; some generators will have an incentive to respond, and others will not. Any are free to maintain a constant output and accept the hourly average price if their maneuvering cost is too high. Studying a year of 5-minute price data, we found that the NYISO 5-minute market provides a significant response incentive with the high and low prices for each interval in the hour differing by \$17.41/MWh on average. The market is continuously sending the 5-minute market a strong price signal to move up or down.

Figure 5 presents a simplified one hour example. Market prices are shown in the upper part of the graph. The 5-minute market price varies every interval between \$55/MWh and \$75/MWh. Clearly, any generator with a production cost below \$55/MWh will provide full output continuously, and will have no incentive to maneuver because it is making a profit during every interval.

Things are more interesting for a generator with a production cost above \$55/MWh. The lower portion of Figure 5 shows the profit that a generator with a \$60/MWh production cost would receive from the two behaviors in the market. The generator would earn a \$5/MWh profit if it maintained a constant output (\$65/MWh average price - \$60/MWh production cost). It would earn \$7.50/MWh profit (\$75/MWh price - \$60/MWh production cost = \$15/MWh profit for half of the time and \$0/MWh for the other half of the time), \$2.50/MWh more, if it responded to the 15-minute price signal and curtailed production during the intervals that the price was below its production cost (we have a *very* flexible generator in this simplified illustrative example).

The 5-minute market provides an economic incentive for generators with marginal costs that are close to the market clearing price to respond. Figure 6 shows how the incentive to respond (solid curve) changes as a function of generator production cost, peaking when the production cost is equal to the market prices. Note that while the incentive to respond rises as generator production cost rises, the actual profit the generator receives for either behavior declines (dashed and dotted curves) as the generator's costs rise.

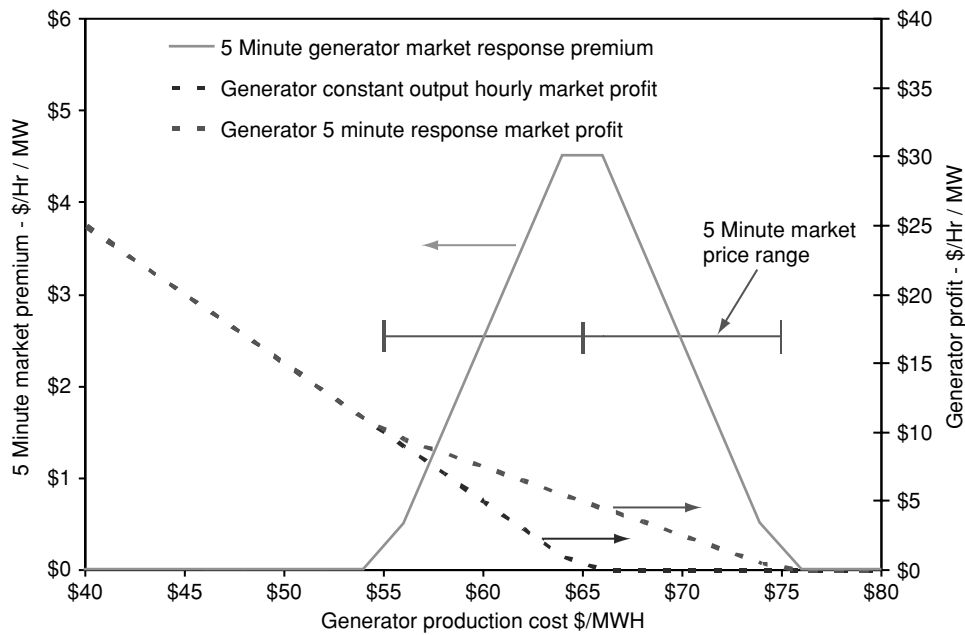


Figure 6: The sub-hourly response incentive is a function of the generator's marginal production cost.

NYISO

The actual NYISO market structure adds an interesting complication to the simplified example presented above:

- \$55.51/MWh average day-ahead hourly price
- \$52.01/MWh average real-time 5-minute price
- \$3.50/MWh average fast-market participation penalty⁶

The average energy price for all of 2006 was \$3.50/MWh *higher* in the day-ahead hourly market than in the 5-minute real-time market. This price difference reflects the difference in value of day-ahead commitment vs. the real-time transaction as well as any difference associated with the faster 5-minute response. This appears to say that there is no overall cost to the power system associated with obtaining 5-minute response from generators; in fact, the faster market clears at a lower price on average.

Given that the hourly market yields a higher average price than the 5-minute market, and given that any unit capable of responding to the 5-minute market is capable of responding to the hourly market (but the opposite is not necessarily true), one wonders why any generator would choose to participate in the 5-minute market instead of the hourly market? One answer lies in a more detailed look at the two markets.

While the annual average prices for the two markets are fairly close, prices during individual 5-minute intervals differ significantly. As stated above, the annual average of the price difference *absolute value* during each 5-minute interval is \$17.41/MWh. The NYISO market is continuously sending the 5-minute market a very strong price signal to move up or down with respect to the hourly market.

Figure 7 presents a simplified example for the NYISO market which is similar to the hypothetical illustration shown above. The difference is that the NYISO market still provides

⁶This price difference also reflects the difference in value of day-ahead commitment vs. the real-time transaction.

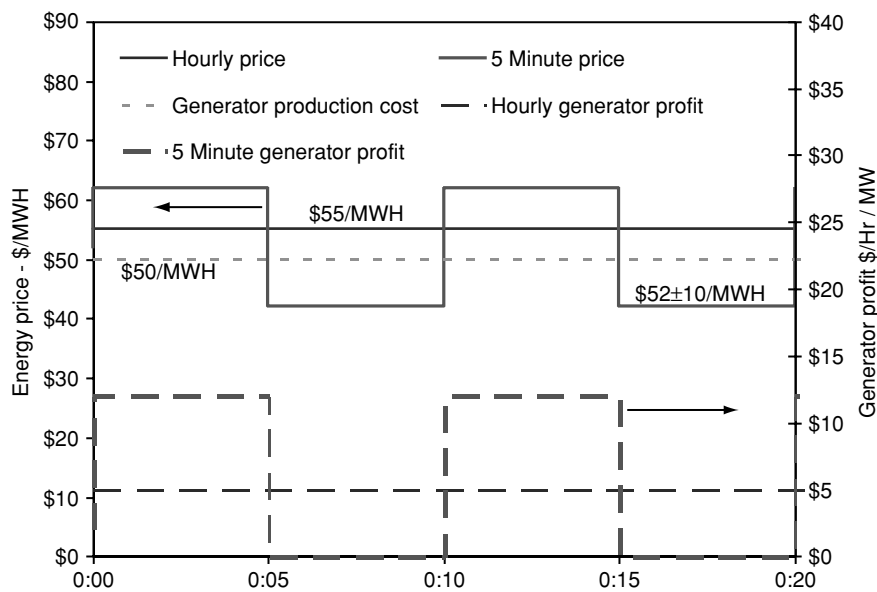


Figure 7: A simplified one-hour example shows there is an incentive for some generators to respond to 5-minute price signals.

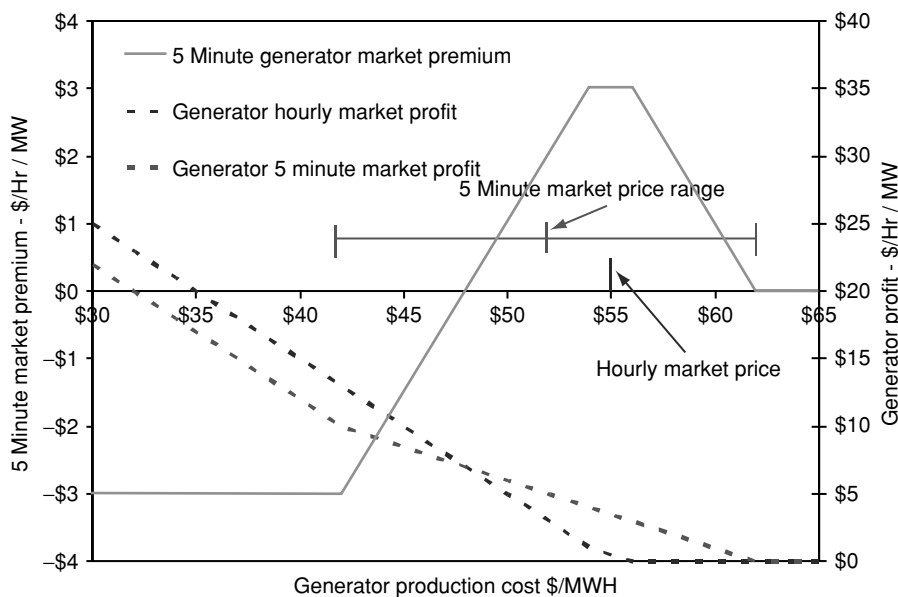


Figure 8: The sub-hourly response incentive is a function of the generator's marginal production cost.

a response incentive even though the hourly price is higher than the average 5-minute price. Figure 8 shows that the response incentive is negative for generators with a production cost below \$48, but is positive for higher cost generators. Finally, Figure 9 presents the incentive results for the full year. A generator with a production cost above about \$40/MWh⁷ has an incentive to respond to the 5-minute market price signals. Of course, any actual generator will move between the two markets throughout the year as price signals dictate.

⁷The price where the response incentive starts is higher at locations with losses and congestion costs, but the concept is the same.

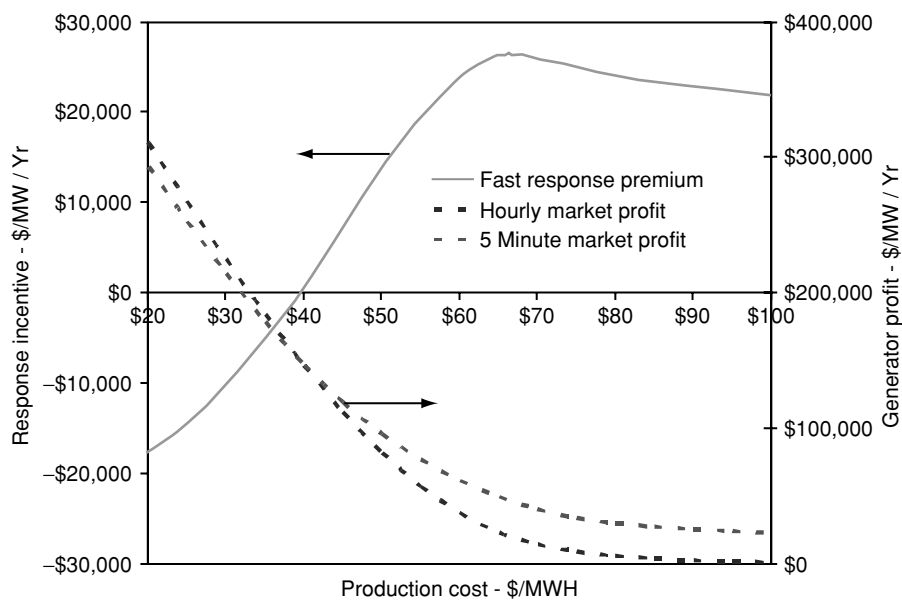


Figure 9: Price data from NYISO 5-minute and hourly 2006 markets shows that generators with production costs around \$40/MWh have an incentive to respond.

The net result is that regions that operate sub-hourly energy markets inherently provide economic incentives to specific generators to voluntarily provide intra-hour response and they can do this at no added cost. While minute-to-minute regulation is inherently an expensive ancillary service, intra-hour load following need not be.

Forecasting Errors, Ramping Requirements and Unit Commitment

The unit commitment process is the multi-day equivalent of the hourly and sub-hourly economic dispatch. It assesses system requirements at least a day ahead (longer for generators with long startup times) to determine the least-cost mix of generation to have available for each interval of the next several days. This is necessary because some generators require significant time to start up. It is also necessary to consider the intertemporal constraints so that the least-cost, on-peak generation mix is also able to economically turn down far enough to operate during off-peak hours. Selecting generators for the least-cost energy supply is the primary consideration, but the unit commitment process must also assure that the selected mix has enough ramping capability to meet the aggregated balancing area's needs each hour.

Forecasting error is important as well. A unit commitment that precisely matched tomorrow's expected conditions might prove to be an expensive mistake if the load was a few percent higher and not enough cheap generation was made available. It can also be expensive to over-commit generation that is not needed. The optimal unit commitment process must consider a range of future conditions and select a robust solution.

Adding wind to the balancing area complicates the unit commitment process. Energy requirements, ramping requirements, and forecast error amounts all change. A robust unit commitment solution is even more important to deal with the greater uncertainty. In calculating the increased unit commitment cost it is important to correctly select the base case. The base case must include the load uncertainty for the comparison to be valid. Wind and load forecast errors will not add linearly. Evidence from the Minnesota 20% Wind study shows that wind

forecast errors from four sites are generally uncorrelated on an hourly basis. The aggregate forecast error is reduced by 38% for the combined sites, as compared to individual sites.

The unit commitment problem is numerically more complex in a large balancing area because of the larger number of generators, but the economic commitment solutions are more robust, less volatile, and lower cost. This is because each individual generator is a smaller percentage of the total system requirements. This gives the unit commitment algorithm more flexibility in achieving a finer resolution solution. Load and wind forecasts are more accurate for larger balancing areas as well. Recent information from Germany characterizes the RMS wind day-ahead forecast errors as follows: single wind farm 10% - 20%, Single Control Area (250 square miles) 7.5% - 10%, and all control areas in Germany (400 × 500 miles) 5% - 6.5%.

Relevance to Wind Integration Studies and Implication for High Wind Penetration

Several wind integration studies have been done in the U.S. during the past few years. These analyses focus on the physical requirements of wind integration, and generally also calculate the wind integration cost based on these requirements. Table 1 shows some results from recent studies (Smith et. al., 2007). Of the integration studies in Table 1, all but one study finds that load following costs are very low. That one is from a region that does not have sub-hourly energy markets.

In two studies of California (Shiu, 2006 and Miller et. al 2007), load following cost was estimated to be approximately zero because of the depth of the dispatch stack. California has a robust energy market which runs every five minutes. The analyses concluded that this market provides sufficient flexibility to provide load following services, and by implication, ramping, because of the fast energy market and large resource stack. As our analysis has shown, fast energy markets can often provide sufficient ramping capability at little or no cost. When the currently running resource mix does not have the ability to ramp quickly enough, a high-cost quick-start unit may be necessary, and this can set the energy price in the market.

It is widely accepted that the wind integration cost will generally increase with wind penetration. Existing studies have shown that to be true, as indicated in Table 1. There has been additional speculation that “at some point,” integrating larger wind penetrations will be difficult and costly. This hypothesis is sometimes known as the hockey stick hypothesis, and says that wind integration cost will increase sharply at some critical penetration rate.

Few, if any, integration studies have successfully identified this point of sharply increased integration cost at penetrations studied so far. In this paper, we have demonstrated that this potential high integration cost could occur if the least-cost energy-producing generators did not have enough ramping capability to meet the aggregate system needs. In that case, faster responding, more expensive generation would have to be brought on line. If this happened very many hours each year, it could be very expensive as it would raise the market clearing price of energy for all buyers and sellers. This could occur if there was not enough physical ramping capability in the energy market generation fleet, or if the market structure did not allow generators to respond to sub-hourly energy market signals.

At the same time, in a previous paper (Wind Engineering Part 1) we have shown that ramping requirements can be reduced by balancing area consolidation. Because markets appear to have the ability of bringing out supply response in sub-hourly energy markets, and because existing thermal resources appear to have significant untapped ramping capability, we believe that a combination of fast energy markets and combined Balancing Area operations can increase the grid's ability to absorb higher wind penetrations without experiencing significant operational problems or costs.

Table I Wind Integration Results

Date	Study	Wind Capacity Penetration (%)	Regulation Cost (\$/MWh)	Load Following Cost (\$/MWh)	Unit Commitment Cost (\$/MWh)	Gas Supply Cost (\$/MWh)	Total Operating Cost Impact (\$/MWh)
May '03	Xcel-UWIG	3.5	0	0.41	1.44	na	1.85
Sep '04	Xcel-MNDOC	15	0.23	na	4.37	na	4.60
June '06	CA RPS	4	0.45*	trace	na	na	0.45
	multi-year						
Feb '07	GE/Pier/CAIAP	20	0–0.69	trace	na**	na	0–0.69***
June '03	We Energies	4	1.12	0.09	0.69	na	1.90
June '03	We Energies	29	1.02	0.15	1.75	na	2.92
2005	PacifiCorp	20	0	1.6	3.0	na	4.60
April '06	Xcel-PSCo	10	0.20	na	2.26	1.26	3.72
April '06	Xcel-PSCo	15	0.20	na	3.32	1.45	4.97
Dec '06	MN 20%	31**					4.41**

*3-year average; total is non-market cost

**highest integration cost of 3 years; 30.7% capacity penetration corresponding to 25% energy penetration; 24.7% capacity penetration at 20% energy penetration

***found \$4.37/MWh reduction in UC cost when wind forecasting is used in UC decision

CONCLUSIONS

Increasing the size of balancing areas, or collectively sharing the balancing obligation among a group of balancing areas (much as is done now for contingency events with reserve sharing groups), holds the promise of significantly reducing wind integration costs. It also reduces utility costs without wind. Some recent studies of integrating wind into large power systems seem to indicate that wind integration costs may rise more smoothly than previously assumed, based on analysis of smaller power systems. The “hockey stick” pattern of dramatically increasing wind integration cost above some threshold wind penetration may not be as pronounced as expected. The analysis in this two-part paper provides some explanation as to why costs may rise more uniformly than previously assumed.

In the first paper, we have shown that ramping requirements can be reduced by balancing area consolidation. Because markets appear to have the ability of bringing out supply response in sub-hourly energy markets, and because existing thermal resources appear to have significant untapped ramping capability, we believe that a combination of fast energy markets and combined balancing area operations can increase the grid's ability to absorb higher wind penetrations without experiencing significant operational problems or costs.

Based on the hourly data used for this analysis, we showed that balancing area consolidation will reduce the ramping requirements for load, wind, and load with wind. Our results show that the ramping penalty associated with operating independent balancing areas increases significantly when there is significant wind on the system, particularly with the extremely high penetration represented by our data set. Because of the declining correlation between wind and load for faster time frames, the aggregation benefit is expected to increase for faster load following time frames. This can be verified by reviewing results from wind integration studies that evaluate the regulation time frame, and is supported by Miller & Jordan's analysis of the NYISO system.

Balancing areas that operate sub-hourly markets can obtain ramping capability from the generators supplying energy at little or no cost. The critical questions are: does the on-line

generating fleet have sufficient physical maneuvering capability and does the market structure provide access to it? Sub-hourly energy markets provide economic incentives for generators to respond when needed. Insufficient ramping capability will manifest itself as a need to dispatch generators out of economic merit order and may (depending on the market rules) increase the market clearing price of energy. Market monitors will be able to determine if this is happening so that it can be remedied. One remedy would be to initiate a specific load following or ramping service, similar to regulation, but over a longer time frame. To date, no balancing area that we are aware of has initiated a load following service.

Our study of the NYISO sub-hourly energy market shows that the market provides strong economic signals to the marginal units to provide ramping response without increasing the average cost of energy. Individual generators are free to respond or to accept the average price and hold a flat hourly output, whichever is more economic for their operation. They can increase their profit considerably, however, if they are able to follow the fast energy price signals.

Generator ramping capability data is not publicly available, but a conservative estimate of that capability can be deduced from hourly energy reports. Examining the output of all thermal generators in Minnesota for a year allowed us to calculate each unit's demonstrated hourly ramping capability, as well as the excess ramping capability that was on line for each hour of the year. The thermal fleet always has dramatically more downward ramping capability than the aggregate system requires. This is not surprising because thermal generators are typically dispatched near full load. This means that the fleet has ample ramping capacity to accommodate unexpected increases in wind generation as long as there is no transmission congestion that blocks access.

The thermal generation fleet also has significant up-ramp capability, generally, over two times what is required for both load and wind. Of course, adding wind to the system displaces thermal generation and frees up that generation to respond to drops in wind as long as the unit commitment continues to keep the generation on line. More detailed simulations are required (and are done as part of wind integration studies) to determine if there is a unit commitment cost associated with assuring the appropriate unit commitment.

In summary, increasing the effective size of balancing areas, either through consolidation or through sharing of balancing obligations, reduces the cost of wind integration. Sub-hourly energy markets provide incentives and rewards for generators to respond to ramping needs. Together, these two effects greatly reduce the cost of integrating wind and mitigate the expected dramatic increase in integration costs as wind penetration levels increase.

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