INTEGRATION OF STOCHASTIC POWER GENERATION, GEOGRAPHICAL AVERAGING AND LOAD RESPONSE

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Abstract - The objective of this paper is to analyze how the variability of wind affects optimal dispatches and reserves in a daily optimization cycle. The Cornell SuperOPF[1] is used to illustrate how the system costs can be determined for a reliable network (the amount of conventional generating capacity needed to maintain System Adequacy is determined endogenously). Eight cases are studied to illustrate the effects of geographical distribution, ramping costs and load response to customers payment in the wholesale market, and the amount of potential wind generation that is dispatched. The results in this paper use a typical daily pattern of load and capture the cost of ramping by including additions to the operating costs of the generating units associated with the hour-to-hour changes in their optimal dispatch. The proposed regulatory changes for electricity markets are 1) to establish a new market for ramping services, 2) to aggregate the loads of customers on a distribution network so that they can be represented as a single wholesale customer on the bulk-power transmission network and 3) to make use of controllable load and geographical distribution of wind to mitigate the variability of wind generation as an alternative to upgrading the capacity of the transmission network.

Keywords - SuperOPF, Ramping, Load Response

1 Introduction

THE current political environment[2] and concerns about global warming have favored the increase in generation from renewable resources, such as wind and solar, with renewable portfolio standards (RPS) in place for many states in the US [2]. The inherent variability of generation from renewable sources may lead to increases in the operating costs of the conventional generators used to follow the net load not supplied from renewable sources[3], as well as increase the amount of installed dispatchable generation capacity needed to maintain System Adequacy. Both of the aforementioned characteristics impose additional costs on the system that should be properly included by regulators. The higher operating costs for conventional generators are partly offset by lower wholesale prices, due to reduced total annual generation from fossil fuels, replaced by zero marginal cost power. Nevertheless, the lower wholesale prices imply lower annual earnings for conventional generators that lead to higher amounts of "missing money" needed to maintain the Financial Adequacy of these generators [3]. The objective of this paper is to study how markets for electricity should be modified to provide the correct economic signals for compensating storage and controllable loads that reflect the true system costs/benefits of ramping services, and reducing the capital cost of maintaining System Adequacy.

The next section discusses the structure of the SuperOPF and how it differs from a conventional optimization that minimizes costs subject to maintaining reliability standards. Sections 3 and 4 discuss the specification of the different scenarios, and Sections 5 and 6 present the results. The final section summarizes the conclusions.

2 The Super OPF for Reliability Standards

NERC has been given the responsibility to set the standards for reliability for the North American Bulk Power Network. NERC uses the following two concepts to evaluate the reliability of the bulk electric supply system [4]: *1) Adequacy - The ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. 2) Operating Reliability - The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated failure of system elements.* We propose a modified formulation of what we call the SuperOPF to deal with the requirements for reliability from NERC. In a standard Security Constrained Optimal Power Flow (SCOPF) [5], the objective is to minimize the cost of meeting load, while being able to respond to the $(n-1)$ contingencies. The covering of the contingencies is treated as a set of physical constraints on the optimization. An alternative way to determine the optimal dispatch and nodal prices in an energy-reserve market using co-optimization (CO-OPT) was proposed by Chen et al. [6]. The proposed objective function minimizes the total expected cost (the combined production costs of energy and reserves) for a base case (intact system) and a specified set of credible contingencies (e.g. line-outages, unit-lost, and high load levels) with their corresponding probabilities of occurring. Using CO-OPT, the optimal pattern of reserves is determined endogenously and it ad-

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[1] A stochastic contingency-based security constrained AC OPF with endogenous reserves, co-optimizing dispatch with a set of credible contingencies. [1].

[2] e.g. the *American Recovery and Reinvestment Act of 2009*.

[3] I.e. due to additional ramping costs

justs to changes in the physical and market conditions of the network. The SuperOPF [1] extends the CO-OPT criterion to include the cost of Load-Not-Served (LNS), also distinguishing between positive and negative reserves for both real and reactive power. A high Value Of Lost Load (VOLL) is specified as the price of LNS. In a conventional SCOPF used by most System Operators, the $n-1$ contingencies are treated as hard constraints rather than as economic constraints, as they are in the SuperOPF.[4] From an economic planners perspective, the standard of one day in ten years for the LOLE[5] should correspond to equating a reduction in the expected annual cost of operating the system, including changes in the expected cost of LNS, with the annual cost of making an investment in additional capacity.

A simplified formulation of the modified SuperOPF objective function is shown in (1).

$$\min_{G_{ik},R_{ik},\text{LNS}_{jk}} \sum_{k=0}^{K} p_k \Bigg\{ \sum_{i=1}^{I} \Bigg[C_{G_i}(G_{ik}^t) + \mathrm{R}_i^+(G_{ik}^t - G_{i0}^{t-1})^+ \\ + \mathrm{R}_i^-(G_{i0}^{t-1} - G_{ik}^t)^+ \Bigg] + \sum_{j=1}^{J} \text{VOLL}_j \text{LNS}(G_k^t, R_k^t)_{jk} \Bigg\} \\ + \sum_{i=1}^{I} [C_{R_i}(R_i^{t,+}) + C_{R_i}(R_i^{t,-})] \tag{1}$$

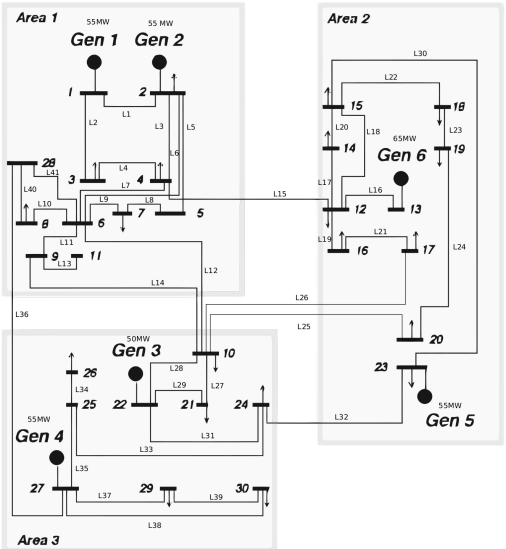
Subject to meeting Load and all of the nonlinear AC constraints of the network, where

$k = 0, 1, \ldots, n_c$	Contingencies in the system
$i = 0, 1, \ldots, I$	Generators
$j = 0, 1, \ldots, J$	Loads
p_k	Probability of contingency k occurring
G_i	Quantity of apparent power generated (MVA)
$C_G(G_i)$	Cost of generating G_i MVA of apparent power
$\mathrm{R}_i^+(G_{ik} - G_{t-1,i0})^+$	Cost of increasing generation from previous hour
$\mathrm{R}_i^-(G_{i0} - G_{t-1,ik})^+$	Cost of decreasing generation from previous hour
VOLL_j	Value of Lost Load, (\$)
$\text{LNS}(G, R)_{jk}$	Load Not Served (MWh)
$R_i^+ < \text{Ramp}_i$	$(max(G_{ik}) - G_{i0}))^+$, up reserves quantity (MW)
$C_R(R_i^+)$	Cost of providing R_i^+ MW of upward reserves
$R_i^- < \text{Ramp}_i$	$(G_{i0} - min(G_{ik})^+$, down reserves quantity (MW)
$C_R(R_i^-)$	Cost of providing R_i^- MW of downward reserves

3 Calculation of ramping costs and limits imposed

This study analyzes the consequences of ramping for load following performed by conventional generators. Henceforth, the simulation is done in hourly steps. Ramping in shorter time scales (e.g. 15 minutes) is assumed to be more associated to the provision of ancillary services different to load following, a different product with a corresponding price. For every hour, a two-stage optimization problem is solved. In the first stage (contracts settlement), the dispatches for the next time period $(t+1)$ are determined by solving the SuperOPF with endogenous reserves, given the best available wind and load forecast. In the second stage (real-time settlement), the wind realization is known. Then, the dispatches for the present time period $(t+1)$ are determined by solving a SuperOPF with reserves determined from the results of the first stage, updating the wind and load information. The outputs of each hour are interlinked, by setting the second-stage dispatches for hour t as the initial conditions for the dispatch in hour $t+1$. Deviations above or below the previous hour dispatch are priced according to the ability of generators to move from their current operating point. Therefore, a high ramping cost is set for generating units that have technical or operational constraints that make it expensive for them to adjust their power output (e.g. certain Nuclear units with limited ramping capabilities). Correspondingly, for combustion turbines with lower adjustment costs, a price close to 0 is set. The ramping costs enter the objective function as quadratic differences from the previous period dispatch. In addition, a set of limits on the maximum and minimum power output at any hour of the day are imposed for each generator. To set these limits, the SuperOPF with endogenous reserves is solved for the following two cases: 1) For estimating the maximum power available at any hour, the power output observed at the maximum load of the day with a low wind forecast is used. This scenario requires other generators to ramp up to compensate for the low output from the wind farms. 2) For the minimum power output, the minimum load of the day with a high wind forecast is used. The high wind forecast scenario is very challenging for System Operators, given the high probability of cutoff to protect the integrity of the equipment at high wind speeds (the cutoff speed is around 25 m/s), leading to either very high generation outputs or none at all. The steady state conditions are obtained by running the test system simulation over identical days, till the outputs stabilize. After simulating the system for three identical days, the differences in the dispatches, voltages, etc. between the corresponding hours in days two and three are close to 1×10^{-4}.

4 The Problem setup and Case Study scenarios



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[4] A hard constraint is equivalent to specifying the VOLL as plus infinity.

[5] Loss Of Load Expectation.

Figure 1: A One-Line-Diagram of the 30-Bus Test Network.

This case study is based on a 30-bus test network (Figure 1) that has been used extensively in our research to test the performance of different market designs using the MATPOWER platform. The capacities of the transmission tie lines linking Areas 2 and 3 with Area 1 (Lines 12, 14, 15 and 36) are the limiting factors. Since lines and generators may fail in contingencies, the generators in Area 1 are mostly needed to provide reserve capacity.

4.1 Characterization of Wind Generation and Load

The load profile chosen corresponds to a day in April 2005, with no large changes in the loads observed hour to hour occur, and relatively low average load levels. The main criterion for selecting a day is to have an example in which the system is not under stress because of lack of conventional generation capacity. Once this day was chosen, the corresponding hourly predictions of wind speed from an ARMA model[6] are used to establish the forecasts that planners would have had hour-to-hour given the available information at the time. Finally, the historical data for that day provides the realizations of wind speed observed and the power available from the wind farm. The observed wind speeds exhibit a substantial amount of variability on a relatively windy day.

4.2 Cases studied

Table 1 summarizes the cases studied. The wind capacity added is consider to have a zero offer price. the existing generation fleet is not modified. Cases 1-4 are run with and without ramping costs. This allows one to compare the effect of ramping on wind adoption [8]. The cases with no ramping costs are referred with a suffix ‘n’.

Table 1: Summary of Cases

	Description
1)	No wind; 35 MW coal unit installed at bus 13.
2)	Baseline single location Wind: 50 MW at bus 13.
3)	No Congestion: No Resistance considered[7].
4)	Constant Wind
5)	Distributed Wind (buses 13 and 27).
6)	Dist. Wind + Load Response (LR): 1 load in area 1.
7)	Dist. Wind + LR: several loads, area 1.
8)	Dist. Wind + LR: several loads, areas 1 and 2.

The 50MW capacity of the wind farm corresponds to around 12% of the installed generation capacity. Case 4 represents the net effect of coupling storage or batteries to the wind generator. The constant potential output means that available power at any point of time is the same. This type of smoothing also occurs with spatial aggregation of the total generation from wind farms at different locations [9]. However, there may be dispatches below the potential wind output because the available wind energy is not forced into the system. In Case 5, the wind forecast corresponds to historical data from New England, as in case 2. The capacity of each wind generator is 25MW, to maintain a comparable total wind capacity. This is equivalent to a lower bound on the effect of geographical averaging [10]. Table 2 contains a summary of the generation characteristics used. Each unit is classified according to the generator’s capability to move from their current operating point, with corresponding ramping costs (peak (p), shoulder (s) or baseload (b))[8].

The contingencies considered include

1. Line outages in the urban area.
2. Line outages between the urban area and the rural areas.
3. Full generation outages at a given bus and
4. Observed realizations of wind speed conditional on a given forecast.

Analyzing the impact of ramping costs requires looking at three main components: 1) The cost of covering the contingencies to maintain Operating Reliability, 2) hour-to-hour changes in the system load and 3) Accommodating the wind variability in the system.

Table 2: Ramping and reserve costs

		Fuel Cost($/MW)	Gen. Avail (MW)	Res. Cost ($/MW)	Ramp Cost ($/MW)
Oil	(p)	95	65	10	0
GCT	(p)	80	45	10	0
CC Gas	(s)	55	40	20	30
NHR	(s)	5	65	20	30
Coal	(b)	25	70	30	60
NHR	(b)	5	50	30	60

These three factors are considered in the evaluation of the different cases.[9] The set of contingencies considered both in the hour-ahead and in the real time stage was maintained constant for all hours of the simulated day.

4.3 Load Response and battery coupling

The characterization of Energy Storage Systems (ESS) for this study took into account charging and discharging over the horizon specified, which is reflected as a limited amount of wind capacity in the system. This allows for a basic modeling of storage in the system. Load response was derived from the optimal results obtained from two runs: the wind dispatches observed in a run with ESS, versus the wind dispatches observed for a run without ESS coupling. The differences in wind dispatches found were then assigned as additional load in Area 1, with a VOLL higher than the most expensive generation cost including ramping costs, but one hundredth of the VOLL for normal demand. This pricing reflects the “inconvenience cost” for

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[6] The ARMA model is developed with hourly wind speed data from New England, the methodology for this modeling is described in [7]

[8] In addition to the operating constraints, environmental concerns also play a role in the optimal price to be set for each unit. The ramping costs used in the case study take into account the considerations from [11] regarding the consequences of ramping for CO_2 and NO_x emissions. Therefore, units with higher potential for pollution when changing their power output are priced with ramping costs. Ideally, this would optimally discourage them from moving from their current operation point.

[9] It should be noted that the variability of wind generation is not the only factor that affects ramping costs.

customers at a higher price than fuel costs, in line with the compensation that is expected to make load response more widespread. The idea behind comparing a case with and without ESS is to bound the load response to an amount similar to the difference in dispatches for wind due to ESS usage. The underlying assumption here is that, everything else being equal, the difference in wind dispatches in the case with and without ESS is thanks to the battery coupling. Setting a similar load response capacity enables for a better leveled comparison between cases.

5 Results for the Wholesale Market

For the results in this section, it is assumed that the wholesale market is deregulated. The main questions of interest in this section are 1) how much generating capacity is needed for Operating Reliability, 2) what happens to the wholesale prices and operating costs, and 3) how do geographical averaging, load response and ramping costs affect operations and costs?. The reported daily costs correspond to sums over 24 hours of the expected costs from the second stage optimization of the modified SuperOPF (i.e. expected costs over 18 contingencies for a given wind realization). The key results for the twelve scenarios are presented in Table 3. The payments from load (row 1) show substantially lower payments for all wind cases compared to the no wind scenarios. The lower payments come from displacement of carbon fuels by wind, whenever it is available. Operating costs (row 2) are substantially decreased when wind is added. The removal of economic inflexibility in the form of ramping costs (Cases with 'n') relieves the need to use generation with more expensive fuel costs. This leads to lower operating costs in all equivalent cases- exclusive of ramping payments. The load response cases (Cases 6 to 8) have the lowest operating costs, explained by the dynamic response to wind outages. While payments from loads are reduced, the generation capacity needed to maintain operational reliability is increased as wind is introduced (move from case 1 to cases 2, 3 and 5). This is due to the possibility of a wind cutoff. Introducing load response for wind outages (Cases 6, 7 8) alleviates this pressure and allows for lower generation capacity needed. Whilst operating costs and payments from loads could be thought as cointegrated, the non-linear nature of the transmission system can break this apparent relation. The distribution of the wind capacity (Case 2 to Case 5) keeps the payments from loads and the amount of wind used almost identical. However, the generation capacity needed to maintain reliability marginally decreases (2%). Load response further reinforces this effect, with modest increases in wind dispatched, but significantly lower generation capacity needed (18% less Case 2 to Case 7). The energy needed to cover the load of the day is relatively constant, with lower requirements when the transmission system is upgraded (Cases 3 and 3n), and in the load response cases, given the curtailment that occurs when wind outages occur. As noted in the operating costs, relieving ramping constraints allows for higher usage of the wind resource (M.WE, wind energy dispatched), and lower utilization of conventional Generation (C.Gn, row 6). The use of storage eliminating the uncertainty of the wind (Cases 4 and 4n) creates a condition that favors the usage of the resource. The expected amounts of LNS are small and occur only in certain contingencies. The amount of wind dispatched is expectedly higher in cases in which no ramping costs are included [8]. The maximum amount of wind dispatched occurs in Case 4, with coupling of an ESS to the wind generator, and even higher when ramping costs are not included in the optimization.

As a side effect, load response decreases the amount of wind generation used. This is a consequence of the increased LNS in non-peak hours, coming from changes in the load pattern of the day.

6 Wholesale Market Payments and the Daily Cycle

The analysis will initially focus on the impact of ramping costs, and then explore the effects of geographical distribution and load response in a daily cycle. Figure 2 has the composition of payments by customers for cases 1 - 3. From left to right, the operating costs are progressively reduced by adoption of zero-cost wind. Cases with no congestion (Cases 3 and 3n) contribute the most to system benefits, extending to the payments made from loads. This is not always the case, as the fact that there is no congestion in the system leads to homogeneous Locational Marginal Prices (LMP), which can revert as higher payments from customers to cheap generation sources. [10] Ramping costs on the other hand do not reflect big changes among cases, and are comparable in the 2 wind cases shown. The net revenues for generators follow a change similar to the operating costs, decreasing as the amount of wind dispatched increases. With the exception of the no congestion cases, the inclusion of ramping costs leads to cases in which generators revenues are lower. The difference between what customers pay and what generators receive are assumed to be transferred to transmission owners. In all cases there is a positive amount paid to transmission, with the exception of the no-congestion cases (Cases 3 and 3n). This is due due to uniform LMP's in the system.

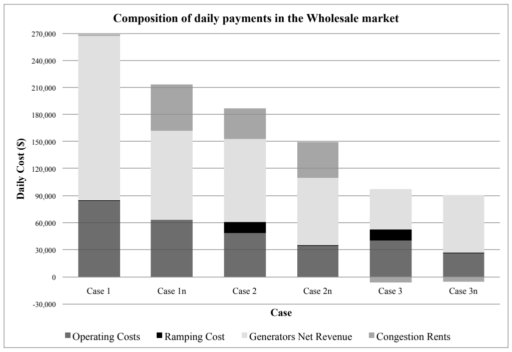

Figure 2: Payments in the Wholesale Market, Ramping

Focusing on the effects of geographical distribution

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[10] For example higher LMPs in rural areas (2 and 3 in the test system, Figure 1). See e.g. [8].

Table 3: Summary of Key Results

	Case 1	Case 1n	Case 2	Case 2n	Case 3	Case 3n	Case 4	Case 4n	Case 5	Case 6	Case 7	Case 8
L.Paid ^{a}	268	213	175	150	79	86	196	134	183	141	150	151
Op.C ^{b}	84	63	49	36	41	27	38	29	49	37	39	39
GCap^{c}	190	191	237	241	230	242	190	192	233	211	195	199
GEn^{*,d}	4,011	4,026	4,031	4,015	3,965	3,978	4,018	4,026	4045	3943	3876	3882
M.WE^{*,e}	0	0	518	827	319	745	714	883	530	524	559	559
C.Gn ^{f}	100	100	87	79	92	81	82	78	87	87	86	86
LNS ^{g}	5	7	6	6	8	11	7	7	6	16	16	13
W.disp(%a) ^{h}	NA	NA	53	84	32	76	73	90	54	53	57	57

* 50MW of Wind capacity installed, calculations over 24 hours.
^{a} Payments from loads, $1,000/day
^{b} Operating costs, $1,000/day
^{c} Generation capacity needed (MW)
^{d} Energy needed to cover load of day (MWh)
^{e} Wind energy dispatched (MWh)
^{f} Conventional generation (%)
^{g} Load Not Served (Hours/day)
^{h} Wind used as % of available wind Energy

and load response with ramping costs, Figure 3 has the composition of customer payments for the remaining cases, revealing the lowest operating costs for Case 4, constant potential output, due to the highest wind usage. The load response cases (Cases 6 to 8) show similarly low operating costs, explained by lower demand in high demand hours that make use of expensive generation sources. While ramping costs are generally low in all cases, the demand response cases command the highest payments, due to moves in the contracted amounts.[11]

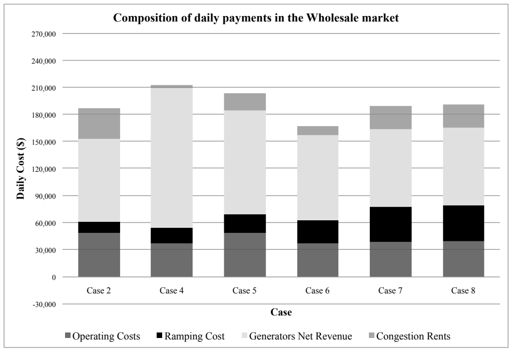

Figure 3: Wholesale Market Payments, Distribution and Load Response

In all cases, congestion rents are positive, with the largest amount in the baseline wind case (Case 2), due to separation of LMP's between demand centers and generation buses. Case 4 on the other hand, with low congestion in the system, leads to the lowest payments to transmission owners. In terms of system benefits, Case 6 (Load Response and Wind distribution) leads to the lowest overall payments for consumers. Interestingly, distributing the amount of load response among many loads - each one with lower capacity response - leads to cases in which the ramping costs are high, while the benefits to customers are not too high, a byproduct of the test network used.

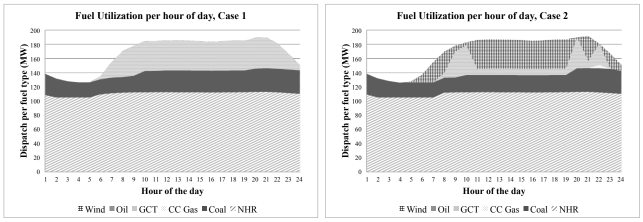

Figure 4: Daily Cycle, Effects of Adding Wind

Figure 4 shows the effect of adding wind in the system, while including ramping costs for the historical daily pattern of wind and load (forecasts for hour-ahead and realizations for real time). While baseload units (NHR, Coal) usage remains relatively unchanged, the introduction of wind mainly affects the amount contracted and dispatched of Gas Combustion Turbines (GCT). Due to the excess capacity installed, not all fuel types are dispatched, e.g. Oil and Combined Cycle Gas (CC gas).

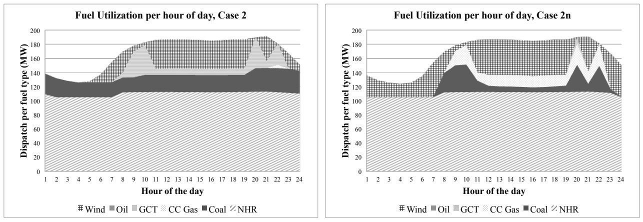

Figure 5: Daily Cycle, Effects of Ramping Costs

The inclusion of ramping costs affects the amount of wind dispatched as well as the units used to cover demand and wind shortages. Figure 5 compares the baseline Wind with and without ramping costs (Cases 2 and 2n). The removal of ramping costs (Case 2n) substantially increases the amount of zero marginal cost wind (59% increase) but also leads to no utilization of coal units in low demand periods. In cases in which wind is curtailed for equipment protection, the ramping is done by GCT when including ramping costs (Case2, left pane), while when the ramping costs are not included (Case 2n), the ramping is done by Coal, and it is optimal to use CC Gas in peak demand

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[11] The wind shortages simulated are unexpected, for equipment protection. As such, the first stage contracted large amounts of wind power, due to the expected high wind outputs that realized, but could not be used.

times. This result is consistent with a least-cost merit order dispatch in each case, taking into account the costs included in the optimization.

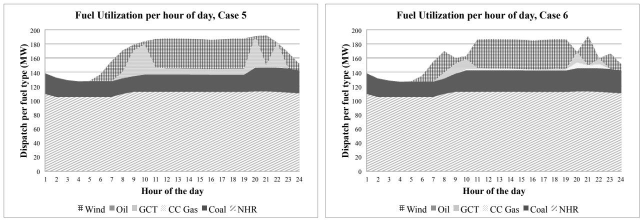

Figure 6: Effects of Geo-Distribution and Load Response

The following cases will all have ramping costs included, to analyze the patterns of generation with further changes aimed at better use of both the stochastic and the conventional generation capacity. The distribution of Wind Capacity (Case 5, left pane Figure 6) leads to a similar dispatch pattern to that observed in the base case wind (Case 2), with more pronounced replacement of conventional capacity by wind. If load response is joined with geographic distribution of wind, coal baseload units are dispatched in an almost-constant fashion, and some CC gas is required to cover wind shortages, due to the location of these units in the test network used. The combination of Load Response in several locations and wind capacity distribution leads to a case in which all dispatchable generation is used with little changes from hour to hour, therefore avoiding sudden increases in usage of the ramping units (Figure 7). This regimen allows for less stress in the network, and therefore helps to reduce the needs for transmission upgrades. Given the technical and political hurdles to transmission expansion, establishing mechanisms by which Loads can respond and be compensated[12] can help to meet the RPS and goals that policy makers have regarding Wind and other Stochastic generation sources, while improving the situation for all market participants.

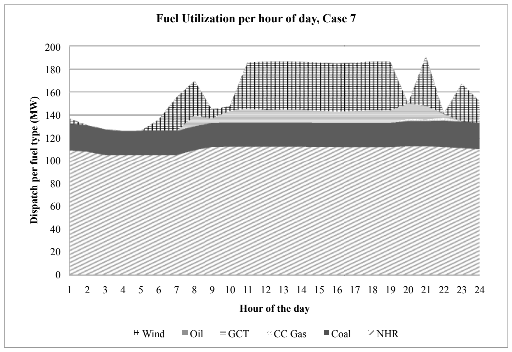

Figure 7: Load Response, Ramping Costs and Wind Distribution

7 Conclusions

This paper proposes a basic ramping product for load following, analyzing the hourly effects it has on generation dispatches, operating costs and welfare for the wholesale electricity market participants. Policies like distribution of the wind capacity and aggregation of customers at the distribution level, with capacity to respond to changes in the availability of stochastic generation sources, are analyzed. A representative day is used, with high potential levels of wind generation and substantial hour to hour variability in the amount of wind power available.

There are three main results obtained: 1) Ramping Costs have substantial effects on the amount of wind dispatched, as well as the generation mix dispatched to cover load, as shown in Figure 5 and the paragraph that follows the said figure. 2) Geographical distribution of the wind capacity may help to alleviate the problems derived from wind variability. Using a lower bound on geographical differences, with wind characteristics of the locations being not complementary, the gains accrued by distribution of wind capacity are shown in Figure 6 and the last paragraph of section 6. 3) Load Response provides support for the network in the instances in which wind generation capacity is not available, as shown in Figures 6 and 7. The analysis was performed using a modified SuperOPF, in the Co-Optimization framework of minimizing the expected cost of serving load for a set of credible contingencies in the system, linking period-to-period outcomes of the optimization. Since both up and down reserves are determined endogenously, it internalizes the variability of stochastic resources. Furthermore, load is modeled as a dispatchable resource, with valuations (VOLL) according to the location in the system. Therefore, the total social welfare is maximized.

As shown as illustration in the differences in dispatches between Case 2 and Case 2n (Figure 5), the introduction of ramping costs affects the usage of the generation fleet. Given the modeling of ramping costs done in this paper, the dispatching of generation trades-off fundamentally different unit characteristics. Therefore, the introduction of a ramping market, and the assignment of ramping costs to generating units establishes the economic problem of determining what kind of generation is needed to sustain the stochastic nature of wind: high-fuel-cost, low-ramping-cost units, akin to peaking capacity, or low-fuel-cost, high-ramping-cost units, akin to baseload capacity. Though such modeling simplifies the choices that planners and system operators face, it reflects the underlying difference that is characteristic of many legacy generators. To determine the systemic economic benefits, the objective would be to jointly reduce the total operating costs, and the payment for wear and tear (ramping costs). Congestion rents in this case are just transfers from customers to generators, and depending on the use to transmission operators [12].

Geographic distribution of the stochastic capacity leads to marginally higher usage of the resource, even if the wind characteristics of the sites are identical. Higher negative correlation between wind sites helps to further use the installed capacity[13]. This is a key factor when determining the location of future wind capacity installation. In all wind cases, the realized wind speed determines the maximum amount of generation from the wind tur-

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[12] As in this case, above the marginal cost of the most expensive generation unit.

bines but some of this potential generation may be spilled in the optimum dispatch (e.g. ramping constraints of conventional generation). In addition, cutouts occur to protect the turbines when the wind speed is above 25m/s. Since the results are based on an hour-to-hour optimizations instead of a multi-period optimization for all hours, the specifications do not use tight physical constraints on the ramping of baseload units to limit their generation.

The usage of load response to support stochastic resources provides a decreased variability in the use of dispatchable resources necessary. A question at the core of how to better integrate renewables is what resources provide better variability mitigation: demand-side management and load aggregation to deal with new technologies like electric vehicles, or supply-side management, like increase in transmission capacity and storage at utility-scale[14]. The answer to this quandary will change depending on the topology and current characteristics of the system in question. Nevertheless, the implementation of demand-side policies is likely to be biased towards the design of clear mechanisms for compensation, while the supply-side policies are likely to be more capital intensive.

These three factors are an important consideration to inform further policy for renewables adoption.

Acknowledgments

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