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Estimating the Value of Additional Wind and Transmission Capacity in the Rocky Mountain West.

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Abstract

The expansion of wind-generation in the United States poses significant challenges to policy-makers, particularly because wind's intermittency and unpredictability can exacerbate problems of congestion on a transmission constrained grid. Understanding these issues is necessary if optimal development of wind energy and transmission is to occur. This paper applies a model that integrates the special concerns of electricity generation to empirically consider the challenges of developing wind resources in the Rocky Mountain region of the United States. Given the lack the high frequency data needed to address the special problems of intermittency and congestion, our solution is to create a dispatch model of the region and to use simulations to generate the necessary data, then use this data to understand the development patterns that have occurred as wind resources have been developed.

Our results indicate that the price effects caused by changes in power output at intermittent sources are strongly dependent on supply conditions and the presence of market distortions caused by transmission constraints. Peculiarities inherent in electric grid operation can cause system responses that are not always intuitive. The distribution of the rents accruing to wind generation, particularly in unexpectedly windy periods are strongly dependent on the allocation of transmission rights when congestion occurs, which impacts potential returns to developing wind resources. Incidents of congestion depend on the pace of development of wind and transmission capacity. Not accounting for such distortions may cause new development to worsen market outcomes if mistaken estimates of benefits or costs lead to sub-optimal development of wind and transmission facilities.

Introduction:

The expansion of wind-generation in the United States poses significant challenges to policy-makers. Of primary concern is how to incorporate wind and other renewable resources into the existing electricity-grid while maintaining power supply at low cost and high reliability. On the supply side, adding generation with the unique characteristics of wind and solar power to the grid presents significant reliability and cost challenges. Electricity cannot easily be stored and the intermittency and unpredictability of these sources can make scheduling electricity in a reliable but efficient way difficult. Transmission capacity and network congestion also complicate these efforts (see Green and Vasilakos, 2008, DOE, 2009 and NREL, 2010 as examples). On the demand side, electricity demand is unresponsive to cost change, lacking both the information to react to cost conditions and changes, and the short-run flexibility to meaningfully change an inelastic demand. Given supply must always equal demand on an electricity system and that demand does not respond to changes in the availability of wind energy, sudden increases in windpower can cause significant economic changes as well as operational problems on the electricity-grid. This paper attempts to illuminate some of these problems and their interrelationships with a simulated model of the Rocky Mountain Power Area.

Among renewable sources, wind power poses the most serious challenge to electricity network planners and regulators due to the intermittency of the resource. While back-up sources can be added to the grid for use when wind or other renewable resource availability is low, these large fixed capital investments are costly and their use as a backstop ensures lower capital return and higher system costs than when the same technologies are used as primary generators. The determination of optimal diversity of generation sources, along with the spatial location of wind generating sources could reduce the potential intermittency of total generation, and reduce the fixed costs of back-up sources necessary to ensure system reliability.

Location of wind resources, however, often requires transmission capacity to deliver power to market when it is available. Since intermittency exists, the coordination of wind generation to total demand on a fixed transmission system can be difficult and result in problems of congestion. Congestion may occur due to demand spikes in one portion of the grid requiring delivery of additional power using the transmission network, or from unexpected increases in renewable generation, which strains the transmission system capacity to deliver this low-cost power to load. When such congestion events occur, local rents can be created for generators in areas where congestion constrains deliverable energy as the value of energy on the downstream side of any constraint rises relative to uncongested conditions. Significant rents may not only be created for generators within the areas affected by constrained delivery capacity, but they may also be created for the holders of transmission rights able to deliver to such areas. Understanding the stochastic nature of wind energy and the grid-cost dynamics of this resource also requires an understanding of system-wide transmission outcomes and the associated economic rents generated by wind installations. This requires a modeling framework that mimics the special nature of electricity markets, the problems posed by inelastic demand and lack of inventory or storage.

A challenge to the empirical study of renewable energy integration is a lack of data, specifically high frequency (hourly or higher frequency) wholesale electricity price data that describe market outcomes. Spot prices for electricity are not available in many areas as spot markets do not exist. Where such markets exist, prices are often reported as an index of average prices representing lower frequency intervals. The nature of demand, renewable generation changes, as well as transmission congestion on an electricity system is that they are intermittent. Congestion can occur for only minutes or for several hours in a day and then disappear for several hours or days depending on network conditions. In order to understand the nature of intermittent sources, congestion rents and price impacts, high frequency (hourly or better) data is necessary. To overcome this challenge simulation methods are used here to model market prices and estimate potential congestion effects using available hourly demand and transmission data.

This paper informs policy with a simulation model of an electricity grid that incorporates the stochastic nature of wind resources to explore the dynamics of system costs. Results are presented for a model of the Rocky Mountain Power Area (RMPA), an area that encompasses most of the state of Wyoming, all of the state of Colorado and small areas of some adjacent states in the western United States. This geographic region is of particular interest to consider the potential economic issues of integrating wind resources for several reasons. First, areas of the RMPA have some of the best potential for wind power development in the United States. Second, this area experienced a significant build-out of wind development and other transmission sources over a short period of time while transmission capacity and other grid conditions remained relatively unchanged. Third, because of its relative size compared to other control regions in the United States, the Rocky Mountain Area is more easily modeled than other larger regions. These characteristics allow a study of the area to inform and quantify the congestion costs of integrating large quantities of wind energy onto an electricity grid.

The RMPA simulation model maximizes estimated producer surplus (minimizes system cost) in a competitive electricity wholesale market while meeting transmission constraints and power demand on an hourly basis. Using actual data from the years 2008 to 2010, hourly generation, price outcomes and network congestion conditions are simulated. Two types of generation sources are used with unique cost and capacity characteristics reflecting actual field relationships: (i) traditional and non-intermittent sources including fossil-fuel generating (coal and natural gas) units and hydro-electric generation, historically developed to exploit the existing natural resources in the study area, (ii) wind generators whose cost and capacity conditions reflect the local stochastic climate conditions. Using the model output, hourly estimates are computed of efficient power market prices. When transmission congestion occurs these are used to estimate congestion rents that occur over a three-year period. These rents form an estimate of the social benefits of reducing grid congestion through possible transmission system expansion if additional renewable resources are to be added to the electrical grid. Congestion rents are also related to wind outcomes to describe the potential impediments to wind development caused by grid conditions, and which may explain observed patterns of actual development while predicting future challenges to additional large scale wind development.

Such information is critically important to policy-makers, especially if there is to continue to be public-sector involvement in fostering conditions for renewable energy development and integration, and in identifying where such public involvement would be most beneficial. For example, the state of Wyoming's wind generation capacity in the RMPA increased by a factor of eight from 2007 to 2010, jumping from 143.4 MW of potential capacity in 2007 to over 1,129 MW. Since then, however, no new generation capacity has been added yet the potential in the state is still largely untapped. In Colorado during the period from 2008-2010 only 236 MW of wind capacity was built (increasing from 1063 MW to 1299 MW), but since then it has increased by over 500MW, with an additional 16,602 MW planned.[1] This shift in development has had significant economic impact on both states. According to officials in Wyoming and Colorado, the greatest impediment to additional development in both states is the lack of transmission capacity out of the RMPA. Transmission congestion between Wyoming and Colorado within the RMPA, however, has also been cited as the reason why development in Colorado continues to occur while in Wyoming development has not since 2010, despite the fact that wind resources in Wyoming are considered to be better than those in Colorado. To overcome this hurdle the state of Wyoming embarked on financing transmission capacity enhancement between the two states estimated to cost between $200 and $300 million. Some might wonder why, if such development were so valuable, is state involvement necessary when in the past private entities have developed such transmission capacity? This question is even more relevant given several multi-billion dollar fully private projects are underway to expand potential transmission capacity out of Wyoming to locations over five times more distant than Colorado loads. This puzzle regarding why there is less private interest in making smaller investments to improve transmission infrastructure to nearby markets than to embark on very expensive projects to serve more distant ones is also an example of questions that might be answered using such a model.

[1] American Wind Energy Association (AWEA) website, 2012.

The paper proceeds as follows: a description of the generation, transmission and institutional context present in the western United States and Canada is described and the study region is introduced. A simple theoretical model is then presented to describe the electricity dispatch problem. A solution to this system provides a simulation framework that can then be parameterized for the study region. A simple parameterization of the Rocky Mountain Power Area is outlined in a static context to demonstrate how problems of intermittency and transmission capacity can impact energy cost outcomes. Solutions are then presented from the hourly simulation model. These results are used to estimate market price outcomes and to describe how the rents created by wind generation can vary with the stochastic nature of wind as an energy resource, as well as the stochastic nature of electricity demand, and how these rents could be influenced by the existence of specific transmission constraints. Conclusions are then presented based on the findings described.

Electricity Generation in the Rocky Mountain Power Area.

The North American electricity-grid in Canada and the United States actually consists of three separate and isolated grids, the eastern and western interconnects, and the ERCOT (Texas) interconnect. These span the United States and Canada and include a small portion of Mexico. The North American Electric Reliability Corporation (NERC) administrates standards to ensure the coordination between interconnections and the reliability of the grid within each. Electricity generation and supply in the western United States and Canada is administrated by the Western Electricity Coordinating Council (WECC), which further sub-divides this grid into four reporting areas, one of which is the

Rocky Mountain Power Area (RMPA). The geographic boundaries of the WECC administrated western interconnection and the RMPA are shown in Figure 1.

The Rocky Mountain Power Area (RMPA) provides power to over 5.5 million people within all or parts of five US states: the entire state of Colorado, eastern and central Wyoming, portions of western South Dakota and Nebraska, and a small area in the extreme northwest corner of New Mexico. Figure 2 presents the RMPA transmission network. Power to retail customers is primarily supplied by three regulated investor owned utilities, and several much smaller municipal utilities and rural electric associations.[2] These entities engage in generation and/or purchase wholesale power through bilateral trades with suppliers of electricity. Generation facilities are located throughout the RMPA, however renewable sources; specifically wind generators are primarily located in central Wyoming and northeastern Colorado. Transmission access to deliver generated power to RMPA load-centers may be scheduled through utilities' own transmission facilities or through two transmission networks. A simplified schematic of the RMPA transmission networks is shown in Figure 2. The simulations presented here assume an efficient market outcome and ignore any price distortions that may actually occur due to institutional realities.[3]

Modeling Framework

To model and evaluate the wind energy generation, transmission and policy issues within the RMPA, a Decoupled (DC) power-flow modeling framework is used to model

[2] Three investor owned utilities serve the RMPA: Rocky Mountain Power (a subsidiary of PacifiCorp) in central and southeast Wyoming, Black Hills Power serving eastern Wyoming, parts of Nebraska, South Dakota and Colorado, and the Public Service Company of Colorado (Xcel Energy) serving central Colorado including the Denver region. There are also 29 municipal utilities in Colorado and three in Wyoming, 15 rural electrical cooperatives in the RMPA area of Wyoming and 26 in Colorado (Navigant, 2010 and Wyoming Office of Consumer Advocate website).
[3] The RMPA does not utilize an organized power market. Some authors have noted that the existence of multiple power providing agencies using bilateral power contracts could result in a less than efficient outcome (Beck, 2009).

hourly generation price and generation outcomes as an approximation of the actual AC system.[4] The modeling framework follows the nodal pricing model outlined by Green (2007) and formalizes the choice of generation sources used (referred to as "dispatch") to serve a given demand or "load" subject to the technical constraints of the electric-power network. The general modeling problem to in each period assumes that the system maximizes producer surplus (minimizes generation cost) given electricity demand (Equation 1) by choice of power generated across a set of generators.[5] The relevant cost of electricity generation is the variable cost of producing power output measured in megawatts (MW), and ignores fixed costs of production.[6] Equation 1 is maximized subject to the technical constraints of the system; specifically that total generation in any node cannot exceed the individual generator capacities within that node (Equation 2), that total generation plus any net imports of power and demand including line losses are always balanced (Equation 3), that transmission flows do not exceed capacity constraints (Equation 4), and that generators produce a non-negative power level that is less than or equal to their given capacities (Equation 5).[7] Generation and demand occurs at all nodes in

[4] Such a modeling framework simplifies an AC power-flow optimization problem by linearization. Since AC voltage is sinusoidal, any optimization solution requires the voltage and phase angle to be defined at each node in our model. Such power-flow solutions can be "maddeningly difficult to obtain" (Overbye *et al*, 2004). For this reason it is very common in planning problems like ours to use a simplification, a "decoupled" (DC) load flow model by assuming the resistance of the transmission lines in our system is much less than their reactance. This is a reasonable assumption for the line lengths in our system and allows us to consider only real power ignoring reactive power outcomes. For a comparison of the AC Optimal Power Flow problem and the simplification involved in using a DC load-flow system, see NREL (2011), pages 76-78. For a discussion of the differences in outcomes between AC Optimal Power Flow modeling and DC modeling, see Overbye *et al*. (2004). Generally it is accepted that a DC modeling methodology is reasonable to determine general economic outcomes that determine system pricing and generation (see Green, 2007).

[5] Unlike Green, 2007, due to the hourly frequency of the simulation we take reported hourly demand within the region as given. This makes the demand modeled perfectly inelastic.

[6] This is consistent with the theory of profit maximization in the short run. Variable costs include fuel and production input costs, operation and maintenance costs that vary with the quantity of output. See standard textbook descriptions of electricity market theory such as Stoft (2002) for an overview of the relevant cost factors.

[7] We assume that the all generators face no constraints regarding the ability to supply less than full capacity.

the transmission system, and transmission allows power flow between nodes. The problem is solved repeatedly on an hourly basis, using hourly demand, transmission capacity and generation constraints.

$$\underset{\underline{w}}{\text{maximize}}$$

$$\sum_{k=1}^{K} p_k d_k - \sum_{k=1}^{K} \sum_{j=1}^{J} C(w_{j,k}) \qquad (1)$$

s.t.

$$\bar{w}_k = \sum_{j=1}^{J} \bar{w}_{j,k} \qquad (2)$$

(Generation capacity constraint)

$$NI + \sum_{k=1}^{K} \sum_{j=1}^{J} w_{j,k} = \sum_{k=1}^{K} d_k + \ell \qquad (3)$$

(energy balance constraint)

$$\left| d_k - \sum_{j=1}^{J} w_{j,k} \right| = |z| \le z^{max} \qquad (4)$$

(transmission line flow constraint)

$$\bar{w}_{j,k} \ge w_{j,k} \ge 0 \qquad (5)$$

(individual generator production constraints)

The associated Lagrangian for the problem above suppressing constraints (2) and (4) for clarity is defined as:

$$\mathcal{L} = \sum_{k=1}^{K} p_k d_k - \sum_{k=1}^{K} \sum_{j=1}^{J} C(w_{j,k}) - \mu_e \left[\sum_{k=1}^{K} d_k + \ell - NI - \sum_{k=1}^{K} \sum_{j=1}^{J} w_{j,k} \right] - \mu^{TS} \left[|z| - z^{max} \right] \qquad (6)$$

where d_k is the net demand at node k, p_k is the price of power at node k, and $c(w_{j,k})$ is the cost to generate power $w_{j,k}$ at generator j in node k where $k = 1, 2$ given the RMPA can be modeled as a 2-node network. Marginal costs at each generator are modeled as constant thus the total cost of at each generator is the product of the marginal cost and the level generated, while the total cost of generated power is the sum of the individual generators *j* costs across both nodes *k*. The flow of power along the transmission line connecting nodes *k = 1, 2* is denoted by *z.* . The transmission line between nodes 1 and 2 has a fixed capacity of z^{max} and flow on the transmission line is defined as the difference between demand and supply within each node. The energy balance constraint equates the sum of total demand plus total line losses, ℓ to total supplied energy which includes total generated power and *NI,* the exogenous system net imports of generated power from outside the RMPA. The Lagrangian multiplier μ_e is associated with the energy balance constraint, and μ^{TS} is the multiplier associated with the transmission line capacity constraint. The first order conditions of equation (6) with respect to optimal choice of generator output (dispatch) taking constraints and net imports as given can be used to define the optimal price at each node in the 2-node system:

$$p_k = \mu_e \left[1 + \frac{\partial \ell}{\partial d_k}\right] + \mu^{TS} \qquad (7).$$[8]

The multiplier on the energy balance constraint is equal to the marginal cost of generation at the swing bus in the absence of line losses, where the swing bus is the node defined to contain the last unit of generation called upon in an optimal (cost-minimizing) dispatch plus any change in line losses. Line losses may change with changes in demand. Increasing line losses would require a greater than one unit increase in generation to create one more unit of power at the load. If, however, due to line constraints, the optimal configuration of generators across the network changed to accommodate the extra power needed for such

[8] In more complicated systems with more than one route to some nodes, net transfer distribution factors describing net power flows must also be defined. See the Appendix in Green (2007).

losses, it can be the case that line losses fall (the additional power is generated on the other side of the transmission constraint), resulting in less than one unit of additional generated power being necessary to create one additional unit of power delivered to final demand. For this reason the partial derivative is required in the parentheses and it may be positive or negative.[9]

The second term in this equation shows how line constraints affect marginal costs at each node. When the transmission constraint is non-binding, $\mu^{TS}=0$ and the price in the two nodes is equal. Consider a cost-minimizing outcome in a 2-node system and suppose that in the optimal solution the combined load of both nodes is just met by the combined generation in each node, with the last unit of generation dispatched in the upstream node. If a single transmission line operates between the nodes and is just at maximum capacity (in which case the transmission line is said to be "just congested"), any additional unit of demand added at the downstream node will require the additional generation to take place in that node and the transmission constraint will be binding. The price in node 2 will differ from that in node 1, with the price in node 1 equal to the price of the marginal unit of generation there, and the price in node 2 equal to the price of the marginal generation at the new source of generation. The value of μ^{TS} would then become the difference between the marginal costs of the last generators dispatched in each node. The second multiplier in (7) is therefore the difference between the cost of power on the network at the swing bus and the marginal cost at a node with a line constraint.

[9] In electrical systems it is possible the additional unit of power would cause power flows to change across the network and could reduce line losses (see Green, 2007 or Stoft, 2002)

To implement the model in a simulation context the transmission network described in Figure 2 was reduced to a 2-node network. This methodology is consistent with published results in other power studies including DOE (2009).[10] Node 1 comprises all areas in the RMPA north of Wyoming border and Node 2 all areas south (the state of Colorado). Power can flow between Wyoming and Colorado only using a transmission pathway referred to in the industry as Path 36/TOT3. Figure 3 presents the simplified nodal network, identifying average demands, generation capacities transmission capacities used in the simulations. WECC Path Data is used to define *NI* for the pathways shown in Figure 2 leading out of the RMPA and it is subtracted from total nodal loads consistent with Equation 3.[11]

Implementing the simulation model also required identifying RMPA generation potential. Generator capacities by site were defined using EIA form 860 data for over 360 individual sources. Fuel sources within the RMPA include coal, natural gas, hydropower, diesel fuel, wind, solar power, and renewable gases. Table 1 describes generation capacity by fuel type or power source within the RMPA at the end of 2008 and changes in capacity through 2010. The growth of wind resources is clear – wind potential grows 66% from 8.8% to 13.1% of total generation capacity from 2008-2010. The growth in wind capacity is even more dramatic when considered by node. Wind generation capacity in Wyoming (Node 1) increased from 143 MW to 1130 MW of potential power, while Colorado Wind potential increased by 229 MW to 1292.1 MW over the same period. The only other major

[10] WECC (2012) and DOE (2009) model the RMPA as a three-node system splitting Colorado into eastern and western nodes. Both studies find no congestion on this pathway, these two areas are modeled as a single node.

[11] Data for the TOT80 southeast Montana link is only available in 2010 and average only 50MW. We assume in other years these flows are zero. Path 19 is also not included. It operates at 100% capacity to export power from two dedicated plants in Wyoming that do not serve the RMPA. Remaining lines in Figure 2 are used to define *NI*.

source of growth in generation capacity over this time period was in coal generation, which increased by 12%, increasing coal's share of total potential generation from 40.4% to 40.8%.

To estimate an efficient dispatch outcome that minimizes total generation costs, individual generator marginal costs must be identified or estimated. Since such costs are proprietary, little of such data exists publicly. Many cost estimates exist in the economic and policy literature, but these studies most often consider the capital costs necessary to create new generating capacity, which are inappropriate for use in the theoretic model described.[12] Marginal generator costs are estimated using published production engineering estimates of their determinants, plant characteristics from EIA Form 860 data, published fuel and transport costs, and transmission costs based on the location of generators. The methodology used to estimate these costs deterministically is detailed in the Appendix.[13] Figure 4 shows the modeled efficient dispatch "merit order" or supply curve for the entire RMPA assuming no transmission congestion occurs between nodes using summer 2008 reported peak capacities, and estimated marginal costs by generator expressed in 2008 dollars. Maximum generator capacities are shown by fuel type, which determines plant marginal costs. Lowest cost generators in the dispatch order are renewable sources: solar, wind and hydro as their fuel is effectively free and the only costs

[12] Studies often consider "levelized" costs of energy - the cost of generation necessary for a plant to break even over its operating lifetime. This is computed as the present value of all capital and fixed costs, financing costs and forecasted operating costs including fuel over the projected lifetime of the plant, divided by the present value of energy output from the plant. Other studies cite the "overnight cost" of a plant - the total cost to construct a plant if it were built in one night. Neither of these costs is appropriate to model dispatch and only marginal production costs are used. See Stoft (2002).

[13] An alternative method is to derive plant efficiencies using reported fuel use and output also reported on the EIA Form 860 surveys. This was attempted, however, missing or incomplete data across some generators combined with problems in the reported data that yielded unreasonable efficiencies.

faced are those operations and maintenance costs that increase with output. Solar and wind power have significant intermittency and the potential effect on the estimated supply curve of wind intermittency in particular is shown by the broken line, which reduces wind capacity to 12% of potential capacity as used by NERC to estimate system reliability. If renewables were to provide 100% potential power, this would shift the supply curve by about 1300MW to the right, and this could significantly alter power market conditions.

To illustrate the hourly power dispatch market outcomes the simulation model computes (without the complication of transmission congestion) and how they vary with the potential intermittency of wind generation, Figure 4 shows summary measures of actual 2008 hourly RMPA load data reported, along with NERC's summer 2008 forecast peak load (NERC, 2008). The efficient market price and quantity of electricity is shown for the minimum, maximum (average and forecast), average, 5% and 95% load levels by the intersection of the supply curve and these demand levels, conditional on wind output.[14] The estimated equilibrium wholesale price of electricity in the market would have ranged from a minimum cost of $15.38/MWh to a maximum of $77.02 ($77.10 at the forecast peak), would have ranged from $15.50 to $39.63 in ninety percent of the hours in 2008, and averaged $29.38 over 2008 assuming that the wind output was 12% of potential capacity. This is a very conservative worst-case scenario but in any hour the shift of the supply curve could be more dramatic than presented, as occasionally almost no wind power is present on the grid. At maximum wind potential, the efficient market prices at the given loads would have ranged from $12.24 to $45.90/MWh ($59.76 at the forecast

[14] It is understood solar intermittency would have an impact as well, however, as shown by the generation shares in Table 1, wind is the primary source of intermittency since solar energy accounts for only a very small portion of RMPA generation through the study period.

maximum), would have ranged from $12.93 to $39.21 in ninety percent of the hours, and averaged $15.50 over the year. These results, however, assume no congestion occurs on the transmission pathway between Nodes 1 and 2. If congestion were to occur, the RMPA market would separate into two distinct markets, and a dispatch solution similar to that in shown in Figure 4 would be computed in each. Power would flow along the transmission line from the node with the lower price to that with the higher price. The supply curve in the higher priced node would be composed of the residual supply curve from the other node up to the capacity of the transmission line, and the generator marginal costs located in that node.

Hourly simulation solutions solve the simple problem illustrated in Figure 4 using estimated generator marginal costs, generator capacities for traditional generators, simulated wind capacities using weather data at each wind farm in the RMPA, actual RMPA demand data and actual transmission constraints hourly from 2008 to 2010.[15] The hourly wind outcomes used in the simulations are summarized in Figure 5 and Tables 2 and 3. The RMPA included 28 windfarms in 21 separate locations during the 2008-2010 period. As noted in Tables 1 and 2, wind capacity grew over the simulation period. Lacking data on exact start-up dates for new expansions, a plant was assumed to come online in the first hour of the month it began operation. To model the wind at each plant location, the National Renewable Energy Laboratory (NREL) Western Wind Dataset was used.[16] This dataset models hourly wind patterns across the western United States based on 2004-2006

[15] The model also includes seasonal output cycles for hydro and solar power, and daily cycles for solar output to describe the estimated hourly output capacities of these sources. These were modeled using reported 10-year rolling average monthly generation data by facility from the US Bureau of Reclamation. Missing stations were assumed to follow the same cycles as reported stations within their specific watershed. Solar cycles were fitted using sunrise and sunset times defined by U.S. Naval Observatory Astronomical Applications Department data.
[16] Information regarding this dataset can be found at NREL's Western Wind Dataset webpage portal.

data over 32,403 actual and potential windfarm locations in the western United States. The meteorological model also accounts for and simulates spatial and temporal correlations across the region. Data from the nearest locations modeled by NREL to each of the RMPA windfarms was used to simulate wind outcomes by farm. The summary data in Table 2 explains why wind resources are so valued, particularly in Wyoming. The average capacity factor of all Wyoming sources in the simulation was 41.1% while in Colorado it was 27.3%.[17] Both wind areas have a strong seasonal component as well as a diurnal one. Both experience stronger winds and higher capacity factors in winter than summer months. Colorado wind tends to peak at night, while Wyoming wind often peaks in late afternoon.

Hourly balancing-area load-data from Federal Energy Regulatory Commission (FERC) Form 714 was used to define nodal demands.[18] Since balancing areas do not correspond to the nodes defined in the simulations, it was assumed underlying demand is similar on a per-person basis in each node, and annual county-level census data from 2008-2010 was used to define nodal demands as the population-weighted shares of the total load. This leaves an asymmetric pair of markets with Node 2 accounting for approximately 88% of total demand over the three-year period. Demand patterns on a daily basis reflect a typical diurnal pattern, peaking in daylight hours, with clear shoulder periods in evening and mornings, and minimum demand occurring overnight. Seasonal peaks occur in mid-

[17] Capacity factor refers to actual power produced relative to the potential generation, or "nameplate" capacity.

[18] FERC Form 714 data reports load by the two RMPA balancing areas controlled by Xcel Energy and the Western Area Power Administration (WAPA). As data is only reported for the Xcel Energy balancing area in 2008, the missing 2008 WAPA data was estimated using the hourly proportional load differences between areas in 2009 to create simulation data in the missing area for 2008. These estimates were then added to the reported data in 2008 to create an estimate of total hourly load. This data was then compared to data published in Beck (2009) describing average, maximum, minimum, 5% and 95% load levels. The constructed data overstated the reported average, maximum and minimum loads by approximately 5.2% and was deflated by this amount. Resultant estimates of hourly load at the 5% and 95% levels differed by less than 2% from those in Beck (2009) and were used as proxies for actual 2008 hourly load outcomes.

summer, with a secondary peak in mid-winter. The data may also contain an economic cycle, with average load falling during the 2008-2009 national recession. Hourly demands are treated as perfectly inelastic and exogenous in the simulation model, as almost all residential and commercial demand in the region does not have real-time metering, nor are instantaneous spot prices posted or charged. The three-year demand pattern is shown in Figure 5 and described in Table 3.

The ability of the grid to maintain low generation costs depends on transmission constraints present on the grid. Actual hourly transmission limits for Path 36/TOT3 in 2008-2010 are also described in Figure 5 and Table 3. While the nominal capacity of this link is 1605MW, its maximum rating in any given hour can vary depending on load and generation conditions, temperature and weather, maintenance operations and configuration changes, other transmission line conditions in the RMPA and reliability considerations.[19] For these reasons the average capacity over the simulation period was 1331 MW with a standard deviation of 173 MW. Transmission rights across this link are determined by the ownership of the lines, which are both privately and publicly owned. As of 2008, 71.4% of the capacity was owned by a consortium of utilities and agencies involved in the Missouri Basin Power Project and owners of the Laramie River Generating station in Wheatland, Wyoming, which can produce up to 1140 MW of power for the RMPA. The remaining Path 36/TOT3 capacity is held by Xcel Energy (3.7%) and the federally owned Western Area Power Administration (24.9%), which markets transmission rights on its share of the link.

[19] Some reserve is usually maintained to ensure that if a failure occurred elsewhere on the system, resulting changes in power-flows could be accommodated.

Results:

Electricity price outcomes are solved using the dispatch model and incorporating actual RMPA demand (load) and transmission constraints, estimated generation costs, and wind conditions over the 26,304 hours simulating Jan 1, 2008 at 12:00 am to December 31, 2010 at 11:00 pm. The simulation was programmed using GAMS.[20] A simulated unconstrained transmission solution in which no transmission capacity constraint was imposed between Nodes 1 and 2 was also computed to determine the impact of transmission constraints on the system. Results were also used to consider the effects of wind intermittency and increased capacity on power prices and transmission congestion, and to construct an estimate of congestion rents created by inadequate transmission capacity between the two nodal markets. A summary of the computed market price outcomes is presented in Table 4.

Price results indicate the effects of congestion on the grid, consistent with Equation (7). When the transmission constraint is not binding a single market clearing price occurs across Nodes 1 and 2. We define the price differential here as the Node 2 price less the price in Node 1 in any period. In the simulations reported here it was always the case that congestion occurred as power flowed north to south (from Node 1 to Node 2) and never occurred due to power flowing in the opposite direction, thus price differentials observed were never negative. This occurred because of the relatively low generation costs in Node 1 relative to those in Node 2 and the large generation capacity relative to demand in Node 1. These results also reflect the evolution of power development in the RMPA where

[20] General Algebraic Modeling System (GAMS), GAMS Development Corporation (www.gams.com). Code and data are available upon request from the authors.

historically power generation facilities have been built not only to serve the Wyoming market (Node 1) but also to exploit the low cost of fuel in Wyoming to export power to the Colorado market. In contrast, historically Colorado power generation has been built to serve the Colorado market, particularly demand in the Front Range region where the majority of the RMPA population is located.

Comparison of the efficient results to the results using the actual Path 36/TOT3 transmission limits shows the constraint causes average prices in Node 1 to fall and Node 2 to rise relative to the unconstrained case, as expected if power flows from north to south along the transmission link. The impact of the constraint appears to increase over time as the average price differential increases in each year, as does the standard deviation of prices in Node 1 and for the price differential. Node 2 prices fall on average throughout the simulation. Despite the fact that, all else equal, congestion should raise price in the downstream node relative to the unconstrained outcome, the increase in the amount of cheaper wind energy available in Node 1 over the simulation period both creates transmission congestion, which has the effect of raising Node 2 prices, and reduces the cost of power exported from Node 1, potentially reducing costs in Node 2. In the unconstrained transmission simulation the removal of the first effect (congestion) is clear as the availability of increased low-cost wind energy over time reduces average power prices.

The change in congestion over time can also be seen by comparing annual price differentials in the results. Figure 6 shows the duration of price differentials expressed as a percentage of the total hours in each year of the simulation. Price differentials of a penny or more between the nodal markets occur in only 1.8% of the hours in 2008, but this rises to 13.2% of hours in 2009 and 56.6% in 2010. Additionally the maximum price differential increases from $32.51 in 2008 to $36.32 in 2010, while average price differentials increase from $0.29 to $11.18. While the incidence of congestion will always occur more often when transmission capacity is reduced, as growth in wind capacity occurred in Node 1 the transmission capacity constraint appears binding in significantly more hours regardless of the constraint level.

To quantify this impact, a hurdle regression model was used to determine the relationships between demand, transmission capacity and the levels of wind generation available in Nodes 1 and 2 on congestion and price differential outcomes. These results are shown in Table 5 noting all variables are measured in megawatts (MW). The first stage of the model was run as a Probit regression to quantify the relationship in the simulation data between total load (demand), transmission capacity, wind output in both nodes, hydro output from Node 1 and the incidence of transmission congestion. All else equal, greater total load causes greater demand in Node 1, which reduces the amount of power available for export and the potential for transmission congestion. Greater transmission capacity will also reduce incidences of congestion. One would expect that since wind is unpredictable but nearly free when available, greater wind output in Node 1 will increase congestion by making more cheap power available for export to Node 2. Increased wind in Node 2, however, will lessen the demand for Node 1 power. Efficient dispatch would use this energy first in Node 2 given it is cheaper than any exported power from Node 1 (it incurs no transmission costs since it is located in Node 2 and generation costs at each wind location are assumed equal), which in turn would reduce congestion. Hydro output in Node 1 is also included in the regression as it is also a very cheap source of power, and when more power is available, especially in the spring run-off months, more power is available for export to Node 2, increasing the potential for congestion.[21] The results are shown in Table 5a.[22] As expected all variables are of expected sign. Regression results suggest the marginal effects of transmission constraints and wind output in Node 1 are much larger (often depending on the year an order of magnitude greater) than demand changes or wind output changes in Node 2, while hydro effects are very similar to those of wind in Node 1 suggesting these are the primary determinants of transmission congestion.

Conditional on the transmission congestion occurring, the magnitude of the price differential was then explored using a truncated regression to quantify its relationship with load (demand), transmission constraints, and the levels of Node 2 wind and hydropower output. Results are described in Table 5b. All else equal, one would expect that growth in hourly demand Node 2 to increase Node 2 prices and the price differential when congestion occurred. In contrast, greater transmission capacity and therefore greater imports should reduce the price differential by shifting supply outward of power outward, thereby lowering prices. Node 2 wind and hydropower output should also have the same effect on the supply curve and price differentials. Again all signs are as expected and the magnitudes of the effects of each determinant broadly similar. Over the 2008-2010 period, on average a 100 MW increase in transmission capacity during a period of congestion decreased the price differential by approximately $0.82. The same increase in Node 2 wind or

[21] Since in an efficient dispatch with congestion power is always used in each node to first satisfy nodal load and then for export, most exported power from Node 1 to Node 2 is coal power. Greater wind and hydropower availability increase the use of this power in Node 1, making more coal generation available for export to Node 2. Since Node 1 coal power is cheaper than most power generation in Node 2, this exported power is always used if available.

[22] Node 2 Hydro output was not included in the regression due to very high correlation between Node 1 and Node 2 Hydro output (watersheds are shared in some cases, and seasonal snowmelt leads to very similar water flow patterns) and multicollinearity concerns.

hydropower output decreased the price differential by $0.57 , while an increase in load of 100 MW during a period of congestion increased the price differential by $0.54.

To quantify the cost of increased congestion caused primarily by additional wind capacity and inadequate transmission capacity, congestion rents were also determined. These rents were computed as the value of the exported flows from Node 1 to Node 2 given the price differential in that hour. For example, if 1300 MW of electricity were exported from Node 1 to Node 2 in a given hour and the price differential between these two areas was $10.00, the "rents" accruing to exporters of power from Node 1 to Node 2 would be $13,000. This represents the additional profit created by selling power in Node 2 instead of Node 1 or the total rents from holding transmission rights during this period of congestion. These form our estimate of the potential benefit of additional transmission capacity under efficient market conditions.[23] To determine the amount of capacity necessary to avoid these rents, simulations were run increasing the available transmission capacity in each hour by 100 MW increments up to 1000 MW. Table 6 describes the total congestion rents occurring in each year for the actual hourly transmission limits, and what would have occurred had each of those hourly limits been increased by 100 MW up to an additional 1000MW in each year. In addition, the total avoided rents or marginal benefits of these increases over the entire three year period are also tabulated.

Computed results in the first row of Table 6 show the increase in congestion rents accruing to transmission rights holders under the actual transmission limits as incidences of congestion increased over time. Again, these incidences appear to have been driven

[23] Actual benefits in the RMPA are potentially higher given the fact that the wholesale market is not organized as a competitive auction but instead relies on bilateral agreements between utility providers and power generators.

primarily by the additional generation capacity installed on the grid, particularly wind in Node 1.[24] The estimated value of total rents accrued over the three simulated years was over $149.1 million. As shown in Table 6, a relatively small addition of transmission capacity could have significantly reduced total congestion rents in any year, with the first 100 MW potentially avoiding over 31.5 percent of the total rents generated in the three years, and over 53.1 percent of the total rents generated in the years 2008 and 2009 respectively. In the first two years of the simulation an additional 300 and 600 MW of capacity would have eliminated all congestion rents, while an increase of 1000 MW would have been necessary to eliminate all rents in 2010.

Analysis of the distribution of estimated rents and how they change reveals how the price and quantity changes in the market affect specific generator's revenues, especially in the presence of transmission congestion. Referring to the actual ownership shares of transmission rights over the Path 36/TOT3 link referred to earlier, one coal-fired generating station (the Laramie River Station) could earn an estimated $105.9 million (71.4%) share of the total congestion rents estimated to be generated here.[25] Just over $37.1 million (24.9%) of the total congestion rents could be earned from users of the transmission rights marketed by the Western Area Power Administration's (WAPA) to other producers in Node 1. The largest utility in Node 2, Xcel Energy would be estimated to receive a $5.5 million (3.7%) share of these rents.

[24] Table 1 reports 1006 MW of additional coal and gas-fired generation came online in 2008-2010. Only 185MW was added in Node 1, thus little of this new capacity would have added to congestion given power flowed mainly from north to south (Node 1 to Node 2) in the simulations.

[25] Simulation results indicate that the Laramie River Station would only earn $69.1 million from rents due to exports to Node 2. The efficient dispatch would allocate some of this plant's production to Node 1, leaving it unable to use its entire transmission rights allocation. If the plant were to sell its excess transmission rights to other firms in Node 1 it could potentially capture the rents available, thus the actual rents accruing to the firm would likely be between $69.1 million and $105.9 million.

A further analysis of rents accruing to all producers in Nodes 1 and 2 is presented in Table 7. The presence of congestion and the impacts this has on prices in each node are clear from comparison of profits for generators in Nodes 1 and 2 under the simulations using actual hourly transmission limits, and those that could occur if such constraints were not present. In Node 1, 7.8 percent of potential profits are lost due to congestion and the resultant lower prices in that node, costing over $96 million over the three years of the simulation. Node 2 producers reap the benefit of the higher prices the congestion causes, which causes total profits to rise by over $52 million, or 1.9 percent relative to outcomes had no transmission congestion occurred over the three years.

Wind producers are even more affected than the general market in Node 1 by profit losses due to congestion effects. Because of the cost-minimizing dispatch that is assumed to occur in each node, wind power is almost always sold in the node it is produced. For Node 1 producers, very seldom is there a surplus of power available for export after such dispatch occurs thus they earn very little rents. As wind capacity increases in Node 1 this pushes coal-fired generation up the supply curve and closer to the margin, and contrary to what might be expected, this actually can benefit some coal-producers as it allows them to export more of their power. In times of congestion this allows coal-fired producers to earn most of the congestion rents available. The result is improved profitability for the coal-generation sector over what it would have been without such rents.

Wind producers in Node 1 have the opposite experience. As their power production rises over time, it causes more congestion on the grid and prices fall in Node 1, lowering wind-producer's profitability. In effect, windier conditions, causing greater wind production costs wind producers while benefiting coal producers. Wind profits are 29% lower than they would be in the absence of congestion, and wind producers suffer over 71 percent of the total profit loss experienced in the Node 1 due to congestion effects. Most of the remainder of the profit loss in Node 1, particularly in the last year of the simulation is experienced by hydro-electric producers.[26] While some coal plants can experience profit loss due to lower prices in Node 1 caused by congestion , as a sector, coal-generation in Node 1 becomes the primary export power source when congestion occurs and actually experiences increased profits due to that congestion.[27] Node 2 wind producers benefit from the congestion caused by abundant and low-cost production in Node 1. Their profits over the entire simulation rise by over 15 percent relative to simulations without a transmission constraint, accounting for 73 percent of the total profit increase in that node.

Discussion of Results

The impact of the additional wind output in our simulated RMPA markets is dramatic when transmission congestion occurs. Congestion caused by additional wind energy causes regional market prices to diverge, sometimes significantly from those that would occur in uncongested circumstances. Price results presented in Table 4 for the RMPA simulations suggest the greatest impact occurs in Node 1 where prices fall due to the stranded wind power flooding the local market and driving wholesale prices downward. While it may seem initially counter-intuitive, additional wind energy arriving on the grid is

[26] Hydroelectric generation accounts for 290.1 MW of potential power in Node 1 and collectively defines the next step on the supply curve above wind generators. Coal generators are collectively grouped in the next portion of the supply curve in Node 1, and are the marginal generation type in most hours.
[27] Recall that Node 1 coal-generator costs are much lower than those in Colorado due to their location to nearby coal-mines. This results in exported power from Wyoming always being dispatched in Colorado when it is available.

not necessarily a benefit to wind producers as the price decreases caused in Node 1 by congestion can eliminate much of the additional profits the additional power might create.

Further, traditional fossil-fuel power producers are displaced in the dispatch queue by sudden and unpredicted increases in wind power. Such conditions might be expected to lower the profits to these firms if their generated power were dispatched in Node 1 due to the lower prices caused by the additional wind power and the reduced need for coal-fired power output when wind power increases, but this may not happen. Our simulations show that if these coal-fired plants have transmission rights, exporting their power to neighboring markets where prices due to congestion become higher can allow them to offset such losses and actually benefit from the presence of wind-generators. Overall then, the addition of unpredictable wind resources in a transmission constrained area such as Wyoming can have the effect of lowering returns to capital for wind producers relative uncongested transmission conditions, while having an ambiguous effect on higher-cost traditional generators.[28] Downstream of the congestion the effect is the opposite. Congestion has the effect of raising profits over what they would have been without congestion. The effect to consumers in the downstream market would likely be unambiguous; customers whose utilities were forced to pay higher wholesale prices than would occur in the absence of congestion would face higher prices.

The impact of congestion on power market outcomes also may not create price incentives for the creation of additional transmission capacity. In the results presented, the estimated additional capacity needed to avoid congestion is over approximately 900 MW

[28] In a rate of return regulated utility market, this could also stop any reduced wholesale power-rates from being passed on to consumers in the area where price has fallen. If the utility also owned the wind generation, to ensure adequate capital return consumer prices may not be allowed to fall to maintain the utility's rate or return on its wind investments.

by the end of the simulation. While transmission expansion costs vary by location, the Wyoming Infrastructure Authority estimates the cost of an 800-900 MW expansion of the Path 36/TOT3 line modeled to be less than $300 million.[29] Simulated Node 1 price and profit outcomes suggest that wind generators have little incentive to provide additional transmission capacity to Node 2. Node 1 wind producers' lost profits over the three year simulation total $69.3 million, suggesting the payoff time to such an investment could be decades. Further, wind generators are owned by multiple firms suggesting that coordination for such an investment could be difficult and free-riding incentives could undermine any such effort. Ironically, increases in wind output seem to create the greatest benefits in Node 1 to fossil-fuel generators with transmission rights to Node 2 thus they would have little incentive to invest in additional capacity.[30]

In Node 2, increases in transmission capacity would create losses for wind producers thus they have no interest in such investment (short of accessing another market for special non-qualified facility arrangements).[31] Transmission congestion shelters these producers from competition with wind producers in Node 1 and any reduction in congestion would eliminate the price increases that drive their additional profit in the simulations presented. Other Node 2 power producers would similarly not be

[29] See the Wyoming Infrastructure Authority Wyoming-Colorado Intertie (WCI) project website.

[30] This non-intuitive result occurs because an increase in wind output in Node 1 shifts the dispatch curve right, displacing power coal production in Node 1. Coal producers, however, are the marginal producers in the optimal dispatch for Node 1 and therefore generate the power exported to Node 2. When increases in wind output cause transmission congestion, these exporting companies sell more power in Node 2 (assuming they have transmission rights to do so) and the exporters' increase in profits due to the transmission congestion-caused price differential between Nodes 1 and 2 more than makes up for the loss in generation sales in Node 1 caused by the greater abundance of lower cost wind.

[31] There still could be some incentive for special bilateral supply contracts to be made with other regions in the western grid that could create incentives for transmission investment. We cannot quantify those in our region-specific simulation.

interested in financing additional transmission expansion as it would only increase the competition they would face from lower-cost Wyoming producers. Third-party transmission companies may also not be willing to invest in additional transmission capacity for the same reasons - doing so would reduce the rents and potential profits of building more lines.

Comparing the predicted simulation outcomes and implied incentives to actual development in the RMPA suggests the results are consistent with the observed pattern of development that has occurred in the region. Initially wind resources were exploited in Colorado nearest the major load center in the area (the City of Denver and the Colorado Front Range). While Wyoming's wind resources were known to be superior in quality to those in Colorado they were initially developed slowly. By the mid-2000s however, these resources began to be developed quickly by several large power companies. Development of the wind potential appears to have contributed to transmission congestion by 2010 in the area, with the result that lower prices in Wyoming (Node 1) drove down potential rates of return to these new investments, while raising prices over what would otherwise have been expected in the absence of congestion in Node 2 (Colorado). While lower rates of return may not necessarily cause consumer electricity rates to rise, PacifiCorp did request rate increases in its Rocky Mountain Power service area in Wyoming during this time. The primary impact, however, of the increased congestion and its effects on prices and profits appears to have been in halting wind development in Wyoming. No new wind generation development of any kind has occurred in the Wyoming portion of the RMPA since 2010. Simulation results here suggest that was the year congestion impacts became critical.

In Wyoming, concerns over congestion have spurred the state government's Wyoming Infrastructure Authority (WIA) to engage in transmission development. The stated goal of the WIA was to encourage development of Wyoming's electricity resources, including wind.[32] It was understood that without additional transmission capacity to move the power to market such development may not occur. The first major transmission project the WIA will complete is an 800-900 MW expansion of the Path 36/TOT3 transmission link to Colorado, at an estimated cost of between $200 and $300 million. The proposed line is currently under construction and planned to be in operation by summer 2014. The simulations presented here suggest the size of expansion will nearly eliminate congestion that would occur under efficient dispatch conditions. The WIA also has been active in developing additional transmission capacity between Wyoming and Colorado. Other efforts have focused on transmission expansion westward to allow wind resources to have transmission access to western markets such as California and the Pacific Northwest. Due to planned renewable portfolio standards being implemented in these regions, both areas are expected to have significant demand for wind power, and wind resources in Wyoming with their high capacity factors and favorable peak output cycles could be a very lucrative location for generation.[33]

Conclusions:

This paper has presented a framework for modeling electricity dispatch, with a specific application to the Rocky Mountain Power Area. Specific data sources required to model such an area have been identified, and a method of estimating proprietary

[32] Wyoming would also like to see additional fossil-fired fired generation created in the state to export power.

[33] In November 2012, Federal permits were granted for the largest wind farm in the United States to be built in central Wyoming (the Chokecherry-Sierra Madre project). The first phase will have a capacity of over 1000 MW. Completion of the project is expected to occur when transmission capacity becomes available.

production costs has been outlined. The outcomes were simulated in efficient as well as transmission constrained conditions. Results indicate that the market effects caused by changes in wind power and other intermittent sources are dependent on the demand conditions in the market and the presence of transmission constraints. The outcomes may not always be as one might expect intuitively due to market imperfections causing outcomes to depart from first-best conditions. Efficiency outcomes in the presence of second-best market conditions may not always be predictable. Electricity markets are bound to be distorted by such market imperfections. Output is not storable, markets include constraints to output and transmission, and rights to use portions of the grid may not be distributed in a manner that ensures efficiency. Accounting for such problems is necessary if economics is to be useful in making informed policy decisions regarding electricity grid development.

The simulations presented here demonstrate the club-good aspects of transmission capacity. As a club-good, transmission capacity is excludable but non-rivalrous until congestion occurs. Because the incentives to create additional transmission capacity may be weak, transmission may be privately provided at a level that is socially inefficient. This could eliminate incentives to develop otherwise high-quality power resources if the location of such resources is distant from adequate transmission capacity and suggests a possible role for public involvement in transmission provision. Finally, the analysis above suggests that any policies that effect power pricing are not easily predicted in a market that is distorted by technical constraints such as transmission capacity limits. Market outcomes in such circumstances cannot be assumed to be efficient and therefore costs and benefits of policy changes (carbon taxes, regional renewable portfolio standards, endangered species protections that affect electrical generation or transmission development, wind production taxes, or coal severance taxes) that have an impact on electricity production costs may not be straightforward to predict. Similarly it is important to assess the resulting winners and losers for any policy change – as demonstrated here, renewable energy expansion may benefit the traditional sources it is meant to displace. The results presented here suggest that if society desires more renewable energy sources to be developed, efforts may require more than production subsidies to be employed. Such development may need to focus on other impediments such as transmission congestion.

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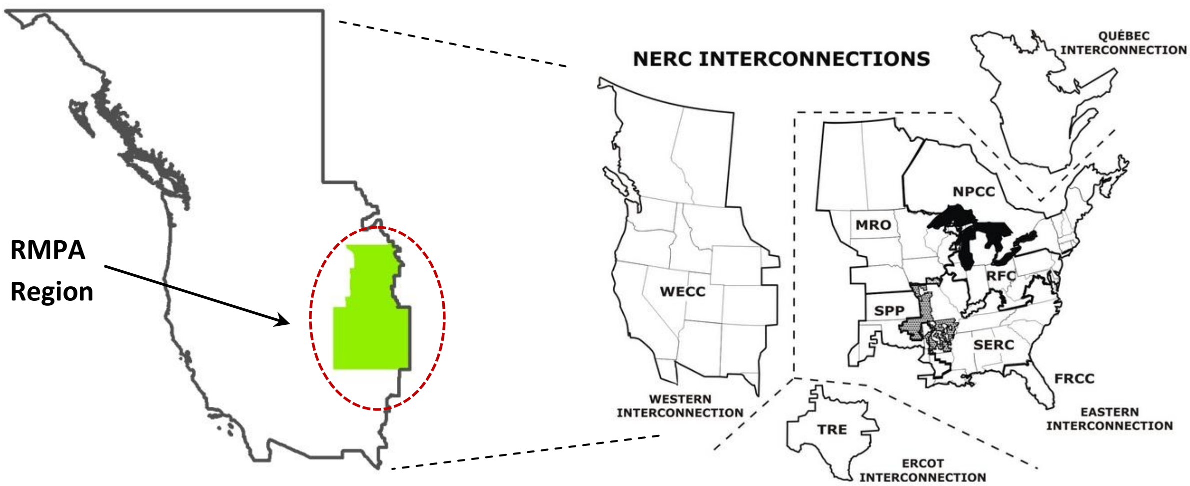
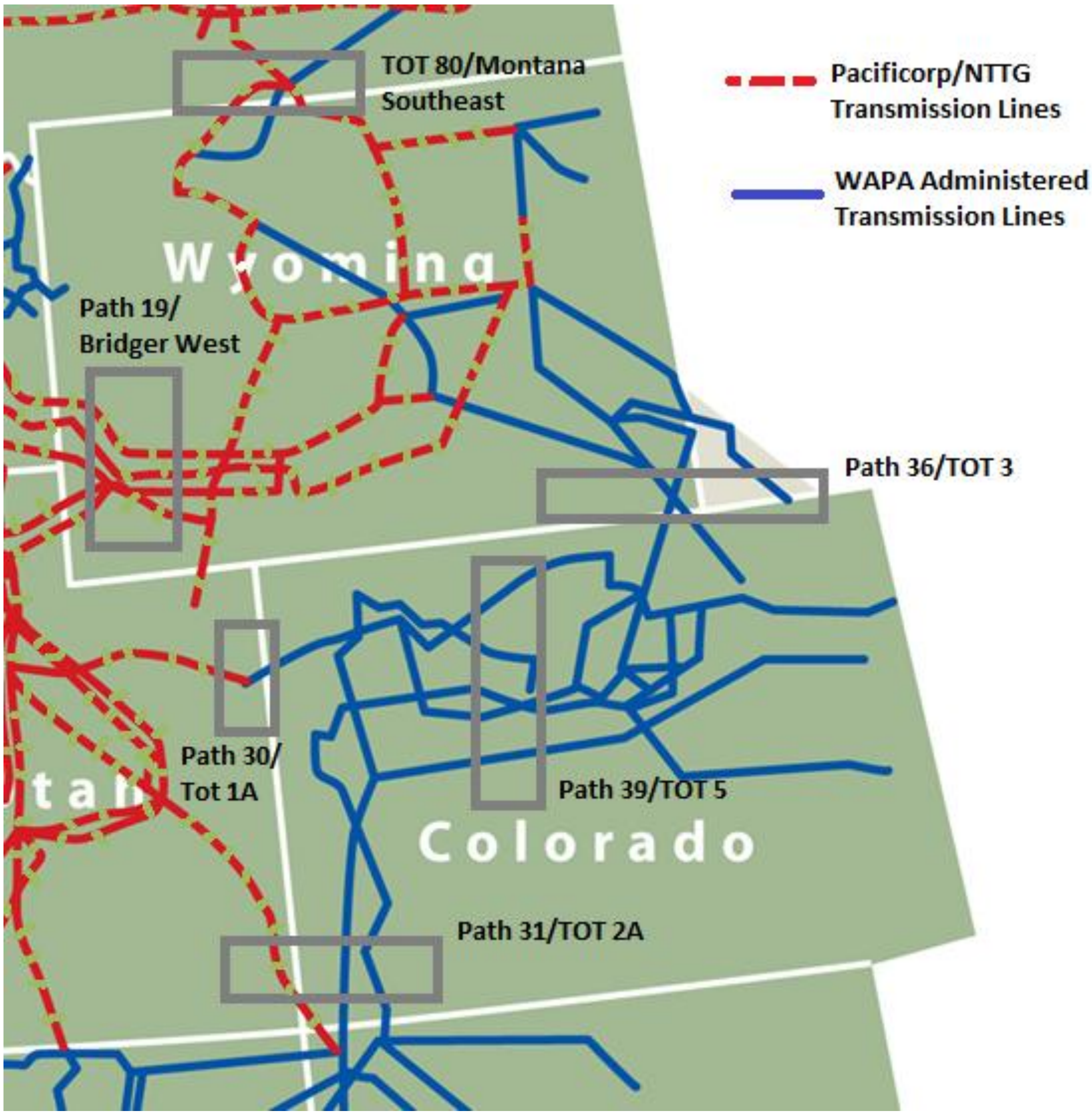
Figure 1: The RMPA within the Western Interconnect.



Source: North American Electric Reliability Corporation (NERC).

Figure 2: RMPA Transmission System including Major Power-flow Pathways



Source: NTTG Website with modifications made to show major transmission pathways.

Figure 3: Simplified Nodal Network with Simulation Parameters.

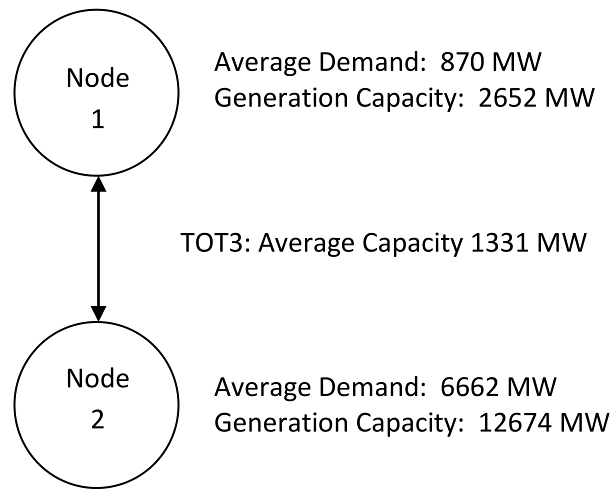


Figure 4: RMPA-wide Estimated 2008 Supply Curve assuming no Congestion

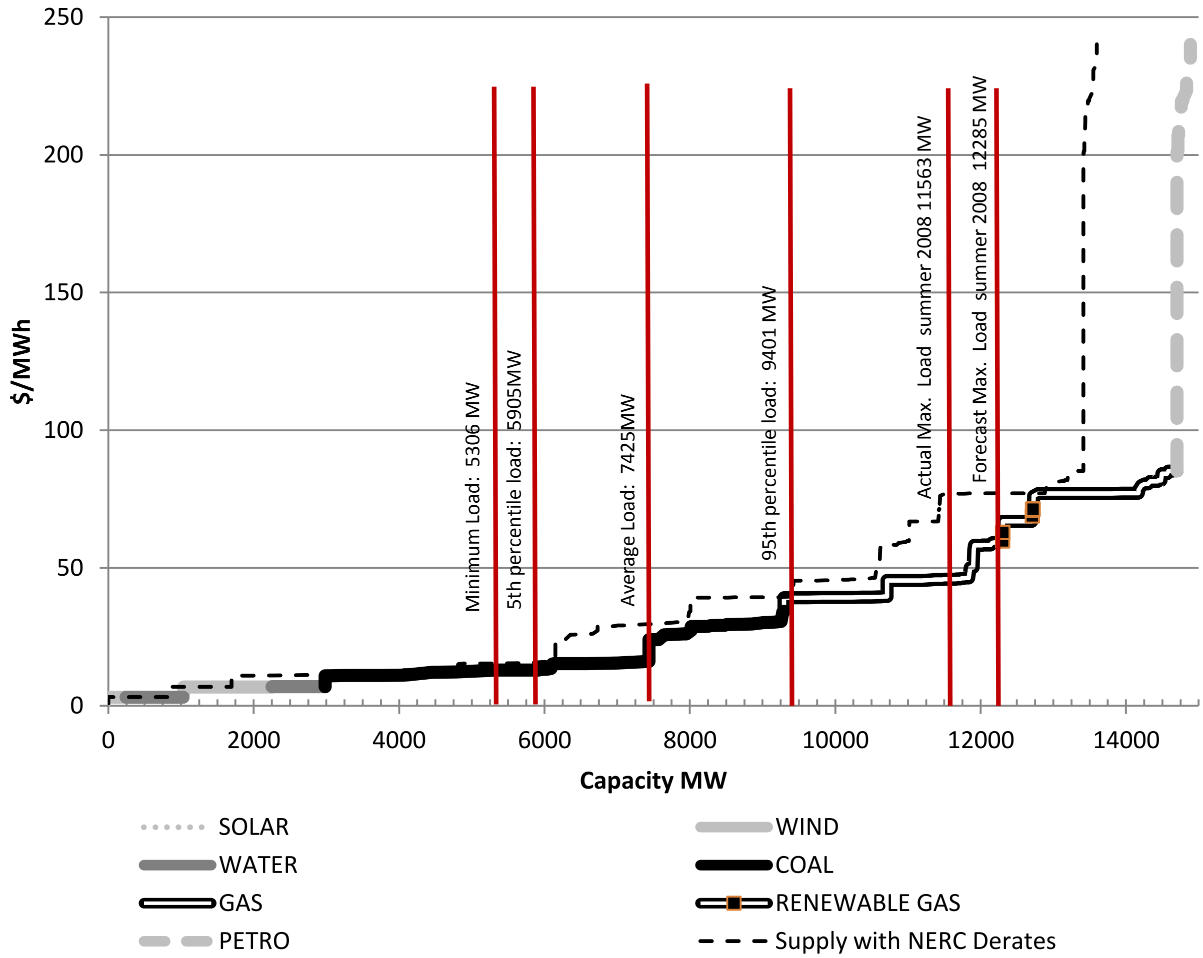


Figure 5: Total RMPA Hourly Wind Output, Load and Transmission Capacity

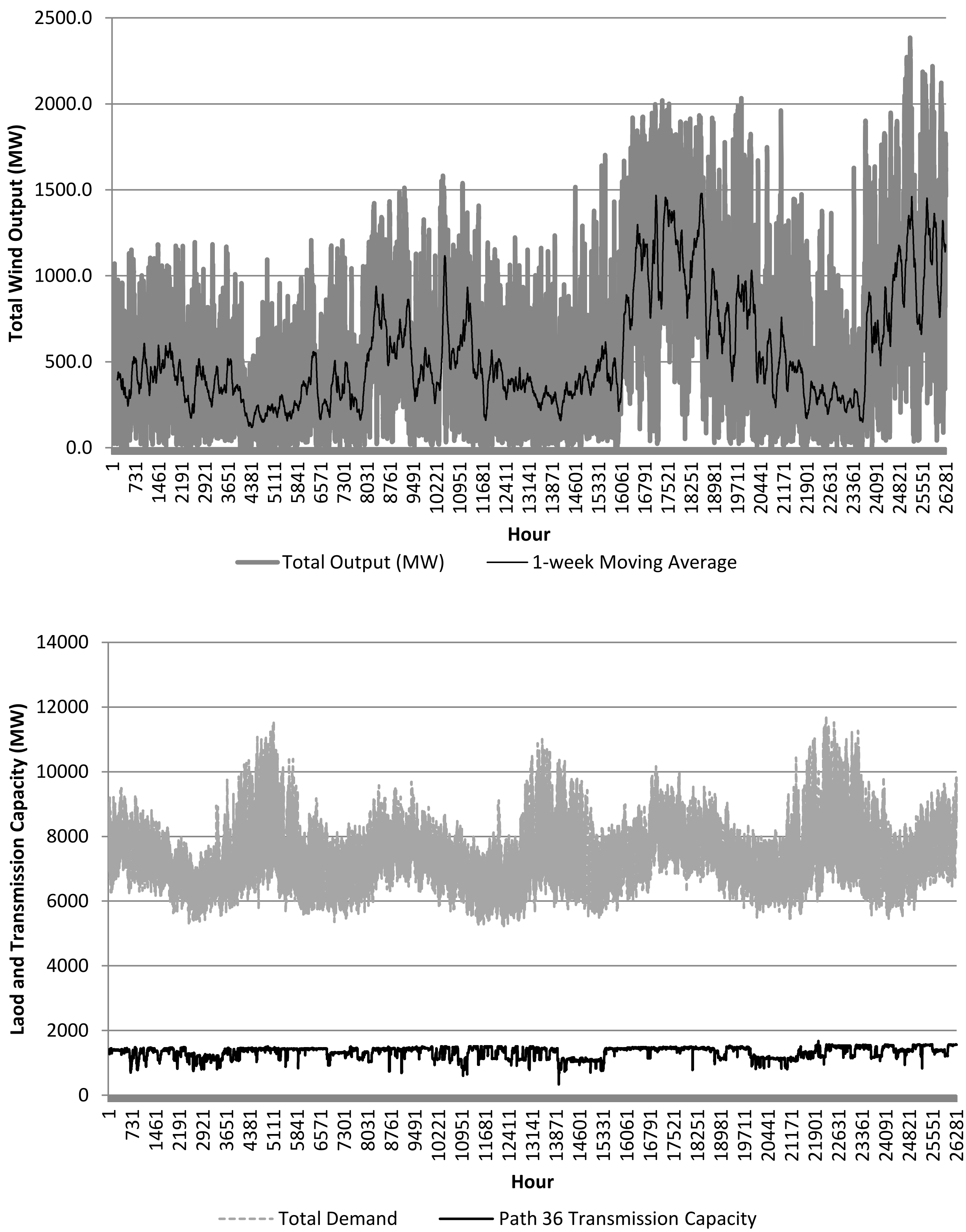


Figure 6: Percentage of Hours of Congestion by Year

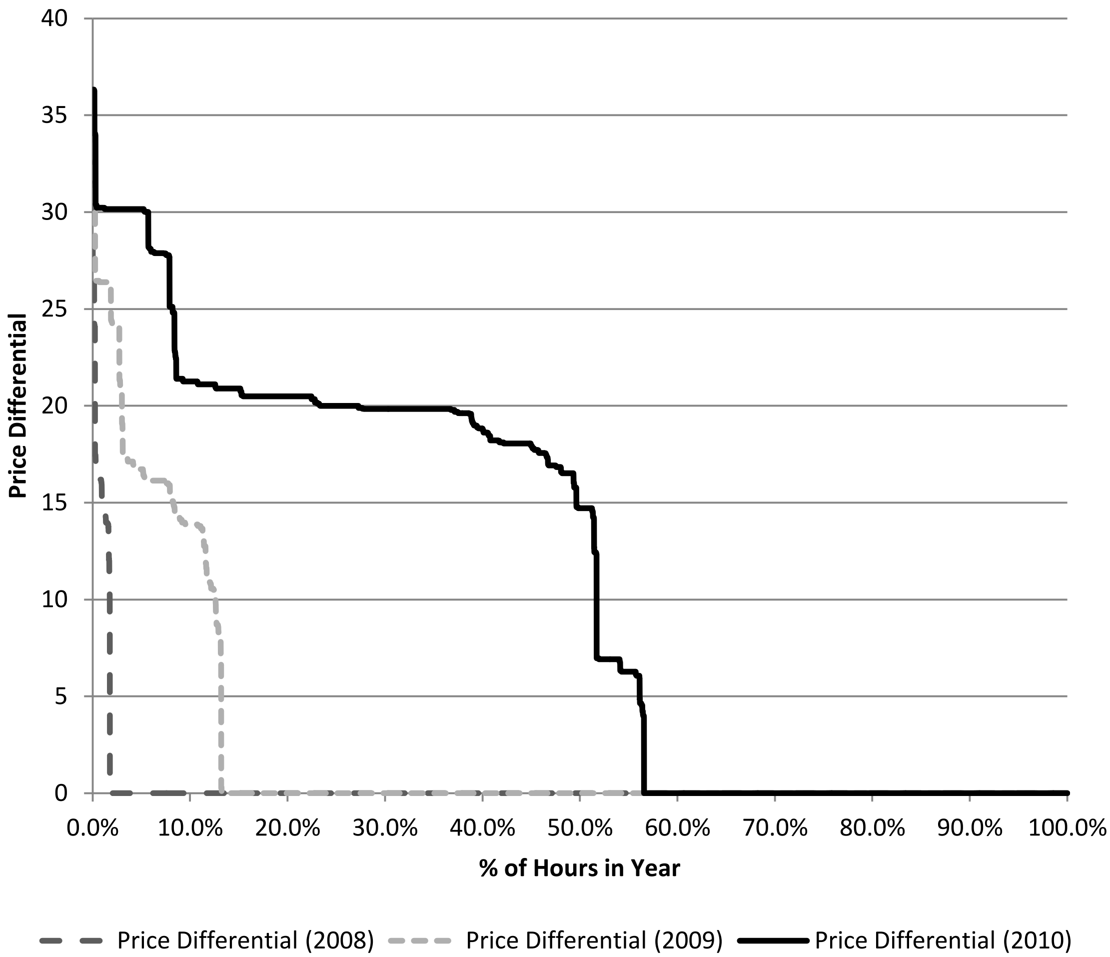


Table 1: RMPA Electricity Generation by Power Source (2008)

Power Source		Total Nameplate Capacity (2008)	% of Potential Total Capacity (2008)	Average Age of Generating Sources (2008)	Change in Capacity 2008-2010	% Change in Capacity 2008-2010
Regular Generation:						
Coal	Bituminous	1,982.9 MW	11.9%	43 years	-72.7 MW	-3.7%
	Sub-bituminous	4,742.8 MW	28.5%	37 years	881 MW	18.6%
	Total Coal:	**6,725.7 MW**	**40.4%**	**39.9 years**	**808.3 MW**	**12.0%**
Natural Gas		**6,784.1 MW**	**40.7%**	**15 years**	**198 MW**	**2.9%**
Hydro	Pumped Storage	508.5 MW	3.1%	38.4 years	0	0%
	Hydro	930.3 MW	5.6%	54.6 years	0	0%
	Total Hydro:	**1,438.8 MW**	**8.6%**	**52.9 years**	**0**	**0%**
Petroleum		**36.4 MW**	**0.2%**	**40 years**	**0**	**0%**
Renewable Gases		**10.2 MW**	**>0.1%**	**3.7 years**	**0**	**0%**
Wind		**1460.7 MW**	**8.8%**	**6.7 years**	**963.4 MW**	**66%**
Solar		**11.7 MW**	**>0.1%**	**1.3 years**	**56.8 MW**	**485.4%**
Total Potential Regular Generation:		**16,457.6 MW**	**98.8%**	**27.8 years**	**2,026.5 MW**	**12.3%**

Source: EIA Data, for 2008 to 2010 reporting years.

Table 2: Wind Farm Capacities, Capacity Factors and Locations

Plant Name (Company)	Capacity (MW)	Year/Month Opened	Capacity Factor	NREL Location ID
Node 1				
Medicine Bow (Platte River Power)	8.6	1996-2005	41.4%	18519
Foote Creek (AES SeaWest)	84.8	1999-2000	47.1%	16563
Rock River (AES SeaWest)	50	2001	46.5%	31422
Happy Jack (Duke)	29.4	2008/8	34.8%	14318
Seven Mile Hill (PacifiCorp)	123.6	2008/12	40.1%	18627
Glenrock I (PacifiCorp)	99	2008/12	33.4%	23909
Glenrock II (PacifiCorp)	39	2009/1	32.6%	23909
Rolling Hills (PacifiCorp)	99	2009/1	32.6%	23909
High Plains (PacifiCorp)	99	2009/9	39.8%	16676
McFadden (PacifiCorp)	28.5	2009/10	39.8%	16676
Silver Sage (Duke)	42	2009/10	35.2%	14318
Campbell Hill (Duke)	99	2009/12	31.4%	23835
Casper Wind Farm (Chevron)	17	2009/12	31.4%	23835
Dunlap (PacifiCorp)	111	2010/10	34.6%	19280
Top of the World (Duke)	200	2010/10	35.6%	23389
Node 1 Total (end of 2010)	**1129.9**			
Average Capacity Factor*			**41.1%**	
Standard Deviation			32.7%	
Node 2				
Ponnequinn (Xcel)	31.6	1998-2001	25.8%	13661
Ridge Creek (Enxco)	29.7	2001	25.4%	13547
Colorado Green Holdings (PPM)	162	2003	33.6%	31007
Lamar (City of Lamar)	6	2004	25.1%	31053
Spring Canyon (Invenergy)	60	2006	24.9%	13462
Cedar Creek (Babcock & Brown)	300.5	2007	26.5%	13282
Logan (Logan Wind)	201	2007	26.4%	13667
Twin Buttes (PPM)	75	2007	33.6%	30973
Peetz Table (FPL Peetz)	199.5	2007	26.4%	13667
Northern Colorado (Northern CO Wind)	174.3	2009/8	26.7%	13667
DOE Golden (NREL)	3.8	2010/1	19.4%	11949
Vestas Towers (Vestas)	1.8	2010/4	21.4%	9981
Kit Carson (Duke)	51	2010/11	30.9%	10928
Node 2 Total (end of 2010)	**1296.2**			
Average Capacity Factor*			**27.3%**	
Standard Deviation			23.3%	
Capacity Factor Correlation - Node1 - Node2 (2008-2010):			**0.403**	

* Actual simulated average over entire node, weighted for power output and new plant openings

Table 3: Simulation Parameter Summary

	Year	Demand (load) MW	Path 36/TOT3 Limit (MW)	Total Wind Output (MW)	Node 1 Wind Output (MW)	Node 2 Wind Output (MW)
Maximum	2008	11562.7	1510.4	1433.4	393.0	1057.9
	2009	11007.6	1516.9	2019.6	812.9	1232.8
	2010	11736.6	1680.0	2384.7	1121.5	1284.5
	2008-2010	11736.6	1680.0	2384.7	1121.5	1284.5
Minimum	2008	5305.8	702.8	0.3	0	0
	2009	5154.7	337.3	0.2	0	0
	2010	5540.9	783.9	0.2	0	0
	2008-2010	5154.7	337.3	0.2	0	0
Average	2008	7424.8	1321.3	371.3	81.6	289.7
	2009	7481.7	1309.2	548.7	235.5	313.2
	2010	7690.5	1363.2	717.2	355.6	361.5
	2008-2010	7532.2	1331.2	545.6	224.1	321.4
Std. dev	2008	1039.4	154.8	296.7	85.5	257.8
	2009	993.7	192.2	436.1	207.2	299.3
	2010	1065.0	165.6	531.0	304.1	329.5
	2008-2010	1039.4	173.1	454.5	245.2	298.5
5th Percentile limit	2008	5910	1000	33	1	14
	2009	5798	868	54	8	14
	2010	6105	1123	61	16	14
	2008-2010	5965	1043	48	3	15
95th Percentile limit	2008	9400	1457	998	275	845
	2009	9289	1504	1140	481	812
	2010	9675	1559	1715	967	1040
	2008-2010	9440	1535	1528	761	963

Table 4: Summary of Computed Price Outcomes

		Node 1 Prices (MWh)	Node2 Prices (MWh)	Price Differential (MWh)	Unconstrained Transmission Price (MWh)
Average Price					
	2008	$37.33	$37.62	$0.29	$37.61
	2009	$33.54	$35.81	$2.26	$35.68
	2010	$21.60	$32.84	$11.18	$31.70
	2008-2010	$30.85	$35.42	$4.57	$35.00
Std. Deviation					
	2008	$9.45	$8.98	$2.25	$8.99
	2009	$10.87	$8.15	$6.11	$8.24
	2010	$14.77	$8.03	$10.68	$8.92
	2008-2010	$13.65	$8.63	$8.63	$9.06
Maximum					
	2008	$77.09	$77.09	$32.51	$77.09
	2009	$77.07	$77.07	$32.46	$77.07
	2010	$68.99	$68.99	$36.32	$68.99
	2008-2010	$77.09	$77.09	$36.32	$77.09
Minimum					
	2008	$12.98	$15.50	$0.00	$15.50
	2009	$13.03	$13.03	$0.00	$13.03
	2010	$9.28	$13.39	$0.00	$12.24
	2008-2010	$9.28	$13.03	$0.00	$12.24
5th Percentile limit					
	2008	$29.17	$29.17	$0.00	$29.17
	2009	$13.03	$25.79	$0.00	$25.79
	2010	$9.33	$16.25	$0.00	$15.60
	2008-2010	$9.33	$25.85	$0.00	$23.99
95th Percentile limit					
	2008	$58.25	$58.25	$0.00	$58.25
	2009	$45.99	$45.99	$16.73	$45.99
	2010	$45.65	$45.65	$30.15	$45.65
	2008-2010	$46.07	$46.07	$21.11	$46.07

Table 5a: Probit Estimates of Congestion Determinants

Dependent Variable: Price Differential		All Hours (2008-2010)	2008	2009	2010
Total Load	Coefficient	-0.0015407	-0.0047955	-0.0039717	-0.0017803
	Robust Std. Error	0.000033	0.000556	0.0005399	0.0000489
	p-value	0.000	0.000	0.000	0.000
Transmission Capacity	Coefficient	-0.0098175	-0.0378671	-0.0346624	-0.0092874
	Robust Std. Error	0.0002025	0.0040369	0.0046121	0.0002608
	p-value	0.000	0.000	0.000	0.000
Node 1 Wind Output	Coefficient	0.0136629	0.0411695	0.0352191	0.0117419
	Robust Std. Error	0.0002477	0.0052508	0.0049814	0.0003061
	p-value	0.000	0.000	0.000	0.000
Node 2 Wind Output	Coefficient	-0.0006828	-0.0008686	-0.001156	-0.0004996
	Robust Std. Error	0.0000595	0.0006584	0.0002654	0.000076
	p-value	0.000	0.187	0.000	0.000
Node 1 Hydro Output	Coefficient	0.0144296	0.0524094	0.0293363	0.0090719
	Robust Std. Error	0.0005027	0.0075634	0.004944	0.0007242
	p-value	0.000	0.000	0.000	0.000
Constant	Coefficient	15.6064	55.72214	50.606	18.77937
	Robust Std. Error	0.323821	5.89912	6.63975	0.5493164
	p-value	0.000	0.000	0.000	0.000
	Wald chi-squared (5)	3139.36	113.93	93.63	1804.98
	Prob > chi-squared	0.0000	0.0000	0.0000	0.0000
	Pseudo R-squared	0.7742	0.9177	0.8735	0.7138

Table 5b: Truncated OLS Regression of Positive Price Differentials

Dependent Variable: Price Differential		All Hours (2008-2010)	2008	2009	2010
Total Load	Coefficient	0.0054379	0.0039344	0.0053526	0.0050703
	Robust Std. Error	0.0000603	0.0003766	0.0000965	0.0000708
	p-value	0.000	0.000	0.000	0.000
Transmission Capacity	Coefficient	-0.0082047	-0.0110561	-0.0084254	-0.0138304
	Robust Std. Error	0.0002281	0.001503	0.0004161	0.0003006
	p-value	0.000	0.000	0.000	0.000
Node 2 Wind Output	Coefficient	-0.0056763	-0.0047398	-0.006331	-0.0056277
	Robust Std. Error	0.000143	0.0011341	0.000241	0.0001542
	p-value	0.000	0.000	0.000	0.000
Node 2 Hydro Output	Coefficient	-0.0056856	-0.0101016	-0.0078234	-0.0074635
	Robust Std. Error	0.0003539	0.0017091	0.0004895	0.0004073
	p-value	0.000	0.000	0.000	0.000
Constant	Coefficient	-5.401459	5.168447	-5.723182	5.609197
	Robust Std. Error	0.444772	2.967406	0.8628977	0.5868417
	p-value	0.000	0.082	0.000	0.000
sigma	Coefficient	3.350332	2.376014	2.237626	3.239331
	Robust Std. Error	0.0276274	0.1639854	0.0460698	0.0327519
	p-value	0.000	0.000	0.000	0.000
	Wald chi-squared (4)	8838.66	210.79	5377.18	6839.39
	Prob > chi-squared	0.0000	0.0000	0.0000	0.0000

Table 6: Congestion Rents: Simulations for Incremental Transmission Increases

	Total Congestion Rents (2008)	Total Congestion Rents (2009)	Total Congestion Rents (2010)	Marginal Benefit over 3-year period
Actual Transmission Capacity	$2,251,141	$19,948,045	$126,914,043	
Additional 100MW	$968,154	$9,441,329	$92,975,861	$45,727,884
Additional 200MW	$193,400	$4,112,338	$64,390,727	$34,688,879
Additional 300MW	$0	$1,424,746	$41,316,304	$25,955,415
Additional 400MW	$0	$357,367	$21,280,007	$21,103,676
Additional 500MW	$0	$67,018	$9,357,024	$12,213,333
Additional 600MW	$0	$0	$3,581,945	$5,842,097
Additional 700MW	$0	$0	$1,084,004	$2,497,942
Additional 800MW	$0	$0	$334,200	$749,804
Additional 900MW	$0	$0	$69,159	$265,041
Additional 1000MW	$0	$0	$0	$69,159
			Total	$149,113,228

Table 7: Estimated Profits by Generators in Nodes 1 and 2

		Node 1 Profits (total)	Node 2 Profits (total)
Actual Case			
	2008	**$369,438,674**	**$992,190,907**
	2009	**$387,649,645**	**$942,910,259**
	2010	**$378,491,442**	**$840,323,561**
	2008-2010	**$1,135,579,760**	**$2,775,424,726**
No Transmission Constraints			
	2008	**$371,493,432**	**$991,850,261**
	2009	**$404,254,839**	**$937,530,337**
	2010	**$456,648,200**	**$793,389,245**
	2008-2010	**$1,232,396,471**	**$2,722,769,843**
		Wind Producer Profits (Node 1)	**Wind Producer Profits (Node 2)**
Actual Case			
	2008	**$23,822,042**	**$80,804,393**
	2009	**$78,487,190**	**$76,351,548**
	2010	**$66,987,385**	**$50,596,414**
	2008-2010	**$169,296,617**	**$207,752,355**
No Transmission Constraints			
	2008	**$24,246,188**	**$81,361,823**
	2009	**$85,741,020**	**$81,554,604**
	2010	**$128,606,171**	**$83,517,599**
	2008-2010	**$238,593,378**	**$246,434,026**
Wind Profit % of Total Actual Case			
	2008	6.5%	8.1%
	2009	20.3%	8.1%
	2010	17.7%	6.0%
	2008-2010	14.9%	7.5%
No Transmission Constraints			
	2008	6.5%	8.2%
	2009	21.2%	8.7%
	2010	28.2%	10.5%
	2008-2010	19.4%	9.1%

Appendix: Modeling Generator Marginal Costs:

The most important determinants of generation production cost have been identified in the power engineering literature as the technology used in power production, the efficiency of that technology, and the fuel cost of the technology. Critical information to estimate these three characteristics is available using US Energy Information Administration (EIA) Form 860 data, and while private information is not available to estimate costs statistically, the power-engineering literature includes known relationships from such studies that can be applied to approximate the potential costs conditions each generator faces.

Estimates of marginal costs of production for this study utilize the following simple model. Costs are expressed in price per megawatt hour of production (MWh). All fuel costs are computed using the known conversion constant of MWh to btu equivalent. Generator fuel cost can then be computed by assuming a generator's efficiency and the btu content of the fuel it uses. Efficiencies assumed in this study use published engineering studies that detail typical plant efficiencies or "heat-rates" given technology and vintage and are detailed in Table 1A, as are the assumed energy contents of the fuels used, and assumed transport costs where applicable. Fuel costs are the average 2007-2010 annual fuel costs by type reported by the EIA.[34] Conversion factors used are described in Table 2A.

For example, a bituminous coal-burning power plant with an assumed 30% efficiency would have the following estimated fuel cost: assuming one short-ton of

[34] Fuel costs reported by the EIA typically utilize reported market spot prices. Utilities and generating stations may purchase fuel using spot price contracts but more often negotiate contracts as long as 10-years to avoid energy price volatility. The nature of such contracts is not available publicly by generator thus average prices over the three-year period are used assuming that such contracts will include spot prices as part of the negotiated price.

bituminous coal contains 23,400,000 btu, at 100% efficiency in the conversion of coal energy content to electricity, one short-ton would create (23,400,000/3,412,141.63) = 6.857863 MWh. Assuming 30% plant efficiency reduces this electricity output to 2.057359 MWh/short ton. Assuming a market price of $42/short ton of bituminous coal in Colorado in late 2008 or early 2009 results in a marginal price of $20.41/MWh produced.

This would be the estimated fuel cost if the plant were located at the mine (a mine-mouth generator). Since transport costs are a significant portion of fuel cost, and since coal is typically delivered by rail, using the reported EIA freight rates in Colorado for coal and an assumed distance to the mine, fuel prices can be adjusted to reflect transport cost. For example, if the mine considered were located 215 miles from the source of coal it uses, and assuming the freight rate was $0.0655/ton-mile, the assumed fuel price would increase by $14.0825/ton and the marginal fuel cost would rise to approximately $27.48/MWh. Transportation costs here reflect EIA way-bill surveys to generators in the Colorado in 2008-2010 and these are reported by the EIA publicly.[35] Utility and power-plant power websites typically report location for the plant and the source of coal by mine thus typical shipping distances and costs can be accounted for in the estimation of generator fuel costs per MWh. Estimation of generator marginal production costs should also include any other marginal cost of production and power delivery, including the variable portion of operations and maintenances costs (O&M) and transmission costs to bring the power to market as shown in Equation 1A.

$$MC_{per\ MWh} = \textit{fuel cost per MWh (including freight costs) + O\&M per MWh + transmission per MWh.} \quad (1A)$$

[35] See The EIA waybill survey data at http://205.254.135.7/coal/transportationrates/

All combustion fuel-powered generator marginal costs can be estimated using engineering estimates from the literature, though some will not include fuel transport costs and O&M costs differ by technology.[36] Additionally efficiencies of some technologies change over time and this is also accounted for using plant age and published technology-specific efficiency depreciation rates. O&M cost estimates are reported in various generator studies and by the EIA (see references in Table 1A), and are assumed here by plant type based on the age and generation technology utilized. Transmission costs can also be assumed by identifying plants that are distant from major electricity markets and the reported transmission tariffs charged in 2008 TO 2010. In the RMPA region modeled here, transmission networks use "postage stamp" pricing in which a flat fee is charged per unit of power delivered, regardless of the distance the delivery requires. Such information is available on WAPA an NTTG websites.[37]

An alternative means of estimating generator fuel conversion efficiency, or "heat-rates" is also available. Monthly net heat rates can be found for many plants in the United States at the EPA eGrid database.[38] Alternatively heat rates can be computed using EIA Form 923 data for electricity output and coal usage, although this data is reported on an annual basis. The eGRid reported heat rates can be unrealistically high or low in any month, as can the computed heat rates using EIA data due possibly to measurement and reporting errors in fuel use or energy output. Pratson, Haerer, and Patiño-Echeverri

[36] Gas power-plants were assumed to have fuel delivered by pipeline. Local natural gas prices as reported by the EIA in the RMPA region were used to define the gas prices over the 2007-2010 period. No freight cost was assumed between these prices and the delivered price as fuel delivery system costs were assumed to be sunk or fixed and not included in the price of fuel delivered.

[37] Such tariffs are not distance dependent. The rate was $3.75/MWh on both networks in 2008.

[38] U.S. Environmental Protection Agency. eGRID; available from: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

(2013) note this problem with respect to eGrid data and suggest using the median of monthly reported rates. Such a correction, however, is not available for EIA computed data given the annual nature of the data. A drawback to using reported or computed heat rates is a lack of available data for some plants. Due to both the problems of unreasonable computed heat rates, and missing plant data for generators in the study region reported here, power engineering efficiencies were used instead.

Emission costs are another important source of plant variable costs. Data for these costs can also be found at the EPA's eGrid database. For a recent example of a cost estimation using such data see Pratson, Haerer, and Patiño-Echeverri (2013). Due to the fact that the eGrid database did not include data for all plants in the study region modeled in this study, such costs were not included in the marginal cost estimates used in the simulations reported. Extensions of this model could include control costs as an added term in Equation 1A above. As an alternative to data provided by eGrid, data is available from EIA Form 860 data to identify some of the important control technologies used at each generator in each year and summary estimates from the engineering literature like those shown in Table 1A could be created for the various emissions technologies employed.

Renewable source marginal costs reported in Table 1A are based only on variable O&M costs reported in the literature. Fuel costs for these sources are zero. The literature is sparse with respect to O&M costs for such plants, particularly wind and solar installations. Further, these costs are likely quite variable and plant dependent as technology for these sources continues to change at a rapid pace. Further work to identify such costs could improve the accuracy of simulation results with respect to potential profit estimations for these sources. The lack of such data, however, should not change their dispatch outcome and therefore the pricing outcomes in simulations like those reported here as it is generally understood that the marginal costs of such plants are far below those of traditional combustion-powered generators.

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Table 1A: Assumptions used to Model Generation Marginal Costs

Fuel	Technology	Assumed Efficiency	Fuel cost	Freight rate (ton-mile)	O&M Variable Cost/MWh
Bituminous Coal	Steam turbine sub-critical boiler	Pre-1970: 28% 1970-1989: 30% Post-1989: 30%	$42/short ton	$0.0655 Uinta Basin	$4.25 rising at 1.5% per year
	Steam turbine super-critical boiler	Pre-1970: 31.5% 1970-1989: 35% Post-1989: 31.5%			
Sub-bituminous Coal	Steam turbine sub-critical boiler	Pre-1970: 28% 1970-1989: 30% Post-1989: 30%	$15/short ton	$0.0655 Uinta Basin $0.0221 PRB coal	$4.25 rising at 1.5% per year
	Steam turbine super-critical boiler	Pre-1970: 28% 1970-1989: 30% Post-1989: 30%			
Natural Gas	Combined-cycle	1980-1999: 40.8% Post-1999: 47.5% falling at 0.2% per year	$4.97/mcf (WY & SD) $4.91/mcf (CO)	N.A.	$4.42 $4.28 with duct-firing
	Gas turbine	Pre-1997: 30.5% 1997-2005: 32.1% Post-2005: 39.9% falling at 0.05% per year		N.A.	$25.72 Small (25 MW or less) $26.10
	Internal combustion (Wartsila engine)	38% falling at 0.05% per year		N.A.	$15
	Internal combustion	35% falling at 0.05% per year		N.A.	$0.0233 \cdot \text{MW output}^{-0.1209}$
	Steam Turbine	30.3%		N.A.	$4.25 rising at 1.5% per year
Renewable Gas	Internal combustion	35% falling at 0.05% per year	$2/mcf	N.A.	$0.0233 \cdot \text{MW output}^{-0.1209}$
	Gas Turbine	30.5%			$26.10
Petroleum (diesel fuel)	Internal combustion	33.3% falling at 0.2% per year	$2.25/gal	N.A.	$0.0233 \cdot \text{MW output}^{-0.1209}$
	Gas turbine	25.6%		N.A.	$26.10
Hydro (Water)	Simple turbine Pumped storage	N.A.	N.A.	N.A.	$3.11 $13.47
Wind	1.5 MW Turbine	N.A.	N.A.	N.A.	$3.10
Solar	Photo-voltaic	N.A.	N.A.	N.A.	$0.80

Sources: Nyberg (2011), Nichols *et al* (2008), Beer (2006), CPUC (2007), EPA (2010), Hassler (2009), Brooks (2000), Ragland and Stenzel (2000), NWPP (2002), Simon *et al.* (2007), Klein and Rednam (2007), Kaplan (2008), EPRI (2011), Wärtsilä Corp. (2005).

Table 2A: Energy Conversion Equivalents Used:

- 1MWh = 3,412,141.63 btu
- 1 short-ton (2000 lbs) bituminous coal = 23,400,000 btu
- 1 short-ton (2000 lbs) sub-bituminous coal = 17,600,000 btu
- 1 mcf (one thousand cubic feet) natural gas = 1,020,000 btu
- 1 mcf (one thousand cubic feet) methane or land-fill gas = 500,000 btu
- 1 US gallon diesel fuel = 129,500 btu