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***A CRITICAL REVIEW OF WIND TRANSMISSION COST ESTIMATES
FROM MAJOR TRANSMISSION PLANNING EFFORTS***

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Abstract

It is difficult to evaluate the cost of new transmission for wind energy due to the complex and data intensive process of transmission planning. The requirement for wind to be sited in high wind resource areas that are often far from load centers and the low capacity factor of individual wind farms leads to concerns that transmission for wind may have excessive costs. However, regional transmission planning groups are increasingly including wind energy in transmission plans. We analyze 17 transmission plans that include between 500 MW and 25.5 GW of new wind generation to evaluate the range of expected unit costs of transmission for wind. Based on a simplified methodology we find that transmission for wind ranges from \$0.40 to 95/MWh or \$8.5 to \$1,940/kW. However, nearly 75% of the scenarios studied cost less than around \$20/MWh or \$420/kW. We find no correlation between the unit cost of transmission and the amount of new wind analyzed in each scenario. We also find that no uniform set of methods and assumptions has emerged for evaluating the transmission requirements for wind energy.

1. Introduction

Differences between conventional power and wind power make transmission more important to wind projects than to conventional power plants. The location of wind farms is dependent on the wind resource, which is often some distance from loads. Natural gas power plants, for example, require much less transmission because they can be sited near load centers. Wind projects also have a lower ratio of the volume of energy produced to the rated capacity of the power plant (a lower capacity factor) compared to baseload power plants. The need for transmission expansion and the low capacity factor for wind lead to concerns that the cost of transmission per kWh generated may be excessive compared to other generation options.

Unfortunately, transmission planning is a relatively complex, data-intensive process that does not lend itself well to simplified analysis. We approach the question of the cost of transmission for wind through a meta-analysis of 17 regional transmission planning studies from across the United States that include accessing new wind resources. While the transmission studies usually provide only first-order cost estimates, the results reveal that, in many cases, concerns about extremely high costs of transmission for wind are unfounded.

Table 1. Description of studies evaluated in analysis

Region	Principal Author	Type of Organization	Date	Title of Study	Study Abbreviation
	California ISO (CAISO)	ISO/RTO	December 2006	CAISO South Regional Transmission Plan for 2006: Tehachapi Transmission Project	Tehachapi
California	Southern California Edison (SCE)	IOU	November 2006	SCE Conceptual Transmission Requirements and Costs for Integrating Renewable Resources	SCE 1,2E, 2N, 3
	San Diego Gas & Electric (SDG&E)	IOU	November 2006	Transmission Ranking Cost Report of San Diego Gas & Electric Company for Renewable Portfolio Standard Procurement	SDG&E
	Midwest ISO (MISO)	ISO/RTO	February 2007	Midwest ISO Transmission Expansion Plan (MTEP) 2006: Vision Exploratory Study (Section 7.4)	MISO '06
	CapX Utilities	Voluntary Utility Organization	January 2007	Community Based Energy Development Transmission Study: West Central (MN) Transmission Planning Zone	CapX-CBED
Midwest	CapX Utilities	Voluntary Utility Organization	May 2005	CapX 2020 Technical Update	CapX-1 and -2
	Xcel Energy	IOU	May 2005	Buffalo Ridge Incremental Generation Outlet Electric Transmission Study	Xcel-31A
	Southwest Power Pool (SPP)	ISO/RTO	May 2005	Kansas/Panhandle Sub-Regional Transmission Study	SPP-X
	MISO	ISO/RTO	June 2003	MISO MTEP 2003	MISO '03-1 and 2
	SPP	ISO/RTO	April 2007	SPP Transmission Expansion Supplement to Support Development of Texas Panhandle Competitive Renewable Energy Zones	SPP-2
Texas	SPP	ISO/RTO	December 2006	Southwest Power Pool Inc's Analysis of Transmission Alternatives for Competitive Renewable Energy Zones in Texas	SPP-1
	Electric Reliability Council of Texas (ERCOT)	ISO/RTO	December 2006	Analysis of Transmission Alternatives for CREZs in Texas	ERCOT C3, CW3, M2, P4, Cb1, Cb2, and Cb3
	Western Regional Transmission Expansion Partnership (WRTEP)	State-led Organization	April 2007	Western Regional Transmission Expansion Partnership: Benefit-Cost Analysis of Frontier Line Possibilities	Frontier A and B
	Northwest Transmission Assessment Committee (NTAC)	Voluntary Utility Organization	May 2006	Canada-Northwest-California Transmission Options Study	NTAC 1, 2A', 2A, and 2B
West	Clean and Diversified Energy Advisory Committee (CDEAC) Transmission Task Force	State-led Organization	March 2006	Report of the Transmission Task Force to the Western Governors Association (WGA)	WGA '06
	RMATS	State-led Organization	September 2004	Rocky Mountain Area Transmission Study (RMATS)	RMATS 1 and 2
	Seams Steering Group of the Western Interconnect (SSG-WI)	Voluntary Utility Organization	October 2003	Framework for Expansion of the Western Interconnection Transmission System	SSG-WI

Generally, we include in our sample transmission expansion plans that evaluate 300 MW or more of new wind power and focus on the deeper network upgrades required to ship power from wind resource regions to load centers. The spectrum of studies ranges from very conceptual pre-feasibility evaluations of potential transmission solutions to highly detailed studies that model system impacts such as thermal overloads of specific facilities, excessive voltage drop along particular paths, or stability criteria. Our list of studies, however, excludes more-academic studies that are not based on detailed transmission characterizations, as well as case-by-case system impact studies performed for specific project interconnection requests. A full list of studies is found in Table 1 and the references.¹

The remainder of the report is organized as follows. In Section 2 we review the evolution of transmission planning, discuss the importance of including wind energy in transmission planning, and the general method used by transmission planners to evaluate transmission system investments required to connect wind resource centers. In Section 3 we describe the methodology we apply to estimate the unit cost for wind transmission from each of the studies. We present the results of the analysis in Section 4. Although the results focus on the unit cost of wind transmission, we also discuss the factors that drive differences in the cost of wind transmission. In Section 5 we conclude with a discussion of the results and recommendations for future transmission plans that include wind energy.

2. Background: Regional Transmission Planning

In this section we introduce the concept of regional transmission planning and contrast it to traditional utility planning. We then summarize the trend toward wind power's inclusion in regional transmission plans and describe in very general terms the methodology used in transmission expansion plans.

The bulk transmission system in the United States is highly interconnected within three large interconnects (Figure 1). The Western Interconnect extends west from Montana, Wyoming, Colorado, and New Mexico to the Pacific Ocean and north to the Canadian provinces of British Columbia and Alberta. The Eastern Interconnect extends east to the Atlantic Ocean, but excludes the majority of Texas. Most of Texas is within its own separate interconnect operated by ERCOT. The highly interconnected nature of the transmission system within these interconnects means that system operation in one region (within the interconnect) can impact operations throughout the system. Conversely, power flow across the interconnects is limited by the small capacity of relatively expensive AC/DC converters between links.

Traditionally, utilities have been responsible for ensuring that the local transmission system is built to reliably deliver power to customers within their footprint and to facilitate economic exchange of power with neighboring utilities. Voluntary reliability councils within each interconnect promoted coordination of planning for reliability across multiple utilities. Coordination of utility transmission planning efforts helped to reduce redundancy in transmission investments and to ensure that projected load growth would be met reliably. However these reliability councils had no inherent long-term planning authority (Joskow 2005a).

Restructuring of the electric power system in the 1990's and the development of several independent organizations to operate the transmission system (ISO/RTOs) introduced the need for transmission planning to include the promotion of wholesale power competition. FERC Order 2000 provides guidance for RTOs and places responsibility for regional transmission planning, which includes increasing access to low-cost generators, on the RTOs (NWCC 2004). Transmission planning in many ISO/RTOs is moving from evaluating only a compilation of member utilities' local transmission plans to coordinating

¹ Our sample also excludes results from the Intermittency Analysis Project in California (Porter et al. 2007). The results from this analysis were not finalized at the time this paper was written due to pending revisions in the Integrated Energy Policy Report (IEPR) process.

interregional reliability and considering projects that cannot be justified on a reliability basis alone. Beyond contributing towards reliability requirements, these projects reduce costs by promoting interregional power flows (ISO/RTO Planning Committee 2006, p3).

Even utilities that are not within an ISO/RTO are being pushed by FERC to expand the transmission planning process from simply responding to interconnection requests from non-utility generators on a case-by-case basis to participation in an open transmission planning process on a local and regional level. FERC Order 888 in 1996 required transmission owners to provide open access on a non-discriminatory basis to potential transmission service customers like non-utility generators. A standardized interconnection procedure, the Large Generator Interconnection Procedure in FERC Order 2003, outlined the process for transmission owners to study the system impacts of interconnecting power plants on a case-by case basis.² Major pitfalls of this process, including clogged interconnection queues and individual system impact studies that missed potential opportunities for joint transmission investments, led to FERC Order 890, issued in 2007. Order 890 requires transmission owners to develop and file a description of a transmission planning process that is coordinated with other transmission owners, promotes openness and transparency, and includes participation in regional transmission planning efforts (NWCC 2003; NWCC 2007a).

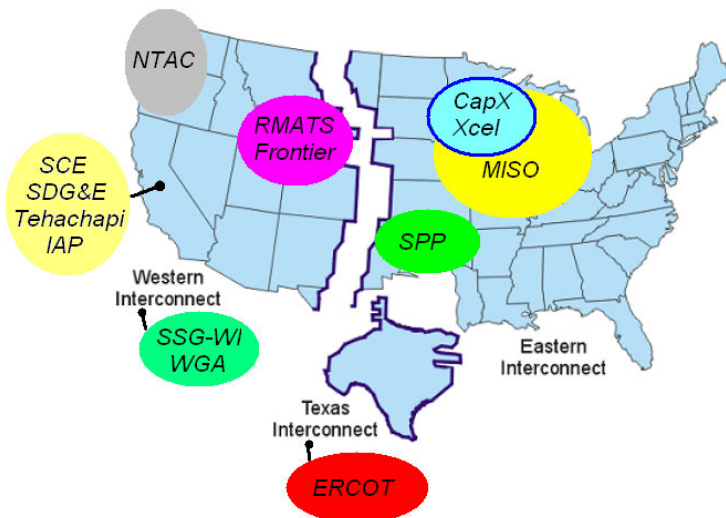


Figure 1. Location of transmission studies relative to the three interconnects in the United States

2.1 Wind in Transmission Plans

The unique features of wind power projects make the move toward open, regional transmission planning especially important for wind energy projects. Utility-scale wind projects are primarily characterized by non-utility ownership, short project development periods, significant dependency on high wind regions for project siting, and small project size relative to the economically developable resource in most locations. Transmission projects on the other hand are primarily characterized by utility ownership, long lead times, large economies of scale, and significant interdependence with other network users.

² Order 888 requires transmission owners to file a pro-forma tariff that describes under what terms and conditions available transmission capacity will be made available to a potential transmission customer (Joskow 2005a, p103). Order 2003 standardizes the requirements for generators to interconnect with the bulk transmission system (NWCC 2003)

It is widely recognized that in many cases it is inefficient to build transmission to respond to one wind plant interconnection request, only to have to upgrade or replace the investment when the next plant is built in the same wind resource area (CAISO 2006b). The wind resource near Tehachapi, CA for example is estimated to support over 3,500 MW of wind power but no single wind project in the transmission queue is larger than 600 MW (CAISO 2006a, p 25). Similarly, it is sometimes the case that the availability of transmission capacity, rather than the location of the best wind resource, drives the siting of wind projects. In other words, it may be the case that it is more economically efficient to utilize existing transmission capacity with a lower-performing wind farm than to build new transmission capacity to interconnect a higher-performing wind project, but such a comparison cannot be made without evaluating the cost to increase transmission capacity for high-performance wind sites. A reactive planning approach that responds to single interconnection requests is therefore unlikely to produce as an efficient transmission system as a proactive transmission plan that seeks to upgrade the transmission system to support the expected economical wind power development in the region.

Figure 2 shows that a variety of organizations are performing transmission expansion studies that include wind energy. The authors of the studies are primarily ISO/RTO's, but most of the studies in the West are performed by voluntary utility organizations or state-led organizations. The two studies performed by IOU's in California were performed at the request of the state regulator to facilitate the state mandated renewable portfolio process.³ Wind energy is increasingly being included in regional transmission plans based on the recognition of three trends:

- (1) In many areas, state policies will drive an increasing demand for renewable energy, which in most areas is projected to come from wind energy (Chen et al. 2007)
- (2) Expanding the transmission system in a piece-by-piece manner is not the most efficient way to access more wind
- (3) The existing system and upgrades based on reliability needs, transmission congestion relief, or accessing other generators (e.g., coal plants) can be leveraged to efficiently move wind power from wind resource areas to loads.

The inclusion of wind in regional transmission planning studies is driven by various parties. In ISO/RTO transmission planning studies, wind industry advocates and project developers can participate in the open transmission planning process as a stakeholder to propose wind development scenarios. One of the earliest examples was the inclusion of 10,000 MW of wind energy in a Midwest ISO exploratory study in 2003 as proposed by the American Wind Energy Association (AWEA) and Wind on the Wires (WOW) (MISO 2003). State officials have pushed for the inclusion of wind in transmission planning studies within their state, as in the case of the Competitive Renewable Energy Zones in Texas or the Tehachapi Collaborative Study Group in California (ERCOT, 2006; CAISO, 2006). States have also led multi-state transmission planning efforts that evaluate the need for wind transmission, including the Frontier Line, which would bring wind and coal power from states in the interior mountain west to the southwest and California (WRTEP 2007) and the Western Governors Association Clean and Diversified Energy Initiative (CDEAC 2006). FERC has signaled approval for transmission solutions that assist states in meeting mandated goals with its recent adoption of the California ISO's proposed financing mechanism to connect location-constrained resources through its Remote Resource Interconnection Policy (NWCC 2007b).

³ The third IOU in California, PG&E was also required to provide a similar report. The PG&E report is not included in our sample, however, because it does not specifically evaluate wind projects in the analysis.

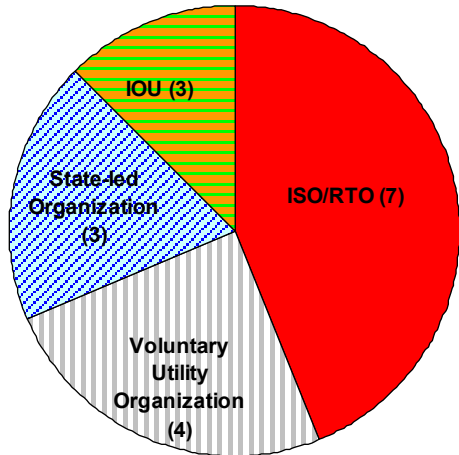


Figure 2. Type of organizations performing transmission studies that include wind energy

2.2 General Methodology Employed in Transmission Plans

For the most part, transmission studies include large aggregations of renewable energy that would be shipped from a remote location to load centers. As such, it is important to distinguish between a generator tie (also referred to as a generator interconnection) and a network upgrade. A gen-tie line, as they are called, connects the actual generating resource to the existing network of transmission facilities. The costs of a gen-tie line and interconnection are usually borne by the generator.

Once the resource is connected to the existing network, shipping the power from the ‘injection point’ to the load center becomes an issue for the utilities or network operators. All of the studies in our sample only examined the network upgrades required to ship wind power from the remote location to the load center, and did not include the cost of the gen-tie lines. Network upgrades include upgrading or replacing power lines, new power lines, new or upgraded substations, and various other transmission equipment. Studies generally did not consider equipment at voltages below 69-115kV.

In general, transmission studies employ a power flow model to assess impacts and necessary upgrades to the grid. The power flow model simulates the grid under conditions of a given load and mix of resources to determine where elements in the grid will become overloaded. An element is assumed to become overloaded if power flow through the element exceeds a thermal rating for how much power can be sent through the system. Once overloaded elements are identified, the power flow model is used to determine transmission upgrades that will mitigate overloaded elements. More detailed studies will include additional criteria such as minimum voltage drop to determine the need for transmission upgrades.

Studies that tend to focus on reliability criteria will generally assume that the nameplate capacity of a wind farm is produced at the same time as the grid is under the highest stressed conditions, for instance peak summer load in California. These studies will sometimes go further to estimate overloaded elements when the system is fully stressed and one or two primary grid elements, such as major transmission lines or large generators, are out of commission. This type of analysis is called a contingency analysis.

Studies that tend to focus on enabling access to low cost resources rather than on satisfying reliability criteria evaluate the production cost savings – i.e., the savings resulting from the ability to access cheaper power sources and reduction in congestion – due to the new transmission upgrades. These studies generally employ an optimal power flow program that optimizes the dispatch of generation over a region (as in least-cost) subject to reliability-based constraints (a “security constrained dispatch”). These studies

rely on hourly wind profiles from expected wind resource regions to simulate the operation of the grid over a specified time period.

Based on this multitude of transmission planning studies that include accessing wind resources, we draw out general conclusions on how wind power is considered in transmission plans and estimate the cost of building transmission for wind.

3. Methodology

While many transmission planning studies have included wind power, no uniform methodology, assumptions, or presentation of results has evolved. Comparing the cost of transmission for wind across all of the studies is therefore not a straightforward process. First we will describe what would ideally be provided in a transmission planning study to assess the cost of transmission for wind. Then we discuss our simplified methodology for comparing the existing transmission cost estimates across studies.

In general, transmission for wind projects is conceived of as being transmission that is built to isolated, remote regions. The cost of building transmission to the region with the high wind resource is therefore the full cost that should be assessed for wind transmission. In reality, however, transmission need not be built from a load center to the wind resource region. Instead, a generator tie line that connects the wind plant to the nearest bulk transmission line is the only dedicated facility that must be built solely for the benefit of the wind plant. Further upgrades to the existing transmission network may benefit other transmission system users. For example, improving the capacity of a transformer deep into the network so that power can be transferred from a wind plant to a load center may offset a planned upgrade for reliability purposes or reduce existing congestion on a line heavily used for economic transfers. These benefits will be realized by transmission users other than the wind plant that triggered the upgrade.

In general, for a transmission planning study to be able to assess the ‘additional’ cost of building transmission to access a wind resource the transmission investments required to connect the new generation must be compared to an alternative future that includes all transmission investments that would be built to meet reliability and economic transfer criteria if new wind farms were not connected. Figure 3 illustrates how a transmission planning study might evaluate the true ‘additional’ cost of building transmission to access a wind resource region. The transmission plan would need to first create a reference or baseline future that includes all transmission investments required to meet load growth, reliability requirements, relieve congestion created by economic transfers on constrained transmission lines (or conversely, pay congestion rents), and transfer power from any new generators to loads. For comparison, the transmission planner would then create a “high wind future” scenario in which transmission is built to a high wind resource area. This future would still require transmission to any other new generators required to meet load growth, upgrades for reliability purposes, and upgrades to relieve congestion. An ideal transmission planner would try to minimize the total transmission investment by combining investments for congestion mitigation, reliability requirements, and network upgrades for connecting new generation as much as possible. The true additional cost of the high wind future in comparison to an alternative future would then be the difference in total required transmission investments. The total additional cost would need to be divided between all of the new generators (i.e., not just wind projects) in the high wind future that benefit from the transmission upgrades. The result would be the true additional cost for building transmission for wind energy.

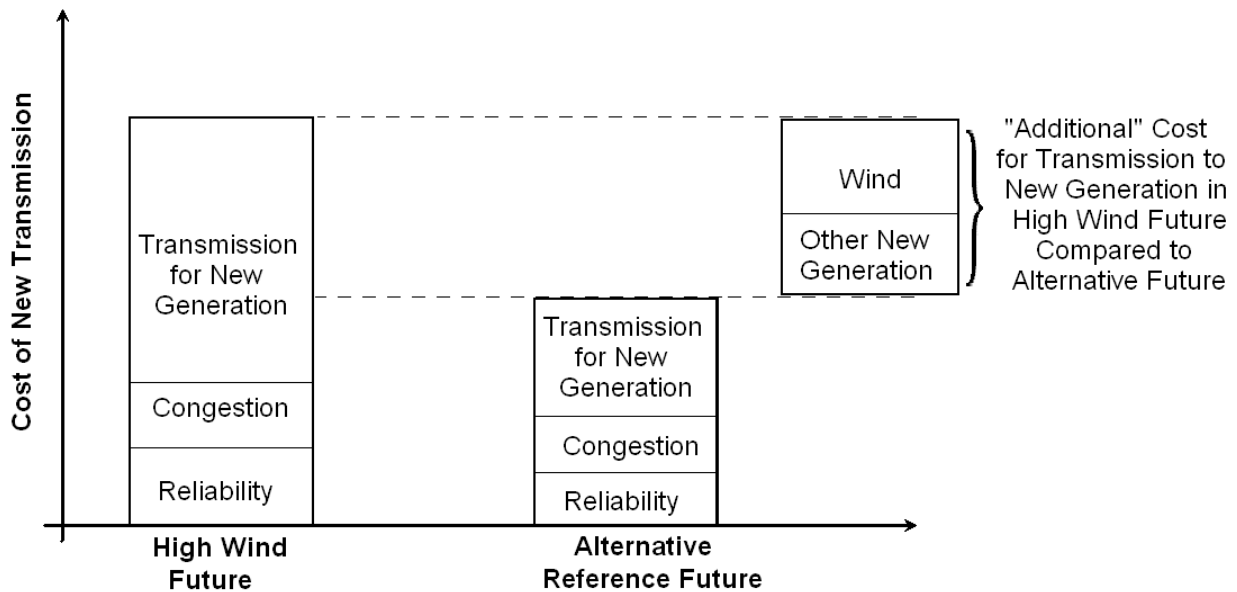


Figure 3 – Illustration of information required to assess the true ‘additional’ cost of building transmission for wind energy.

Unfortunately, none of the transmission planning studies were designed to specifically answer the question of the additional cost of transmission for wind and therefore do not provide adequate information to make an ideal assessment. Often, for example, the only value that the study provides is the total cost of transmission for the high wind future and the total amount of new generation that was modeled. In many cases this overstates the true cost of transmission attributable to wind because some of the network upgrades relieve existing congestion, or offset reliability upgrades that would have to be made even if the transmission were not built to the wind resource area. Furthermore, attempting to separate transmission investments strictly for reliability from investments strictly for economic enhancements is not a simple if even possible task (Hirst and Kirby 2001; Joskow 2005b).

Even though we are not able to perfectly assess the cost of transmission based on these regional transmission planning studies, we can use a simplified methodology to understand the relative impacts of the cost of transmission for wind energy. Only in very particular circumstances, described below, does this methodology lead to a value that represents the additional cost of transmission for wind. The exact numerical results from this analysis should therefore be treated with all due caution.

Our simplified approach is to extract the total required transmission investment from scenarios in transmission planning studies that involve wind and divide the cost by the relative share of capacity and energy from the modeled wind resource. Depending on the results presented in the study, this total required investment may be incremental network investments required to connect new generators (the top section of the bar for the high wind future in Figure 3) or it may be the total investment to connect new generators, satisfy reliability requirements with projected load growth, and relieve existing congestion (the entire bar in the high wind future in Figure 3). Either way, we are not able to take into consideration investments that would have to be made in an alternative reference future without the wind plants (the entire bar in the alternative reference future in Figure 3).

Based on the transmission costs, we present four numbers to estimate the unit cost of transmission upgrades: the cost per kW and per MWh weighted by generator capacity, and the cost per kW and per MWh weighted by energy. The typically higher capacity-weighted number represents the cost of

transmission assuming that transmission must be reserved for the full capacity of the wind power plant at all times. The typically lower energy-weighted number represents the assumption that transmission costs are allocated based on the average power output of a resource, not its peak capacity. In cases where wind is the only generation source that uses the transmission upgrade, the two methods produce the same estimate.

In reality we do not know exactly what portion of transmission line capacity should be attributed to each generation type. The capacity weighted cost may reflect the cost imposed by a wind farm and a coal plant co-located at the end of an essentially radial line. This method, however, clearly does not reflect the cost that dispersed wind plants and gas plants co-located with load impose on the transmission system. Unfortunately many studies did not attempt to directly estimate the cost imposed by each generation technology separately and we are forced to use our simplified assumptions.

Table 1 details the assumptions used in calculating the unit cost of wind transmission upgrades. Equation 1 and 2 describe the method for calculating the unit costs of transmission in terms of \$/kW and \$/MWh, respectively.

Table 1. Assumptions used in calculating the unit cost of wind energy transmission upgrades.

Calculation Method:	Capacity	Energy
Capital Recovery Factor (CRF):	15%	15%
Wind Capacity Factor:	35%	35%
Coal/Geothermal/Biomass Capacity Factor:	-	85%
Natural Gas/ Hydro Capacity Factor	-	60%
Solar Capacity Factor	-	20%

$$TC = c_c (P_w + P_c + P_g) = c_{v,w} P_w + c_{v,c} P_c + c_{v,g} P_g$$

Therefore,

$$c_c = \frac{TC}{(P_w + P_c + P_g)}$$

$$c_{v,w} = \frac{CF_w \cdot TC}{CF_w \cdot P_w + CF_c \cdot P_c + CF_g \cdot P_g}$$

Equation 1

Where:

TC = Total cost of transmission investment

c_c = unit cost of transmission weighted by capacity

$c_{v,i}$ = unit cost of transmission weighted by energy for generator (w = wind, c = coal, g = gas)

P_i = nameplate capacity of generators

CF_i = Capacity factor of generators

$$COE_j = \frac{c_j \cdot CRF}{CF_w \cdot 8760}$$

Equation 2

Where: COE_j = Transmission cost per unit of wind energy weighted by capacity ($j = c$) or weighted by energy ($j = v$). COE_j is in units of \$/kWh when c_j is in terms of \$/kW
 CRF = Capital recovery factor

Because we use the total cost of transmission upgrades, and not the additional cost relative to an alternative reference future, the unit costs we present are indicative of costs for building transmission for wind but should not necessarily be interpreted as a transmission ‘adder’ to the bus-bar cost of wind. In almost all cases the studies do not present the information required to assess the additional cost of transmission that would be required to develop a true transmission adder. In special circumstances, however, our methodology does approximate the true additional cost of wind transmission.

Understanding these special circumstances helps to elucidate the limitations to our methodology and the implicit assumptions being made when transmission planners only present the total cost of transmission for a scenario that involves new wind. The only circumstances by which our methodology produces a true transmission adder is when the following conditions are met:

- (1) The alternative reference future requires no new transmission for new generators.
- (2) The transmission required to connect the new generators in the high wind scenario does not relieve any pre-existing congestion on network lines, nor does it defer or offset transmission upgrades required for reliability purposes.
- (3) Any new non-wind generation in the high wind scenario shares in the responsibility for transmission investments weighted by either capacity or energy.

If these conditions are met, then the cost of transmission for new generation (the top section of the bar for the high wind future in Figure 3) represents the true transmission adder for new generation, which is then parsed out among the new generation resources. The first condition can typically be met if the alternative future uses new strategically sited power plants to meet load growth that do not require any additional transmission investments. Typically these would be natural gas plants sited very near load centers. The second condition is met if the new wind farms can only be connected to load centers through essentially dedicated, or radial, transmission lines that do not benefit any other users on the network. The third condition is met if other generators in the high-wind scenario are located in a similar manner to the wind resource. A number of studies, for example modeled wind and coal resources from the same region that are shipped over a large transmission line, such as the Frontier Line (WRTEP 2007). In some studies with a poorly connected network and very remote wind resources, these conditions are roughly met. In cases where the transmission investments required to move wind power to loads benefits other network users by deferring reliability upgrades or relieving congestion our method overstates the cost of wind transmission. In other cases where the high wind scenario includes other generation that may not utilize the new transmission our method understates the cost of transmission attributable to new wind generation.

In addition to the unit cost of transmission, we collect information from each study that allows us to assess factors that drive the differences in the unit cost of wind transmission. By collecting the total miles of transmission that are built in each case, we calculate the average cost of transmission per MW of new generation capacity per mile of transmission line (\$/MW-mi). It is important to note that the “MW” in \$/MW-mi refers to new generation capacity, and not new transfer capacity. The \$/MW-mi statistic

reveals differences in network conditions where transmission investments are made. For example, a transmission investment required to connect a wind resource area in a highly interconnected network may only require a short transmission line and multiple transformer or substation upgrades on the existing network. In this case the distance of the new transmission is much shorter than the distance between the wind resource area and the loads. Conversely, multiple studies propose long distance, dedicated high voltage direct current (HVDC) lines with a transfer capacity designed to handle the peak load of the new generators that stretch from the resource area to the load without utilizing any of the existing transmission infrastructure. These studies lead to very different \$/MW-mi and show that a uniform assumption for the \$/MW-mi for wind transmission is not appropriate. We also collect information about the general methodology or approach to modeling transmission investment needs and indicators that the transmission for wind will benefit other network users through offsetting reliability upgrades or relieving existing congestion.

4. Results

We begin this section with a brief overview of the approach and the scope of what was included in each study. Next, we show the full range of the unit cost for wind transmission from all 17 studies. Finally, we show that the average cost of grid extension greatly varies across studies.

4.1. Overview of Studies

The 17 studies employed a variety of analysis methods to estimate the transmission needs to access new generation resources (Table 3). Almost all of the transmission studies relied on a power flow model at some point of the study. But in only 10 of the studies was it clear that a power flow model was used to perform a detailed evaluation of thermal limits of equipment. The purpose of upgrading equipment or adding transmission lines was usually to mitigate thermal overloads in these 10 studies. The majority of the studies that included a detailed power flow model also include an analysis of the system under various contingency scenarios to ensure reliable delivery of power even if components failed or generators had a forced outage event.

On the other hand, 7 studies did not focus on a detailed power flow case. Instead, the study either relied on engineering judgment from previous or similar studies or in 4 of the studies the criteria for adding transmission lines was not to mitigate thermal overloads but rather to reduce congestion under a security-constrained economic dispatch.

More thorough studies, typically performed by ISO/RTO's, included detailed power flow models, contingency analysis, and an evaluation of the production cost savings of each of the transmission options.

The amount of new wind generation evaluated in the studies ranged from 500 MW to 25.5 GW. Many of the studies simultaneously – i.e., within the high-wind scenario – studied other various new generation options including coal, gas, and other renewables. When included, the new non-wind generation ranged from 300 MW to 37.6 GW. The transmission solutions required to deliver the new generation to load centers almost always included new high-voltage transmission lines. One study, however could connect 500 MW of new wind with only an upgrade to a substation. The total cost of new transmission facilities ranged from \$25 million in for 500 MW of additional wind in the Buffalo Ridge area of Minnesota to \$31 billion to ship 16 GW of wind energy from the western regions of the Midwest ISO to states in the Northeast.

Table 3. Overview of transmission studies

Region	Study Abbreviation	Analysis Methods Included in Study				Scenario	Wind Analyzed (GW)	Non-Wind Simultaneously Analyzed (GW)	Total Transmission Cost (\$ Billion)	Primary Transmission Line Voltage (AC Unless Noted)	
		Detailed Power Flow	Contingency Analysis	Economic Dispatch Production Cost Model	Simplified Spreadsheet Economic Analysis						
California	Tehachapi	✓	✓	⊖	⊖	Tehachapi	3.6	0.8	\$1.80	500 kV initially operated at 230 kV	
	SCE 1, 2E, 2N, 3	⊖	⊖	⊖	⊖	SCE - 1	4.5	0.0	\$1.31	500 kV initially operated at 230 kV	
		⊖	⊖	⊖	⊖	SCE - 2E	2.0	2.3	\$1.82	500 kV	
		⊖	⊖	⊖	⊖	SCE - 2N	0.6	1.1	\$1.04	230 kV	
		⊖	⊖	⊖	⊖	SCE - 3	0.5	0.8	\$0.32	500 and 230 kV	
	SDG&E	⊖	⊖	⊖	⊖	SDG&E	0.5	0.3	\$0.06	-	
Midwest	MISO '06	⊖	⊖	✓	⊖	MISO '06	16.0	0.0	\$31.00	765 kV	
	CapX-CBED	✓	✓	⊖	⊖	CapX-CBED	3.5	0.0	\$0.38	115 kV	
	CapX-1 and -2	✓	✓	⊖	⊖	CapX-1	2.3	4.1	\$1.41	345 kV	
						CapX-2	2.3	4.1	\$1.51	345 kV	
	Xcel-31A	✓	✓	⊖	⊖	Xcel-31A	0.5	0.0	\$0.03	115 kV	
	SPP-X	✓	✓	✓	⊖	SPP-X	2.5	0.6	\$0.46	345 kV	
	MISO '03-1 and 2	⊖	⊖	✓	⊖	MISO '03-2	10.0	37.6	\$0.66	500 and 345 kV	
						MISO '03-2	10.0	37.6	\$1.89	500 and 345 kV	
	Texas	SPP-2	✓	✓	✓	⊖	SPP-2	4.5	0.0	\$1.13	345 kV
		SPP-1	✓	✓	✓	⊖	SPP-1	1.5	0.0	\$0.19	345 kV
ERCOT C3, CW3, M2, P4, Cb1, Cb2, and Cb3		✓	✓	✓	⊖	ERCOT C3	3.0	0.0	\$0.32	345 kV	
						ERCOT CW3	3.8	0.0	\$0.96	345 kV	
						ERCOT M2	3.8	0.0	\$0.86	345 kV	
						ERCOT P4	4.6	0.0	\$1.52	345 kV	
						ERCOT Cb1	3.3	0.0	\$0.86	345 kV	
						ERCOT Cb2	4.0	0.0	\$1.16	345 kV	
ERCOT Cb3	5.3	0.0	\$0.94	345 kV							
West	Frontier A and B	⊖	⊖	⊖	✓	Frontier A	3.6	0.0	\$4.30	500 kV	
						Frontier B	2.6	1.0	\$4.30	500 kV	
	NTAC 1, 2A', 2A, and 2B	✓	⊖	⊖	✓	NTAC-1	3.2	0.8	\$6.43	500 kV (Submarine DC)	
						NTAC-2A'	1.1	0.7	\$0.86	230 kV	
						NTAC-2A	1.1	0.7	\$2.21	500 and 230 kV	
	NTAC-2B	1.1	1.2	\$2.58	500 (includes Submarine DC) and 230 kV						
	WGA '06	✓	⊖	✓	⊖	WGA '06	25.5	17.3	\$6.79	500 kV	
RMATS 1 and 2	⊖	⊖	✓	⊖	RMATS1	3.0	3.3	\$0.97	345 kV		
					RMATS2	5.0	6.8	\$4.27	500 kV		
SSG-WI	⊖	⊖	✓	⊖	SSG-WI	18.5	15.8	\$6.71	500 kV		

4.2 Unit Cost of Transmission for Wind Across all Studies

We use in-depth reviews of each of the transmission studies to collect sufficient information to assess the unit cost of transmission for wind based on both the capacity of the new wind plants and the volume of energy expected to be produced by the wind plants based on the simplifying assumptions in Table 1. The unit cost of wind transmission is presented in Figure 4 and 5 both in \$/kW-wind and \$/MWh-wind terms, respectively.

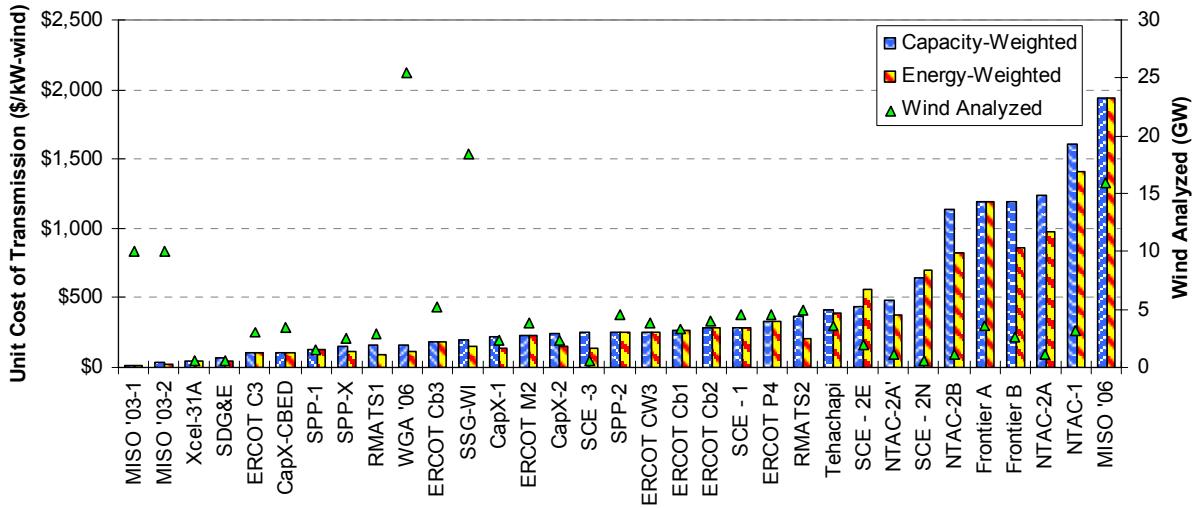


Figure 4. Unit cost of transmission for wind in \$/kW-wind terms

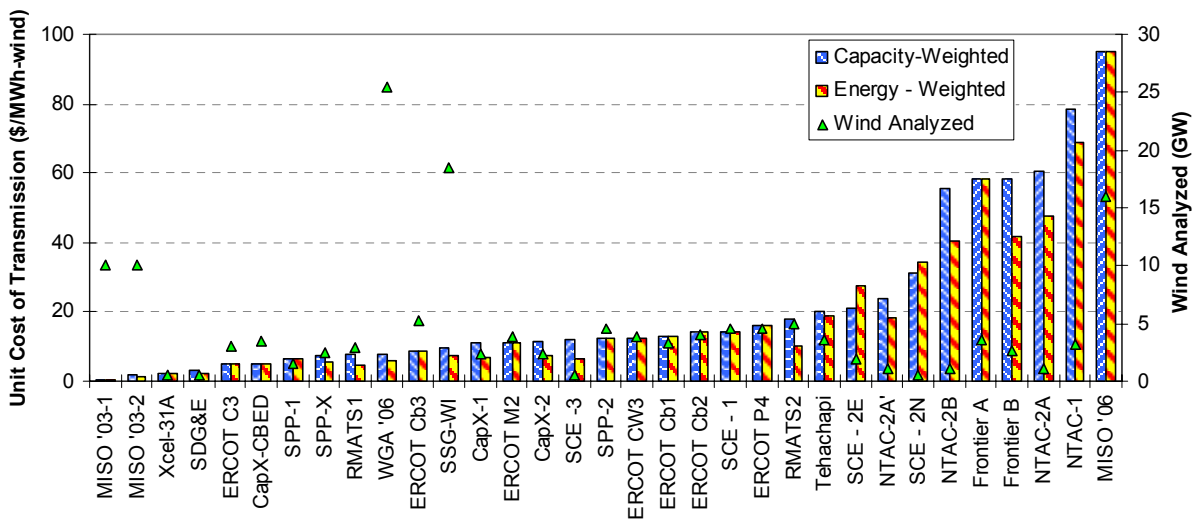


Figure 5. Unit cost of transmission for wind in \$/MWh-wind terms

The wide variety of regions, modeling methods, network conditions, and assumptions in the studies lead to an equally wide range of unit costs for wind transmission. The range of costs is from \$0.40 to 95/MWh or \$8.5 to \$1,940/kW. However, nearly 75% of the scenarios studied cost less than around \$20/MWh or \$420/kW weighted by either capacity or energy. The median cost of transmission is around \$11-12/MWh or \$225-250/kW.

The 6 scenarios that lead to unit costs of transmission that are well above the other 75% of the scenarios all involve very conceptual export scenarios where transmission is built to deliver wind to extremely distant loads. For example, the NTAC 2A' and 2A scenario both involve building transmission to access the same resources in Western Canada and the Pacific Northwest. The transmission solutions evaluated in the 2A scenario, however, bring the resources all the way to Northern California load centers instead of using the new generation to serve more local loads in Washington and Oregon as is done in the 2A' scenario. The difference in cost between the two scenarios is approximately \$30-37/MWh or \$600-

760/kW. An optimal power flow model, which was not performed in the study, may help to evaluate the need to actually transmit the new resources over new high-voltage lines instead of displacing more-expensive local generation based on the existing grid configuration in the Pacific Northwest.

In another case, the Frontier Line study, which estimated transmission needs for moving wind and coal power from the Interior West to load centers in the Southwest and California, produced considerably higher unit cost estimates than the RMATS2 case which was the original impetus for the Frontier Line analysis. One major discrepancy between the two methods was that the RMATS study used a least cost economic dispatch model to identify transmission needs to relieve congestion while the Frontier Line study based its transmission recommendations on engineering judgment and existing transfer capacity. The end result is that the Frontier Line study recommends \$4.3 billion in transmission lines from WY to western loads to connect 3.6 GW of new resources while the RMATS2 case proposed connecting 11.8 GW of new resources at the same cost using similar lines from WY to western loads.

Two final interesting points that emerge from Figures 4 and 5 are that the unit cost of transmission for wind does not appear to be correlated with the quantity of new wind generation studied and that assessing the unit cost weighted by energy or capacity has far less importance than the differences across studies.

4.3 Average Cost of Grid Extension

It would be convenient to be able to estimate the cost of transmission required to connect wind resource areas to loads by calculating the product of the nameplate capacity of the expected wind farms, the distance of new lines that would need to be built, and an assumed average cost of transmission extension. Figure 6, however, reveals that a simple average cost of extension would not be appropriate across many of the studies in our sample. In the extremes, the average cost of grid extension can vary by a factor of over 200.

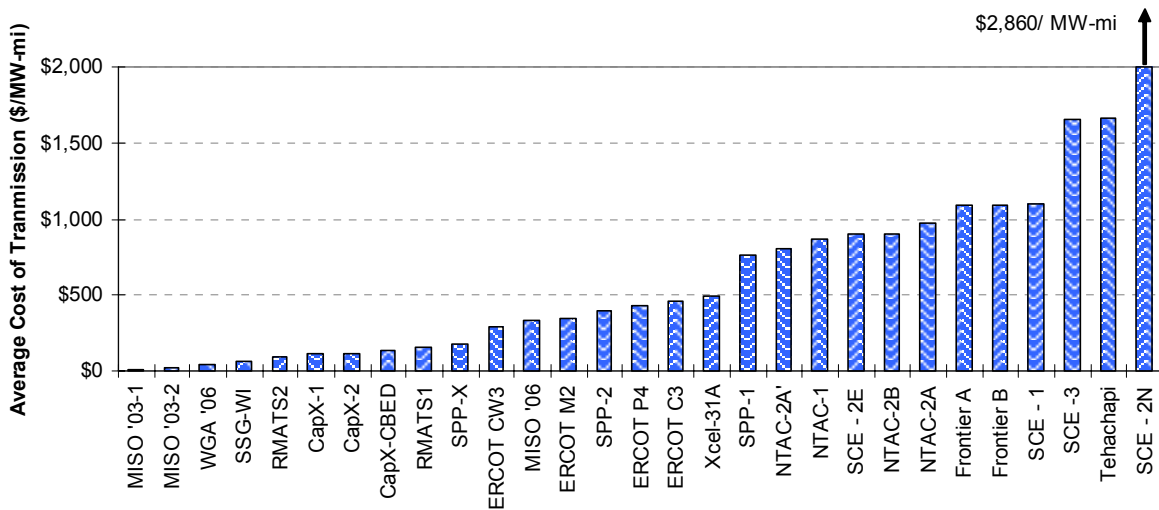


Figure 6. Average cost of grid extension based on the total miles of new or upgraded lines and the nameplate capacity of new generation (not new transfer capacity)

The wide variation in the average cost of extension can be due simply to the fact that, as suggested by Joskow (2005b), some expensive transmission upgrades do not involve building new lines, such as DC ties or DC/AC terminals. The factor that seems to dominate, however, is the ratio of additional transfer capacity required to connect new resources to the nameplate capacity of the resources. The ratio greatly depends on the choice of modeling approach. Again referring to the Frontier Line and RMATS2 scenario

which essentially model the same lines, the RMATS2 average cost of grid extension is multiple times cheaper than expected compared to the average cost of the Frontier line. The primary reason is that the model used in RMATS2 allowed 11.8 GW of new generation to be connected while the Frontier Line study only allowed 3.6 GW of new generation to be added even with very similar transmission line requirements. The RMATS study used an optimal power flow model of the entire Western Interconnect while the Frontier line study was based on engineering judgment that 3.0 GW of new transfer capacity (based on a double circuit 500 kV line) between the resources and load centers would only allow 3.6 GW of new generation to be connected. The RMATS study group concedes that the assumption of a centralized, least cost dispatch for the entire Western Interconnect used in their study may model much fuller use of the grid than occurs in practice with over 33 control areas in the West. However, the assumption in the Frontier Line study that essentially all of the power produced by new generation in the Rocky Mountain Area must flow over one path may be too far to the other extreme.

The differences in the RMATS and Frontier line studies parallel many of the differences in studies that lead to a low versus high average cost of grid extension. In between are many studies where the assumption of a centralized, least-cost dispatch actually models the real situation, particularly for transmission extensions within ISO/RTO areas. Within the ISO/RTO, new generation can fully utilize the existing network in a least-cost manner, only requiring grid enhancements in severely congested areas, which, due to network effects, may not be on the path with which the new generation interconnects.

It is also important to note that the average cost per mile of transmission extension is not the only factor that affects the unit cost of transmission for wind. In particular, the MISO "Vision Plan" (MISO '06) which models grid upgrades required to ship wind power from the western MISO region to the Northeast over a 765 kV network, has an average cost of extension of \$340/ MW-mi. The average cost of extension of the MISO Vision Plan is very similar to many of the studies that lead to a unit cost of wind transmission that is well below \$20/MWh. The unit cost of transmission for the Vision Plan, however, is over \$90/MWh simply because of the vast distance that the wind power must be transmitted in the study.

5. Discussion

In nearly 75% of the scenarios evaluated among our 17 studies, the unit cost of wind transmission was less than \$20/MWh. Furthermore, all but a few of these scenarios modeled more than 2 GW of new wind simultaneously connecting to the transmission network with a small number modeling more than 5 GW of new wind. Based on these scenarios, there is significant potential to develop new wind resources through proactive transmission planning without paying extraordinarily high costs. On the other hand, not all projects are economically justifiable. The most expensive transmission plan, the MISO Vision Plan, would cost \$95/MWh, which clearly is an extraordinarily high cost for building new transmission.

Not surprisingly, no uniform methodology for assessing the cost of transmission to access new wind resources has emerged. Except in a few cases, wind energy is not the primary focus of the transmission planning studies. In some cases wind is included in a scenario that evaluates the transmission needs for a high renewables future while in others transmission planners include wind along with other generation types simply as a reaction to changes in the fuel mix in interconnection queues.

The choice of methodology and use of different models can have a substantial impact on the estimated unit cost of transmission for wind. Decisions regarding how far the new resources must be transmitted, how to model the existing grid and generators, how much of new lines are shared with other resources, and the level of detail in the analysis can all have significant impacts on the ultimate estimated cost of transmission. Studies that had the highest cost tended to assume that the connection of new generation would require an equal amount of new transfer capacity between the resource and load center. While studies with lower costs tended to evaluate both the upgrades required to mitigate thermal overloads and to

mitigate congestion under an optimal power flow. In many cases the additional required transfer capacity between the wind resource center and major load centers less than the nameplate capacity of the new generation.

While we have estimated the unit cost of transmission for wind projects across the United State, the values we present should not necessarily be interpreted as a transmission cost adder to the bus bar cost of wind. None of the studies had the objective of establishing a wind transmission cost adder with respect to an alternative future in which wind was not built. In many cases, the study authors acknowledged that transmission investments to connect new wind generation would defer reliability upgrades or reduce existing congestion on the transmission network. Our simplified methodology did not separate out any of these other benefits, but instead assigned the full cost of the transmission upgrades to new wind plants. In some cases the unit costs we present in this study would probably overstate the cost of transmission that is directly attributable to new wind plants. In other cases the assumption that all generation resources in a scenario would equally use the new transmission weighted by capacity or energy probably understates the cost attributable to new wind. Nevertheless, with our simplified methodology the majority of scenarios lead to a reasonable unit cost for accessing new wind resources.

Future studies of transmission required for wind should be sure to assess whether it is reasonable to assume that the additional transfer capacity between a wind resource area and load centers must be equivalent to the name plate capacity of the new generation. If it is not reasonable or not known prior to undertaking the study, a detailed optimal power flow model should be used to assess the ability to alter the dispatch pattern and utilize any existing transmission capacity prior to modeling new transmission lines between the load center and wind resource area. Studies should also consider a large number of transmission alternatives, as the least cost solution might involve increasing transfer capacity on a parallel line rather than incrementally increasing the capacity of the line to which the generators connect. Overall, the best way for transmission planners to learn to include wind in transmission plans is to build upon the myriad transmission studies that have been produced in recent years.

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