Renewables-First Generation/Transmission Projects

David Olsen
Center for Energy Efficiency and Renewable Technologies

Presented at the Windpower 2007 Conference,
Los Angeles, California
June 6, 2007

Abstract:

Many policy-makers and generation developers think that, especially in the West and Midwest, renewables cannot be developed on a large scale without coal as a transmission partner.

This paper presents a contrary case—that large-scale renewable energy generation projects ("Mega-Projects") appear able to economically justify major transmission infrastructure, with no initial participation by coal. This approach supports development of major new transmission capacity, and facilitates diversification of utility supply portfolios with renewables. And it buys time for low-emission coal technologies and durable sequestration to be developed and proven. Advanced coal generation can thus later take advantage of transmission facilities built initially for renewables.

Several renewables-only transmission lines are now operating, several others are in advanced development, and this approach appears to require no changes to FERC tariffs. It may, however, require utilities to plan their portfolios and operate their capacity resources differently, in order to take best advantage of low-cost energy resources. It also creates an opportunity for utilities to join with equipment manufacturers and generation companies in consortia assembled to build, own and operate renewables Mega-Projects.

Contents

Tables

Figure

Renewables-First Transmission Development

1.0 Market and Policy Context for Renewables-First Transmission

Many large hydro and coal projects built in the mid-20th century—the Colstrip generating plants in eastern Montana, to name just one example—could not have been developed without dedicated transmission. Most of our highest quality wind, solar and geothermal resources are similarly far from load centers; developing them requires building major new transmission.

Transmission investment has lagged load growth for more than 20 years, and new infrastructure is needed in many parts of the country to relieve congestion and maintain or improve reliability. In response, major projects are planned in many regions of the country.[1] The extent to which new transmission needed for access to new generation can also provide congestion relief and reliability improvement has become a key regulatory issue.

The increasing complexity and interdependence of the grid lean heavily on the structure provided by FERC non-discriminatory transmission access policies. Unlike earlier vintage coal and hydro projects, transmission built today must respect Open Access requirements. But transmission built initially to access renewables can conform to both the spirit and the letter of the OATT. This is important, because adding renewables to the U.S. electricity supply mix on any significant scale is likely to require renewables-first transmission.

1.1 Renewables Market Transformation

The worldwide market for wind power has grown at a 37% average annual rate for the past seven years. Demand for solar electric generation is increasing almost as fast. Europe has 48,545 MW of wind power installed (vs.11,600 MW in the US); it now provides 18.5% of all electricity in Denmark, 12.9% in Spain, and 5.5% in Germany, and in 2006 supplied 100 TWh of European electricity overall. In March 2007, European Union Heads of State replaced an earlier planning directive with a binding target of generating 20% of all electricity from renewables by 2020.[2]

This growth is driven by concerns everywhere about increasing fossil fuel prices, energy security, and the environmental effects of traditional power generation. Major factors now appear poised to transform fundamental growth trends into quantum increases in renewables market penetration in the US:

---

[1] These include the Tehachapi, TransWest, Frontier Line, High Plains, Northern Lights and SunZia projects in the WECC; CapX 2020 and other projects in the MISO Transmission Expansion Plan; and lines to access Competitive Renewable Energy Zones in Texas.

[2] Statistics and press releases on EU targets at Global Wind Energy Council, www.gwec.net/.

- **Climate Change**. New California laws require a 25% reduction in CO_2 by 2020, prohibit the import of coal power, and limit tailpipe CO_2 emissions. Other states are moving to institute similar policies. Leaders of some of the largest US utilities support a carbon cap, and almost all expect the US to adopt carbon limits in the next three to five years. Valuing carbon at current international levels will drive renewables to qualitatively new levels of electricity supply. Future emissions reductions targets stand to greatly increase the value of carbon, driving additional quantum increases in renewables generating capacity.

- **Production Tax Credit**. Extension of the PTC through 2012 or longer will drive wind power sales (and geothermal and solar market growth, if extended to those technologies), accelerate technological innovation, stimulate investment in US manufacturing capacity and position the industry for self-sustaining growth. Bi-partisan support for the PTC expresses collective national concern about increasing fossil fuel prices, energy security and price stability, environmental impacts of electricity supply, and the critical need for rural economic development in many regions of the country. Within ten years, the value of carbon (e.g., under a US cap-and-trade program) is likely to be high enough to replace the PTC as the major factor forcing wind power market growth.

- **Technological Innovation**. In the 1980s-1990s, rapid growth of gas-fired generation and huge federal R&D investment enabled that industry to introduce increasingly efficient and lower-cost turbines every three-five years; CCGT and SCGT installations jumped from 3.5 GW in 1999 to 63 GW in 2002. Similar dynamics are now driving continuous improvement in renewables generation technology, with corresponding reductions in Cost of Energy spurring further increases in renewables market growth.

- **Utility Ownership of Renewables**. The great majority of renewables power output today is sold to utilities under long-term Power Purchase Agreements. This may negatively affect utility balance sheets, to the extent that PPAs are treated as debt. More important, with no financial stake in the expansion of renewables generation, utilities have little incentive to add it proactively to their supply portfolios. Utility ability to ratebase and thereby earn a return on renewables generating assets stands to drive large increases in renewables capacity. As more and more renewables projects are financed with lower-cost utility capital, this in turn will reduce the cost of renewables in utility portfolios. Widespread utility ownership is likely to completely transform the renewables power market into a mainstream utility business.

- **Changes in Utility Supply Planning**. Wind and solar, as energy resources, are often undervalued in utility capacity planning, despite their near-zero marginal cost and their emissions-free character. Increasing carbon prices, however, are likely to require a priority focus on energy, not capacity, because emissions are a function of energy. Today, LSEs expect capacity resources to supply the bulk of their energy. Instead, planning supply portfolios around low-carbon generation may lead utilities to maximize the use of wind power, building capacity strategically to support carbonfree and fixed price energy. Such a change will drive further quantum increases in wind generation.

The likely effect of the first three of these dynamics can be readily foreseen. Extension of the PTC beyond 2008 will drive widespread utility purchases of wind power. Manufacturers already plan to introduce new turbine models approximately every three years. A national carbon policy, even one that values carbon at a low initial level, will drive a further large increment of growth; subsequent increases in carbon value will support further multi-GW-scale growth.

The timing of the emergence of widespread utility wind ownership and changes in utility supply planning is less certain. But as these five dynamics emerge and interact over the next 10-20 years, they appear able to support very large renewables market growth.

In recognition of this, the US Department of Energy and the National Renewable Energy Laboratory (NREL), in partnership with the American Wind Energy Association (AWEA) is preparing a plan, to be released in mid-2007, showing how the US can generate 20% of its electricity—more than 300,000 MW—from wind before 2030.

Diversifying utility portfolios to include renewable energy on a such a scale is likely to require much larger generating projects than have yet been built. And in fact, several GW-scale wind projects are now being developed, with others planned. Many policymakers, however, assume that large-scale development will require wind to share new transmission facilities with coal plants. But large renewables projects—referred to as Mega Projects here—appear able to afford their own dedicated transmission, with no initial participation by coal. Deferring coal development delivers crucial benefits.

1.2 Buying Time for New Coal Technologies

Any coal projects approved in the next few years will likely still be operating in 2060. To focus only on global warming impact, just ten large coal projects—10,000 MW—having current emission profiles would generate 87 million tons/year of CO_2, or 4.8 billion tons of CO_2 over that period.[3] CO_2 stays in the atmosphere for periods ranging from 50 years to 200 years. Adding emissions on such a scale makes it effectively impossible to stabilize the atmospheric concentration of CO_2. More than 150 coal projects are now proposed in the US. We can avoid this impact, and we must.

There are other compelling reasons to do so. US electric generation is already heavily concentrated in coal. Diversifying our supply mix requires investing less in coal, not more. The risk premium for potential carbon liability is growing, in step with the worldwide movement toward carbon regulation and financial market demands for carbon disclosure. Renewable energy projects provide larger and more widely distributed local economic development benefits than coal projects. If acquired on a large-enough scale, renewables generation provides an effective hedge against fossil price volatility. In the western US, the

[3] Plant capacity factor 85%; emissions rate 2.352 lbs CO_2/kWh (DOE eGrid for WECC/Rockies), 55 years.

water-use impacts of coal projects are significant. The environmental and public health impacts of coal projects and long-distance coal transportation—particulates, sulfur, mercury, regional haze, habitat destruction—are both well documented and increasing.

Further, the high quality carbon in coal deposits has an enormous future in chemicals, fibers and pharmaceuticals over centuries ahead. Burning this resource for low quality energy uses in century-old technology generating plants may be a strategic mistake—especially since better options are available now.

The renewables industry—and much of public opinion—supports the rapid development and commercialization of low-emission coal-fired generation technologies, including durable carbon sequestration. If afforded an Apollo Project kind of urgency, such technologies could become commercially available and competitive in the next 20-30 years.

Several recent studies make this point. To mention only two: the Western Business Roundtable summarizes the case for ultra-low emissions plants that could be constructed on a commercial scale in the 2025 to 2035 time period in its backgrounder, "The Path to Clean Coal for the West."[4] These plants would remove >99% of SO_2, NO_x and particulate matter; remove 95% of mercury; achieve thermal efficiencies of 50%-60%; and capture and sequester up to 90% of CO_2. Identifying the optimum clean coal technology, the Roundtable argues, requires supporting demonstration projects in a variety of technologies. Western Resource Advocates makes the case that gasification technologies offer the best prospects for maximizing emissions reductions and related sequestration. Its study, "Western Coal at the Crossroads," presents a plan for jump-starting the development of Integrated Gasification Combined Cycle (IGCC) technology in the western US.[5]

Diversifying the supply mix with wind, geothermal, biomass and solar generation can help buy the time for this development. As described below, renewable energy generation can be organized into large-scale projects capable of meeting the need for new generation in many regions of the country, without the need for more conventional coal.

2.0 Renewables Mega Projects

Mega Projects, 2,000 MW or larger in nameplate capacity, bring renewables from generally unpopulated, high capacity-factor resource regions to load centers. They are large enough to justify dedicated transmission. They may be organized as aggregations of smaller sub-projects. Developers, manufacturers, utilities and investors may own the sub-projects or shares of an overall Mega Project consortium.

Meeting aggressive renewables supply goals will likely require development of a number of such very large projects, for several reasons. Many of the best solar, wind and geothermal resources are remote from load centers. Most of the highest quality on-shore

---

[4] Western Business Roundtable, 2006; www.westernroundtable.com

[5] April, 2006; available at: www.westernresourceadvocates.org. This study also assesses the risks to coal markets of failing to develop this technology.

wind resources, for example, are in Mountain and Plains states. Meeting a 20% supply target requires utilizing a significant amount of these resources. Installing large numbers of wind turbines in unpopulated regions avoids landowner and public objection to dense turbine siting in populated areas. A few very large projects can add as much wind generation capacity as hundreds of traditional 100 MW projects, and can be developed and built much more quickly. Compared to traditional wind plants, Mega Projects are likely to provide significant economies of scale not only in development and permitting, but also in financing, component sourcing, construction, power marketing and operation. These economies may help drive down the cost of energy from large-scale renewables development.

Large-scale renewables developments are best organized as integrated generation-transmission projects. This enables transmission to be optimized to access renewable resource areas, and generators to subscribe for the full capacity of the transmission before it is built. It requires cooperation between generators and transmission developers, who may be utility transmission providers, merchant transmission companies, or both. It may also require cooperation among different renewables technologies, e.g., wind, geothermal and/or Concentrating Solar Power (CSP) companies.

Mega Projects are large enough to justify the interest of even the largest utilities, as investment opportunities or sources of bulk energy supply. Utility participation may be essential for solution of the transmission and power marketing challenges of such very large projects. Rapid expansion of wind generation requires the active involvement of utilities; Mega Projects provide a mechanism to give them a substantial financial stake in this growth.

By making wind power available to utility buyers in very large increments, Mega Projects provide a structure that enables wind to better compete with supply alternatives. Mega Projects may make the delivered cost of such large blocks of wind power less expensive than the delivered cost of power from state of the art conventional coal plants. Where new EHV transmission must be built to access wind resources, Mega Projects may deliver wind power at lower cost than current industry standard 100 MW-300 MW wind projects.

To spread risk and make the development of such large projects manageable, Mega Projects may best be structured as consortia, with each partner taking e.g., a 300 MW-500 MW stake. A lead partner would coordinate permitting, transmission and power marketing; individual consortium members would have responsibility for siting, constructing and operating the turbines making up their sub-projects. Consortia partners may include utilities (IOUs, munis, coops); turbine manufacturers; engineering firms; merchant transmission companies; financial investors; and wind/renewables development companies. Because wind projects can be built quickly, Mega Projects can be planned in modular increments.

States having high capacity-factor wind resources are key stakeholders in Mega Project development. Such projects will bring significant investment to those states, with large benefits to rural economic development. States can do much to facilitate the siting, permitting and transmission routings for such projects, and can assist in financing them as well. Wyoming, South Dakota, Kansas, New Mexico and other states have created

Infrastructure Authorities having the ability to issue debt for such projects. Regional and interstate cooperation will also be essential in coordinating the transmission construction for such Mega Projects. This requires active support by state public utility commissions, and political leadership.

Other key stakeholders include utilities, turbine manufacturers, financial interests and wind development companies. Utilities (IOUs, munis and G&T coops) have may roles as power purchasers, transmission owners/operators, and equity investors in Mega Projects. The portions of such projects qualifying for ratebase treatment can be financed at utility cost of capital, which will appreciably reduce the delivered cost of power from the project. Manufacturers can use their participation to guarantee turbine sale volumes, and time turbine installations to smooth or manage their manufacturing schedules. Financial interests can provide both debt financing and equity participations. Wind companies may organize the overall projects, taking responsibility for resource assessment, project layout, and permitting.

Mega Projects under active development include: in South Dakota, Clipper Windpower's 3,000 MW+ Rolling Thunder Project; in California, the 4,500 MW Tehachapi Transmission Project, and projects to export 2,200 MW of geothermal and Concentrating Solar Power resources from the Imperial Valley region; in British Columbia, Katabatic Power's 3,000 MW wind project (for possible export to California). Development of Competitive Renewable Energy Zones now underway in Texas may result in Mega Project construction there. Additional Mega Projects are proposed in Mountain and Plains states, and others are under study. MISO, for example, recently studied a 6,400 MW project to bring North Dakota/Manitoba generation to Toronto, New York and New England.[6] In April 2007, American Electric Power began study of a 765 kV network capable of accessing large concentrations of wind power in wind regimes across the country. Mega Projects and large-scale transmission are likely to evolve together; both will be needed if renewables are to provide 20% of US electric supply.

In December 2006, Southern California Edison signed a Power Purchase Agreement with a 1,500 MW wind project, with power to be delivered via the Tehachapi Transmission Project. Many in the industry believe that the market and regulatory trends reviewed in Section 1 are likely to drive increasing numbers of such GW-scale purchases.

3.0 Engineering Design of Renewables-First Generation/Transmission Projects

With their relatively low capacity factors, most wind and solar projects cannot by themselves load transmission lines to economic levels. Economic loadings are generally in excess of 60% of transmission line capacity, depending on the size, length, terrain and electrical complexity involved. This has led to the conventional wisdom that variable-output resources must have on-demand generation as transmission partners, or be coupled with energy storage projects, to achieve economic levels of line utilization. As a baseload

---

[6] Dale Osborn et. al., "MISO Status Report to the Upper Great Plains Transmission Coalition," PowerPoint presentation, January 31, 2006.

resource, however, coal makes a poor transmission partner for wind and solar generation. Coal can share the cost of new transmission, but do little to optimize line utilization.

Over-building the installed generating capacity of variable-output projects offers an alternative. In this approach, a wind project, for example, would install 10%-30% excess generating capacity. Building 3,600 MW of wind generation to supply a 3,000 MW-rated double-circuit 500 kV line (20% over-build) could increase line loading to the 60% range, depending on the capacity factor of the wind project. Wind plant capacity factors of the best regimes in several Midwestern and Mountain states are in the 45%-50% range with no over-building. Projects in these areas appear capable of achieving and maintaining line loadings in the 55%-60% range with limited over-building. Table 3-1 indicates the correlation between generation capacity factor, over-build and transmission line loading.

Table 3-1. Over-Built Generation Capacity vs. Transmission Line Loading

Nameplate Wind Capacity MW	Generation Over-Build %	Native Wind Capacity Factor, Net	Wind Generation MWh/yr	Capacity Factor per 1000 MW	Transmission Line Loading
1,000		45%	3,942,000	45%	45%
1,100	110%	45%	4,336,200	50%	50%
1,200	120%	45%	4,730,400	54%	54%
1,300	130%	45%	5,124,600	59%	59%

In periods of high wind output, if wind generation exceeds the thermal rating of the line, some of the wind capacity would be curtailed. Any curtailment would be shared pro rata among participating generators. The financial impact of such curtailment on investment return expectations appears manageable. The number of hours per year that wind projects generate at their rated output (i.e., a 1,000 MW nameplate wind project generates 1,000 MW per hour) is location-specific and changes with the annual variation in the resource, but averages roughly 10% of the hours per year. The larger power deliveries made possible by the higher transmission line loading more than compensate for both the power revenue lost to curtailment in the highest wind hours and for the increased capital cost of the excess wind generation capacity.[7] The economics of a renewables-first transmission line combined with an over-built wind project are illustrated in section 4 below.

[7] Curtailment has the effect of reducing the average annual capacity factor of the project, by the percentage of hours curtailed. The Frontier Line feasibility study discussed below decided to ignore the effect of curtailment on project capacity factor, reasoning that wind generation in excess of the 500 kV transmission line thermal limit could be absorbed for limited periods on lower voltage lines in the vicinity of the wind project.

The effective capacity factors of variable-output generation projects can also be increased with other mechanisms. One is to "de-rate" the wind turbines, so that they spend a greater portion of their time at maximum power. This yields a higher capacity factor, and potentially a lower cost of energy through savings in generator size and component cost.[8] De-rating avoids the curtailment (i.e., loss of generation) inherent in installing "excess" wind capacity.

Energy storage, either hydroelectric pumped storage or compressed air energy storage, can be combined with as-available generation to produce high levels of transmission line utilization.[9,10] With currently available technologies, however, the capital cost of the storage plant overwhelms the benefit of larger power revenues from increased transmission line utilization and timed and/or firmed generation deliveries.

4.0 Illustrative Economics

In 2005, the Governors of Wyoming, Utah, Nevada and California proposed development of a "Frontier Line" to transport low-cost coal and wind resources to load centers across the region. The major utilities serving those states—PacifiCorp/MidAmerican, Pacific Gas & Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), Sierra Pacific, Nevada Power, with Arizona Public Service (APS) and Public Service New Mexico (PNM) also participating—subsequently formed the Western Regional Transmission Expansion Partnership (WRTEP) to explore the feasibility of major interstate transmission, and opened the study process to other stakeholders as well. WRTEP plans to issue a report on the economic viability of generation and transmission alternatives for such a project, and to announce follow-on work, in mid-2007.

The Frontier Line Loads & Resources Subcommittee established load growth and generation supply projections for each sub-region of the WECC and evaluated regional supply-demand balances under scenarios built around different combinations of fossil generation, renewable generation and energy efficiency deployment. The Frontier Line Transmission Subcommittee then identified several routing alternatives connecting Wyoming and Montana wind and coal resources to load centers, with intermediate generation on-ramp and/or delivery points in UT, NV, AZ, NM, ID, OR and CA. The Transmission Subcommittee developed cost estimates for all required transmission facilities, for both AC and DC options, including costs per mile in different states. This work benefited from similar

---

[8] See, e.g., Denkenberger, David, "'Derating' of Wind Turbines to Reduce Cost of Energy in Large Arrays with Long-Distance Transmission." Presented at American Wind Energy Association Windpower 2006 Conference, Pittsburgh, PA June 5-7, 2006.

[9] Eastwood, John and David Olsen, "Modular Design Expands Applications of Pumped Storage," American Society of Mechanical Engineers publication 90-JPGC/Pwr-18. Presented at the ASME/IEEE Power Generation Conference, Boston, MA October 21-25, 1990.

[10] See, e.g., Greenblatt, Jeffery B., S. Succar, D. C. Denkenberger, R. H.Williams and R. H. Socolow, "Baseload Wind Energy: Modeling the Competition Between Gas Turbines and Compressed Air Energy Storage for Supplemental Generation." Energy Policy, 35 (2007) 1474–1492.

analysis performed in 2006 by APS for its proposed TransWest Express project, which would export Wyoming resources to Arizona.

As Frontier Line study work began, California enacted legislation prohibiting Load Serving Entities in the state from importing power having CO_2 emissions greater than that of gas-fired Combined Cycle generation. This eliminated California as a market for power from conventional coal plants. The feasibility study accordingly turned its attention to evaluating combinations of renewable resources and “clean coal”—generation from future coal plants able to capture and durably sequester carbon. Study alternatives also considered routings to Utah, Nevada and Arizona for potential delivery of conventional coal.

The Frontier Line Economic Analysis Subcommittee compiled generation cost and performance data and, led by PG&E, developed a spreadsheet model to evaluate the costs and benefits of different combinations of generation resources in various states on different transmission routings. Transmission carrying only wind power emerged as one of the best-performing alternatives.

All of the generation and transmission cost and performance data in the example presented here are those used in the Frontier Line study, and the calculations were performed using the Frontier Line spreadsheet model employed in that study. It is important to note that all costs are for a 2015 in-service year, i.e., assumptions about the capital and operating costs of each of the technologies are those estimated to be available then. All figures are presented in 2006 constant dollars.

4.1 Frontier Line 3,000 MW Wind-Transmission Scenario

This example considers a 3,000 MW wind-transmission project delivering Wyoming wind power to the Southern California load center. Double-circuit 500 kV AC transmission rated at 3,000 MW is routed from the large wind resource area in east-central Wyoming to Mona, Utah; then to Las Vegas; and finally to Los Angeles. Line length is 1,090 miles, with 200 of those miles in California. The transmission could alternatively be built as 3,000 MW DC facilities. DC construction would be roughly 37% less expensive but eliminates participation by states in between the source and sink regions.

The Frontier Line feasibility study used a capacity factor for Wyoming wind of 48%, from data supplied by the National Renewable Energy Laboratory. NREL wind resource assessment of Wyoming shows more than 57,000 MW of Class 6 and Class 7 wind, at developable sites, with net capacity factors in the 40%-48% range. To be more conservative, the scenario presented below uses a capacity factor of 45%. Per the design approach outlined in Section 3 above, 20% excess wind generating capacity is installed, making the total generation capacity 3,600 MW nameplate. This increases the transmission line loading to 54%, as shown on Table 3-1.

The 3,600 MW of wind generation displaces an equivalent amount of energy in California, assumed produced by 2,077 MW of Combined-Cycle Combustion Turbine operation. Table 4-1 summarizes the cost and performance assumptions of the wind and gas generation, as compiled by the Frontier Line Economic Analysis Subcommittee.

Table 4-1. Wind and Gas-Fired Generation Project Data

Wind Generation (East-Central Wyoming)		**Power Displaced at Sink (Los Angeles)**	
Wind Generation, MW	3,600	CCGT, MW	2,077
Capacity Factor	45%	Capacity Factor	78%
Annual Energy, MWh	14,191,200	Annual Energy, MWh	14,191,200
Capital Cost, 2015, $/kW	$1,300	Capital Cost, 2015, $/kW	$1,000
Fixed O&M, $/kW-yr	$11.50	Fixed Costs, $/kW-yr	$52.90
Variable O&M, $/MWh	$5.50	Variable O&M, $/MWh	$2.40
Production Tax Credit, $/MWh	$0	Gas Price, $/MMBTU	$6.50
Renewable Energy Credit, $/MWh	$0	Heat Rate, BTU/kWh	6,920
Wind Integration Cost (CA) $/MWh	$3.00	CO_2, tons/MWh	0.4
Total Wind Generation Cost, $/MWh	$46.90	GHG Adder, $40/ton CO_2, $/MWh	$16.00
		Total Gas Generation Cost, $/MWh	$84.10

Transmission line cost data presented on Table 4-2 was developed by the Frontier Line Transmission Subcommittee. Single-circuit 500 kV AC transmission is assumed to cost $1.7 million per mile; Right of Way (ROW) outside of California is assumed to cost $300,000 per mile, with ROW inside California costing $450,000/mile. Double-circuit construction is assumed to cost 1.6 times that of single-circuit construction and ROW. Route miles are assumed to be 1.3 x straight-line miles between substations. Equipment for each 500 kV AC substation includes three 500/230/345 kV transformers, one set of shunt reactors and terminal equipment, for an all-in cost of $50 million per substation. The $4.3 billion total cost of the double-circuit 500 kV AC facilities includes provisions for contingencies, such as Special Protection Schemes that may be required. Losses were calculated using standard high voltage engineering assumptions.

Table 4-2 also shows costs for a +/- 500 kV DC alternative, with terminals in east-central Wyoming and Southern California. The DC alternative increases the Benefit-Cost ratio of the project by 40%.

Table 4-2. Transmission Cost Data

AC Transmission		DC Transmission	
Line: 2 x 500 kV AC, rated MW	3,000	Line: 1 x +/-500 kV DC, rated MW	3,000
Line miles, WY-UT-NV-SoCal	1,092	Line miles, WY-SoCal	850
Line Capital Cost, $/kW	$1,433	Line Capital Cost, $/kW	$900
Total Transmission Cost ($ millions)	$4,300	Total Transmission Cost ($ millions)	$2,700
Transmission Losses	4%	Transmission Losses	13%
Fixed Costs, $/kW-yr	$55.10	Fixed Costs, $/kW-yr	$36.40
Line Capacity, MWh/yr	26,280,000	Line Capacity, MWh/yr	26,280,000
Line Utilization	54%	Line Utilization	54%
Transmission Cost, $/MWh	$29.90	Transmission Cost, $/MWh	$19.10

The transmission project is assumed built using utility financing; the wind project, merchant financing. These parameters are presented in Table 4-3. Merchant financing of the transmission project would likely incur a higher average cost of capital, similar to that shown for the generating projects, and would be more expensive.

Table 4-3. Financing Assumptions

Utility Financing--Transmission		Merchant Financing--Generation	
Equity	55.3%	Equity	30.0%
Debt	44.8%	Debt	70.0%
Cost of Equity	10.7%	Cost of Equity	18.0%
Cost of Debt (before tax)	6.0%	Cost of Debt (before tax)	7.5%
Discount Rate, ATWACC	7.5%	Discount Rate (ATWACC)	8.5%
Inflation Rate, 2006-2015	2.0%	Inflation Rate, 2006-2015	2.0%
Inflation Rate, 2015 on	2.0%	Inflation Rate, 2015 on	2.0%
Loan/Debt Term (Years)	40	Loan/Debt Term (Years)	20
Equipment Life (Years):	40	Equipment Life (Years):	20

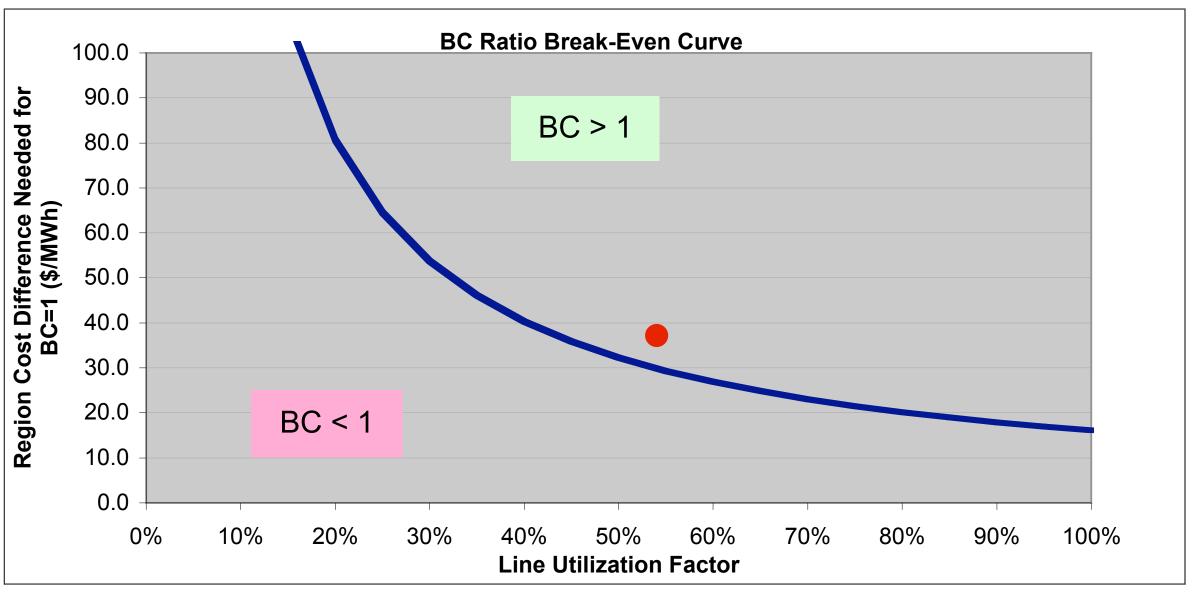
The economics of the overall project are driven by the cost differences between Wyoming wind generation and gas-fired generation in Southern California, net of transmission losses and state-mandated greenhouse gas adder. The results calculated by the Frontier Line spreadsheet model are shown on table 4-4, in levelized 2006 dollars.

Table 4-4. Cost and Benefit of Generation-Transmission Project

	Regional Difference Source $/MWh	Sink $/MWh	Diff $/MWh	Annual Benefits $million
Power Cost	$42.10	$70.00	$27.90	$396
GHG Adder	$0.00	$16.00	$16.00	$227
Renewable Credit	$0.00	$0.00	$0.00	$0
Wind Integration Cost	$3.00	$0.00	-$3.00	-$43
Production Tax Credit	$0.00	$0.00	$0.00	$0
Transmission Losses	$1.80		-$1.80	-$25
Credit for Dependable Capacity		-$1.90	-$1.90	-$27
Totals	$46.90	$84.10	$37.20	$528
Line Cost, levelized annual, $ millions				$424
Benefit/Cost Ratio				1.25

The $37.20/MWh difference in the cost of power shown on Table 4-4 between gas-fired generation in the Los Angeles area and wind generation in Wyoming is large enough to pay for the necessary transmission ($29.90/MWh, as shown on Table 4-2), while supporting a competitive rate of return on the overall generation-transmission project.[11] Regional differences in the cost of power drive the economics of the overall project. These are presented on Figure 4-1 as a function of line utilization. Large regional power cost differentials support projects having relatively low line loadings; higher line utilization supports projects taking advantage of smaller regional power cost differences.

Figure 4-1. Regional Power Cost Difference v. Line Utilization



[11] For comparison, configuring the project with 500 kV DC transmission, using the costs presented on Table 4-2, produces a Benefit-Cost ratio of 1.75.

Regional power cost differentials calculated by the Frontier Line study are sensitive to gas price, capacity factors of both wind power at the source and Combined Cycle units at the sink, carbon price and project capital costs. Breakeven gas price for the scenario presented here is $5.45/mmBtu. Higher wind capacity factors or lower Combined-Cycle unit capacity factors increase the regional power cost difference and so make the generation-transmission project more attractive; the converse would narrow the regional cost difference. Sensitivity runs performed to model the effect of different input assumptions on project economics, including carbon prices and capital costs, produced positive results across a range of reasonable values for key parameters.

The Frontier Line spreadsheet study is a screening-level analysis and does not provide a basis for investment decisions. Results of its wind-transmission case, however, are in line with those of some renewables Mega Projects under development, and indicate renewables-first generation–transmission projects to merit detailed study, if not commercial consideration.

5.0 Open-Access Tariff Issues[12]

Anyone owning transmission in interstate commerce must allow non-discriminatory access to their available transmission capacity, in exchange for fair compensation. Transmission owners cannot prevent others from using their monopoly lines simply to restrict the market, when they are not using available capacity themselves. Non-discriminatory access only requires surrender of capacity that is not being used, or cannot be reasonably shown to be put into use. There is no requirement that transmission lines hold "open seasons" to auction capacity, as there is with gas pipelines. Anyone, including generation project developers, building transmission facilities for their own use, and who are using it, cannot be compelled to auction capacity where they could be outbid for use of the facilities.

Like other dedicated transmission projects serving some coal, hydro and nuclear plants, renewables-only projects do not conflict with the open-access provisions of Order 890 as long as they have a FERC-approved Open Access Transmission Tariff in effect. This tariff provides that any transmission capacity that may become available on the line is offered to all generators on a non-discriminatory basis. This offer to make future capacity available does not preclude initial project proponents from fully subscribing for initial line capacity.

The same principle applies under "financial rights" tariffs such as those in PJM, MISO, NYISO and CAISO. These tariffs employ congestion pricing based on auctions and bidding. Transmission owners (including, for example, generation-project developers building new facilities) turn operation of their lines over to the ISO, in exchange for congestion revenue rights. These confer the right to be made whole *financially* for congestion payments. Capacity that becomes congested on a given line in day-ahead, hour-ahead or real-

[12] Chris Ellison, of Ellison, Schneider and Harris LLP, provided insight and perspective on tariff issues.

time markets is allocated by a bid system. The revenues from this bidding are redistributed back to those who were awarded (or who purchased) congestion financial rights. Builders/owners of new transmission facilities who were awarded such rights receive a share of these revenues that offsets their bid for capacity on the line. This enables them to outbid others for the capacity and secure physical delivery, compared to bidders who have no such financial right.

There is no definitive FERC ruling that transmission built initially to carry only wind or other renewables generation complies with the open access provisions of Order 890. There are, however, several wind-only transmission lines in operation now. The Sagebrush line in Central California, for example, has carried only wind generation, as it was designed to do, for nearly 20 years. And as discussed below, wind-first lines are under active development or are planned, in California, Minnesota, South Dakota, Texas and other states (and Canadian provinces). These lines have been approved, or have applied for state approvals, based on an intention to transport renewables, primarily or exclusively. Renewables-first transmission can apparently be designed not to conflict with either the letter or spirit of open access policy.

6.0 Existing, Planned and Proposed Renewables-First Transmission

Renewables-first transmission appears to be an emerging trend, with projects already in operation and others planned. Renewables Mega Projects may support wider development of dedicated transmission, but smaller project structures can also justify renewables-first facilities.

The Sagebrush Line, a dedicated 230 kV line built to transport power from wind projects in California's Tehachapi Wind Resource Area to Los Angeles, has been in operation since the mid-1980s. The Minnesota Public Utilities Commission, acting on legislative mandate, has ordered Xcel to build new facilities to provide transmission access for wind projects in the southwest sector of that state. It is highly likely that wind will be the only generation on these new lines, at least initially. Xcel has applied to FERC to recover the costs of these facilities in its transmission tariff, and it appears that FERC has acceded to the request.

The Montana-Alberta Tie Line (MATL) is a proposed 230 kV, 300 MW merchant transmission project connecting Lethbridge, AB with Great Falls, MT. In its Open Season capacity reservation process, MATL received bids exclusively from wind projects. It subsequently signed contracts to deliver 300 MW of wind power from Canada to Montana, and 300 MW from Montana to Canada. MATL has received permitting approvals in Canada and is awaiting approvals in the US; it expects to begin construction in 2007.

Tot 3 is a heavily congested path connecting SE Wyoming to Colorado Front Range load centers. Lack of transmission capacity has blocked development of many proposed wind and coal projects seeking to export power over that path. In response, the Wyoming Infrastructure Authority has proposed to add new capacity to this path, in conjunction with Trans-Elect, a merchant transmission developer, and the Western Area Power Administration

(WAPA). As a result of an Open Season WAPA conducted in 2005, Trans-Elect announced that new facilities could be justified solely for wind projects, which could be built even more quickly than the transmission itself; coal generation could be added later.

Several large-scale transmission projects are also being developed or proposed to serve renewables, primarily or exclusively. Texas has committed to build transmission—much of it 345 kV facilities—to connect wind projects in recently-designated Competitive Renewable Energy Zones (CREZ) to load centers. Most of the new transmission will be network facilities rather than wind-only lines, but they are economically justified on the basis of exporting wind power from remote regions to load centers.

In January 2007, the California Independent System Operator (CAISO) approved the 4,500 MW Tehachapi Transmission Project to export wind power from the Tehachapi Wind Resource Area to the state high-voltage grid. More than 6,000 MW of wind and solar CSP projects have applied to the CAISO for interconnection at Tehachapi. All of the new Tehachapi lines will be network facilities, and so not dedicated exclusively to transport wind power. But the primary justification for this project remains access to wind resources, to meet renewables-purchase and emission reduction requirements. Imperial Irrigation District and San Diego Gas &Electric are developing a similar project for access to 1,000 MW of geothermal and solar resources in California's Imperial Valley; other renewables export from that region is planned.

The BP-Clipper Windpower 5,000 MW Rolling Thunder wind project, and the 3,000 MW Katabatic-SeaBreeze Pacific proposed project to bring wind and hydro from British Columbia to California via undersea cable are other large-scale renewables projects built around dedicated transmission. Several additional large-scale wind/transmission projects are proposed by developers in Mountain and Midwest states but have not yet been publicly announced.

7.0 Marketing and Delivery Challenges

Materially reducing electric sector CO_2 emissions is likely to require relying on renewables to provide 20% or more of US supply, several hundred thousand megawatts in the aggregate. Mega Projects bringing renewables from areas where high-quality resources are concentrated may help organize the needed development. But ability to market large quantities of renewables may revolve around changes in the ways utilities evaluate the costs and risks of their resource choices. Large-scale projects also face difficult transmission planning and delivery challenges. Addressing them argues for early involvement of power buyers in project planning.

7.1 Building Supply Around Energy Resources

Utilities and regulators approach supply planning primarily as the need to add generating capacity, with the assumption that new capacity will supply the bulk of system energy needs. Increasing carbon prices and environmental restrictions, however, urge a priority focus on energy, not capacity, because emissions are a function of energy.

In energy-dominated portfolios built to take advantage of low-carbon, low-marginal cost generation, capacity resources might be acquired strategically, to support peak demand and reserve needs, and operated primarily to fill in around gaps in energy resource output. Capacity additions would not be expected to supply a large proportion of system energy. In a carbon-constrained world facing increasingly volatile fuel prices, such a planning approach might reduce the total combined cost of energy and capacity supply.

Even though the capacity contribution of new bulk power renewables may be significantly larger than utility planning practice assumes, renewables will rarely be able to meet all incremental capacity needs by themselves. But they may be able to do so in combination with expanded energy efficiency programs, solar peaking generation and Combined Heat and Power projects. Portfolios constructed to maximize use of low marginal cost energy may be able to meet incremental capacity needs by adding efficiency and diverse renewables alongside existing fossil, nuclear and hydro generating assets.

Reluctance to build significant renewables penetrations into supply portfolios stems in part from concern that variable-output generation cannot meet utility load-serving obligations.[13] But large-scale renewables projects can be organized to manage and reduce the variability of their power delivery in several ways, without energy storage. One is to combine wind, geothermal, biomass and/or CSP generation in one generation/transmission project, so that aggregate power output of the combined generation meets at least some baseload and peaking power requirements. Another, as discussed above, is to overbuild wind generation capacity to meet minimum delivery requirements over a larger number of hours. A third is to design the transmission and generation project (or projects) to access different wind regimes, so that short-term lack of wind in one region can be offset by wind in another. This has been demonstrated to significantly reduce the variability of aggregate wind output. Advanced turbine controls make it possible to operate entire wind projects at prescribed output levels and in some circumstances to increase output in response to dispatch directions.

Combinations of these approaches can enable large renewables projects to meet a range of supply needs. Requiring them to meet baseload needs is unnecessary. The immediate opportunity is to diversify supply portfolios, to hedge fuel risk and reduce carbon risk; the large amount of existing coal and gas-fired combined cycle generation will continue to provide adequate baseload supply in most regions of the country for the next few decades.

Fossil generation will of course still have a crucial role in ensuring reliable operation of utility systems. Wind integration studies of Minnesota, New York, California and other US and European utility systems have found existing utility systems and their generation stacks to have sufficient flexibility to accommodate penetrations of variable-output renewables up to about 20%. But as such penetrations become larger, balancing generation

---

[13] State-of-the-industry thinking about integrating wind power into utility systems is summarized in the November/December 2005 special issue of IEEE Power & Energy magazine (Vol. 3, No. 6), available from the Utility Wind Integration Group at www.uwig.org.

supply with customer load will require more dispatchable generation. Because construction of new hydroelectric plants is severely constrained, new dispatchable resources will likely be gas-fired. Turbine manufacturers have worked in recent years to improve heat rates and reduce emissions, but this has come at the cost of eroding the operating flexibility of Combined-Cycle units. In energy-dominated portfolios, procurement of new fossil resources is likely to value ramping capability and efficient operation at partial loadings.

The role of fossil generation may evolve into one of filling in around low carbon energy resources. The character and amount of thermal generation required to serve load in all hours will vary with unique operating needs as well as the amount of low-carbon energy available to each utility system. Locational Capacity resources will continue to be required in geographically- or transmission-constrained areas and in many load centers to ensure grid stability and reliable service.

Electric supply planning today relies on the statistical probabilities of fossil generators being available to meet peak demands. Taking advantage of low-carbon energy resources requires utility planners and regulators to become comfortable with the statistical probabilities of variable-output renewables generators being available to meet system needs. Established Effective Load-Carrying Capability (ELCC) analysis can be used to determine the capability of renewables portfolios to meet the full range of such demands. Mechanical reliability is not at issue, as modern wind turbines offer higher warranted machine availabilities than any fossil generator. Instead, the challenge is to look objectively at the operating characteristics of unfamiliar resources. This is easier said than done, and everyone concerned with reducing the environmental impact of the electric sector has a role in supporting the industry and its regulators to put carbon-limiting performance requirements at the center of accepted utility practice.

7.2 Marketing Challenges

Selling the output of a GW-scale project poses a challenge for any power resource. Deliveries may be required to multiple customers having different needs. A challenge for renewables projects is that regulatory practice and industry custom are adapted to fossil procurement, while renewables procurement is relegated in many states to processes and proceedings separate from mainstream supply additions. Although more renewables are being acquired through all-source solicitations, separate renewables procurement makes it difficult for utilities to objectively evaluate large renewables acquisitions alongside large fossil additions. The sizes of renewables projects developed to date have been determined by procurement limitations rather than by resource potential.

Structuring projects to deliver renewables in larger increments and in aggregate combinations that meet a range of operating requirements can help to break down existing bias in favor of fossil procurement. The offer of large-scale supply can help give regulators and power buyers an opportunity to rely more heavily on renewables to meet power needs for the period until new coal technologies can deliver emissions-free power. Meanwhile, the involvement of utilities and major manufacturers in project consortia might be the most effective mechanism for bolstering confidence in large-scale renewable energy supply.

7.3 Transmission Planning and Delivery Challenges

The contingent loss of any new high voltage transmission facility greatly affects existing regional grids, and must be planned for appropriately. In some cases, this may entail adding reserves not needed for economic operation of the combined generation-transmission project. Mitigations for the contingent loss of major lines are determined by unique local and regional factors, such that the costs of such mitigation cannot be generalized. The contingency built into the capital cost of the transmission example presented in section 4 above includes some consideration for such mitigation, but detailed power flow studies are necessary to determine what kinds of mitigation, if any, would be required for specific projects.

Perhaps the most difficult challenge facing large-scale transmission projects is the likely need to upgrade off-take transmission and distribution facilities at the delivery point. Delivery of, e.g., 2,000 MW to a single point could require the expansion or construction of several 230 kV lines to transmit the power into the local grid. Relatively few existing terminal substations have the ability to accept such large incremental deliveries. Off-take substations are often in or near load centers, where upgraded lines are difficult to site and Right of Way is expensive to obtain.

Spreading deliveries across several substations provides one mitigation for this problem. In the transmission project modeled in section 4, for example, power deliveries could be made at the Mona substation in Utah, at a substation in Las Vegas, or at both, in addition to those made to substations in Southern California. The seriousness of this problem argues for the early involvement of power buyers in the planning of large-scale transmission projects.

8.0 Opportunities for Policymakers, Industry and Advocates

The economic analysis presented here shows renewables-first transmission to merit further study. Despite precedent-setting developments underway, it remains to be seen how well renewables-first transmission can be adapted to fit a range of utility supply needs, in diverse regions. Ensuring objective evaluation of such alternatives is an immediate task.

Major generation-transmission infrastructure projects are now proposed in many regions of the country. Prudent practice or state planning policy requirements may lead regulators in affected states to order their jurisdictional utilities to perform studies required to determine the feasibility of renewables-first alternatives, alongside proposed coal or coal-wind generation projects. The grounds for such insistence include long-term economic effect of projects on ratepayers; achievement of state clean energy and energy independence goals; potential carbon liability risk; differential economic development benefits of fossil vs. renewables generation development; public health impacts; water consumption; and life-cycle environmental impacts.

The risk-adjusted cost of project alternatives should also consider that renewables projects can be built much more quickly than coal plants. In many western and Midwestern states, wind projects can be permitted, built and brought on-line in 24 months or less. Renewables projects can also be constructed in modular increments. The 4,500 MW Tehachapi wind-transmission project, for example, is phased into eleven segments to be built over a four-year period; most of the upgrades are required not to access the wind resource, but to make the power deliverable throughout a larger area of Southern California. The economic benefits of rapid and modular construction should be accounted for in evaluating project alternatives.

Where renewables-first project configurations are not studied, the preferred transmission project will likely be open to court challenge by ratepayer advocates and environmental interveners intent on finding lower cost, lower impact alternatives. This exposes even approved projects to the risk of potentially lengthy delays, at the end of the development process when delay is the most expensive.

For all of these reasons, it is in the interest of the renewables industry to support regulators and policymakers in insisting that renewables-first generation-transmission alternatives be evaluated as part of every major infrastructure application. This is likely to require active industry participation in commission proceedings in affected states.

Because competitive pressures make it difficult for industry players to cooperate, there may be a role for states, regulatory commissions or other public interest organizations in catalyzing the formation of consortia capable of undertaking large renewables generation-transmission projects. Renewables-first projects could play a role, for example, in meeting the 30,000 MW clean energy goal of the Western Governor's Clean and Diversified Energy Initiative.[14] They will necessarily play at least some role in any larger effort to make renewables a significant contributor to US electricity supply.

About the Author

David Olsen has helped pioneer collaborative planning for new transmission infrastructure in the U.S. West and Midwest.

In 2000, he led creation of the California Climate Action Registry, the first state registry of greenhouse gases. The reporting and verification protocols developed by CCAR provide the framework for the U.S. Climate Registry.

He is the former President/CEO of Patagonia, Inc., one of the first corporations to get its electricity from renewable energy. Earlier, he led the development of wind, solar, hydro and geothermal power projects in more than 20 countries, as President of Clipper Windpower Development, President of Peak Power Corporation, President/CEO of Northern Power Systems, and Vice President of Magma Power Company.

[14] The Governors' initiative and supporting task force reports are posted at: http://www.westgov.org/.