American Tradition Institute

The Hidden Costs of Wind Electricity

Why the full cost of wind generation is unlikely to match the cost of natural gas, coal or nuclear generation

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Preface

There have been two big misunderstandings about wind electricity. One, that it can operate by itself, and two, that its cost is approaching the cost of conventional sources such as coal, natural gas or nuclear. Neither of those assumptions is correct. The first because, in the absence of energy storage or hydro generation, the only way wind can operate is as an appendage to coal or natural gas generation; and the second, because wind imposes costs on other parts of the system which no previous technology has imposed and requires more new transmission infrastructure than any previous technology has required.

These indirect and infrastructure costs are not difficult to understand or difficult to measure. They have not been counted in most "cost of electricity" comparisons because utility regulators have not required wind operators to pay for them -- they've required consumers to pay for them. But that should not be an excuse for policymakers to ignore their impact on consumers, businesses and the economy.

Our investigation shows that, in the absence of subsidies, adding just the four largest missing costs would reveal that wind's full cost is about twice what the Energy Information Administration reported in its most recent "levelized cost of electricity" comparison, three times the current cost of gas-fired electricity, and 40-50% more than EIA's estimates for the cost of new nuclear or coal generation.

The purpose of this report is

- to explain why wind's cost has been calculated incorrectly,
- to explain the largest missing costs,
- to estimate their values,
- to point out the information that utility regulators have failed to report about wind's costs, and
- to note that, without this information, the "avoided cost" payments that wind operators are due under the Public Utility Regulatory Policies Act (PURPA) cannot be determined accurately.

We recognize that levelized cost analysis is a screening tool used by resource planners, and does not eliminate the need for more-detailed analysis carried out through chronological dispatch or macro-economic studies. However, since policymakers often refer to levelized costs, it is important to make them as complete and accurate as possible. Despite the challenges posed by variable generation technologies, we believe reasonably accurate calculations are possible.

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Executive Summary

Most "cost of electricity" comparisons have significantly understated the cost of wind electricity because they failed to take its unusual indirect and infrastructure costs into account:

- the cost of keeping available the primary plants that must balance wind's variations, even though adding wind to the system reduces the quantity of generation for which they are paid;
- the higher fuel consumption (per unit of output) that wind imposes on those plants;
- the cost of additional long-distance transmission that wind requires, and
- the losses that come with it.

Using conservative estimates for these missing costs (and backing out two subsidies) reveals that the full cost of wind electricity is nearly twice what the Energy Information Administration (EIA) reported in its most recent Annual Energy Outlook [1], three times the current cost of gas-fired electricity, and 40 to 50% higher than EIA's estimates for the cost of nuclear or coal electricity from new generation facilities.

Table 1 summarizes how the six factors examined in this report would increase the estimated cost of wind electricity from the 8 cents per kilowatt-hour that EIA reported to at least 15 cents per kilowatt-hour (kWh) if wind were combined with natural gas and 19 cents/kWh if wind were combined with coal.

The reason for showing one cost for "wind added to natural gas-fired generation" and another for "wind added to coal-fired generation" is that wind's principal benefit is to supply energy rather than capacity. Consequently, part of its cost must be to pay for maintaining the availability of whatever sources it's combined with. Therefore, unlike conventional sources which can operate by themselves, there is not just one cost for wind electricity, but a different cost for each primary source that wind can be combined with.

	Table 1. Levelized Cost of Wind Electricity, (starting from the assumptions in the Energy Information Administration's 2012 Annual Energy Outlook)	**Onshore Wind Added to Natural Gas (c / kWh)**	**Onshore Wind Added to Coal (c / kWh)**
	As reported by EIA, but using lower wind turbine cost from DOE's Office of Energy Efficiency and Renewable Energy [5]	**8.2**	**8.2**
1 2	Backing out an implicit subsidy, and assuming a 20-year lifetime	10.1	10.1
3	Plus the cost of keeping primary fossil plants available	11.8	15.6
4	Plus the extra fuel that fossil plants are forced to consume	12.4	16.5
5 6	Plus estimated costs for transmission and transmission losses, as wind penetration increases from today's levels	**15.1**	**19.2**

Stating The Same Result Another Way

At the current price of natural gas and before counting any costs of transmission, wind's cost is 6-7 cents per kilowatt-hour (kWh) more than its benefit -- the cost of the fossil fuel it can save and the conventional generation facilities it can replace. For wind's existing 3.5% share of all U.S. generation, that 6-7 cents/kWh translates into $8.5 to $10 billion extra that ratepayers have paid this year, and will continue paying every year for as long as existing wind facilities (or their replacements) remain in operation.

The Cost of Wind Electricity Versus The Cost of Gas-Fired Electricity

The bottom line is that the cost of wind electricity is not close to matching the cost of coal, natural gas or nuclear electricity today; and would not break even with gas-fired electricity unless the delivered price of natural gas were four to five times higher than today's price.

Figure 1 shows that wind electricity would not break even with gas-fired electricity unless the delivered price of natural gas were about $20 per million Btu (if adding wind to gas were 90% efficient at saving fuel) or about $23 per million Btu (if adding wind to gas were 80% efficient at saving fuel[1].) At either point, however, both wind and gas generation would be far more expensive than nuclear generation, and probably more expensive than coal with carbon capture and storage.

Note that because wind electricity does not save 100% of the fuel that the fossil plants the must be paired with it would otherwise have consumed to produce the same amount of electricity, as the price of either natural gas or coal increases, wind's cost of generation increases as well.

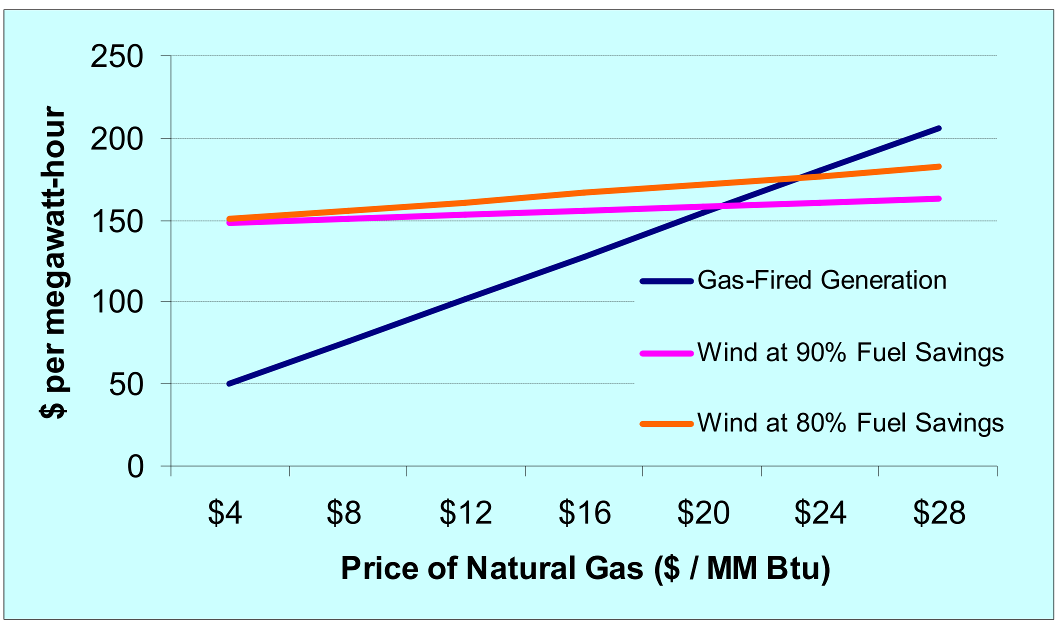


Figure 1. The Cost of Wind Electricity Versus the Cost Of Gas-Fired Electricity

[1] For comparison, the average delivered price of natural gas was about $5 per million Btu from 2009-2011 and about $4 per million Btu in 2012 [6].

What Policymakers Need To Know About Wind Electricity

- Since wind generation reduces the average level of output of primary fossil plants, but reduces the need to keep those plants in operation by a far smaller amount, part of wind's cost must be to pay for the appropriate portion of those plants' costs of capital recovery, operations and maintenance. This is not a policy issue – it's a matter of arithmetic.

- Since wind generation also imposes inefficiencies on those primary fossil plants, and requires additional reserves in order to maintain system reliability, **wind cannot save 100% of the fuel that would otherwise have been consumed.** This shortfall has not been counted in most cost of electricity tables, although it has been reported as a "cost of intermittency" in studies on the cost of wind integration.

While levelized costs are not necessarily accurate estimates for the wholesale price of electricity, they are designed to enable the cost of various options to be compared over their respective lifetimes. Levelized costs reflect the net present value of the total cost of constructing, maintaining and operating an electricity generation plant over its lifetime, expressed in terms of dollars per unit of output [6].

- Because its best locations are remote from major cities, **wind requires new long-distance transmission lines** which were rarely necessary before, and would not be necessary today, except to support wind. For every other type of generation except hydro, it has always been less expensive to site the plants near major cities and move the fuel rather than the electricity. Nothing has changed, except the introduction of wind electricity.

- Even cost studies which claim to have excluded subsidies typically still contain a special accelerated-depreciation subsidy for wind, solar and biomass.

- **Over $200 billion is at stake in capital expenditures alone**. Through mid-2012, over $100 billion had been spent on wind installations in response to state-level mandates and federal subsidies, even before counting the cost of new transmission. Fulfilling the existing mandates in their entirety would require at least $200 billion more (plus transmission).

  Yet the payback from the $100 billion spent to date is arguably no more than $4 billion saved in capital spending on conventional generation facilities (8% times the 50 GW of installed wind capacity times $1000/kW for the cost of new combined-cycle gas generation), plus savings of at most $4 billion per year in fossil fuel (3 cents/kWh times 140 billion kWh of wind generation this year), minus $1.4 billion per year for wind operations and maintenance (1 cent/kWh times the same quantity of generation.)

  Thus the return on $96 billion of net investment is at most 2.5% per year, even before counting transmission costs – far below the threshold which any other investment in electric system infrastructure would have to meet.

- **Wind's cost per kilowatt-hour will grow larger over time**, because while early wind installations could piggyback on spare transmission and fossil generation capacity in the system, further deployment will increasingly require new infrastructure.

- **Some of the most crucial information about the cost of wind electricity is not being reported**. Given that most of wind's value is the amount of fossil fuel it can save, and that without this number, the "avoided cost" that wind facilities must be paid under the terms of the Public Utility Regulatory Policy Act (PURPA) cannot be calculated accurately, it is surprising that no regulatory authority has reported how much fuel wind has saved, based on real-world experience.

- To enable independent evaluation of wind's full cost, regulators need to begin reporting for each region or grid-balancing area:

  1. how much fossil fuel wind has saved, and how the savings have changed with different levels of wind generation,
  2. the cost of transmission that has been added to support wind, and the associated transmission losses,
  3. aggregate wind generation by region on a fine-grained time scale, and
  4. wind's measured capacity factor.

None of this information should be proprietary or difficult to calculate to a reasonable degree of accuracy. It needs to be reported so that policymakers and the public will know the true costs of expanding wind generation.

Section 1.1 What the Energy Information Administration Reported

For years the Energy Information Administration (and others) have produced tables which compared the cost of all major sources of electricity. While these "levelized cost of electricity" (LCOE) calculations were never intended to reflect the exact cost of electricity in commercial markets, utility regulators, policymakers and the public have relied on this information in discussions about U.S. energy policy.

Table 2 shows the EIA's most recent comparison of the levelized cost of electricity from various generation sources, while Table 3 (on the next page) shows the type of entries which would more accurately reflect the indirect costs that wind generation imposes on other parts of the system. Both tables express costs in dollars per megawatt-hour, as is standard practice in such reports. ($10 per megawatt-hour = 1 cent per kilowatt-hour.)

Table 2. Estimated Levelized Cost of New Generation Sources, 2017
U.S. average levelized costs (2010 $ per MWh) for plants entering service in 2017

	Plant Type	Capacity Factor (%)	Levelized Capital Cost	Fixed O&M	Variable O&M	Fuel	Trans-mission	Total Levelized Cost
	Dispatchable Technologies							
1	**Conventional Coal**	**85**	**64.9**	**4.0**	**4.2**	**23.2**	**1.2**	**98**
2	Advanced Coal	85	74.1	6.6	6.9	22.2	1.2	111
3	Advanced Coal w/ CCS	85	91.8	9.3	8.0	28.4	1.2	139
	Natural Gas							
4	**Adv Combined Cycle**	**87**	**17.5**	**1.9**	**3.1**	**39.3**	**1.2**	**63**
5	Adv CC w/ CCS	87	34.3	4.0	6.4	44.2	1.2	90
6	Combustion Turbine	30	45.3	2.7	14.7	61.7	3.6	128
7	Adv Combustion Turbine	30	31.0	2.6	10.0	54.7	3.6	102
8	Advanced Nuclear	90	87.5	11.3	2.0	9.6	1.1	111
9	Geothermal	91	75.1	11.9	9.6		1.5	98
10	Biomass	83	56.0	13.8	5.0	39.3	1.3	115
	Non-Dispatchable Technologies							
11	Wind, As Reported @ $2438/kW	33	82.5	9.8			3.8	96
12	**Wind, As Restated @ $2000/kW**	**33**	**68**	**9.8**			**3.8**	**82**
13	Solar PV	25	140.7	7.7			4.3	153
14	Solar Thermal	20	195.6	40.1			6.3	242
15	Hydro	53	76.9	4.0	6.0		2.1	89

Source: Energy Information Administration 2012 Annual Energy Outlook [3]
Note: EIA listed hydro as non-dispatchable to reflect its seasonal nature, even though it is fully dispatchable for much of the year.

We modified Table 2 to separate the cost of fuel from the cost of variable operations and maintenance, based on information from EIA's supporting material [4]. We also added line 12 to show what wind's levelized cost of electricity would be if its construction cost (before interest) were $2000/kW, rather than the $2438/kW that EIA assumed, an adjustment based on information in the Department of Energy's latest Wind Technologies Market Report [5] which was released in August of this year.

In constructing Table 2, EIA assumed that:

the price of coal was $2.60 per million Btu,
the price of natural gas was $6 per million Btu, and
$15/MWh should be added to the cost of coal w/o carbon capture and storage

EIA also noted that "these results do not include targeted tax credits such as the production or investment tax credit available for some technologies. For example, … new wind, geothermal, biomass, hydro-electric, and landfill gas plants are eligible to receive either: (1) a $22 per MWh ($11 per MWh for technologies other than wind, geothermal and closed-loop biomass) inflation-adjusted production tax credit over the plant's first ten years of service or (2) a 30-percent investment tax credit, if placed in service before the end of 2013 (or 2012, for wind only)."

Section 1.2 What Would Be More Accurate For Wind Electricity

Table 2 reflects an important change which EIA initiated with this year's report – separating technologies which are available on demand (dispatchable) from those which are not. While EIA's decision to make this differentiation is commendable, dividing the table into two parts is only the first step. To make wind's LCOE more accurate, there needs to be an entry for each type of primary source that wind could be paired with, as shown in Table 3. Since the capital cost of each the technologies that wind might be combined with is different, wind's LCOE when added to each of those technologies must be different as well.

Table 3. What Would Be More Accurate for Wind Generation	Capacity Factor (%)	Levelized Capital Cost	Fixed O&M	Variable O&M	Fuel	Trans-mission .+ Loss	Total Levelized Cost
Non-Dispatchable Technologies							
Wind, Added to Combined Cycle Gas	**33**	**100**	**11.2**	**2.3**	**4 - 8.**	**31**	**149-153**
Wind, Added to Conventional Coal	**33**	**136**	**13**	**3**	**7 - 11.**	**31**	**190-194**
Wind, Added to Hydro		not covered in this report					
Wind, Combined with Energy Storage		not covered in this report					

With the New Tables, Production-Weighted Averages Would Produce Correct Results

One major advantage of the new entries for "Wind Added to Gas" and "Wind Added to Coal" is that they can be used to compute the average cost of generation from any combination of sources, by taking a production-weighted average of the cost of electricity from each of the components. Whereas, with EIA's existing table, any production-weighted average which includes wind generation produces an incorrect result, because the purported cost of wind is missing part of the cost.

Section 2: Derivation of Six Additional Costs for Wind Added to Gas

Table 4 summarizes our calculations that:

(1) assuming an operating life of 20 years as opposed to 30 years would increase EIA's wind LCOE from $82 to $93/MWh (and match the Electric Power Research Institute's result, given the same assumptions)

(2) backing out a hidden subsidy would increase wind's LCOE from $93 to $101/MWh

(3) counting the appropriate portion (75%) of a primary natural gas plant's costs of capital recovery and O&M (operations and maintenance) would add $17/MWh,

(4) taking into account the additional fuel consumption that wind imposes on those primary plants would add $4-8/MWh,

(5) adding the cost of transmission outlined in a large-scale onshore wind expansion scenario from the National Renewable Energy Laboratory's Eastern Wind Integration and Transmission Study (EWITS) would add $15/MWh, and

(6) adding the transmission losses reported for a DC transmission line in China similar in length to the ones proposed by EWITS would add $12/MWh.

	Table 4. Levelized Cost of Electricity for Wind Added to Combined-Cycle Natural Gas	**EIA ($/MWh)**	**EPRI ($/MWh)**
	EIA's wind LCOE, from Table 2, line 12	**82**	
	EPRI's wind LCOE, using EIA plant cost, capacity factor and transmission		93
1	**EIA, after matching EPRI's assumption for debt life (20 years)**	**93**	**93**
2	Using standard 20-year depreciation, as opposed to special 5-year	101	101
	Costs imposed on primary plants (from Table 2, line 4)		
3	Capital Recovery * 75%	+13	
3	Fixed O&M * 75%	+1.5	
3	Variable O&M * 75%	+2.3	
4	Additional fuel consumption, assuming wind saves 80-90% and the delivered price of natural gas = $6 per million Btu	+4-8	
5	Transmission cost, derived from EWITS, as described	+15	
6	Transmission losses	+12	
	Total	**149-153**	**149-153**

Sources: EIA 2012 Annual Energy Outlook [3] and EPRI Generation Technology Options 2011 Technical Update [7]

The following sections explain the derivation for each factor.

① Adjusting for 20-Year Lifetime

EIA's levelized cost of electricity (LCOE) for wind, as restated on line 12 of Table 2, is $82/MWh.

Instead of reporting a single wind LCOE, the Electric Power Research Institute (EPRI) reported a range, depending on the value of certain factors. Plugging EIA's assumptions for overnight plant cost ($2000/kW), capacity factor (33%) and transmission cost ($4/MWh) into EPRI's formula results in $93/MWh.

The difference between EIA's and EPRI's numbers arises from different assumptions about the average life of wind facilities. EIA assumed 30 years, but if it had used EPRI's assumption of 20 years instead, its overall wind LCOE would have matched EPRI's at $93/MWh. EIA's assumption that all generation technologies would have the same 30-year lifetime is highly unusual, and not supported by the claims of any wind manufacturers.

Calculation: The capital cost component of EIA's wind LCOE is $68/MWh.
20-year amortization requires 16.5% higher monthly payments than 30-year amortization.
$68/MWh * 1.165 = $79/MWh.
Difference: $11/MWh

Monthly Payment per $1000 of Capital

Real Weighted Average Cost of Capital	20-year	30-year	Ratio
7% (EIA)	$7.75	$6.65	1.165

② Backing Out a Hidden Subsidy

Both EIA and EPRI include a subsidy based on special accelerated depreciation rules, even though they exclude more explicit subsidies, such as the investment and production tax credits. Eliminating this subsidy increases the levelized cost of capital by 10%, from $79 to $87/MWh, and the levelized cost of electricity from $93 to $101/MWh. See section 6.3 for the derivation of the 10%.

③④⑤⑥ Four Missing Costs

The four largest costs of wind electricity that typical levelized cost of electricity reports have omitted are:

(1) the capital costs of intermittency that wind imposes on the primary sources that must be paired with it
    a) capital

b) fixed operations and maintenance
c) variable operations and maintenance

(2) the additional fuel costs that wind imposes on primary plants
(3) the cost of transmission, and
(4) the cost of transmission losses.

To cite a typical example, the NREL Eastern Wind Integration and Transmission Study [6] reported that the cost of integrating a large quantity of wind capacity into the Eastern Interconnect would be about $5 per megawatt-hour of electricity, in 2009 dollars. But that was because integration costs were narrowly defined as "those incremental costs incurred [during operation] that can be attributed to the variability and uncertainty introduced by wind generation," a definition which counts fuel consumption, but not the other costs of intermittency listed above, or the costs of transmission and transmission losses.

③ The Gas Plant's Cost of Capital Recovery

While the cost of capital recovery that wind imposes on complementary sources was acknowledged in the UK Energy Research Centre's 2006 report on the "Costs and Impacts of Intermittency" [10], it has not been incorporated into EIA's or other widely-referenced levelized cost of electricity reports.

The UK ERC summarized its formula for the additional costs of maintaining system reliability in the presence of intermittent generation resources as follows:

*"The change in total system cost can be characterized as the cost of building and operating intermittent plant, **minus** the cost associated with displaced fuel use, **minus** the costs of thermal plant that can be displaced (or new investment avoided) because of the capacity credit of the intermittent plant."* [8]

Which raises the question, how much thermal plant can wind displace?

Regional System Operators Have Concluded That Wind Generation Can Displace About One-Fourth As Much Capacity As Energy

Based on the information cited in Section 6.2, we found that regional system operators have concluded that each megawatt of wind capacity can replace about one-quarter megawatt of conventional generation capacity.

Thus 75% of a gas facility's levelized cost of capital must be added to wind's levelized cost of capital.

		Levelized Capital Cost	Fixed O&M	Variable O&M
75% * Adv Combined Cycle		17.2	1.9	3.1
equals		13	1.5	2.3

Why Must This Cost Be Counted?

For the purpose of illustration, take the case of combining equal quantities of wind capacity and gas capacity, and assume that wind's average annual level of generation (its *capacity factor*) is 32%, while the amount of generation it can be relied upon to produce at times of peak demand (its *capacity value*) is 8%. See further discussion in sections 6.1 and 6.2.

Then the reason most of the primary source's cost of capital recovery must be included in wind's LCOE is that

(1) Total Capital Cost does not equal 68% * Gas-Plant-Cost + Wind-Plant-Cost

as it would if a dispatchable source had replaced 32% of the gas capacity, but instead

(2) Total Capital Cost equals 92% * Gas-Plant-Cost + Wind-Plant-Cost

The difference between equations (1) and (2) means that for every kilowatt-hour for which wind replaces gas, nearly all of the capital cost of the gas facility must still be recovered (in addition to the capital cost of the wind facility.)

③ The Gas Plant's Costs of Operations and Maintenance (O&M)

Fixed O&M should be treated the same as capital recovery.

Variable O&M is different. We do not know at this time whether a gas facility's total variable O&M over a long period of time would increase, decrease or remain the same if its operating hours were reduced, but its operating conditions were made more strenuous. For this study, we assumed that total variable O&M over any given period of time would remain the same because the more frequent ramping, shutdowns and restarts that wind imposes on a fossil plant would override any savings that resulted from fewer hours of operation.

④ Additional Fuel Consumption

If wind saved a megawatt-hour's worth of fuel in a fossil-fired power plant for every megawatt-hour of generation it replaced, no correction would be necessary. But wind generation imposes four types of inefficiencies on the primary fossil plants that must operate in combination with it:

1) Increased hours of operation at partial load (to provide necessary spinning reserve)
2) Increased ramping between different levels of output
3) Additional shutdowns and restarts
4) Operation in less efficient but faster reacting combustion-turbine mode as opposed to more efficient but slower reacting combined-cycle mode, at a fuel penalty of 50% or more, when combined-cycle mode cannot respond quickly enough to match wind's rapid variations

Unfortunately, the exact magnitude of the overall inefficiency penalty in various gas+wind combinations is unknown, and depends on the specific design of each power plant, the demand pattern, the wind pattern and degree of wind penetration on the grid[2]. Some studies have addressed one or more of the four types of inefficiencies listed above, but none have addressed all of them and none have used the gold-standard technique of running the chronological dispatch for a given set of generation resources (using actual performance metrics, including transition heat rates), with and without wind generation, against a given time series of demand.

After an exchange of arguments with critics, Katzenstein and Apt reported fuel savings of 76% to 94% for wind added to combined-cycle gas [9-11], while Fripp reported savings of 94% for wind added to a system containing both combined-cycle and combustion turbine gas, but did not count the additional fuel consumed in shutdowns and restarts, or the impact of ramping [12].

Given the numbers in these reports, we concluded that a reasonable upper bound for the fuel savings achieved by a gas+wind combination would be 80-90%. This level could decrease as the level of wind penetration increases, due to operating the primary gas plants at lower (and less efficient) average levels of output, and the need to curtail wind generation if its hours of highest output coincide with hours of lowest demand.

Table 5. Fuel Savings, Wind Added to Gas	Calculated Savings	Factors Taken Into Account			
Source		Partial Load	Ramping	Shutdown Restart	CT vs CC
Katzenstein & Apt, single plant	76%	X			
Katzenstein & Apt, multiple plants	76-94%	X			
Fripp, over a 500 km diameter region	94%	X			X

⑤ Transmission

Only a limited amount of new long-distance transmission had been constructed to support the 50 gigawatts of new wind capacity installed through mid-2012, because (a) there was unused capacity in the existing transmission system and (b) demand from cities within a few hundred miles of most wind installations was large enough to absorb their output. However, at higher levels of wind penetration, regional consumption will no longer be sufficient to absorb all wind generation and longer distance transmission will become increasingly necessary. In our calculations, we have assumed that these new transmission lines will have the same capacity factor as the wind facilities themselves.

[2] When fossil power plants are frequently and rapidly ramped up and down to compensate for wind variation, their fuel consumption per kilowatt-hour increases.

Transmission studies consistently report that the AC transmission lines which make up nearly all of the existing grid cannot transmit power economically more than about 500 miles (although, of course, they've rarely had to.) Thus, there have been few proposals which analyzed moving wind energy all the way from the Great Plains to the Midwest, the East Coast or the South.

To establish a lower bound on what this cost might be, we can look at the EWITS proposal for using point-to-point DC transmission lines to move wind electricity from its most productive locations on the Great Plains to large centers of demand in the East and Southeast. EWITS' estimate is a lower bound, however, because it primarily counted the cost of the DC lines and did not fully account for the cost of gathering wind energy with an AC system on one end and distributing it into the existing AC system on the other end [30].

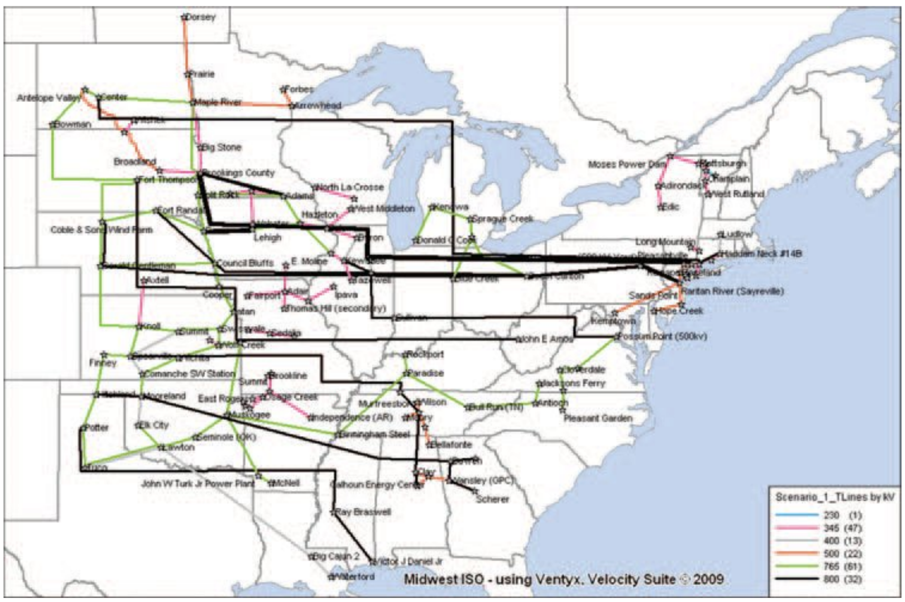


Figure 2 – EWITS Scenario 1 for Onshore Wind Transmission [6]

In Table 2, EIA included a simple placeholder for the cost of transmission, equal to approximately $1 per MWh divided by the capacity factor of each technology. This small amount covered only the cost of local connections.

EWITS' Scenario 1, on the other hand, estimated that transmission would add an average of $520/kW to the cost of installing 225 gigawatts of onshore wind capacity in the Eastern Interconnect. While EWITS' evaluation of the cost of transmission was incomplete, we can use its results as a lower bound for the transmission cost that should be anticipated for a large wind buildout. See additional maps in Section 5.8.

Table 6. Transmission Cost, Derived From EWITS	Assumed Value	2009 $ billions	2012 $ billions (interpolated)	2024 $ billions	**$ per kW of Capacity (223.6 GW)**
Grid Overlay Cost, Tables 4 and 4-5		93.2	105.8	156.2	
Overload Correction, Table 4-7	10%		116.4		**520**

$520/kW equals 26% of the $2000/kW plant cost that was the basis for line 1 of Table 5. This plant cost resulted in an initial capital cost of $68, which increased to $75 as a result of line 4. (Line 3's correction does not apply to transmission, because transmission's expected lifetime is at least 30 years)

26% times $75 = $19, which is $15 more than EIA's assumption in Table 2, line 12.

⑥ Transmission Losses

Although short-distance transmission and local distribution losses have averaged 6-7% of power plant generation [13], long-distance transmission losses have not been a major factor to date because most power plants are located near the loads they serve, and it has almost always been less expensive to move the fuel than to move the electricity.

The backbone for EWITS' onshore wind transmission proposal (Scenario 1) consists of nine 1200-mile-long 800 kilovolt DC lines. According to the builder of the one 800kV HVDC line in operation today, the Xiangjiaba to Shanghai line of approximately the same length has a 7% line loss at its rated capacity of 6400 MW [14]. We assume that this figure includes losses in the transformers at either end, as well as the line itself.

Given the expected losses in the shorter AC gathering and distribution network on either end of the DC lines, 10% would be a conservative assumption for the total end-to-end losses under EWITS Scenario 1.

The sum of line 4 ($101) and line 9 ($15) in Table 5, divided by 0.9 = $12/MWh.

Section 3: Derivation of Six Additional Costs for Wind Added to Coal

Although we doubt that anyone would advocate keeping coal plants in operation indefinitely in order to complement wind generation, coal is in fact wind's principal complementary source in many parts of the U.S. today. Table 7 shows the same calculation for coal as Table 4 showed for natural gas.

	Table 7. Levelized Cost of Wind Added to Coal	**EIA ($/MWh)**
	Wind LCOE, from Table 4, line 4	101
	Costs Imposed on Primary Plants (from Table 2, line 1)	
3	Capital Recovery * 75%	+49
3	Fixed O&M * 75%	+3
3	Variable O&M * 75%	+3
4	Additional fuel consumption, assuming wind saves 50-70% and the delivered price of coal = $2.60 per million Btu	+7-11
5	Transmission cost, derived from EWITS, as described	+15
6	Transmission losses	+12
	Total	**190-194**

Costs of Capital Recovery and Operations & Maintenance

Based on Table 2, line 1:

		Levelized Capital Cost	**Fixed O&M**	**Variable O&M**
75% * Conventional Coal		**64.9**	**4.0**	**4.2**
equals		**49**	**3**	**3**

Additional Fuel Consumption

Based on the limited evidence available and the known operating characteristics of coal-fired power plants, we concluded that a plausible upper bound for the amount of coal that wind could save is 50 to 70% of the amount that would have been consumed to produce the same quantity of electricity, had no wind been added to the system.

Bentek Energy studied the hourly generation and fuel consumption of three coal plants which were ramped down and up across a period of several hours to match wind variations, and followed the operation of the plants for up to 20 hours after they had returned to their original levels of output, in order to assess the total impact of the interruption. Bentek concluded that the

fuels savings in the three cases were less than zero, 36% and 72%, respectively, a result that does not indicate a simple answer, but does indicate that the impact of cycling a coal plant can be severe [15]. Because Bentek relied on actual fuel consumption data rather than a model, their results account for the impacts of both ramping and partial-load operation for a single plant, although not the costs of shutdown and restart. The results for a larger fleet of coal plants could be different, and the answer would depend in part on the ratio of wind capacity to coal capacity.

In a report issued earlier this year by Argonne National Laboratories, Valenzuela et al. [16] reported that 10% wind penetration in a generation mix dominated by coal resulted in a 12% reduction in CO2 emissions. However, the 10% wind penetration statistic was misleading. In fact, in Valenzuela's example 16% of the original coal-fired generation was replaced by wind (while none of the original nuclear generation was replaced by wind.) Therefore, the CO2 emission reduction should have been reported as 75% of the wind penetration. Partial-load operation and shutdown/restart were accounted for in this study, but impacts of ramping and the substitution of combustion-turbine gas generation for combined-cycle gas generation were not. Since there was also some substitution of gas generation for coal generation, the fuel savings ratio would have been less than the reported reduction in CO2 emissions.

Table 8. Fuel Savings, Wind Added to Coal	Calculated Savings	Factors Taken Into Account				
Source		Partial Load	Ramping	Shutdown Restart	Substi-tution of Gas for Coal	24-Hr Effects
Bentek Energy -- single plants, single days	0-72%	X	X	X		X
Valenzuela et al. -- 24 GW region, 4 months	75%	X		X		

Transmission and Transmission Losses – the same as in Table 4.

Section 4: Conclusions

This report has shown that the cost wind electricity is not approaching parity with conventional sources, and is unlikely to reach parity unless the price of natural gas, the price of coal and the capital cost of nuclear facilities were all to increase dramatically.

Even with estimates which are favorable to wind's case, its full cost is about three times the current cost of gas-fired generation and one-and-a-half times the cost of nuclear or coal-fired generation. Further deployment of wind would increase a number of indirect costs, and tie us to greater reliance on fossil fuels, not less.

Wind electricity would not reach breakeven with gas-fired electricity unless the delivered price of natural gas were about $20 per million Btu, if wind were 90% effective at saving natural gas, or about $23 per million Btu, if wind were 80% effective at saving natural gas. At which point, in either case, both wind and gas generation would be far more expensive than nuclear generation, and perhaps even more expensive than coal with carbon capture and storage.

Wind developers are only able to offer contract prices approaching parity with traditional generation sources because they are able to avoid financial responsibility for costs they impose on others. We would argue that in order to facilitate the best long-term decisions, every generation facility should pay for its own costs, including its fair share of any costs for common use infrastructure. No technology should offload its direct or indirect costs onto ratepayers who are not direct beneficiaries, or onto taxpayers.

Counting and allocating costs incorrectly creates distortions which have long-lasting consequences. Failing to count costs properly also means that the avoided-cost calculation defined by the Public Utility Regulatory Policy Act (PURPA) is being misapplied.

As this study had indicated, some of the most crucial information for understanding the full cost of wind electricity has not been made available to the public or to policymakers:

- **How much fossil fuel wind has saved**, a number which is best determined either by re-running the chronological dispatch of all generation facilities against a time series of historical demand, with and without wind generation in the mix, or from studies based on models which include <u>all</u> of the factors which contribute to additional fuel consumption, including the actual measured performance metrics of each generation facility.

- **Transmission costs and transmission losses**, properly allocated to the technologies and locations that necessitate them.

- **Operations and maintenance costs**, as a function of wind turbine age and other relevant characteristics,

- **Wind generation aggregated by region**, at a fine-grained (~5 to 15 minute) time scale

- **Wind's measured capacity factor**

Why Has The Full Cost Of Wind Electricity Not Been Reported?

We can identify three reasons. With regard to the failure to report the costs of capital, operations and maintenance of the fossil plants that must be paired with wind, the reason appears to be force of habit. Since all previous facilities were able to operate independently, the authors of cost of electricity reports never had to consider the costs that one technology might impose on another technology which was required to operate in parallel with it.

With respect to the extra fuel consumption that wind imposes on fossil plants, the failure to report stems from a lack of credible information. Regulators have not required utilities or regional system operators to calculate and report how much fossil fuel wind has saved. Research papers have reported certain results based on wind generation models, but few have used actual wind generation data, and none have taken all factors into account.

With respect to the costs of transmission and transmission losses, the difficulties have been that (a) only limited amounts of new transmission infrastructure have been built, (b) the costs of such infrastructure are difficult to estimate without proprietary tools owned by the utilities, (c) the costs per unit of wind generation are likely to increase as more wind capacity is added to the system and (d) most utility regulators have chosen to socialize the costs of new transmission rather than to identify the costs which should have been attributed to wind. In the absence of credible information, agencies such as EIA have been understandably reluctant to forecast what the costs might be.

But just because certain costs are difficult to estimate does not mean that they should be ignored. Instead, EIA and others should acknowledge that important information is missing and call for utility regulators to provide it.

Section 5: Background Information

5.1 The U. S. Generation Mix

Coal, natural gas, nuclear and hydro account for 95% of all U.S. generation. The largest change over the past four years has been the substitution of gas for coal, while the second largest change has been the increase in wind generation from less than 1% in 2007 to about 3.5% this year.

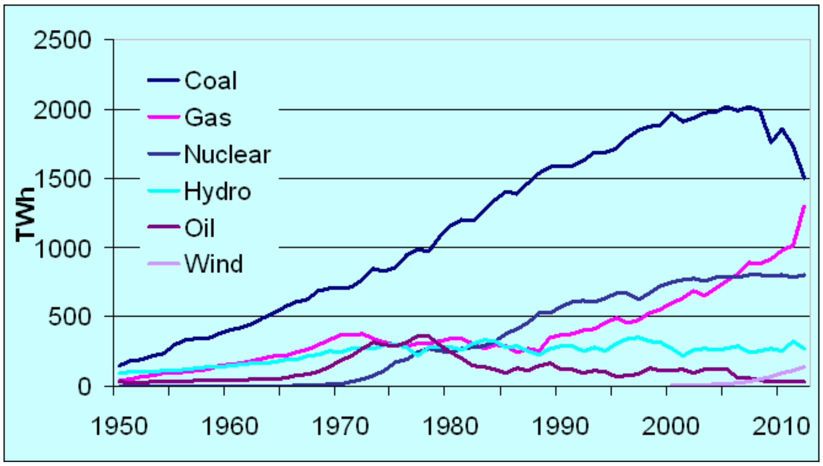


Figure 3 -- Source: EIA Electric Power Annual [13]

5.2 What's Been Driving The Increase in Wind Generation?

Mandates and subsidies. As summarized in Figure 4, 37 states have enacted renewable electricity mandates or goals, with typical targets ranging from 15% to 25% of all generation, to be achieved by 2020 to 2025. In practice, RES mandates have nearly always been wind mandates.

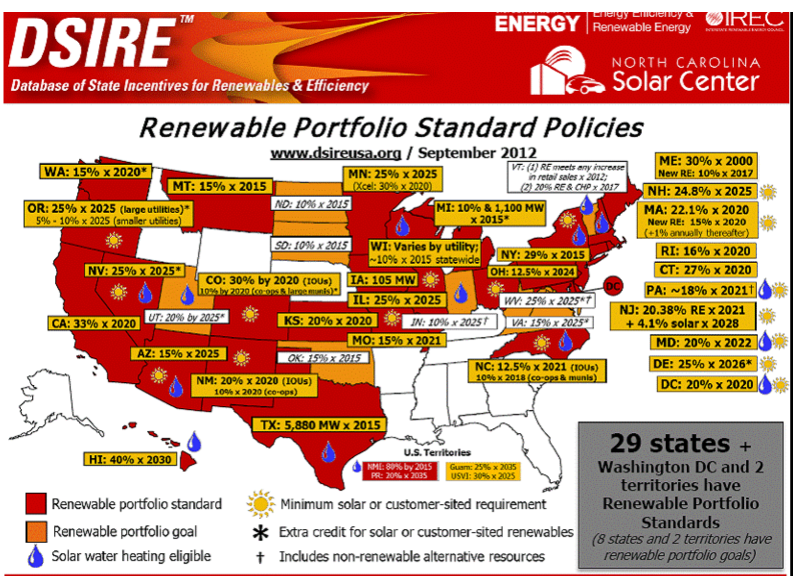


Figure 4 -- Source: www.dsireusa.org [17]

5.3 What Have Been The Results?

Almost 40% of capacity additions since 2007 have been wind installations. The integration of this surge was made easier by the 200 GW of new gas capacity which was added between 2000 and 2005.

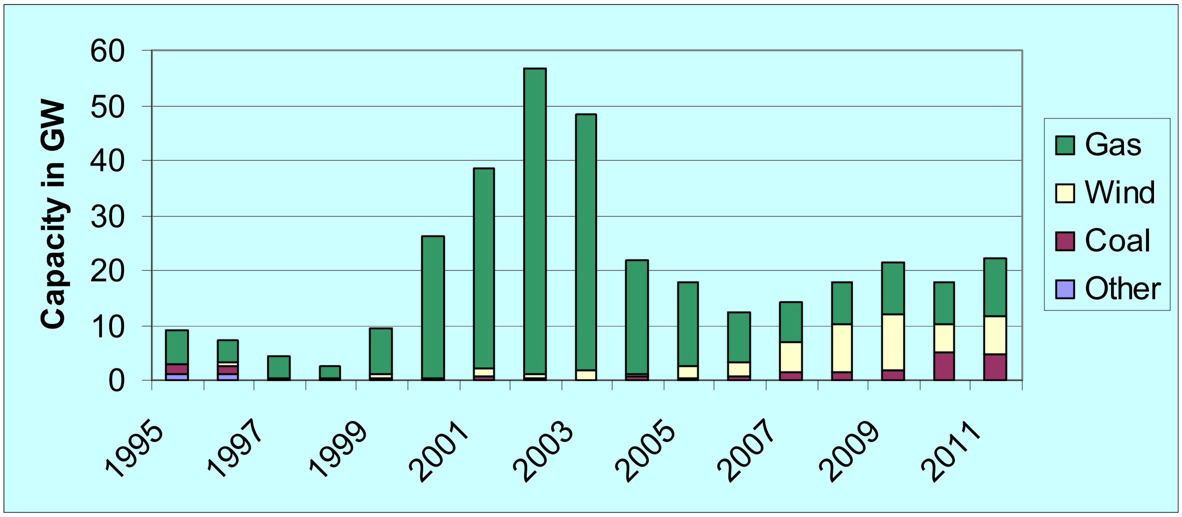


Figure 5 -- Source: EIA Electric Power Annual [13]

Cumulative wind installations reached 40 GW by the end of 2010 and are predicted to reach 60 GW by the end of 2012.

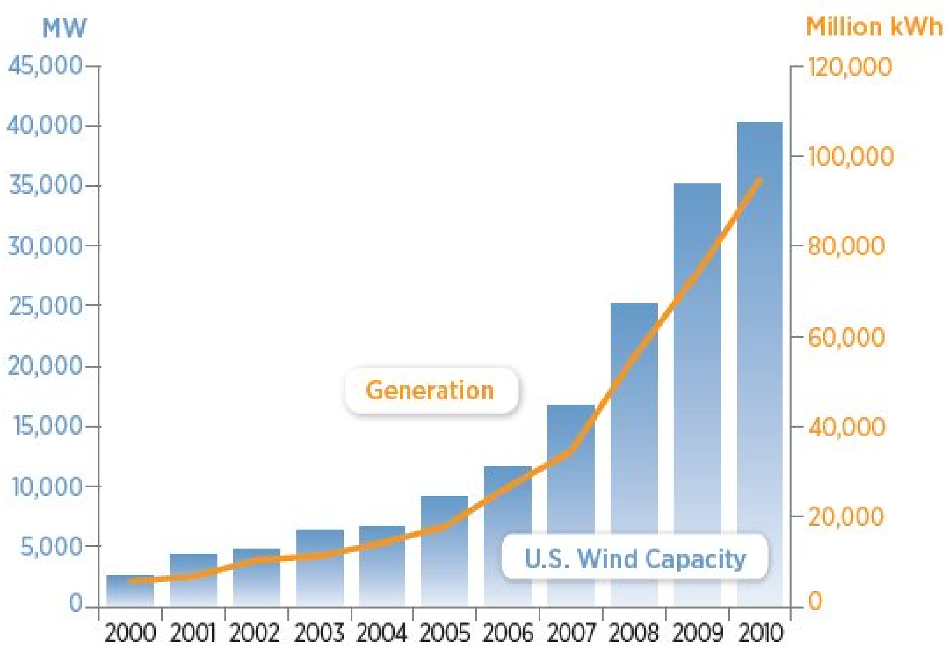


Figure 6 -- Source: EnergyForumOnline.com

5.4 How Does Wind Electricity Work?

The most important characteristic of wind electricity is that no one can use it in its raw form. Thus, in the absence of energy storage (which no one has advocated building because of its cost and/or environmental impact), wind generation can operate only in conjunction with some primary source (such as coal, gas or hydro) which will most likely need to supply the majority of the electricity.[3]

Thus, the major choices for the future of electricity are not fossil, nuclear and wind -- the major choices are fossil, nuclear and fossil+wind. Moreover, the characteristics of fossil+wind are quite different from the characteristics that advocates have attributed to wind generation by itself.

5.5 How Much of the U.S. Generation Mix Is Already Fossil+Wind or Hydro+Wind?

One could argue that a significant portion of all fossil and hydro generation is already serving as a complement to wind. While the exact amount of fossil and hydro generation which is being ramped to counterbalance wind is not known, if we assumed that complementary capacity merely equaled installed wind capacity, the combination would have accounted for 10% of all generation in 2011. Of course, in today's grid the ratio of complementary capacity to wind capacity is many to one. But as wind penetration increases, this ratio will decrease to some lower bound which is determined by the characteristics of the wind resource and the characteristics of the complementary plants.

Table 9. U.S. Generation Mix Generation Sources	**2011 Share of Generation, as Reported (%)**	**Minimum Share of Generation Which is Already Fossil+Wind or Hydro+Wind**
Coal	42	high 30's
Natural Gas	25	low 20's
Nuclear	19	19
Hydro	8	< 8
Wind	3	
Coal + Wind **Gas + Wind** **Hydro + Wind**		**10**
Biomass, other	3	3

Sources: column 1, EIA Electric Power Monthly [13]; column 2, this report.

[3] While in theory wind could supply more than half of the generation from some gas+wind combinations, it could do so only at increasing higher cost, due to both increased wind curtailment during periods of high output and the need to use more fast-responding but less efficient balancing plants, such as combustion turbine gas, instead of slower-responding but higher-efficiency combined-cycle gas. CT typically requires 50% more fuel per unit of output than CC at full load, and more than 50% more fuel per unit of output than CC at partial load [18].

5.6 Can Subsidies Create the Illusion of Grid Parity?

Power purchase agreements (PPA's) have been cited as evidence that cost of wind electricity would have approached grid parity had the price of natural gas not declined in 2012 from its levels in 2009-2011. However, what makes low-priced wind PPA's possible are subsidies such as the federal investment tax credit (ITC), the federal production tax credit (PTC), technology-specific accelerated depreciation rules, renewable energy certificates which can be sold to buyers who must satisfy state-level mandates, and other state and local subsidies and tax abatements.

Table 10. Impact of Subsidies	**Cents per Kilowatt-hour**
Wind, from Table 2 at $2000/kW	8.2
Wind, net of the after-tax value of the production tax credit	4.5-6.0
Wind, net of the 30% investment tax credit (if taken as a cash rebate, as was an option for projects which began construction in 2009-11)	6.2

Since 1992, wind developers have had the choice of selecting either the ITC or the PTC, and for projects which started between 2009 and 2011, the choice of taking the ITC as a 30% cash payment, as opposed to a tax credit.

While the PTC's nominal value is 2.2 cents/kWh, its pre-tax value to a tax-paying entity can be as high as 3.7 cents/kWh.

5.7 Location of Wind Installations to Date

Figure 7 below shows the location of existing wind installations.

Figure 8 shows the same information (aggregated in gigawatts of capacity) overlaid on a map of wind resources, where the purple and red zones on the Great Plains are the areas of highest wind generation potential. Approximately 10 GW of wind capacity have been constructed on the West Coast, 4 GW have been constructed in the Mountain West, 11 GW in Texas and 25 GW in the Eastern Interconnect. 90% of the nation's wind capacity is located west of Chicago.

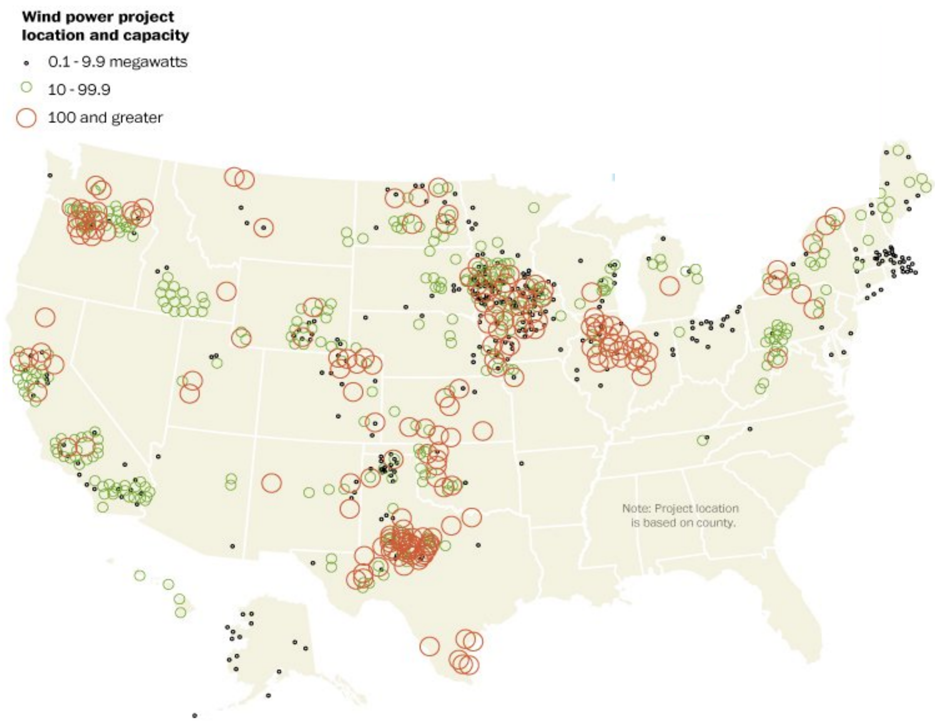


Figure 7 -- Source: The Washington Post, September 20, 2012

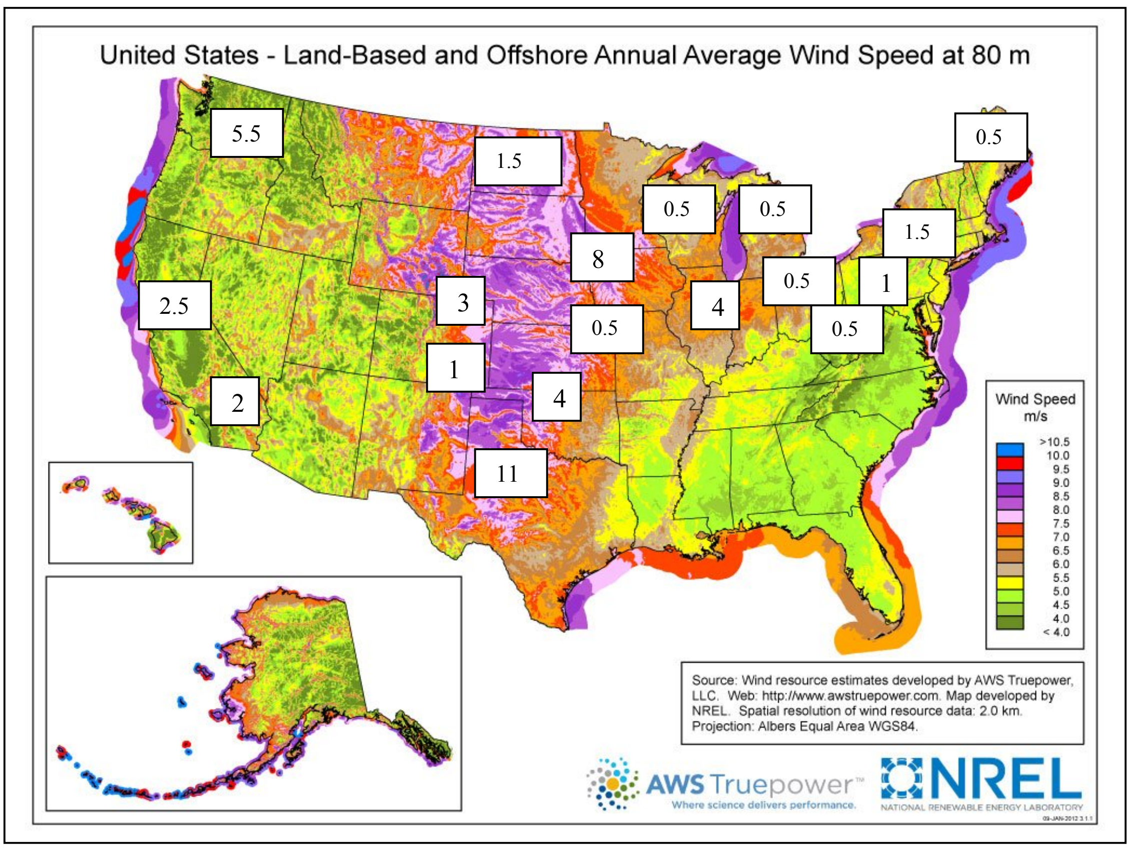


Figure 8 -- Source: www.windpoweringamerica.gov/pdfs/wind_map

5.8 Location of Wind Installations Proposed by EWITS

EWITS Scenario 1 proposed to connect 224 GW of onshore wind capacity from the following regions, which can be identified on the right hand side of Figure 9:

42.5% in Midwest ISO + MAPP (Mid-Continent Area Power Pool)
41% in SPP (Southwest Power Pool)
10% in PJM
5.5% in New York and New England
1% elsewhere

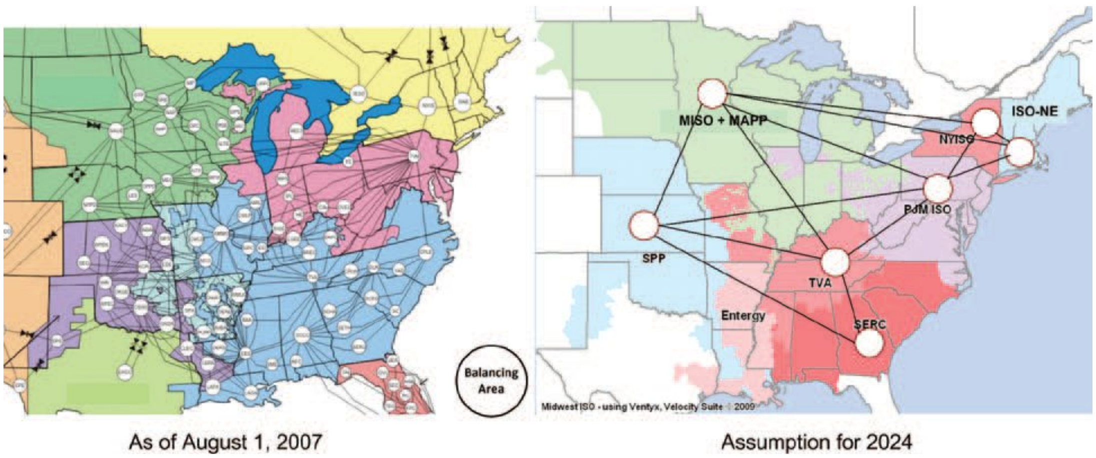


Figure 9 -- Source: EWITS Figure 5-6: Eastern interconnection balancing authorities

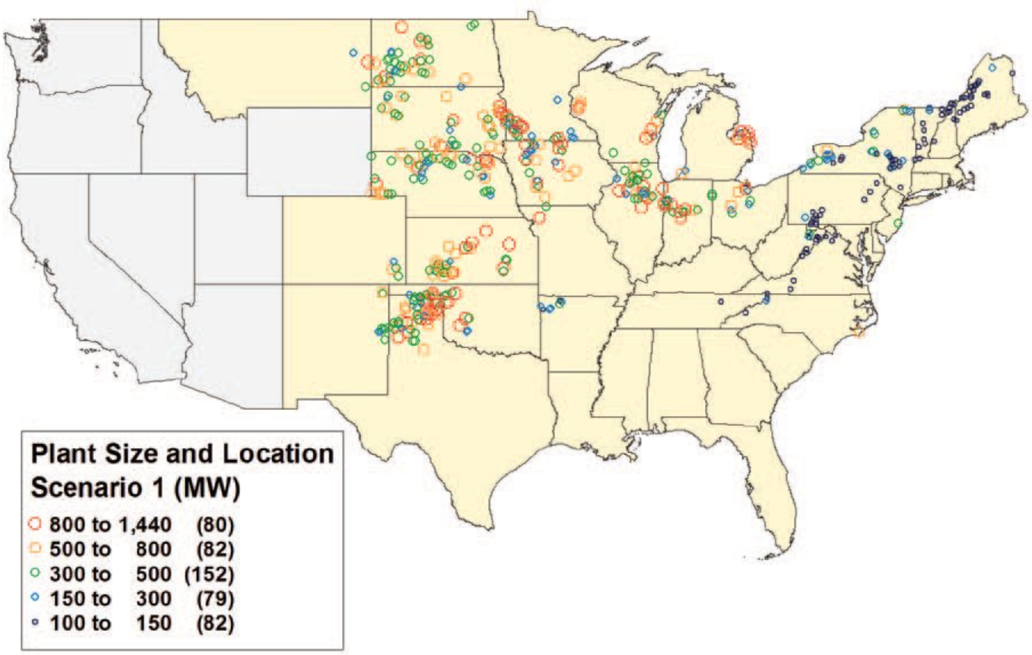


Figure 10 -- Locations of New Wind Capacity in EWITS Scenario 1 [6]

Section 6: Appendices

6.1 Wind's Capacity Factor

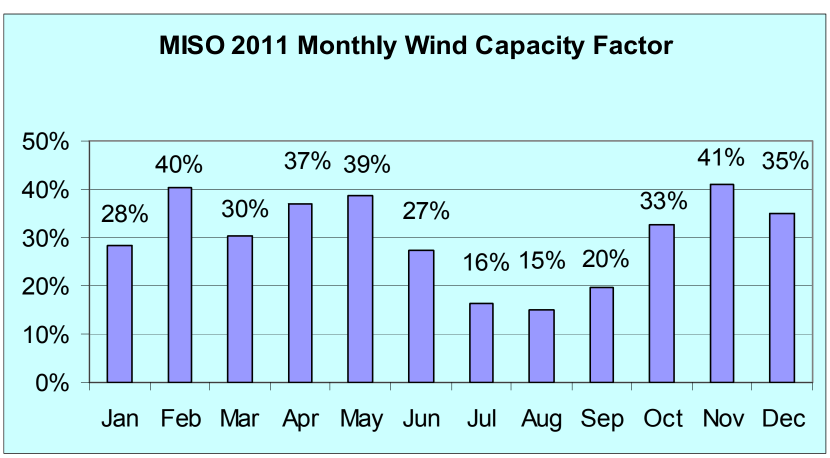
Although EIA reports electricity generation monthly by type of source and by state, it does not report installed wind capacity by month, and therefore does not report wind's capacity factor by month, either. The EIA does issue a forecast of the upcoming year's anticipated wind installations, by month, but does not update the forecast to match actual results.

One way around this problem is to divide EIA's monthly generation statistics [13] by the American Wind Energy Association's quarterly installed wind capacity reports [19], as shown in the following table, which indicates that wind's average measured nationwide annual capacity factor in 2011 was about 32%.

Table 11. Wind's Nationwide Average Annual Capacity Factor

	EIA 2011 Wind Generation (GWh)	AWEA 2011 Wind Capacity (GW)	Quarterly Average Capacity (GW)	**Quarterly Capacity Factor**
		40.3		
Jan	8888			
Feb	10528			
Mar	10452	41.4	40.9	**0.34**
Apr	12447			
May	11586			
Jun	10831	42.4	41.9	**0.38**
Jul	7364			
Aug	7429			
Sep	6883	43.6	43.0	**0.23**
Oct	10623			
Nov	12354			
Dec	10469	46.9	45.3	**0.34**
Total	119854			**0.32**

A second way is to refer to the Midwest ISO's monthly capacity factor report [20].



6.2 Wind's Capacity Value

Capacity value describes how much primary generation capacity the sum of all the wind installations in a given region can replace, or avoid the need to construct. It also determines what portion of a complementary plant's capital cost must be counted in wind's LCOE. Recent investigations into this value have been conducted by the National Renewable Energy Laboratory [21], the North American Electric Reliability Council [22], the IEEE Power and Energy Society [23], the Midwest Independent System Operator [24] [25], and EWITS [6].

Capacity value is typically computed by examining how much generation capacity wind can replace at hours of peak demand. Or, as the IEEE Power and Energy Society's Task Force on the Capacity Value of Wind Power defined it, "capacity value, or effective load carrying capability (ELCC), is the amount of additional load that can be served due to the addition of a generator, while maintaining the existing levels of reliability [23]." However, this definition is open to some disagreement, and it is not clear that the same statistical techniques should be applied to both traditional generation sources and wind generation.

Across any large region, there would typically be many traditional plants whose probabilities of failure are essentially independent. Thus, there is a low probability that more than a small number of such plants would suffer unplanned outages simultaneously. But wind generation is different. Since it is highly correlated across large regions, hours of low output from one facility are likely to coincide with hours of low output from all facilities in the region. Thus, the wind facilities across a large region act a single entity, which poses a much larger threat of insufficient output than aggregations of traditional independent sources.

Furthermore, the accuracy of any prediction about future wind availability at hours of peak demand depends on the length of the historical record on which the prediction is based. The longer the record, the more accurate any prediction is likely to be. But no such limitation applies to traditional generation sources. Not only are their historical records much longer, but their failure mechanisms can be investigated under controlled conditions.

One indication that wind's capacity value is different from the capacity value of traditional sources is the slope of the ELCC curve shown in Figure 11 below, which is Figure 5 from the IEEE Task Force's summary of prior work [23]. As wind penetration increases its capacity credit decreases, whereas for traditional sources, the addition of more capacity leaves the capacity credit per MW unchanged.

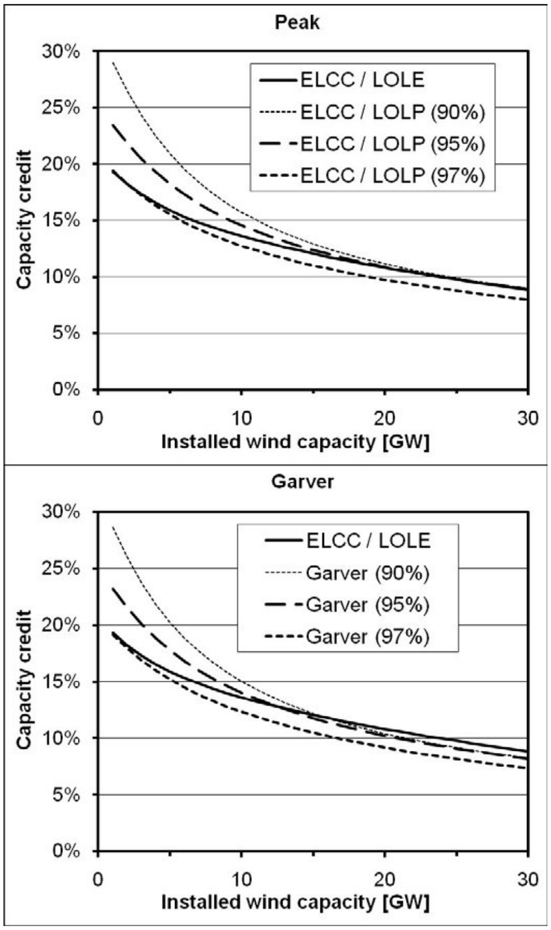


Figure 11 – Effective Load Carrying Capability of Installed Wind Capacity [23]

The IEEE Task Force also noted that computed wind ELCC values can vary widely from year to year, which means that the accuracy of predictions about future ELCC's depends on the number of years of data available. One Minnesota study cited by the Task Force [26] found a range of 4% to 20% across three years of data, as shown in Figure 12.

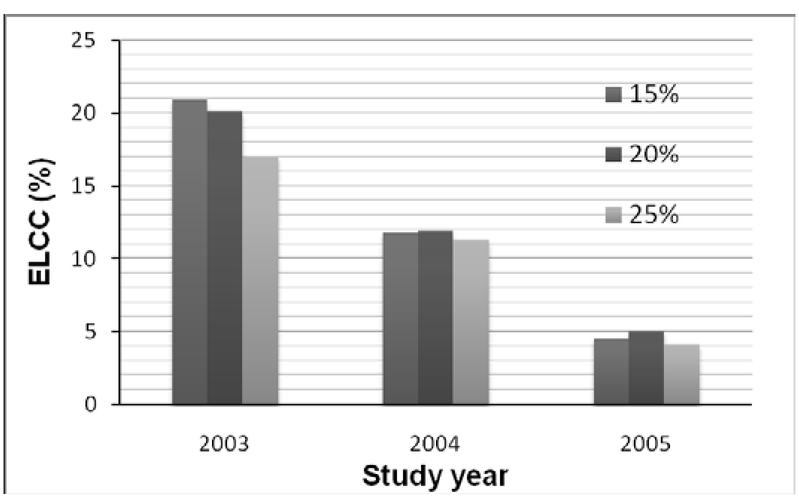


Figure 12 – ELCC from a Minnesota Public Utility Commission study [26]

Capacity Values Adopted By Regional System Operators

Table 12 summarizes the range of capacity values adopted by the major regional system operators. The most conservative operator (Bonneville Power) adopted a value of zero after experiencing a 9-day period in 2009 when wind generation remained essentially zero during a period of cold weather and high demand. Operators in areas with large wind capacity have computed values ranging from 5% (SPP) to 15% (Midwest ISO), although we note that only about half of Midwest ISO's 15% potential value has actually been used in capacity planning by its member organizations.

Midwest ISO's 15% potential value is also surprising because one would not expect it to be as high as wind's capacity factor for an entire month. Yet it matches wind's average capacity factor for the months of July and August 2011 (shown in Figure 11 above.)

Table 12. Wind Capacity Values Adopted by Regional System Operators

Regional System Operator	Computed Value	Default Value	Procedure (CF = capacity factor)
PJM		13%	3-year rolling average of CF from 2 to 6 PM, June thru Aug
New York ISO		10% summer 30% winter	rolling average of CF from 2-6 PM, June-Aug and 4-8 PM, Dec-Feb
ISO New England			5-year rolling average CF from 1 to 6 PM, June thru Sep and 5 to 7 PM, Oct thru May
Midwest ISO	15% potential 7% designated		Effective-load-carrying capability methodology
Southwest Power Pool	5.5% annual 5-15% monthly		15^{th} percentile of CF's during top 10% of load hours
Ercot -- Texas	8.7%		ELCC methodology
California ISO			3-year rolling average of 30^{th} percentile of CF's from 4-9 PM, Nov-March and 1-6 PM, Apr-Oct
Bonneville Power		0%	
Idaho Power		5%	
Xcel -- Colorado		12.5%	

Sources: Utility Wind Integration Group [27] and Southwest Power Pool [28]

Midwest ISO Summer Wind Production at Peak

To illustrate the variability of wind generation at peak hours, Table 14 shows "Wind Production At Peak" from Midwest ISO's latest generation resource assessment [24]. As column 4 of the table demonstrates, this value has ranged from 1% to 56% over the past six years. The column on the far right shows the percentage of nameplate capacity (the "Designated Capacity Value")

which Midwest ISO's member utilities have chosen to adopt as wind's capacity value for the purpose of reserve margin planning.

Table 13. Midwest ISO 2012 Summer Generation Resource Assessment					
Year	**Registered Max MW**	**Metered Wind at Peak Load MW**	**Metered % of RMax**	**Designated MW**	**Designated % of RMax**
2006	1251	700	**56**	148	**12**
2007	2064	44	**2**	147	**7**
2008	3085	384	**13**	224	**7**
2009	5636	78	**1**	290	**5**
2010	8179	1740	**21**	197	**2**
2011	9107	4492	**49**	382	**4**
2012	10791			765	**7**

Source: Table 4-4, Midwest ISO 2012 Summer Resource Assessment [24]

6.3 Special 5-Year Accelerated Depreciation

The following table illustrates the value of the subsidy for a hypothetical plant costing $1000 per kilowatt. Accelerated depreciation has the effect of deferring tax liability from the first 6 years of the plant life into the following 14 years, which results in a lower estimated total cost because future liabilities are discounted relative to current liabilities. If the 20-year depreciation schedule which applies to most technologies had been used instead, the net present cost would have increased from $1216 to $1336, or 10%. Depreciation schedules taken from CCH [29].

Year	Debt 50% 0.07	Equity 50% 0.11	Inc Tax 0.65	Principal	Accel Depre-ciation	Deferred Inc Tax 0.393	Property Tax 1.235	Sum	Discount Factor 1.075	Net Present Value
1	35	55	36	50	350	-124	12	64	1.1	60
2	33	52	34	50	260	-89	12	93	1.2	80
3	32	50	32	50	156	-49	12	127	1.2	102
4	30	47	30	50	110	-31	12	138	1.3	103
5	28	44	28	50	110	-32	12	131	1.4	91
6	26	41	27	50	14	5	12	162	1.5	105
7	25	39	25	50		10	12	160	1.7	96
8	23	36	23	50		9	12	153	1.8	86
9	21	33	21	50		8	12	146	1.9	76
10	19	30	20	50		8	12	139	2.1	68
11	18	28	18	50		7	12	132	2.2	60
12	16	25	16	50		6	12	125	2.4	53
13	14	22	14	50		6	12	118	2.6	46
14	12	19	12	50		5	12	111	2.8	40
15	11	17	11	50		4	12	104	3.0	35
16	9	14	9	50		3	12	97	3.2	31
17	7	11	7	50		3	12	90	3.4	26
18	5	8	5	50		2	12	83	3.7	23
19	4	6	4	50		1	12	76	4.0	19
20	2	3	2	50		1	12	69	4.2	16
total	368	578	374	1000	1000	-246	247			**1216**

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Year	5-year depre-ciation	20-year depre-ciation	Diff	* Tax Rate 39;3%	Discount Factor 1.075	Net Present Value
1	350	66	284	112	1.1	104
2	260	70	190	75	1.2	65
3	156	65	91	36	1.2	29
4	110	60	50	20	1.3	15
5	110	55	55	21	1.4	15
6	14	51	-38	-15	1.5	-10
7		47	-47	-19	1.7	-11
8		45	-45	-18	1.8	-10
9		45	-45	-18	1.9	-9
10		45	-45	-18	2.1	-9
11		45	-45	-18	2.2	-8
12		45	-45	-18	2.4	-7
13		45	-45	-18	2.6	-7
14		45	-45	-18	2.8	-6
15		45	-45	-18	3.0	-6
16		45	-45	-18	3.2	-6
17		45	-45	-18	3.4	-5
18		45	-45	-18	3.7	-5
19		45	-45	-18	4.0	-4
20		50	-50	-20	4.2	-5
sum	1000	1000	0			**120**

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