Are Renewables Portfolio Standards Cost-effective Emission Abatement Policy?

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Renewables portfolio standards (RPS) could be an important policy instrument for 3P and 4P control. We examine the costs of renewable power, accounting for the federal production tax credit, the market value of a renewable credit, and the value of producing electricity without emissions of SO_2, NO_x, mercury, and CO_2. We focus on Texas, which has a large RPS and is the largest electricity producer and one of the largest emitters of pollutants and CO_2. We estimate the private and social costs of wind generation in an RPS compared with the current cost of fossil generation, accounting for the pollution and CO_2 emissions. We find that society paid about 5.7 ¢/kWh more for wind power, counting the additional generation, transmission, intermittency and other costs. The higher cost includes credits amounting to 1.1 ¢/kWh in reduced SO_2, NO_x, and Hg emissions. These pollution reductions and lower CO_2 emissions could be attained at about the same cost using pulverized coal (PC) or natural gas combined cycle (NGCC) plants with carbon capture and sequestration (CCS); the reductions could be obtained more cheaply with an integrated coal gasification combined cycle (IGCC) plant with CCS.

Introduction

The more than 50% of the US's electricity generated by coal emits large amounts of air pollutants and CO_2. Renewable portfolio standards (RPS) in several states have been enacted to deal with these problems, as well as with fluctuating prices of fossil fuels, energy independence, diversity of fuel supply, sustainability, and job creation. Fifteen U.S. states and the District of Columbia have enacted some form of renewables policy for electricity generation (*1*). We focus on Texas because one of the most stringent RPS was enacted in that state in 1999 and because Texas produces ten percent of all electric power in the United States, nearly twice as much as the next largest state. Texas power generation in 2002 resulted in emission of 5.7×10^8 kg of SO_2 (6% of the U.S. total), 3.1×10^8 kg of NO_x (14%), 4.7×10^3 kg of mercury (10%), and 2.5×10^{11} kg of CO_2 (19%) (*2*, *3*). Texas renewable generation in 2002 accounted for 0.72% of all Texas electric generation.

Here we quantify the costs associated with the Texas RPS, accounting for the zero direct pollution and CO_2 emissions. We do not account for the value of sustainability, since the US has vast coal reserves.

Characteristics of the 2002 renewables market in Texas

We focus on Texas in 2002, the first year of the program for which full data are available. Langniss and Wiser (*4*) describe the 2002 program features. Two studies argue that an RPS with tradable renewable energy credits (RECs) such as in Texas provides an efficient mechanism for increasing renewables' share of net generation (*5, 6*). The Texas RPS requirement for 2002 was 400 MW from renewables installed between September, 1999 and December, 2002. This is converted into an energy requirement of 1.23×10^6 MWh via a "capacity conversion factor" of 35%, set by the Electric Reliability Council of Texas (ERCOT). Older renewables count toward an overall goal.

Since 80% of the electricity in Texas is sold under retail competition (*7, 8*), the RPS is implemented by requiring load-serving entities (LSEs) open to retail competition to secure Renewable Energy Credits (RECs) as a *pro rata* share of their sales. One REC is defined as one MWh of renewable energy produced. The otherwise-predictable targets of the Texas RPS are blurred by ERCOT's authority to change the capacity factor biennially (for 2004 and 2005, it was lowered to 27%; the measured capacity factor for wind farms installed at the best wind conditions in Texas is 37% (*9*)).

Renewable sources added in response to the Texas RPS between September 1999 and December, 2002 are shown in the middle column of Table 1. The "total capacity certified under RPS" designation in the right column includes 225 MW of renewables installed prior to September, 1999 and going to LSEs.

Table 1. Texas new renewable capacity added in response to the RPS (middle column) and total capacity (right), including generation which pre-dated the RPS (*8*)

Technology	Texas capacity (MW) installed 9/99 - 12/02	Total capacity (MW) certified under RPS
Biomass	5.40	5.40
Hydroelectric	10.3	116
Landfill Gas	30.7	34.0
Solar	0.17	0.17
Wind	942	1058
Total	**989**	**1214**

Table 2. Texas 2002 electric data (*7,8*)

Net generation (MWh)	3.86×10^8
In-state competitive load sales (MWh, all sectors)	2.50×10^8
RPS new source obligation[a] (REC = MWh)	1.23×10^6
RPS pre-existing generation used as offset credits[b] (MWh)	3.42×10^5
Actual RPS new source generation (MWh)	2.17×10^6
Actual RPS pre-existing generation (MWh)	6.07×10^5
Total RPS generation (MWh)	2.79×10^6

[a] Calculated per ERCOT as 400 MW at 35% capacity for 8760 hours. [b] The Public Utility Commission of Texas (PUCT) used the average generation for the decade prior to the start of the RPS to calculate a capacity factor of 24.5% for the older units (*10*).

Some LSEs buy more renewable power than their requirement. They are allowed to sell the RECs unbundled from power to LSEs that are short of renewables. When new source generation exceeds the new source obligation, as it did in 2002, RECs can be banked for 2 years. Not surprisingly, spot and long-term REC prices in 2002 were similar.

Before 2004, LSEs faced penalties if they failed to meet 90% of the obligation shown in Table 2 (*11*); after that year, they are expected to meet the entire obligation.

Costs

87% of the Texas renewables capacity in 2002 was from wind. The cost of wind power without any subsidies or other credits is derived from the capital cost of the turbine, the annual maintenance and the number of hours that it produces power. Assuming that the capital cost of a turbine is $1,000/kW, a combined interest and depreciation of 10% per year over a 15-year capital life, a capacity factor of 35% and annual operations and maintenance (O&M) costs of $25/kW, wind power would cost 5.1 ¢/kWh.

Capital and operations costs are associated with generation or storage (which is required from other sources to buffer the intermittent nature of wind). Although Scandinavian hydroelectric power is used to buffer wind in western Denmark, the 9:1 ratio of wind to hydroelectric capacity in Texas means that hydropower is insufficient to buffer wind, in contrast to the 1:34 capacity ratio in Denmark. DeCarolis and Keith (*12*) find that capacity reserves to maintain system security and non-marginal intermittency costs of wind at all levels of wind penetration (principally gas-fired generation) amount to 1.1 ¢/kWh. Strbac (*13*) found 0.9 – 1.2 ¢/kWh for such costs in the U.K.

The owner of a wind turbine would find that these costs are reduced by the federal production tax credit for wind (PTC). Assuming that the wind turbine were owned by a company also owning a coal fired facility whose generation was curtailed for each MWh generated by the wind turbine, the owner would also be able to sell SO_2 and NOx emission allowances no longer needed by the coal plant. In addition to the PTC, society subsidized wind power by paying the costs arising from transmission curtailment, construction of new transmission lines to relieve congestion, and RPS administration.

Federal Production Tax Credit

The U.S. Energy Policy Act of 1992 created a production tax credit (PTC) for renewable facilities placed in service between December 31, 1993 and June 30, 1999 for the first ten years of the facility's existence. Wind and biomass that is grown for the sole purpose of electricity production qualified. The PTC was later extended to facilities placed in service by December 31, 2003. In October, 2004, the PTC was extended for facilities operating by the end of 2005, including for the first time open-loop biomass, geothermal, solar, small hydro and municipal solid waste power (the PTC for some of these has a 5 year limit). The PTC acts to reduce corporations' federal tax burden towards levels where only the Alternative Minimum Tax applies, as a component of the General Business Credit (GBC). While the GBC carry-back period is limited to one year, the carry-forward period is 20 years (for credits accruing in 1998 or later), making the

PTC particularly attractive. While not a direct payment, the PTC is a significant incentive. We assume that the PTC is used and so is a federal tax expenditure.

If an RPS brings more expensive generation into the production mix, it raises the dollar cost of producing electricity and so increases retail prices. This is true only if the RPS sets targets which bind (Maine's RPS, for example, merely ratified the status quo in hydro generation). A PTC does not affect generation costs, but the tax expenditure must be paid from raising other taxes, increasing borrowing, or cutting government programs. Evaluating the social costs of the increased retail price due to an RPS or the effects of raising taxes, increasing borrowing, or cutting other programs is beyond the scope of this paper.

One argument for a PTC is that it equalizes the costs between wind and other sources of electricity. Under the assumptions discussed above, the cost of production (capital + O&M) of wind power is 5.1 ¢/kWh. Since the spot price of electricity in Texas in 2002 averaged 3 ¢/kWh (*14*), the 1.8 ¢/kWh PTC did make wind power nearly competitive with other generation.

Table 3: Wind projects in Texas as of 2002 (*15*, *16*, *17*)

Project	Capacity (MW)	Date placed in service	Power purchaser
King Mountain Wind Ranch	278	July - December 2001	Austin Energy (76.7 MW); Reliant (198.9 MW); TNMP (2.6 MW)
Desert Sky (Indian Mesa II)	161	December 2001	City Public Services of San Antonio
Woodward Mountain Ranch	160	April 2001	TXU
Trent Mesa	150	August 2001	TXU
Indian Mesa I	82.5	December 2001	LCRA (51 MW); TXU (31.5 MW)
Llano Estacado Wind Ranch	80	November 2001	Xcel Southwestern Public Service
Southwest Mesa	74.9	May 1999	AEP
Big Spring Wind Power	34.3	April - June 1999	TXU
Delaware Mountain Wind Farm	30	June 1999	LCRA
(Fort Davis Wind Farm)	6.6	September 1999	AEP (decommissioned in April, 2002)
Hueco Mountain Wind Ranch	1.32	March 2001	El Paso Electric
TOTAL	**1058**		
Total qualifying for RECs (September 1999 and later)	**942**		

Wind generators placed in service during and before the period examined here (Table 3) were eligible in 2002 for a federal production tax credit of 1.8 ¢/kWh. Texas production of wind power during 2002 by facilities qualifying for the RPS totaled 2.45 x 10^6 MWh, for a total PTC cost of $44.1 million.

Curtailments

The rapid building of wind generators in West Texas (Tables 1 and 3) outstripped transmission capacity. Congestion prevented full transmission of wind power generated in West Texas to load centers in the populous east. To mitigate this congestion, ERCOT asked wind producers to curtail 380,000 MWh, 13% of the wind power that would have been generated in the absence of such restrictions ([18]). ERCOT compensated wind producers for the curtailments with payments of $9.1 million (2.4 ¢/kWh curtailed) during 2002. The costs were passed along to consumers as an uplift charge (*18*).

In addition, a $10 million fund was set up in 2002 by ERCOT to compensate wind producers for "the value of lost tax credits and renewable energy credits, both of which normally accumulate value on the basis of actual output" (*19*, *20*, *21*). We note that the value of the foregone PTC due to 2002 curtailments was $6.84 million. This fund was fully expended, and the costs passed through to consumers. The fund was used for curtailment compensation in both 2002 and 2003 (it was fully expended by April, 2003). Since 89% of the curtailments for those two years occurred in 2002, we assigned this fraction of the cost ($8.9 million) to that year.

Total curtailment costs for 2002 were $18.0 million (4.7 ¢/kWh curtailed).

Transmission

The areas in West Texas with wind farms had little generation previously and are located far from load (prior to the wind building boom, the only generator had been a 140 MW gas unit at Rio Pecos, serving the cities of Odessa and San Angelo via 138 kV lines). The remote location of wind generation in Texas makes it possible to account for the transmission costs which should be allocated to wind. In 2001, 681 MW of wind generation was constructed in west Texas. The wind related transmission identified for this area includes 28 projects with budgets from approximately $68 thousand to $20 million, totaling $128 million (*22*, *23*), as listed in Table 4. Construction for these projects began in early 2001, and the last will be completed in 2005. Twenty 138 kV lines are under construction; some were upgraded from 69 kV lines while some are new lines.

The annual amortized cost of these 28 transmission projects, assuming a forty year lifetime of transmission lines and a 10% interest rate, is $13.0 million per year.

RPS Administration

LSEs incur costs in managing their renewable portfolio. Large companies such as TXU estimate that they use ½ full-time equivalent (FTE) employee to manage their renewable mandate (*24*). In smaller retail companies, RPS management is estimated to require 5% of an FTE (*25*). Since these administrative costs for LSEs represent a small fraction of overall cost, we neglect them in our calculations.

ERCOT manages the REC program. ERCOT estimates that 1.5 FTE support their RPS work. Total ERCOT annual administration cost is estimated to be $240,000 (*26*). ERCOT contracted for development of the electronic tracking system for RECs. While the winning bid price has not been released, the received bids ranged from $500,000 to $3,000,000 (*26*). To estimate the system capital cost, we averaged these. Amortizing this over the 7-year life of the RPS, at an interest rate of 10% gives an annual cost of $360,000.

The Department of Market Oversight at the Public Utility Commission of Texas estimates that less than one FTE is engaged in RPS related work. The total annual RPS administration cost for the PUCT is estimated as $50,000 (*27*). The Public Utility Commission of Texas completed six internal projects specifically related to implementing the RPS (Table 5).

Table 5. PUCT projects undertaken in support of the RPS (*28*)

PUCT Project number	Number of staff hours	Project timeline
20944	1551	06/1999-12/1999
22200	106	02/2000-01/2001
26848	193	10/2002-02/2003
26912	157	11/2002-01/2003
28407	53	08/2003-02/2004
29595	6.5	4/2004

Staff time totaled 1 FTE. Thus, we estimate that at an average FTE cost of $62,500, the PUCT implementation cost was $62,500, giving an annual amortized cost of $13,000.

Total non-LSE RPS administrative annual costs were $663,000, composed of the two ERCOT and two PUCT components identified above.

Summary of 2002 Texas RPS costs

Production Tax Credit	$44,100,000
Curtailments	$18,000,000
Transmission	$13,000,000
RPS Administration	$663,000
Total	**$75,763,000**

When divided by the total RPS generation (Table 2), this cost represents 2.7 ¢/kWh. Since the intent of the RPS was to stimulate new renewable generation, the cost should be divided by the energy generated by new sources (Table 2); when the PTC cost of existing generation is removed and curtailment costs are pro rated between new and existing renewables, the incremental cost becomes 3.1 ¢/kWh. We stress that this is not the cost of generation, but rather the additional cost of the administration and subsidy for RPS.

2002 was an unusual year for transmission curtailments; the transmission projects listed in Table 4 are designed to relieve most congestion in subsequent years. Removing the payments for curtailments (but adding in the cost of the PTC for MWh which would no longer be curtailed), the incremental cost of transmission, administration and subsidy would become 2.7 ¢/kWh for new source generation (the RPS administration costs are very small; this 2.7 ¢/kWh is composed mainly of the 1.8 ¢/kWh PTC and 0.9 ¢/kWh for transmission).

These costs do not include costs of reserves to maintain system security or costs of intermittency, which are estimated by the studies discussed above (*12*, *13*) to add approximately 1.1 ¢/kWh at the level of wind penetration in Texas in 2002. Thus, for new source generation the total cost of administration, subsidy, and maintaining power quality was 4.2 ¢/kWh in 2002 would be expected to decline to 3.8 ¢/kWh after transmission is no longer constrained.

Carbon mitigation cost comparison

One of the quantifiable goals of a renewables portfolio standard is reduction of pollution and CO_2 emissions from electric power generation. This would be true if the renewables displaced fossil fuel generation that was subject to a constraint on each plant (such as in New Source Performance Standards). It need not be true if the plants are governed by a cap and trade system. In the former case, each fossil MWh displaced by a renewable source would lower pollution and CO_2 emissions. In a cap and trade system, the total emissions of SO_2, NO_x, mercury (if a 3P system is enacted), and CO_2, (if 4P) is fixed. Generating plants buy and sell the allowances to emit these gases, but the total quantity is frozen. If, for example, a wind turbine displaced a MWh from a coal plant, the coal plant could sell its SO_2 emission allowances. These would be purchased by another coal plant that would use them to offset greater use of low price, high sulfur coal. If the number of SO_2 emissions allowances (the cap) is not reduced, total SO_2 emissions are unlikely to fall. The price of an SO_2 emissions allowance would fall, reducing the cost of generation from coal plants, but the air is unlikely to be cleaner. If society wanted the air to be cleaner, the cap and trade program could be modified to reduce the number of allowances by the current emissions of any fossil plant displaced by renewables.

The above conclusions assume that the caps will continue to be binding. If, for example, high sulfur coal were to become more expensive per BTU than low sulfur coal, the cap might cease to be binding and the RPS would improve air quality.

We seek to estimate the costs of controlling CO_2 emissions via an RPS. Since renewables don't generate pollutants or CO_2 , we need to account for these benefits in order to estimate the net cost of CO_2 control.

Fossil generators displaced by renewables due to economics of pollution control are likely to be lower efficiency units with high emissions rates. Palmer and Burtraw (*29*) find that renewables displace mainly gas generators in their model, but gas prices in 2002 were high enough that many gas generators in Texas and elsewhere were already idle. We assume here displacement of an older coal generator with a 12,000 BTU/kWh heat rate.

Approximately 50 million tons of Powder River Basin (PRB) coal are shipped to Texas each year because of its low sulfur content (*30*). Although the coal costs only $7 per short ton as it goes on the rail car in Wyoming, it costs $17 – 29 per short ton when it is delivered in Texas. It contains 16,680,000 BTU per short ton. Using the average of $23 per short ton, the PRB coal fuel cost for our older generator is 1.65 ¢/kWh. We will use 0.2 ¢/kWh for non-fuel O&M costs, for a total of 1.85 ¢/kWh.

Coal plants, like wind generators, require transmission lines. However, coal generators are sited much closer to load than wind. The wind farms near McCamey, Texas are located 600 km from load in Houston and Dallas, while the average distance from Texas coal generators is 150 km to the same cities (*31*). Under the assumption that transmission costs scale linearly with distance, the direct transmissions cost which should be assigned to coal plants in the state would then be ¼ of the 0.9 ¢/kWh computed above for the Texas wind transmission, or 0.23 ¢/kWh.

The PRB coal contains 0.4% sulfur. Thus, .0114 pounds of SO_2 are released per kWh. Sulfur dioxide allowances in 2002 sold for $880 per short ton. Assuming that a wind farm would displace electricity from this coal plant, it would have either allowed the utility to buy fewer SO_2 emission allowances or to have sold some of its existing emissions allowances at the market price of $880 per short ton. Not having to buy emissions allowances would save the utility 0.5¢ for each kWh of power displaced from the coal plant by the wind farm, assuming that total emissions are reduced by the full amount displaced.

This old coal plant also emits NO_x and (if it is in a controlled region) must buy allowances for each ton emitted or could sell some of its current allowances if there were fewer tons emitted. We calculate the amount of NO_x that would not be generated if a wind farm displaced some coal fired power using the Oak Ridge National Laboratory average emission rate of .0053 pounds of NO_x per kWh (*32*) and value this at $750 per short ton, a 2002 price. Thus, the utility would save 0.2¢ for each kWh displaced.

The average Hg emission rate for Texas coal plants in 2002 was 7.2×10^{-8} pounds per kWh. Using the EPA's estimate that Hg allowances might trade for $55,000 per pound (*33*), the utility would save 0.4¢ for each kWh displaced if a mercury cap were binding.

We first compute the private costs to the utility. With the PTC of 1.8 ¢/kWh, the 5.1 ¢/kWh capital and O&M cost of wind calculated above would be reduced for the utility to 3.3 ¢/kWh. Assuming that the wind turbine displaced a coal plant, the utility would save the cost of coal and would be able to sell allowances. The utility would save the cost of the coal, non-fuel O&M, SO_2 allowances, and NO_x allowances for each kWh displaced by the wind farm: 1.65 + 0.2 + 0.5 + 0.2 = 2.55¢ for each kWh displaced. If Hg caps were added, the total savings would be 2.95 ¢/kWh. The utility would still not recover the full cost of wind power.

However, if CO_2 control were added, this would change. Texas coal-fired plants in 2002 emitted 1.015×10^{-3} metric tons of CO_2 per kWh (*34*). Breaking even would require that the value of the CO_2 displaced would have to be greater than 3.3 – 2.95 = 0.35 ¢/kWh, or $3.45 per metric ton of CO_2 ($13 per metric ton of C). If the PTC were eliminated, the price of CO_2 would have to be at least $21.20 per metric ton of CO_2 ($78/metric ton C).

We now compute the public costs. In Texas in 2002, the administrative, transmission, and intermittency costs added 4.2 ¢/kWh to the cost of wind. This cost is expected to decline to 3.8 ¢/kWh after unusual transmission congestion costs are eliminated. That means that the public cost of wind is 5.1 ¢/kWh plus 3.8 ¢/kWh or a total of 8.9 ¢/kWh. The cost of the old coal plant is 2.95 ¢/kWh, including the SO_2, NO_x, and Hg emissions. We add 0.23 ¢/kWh for transmission as estimated above, getting 3.2 ¢/kWh for the public cost of coal-fired generation from our old (fully amortized) generator. Thus, the people of Texas and the US taxpayers supporting the PTC were paying 8.9 – 3.2 = 5.7 ¢/kWh for CO_2 abatement, sustainability and energy security, or $56 per ton of CO_2 ($205/metric ton C), if it were allocated to CO_2 abatement.

The 3.8 ¢/kWh costs are not likely to be significantly lower in other areas. The best wind sites are not located close to electricity customers and so transmission costs are likely to be high. Similarly, the intermittency costs are real and must be paid.

However, wind power reduced the mining and transport of coal, preventing undesirable land use and other environmental consequences, nuisance from the rail transport, and deaths and injuries from the rail transport. In addition, in displacing coal, wind turbines made electricity generation more sustainable. The RPS may have reduced the costs due to fluctuating prices of fossil fuels, and supported the goals of energy independence, diversity of fuel supply, and job creation. We do not in this work quantify these costs, but conjecture that they are much smaller than 5.7 ¢/kWh.

Discussion

The Texas RPS, acting in concert with the federal production tax credit, encouraged the construction and operation of renewable generation which avoided in 2002 3300 metric tons of SO_2 emissions, 1800 metric tons of NO_x, 27 kg of Hg, and 1.4 million metric tons of CO_2.

Having quantified the costs associated with the Texas RPS and the avoided emissions, we return to the question "is the Texas RPS a cost-effective method of achieving these objectives?" Rubin, Rao, and Chen (*35*) have reviewed 11 recent studies on the range of costs using commercial power generation and CO_2 capture. Table 6 compares ranges of costs for several options for carbon dioxide removal from power plants from their review. The range these studies find for costs of CO_2 avoided using IGCC with CCS is \$13 – 37 per metric ton. Applying this range to the Texas emission rate, CO_2 control in the state using IGCC generation would result in incremental costs of 0.8 – 2.4 ¢/kWh, compared to the RPS cost of 5.7 ¢/kWh (after credits for 3P control are given to the RPS). Our estimates do not include the benefits of achieving a more renewable generation mix, shielding part of the generation from the fluctuations in fossil fuel prices, increasing energy security and eliminating the uncertainty surrounding where CO_2 injected deep underground will stay in place for the required time.

Table 6. Cost comparison of several CO_2 removal options. Parenthetical ranges are for the 11 recent studies reviewed by Rubin et al. (*34*), while the given values are their Integrated Environmental Control Model (IECM) values.

Technology	Cost per metric ton CO_2 avoided	Cost per metric ton C avoided
IGCC with capture and sequestration	\$29.50 (13-37)	\$108 (48-136)
PC with capture and sequestration	\$51.20 (42-55)	\$188 (154-202)
NGCC with capture and sequestration (cost of fuel \$4/GJ in Rubin et al.)	\$58.70 (35-74)	\$215 (128-271)

A carbon tax of at least \$56 per ton of CO_2 would make wind power, including intermittency and transmission costs, competitive with older coal generation without the PTC. It is quite possible that the capital expense for land-based wind may decline to \$800/kW and the annual operating and maintenance cost to \$15/kW (however, we note that increases in materials prices have driven up current installed costs for wind turbines to \$1300 per kW or more). This would lower the direct generation cost of 5.1 ¢/kWh to 3.9, reducing the total public cost from 8.9 ¢/kWh to 7.7 and the implied CO_2 price to \$45 per ton (\$165 per metric ton of carbon). The latter number is within the range of estimates for carbon capture for PC and NGCC units, but significantly higher than estimates for the cost of IGCC with CCS.

Cost of CO_2 avoided are one metric for evaluating policy, but a broader measure is the cost of electricity with 4P control. The lowest avoidance cost does not imply the lowest cost of electricity, since the latter includes capital and O&M costs, which vary among the technologies. Further work is required to quantify fully the cost of electricity from wind serving 30% of demand.

Renewables portfolio standards are attractive politically because they accomplish multiple objectives with one policy, and are not perceived as a tax. Broader alternative energy portfolio standards (AEPS) legislation like that recently enacted in Pennsylvania includes IGCC, and thus addresses directly the issue of carbon control within the framework of a politically palatable mechanism. However, an RPS is somewhat more expensive than a CO_2 tax, cap and trade system, or renewable subsidy. Since Americans spend $250 billion per year on electricity, it is important to attain environmental objectives at least cost. We favor focusing on the environmental goals rather than subsidizing a particular technology in order to encourage innovation.

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Table 4. Wind related transmission projects in Texas (*23*)

Project Name	Description	Cost of project ($US)	Amortized cost per year (40 years, 10% interest, $US)
Fort Lancaster/Friend Ranch	New double-circuit capable 138 kV transmission line, Fort Lancaster to Friend Ranch	$ 20,189,177	$ 2,064,533
Rio Pecos - Mesa View 138	Rebuild the existing 138kV H-Frame line.	$ 11,401,500	$ 1,165,911
Crane-Midkiff 69 kV Line, Convert to 138 kV	Rebuild existing 69 kV wood H-Frame line with new 138 kV single pole structures and one circuit of 1233.6 kcm ACSS/TW conductor	$ 9,800,000	$ 1,002,142
Rio Pecos - Crane 69 kV Rebuild	Rebuild existing 69kV H-Frame line with single pole, double circuit capable construction.	$ 9,721,600	$ 994,125
S. Abilene to Eskota Reconductor	Reconductor and rebuild approximately 25.7 miles of existing 138kV line.	$ 9,275,000	$ 948,456
N McCamey - LCRA Crane Tap Reconductor	Rebuild 25 miles of existing N McCamey to McElroy 69kV to 138kV	$ 8,748,410	$ 894,607
Mesa View - Ft. Lancaster	Rebuild the existing 138kV H-Frame line.	$ 8,342,686	$ 853,118
Crane-Odessa EHV 138 kV line, Rebuild and Upgrade Capacity	Rebuild existing wood H-Frame line with 138 kV single Pole, and extend line to new Crane LCRA station	$ 8,100,000	$ 828,301
Spraberry-Midkiff 138 kV Line	Rebuild approximately 26.2 miles of existing wood H-Frame line with new 138 kV single pole structures and one circuit of 1233.6 kcm ACSS/TW conductor	$ 6,850,000	$ 700,477
N. McCamey-to-McElroy/N. McCamey	Add a second 138-kV circuit to existing North McCamey to McElroy/North McCamey Cut-In line	$ 5,210,242	$ 532,796
N McCamey- McCamey - Tippett	Rebuild 13.46 miles of 69kV line to 138 kV	$ 4,990,000	$ 510,274
Rio Pecos - N McCamey	Rebuild the existing 138kV H-Frame line.	$ 3,932,021	$ 402,086
Tippet to W Yates Tap Reconductor	Rebuild 9.98 miles of 69kV to 138kV	$ 3,803,891	$ 388,984
North McCamey/Southwest Mesa Tap	New double-circuit capable 138 kV line from North McCamey to the SW Mesa Tap	$ 2,726,238	$ 278,784
N. McCamey-to-Rio Pecos 2nd Ckt Addition	Add a second 138-kV circuit to the existing North McCamey to Rio Pecos line	$ 2,583,808	$ 264,219
System Improvements for FPL Wind Farm	Conversion of 69kV line and substations to 138kV for interconnection of wind power.	$ 2,395,000	$ 244,911
Mesa View - Mesa View Switch 138kV Line	Rebuild the existing Mesa View - Mesa View Switch 138kV H-Frame line.	$ 2,267,387	$ 231,862
W Yates Tap - West Ytes Pump	Rebuild existing 69kV H-Frame line with single concrete pole, double circuit construction.	$ 2,019,654	$ 206,529
Eskota - S. Abilene 138 kV: Rebuild	Rebuild the 5.61 Eskota - S. Abilene 138kV line.	$ 1,201,960	$ 122,912
Crane-McElroy/McCamey North Cut-In Line	New 138 kV line from Crane to tie into existing McElroy/McCamey North line	$ 1,026,160	$ 104,935
Rio Pecos - Crane Line Extension	Extend the existing 138kV H-Frame line.	$ 900,000	$ 92,033
Crane to McElroy Cut-In 69 kV	Construct 1.57 miles of 69 kV from Crane to the McElroy/N. McCamey Cut-In	$ 748,326	$ 76,523
Crane Line Extension	Extension of the Rio Pecos - Crane 69 kV rebuild into the new LCRA Crane Switching Station.	$ 358,768	$ 36,687
Crane (LCRA)- Crane (Oncor) 138 kV Tie Line	Rebuild existing line and construct an extension of the Crane to Odessa line to connect Oncor's existing Crane Sw. Station and LCRA's new Crane Sw. Station.	$ 350,000	$ 35,791
W Yates Pump - Mesa View	Install approximately 300' of single circuit 2-795, 138kV line.	$ 200,000	$ 20,452
Crane Bus-Tie Extension	Extend 138kV line from AEP Texas North Crane Substation to LCRA Crane Switching Station	$ 200,000	$ 20,452
Morgan Cr. - Mulberry Cr. 345 kV: Line Changes for LCRA Bitter Cr. Sw. Station	Connect the existing 345 kV circuit to two new steel angle towers and relocate one steel pole.	$ 175,000	$ 17,895
US 87 Morgan Creek-Spraberry 138 kV	Replace and relocate.	$ 67,890	$ 6,942
TOTAL		**$127,584,718**	**$13,046,737**

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