

CUTTING EMISSIONS - COMPARING GREENHOUSE GAS ALLOWANCE PRICES AND OPTIONS FOR MEETING CO2 EMISSION TARGETS AT TWO UTILITIES

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Overview

Utilities are grappling with two potentially conflicting forces these days. First, there is the chill wind of the economy, which has slowed growth in sales and pulled down expected revenues. Second is the increased commitment to cut greenhouse gas (GHG) emissions. Given that there is almost certainly going to be increased pressure to reduce the level of GHG from their operations, utilities will be exploring options to reduce their carbon footprint with the smallest adverse impacts on rates, costs, and margin.

Congress has pointed the way in outlining how it believes GHG reductions should be tackled: increasing generation using both renewable energy sources and increasing conservation through greater energy efficiency. The U.S. House of Representatives has debated these issues before passing the American Clean Energy and Security Act of 2009 (ACESA) introduced by Chairman Henry A. Waxman (D-CA) of the Energy and Commerce Committee and Chairman Edward J. Markey (D-MA) of the Energy and Environment Subcommittee. Now it is up to the Senate to debate its energy vision. ACESA provides for utilities to increase investments in both renewables and energy efficiency as ways to reduce carbon emissions. One of the problems utilities have with promoting energy efficiency as a solution is that it reduces GHG emissions but also reduces electricity sales. Renewable energy deployment does not involve the sales reduction problem, but is often accompanied by increasing average and marginal costs. Which is the best alternative for a utility to pursue, and is it possible to tell how much better?

This paper explores how to address the question and looks at the issue empirically using 2008 data for two utilities. It sets up experiments to compare costs for voluntary renewable power programs at two utilities in 2008: the Tennessee Valley Authority (TVA) and one of the utilities purchasing power from the Pennsylvania, New Jersey, Maryland (PJM) Interconnection (PJM Utility X). TVA is the largest federally-owned public utility in the United States, whose service

area touches on seven states centered on the state of Tennessee. It is a wholesale power producer, selling to 158 power distributors (rural electric cooperatives and municipal systems) and 59 directly-served customers (large industrial, commercial and federal consumers). The details of PJM Utility X were obtained from publically available information, and should be considered representative of a general eastern utility rather than specific to any particular utility.

Using hourly load and market price data, this study identifies what the price of GHG allowances would have to have been for renewable energy investment programs in place in 2008 to have had a positive effect on each utility's margin if they had been paying the market price of electricity as their opportunity cost and assuming that rates were allowed to increase to cover the price of GHG allowance savings. It then explores what the GHG allowance price would need to have been to cover the price of the energy efficiency programs in place at TVA, and a similarly-sized program at PJM Utility X. The exercise confirms what other authors have discovered (Peters, 2009), that energy efficiency is the least-cost option for utility investment in reducing GHG emissions, even after considering the reduction in revenues. That does not mean it is necessarily the least-cost overall option, since the investment in capital equipment to implement the energy efficiency option is assumed to be made by the customer and is not paid for by the utility. What is interesting in the comparison of the utilities is that pricing under PJM used in the exercise for the opportunity costs for PJM Utility X actually resulted in a revenue increase with the reduction in sales. For TVA, using pricing from the Entergy hub, the reduction in sales did result in reduced revenues.

Method

Utility Margins (M) are defined as a function of Revenues (R) and Costs (C)

$$(1) \quad R - C = M$$

Revenues are a function of prices paid (r) and quantity sold (q) in each hour (i):

$$(2) \quad R = \sum_{i=1}^{8760} r_i q_i$$

Prices paid by consumers for electricity are defined through a complex set of rate schedules, often differing by class, by demand and energy components, some by time-of-use, others by having different customer charges, fuel adjustment charges, special fees or allowances, and so forth. For simplicity in this analysis, average price was identified quarterly from the company's 10-Q or 10-K filing, and represents average revenues divided by kWh sales for the quarter.

Costs are a function of dispatch costs, other variable costs, and fixed costs. As anyone who has ever conducted a marginal-cost study can testify, identifying and allocating these cost components across hours is extremely difficult and subject to debate. Therefore, this investigation uses the market price from the nearest electricity-market hub (v) as a proxy to represent the opportunity-cost for generating power at the utility. The market price from the hub is available most trading days, and often is given in a range by the Energy Information Administration (EIA). The high value of the range is used for the peak price (12 hours starting at 6 a.m.) and the low value of the range is used for the off-peak price. The average monthly price is used during off-peak hours when no daily price is reported.

$$(3) \quad C = \sum_{i=1}^{8760} v_i q_i \quad \text{and}$$

$$(4) \quad R - C = \sum_{i=1}^{8760} r_i q_i - v_i q_i = M$$

Recognizing that the use of average price and the cost proxy approximates the net margin picture for a utility, an adjustment constant is calculated (c) to simulate a "base level" return for the utility before investigating what the value of GHG emission allowances would need to be to compensate for the additional costs of carbon-reducing programs. The adjustment becomes:

$$(5) \quad M = \sum_{i=1}^{8760} (r_i - v_i - c) * q_i$$

The value of c captures the error introduced for a number of reasons, including: (1) using average price rather than the detailed rate schedule for each customer class, (2) using the market pricing from a nearby hub rather than actual marginal cost pricing from the utility itself, (3) the difficulty in identifying off-peak daily pricing from the historical market price data, and (4) the issue that rates were not necessarily set to earn a targeted rate of return during the calendar year 2008 period but may have lagged or anticipated future cash flows.

In evaluating renewables, each of the utilities has an estimate of the net cost (w) it spends on the MWhs of its renewable program (k); both TVA and PJM Utility X allow its customers to pay a premium for ‘green’ power, which helps to offset the cost of renewable generation. For each of the utility’s systems, there will be a conversion factor (f) that relates to the coal fleet’s efficiency and the translation of tons of carbon into CO2 tonnes per MWh. The goal is to find the allowance price (a) that when added to the average price paid by consumers, it will provide enough “savings” to compensate for the additional costs of the renewables program:

$$(6) \quad M = \sum_{i=1}^{8760} (r_i - v_i - c) * q_i - w/q_i + fka/q_i$$

The equation for the energy efficiency program had an additional component because of the loss of revenue due to energy savings. There is an estimate of the net costs of the energy efficiency programs (e) and the MWh savings in those programs (m). Again, the goal is to solve for the parameter (a):

$$(7) \quad M = \sum_{i=1}^{8760} (r_i - v_i - c) * q_i - (r_i - v_i) * m - e/q_i + fma/q_i$$

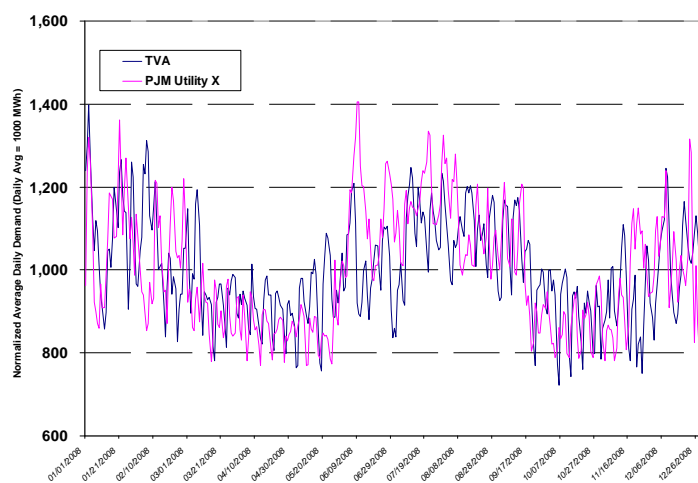
In both equation (6) and (7), the value of (a) is a proxy price of emission allowance savings - not the actual price the utility would have paid, since it is only considering the carbon price as an offset of the investment in either renewables or energy efficiency when the remaining part of the utility's budget is in balance.

TVA and PJM

TVA is headquartered in Knoxville, Tennessee with plants located throughout the seven-state service territory. Its diverse portfolio includes hydroelectric, nuclear, natural gas, renewable, and coal-fired units. Approximately 50% of TVA's generation currently comes from coal. PJM Utility X is headquartered in the eastern United States and operates facilities that include coal, nuclear, hydro, and natural gas.

TVA is almost twice the size of PJM Utility X. In calendar year 2008, TVA's average hourly sales were approximately 20,700 MW. The comparable value for PJM Utility X was 10,800 MW. The trends in daily use patterns show broad similarities, but the details can vary greatly, indicating that the timing and severity of weather impacts can be quite different in the two service areas (see the normalized daily load chart below):

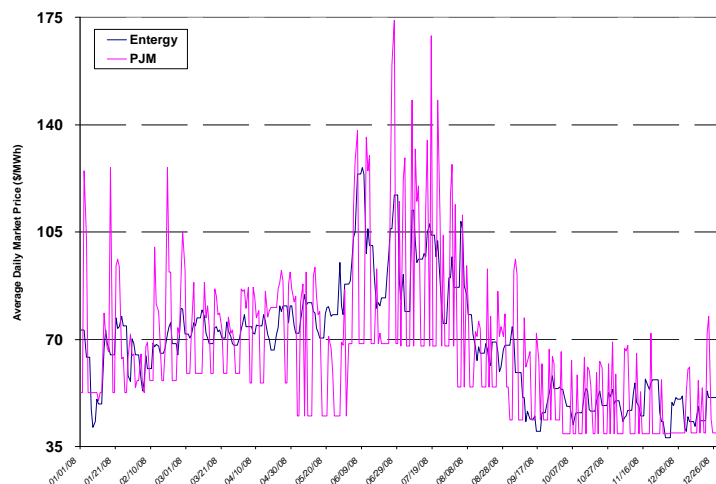
Normalized Electricity Sales Trends Comparison for TVA & PJM Utility X, 2008



Sources: PJM, 2009 and TVA, 2009b.

PJM Utility X makes market electricity purchases through the PJM market hub. TVA makes limited market transactions at independent hub markets, but the Entergy hub based in Louisiana is a good proxy for prices in the Southeast. Daily prices are made available from these hubs from the U.S. Energy Information Administration (2009) and they were used to construct the following chart:

Estimated Trends in Average Daily Electricity Market Prices, 2008



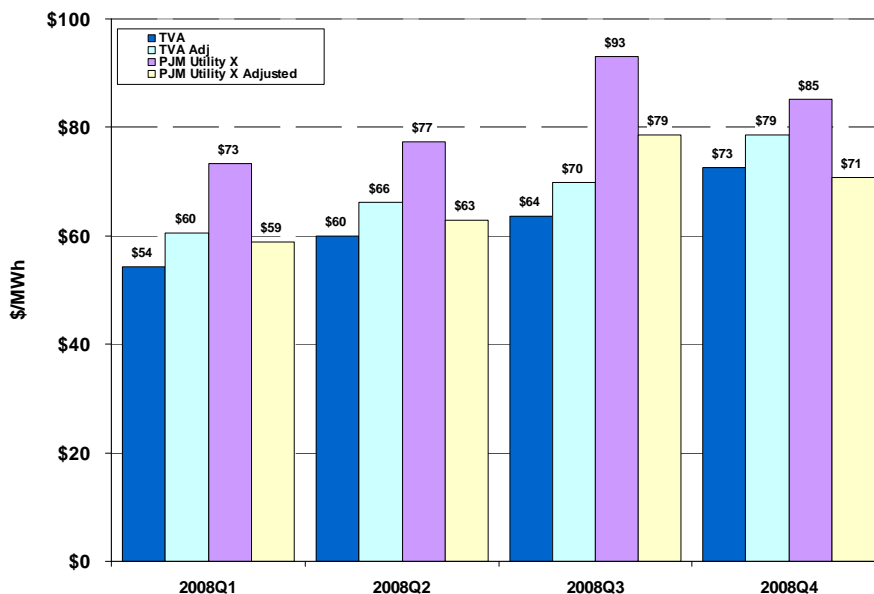
Source: U.S. Energy Information Administration, 2009.

Under this approach, the range of bid prices was used to estimate values for a daily peak and off-peak price to create the price grid matrix for each utility. The range in prices was considerably greater for PJM than Entergy, but the average price was lower. Under these assumptions, the average hourly price for PJM was \$66.57/MWh with a standard deviation of \$24.90 while Entergy's average was \$68.27/MWh with standard deviation of \$18.83.

The next component is average revenues, which is reported in each of the company's quarterly reports to investors and the Securities and Exchange Commission. The simple approach was taken to divide revenues from electricity sales by MWhs of electricity sold to obtain dollars per MWh. Quarterly average revenues were used as the marginal hourly sales prices (r) and estimated hourly prices from the hub were considered costs (v). Equation (5) was solved to find a

value for (c) assuming that each utility earned a 6% return. The results are shown in the chart below:

Comparison of Average Revenue Trends at TVA and PJM Utility X, 2008



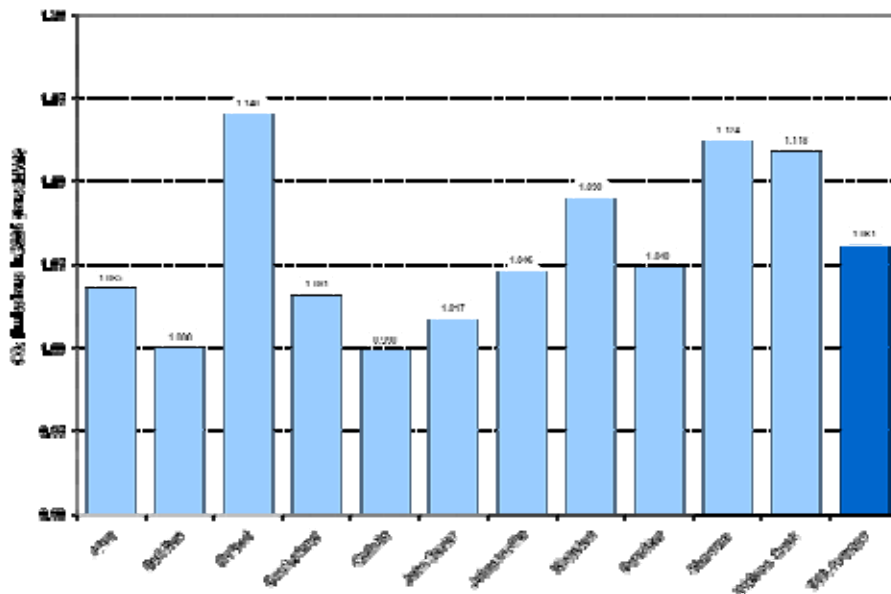
Sources: TVA, 2008 and 2009

Interestingly, for 2008, TVA’s price-cost-load picture required a constant adjustment of a positive \$6.18/MWh. Recognizing that there are a number of error factors introduced by the analysis due to the simplifying assumptions, such a result is an indication that TVA’s system costs are probably below what the general market is presenting at the Entergy hub. On the other hand, the estimated value of constant adjustment for PJM Utility X was \$(14.43). In PJM Utility X’s 10-K, there is a discussion about the need for increased rates in 2008 with approved rates of return at 11.4% and the need for forward-looking rates to cover the costs for increased investment in transmission. The adjustment helps normalize the differences in the profitability pictures between the two utilities so that differences calculated in the later stages are not due to underlying differences in base-level performance.

The next parameter to be estimated is the value of dollars per MWh saved when it is replaced by a renewable generation source or dollars saved though an investment in energy

efficiency. Again, to make this analysis as straightforward as possible, it is assumed that the saved MWh will replace coal-fired generation. The chart below shows the CO₂ value at TVA plants:

Fuel Plant CO₂ Emissions at TVA Coal Plants, 2005



Source: eGRID2007 (see U.S. Environmental Protection Agency, 2008).

The CO₂ parameter for the TVA system was estimated to be 1.061 tons per MWh. The value for the coal plants at PJM Utility X was estimated to be very close to the TVA value, which is one of the reasons it was judged to make for a good comparison. For simplicity, the TVA conversion factor was also used for PJM Utility X.

The tables below summarize the estimated savings associated with each of the programs. For renewables, both TVA and PJM Utility X currently have voluntary customer contribution programs (VCCP) in place that allow their customers to help support the increased cost of green power. At TVA, customers buy blocks of 150 kWh for \$4 a month (or 2.67 cents per kWh). This program is called Green Power Switch. At PJM Utility X, customers are allowed to contribute 1.5 cents per kWh.

TVA currently has an energy efficiency program in place, but it is in the early stages and it is evolving. In FY 2008, TVA reduced peak demand by 72 MW through the program (TVA,

2009). PJM Utility X is also working on developing increased incentives for conservation and energy efficiency and plans to implement programs that were in the pilot phase in 2008. The generic program savings shown in the table below we used to estimate costs for both TVA and PJM Utility X. It was assumed that the program costs were the same for both utilities; what differed between the two systems was the value of the lost revenues.

Comparison of Renewable and Energy Efficiency Program Characteristics, 2008

Fuel Type	TVA (GWh)	PJM Utility X - Estimated (GWh)	Energy Efficiency Program	CY 2008 Savings (GWh)
Biomass	1	600	Residential	109
Digester Gas	30		Commercial	63
Hydro in Renewable Program		1,700	Industrial	25
Solar	1		Demand Response	18
Wind	50	900		
TOTAL with Hydro*	82	3,200	TOTAL	215
TOTAL without Hydro*	82	1,500		

**Indicates Hydro included in Renewable program; does not reflect TVA's hydro generation, which is not counted as part of its renewable generation but is reflected in its clean energy resources.*

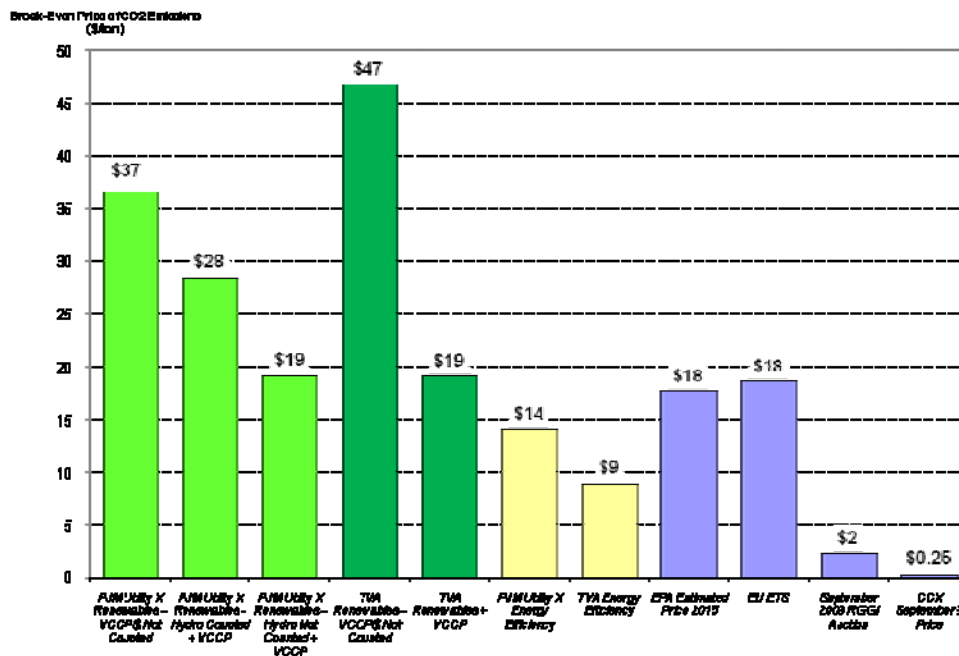
Sources: Renewables estimate based on TVA 2009a; generic energy efficiency estimate based on TVA 2008a and 2008b.

The net cost of the renewables programs were developed by estimating the cost of purchasing renewable energy or the market cost of power plus Renewable Energy Certificates (RECs) versus the market price of power plus the additional contribution from the green power customers. In other words, the net cost of renewable power takes the renewable power price and subtracts the market price and also subtracts the contribution from the Green Power Switch contributors. So the “renewable price” is the extra not covered - on the margin added up over every hour. For TVA, the estimate was \$1.8 million. For PJM Utility X, it was \$81.0 million. For the energy efficiency program, the estimate was developed by the net cost of incentives associated with achieving the energy efficiency reductions in 2008; that value was reported as \$1.8 million. Again, this is what the utility is paying out extra to incentivize energy efficiency programs, not the total investment being made in energy efficiency or a cost/benefit assessment of the society's overall investment.

Results

Using equations (6) and (7) and the empirical information described above, it is possible to calculate the value that would need to be set for GHG emission allowances to be equivalent to the savings resulting from the costs incurred from the renewables and energy efficiency programs considered here. It is also possible to make comparisons with other current and anticipated values for CO₂ prices to see how the equivalent savings in the investments in renewables and energy efficiency would have stacked up against the hypothetical opportunity cost of paying for the allowances. The table below summarizes the results of the calculations:

Comparison of Alternative Estimates of GHG-Allowance-Equivalent Valuations, 2008



NOTE: VCCP: Voluntary Customer Contribution Program; EU ETS: European Union Emissions Trading System; RGGI: Regional Greenhouse Gas Initiative Auction, 2009; CCX: Chicago Climate Exchange, Nelson, 2009. EPA estimates allowance price will be \$11/tonne in 2015 in 2000 dollars (U.S. EPA, 2009b); estimate is approximately \$18 in \$2009 dollar. TVA has never included Hydro as part of its VCCP; PJM Utility X includes some Hydro resources as part of its program.

Energy efficiency investment requires a lower CO₂ allowance price than investment in renewables - by about 50%. The price TVA would have to pay to come out ahead could be lower than what PJM Utility X would have to pay, mainly because the contribution made by customers to the renewable program is higher in the TVA service area. Competitive current markets look like a

lower-cost option than either renewables or energy efficiency investments. If the comparison were to EU ETS and EPA's estimate of anticipated CO2 price, then TVA may be better off investing in energy efficiency.

The costs of these renewable and energy efficiency investments are not necessarily representative of future renewable and energy efficiency program costs under a mandated regulatory program. They can only be considered representative of costs under voluntary programs. For example, under mandatory programs, costs are expected to be lower since renewable generation would probably not come primarily from distributed generation sources for which the utilities pay a high premium. Instead, the trend would be to move toward utility-developed projects or Purchased Power Agreements with other companies to invest in larger-scale renewables that provide power at a much lower cost in dollars per MWh, compared to the premium paid under some of the green power programs.

One issue not considered in this analysis is the relative cost of carbon capture and sequestration, which may be a higher-cost alternative than either of the two options considered here. That investigation will be considered in a later study.

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