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The missing money problem: Incorporation of increased resources from wind in a representative US power market

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ABSTRACT

The paper considers opportunities to reduce emissions of CO_2 through increases in commitments to wind in a representative US power market. A model is applied to simulate market operations for different wind levels focusing on implications of the reduction in clearing prices arising due to increasing inputs of zero marginal cost power from wind, a dilemma referred to as the missing money problem. The resulting decrease in income poses problems for existing thermal and nuclear generating systems, at the same time making investments in wind uneconomic in the absence offsetting policy interventions. Two options are considered to subsidize cost: an investment credit (IC) or a subsidy on production (PC). The dilemma could be addressed also with a carbon tax targeted to increase income. It is assumed that the cost associated with the IC and PC options should be borne by the consumer, offsetting benefits from lower wholesale prices. It is assumed further that income from the carbon tax should be rebated to the consumer offsetting related increases in clearing prices. IC and PC options offer opportunities to reduce emissions at low or even negative net costs to the consumer. Higher costs are associated with the option of a carbon tax.

1. Introduction

The United States, in advance of the 2015 meeting of the Conference of the Parties (COP) to the United Nations Framework Convention on Climate Change (UNFCCC) in Paris, committed to reduce its emissions of greenhouse gases by 26%–28% by 2025 relative to 2005. Earlier, at the 2009 COP in Copenhagen, President Obama announced a longer-term goal, to reduce emissions by 83% by 2050 relative to 2005. CO_2, produced by combustion of fossil fuel, accounts for more than 80% of current US greenhouse gas emissions [2]. The electric power sector was responsible for 38% of US CO_2 emissions in 2013, transportation for 34%, and industry for 18%, with a further 10% from a combination of the residential and commercial sectors, 6% and 4% respectively.

To meet the ambitious goals announced by President Obama, it is clear that the US will need to transition from its current dependence on coal and natural gas as the primary inputs of energy for the electric power sector. At the same time, it will be necessary to cut back on the use of oil-based fuels in transportation. The most promising scenario would be a future in which energy services are delivered to a much greater extent than today in the form of electricity generated primarily from zero carbon sources such as wind and solar, with additional contributions from hydro and nuclear. In what follows, we focus on opportunities to reduce emissions of CO_2 by increased investments in wind. The objective is to estimate the cost incurred to achieve a given reduction in emissions.

The US power system consists of three effectively isolated transmission networks: the Eastern Interconnection, the Western Interconnection and the Electricity Reliability Council of Texas (ERCOT). The Energy Policy Act of 1992 mandated open access to the national transmission system. A variety of organizations, referred to as Independent System Operators (ISO's) or Regional Transmission Organizations (RTO's), were created to oversee grid operations and to ensure equal access in their regions of responsibility. Five of these organizations are located in the Eastern

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Interconnection Region. We propose in this paper to focus on the operational characteristics of a representative one of these organizations, the Midcontinent Independent System Operator (MISO) which serves customers in portions of eleven states in the north central part of the country.

MISO operates a wholesale market designed to reconcile supply and demand for electricity at minimum cost with an emphasis on projections for day-ahead hourly load demand, fine-tuned to respond in real time to departures from anticipated demand. The market operates as follows. Having projected demand, the system operator polls individual generating units to determine how much power they could provide and at what price. Generating units will normally propose to supply power at their marginal costs for production and delivery. Wind plants are predictably the lowest cost providers since the variable operating costs are minimal in this case. Nuclear plants rank typically second, followed by coal and natural gas fired facilities. Oil fired plants are most expensive and are engaged only when demand is exceptionally high. The bidding process establishes the market clearing wholesale price for power, the price at which supplies can be contracted to meet anticipated demand. Generators bidding below this price will be profi. Generators bidding above will not be engaged.

We elected to treat the MISO system as an integrated whole with a single system wide clearing price. We chose to ignore therefore differences in clearing prices that arise in practice over the 2224 nodes of the system reflecting bottlenecks arising from limitations in the transmission network. Ignoring the complications associated with these bottlenecks, the procedure adopted here should lead to an underestimate of the annual averaged clearing price for the overall MISO system. Comparing results for the annual average system wide clearing price realized in 2013 with results from the present analysis provides a check on the validity of this approach. As indicated below, the agreement is satisfactory: $28/MWh as compared to $32/MWh [3].

Increasing the supply of power from wind may be expected to lower the overall clearing price for electricity. What this means is that, all else equal, the greater the contribution from wind, the lower the clearing price. Income earned by the conventional suppliers – nuclear, coal, natural gas and oil – will be lowered accordingly. The income accrued by the wind plants per unit of installed capacity will also be reduced. The problem is that at some point it will no longer be profitable to invest in additional wind plants. Also, the least efficient conventional plants may have difficulty in meeting their routine operational expenses, not to mention problems in earning the income required to compensate for their original capital investments. The dilemma has been referred to as the missing money problem [1] or, recently, more provocatively, as Clean Energy's Dirty Secret [4]. The primary focus for this missing money problem has been on the influence of the revenue stream for thermal units. Revenue sufficiency for thermal units under elevated penetration of renewables has been investigated in Refs. [1,4,5], and possible methods to offset the decreased revenue from the wholesale market for thermal units include higher capacity payments [11,15] and scarcity pricing [1,11]. However, possible policy interventions to support higher levels of investments in wind have not been discussed in detail, especially in the context of an actual power market in the US.

The profitability of a wind investment depends on a number of factors: the magnitude of the initial capital outlay, the income anticipated per kWh of power delivered, the capacity factor assumed for the system, the time interval over which the investment may be amortized, and the value assumed for the related discount rate. We choose to focus on investments in wind systems expected to come on line in 2020 or thereafter. The capital cost for a wind system is projected to average approximately $1674/kW by that time [7]. Amortizing this cost over a 30 year period, assuming a discount rate of 6.1% [6], the annualized cost for this investment is estimated at $122.9/kW.

The demand for electricity in the MISO region was projected to increase at an annual rate of 1.12% between 2013 and 2020, corresponding to an increase of 8.1% by 2020 relative to 2013 [9]. We assume that the temporal pattern of demand and supply from wind in 2020 will be similar to that experienced in 2013: hourly 2013 load data will be scaled upward accordingly. The share of electricity produced from renewable sources (primarily wind and solar) reached levels in 2014 as high as 49% in Denmark, 38% in Spain, and 28% in Germany. Plans are for California and New York to accommodate as much as 50% of their total electric power demand from renewable sources by 2050. We propose here to consider investments in wind systems in MISO ranging as high as 100 GW. Assuming a capacity factor of 33% (the level realized by wind in MISO in 2013) an investment of 100 GW in wind could account for as much as 50% of total power demand projected for MISO in 2020.

Investments in wind energy in the US benefit currently from a production tax credit (PTC) of $23/MWh. This credit is adjusted annually to allow for inflation and is applied over a 10-year period from the time the generating system first enters service. Under present legislation, the PTC is projected to phase down gradually beginning in 2017, decreasing to 40% of the 2015 level by 2019. As we shall see, the PTC subsidy envisaged under the current legislation would be insufficient to support the expansion in wind resources contemplated here. In what follows we explore three options to address this issue.

Option 1 proposes to balance income and expense for the additional wind capacity by means of a subsidy on a per MW basis for the related initial capital investment (referred to in what follows as an investment credit or IC). Option 2 proposes a targeted production credit per MWh (PC) with the subsidy set at the level designed to compensate for the reduction in income anticipated for the wind sector as a consequence of the increase in the low-cost power anticipated from this sector. Option 3 would rely on a carbon tax to raise the overall clearing price for power electing with this strategy to fund the increase in income required to support the additional investments in wind. The expectation is that the power consumer would pay for the subsidies allocated under options 1 and 2, benefitting however from the resulting decrease in clearing prices. Electricity prices would increase under option 3. The assumption in this case is that the revenues earned as a result of the tax should be remitted to the power consumer. All three options may be expected to lead to reductions in emissions of CO_2. The challenge is to identify the least cost option to achieve this objective.

The supply of electricity from wind is intrinsically variable. There will be times when the supply is insufficient to keep up with demand even at the higher levels of installed capacity contemplated here. The problem will be particularly severe during peak demand periods in summer. Operators of ISOs or RTOs can anticipate this risk, identifying in advance generating capacities that should be held in reserve to meet demand on these occasions. Commitments for this capacity can be secured through an auction in which potential suppliers are invited to submit bids identifying prices at which they may be prepared to guarantee this supply. As with the procedure followed in setting the clearing price for power, this process identifies the price required to secure this additional capacity. Suppliers offering bids below this clearing price will be engaged and contracted to ensure that the capacity they tender will be available to the system operator on demand as required. In making this commitment, they will be compensated at the price per unit of capacity defined by the capacity auction. Prices submitted by operators entering the capacity auction will be informed