Negative Bidding by Wind: A Unit Commitment Analysis of Cost and Emission Impacts

By Lin Deng, Benjamin F. Hobbs, and Piet Renson*

In order to meet renewable energy targets, various renewable energy policies and incentive mechanisms have been adopted by many countries. Spain, for example, has set up a Renewable Action Plan (REP) 2011-2020, in order to meet the EU 2020 targets. In Spain, and the EU, feed-in tariffs are generally prevalent, which pay a guaranteed amount per MWh for renewable production. Meanwhile, most U.S. states have adopted renewable portfolio standards in which renewable generation creates credits that can be sold, while the U.S. government has a production tax credit (PTC) amounting to ~$26/MWh produced. U.S. wind power generation has experienced rapid growth in the last 20 years from 1,500 megawatts (MW) total installed capacity in 1992 to more than 50,000 MW in August of 2012. Wind power provided more than 4% of total U.S. electricity generation in 2013, according to the Energy Information Administration (EIA). Two primary policies provide market and financial incentives that support the wind indus-try and have contributed to U.S. wind power growth: (1) production tax credit (PTC)—a federal tax in-centive amounting to ~$26/MWh, and (2) renewable portfolio standards (RPS)—state-level policies that encourage renewable power by requiring that either a certain percentage of electricity be generated by renewable energy sources or a certain amount of qualified renewable electricity capacity be installed.

Negative Bidding by Renewable Producers and Its Impact

In European and U.S. power markets, excess generation conditions are occurring more frequently when heavy wind and light load conditions coincide, and increasingly in the middle of the day during the times of highest solar production. Negative energy prices are a useful tool for encouraging generators to volun-tarily curtail operation during such conditions, and to incent consumers to buy more power. Negative prices occur, for example, when traditional generators would rather stay on line rather than shut down and have to incur start-up costs again soon thereafter. Figure 1, based on USEPA data for a Texas coal-fired generator, shows the significant amount of fuel that is required for that plant's lengthy start-up period.

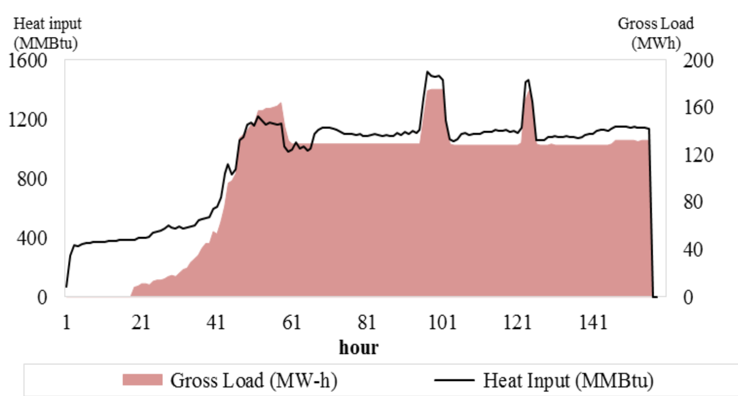

Figure 1: Power output (MW) and fuel use (millions of BTUs) of an example coal generator over time.
Source: USEPA Continuous Emissions Monitoring System data

However, since renewable plant owners usually receive substantial subsidies per unit of energy production, they would also prefer to pay in order to produce power even if prices are negative, as long the mag-nitude of the subsidies exceed the magnitude of the negative energy price. This mutual unwillingness on the part of thermal and renewable producers to turn down drives prices even lower.

Negative prices can also occur in markets just prior to ramping up of net loads in the morning or evening. This is because if loads were higher just before the ramp occurs, it would then be possible to avoid at least some of the cost of turning on peaking plants (such as combustion turbines) to meet steep ramps that online thermal generation cannot keep up with. Steep net load ramps are also occurring increasingly frequently due to renewable variations (e.g., Figure 2 which shows how Texas wind power can soar up and down dramatically). Growing concern about those ramps has lead the California and Mid-Continent ISOs in the U.S. to institute an explicit constraint for the amount of rampable capacity online (called "flexiramp" in California), which results in payments to generators that can provide that ramp.

Negative prices are, of course, welcomed by consumers, and negative prices can be an efficient means of determining which plants stay on and which turn off--if the costs that each generator incurs in order to turn down are real societal costs. However, the subsidy payments to wind producers are transfer pay-ments from ratepayers or tax payers, at least in the short run, and not real costs. Conse-

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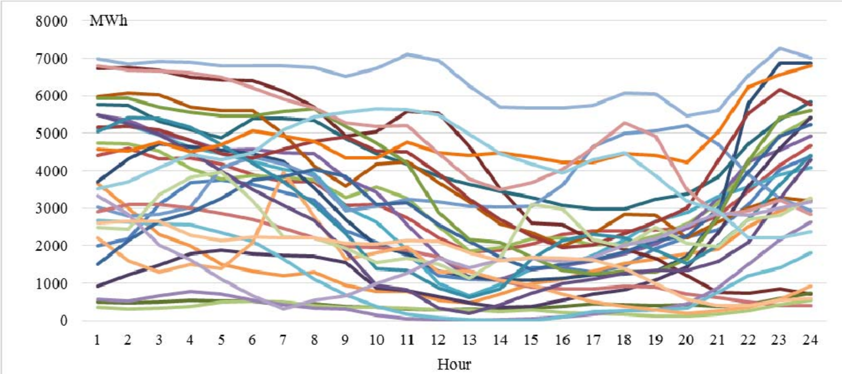

Figure 2: The wind curves of September 2012, ERCOT
Source: Electric Reliability Council of Texas.

quently, if renew-able generation stay during periods of negative prices and force thermal generators to turn off, the result can be higher social costs and also higher emissions from the additional start-ups and shut-downs. In our analysis we focus on these short-term effects, and argue that a fine tuned policy that maintains the subsidy even if wind is curtailed would improve short-run market efficiency. Our study can also be viewed as an examination of the short-run cost and emissions impacts of rules in some countries of the EU that require that wind production be taken by the system operator unless system reliability is endangered. Under such a requirement, an operator may be forced to incur fuel costs to stop and start units, with the resulting costs and emissions possibly more than offsetting the fuel and emissions savings from using more wind power.

Possible long-term effects were on the mind of Public Utilities Commission of Texas Chairman Donna Nelson on September 6, 2012 when she the cautioned policymakers against further subsidies, arguing that the wind production tax credit had undermined generation capacity adequacy in the state:

> "Federal incentives for renewable energy… have distorted the competitive wholesale market in ERCOT. Wind has been supported by a federal production tax credit that provides $22 per MWH of energy generated by a wind resource. With this substantial incentive, wind resources can actually bid negative prices into the market and still make a profit. We've seen a number of days with a negative clearing price in the west zone of ERCOT where most of the wind resources are in-stalled….The market distortions caused by renewable energy incentives are one of the primary causes I believe of our current resource adequacy issue… [T]his distortion makes it difficult for other generation types to recover their cost and discourages investment in new generation."[1]

Impacts of Negative Bids on Short-Run Costs and Emissions Depends on the Characteristics of the Systems

We used a standard industry model of power system operations called a unit commitment model to exam-ine the impact of negative bidding by wind plants. The model decided which generating units to commit in which hours, and the amount of generation from each (including wind plants) over a week-long period. Constraints that have to be met include energy balance (total generation = total load) and individual gen-erator operating constraints, such as ramp limits. We did not model transmission. We considered systems with about 1/3 wind power and 2/3 non-renewable sources, consistent with California's 2020 goals and what Denmark has now. We then modeled different levels of negative bids by wind and examined how system costs and emissions were affected. The largest negative bid (-$300/MWh) can also be viewed as a simulation of the EU policy of absolute priority of wind in system dispatch.

The analysis shows that the impacts of negative wind bidding strategies have on total system cost and CO_2 emission depend strongly on the generation mix. We consider four systems: high nuclear and coal (NUCL), high coal (COAL), high combined cycle (CCGT), and high steam gas (SGAS). These represent a range of actual conditions; e.g., the CAISO, Spanish and Texas systems have, respectively, a low, medium and high share of coal-fired generators. Sensitivity analyses considered different sizes of systems and alternative CO_2 prices.

The least flexible system is NUCL because the nuclear unit always operates at its full capacity of 1000 MW. Consequently, it has the least amount of rampable capacity and the highest minimum production. Our main conclusions are the following. First, wind curtailment is greater when the overall generation mix is inflexible, as measured by total rampable capacity and total minimum run levels. Second, larger negative energy bids for wind force the system to accept more wind generation even though energy prices are negative. As a result, system costs unambiguously increase (disregarding penalties for curtailing wind). It is possible to show, by contradiction, that these costs must increase under negative wind bidding. Third, such bids leads to more starts and stops for generators and associated CO_2 emissions, which partially and, in some cases, more than fully offsets emissions reductions due to decreased thermal gen-eration. In some of our runs, total system emissions for the week were almost 2% higher under a minus $300/MWh bid for wind than under a $0/MWh bid.

We show the results for two of the four systems here as illustrations. The first plot in Figure 3 shows the cost and CO_2 emissions increases as a result of larger negative wind bids for the nuclear system. The system costs exclude penalties for curtailing wind which, as we argued above, are merely transfer pay-ments. For small negative bids (through -\$30/MWh, about the magnitude of the U.S. federal wind produc-tion tax credit), the impacts are very small, but they grow rapidly thereafter as the system's coal capacity is subjected to additional starts and stops. If we calculate the ratio of the incremental costs and incre-mental emissions to the increased wind production (comparing the \$0 and -\$300/MWh solutions), we find that the cost of taking that wind power is \$18/MWh (in added fuel costs) and the additional emis-sions are 0.84 tons CO_2/MWh. Thus, this incremental coal power, in this case, is effectively as dirty as coal-fired generation (generally around 1 ton/MWh). For the gas dominated system, however, additional starts and stops occur mainly in combined cycle capacity, which involves fewer BTUs to start-up, and has lower emissions per BTU. As a result, although costs also go up in the CCGT case (at a rate of \$88/MWh of increased wind output), emissions are relatively unchanged (0.21 tons CO_2/MWh of increased wind). In a few of other cases we considered, the emissions actu-ally decreased.

Thus, the precise cost and environmental effects of allowing negative bids, or requiring that all wind be taken subject to reli-ability constraints, depend on the particular system. Furthermore, transmission, demand response, hydro generation, and energy storage could have a large impact on the flexibility of a power sys-tem and the impact of wind injections during negative price peri-ods; we did not consider those complications, and they could sig-nificantly alter the results shown in Figure 3. We can conclude that policies that encourage wind to bid flexibly (i.e., zero or low nega-tive bids) will improve short-run system cost performance and in many cases emissions as well. This will help society to reap the full economic and, often, environmental benefits of wind power integration. Such policies might include, for instance, renewable energy credit or tax credit systems that provide credits even for curtailed wind, based on statis-tical estimates of how much wind would have been provided in the absence of curtailment.

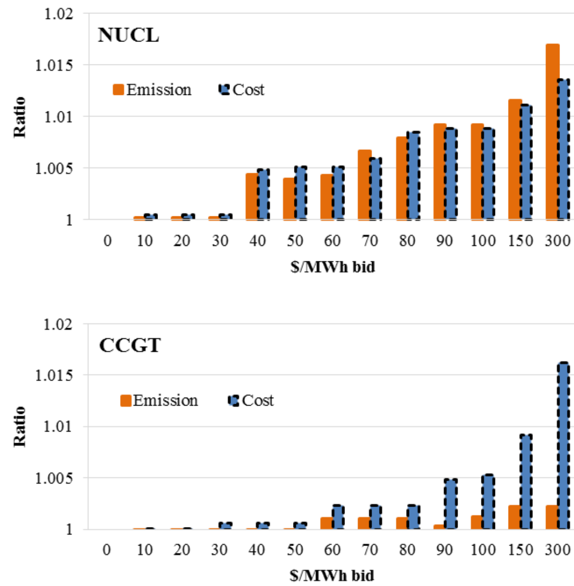

Figure 3: Changes in total system cost (excluding wind bids) and total CO_2 emissions as the magnitude of negative \$/MWh bids by wind increases (ratios are respect to \$0/MWh bid solutions) for the nuclear- and combined-cycle-dominated systems

Footnote

[1] Chairman Donna Nelson testimony before the Texas Senate Natu-ral Resources Subcommittee (Septem-ber 6, 2012), transcribed from http://www.senate.state.tx.us/avarchive/, quoted by Frank Huntowski, Aaron Patterson, and Michael Schnitzer in "Negative Electricity Prices and the Production Tax Credit", http://graphics8.nytimes.com/news/business/exelon.pdf

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