Impacts of Wind Resources and Environmental Regulation to Future Generation Portfolio and its Capacity Factor in ERCOT

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Abstract

As more renewable resources are added into the grid and environmental regulations are imposed to reduce emission from generators, they will result in dramatic market changes. Assessing the impact of these changes is important for policy makers, market participants, and general public to understanding trends of electricity market. This paper addresses this issue by analyzing how the ERCOT generation portfolio evolves with different levels of wind penetration. In order to assess the future power system, the study model should represent the long term dynamics of various factors to find out how investment decision is made economically in a competitive market with given assumptions. Another important aspect should be considered is the short term dynamics from real operation of power system. It is determined by operational characteristics of different units such as heat rate, maximum and minimum capacity, minimum up-time or down-time etc. For this study, AURORAxmp, a commercially available market simulator, is utilized to capture both long term and short term dynamics. This study runs 5 different scenarios: two base cases with and without CO₂ price, 18%, 25%, and 30% wind penetration level. The result shows that, increasing wind penetration reduces production and capacity of both coal and gas units, while CO₂ price impacts coal (negatively) and gas (positively) units in an opposite way. These are natural consequences that one can easily conjecture, but this study assesses the amount of annual addition and retirement of each fuel types by 2040, and their sensitivities with different wind penetration. It provides a detail blueprint of the ERCOT generation expansion. Furthermore, another interesting observation is also found during an early phase of simulation: CO₂ price can actually result in a small increase of coal penetration for the first three years, which is an opposite of the main result above. Although the market returns to the general trend soon, it indicates that ERCOT market can react in a counter-intuitive way, and it is important to capture this in advance with modeling sophistication.

1. Introduction

Wind resources have been added into Electric Reliability Council of Texas (ERCOT) grid rapidly since mid-2000s (Fig. 1 and Appendix A). The investment decision to build wind farm in ERCOT was supported by Federal tax incentives, Investment Tax Credit (ITC) or Production Tax Credit (PTC). Those incentives parallel worldwide efforts to reduce Green House Gas (GHG) emission by generating electricity more from renewable resources like wind, solar, biomass, etc.
However, intermittency of renewable sources results in a number of operational and planning challenges to the Independent System Operator (ISO). For example, ISO should decide the short-term / long-term forecast methodology for renewable energy production, the appropriate amount of ancillary services (Chavez, 2012), ramping capability of the system, cost-effective transmission planning to deliver renewable energy, etc.

Besides, with current high uncertainty in renewable policies and environmental regulation, it is difficult for market participants to make long term investment decision. This is because future generation portfolio can vary significantly depending on the timing and magnitude of these rules.

The purpose of this study is to address the second issue: assessing the impact of wind penetration level and CO$_2$ price on ERCOT capacity expansion. Because marginal cost of wind energy production is essentially zero and even negative considering tax incentives (Baldick, 2012), having more wind will result in reduced production of both gas and coal units by economic dispatch logic.

However, there are other factors that should be taken into account. As having more renewables and corresponding uncertainty in future production, thermal units would be procured and deployed more as forms of ancillary services. Another factor is that electricity demand is growing along with peak demand. ERCOT (2012 e) projects that its demand growth is expected to continue for next decades at least with moderate rates. Therefore, in order to serve increasing demand and to deal with intermittency of renewable resources with the certain level of reliability, ERCOT needs conventional thermal generation built in the future as well.

How much and what type of units are going to be built or retired is solely decided by market and difficult to be answered due to high uncertainty in the market. The decision is affected by various factors such as, but not limited to, overall economic situation, population and GDP growth, electricity demand growth, fuel price projection, environmental regulation, renewable energy policies, capital expenditure (CAPEX) for new generators, demand side management and energy efficiency improvement, regulatory uncertainty, etc. In order to consider all of those factors together with appropriate assumptions, this paper utilizes a commercially available market simulator, AURORAxmp. With the tool, this study forecasts how wind penetration affect investment decision on all generation options, while satisfying the objective of economic dispatch and other reliability constraints in hourly resolution.

The next section starts with the overview of ERCOT market. It explains historical expansion and current issues in ERCOT. Following will describe the study methodology and discuss factors needed to appropriately represent short term and long term characteristics of power market. Assumptions in this study will be delineated next. After that, it shows the main result and indication from simulations of five different scenarios. The last section will conclude this study and suggest further studies.

Note that in this paper, penetration level of a fuel type is defined in energy value. For instance, total wind energy generated in 2011 is 28 TWh, while ERCOT total generation is 331 TWh at the same year. In this case, wind penetration level is 28/331 = 8.5%, which can also be verified in Figure 3.

2. Past and Current ERCOT Market

Figure 1 and 2 show historical capacity expansion for wind and whole ERCOT respectively. ERCOT system has no major interconnections to other systems, so most demand should be served by itself. So far ERCOT market has been successful for inducing new generation capacity into the market. In Figure 2, capacity ‘boom’ between 2000 and 2003 was led by combined cycle units which were added to take advantage of deregulation and high efficiency (Newell, 2012). After that, from 2005 to 2010, wind addition increased significantly every year thanks to favorable policy for renewables. Therefore, current ERCOT is characterized as an energy-only market with higher penetration of both efficient combined cycle and intermittent wind.
Because gas units are marginal for most of settlements, ERCOT markets are highly affected by natural gas prices. Besides, wind and nuclear units are dispatched first by the economic dispatch logic, coal and natural gas units compete with each other for rest of load left. Negative correlation between coal and gas electricity production is evident in Figure 3. Another negative correlation between gas price and gas penetration level except when diverted by outside impacts is shown in Figure 4. Recent turn increase for gas and decrease for coal units have resulted from significant amount of shale gas production and corresponding low gas prices. Once gas prices goes below 3.5 $/mmbtu, generation conversion from coal to gas is accelerated and accounts for the highest penetration level of gas and lowest penetration of coal units this year.

Figure 1: Wind Capacity, Energy, and Capacity Factor (ERCOT, 2011)

Figure 2: Capacity Addition and Retirement [MW] by Fuel Type in ERCOT (Newell, 2012 and SNL, 2012)
Recently, resource adequacy has become an urgent issue in ERCOT. Last year, exceptional drought and high temperature have threatened ERCOT several times to shed load, even though this worst situation of load shedding has not happened. In 2011, actual reserve margin 9% was significantly below the planning reserve margin, 13.75% (Newell, 2012). Abundant gas production from shale reduces gas prices, and this year’s gas price is the lowest in the last 10 years (Figure 4). High gas production level and resulting low gas prices is expected to continue for the next several years. Since, in peak hours of ERCOT, mostly gas units are marginal and setting a market price, low gas price reduces power price, which is good for a customer. But from a generation investor perspective, lower gas price and resulting lower power price may not give enough revenue forecast for them to consider new generation investment. It exacerbates ERCOT’s concern for resource adequacy. The current issue leads market participants and ERCOT to worry whether the ERCOT energy-only market can induce new generation capacity. As a part of the remedies, ERCOT increased its price offer cap by 50% from 3,000 $/MWh to 4,500 $/MWh, effective on Aug. 1st, 2012, and additional increase up to 9,000 $/MWh is under discussion now.

Figure 3: Penetration Levels by Fuel Type (ERCOT, 2011)

![Penetration Levels by Fuel Type](image.png)

Figure 4: Gas Prices and Gas Penetration Level (Global View, 2012 and ERCOT, 2011)

![Gas Prices and Gas Penetration Level](image.png)
As wind capacity adds every year, its penetration level also increases steadily and shows currently 9.42% this year with approximately 10,000 MW capacity. Future wind projects after 2012 highly depends on whether PTCs are extended. Another important impact is the completion of CREZ transmission upgrades by 2014. The upgrade is expected to expand transmission transfer capability to support an additional approximately 10 GW of wind potential across ERCOT and Panhandle area (ERCOT, 2006g)

3. Methodology

As Mills (2012) describes, in order to study the impacts of renewable resources on electricity market from a long term perspective, one should capture both short-term and long-term dynamics of the market. In details, the short term dynamics mean that the model should properly represent operational limits, flexibility and variability of resources at least with hourly resolution. The operational limits that should be modeled are: ramp up or down limits, minimum up-time or down-time, minimum and maximum capacity, average heat rate, heat rate at minimum, wind and solar profiles of a region, Variable Operation and Maintenance (VOM) cost, Fixed Operational and Maintenance (FOM) cost, start-up cost, etc. They are required for the purpose of making unit commitment and optimal dispatch decisions, so as to depict daily and hourly operation of power system and electricity market as closely as possible to reality.

For long-term dynamics, the model should be able to make economic investment decisions for which type of unit to be added to or retired from the current market based on long term market assumptions such as forecasts of fuel prices, demand growth, inflation, CO2 prices, CAPEX variation, transmission upgrades etc.

There are publicly and commercially available market simulators which incorporate the above characteristics at different levels; National Energy Modeling System (NEMS, EIA, 2012), Renewable Energy Deployment System (ReEDS, Short, 2009) are developed by EIA and National Renewable Energy Laboratory (NREL) respectively. PLEXOS, UPLAN, AURORAxmp are examples of commercially available market simulators described in Foley (2010). This paper utilizes the long term capacity expansion functionality of AURORAxmp.

![Figure 5: AURORAxmp Long Term Optimization Logic](image)

The model represents operational characteristics of all ERCOT resources in detail. As a result, it covers short term market dynamics described above. Its long term optimization logic decides economic investments (addition and retirement of a unit) by comparing real levelized net present value (NPV, revenues minus cost) of each existing and candidate units. After that, the model decides an existing unit’s stay or retirement as well as a
candidate unit’s addition. It assumes that all investment decision is made economically in a competitive market. It means that all market participants invest or retire their assets solely based on a unit’s profitability (NPV in the model). Figure 5 shows the logic flows of the long term investment decision in the model (EPIS, 2012). It repeats this iteration until no addition and retirement are economically viable.

The purpose of this study is to analyze how ERCOT generation capacity evolves with different levels of wind penetration. In addition to the wind penetration level, however, there are other important inputs, such as projections for fuel prices, CO₂ prices, CAPEX, and demand during study periods. For this study, all of those market forecasts come from the base case scenario of EIA AEO 2012, except for the demand forecast. ERCOT demand historically has shown a different growth rate from the U.S. average rate, so this study uses long term demand forecast released by ERCOT Planning Group (ERCOT, 2012 e). Detailed modeling assumptions are described in the next section.

4. Assumptions

a. Fixed Addition and Retirement

The study period is from 2013 to 2040 and simulation resolution is hour. Existing resource list and their details (heat rate, fuel type, minimum up-time or down-time, minimum and maximum capacity, etc.) are already constructed and included in AURORAxmp ERCOT model, which mostly come from NERC Electric Supply and Demand Database and EIA Annual Electric Power Report. Most recent unit status are also updated based on publicly available information from Capacity, Demand, and Reserve Report (ERCOT, 2012 a), System Planning Monthly Report (ERCOT, 2012 c), Mothballed Unit Status (ERCOT, 2012 d), MWDaily (Platts, 2012), etc. (See Appendix B in detail list of recent ERCOT resource updates)

b. Fuel prices, CAPEX, and Renewable Incentives

This study basically uses Fuel and CAPEX assumptions from the EIA AEO 2012 base case. All prices are converted to real 2010 dollars using EIA Consumer Price Index (CPI) estimation. However, for natural gas prices which impacts most on the ERCOT market, the study uses the forward prices of Henry Hub actually traded in IntercontinentalExchange (ICE) from 2013 to 2017. Afterwards, EIA Henry Hub forecasts are used. Historical and projected Henry Hub prices are shown in Figure 6.

The study represents 30% Investment Tax Incentives when calculating CAPEXs for renewable resources like wind and solar. For example, ITC reduces capital cost of wind by 48.38 [2010 $/kW] in 2010. PTC, however, is not considered in this study, so does not affect marginal cost calculation of renewable energy production.

PTC and RPS are major drivers of renewable new builds. However, the study does not model them explicitly. Instead, it assumes that different wind penetration levels (page 8) represent resulting wind additions from different renewable incentives like PTC. The purpose of this study is to analyze the impact of different wind penetration levels on future generation portfolio, and various wind levels are assumed to result from PTC, RPS, or any possible forms of renewable incentives. As a result, the study will help us to assess how much wind energy should be generated and what is the impact on the market in order to achieve a desired wind penetration level.
c. Demand Growth

Historical population and GDP growth of Texas have been higher than the US average. Taking into account economic and weather forecast of Texas, ERCOT reports its long term demand forecast up to 2020 in ERCOT (2012 e). This study uses the same demand growth from 2012 to 2020 in the report, and after that extrapolates the demand growth rate from 2021 to 2040 by fixing the 2020 growth rate. This fixed demand growth rate was decided considering population projection (TSDC, 2012), energy efficiency, and demand response impacts (EPRI, 2009) during this period. The graph and values for demand projection of this study is shown in Figure 7. It should be mentioned that different projection for future economy, technology, climate change, etc. could result in different demand growth.

Figure 7: ERCOT Demand Forecast 2013 – 2040 [TWh]

d. Environmental Regulation

Recently, U.S. Court overturned the Cross-State Air Pollution Rule (CSAPR), which was first announced in 2011. Even though Environmental Protection Agency (EPA) will revisit this later and announce the modified version of it, it is still uncertain whether it will have similar impact that it had before or if it will even survive later on.
Not only CSAPR, but other environmental regulations also have a great deal of uncertainty on actual implementation. However, one thing can be conjectured is that whatever the format is, there will be a way to regulate environmental impacts of thermal generation that emits Green House Gas (GHG) and other pollutants (NO\textsubscript{X}, SO\textsubscript{X}, mercury, etc.). Therefore, this study includes GHG15 scenario of AEO 2012 and assumes that this is a representative form of future environmental regulations imposing penalties to the emission produced by thermal units. GHG15 scenario imposes CO\textsubscript{2} price 15$/ton at 2013 and increase it by 5% every year by 2035.

e. Nuclear Expansion

The Fukushima accident froze many of the current and future projects of nuclear units all around the world. For example, Germany has announced that it will shut down all nuclear plants by 2022, and a new nuclear project in ERCOT was also canceled soon after that. Current nuclear plants in Texas – capacity of 5,133 MW – will be operating by 2027 or 2033 according to their current licenses, but for continuous operation in following years, they should apply for the extension of their licenses. This study assumes that current licenses will not be extended, and the units will be retired when current licenses are expired. However, the model is allowed to add a new nuclear unit if the long term investment logic concludes it is favorable to do so.

f. Wind Penetration Level

Given the general assumptions that described so far, this study generates four different scenarios depending on different wind penetration levels - base case, 18%, 25%, and 30%. Wind penetration level is defined in energy values, using a following equation.

\[
\text{Wind Penetration Level (\%)} = \frac{\text{Wind Energy produced in a year [TWh]}}{\text{Year Total Energy [TWh]}}
\]

For given wind penetration levels (10%, 18%, 25%, and 30%) and estimated capacity factor (30%), total wind capacity required to meet a penetration level is calculated based on energy forecast in 2030 (455 TWh). For example, for 10% wind case, 45.5 TWh wind energy should be achieved in 2030. Taking into account 30% wind capacity factor, required total capacity to achieve the target is approximately 17,300 MW based on the equation below.

\[
\text{Required Wind Capacity [MW]} = \frac{\text{Wind Energy [MWh]}}{\text{Capacity Factor[\%] \times 8760 [hours]}}
\]

Then the required wind capacity minus 2012 wind capacity is divided by a number of years between 2013 to 2030, so that the same amount of wind addition is calculated and added every year from 2013 to 2030. Although, as historically observed, actual wind capacity addition will be more variable than this perfectly linear increase, it approximates a consistent increase of wind capacity up to a target level. The resulting wind penetration level is shown in Figure 8. As wind capacity increases, wind energy production and its penetration level increases as well, but after achieving the target, little wind is added economically.

The reason to set target year 2030 is to see how ERCOT market would respond to ‘20% wind by 2030’ scenario described in DOE 2008. Along with this fixed wind addition to system, the model also decides the best economic addition or retirement of any type of a unit by the long term investment logic.

The base case does not add any wind manually, but allows the model decide addition and retirement based on system needs. As a result it has approximately 7% of wind penetration level. It tells us that without any wind-favorable policy, ERCOT is going to have less than 10% wind penetration level in future. The base Case and all
different wind level cases are run with CO$_2$ price. Another base case without CO$_2$ price is also performed to see its impact.

Figure 8: Resulting Wind Generation Penetration Level by Scenarios

5. Results

All scenarios have different paths of generation expansion, but have share similar trends in common. There are capacity boom and bust cycles in all cases. Natural gas units continue to be a major portion of ERCOT capacity and its contribution becomes greater every year in every scenario. Low gas price projection, high fuel efficiency, operational flexibility, and less emission have gas units committed, dispatched, and invested more than coal units. Generation expansions for all scenarios are included in Appendix C, the 25% wind case is shown in Figure 9 for convenience.

Figure 9: Generation Expansion - 25% Wind
a. Impacts of Environmental Regulation

Optimal Power Flow (OPF) logic determines the least cost way to serve a given demand subject to each unit’s capacity, transmission limits, bus voltage limits. A resource offers a price to market based on their marginal cost of a next MW generation. Marginal cost is expressed as,

$$\text{Marginal Cost} \left( \frac{\$}{\text{MWh}} \right) = \text{Incremental Heat Rate} \left( \frac{\text{btu}}{\text{kWh}} \right) \times \text{Fuel Price} \left( \frac{\$}{\text{mmBtu}} \right) + \text{VOM} \left( \frac{\$}{\text{MWh}} \right) + \text{Emission Amount} \left( \frac{\text{ton}}{\text{MWh}} \right) \times \text{Emission Price} \left( \frac{\$}{\text{ton}} \right) + \text{bidding factor} \left( \frac{\$}{\text{MWh}} \right)$$

Figure 10: Average Marginal Cost ($/MWh) of different Fuel Type – Base Case

With negligible amount of emission amount or emission price and no bidding factor, most of marginal cost consists of variable fuel cost. However, high emission cost can have a greater contribution to marginal cost calculation than variable fuel cost if emission price or amount is high enough. Actually, this study found that GHG15 assumption from AEO 2012 increases marginal cost of coal units significantly as shown in Figure 10.

This study imposes $15 of CO$_2$ price at 2013, and it increases by 5% every year from 2013 to 2035. In figure 10 above, starting at 2013 when CO$_2$ price is implemented, average marginal cost of coal unit exceeds that of natural gas by more than 10 $/MWh, making coal units marginal in ERCOT. The difference between average marginal cost of coal units and that of gas units decrease first from 2013 to 2014, and remains less than 10 $/MWh range for three years, and starts expanding over 10$/MWh range after 2017.
Before 2011, coal units have around 40% penetration level historically (Figure 11), serving base load, but recent low gas price due to shale gas production decreases its share by approximately 8% in 2012 from 2011. Historically, operational flexibilities such as ramp up or down capability, minimum capacity, minimum up-time, minimum down-time, etc. have not been an issue for a coal unit since mostly they are not asked to change their dispatch level abruptly.

However, after 2013, marginal cost of a coal unit is greater than that of a gas unit, and they become marginal units of the system. Their commitment frequency has to increase, but is also subject to operational limits. This leads challenges for economical operation of coal units.

From Figure 11, it can be easily found that as having higher CO₂ price, coal penetration decreases while Figure 12 shows that gas penetration increases in all wind penetration scenarios. It is a natural consequence of economic dispatch: since operating cost of a coal unit increases due to the significant emission cost, its production reduces.

However, one interesting observation is found from the first three years of the study: although coal units’ marginal cost is greater than gas units marginal cost after imposing CO₂ price in 2013, coal generation penetration level (also average capacity factor of coal units) increases for all wind penetration scenarios (circled out in Figure 11) for the first period of simulation. After that, starting 2017, coal generation penetration keeps decreasing till the end of study years. The first three year increase of coal penetration level despite of higher marginal cost than a gas unit is due to operational constraints of coal units.

Mostly coal units have longer minimum up-time, longer minimum down-time, and higher start-up cost comparing to gas units, which means less operational flexibility (Wood, 1996). Their commitment and de-commitment decisions are made based on their profits during minimum up-time hours, opportunistic loss during minimum down-time hours, and start-up cost. After imposing CO₂ price, economic operation of a coal unit becomes challenging, because they are marginal units but with much less operational flexibility, so they cannot be committed or de-committed as often as what gas units can be.

Before committing a coal unit after imposing CO₂ price, it should be considered that the unit may not earn positive profits for all operating hours. For example, let’s assume that, after a coal unit is committed, demand goes down and less expensive gas units become marginal, but a committed coal unit is still in the middle of minimum up-time hours. For those hours, a coal unit should stay on line, but will not cover its operating cost due
to lower market prices than a marginal cost of a coal unit, having negative profits; that is, losses. The amount of losses due to operational constraints of coal units depends on the difference between marginal cost of coal units and that of gas units. If the gap is affordable enough to let the coal units stay online with manageable losses but positive net profits over a longer time horizon, their penetration level will increase as demands increase. This accounts for the increase of coal unit penetration from 2014 to 2016 for all wind cases in Figure 11. During those years, average marginal cost difference between coal and gas units is approximately 10 $/MWh as shown in Figure 10. Appendix E also shows total number of start-ups of gas and coal units for 18% wind penetration scenario. In the chart, you can find number of coal units’ start-up decreases from 2014 to 2016, corresponding increase of coal units’ penetration level.

However, when the average marginal cost difference between gas and coal units is greater than 10 $/MWh, it is more beneficial to de-commit coal units, since the amount of loss when coal units are not marginal, but forced to stay online, becomes large enough to make their net profit negative. This is observed in 2013, 2017, and for the rest of study years to the end. Therefore in general, CO₂ price implementation induces coal retirement due to higher operating cost, but gas addition to compensate coal retirement in the system with growing demand. Figure 9 also shows that there is retirement of coal, which is also consistent with decreasing overall production by coal.

b. Impacts of Wind Penetration

As wind penetration increases shown in Figure 8, ERCOT will experience more retirement for coal, but less addition and less retirement for gas shown in Tables 1 and 2. Wind will reduce production from both coal and gas, but the impact to a coal unit is greater than its impact to a gas unit, since coal units are at the top stack of ERCOT resources after CO₂ price implementation. In order to fill the increasing gap from coal retirement, more existing gas units survive, resulting in less retirement of gas units. However, less gas units are added since increasing wind reduces spaces for possible new entries. In conclusion, net gas addition, amount of addition minus amount of retirement, diminishes from 38,861 MW in Base case to 36,224 MW in ‘30% Wind’ along with average capacity factor of gas units from 42% in base case to 32% in ‘30% wind’, lessening gas penetration as well (see Figure 12). Total amount of retirement and addition during the study period (from 2013 to 2040) are summarized at Table 1 and 2 respectively. Annual expansion by fuel types for all different wind penetration levels is available in Appendix C.

| Table 1: Total Amount of Retirement by Fuel Type [MW] |
|----------------------------------|-------------------|------------------|------------------|-------------------|
| Type               | No CO₂ | Base   | 18percent | 25percent | 30percent |
| COAL               | 876    | 9,326  | 9,744     | 10,538     | 11,462     |
| NG                 | 35,626 | 28,950 | 28,729    | 26,831     | 25,952     |
| Uranium*           | 5,133  | 5,133  | 5,133     | 5,133      | 5,133      |

* Uranium retirement is due to the expiration of current licenses

| Table 2: Total Amount of Addition by Fuel Type [MW] |
|----------------------------------|-------------------|------------------|------------------|-------------------|
| Type               | No CO₂ | Base   | 18percent | 25percent | 30percent |
| WIND               | 1,320† | 2,620  | 21,654    | 35,534     | 49,350     |
| COAL*              | 896    | 896    | 896       | 896        | 896        |
| NG                 | 68,676 | 67,811 | 65,067    | 63,499     | 62,176     |
| SOLAR              | 1,000† | 1,000  | 1,000     | 1,000      | 1,000      |
| Uranium**          | 0      | 2,700  | 2,700     | 2,700      | 2,268      |
† Wind and Solar in No CO₂ case start to be added in 2036
* The only coal addition is Sandy Creek (LS power and Brazos Electric Co.) which will be online at 2013
** New Uranium units are added at 2040 for all scenarios except No CO₂ case

Figure 12: Gas Generation Penetration Levels

Gas penetration levels by different wind penetration are shown in Figure 12. Gas penetration level from 2010 to 2012 has increased due to lowering gas prices, and in 2013 it peaks due to the start of CO₂ price implementation. However, from 2014 to 2016 or to 2017 for higher wind penetration, gas penetration decreases as coal penetration increases during same periods. This is because, as described in the previous section, coal units’ operational constraint let them stay online and still give economic viability of coal units despite their higher marginal cost than that of gas units. After that, when the average marginal cost difference between gas and coal units is greater than 10 $/MWh (Figure 10), it is more economical to de-commit or retire coal units and increase gas power production. This tendency continues to the end of study years, increasing gas penetration level.

Another observation is that for all different wind penetration levels, new nuclear units of over 2,000 MW capacity was added at the end of study year by long term investment logic. This tells us that after losing so many coal units due to environmental regulation, even building a new nuclear unit is economically viable at some time. Having stronger environmental regulation will make this happen earlier, but public concern for a nuclear accident might block new project. Extending current licenses would offset new nuclear supply, otherwise greater amount of gas units should be additionally added.

For all cases, the amount of solar addition is same, 1,000 MW, but the starting year is different: 2036 for no CO₂ case, but a few years earlier (2033 and 2034) for other cases. That is because current solar photovoltaic (PV) and solar thermal units have high capital costs and prevent them from building before 2030 based on market prices. However, technological improvement in solar generation and favorable tax incentives would make economic solar addition more and earlier than this study.
6. Conclusion

Given most likely assumptions from ERCOT and EIA, this study assesses the impact of increasing wind penetration on future outlook of ERCOT market. It also studies the impact of environmental regulation as well with the assumption that CO\textsubscript{2} price from EIA GHG15 case is a representative form for any possible environmental regulations in the future. The study has maintained a practical point of view for the purpose of providing realistic results for future capacity expansion of ERCOT.

CO\textsubscript{2} price has huge impacts on accelerating coal units’ retirement. CO\textsubscript{2} price implementation makes average marginal cost of coal units exceed that of gas units, leaving difficult challenges for their economical operation. Consequently, it reduces production and penetration level of coal units throughout most of study periods.

One interesting observation is captured for the first period of the study: coal penetration level increases for the first three years, before starting to reduce consistently till the end of the study. This is due to operational inflexibility of coal units and the model’s capability to capture short term dynamics of a market.

Higher wind penetration level also affects future generation portfolio in ERCOT. As wind penetration increases, coal units’ retirement increases as well, while both retirement and addition of gas units diminish. Increase of coal retirement allows existing gas units to stay in the market, reducing the amount of gas retirement. However, as both wind capacity and wind production increase, there will be less economical chances for new gas units to be built, so new gas units are lowered.

The general results of this study can be conjectured intuitively, but due to the modeling sophistication, the paper can provide more detailed answers and values regarding future ERCOT resource portfolios varying wind penetration levels: amount of retirement and addition in every year, amount of production and profits of a unit or a fuel type, and so on.

Further study should be done regarding how much emission can actually be saved by having different wind penetration and environmental regulations, tax incentives, etc. and how the corresponding results would be in power generation portfolio of ERCOT and elsewhere.

Acknowledgement

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Global View Data, 2012


Appendices

Appendix A. ERCOT wind capacity by year

Figure 13: ERCOT Wind Capacity by Year [ERCOT, 2012 c]

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<th>Status</th>
<th>Unit Name</th>
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IA*: Interconnection Agreement
Appendix C. Generation Capacity Expansion from 2013 to 2040 by Fuel Type

Figure 14: Generation Expansion - No CO₂ case

Figure 15: Generation Expansion – Base Case

Figure 16: Generation Expansion - 18% Wind
Figure 17: Generation Expansion - 25% Wind

Figure 18: Generation Expansion - 30% Wind
Appendix D. Historical Generation by Fuel Type and Demand Growth Rate

Figure 19: Energy (TWh) by Fuel Type and Demand Growth Rate (ERCOT, 2011)

Appendix E. Start-Up Numbers and Profits of Gas and Coal Units for 18% Wind Scenario

Figure 20: Total Number of Start Ups - 18% Wind
Figure 21: Total Profits - 18% Wind Scenario [thousand $ in nominal]