Think Corner Research Note

U.S. Gas-Power Linkages – Building Future Views

A Modeling Exercise with AURORAxmp

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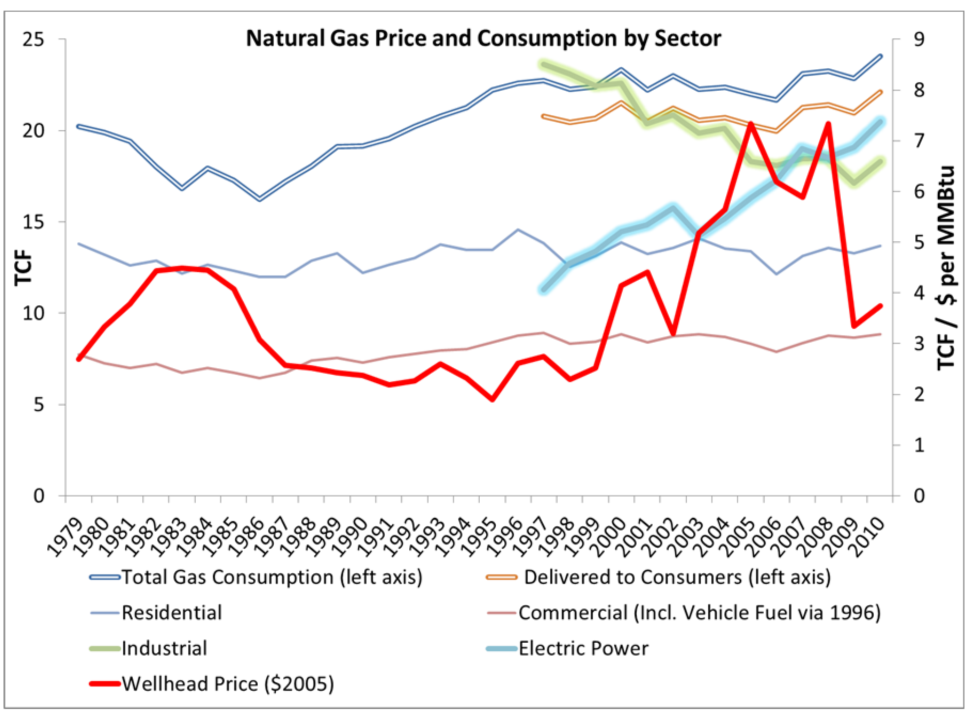
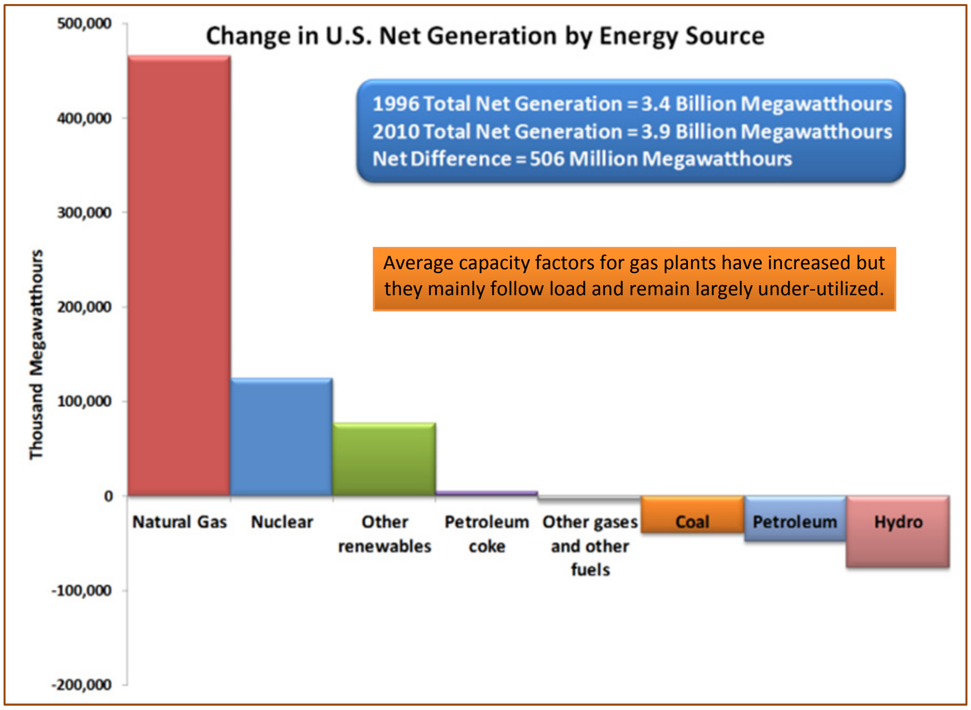
How should we think about, analyze and test the prospects for stronger natural gas and electric power linkages going forward?

Since the late 1990s, there has been a fundamental shift in the U.S. natural gas market: power generation has gradually replaced industrial use as the largest consuming sector (31%) while no significant change occurred in residential and commercial segments. Industrial users, especially in "feedstock" industries like ammonia and methanol, reacted to the rising price of gas in the early 2000s by reducing their demand, switching to other fuels, shutting down and/or moving their operations overseas while power generators increased their use of natural gas despite rising prices. Gas use in power generation occurred primarily to meet increasing demand but also came at the expense of coal and petroleum to a significant extent; hydro generation declined significantly over the same time period. Barring substantial shifts in thinking (which is possible) prevailing opinions are that real, organic growth in natural gas demand going forward could come from the power sector. While industrial use and transportation could take larger quantities of natural gas, gas-fired generation is expected to outpace these applications for a variety of reasons but mainly for environmental benefits.





The industrial and electricity sectors have different consumption patterns for natural gas, with power generation demand being more variable than industrial demand both intra-day and seasonally. This variability is a function of variability of electricity demand throughout the day and across seasons. It is also impacted by various energy and environmental policies and regulations. The integration of intermittent renewables (primarily wind at this time) forces many gas plants (and some coal plants) to cycle to accommodate generation from wind during off-peak hours. The addition of large scale solar systems into the grid and smart grid technologies, especially when combined with increased distributed generation (e.g., solar PV) and demand-side response (e.g., in-home and smart phone devices to manage electricity consumption) will increase the amount of data utilities and system operators will have to manage and add to their struggle to manage increasingly dynamic electricity flows reliably. An increasing role for such demand side changes will also have a yet uncertain impact on the generation portfolio, including demand for gas.

More immediately, a plethora of existing, new and pending environmental regulations both at the state and federal levels impact generation fuel portfolios. Many of these regulations increase the cost of operating coal plants, some of which may retire rather than install pollution control equipment. Studies estimating coal retirements vary as widely as 6 to 65 GW by 2015, a huge range of uncertainty. Announced retirements by an increasing number of companies are moving us closer to the higher end of this range. Planned coal capacity as reported by the EIA declined from 18 GW for the 2010-14 period to 10 GW for the 2011-15 period.

Damage to Japan's Fukushima Daiichi nuclear power complex following the March 11, 2011 earthquake and tsunami led to re-consideration of some projects. In the least, Nuclear Regulatory Commission (NRC) safety regulations of nuclear plants are being revisited with possible consequences for capital and operating costs, already high and problematic pre-Fukushima. Stronger reactions have been observed internationally and building new facilities seems now to be even more difficult. Germany, Italy and some other European countries announced "the end" of their nuclear industry; even France seems to be re-considering the large share of nuclear power in its electricity generation portfolio. Although there are no such strong policy statements in the U.S., public concerns in some communities are heightened.

With the cancellation of the Yucca Mountain project, management of high level radioactive waste remains an issue.

These factors have implications on both the short term and long term demand for natural gas in power generation. Producers of natural gas need to understand these dynamics in evaluating their upstream opportunities. Shale gas production has significantly increased over the last decade and is primarily responsible for the low price of natural gas today, in addition to demand stagnation since the 2008 economic slowdown. The potential for increasing production further is largely thanks to many shale plays that remain to be developed but our analysis shows that the price of natural gas may need to be $6 per MMBtu or higher to justify many projects, especially when drilling is gas directed, i.e., when drilling targets nonassociated, "dry" gas locations. The economics of producing natural gas in association with crude oil and/or natural gas liquids are better, depending upon location and as long as oil prices remain robust. Roughly 60-70 percent of U.S. natural gas production is nonassociated dry gas or methane. Even more challenging, much of that methane is derived from conventional gas fields that are declining rapidly and that have not been a focus for investment during the shale gas "rush".[1] Even with $6 per MMBtu gas, high efficiency combined-cycle generators with heat rates of 7,000 Btu/kWh would result in a marginal cost of around $48 per MWh ($42 for fuel and $6 for operations and maintenance or O&M), which would be competitive with many coal plants given moderate to high emissions costs. This means that older plants would have to invest in emission control equipment and newer plants would have to be designed with those controls in place. There are, however, older coal plants with the necessary emission control equipment and access to high Btu coal that can supply electricity at or below $40 per MWh. Even so, increasing coal exports may sustain an increase in coal prices, which would undermine competitiveness of these coal plants.

Investors in gas-fired generation, on the other hand, need to understand the dynamics of upstream cost structure, especially for shale and other unconventional plays as well as developments in midstream pipeline and storage infrastructure that will have significant bearing on deliverability of natural gas in a timely and cost-efficient manner. Shale plays are different than conventional plays in terms of their production profiles and are in different locations than conventional fields. New pipeline infrastructure is being deployed to connect new supplies with new consumers in the power sector. Storage capacity has increased but low and stable prices challenge commercial viability of some facilities.

Also worth following closely is the emergence of environmental regulations related to hydraulic fracturing, water use and recycling of wastewater that are critical for sustained production of shale gas. Regulation of fugitive methane emissions along the natural gas supply chain is under consideration and can potentially have significant impact on cost of delivery of natural gas.

Finally, what are the prospects for growth in electric power demand? Retail sales of electricity sagged as the 2008-2009 took hold. Demand for electric power has recovered somewhat, but capacity overhangs in many locations, slow economic recovery, and uncertain prospects for accelerated demand cloud the outlook.

In sum, a long list of factors can influence gas use for power generation positively or negatively with commensurate impacts on both gas and power market dynamics. Understanding the net effect requires not only an in-depth analysis of individual factors but also a holistic approach to put all pieces of the puzzle together correctly, capturing dynamics of interactions among these factors. The following

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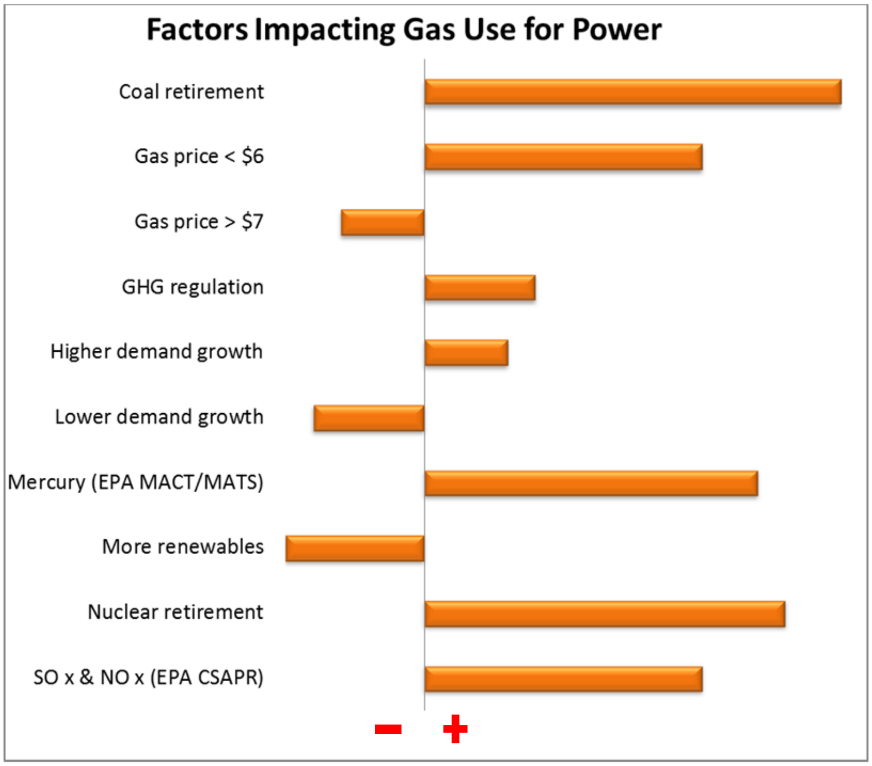
[1] See Foss, *The Outlook for U.S. Gas Prices to 2020: Henry Hub at $3 or $10?*, Oxford Institute for Energy Studies, December 2011, http://www.oxfordenergy.org/2011/12/the-outlook-for-u-s-gas-prices-in-2020-henry-hub-at-3-or-10/ for a comprehensive review of U.S. natural gas market conditions and prospects.

graphic illustrates a list of issues for gas demand in the U.S. power sector. Many of these factors also apply to international locations, which also have their own peculiar challenges.



The graphic is for illustration purposes only – not to scale.

Our Scope

There are many dynamic interactions among the factors listed in the above graphic that cannot be easily captured without the assistance of a modeling tool. In this first of a series of analyses, we used the AURORAxmp software to evaluate the impact of several key issues that has relevance for gas consumption by the power sector in the near future: the impact of Cross-State Air Pollution Rule (CSAPR), and Maximum Achievable Control Technology (MACT) and its implementation standards for power plants, Mercury and Air Toxic Standards (MATS),[2] to control hazardous air pollutants such as mercury on the generation portfolio. We only simulated the Eastern Interconnect (EI) and ERCOT regions since states covered by CSAPR are located in these regions.

We tested the sensitivity of this scenario to natural gas price fluctuations, a price on carbon dioxide or CO_2 and different levels of renewable incentives. Finally, we focused on the ERCOT market in Texas, evaluating the impact of CREZ (competitive renewable energy zones) transmission expansion.

Independently, we also wanted to investigate what would happen if licenses of existing nuclear facilities are not renewed at their date of expiration. In a world of "cheap" gas and increasing share of renewables, and given the uncertainty of the post-Fukushima world as outlined previously, gradual retirement of nuclear plants could be possible.

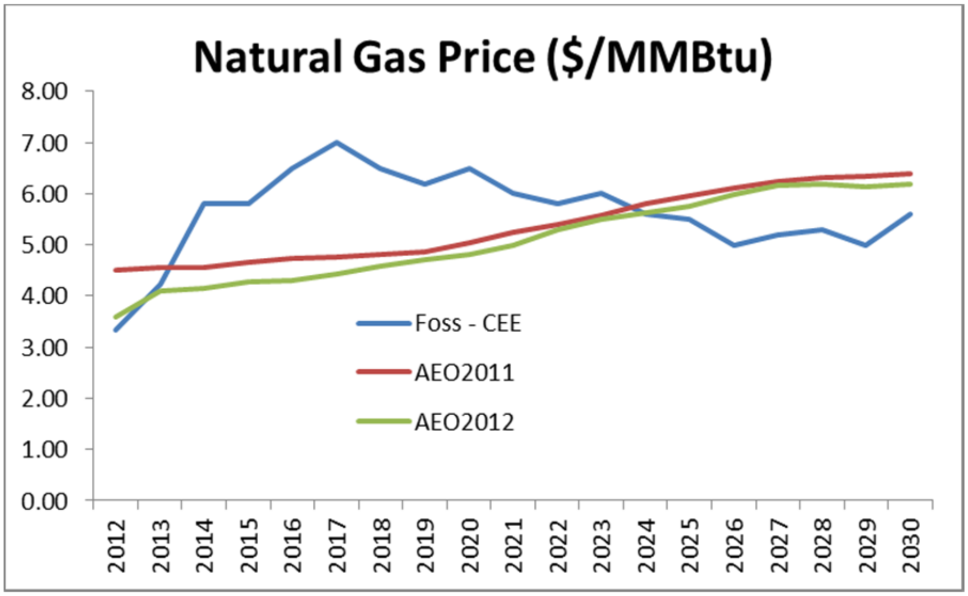
To build our holistic view, we simulated the following set of scenarios:

[2] Standards were announced on December 21, 2011. See http://www.epa.gov/mats/ for details.

1. The **World Without Regulation (WWR)**: in this “baseline” scenario, against which all other scenarios will be compared, we excluded all emission regulation and all subsidies for renewables. Although unrealistic, these assumptions provide an easy to understand baseline.
2. The WWR case with no renewal of nuclear licenses (**WWR No Nuclear**) at their date of expiration.
3. The **CSAPR** case – This scenario covers the following assumptions.
    a. CSAPR for nitrogen oxides (NO_X) and sulfur dioxide (SO_2). The implementation starts in 2012, with two years of trading of allowances across two groups (see detailed description below).[3]
    b. MACT/MATS for mercury and other hazardous air pollutants, becoming binding in 2018. The utilities will either invest in emission control equipment or retire units (see detailed description below).
    c. GHG regulation. Although currently there is no federal law on limiting greenhouse gases, such legislation is possible within the time frame of our study. Already, states are pursuing their own restrictions. We tried to capture this “threat” of GHG regulation via introduction of a CO_2 price ($14/ton in 2018 to $40/ton in 2030). Later, we will eliminate this assumption (see scenario 5 below).
    d. Renewable Incentive of $15/MWh – federal production tax credit historically amounted to more than $20/MWh but it has not been available every year. In years after the Congress let PTC expire, renewables expansion fell significantly. It may be allowed to expire again in 2012. Although there are other incentives such as federal investment tax credits or grants, state-level funds and renewable energy certificate markets, these, too, fail to provide consistent, predictable support for all renewables. For example, in Texas, RECs fell to $1-2/MWh. Finally, all of these programs benefited wind projects, which have the lowest cost, the most. Only recently, and with focused mandates and solar RECs, the investment in solar facilities started to increase. Accordingly, we start with a $15/MWh generic incentive for renewables; we will test a scenario where this incentive will be increased.
4. A natural gas price spike with CSAPR case (**CSAPR-CEE**). In previous scenarios, we used the price forecast from the Energy Information Administration’s Annual Energy Outlook 2011. In this scenario, we replace the smooth upward forecast of the EIA with aprice trajectory developed from other CEE work.[4] The current price of $3/MMBtu (below $3 at time of writing) is too low for all producers to generate acceptable revenues and continue investing in new gas development. Oil field service costs remain strong, pushed by persistent high oil prices and other factors such as technical challenges, work force shortages and so on. In the low natural gas price environment that is expected to prevail through 2013, producer margins will be heavily pressured. The industry is in the process of adjusting; consolidation, write downs, and other

[3] The U.S. Court of Appeals for the District of Columbia Circuit temporarily blocked the implementation of CSAPR on December 30, 2011, after we conducted the analysis. The January 1st target date for implementation of CSAPR was commonly seen as too aggressive; this stay will probably delay that date until late 2012 or early 2013 but not expected to lead to significant changes in CSAPR’s requirements. In our modeling, utilities mostly depend on allowance trading in 2012 and 2013; and most shut-down decisions are not seen until 2017 or 2018 when MACT also becomes binding. As a result, we do not expect the stay decision of the Court to change our results significantly. If the Court decides to change CSAPR requirements significantly, it might be necessary to run the model again.
[4] See Foss, 2011, footnote 1.

actions will eventually restore balance, as will stronger gas consumption in response to the lower price signal. The historical pattern of price cycles is expected to return with an initial increase from the current levels to $7/MMBtu, adjusted for inflation, by the middle of this decade. As readers will see below, the results do not change much in terms of gas consumption or new gas builds, but the timing of retirements and expansion, and the impact on power prices are different, which may have implications for investment and risk management decisions. In any event, the cyclic forecast is historically a more accurate reflection of the gas market.



5. CSAPR-CEE without GHG regulation (**CSAPR-CEE No GHG**). As it is possible to see some form of GHG regulation it is also possible that such regulation will not be implemented, or even if it is implemented it does not cause CO_2 price to rise to levels assumed in scenario 3 above. For example, the cap-and-trade market in Europe collapsed due to generous assignment of allowances to utilities in its first incarnation. The revised market did not fare too well either, this time mainly due to economic slowdown following the 2008 crisis.
6. A case that adds ERCOT's Competitive Renewable Energy Zones (CREZ) to our mix of CSAPR and volatile gas price (**ERCOT CSAPR CEE CREZ**). Texas has built significant wind capacity since the early 2000s, mostly in the Western parts of the state, where there is little load and hence little transmission capacity. The CREZ transmission projects, originally expected to cost less than $5 billion, are now expected to cost close to $7 billion and scheduled to be finished by the end of 2013. We wanted to test whether the CREZ lines with their 18 GW of capacity will lead to additional wind investment.

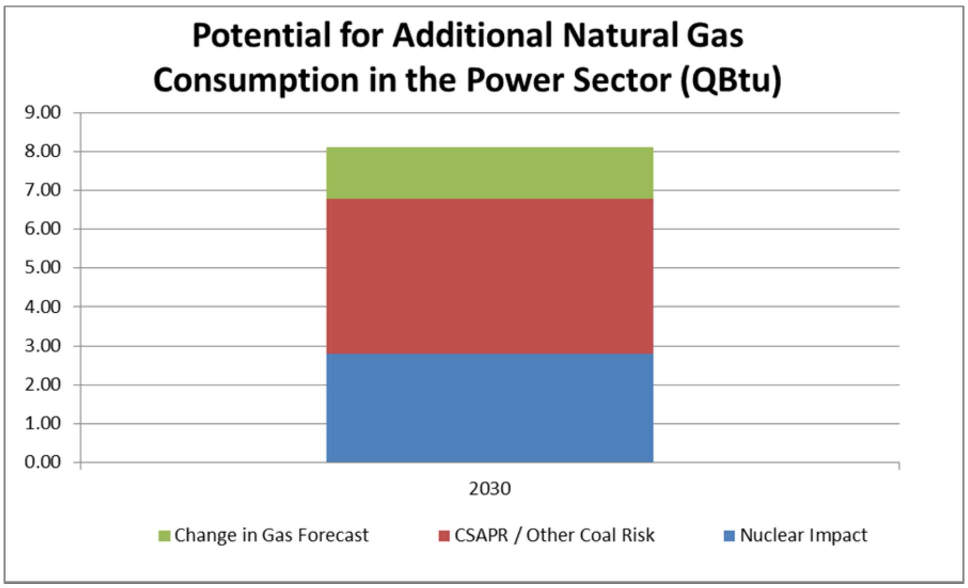
We modeled only the Eastern Interconnect and ERCOT regions where the states subject to CSAPR are located. All runs used the latest new build cost estimates from the EIA.[5] The model was tested based on the EIA 2010 actuals for calibration purposes; the model slightly underestimated gas demand in 2010, indicating that it is somewhat more conservative than actual market but otherwise a good fit. For all cases, we assume regional growth rates, primarily based on historical trends and growth projections from RTOs. In fast growth regions such as ERCOT, electricity demand growth is estimated at above two percent; in MISO and other growth areas 1.2 to 1.3 percent is common; less than 0.5 percent is used for

[5] *Updated Capital Cost Estimates for Electricity Generation Plants*, November 2010. http://www.eia.gov/oiaf/beck_plantcosts/index.html

some regions in the Northeast. Our growth assumption allows for some efficiency improvements but not as aggressive as that of the EIA, the forecast of which is based on an average growth rate of 0.8 percent, which is much lower than historical annualized growth rate of about 1.5 percent for the U.S (between 1990 and 2010).

Key Outcomes

In all scenarios, generation shifts to more natural gas. There is significant potential for increased gas consumption in the power sector – about eight tcf of additional demand in 2030 in EI and ERCOT regions, more than doubling total U.S. consumption in 2010 (7.4 tcf or 31 percent of total consumption of 23.8 tcf in the U.S.).[6] About half of this increased use of gas, or about four tcf, will be driven by the need to replace coal capacity that will be retired either due to old age or due to CSAPR, MACT/MATS and GHG regulation (or the "threat" of it). If nuclear licenses are not renewed at their expiration date, close to 54 GW of nuclear capacity retirements will be seen between 2012 and 2030 and the loss of nuclear will be compensated by gas-fired units, which will add another 2.8 tcf to gas demand. Switching from the EIA gas price forecast to our price trajectory has the potential to add about 1.3 tcf since the price is expected to be lower in outer years of our time frame.



The National Petroleum Council (NPC), in its 2011 study, summarizes various gas demand predictions.[7] For 2030, power sector gas demand ranges from 20 to 35 bcfd (or, roughly 7.3 tcf to 12.8 tcf per year). Considering that the U.S. power sector consumed 7.4 tcf in 2010; predicting that the sector will not consume more than that in 2030 seems unrealistic, especially given the upward trend observed over the last decade and demand growth projections by the RTOs. On the other hand, our estimate of eight tcf of additional gas demand just in EI & ERCOT is quite aggressive and would translate to about 10 tcf of additional demand nationwide. At about 17 tcf, our implied 2030 prediction for the U.S. power sector would be significantly larger than the highest estimate captured in the NPC study, 12.8 tcf. Hence, it is important to underline that our estimate reflects a high case, combining the impact of multiple

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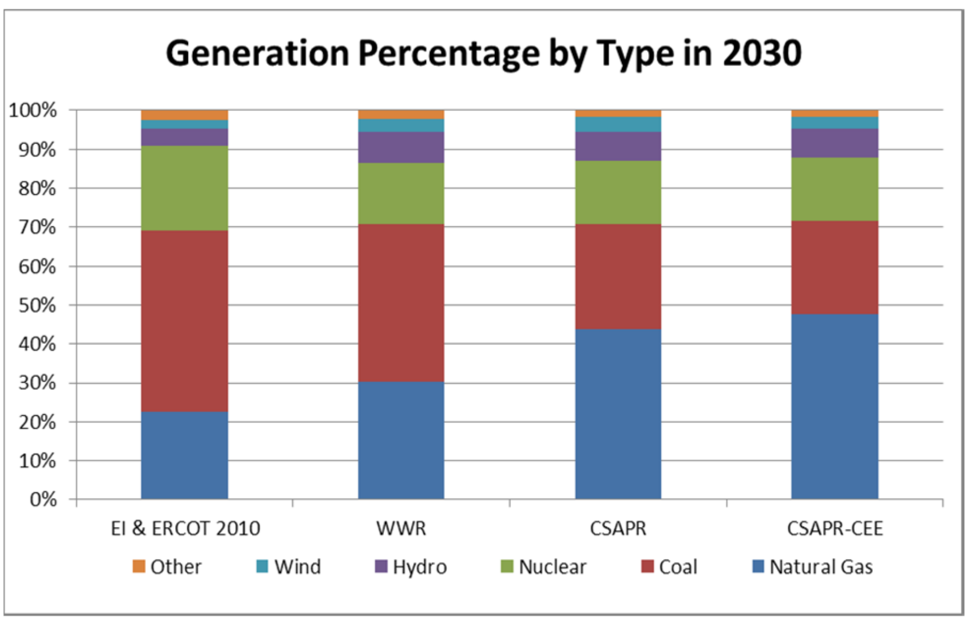
[6] Including WECC would likely result in more gas consumption. Given that EI and ERCOT account for about 80 percent of total power sector gas consumption, total additional U.S. consumption in 2030 could be roughly estimated at about 10 tcf. But since CSAPR does not cover states outside EI and ERCOT, one should be careful about this extrapolation. Accordingly, we plan to simulate WECC in the future.

[7] See Figure 3.2 in Chapter 3 – Natural Gas Demand in *Prudent Development – Realizing the Potential of North America's Abundant Natural Gas and Oil Resources* available at http://www.npc.org/.

developments from a large number of nuclear retirements to low gas prices and from CSAPR to potential GHG regulation. In all likelihood, nuclear retirements will not happen at the full scale assumed in our exercise. Similarly, the impact of CSAPR and MATS will probably be more muted and slower than our assumptions; for example, carbon capture and sequestration may keep some units online.[8] Finally, we may not see carbon pricing at all or at the levels assumed for this study. Nevertheless, even if only half of the additional gas demand we estimated has high probability of occurring, that would place us in the high end of predictions reported in the NPC study at 12-13 tcf.

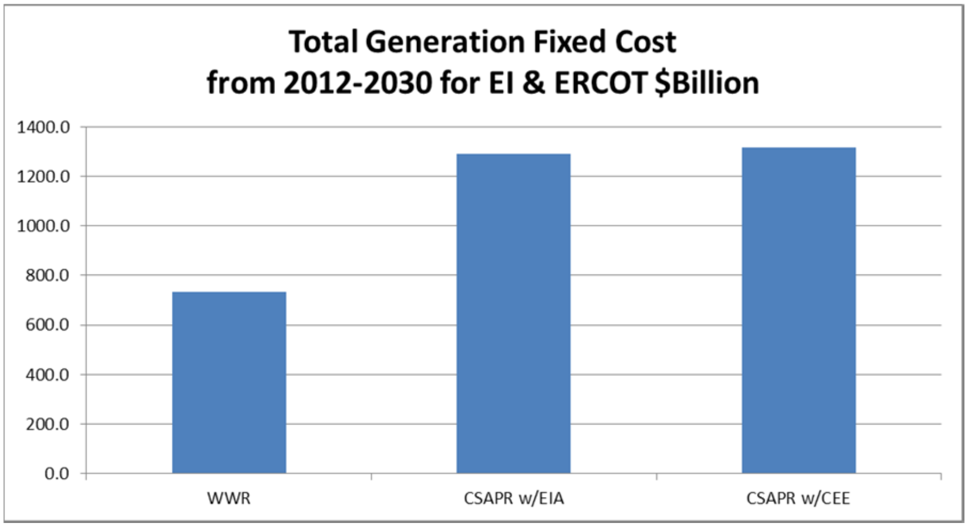
Gas generation could be the dominant generation source for the Eastern Interconnect and ERCOT regions, replacing coal, by 2020. Although our analysis focuses on the Eastern Interconnect and ERCOT due to coverage area of CSAPR; MACT/MATS, carbon pricing, renewables subsidies and gas prices impact all of the United States. As will be discussed later in further detail, more than CSAPR, it is the other factors that appear to be driving the switch to gas. Accordingly, we would expect a similar shift to gas, possibly at differing rates, in other regions of the U.S.[9] With the EIA gas price projection gas becomes the largest contributor to power generation by 2020 under the CSAPR scenario; by 2030, 44 percent of generation could be gas-fired as compared to 23 percent in 2010. With the CEE gas price forecast, the share of gas-fired generation will be few percentage points higher at 48 percent. This expansion of gas occurs mostly to compensate for reduction in coal and, to a certain extent, reduction in nuclear generation. Renewables capacity additions (almost exclusively wind) remain limited at 18.4 GW between 2012 and 2030 despite carbon pricing and a $15/MWh subsidy; without carbon pricing only 1.7 GW of wind will be added.



Although there is significant amount of underutilized capacity in relatively young combined cycle units around the country, including the Eastern Interconnect and ERCOT regions, demand growth will fuel large amounts of investment between 2012 and 2030. Most of this investment will be in gas-fired units. Under the WWR baseline scenario, $734 billion[10] will be needed with almost half of it in gas generation, 22 percent in coal and 20 percent in nuclear. The CSAPR case nearly doubles the need for fixed expenses, requiring $1,290 billion. Changing the natural gas price forecast from that of EIA to that of

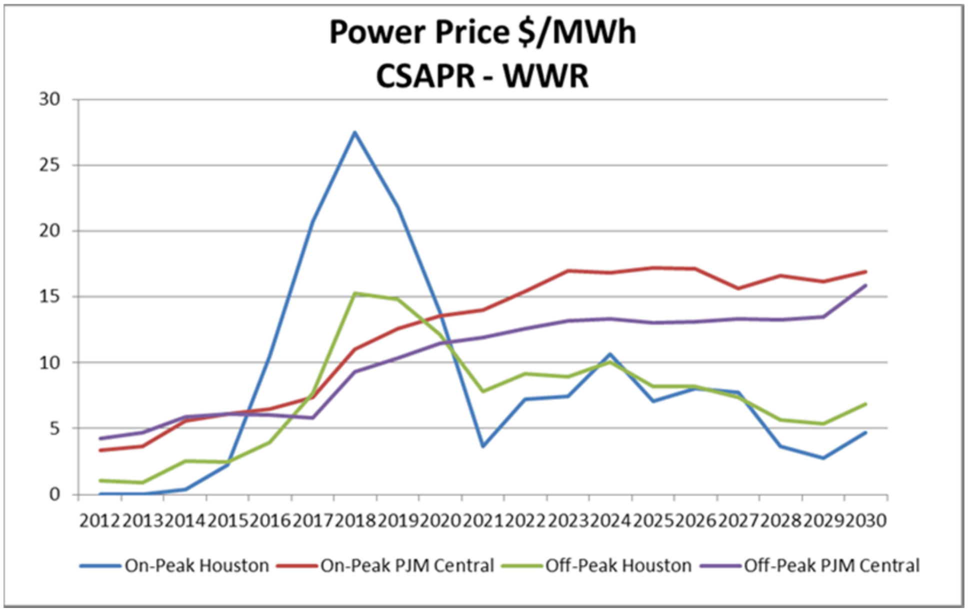
[8] The impact of CCS is another scenario we can test based on the knowledge built at the Gulf Coast Carbon Center at BEG.
[9] We plan to analyze the impact of various scenarios on all of the U.S. in the future.
[10] Investment includes cost of control equipment and fixed O&M in addition to capital cost of new builds.

CEE increases the amount slightly to $1,316 billion. Most of the difference between total fixed cost needs of the WWR case and those of the CSAPR cases is accounted for by investment in coal units, either in the form of emission controls at $600 per kW or as new plants with state-of-the-art emission controls to replace some of the retiring units. Coal investments increase from $161 billion in the WWR case to about $630 billion in the CSAPR cases.

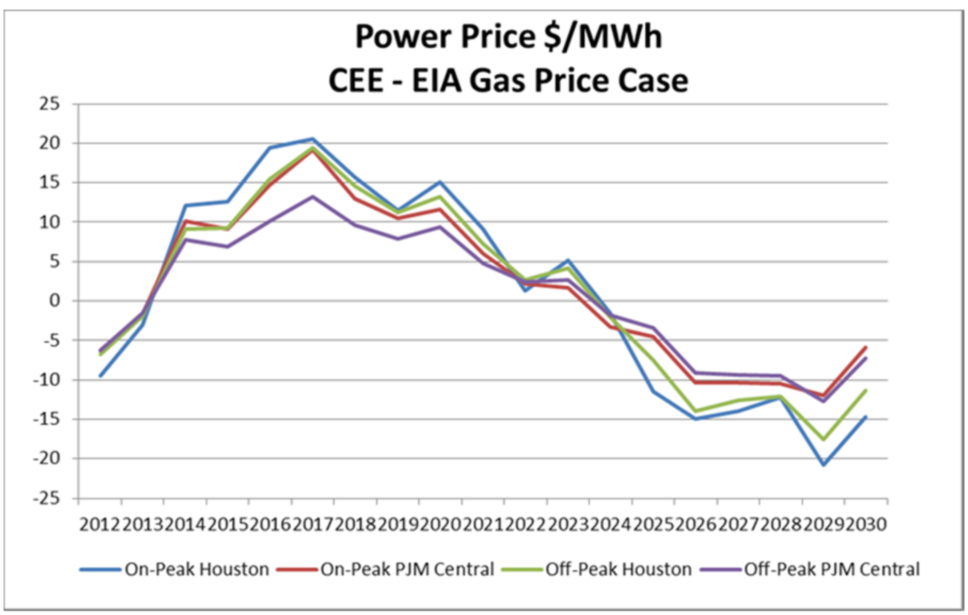


Most of these investment decisions will be made with consideration of future risk of CO_2 price. The impact of a CO_2 price is relatively small for the overall market but can be significant for wind developers. When we tested the CSAPR-CEE case without a carbon cost, new builds declined by about 20 GW, mostly in wind (16.7 GW); because less coal and gas units are forced to retire in this case (about 6 GW of coal and 3 GW of gas stayed operational). However, all remaining units have to install emission control equipment to comply with CSAPR and MACT/MATS. As a result, overall investment is smaller only by about $44 billion relative to the CSAPR-CEE case.

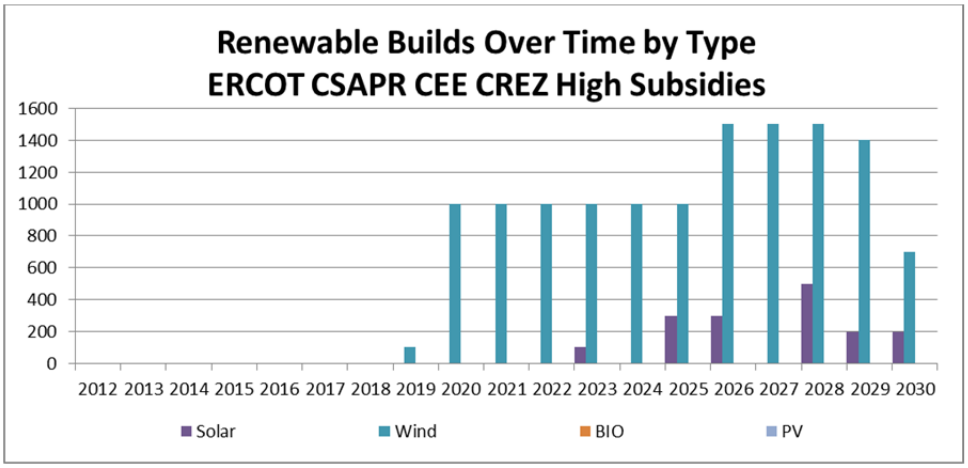
One of the biggest drivers of power prices is natural gas prices. CSAPR will increase power prices as it takes time for the market to adjust to retirement of coal and some older gas facilities. These retiring units will be replaced primarily by combined cycle gas facilities and, as long as there is a carbon price, some renewables (mostly wind). Both sources generate power more expensively than existing coal units. The largest portion of retirements will occur during the 2016-2018 period when both MACT/MATS and CO_2 pricing becomes effective in our CSAPR scenarios.



There will be spikes in on-peak and off-peak prices of electricity in ERCOT's Houston zone coincident with this time period, especially in the CEE gas price forecast case since the gas price also peaks in 2016 and ERCOT depends heavily on gas generation (peaking in particular). The increase in electricity prices of the PJM occur more gradually but it is still possible to see a step change in 2017. In both regions, electricity prices stabilize along with the price of natural gas after the early 2020s. Under the CEE gas price scenario, prices would actually decline in future years as they are lower than those projected by the EIA.



Texas has become a leader in installed wind capacity since the early 2000s. As in many other parts of the U.S., the rapid wind expansion was based on the state's mandates but would not have occurred at the rate it did in the absence of federal production tax credits, high quality resources and high natural gas prices.[11] Since most of the wind capacity was built in West Texas, away from major load centers, new transmission lines were needed. The Public Utilities Commission of Texas decided to encourage the construction of the optimal facilities with the competitive renewable energy zones (CREZ) program. The CREZ lines are now under construction and designed to have a capacity of 18 GW as compared to about nine GW of wind currently built in West Texas. Note, however, that given the competitive market structure in Texas, the gird is open access and any type of facility can be connected to these lines as long as they follow the proper interconnection procedures.



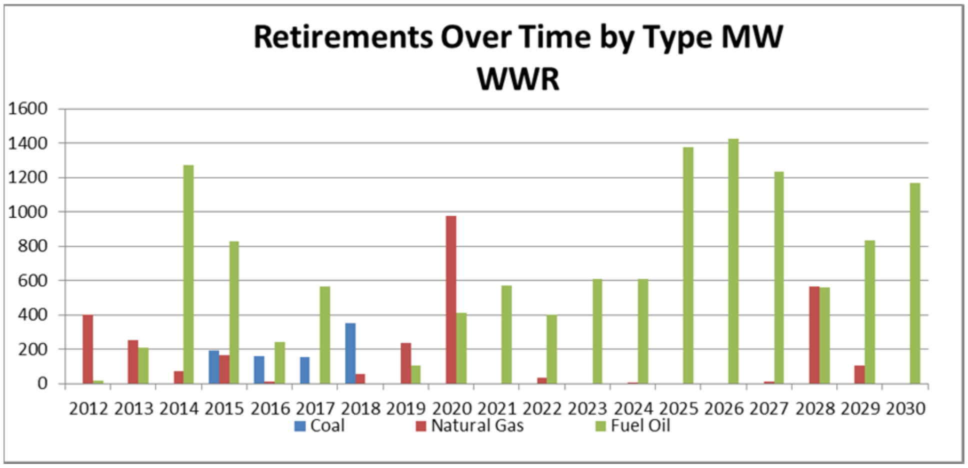
As we have already seen, investment in wind (and other renewables) is limited across both the Eastern Interconnect and ERCOT regions and depends on placing a price on CO_2. In fact, all of the additional investment occurs in the Eastern Interconnect. When we added CREZ capacity into our simulation, it did not lead to any additional investment in wind in ERCOT. However, when we increased incentives from \$15/MWh to \$25/MWh for wind and \$35/MWh for solar, we observe the increased renewables capacity depicted in the above chart: 12.7 GW of wind and 1.6 GW of solar.

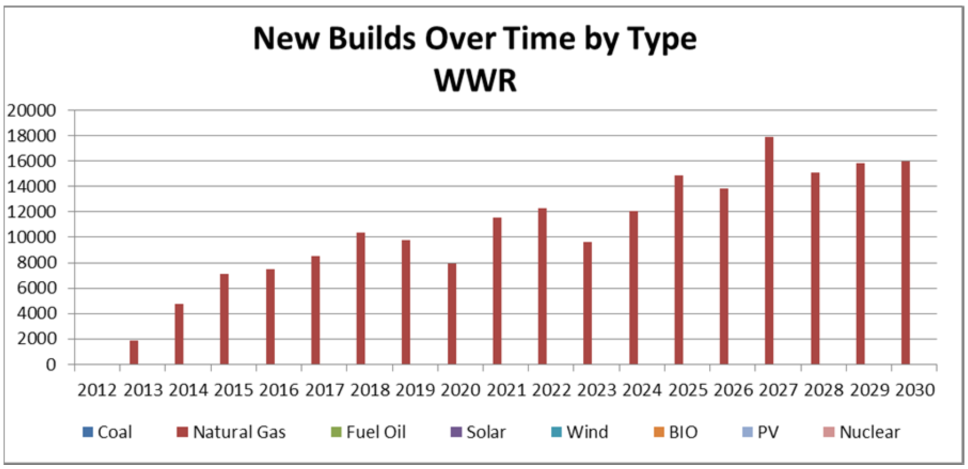
Detailed Results of the Scenarios

The WWR case

In order to establish a baseline, against which we can compare the scenarios of interest, we simulate the model without new EPA regulations, a price on GHG emissions and subsidies for renewables. As one would expect, there will be limited retirements of old coal and gas units; relatively more fuel oil units are retired under this baseline scenario. In order to meet growing demand, expansion will be necessary, all of which can be expected to be gas-fired units.

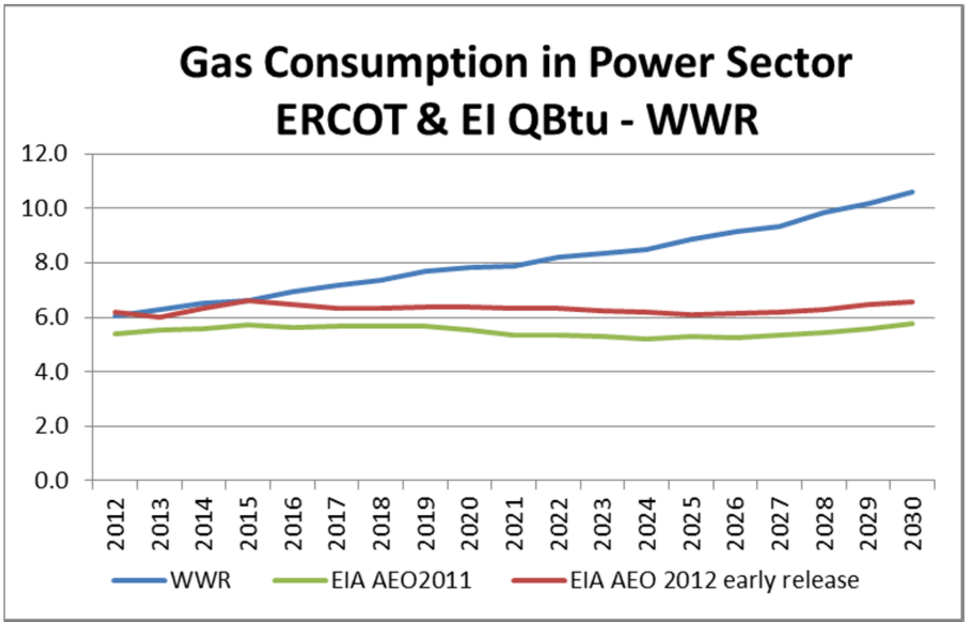
[11] See *Lessons Learned from Renewable Energy Credit (REC) Trading in Texas* (2009), CEE project report to State Energy Conservation Office. (http://www.beg.utexas.edu/energyecon/transmission_forum/tf.php).





Even in this baseline scenario with no regulation to push coal out, the amount of gas consumption can be expected to be much higher than the level forecasted by the EIA in its Annual Energy Outlook 2011, surpassing 10 tcf relative to EIA's forecast of less than 6 tcf.[12] This increase is basically to meet the natural growth in electricity demand. Coal consumption rises 18 percent from 2012 to 2030.

[12] This gas consumption level for Eastern Interconnect and ERCOT is obtained by subtracting Pacific and Mountain region estimates of the AEO 2011 from the total U.S. figures.



Note that the AEO 2012 early release figures are almost identical to our 2012-25 estimates; they rise until 2015 but slightly decline and remain flat afterwards, probably reflecting assumptions of faster growth in renewables and significant efficiency improvements. The AEO 2012 assumes that the share of renewables will increase by six percent between 2010 and 2035. More strikingly, the electricity demand growth between 2010 and 2035 is assumed to grow at an average annual rate of 0.8 percent; this is about half of the growth rate observed between 1990 and 2010 at more than 1.5 percent. We find this assumption difficult to defend as long as the U.S. population and economy continues to grow at historical rates, and all expectations are for the U.S. to remain a "young" nation demographically. Thus, we used regional growth rates that range from less than 0.5 percent to more than two percent.

The CSAPR case:

In this scenario, we add CSAPR, MACT/MATS, CO_2 cost ($14/ton in 2018 to $40/ton in 2030) and renewables subsidies ($15/MWh).[13] As before, we use the EIA AEO 2011 Gas Price Forecast.

CSAPR has two groups of states. Prices for emissions are likely to manifest great variation across states depending on their target levels and current emissions. This variation implies that it will be possible to trade permits. Trading of emission allowances within groups allowed in 2012 and 2013. Banking of allowances is allowed; if any entity ends up with excess allowances in any year, it can transfer them to following year during this two-year period. For example, emitters in Texas can buy permits from Alabama where prices are expected to be much lower; bank the non-used portion of these permits for the first two years without wasting their own permits. Based on these assumptions, we calibrated prices of NO_X and SO_2 in each state to comply with CSAPR limits in 2012 and 2013, which required multiple iterative runs to converge on emission prices and emission limits.

[13] We simulated the impact of CSAPR by itself but it did not lead to significant retirements. The MACT and, to a certain extent, CO_2 cost seem to be a more important drivers.

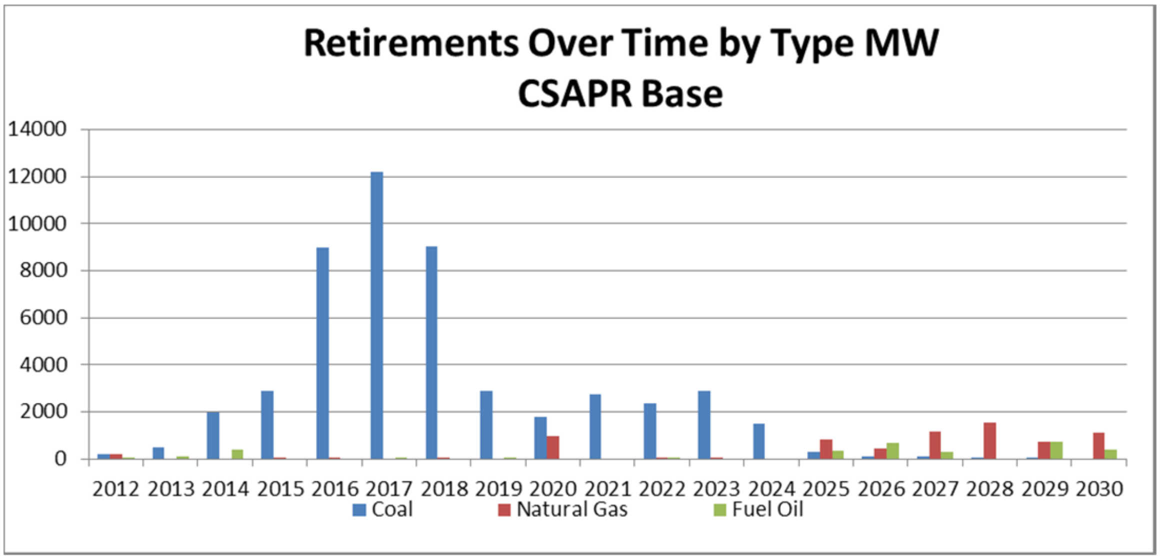
GROUP 1		Bank	Price		GROUP 2			Price
IA		-4750.1	1200		AL		160057.8	800
IL		30175.31	1200		GA		95591.24	800
IN		73623.56	1200		KS		2635.91	800
KY		39762.97	1200		MN		-4327.24	800
MD		8061.764	1200		NE		-11709.2	800
MI		8375.646	1200		SC		69632.81	800
MO		35529.54	1200		TX		-128778	800
NC		86885.79	1200		Sum		183103	800
NJ		3570.376	1200					
NY		10172.09	1200		Ratio to Limit		20%	
OH		28393.65	1200					
PA		43638.61	1200					
TN		73648.12	1200					
VA		41848.54	1200					
WI		-1940.37	1200					
WV		35599.55	1200					
Sum		512595	1200					
Ratio to Limit		21%						

Trading of emissions allowances involves an iterative approach as the actions of one participant may impact another participant. The banking capability impacts the level of the emission price. Banking offers power plant operators an opportunity to meet their emissions targets at a lower cost; but this value maximization is constrained and uncertain. There is an opportunity because some operators in some regions will have permits to sell at a price that is lower than the cost of compliance for some other operators in some other regions. The supply of these allowances will be limited especially if the program is designed with increasingly tighter limits. Finally, the value of banking is uncertain because operators cannot be certain about next year's prices of electricity and permits; weather, demand fluctuations, supply by other generators (e.g., by renewables that receive out-of-market incentives) and decisions by other operators with respect to emissions control (e.g., whether to shut down or install control equipment) will have an unpredictable impact on these prices. In the end, the decision to bank allowances depends on an operator's expectations about future market conditions and how the risks around these expectations are managed. If banking is one of the lower costs options to manage risks, it will be pursued but it will likely represent a percentage of overall requirements. Finally, experience with NO_X and SO_2 trading indicate that EPA will likely restrict the amount of banking in order not to delay environmental benefits.

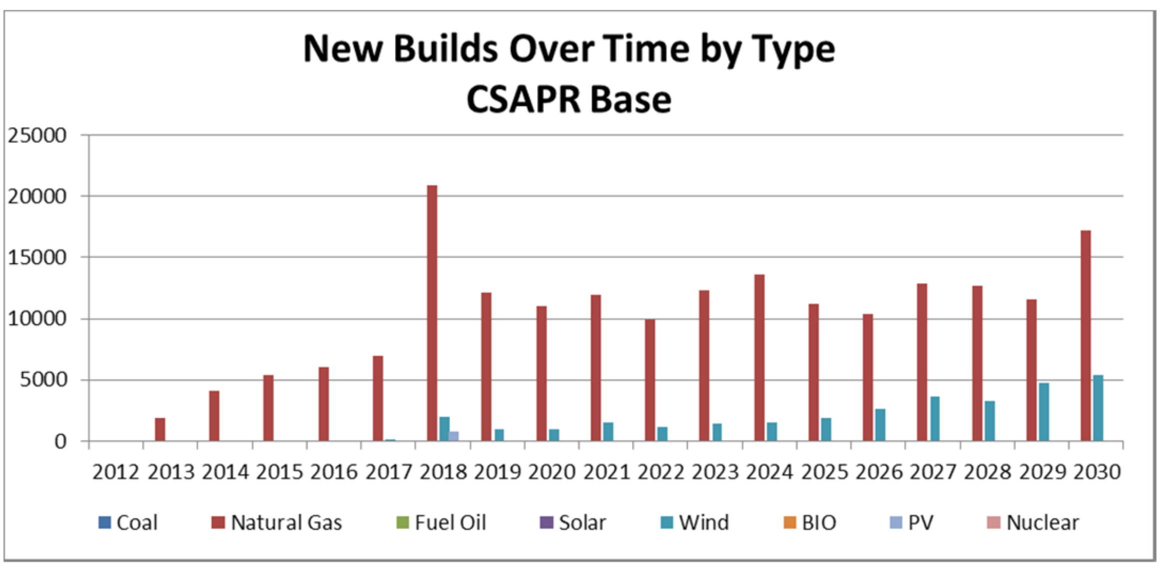
For our exercise, we set the target banking level at around 20 percent;[14] and simulated the model repeatedly until this target level of banking was achieved for each Group (as seen in table). In 2012 and 2013, given the unlimited trading within the group, there should be two group prices – Group 1 and Group 2 ($1,200 and $800 per ton, respectively). Group 2 is less constrained based on the allowances assigned to Group 2 states by the EPA, producing a lower price than Group 1. After 2014, when inter-Group trading ends, each individual state will have a price since there is a limit to trading between states within each Group. Certain states will be significantly constrained with prices as high as $3000/ton for SO2. A similar process was pursued for NO_X.

[14] Historically, the share of banked NO_X allowances has been less than 10 percent of total allowances while the share of banked SO_2 allowances were much higher especially during the transition from Phase I to Phase II of the Title IV program.

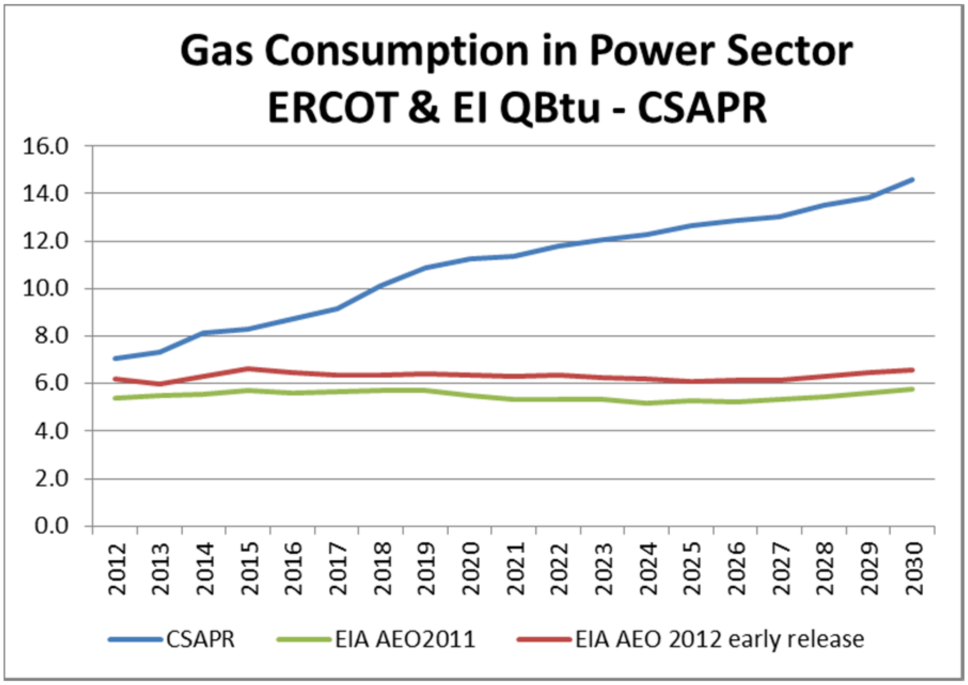
The MACT/MATS will likely require all coal plants to install control equipment by 2018; we assume \$600/kW as the capital cost of control equipment with a 10-year recovery period. Coal units that are currently older than 55 (about 16 GW) were not given the choice to install scrubbers; they were automatically retired in 2018. With these assumptions, the simulation resulted in significant coal retirements (including the forced retirements of units older than 55), which seemed to be more of a function of meeting MACT/MATS requirements than CSAPR. Starting in 2018, CO_2 costs we imposed might have also played a role but that appears to be relatively small and declining towards the future. Overall, more than 50 GW of coal capacity is expected to retire by 2030, most of which occurs before 2020 (about 40GW).



Gas is still the dominant choice for new builds but there is increasing wind capacity additions after 2018, clearly benefiting from MACT/MATS requirements and CO_2 cost imposed on thermal units in addition to \$15/MWh incentive provided to renewables. Overall, 192 GW of gas-fired and 31 GW of wind capacity can be expected to be built.



A 36 percent increase in gas consumption is needed relative to the WWR case by 2030, when about 14.5 tcf of gas will be used for power generation as compared to a little over 10 tcf under the WWR scenario. Coal consumption falls nearly 19 percent from 2012 to 2030 as compared to the 18 percent increase seen under the WWR scenario.

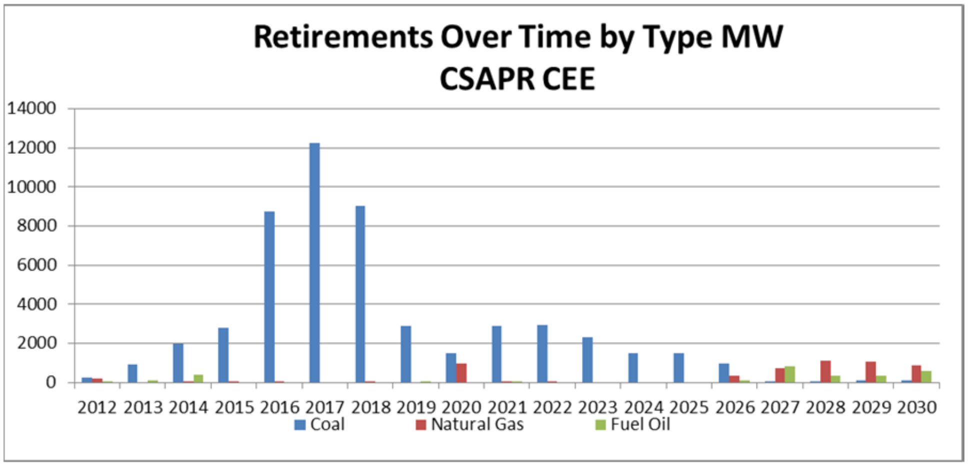


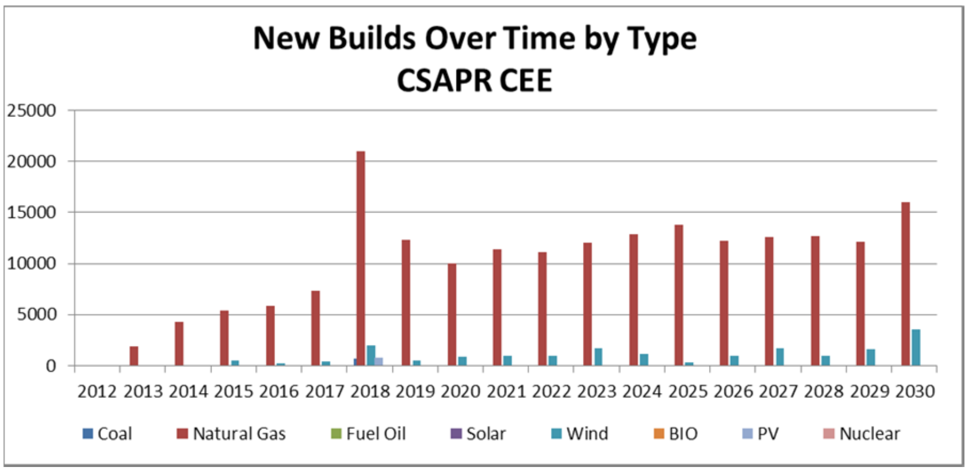
The CSAPR case with CEE gas price forecast

As depicted before, the CEE gas price forecast is more cyclical, hence historically accurate, than the smooth EIA forecast. We envision gas prices that are higher than the EIA forecast in the short to mid-term but lower in the long-term relative to the EIA AEO 2011. The substitution of the smooth EIA forecast with the cyclical CEE forecast resulted in an increase in emission prices as high gas prices in the short to mid-term increase the threshold for coal plants to dispatch more. Over $1,000/ton increase in price still did not achieve the same level of banks as in the CSAPR case.[15]

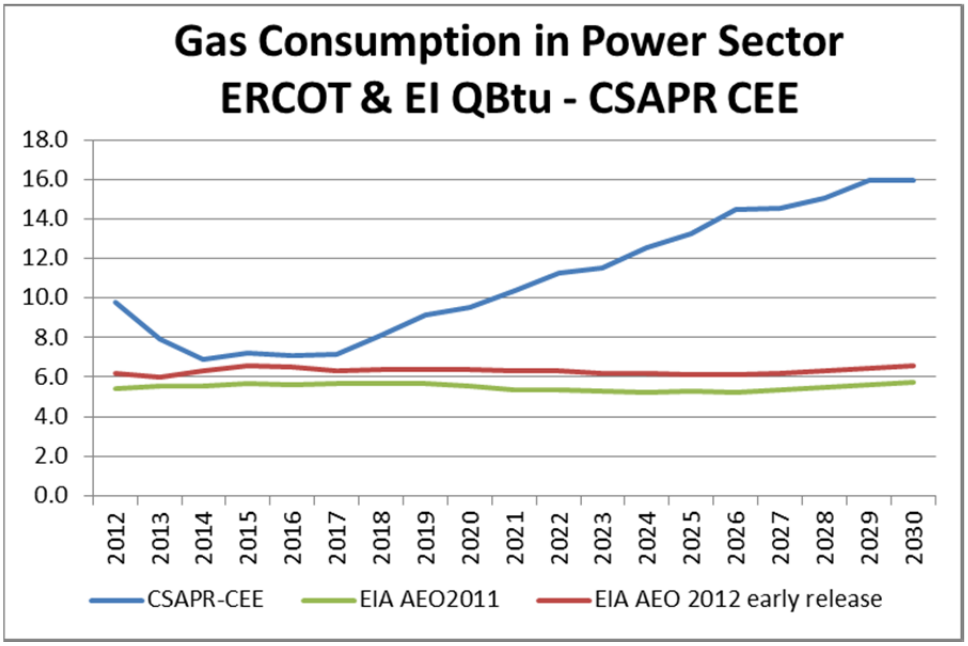
Once the emission markets are balanced, the model yielded similar levels of retirements and new builds as the CSAPR case with the EIA forecast; two GW of more coal retirement, 1.6 GW of less gas retirement, three GW of more gas builds and 13 GW of less wind build. Lower gas prices in the long-term seem to hurt the prospects for wind the most.

[15] We will further investigate the trading scenarios for both CSAPR and CSAPR-CEE cases.



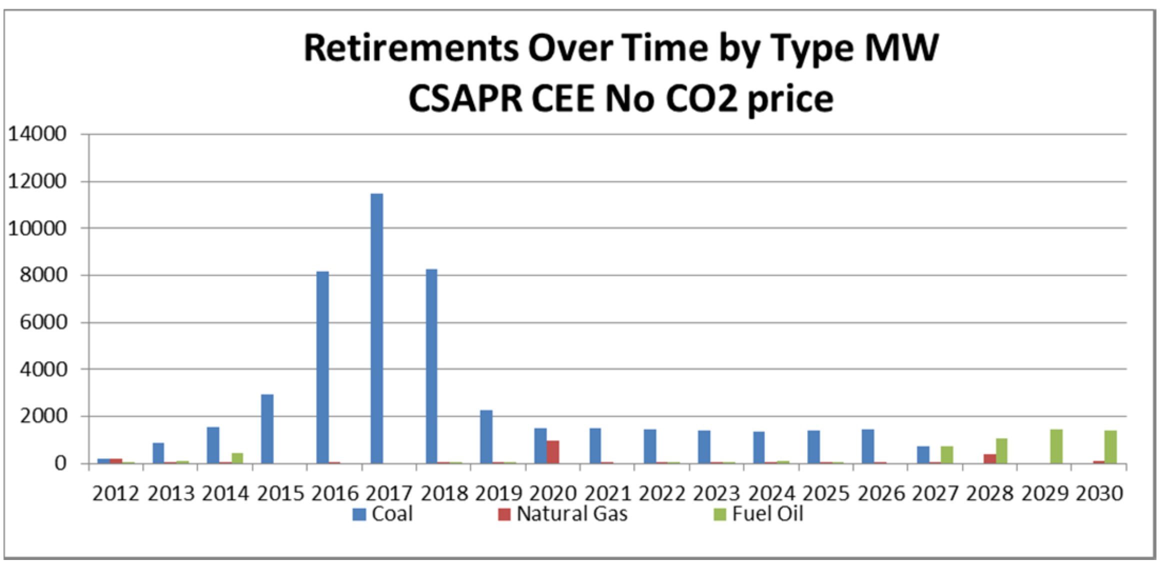


Gas consumption follows a pattern that is negatively correlated with the CEE gas price forecast, declining in the short to mid-term as gas price peaks in 2017 but recovering quite rigorously later as the gas price moderates. Gas consumption eventually reaches almost 16 tcf by 2029. Although this eventual level is higher than the peak reached under the original CSAPR scenario with the EIA price forecast, cumulative gas consumption between 2012 and 2030 is about the same under both price scenarios at about 207 tcf. Similarly, cumulative coal consumption is roughly equal under both cases but, unlike in the original CSAPR case, coal consumption is more stable under the CEE gas price forecast, declining only seven percent between 2012 and 2030 (as opposed to 19 percent decline).

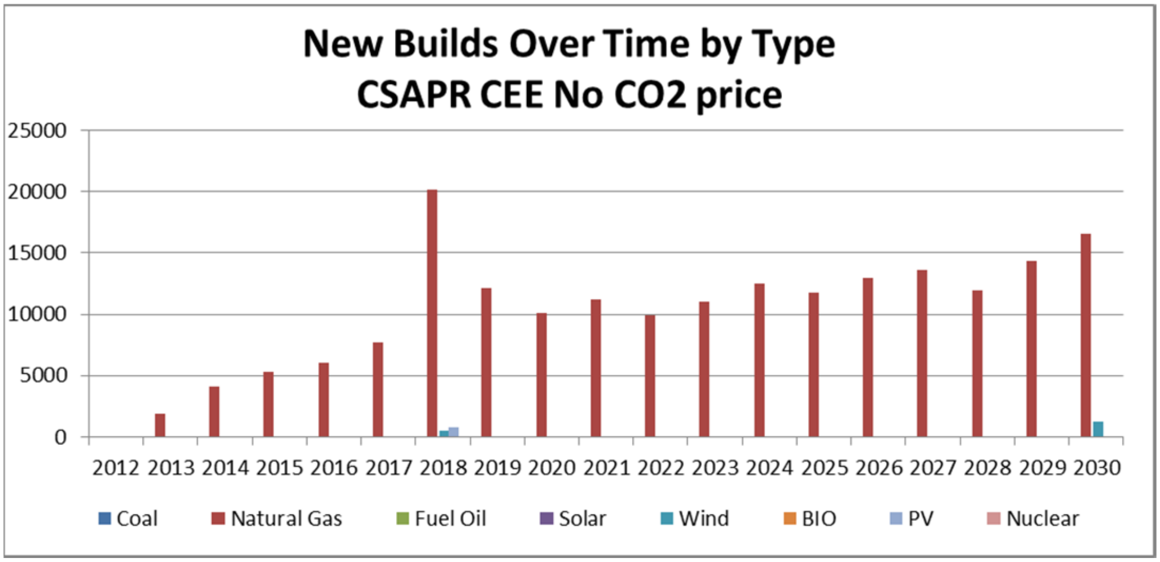


The CSAPR case with CEE gas price forecast and no CO_2 price

In order to evaluate the impact of the GHG regulations, we removed the CO_2 price, which starts in 2018 at $14/ton and climbs to over $40/ton by 2030. Without the cost of GHG emissions, six GW less of coal unit retirement (46.5 GW versus 52.7 GW) and 3.4 GW less of gas unit retirement (5.5 GW versus 2.1 GW) can be expected to occur as compared to the CSAPR-CEE case. Instead more fuel oil units will retire (5.5 GW versus 2.7 GW).

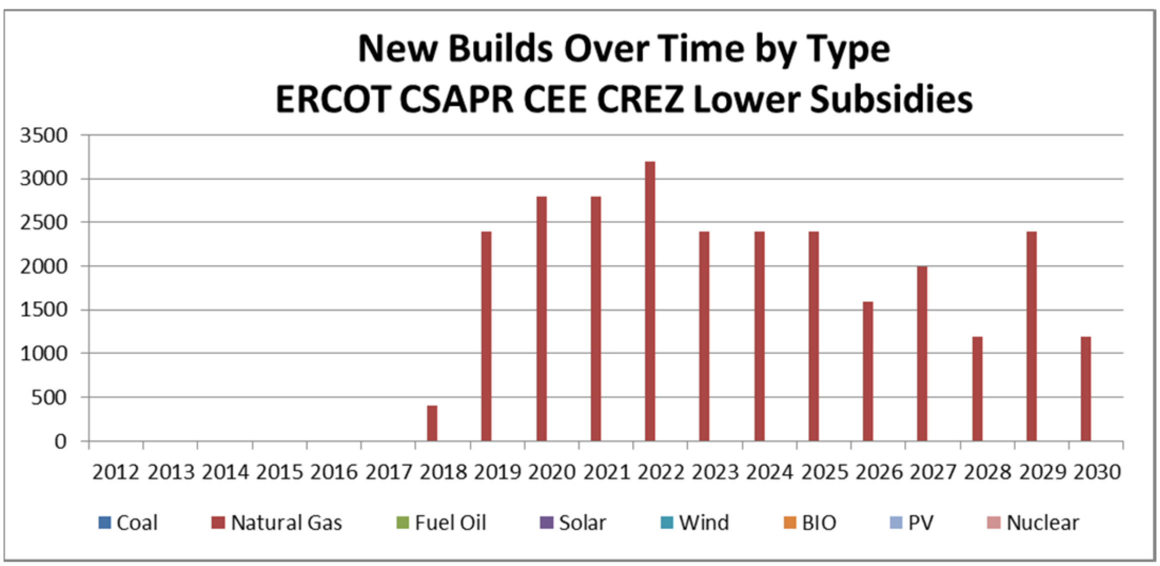


Without CO_2 pricing, 20 GW of less new capacity will get built. Most of this reduced need will hit the wind industry, which will build only 1.7 GW versus 18.4 GW. The gas builds is reduced only two GW (193 GW versus 195 GW). This exercise clearly showed that CSAPR, MACT/MATS, and $15/MWh subsidy are not sufficient to encourage wind in a significant way. Penalizing GHG emissions seems to provide the additional push wind needs, especially in an environment of lower natural gas prices. Other renewables need stronger incentives.

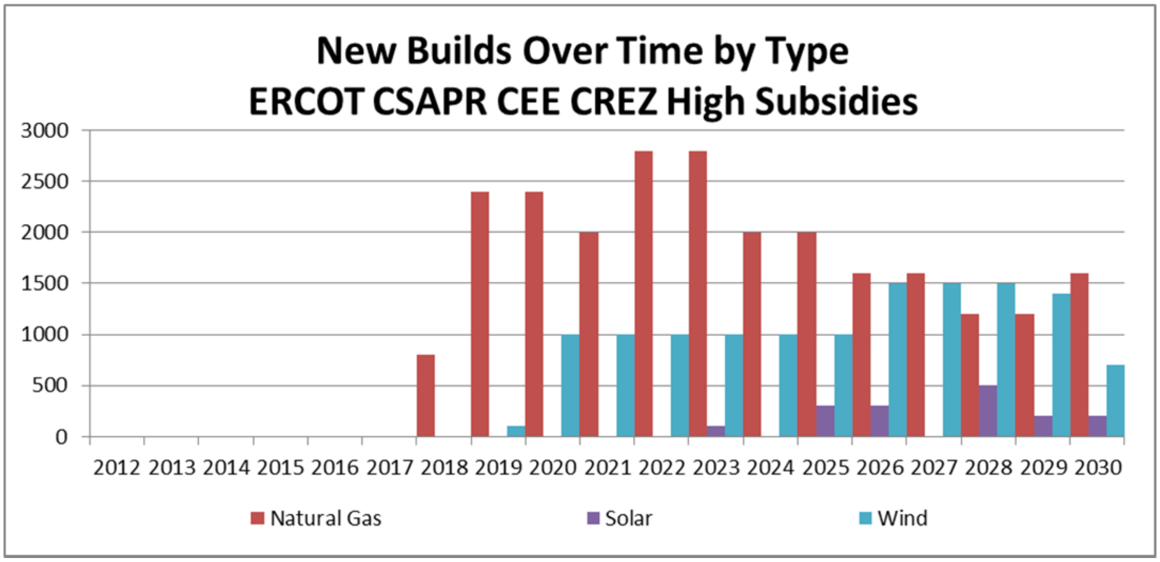


The ERCOT CREZ case

In order to evaluate the impact of additional CREZ lines in the ERCOT grid, we increased the capacity of lines to the planned 18 GW limit in the Western part of the grid. We built this grid capacity expansion on the CSAPR-CEE case with $15/MWh subsidies for renewables and including the price on carbon. This did not lead to any new wind (or any other renewable capacity) in ERCOT beyond what our overall scenario analysis has produced thus far with each successive layer of conditions.



Then, we increased the incentives to $25/MWh for wind (which is more consistent with support provided by federal production tax credits and renewable energy certificates) and to $35/MWh for solar, which remains more costly and requires additional support. These additional subsidies, with an estimate cost of $9 billion from 2019-2030, encourage 12.7 GW of wind and 1.6 GW of solar thermal capacity (see chart on the right).



Future Work

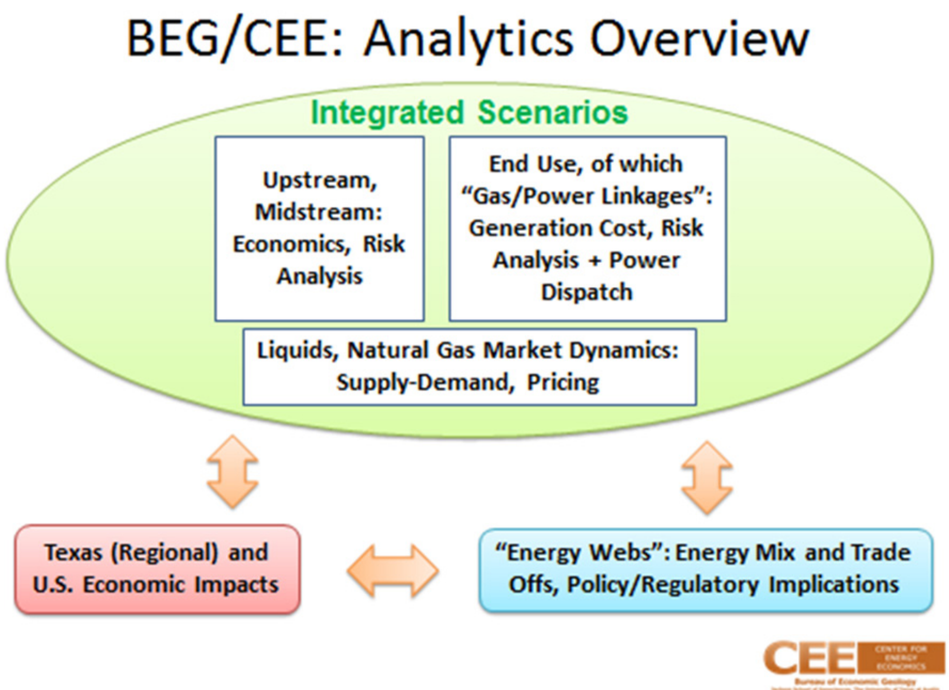
With this exercise, we have seen that it is important to capture dynamic interactions among energy and environmental policies as well as industry developments. Analyses that focus on a single factor will likely miss important forces and counterforces. In the examples above we demonstrate the impact of successive layers of conditions and the importance of posing questions, developing hypotheses and investigating outcomes associated with multiple effects.

Electricity systems are particularly complex. Different generation technologies and fuels compete, each with its own cost fluctuations and unpredictability. A multitude of energy and environmental policies and regulatory actions impact market design, capital and operating costs and affect accordingly economic dispatch. Modeling tools are useful for interactive assessment of a multitude of long-term energy and environmental policies *as long as their fundamentals are well understood and assumptions carefully mapped out by independent investigators such as CEE*.

We intend to refine our estimation of the scenarios presented in this article and consider additional issues. For example:

- We can introduce technology improvement for renewables that would enhance capacity factors and reduce their costs going forward;
- The implementation of demand side response programs along with smart grid investments can reduce demand growth;
- A breakthrough in electricity storage technologies can increase the amount of electricity available from intermittent renewables, hence reducing the need for new builds;
- A "renaissance" in industrial demand could kick natural gas prices higher affecting outcomes; likewise -
- On the gas side, possible regulation on hydraulic fracturing, wastewater treatment and/or methane emissions could add to the cost of natural gas, reducing its attractiveness as a generation fuel (we can evaluate by how much);
- Increased gas exports and use of gas as a transportation fuel will also push its price higher.

Many of these developments will follow parallel paths as they are partially driven by independent forces but they will certainly have an interactive and possibly cumulative impact on the power sector and demand for gas in this sector. Only when each issue is well understood can its future path be reasonably assessed and appropriate assumptions be inputted into a model such as AURORAxmp. The research mission of CEE is to build, independently and objectively, reasonable analytic approaches to explore, to the fullest extent possible, the complex tradeoffs inherent in the energy mix. Gas/power linkages is a large and important subset of our research. Our effort will be supported through an advisory council that we are creating to ensure vigorous collaboration with our industry supporters and colleagues as well as outside experts and peer reviewers. Any and all possible future outcomes have deep implications for the Texas and U.S. economies. Not shown in our examples here is the "coupling" of power sector analysis with regional and national economic costs and benefits associated with alternative scenarios.[16] Underlying these analyses is our evaluation of energy options across multiple dimensions to satisfy numerous and often conflicting objectives (see *The [Energy] Webs We Weave* by Dr. Foss and *Government Support for Energy Technologies and Green Jobs* by Dr. Gülen at our Think Corner). The following graphic depicts this integrated analytics space pursued by CEE to address gas/power and other complex tradeoff problems.



Finally, CEE has long experience in international development assistance, working with local partners and governments in a variety of different countries and regions as they wrestle with energy sector reform, capital requirements and investment flows and other critical challenges emanating from the energy-economy-environment nexus. Consequently, we are working to ensure that lessons learned and international extensions of our work can be realized.

Contact us at energyecon@beg.utexas.edu or 713-654-5400 to learn how you can participate in CEE's gas-power research area.

[16] The CEE team is relying on Regional Economic Modeling Inc.'s Policy Insight Plus (PI+) platform for Texas and U.S. macro- and microeconomic effects.