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AVOIDING RISKS TO POWER SECTOR INVESTMENTS FROM AN UNSTABLE CARBON MARKET

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1. INTRODUCTION

Carbon management in the U.S. and the rest of the world will require a wide range of technologies, including carbon capture and storage (CCS), renewable technologies, nuclear, and the fruition of advanced concepts. It will also require continuing research, development, and demonstration (RD&D) and time for improving the technologies and reducing investment risks, while recognizing the urgency of the issues.

In addition to technology development, economic incentives and related issues will need to be understood and addressed to achieve successful outcomes. The primary objective of this paper is to highlight and aid in understanding market issues and investment incentives.

We present a market equilibrium scenario for gas supply and demand, including the capacity expansion and operation of the electric power sector in the U.S.

Figure 1 illustrates the challenge of reducing carbon dioxide (CO_2) emissions in electric power generation, showing a huge reduction requirement compared with reference case growth. And even if we control everything that would seem likely, we may continue to use uncontrolled fossil fuels in some applications, for example, peaking turbines to backup renewables or distributed combined heat and power (CHP).

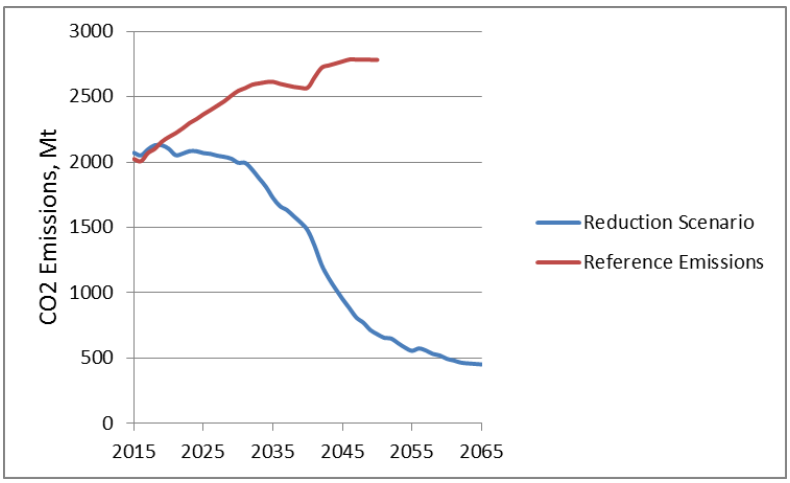

Figure 1. CO_2 emissions reduction path in the U.S., 2015–2065

Figure 1 is based on a low electricity demand growth scenario of about 0.85% per year. The International Energy Agency (IEA) sees much faster growth in electricity demand in developing countries, leading to a much greater challenge on a global scale [1]. But this also creates an economic opportunity for U.S industry, if through RD&D, the U.S. can develop low-carbon technologies that the rest of world wants to buy.

The analysis issues can be thought of as having three phases: current disequilibrium, transition period, and advanced technology penetration. The rapid expansion of hydraulic fracturing and other drilling technologies has created a disequilibrium in gas supply and demand. At the same time, countries of the world are pondering how to accelerate innovation and proceed with CO_2 emission reduction measures.

We describe the transition period phase as the growth in renewable technologies; the retrofitting of existing pulverized coal (PC) plants with carbon capture technologies; and the phasing out of older, less energy-efficient capital stocks.

The third phase is the penetration of advanced coal, biomass, nuclear, and storage technologies. These three phases will somewhat overlap.

Some issues will be specific to regulatory approaches and incentives offered. In this paper, we analyze a carbon emissions charge which is phased-in initially, maintains a modest level over the transition period, and then rises somewhat as advanced technologies penetrate. Most of this paper will address complex economic issues that arise during the transition period.

We begin with one of the most important issues during the transition period, the retirement of existing PC plants which do not retrofit CCS. The economics of this retirement decision involves a comparison of the annual running cost of an existing coal unit with the annual cost of owning a new natural gas combined cycle (NGCC) plant. The running cost of an existing coal plant includes fuel cost; CO_2 emissions charge, if any; variable operating costs; and fixed operating cost to keep the plant maintained for another year.

To do this analysis, we use our Electricity Supply and Investment Model (ESIM). For the scenario that we present in this paper, the running cost path for the marginal PC unit (highest cost, most likely to retire) is shown in Figure 2.

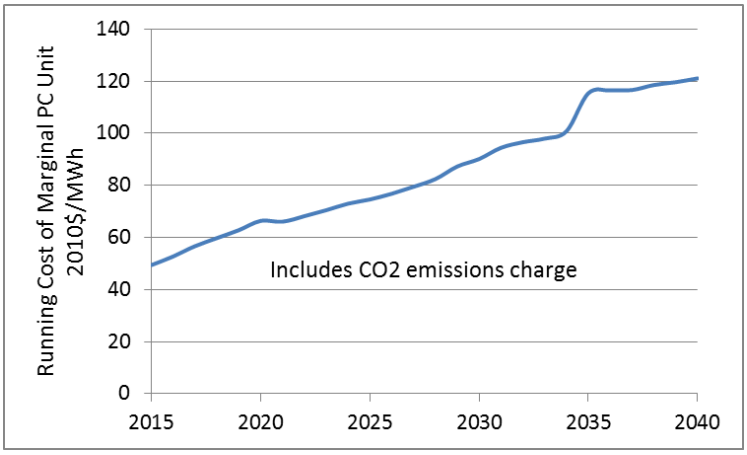

Figure 2. Marginal running cost for existing PC units (includes CO_2 emissions charge)

We could even conclude that the average price of gas in a year is determined by this condition that the cost of running the marginal PC unit must equal the annual cost of starting and running new NGCC capacity. If the price of gas were too low, a large amount of PC capacity would be retired (or perhaps pushed down the loading order), gas demand would rise significantly, and, in turn, raise the gas price.

As a corollary to this proposition, those forecasters who see $4.00–$5.00 gas maintained through the transition period may be unrealistic about the effect that increasing gas demand for electric power generation would have on the supply price of gas.

The ESIM model includes a gas supply scenario model calibrated for three (high, low, and mid) supply scenarios based on Energy Information Administration (EIA) AEO2013 reference and sensitivity cases.

Another way to represent the transition period phenomenon, an approach taken by most models [2], is to rapidly retire the existing fleet of power plants and replace them with new technology. In our view, the transition will take investment in RD&D and growth in experience over time [3]. Thus we reject the ideal of replacing the existing capital stock in a few years' time span with next generation technology. In this paper, we consider a 50-year time horizon, 2015–2065. For perspective, a young professional who starts his/her career in 2015 could see a total transformation of the electric power sector over their professional working years.

This paper is organized as follows. First, we describe a CCS adoption scenario. Next, we examine the gas market, and, in particular, gas generation technologies. The next section includes our representation of the impact of intermittent renewable technologies on the load duration curve and the dispatch curve, and thus the interaction among technologies and their operations. Then we examine the investment requirements associated with this CO_2 reduction scenario. Finally, we raise concerns about gas market stability/volatility, particularly under a high carbon price regime and present conclusions.

2. CARBON CAPTURE, UTILIZATION, AND STORAGE

Figure 3 shows five categories of coal-based technologies (with potential biomass co-firing). This figure illustrates the transition period over which existing PC units are retrofitted with CCS. These units will experience a capacity reduction because of the energy requirements for capturing and compressing CO_2. Figure 3 also shows the remaining PC stock which maintains its full capacity, but eventually retires in economic competition with gas, renewables, and new base load. The figure also shows new capacity with CCS. One type is circulating fluidized bed (CFB) combustion, and the other is advanced base-load such as integrated gasification combined cycle (IGCC).

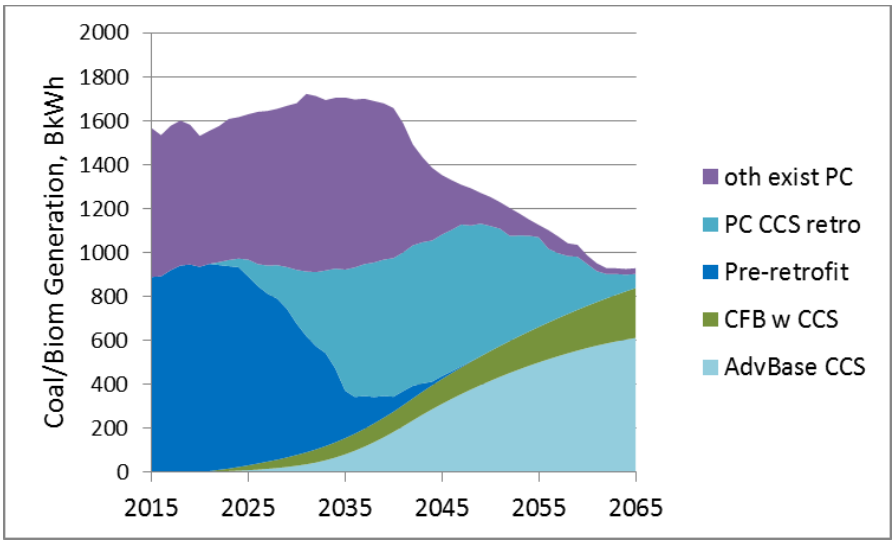

Figure 3. Base-load coal generation technologies

The ESIM model has a unit inventory of power plants and selects those to retrofit with CCS in four categories:

- Ones with access to Enhanced Oil Recovery (EOR) in the state of Texas and receive a credit for selling CO_2. (EOR opportunities outside of Texas will be analyzed later.)
- Then other first or second adopters.
- Best current units (newest, largest, most efficient).
- Lowest performance current units.

The post-retrofit generation by these categories is shown in Figure 4.

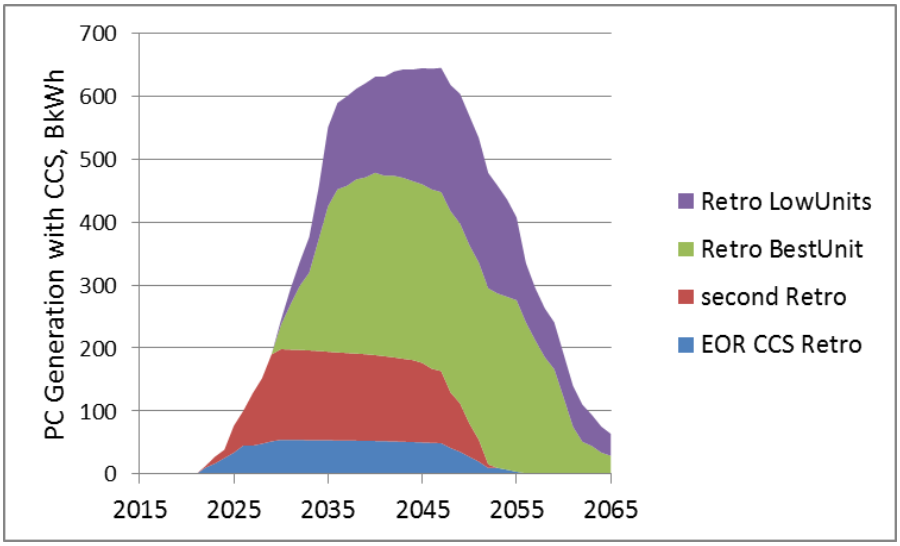

Figure 4. Post-retrofit generation by categories of CCS adopters

Our logic in developing simple selection criteria was that the very best plants are already efficient and unlikely to be the first to adopt CCS in the early years. However, the oldest, smallest plants are also not likely to be the first adopters. Hence, we draw first and second adopters from middle performance units.

Figure 5 shows tonnes of CO_2 captured by four technology categories, including CO_2 captured from NGCC. By far, the largest amount of CO_2 captured is from the retrofit of exiting units. Figure 6 shows the resulting achieved CO_2 reduction and where remaining emissions persist.

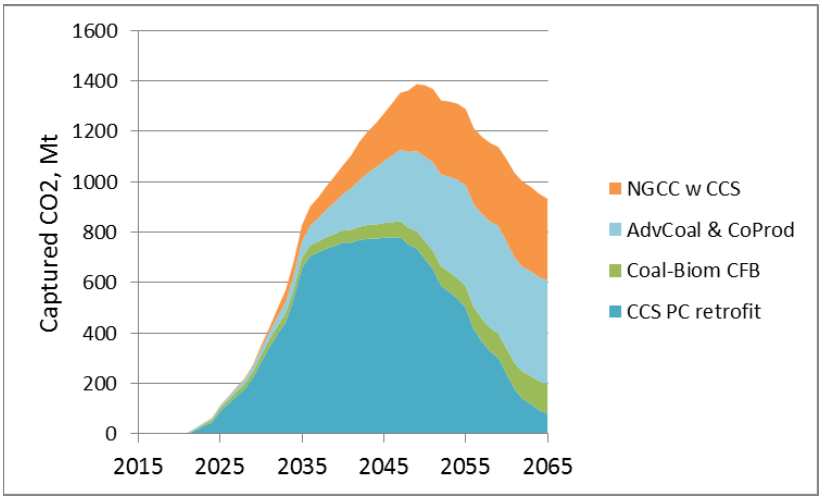

Figure 5. CO_2 captured by four technology categories

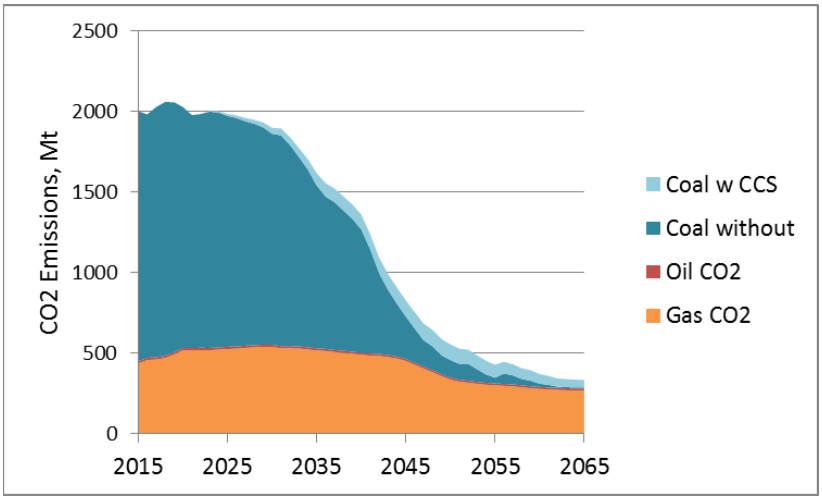

Figure 6. CO_2 emissions by fuel

We end this section with a look at the nuclear base-load scenario shown in Figure 7. Again, we project that some time will be required before the retiring fleet of light-water reactors will be replaced with an advanced nuclear technology. The 2030–2045 nuclear power gap will need to be replaced with new gas, renewables, and existing and new coal capacity. Remaining base-load capacity shown in Figure 7 includes gas CHP, biomass units, and municipal solid waste generators.

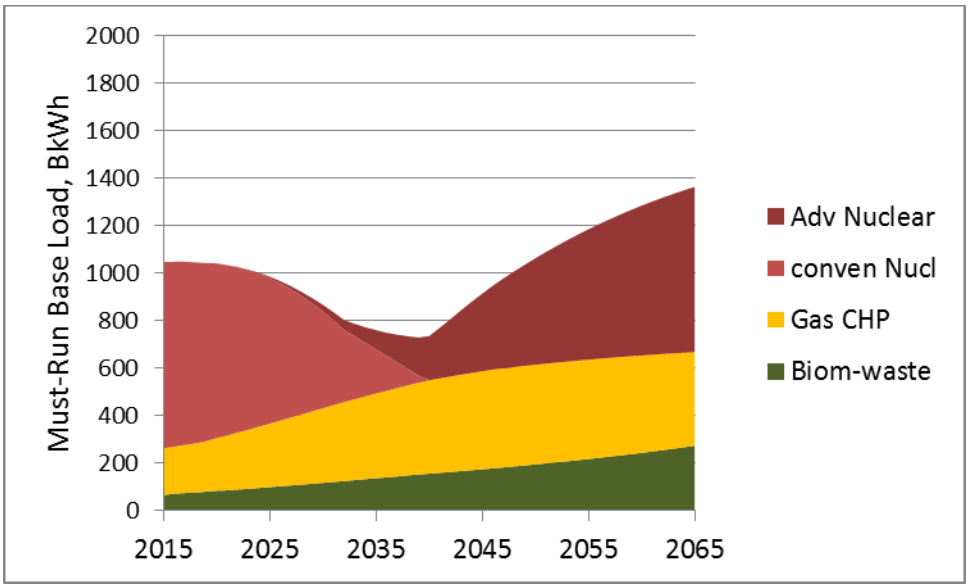

Figure 7. Nuclear, gas CHP, and biomass base load generation

3. NATURAL GAS SUPPLY AND DEMAND

As we shall see in the next section, rapid growth in intermittent renewable generation increases the importance of shoulder-load and peak-load generation technologies. Shoulder load, or intermediate load, represents the hours of the season and day in which electricity demand tends to be in the middle range between minimum base-load and maximum peak load. Figure 8 shows generation for the shoulder and peak-load technologies in the model. Some are more dispatchable than others. For example, hydropower has some but not full dispatch flexibility. The largest gas consumer is NGCC.

In the ESIM model, some NGCC includes CCS. There are two criteria for employing CCS on NGCC. One is a limited amount of early adoption to gain experience with CCS [3] with a technology that is somewhat simpler than coal technologies. The second criterion is to stop building “plain” NGCC capacity and switch to CCS in time to meet the 2065 emission reduction goal. The later situation is clearly shown in Figure 8 in which starting in 2030, NGCC includes CCS, and existing NGCC capacity retires over time and is essentially gone by 2065.

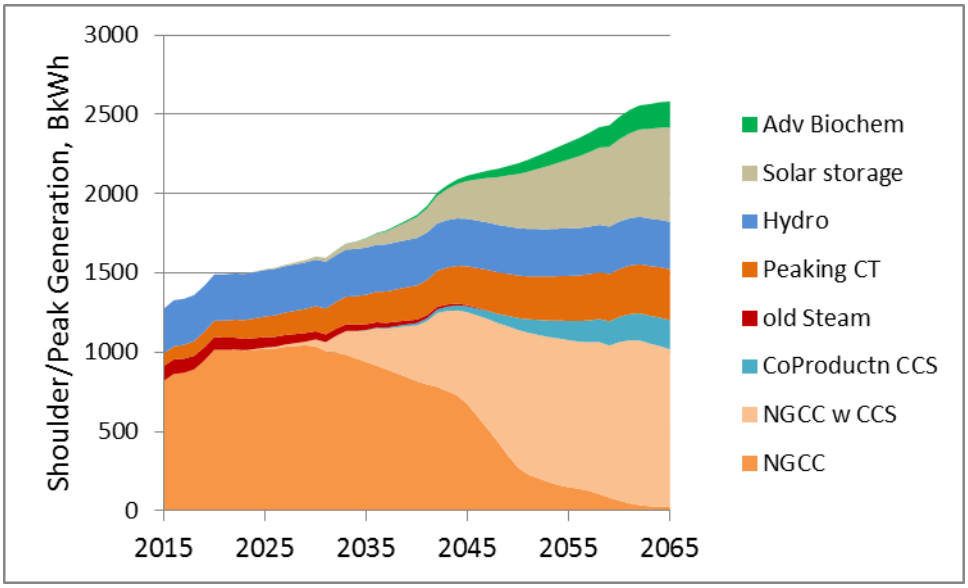

Figure 8. Gas and other shoulder-load generation

Figure 9 show the resulting gas demand associated with power generation. It also shows coal demand for technologies with and without CCS.

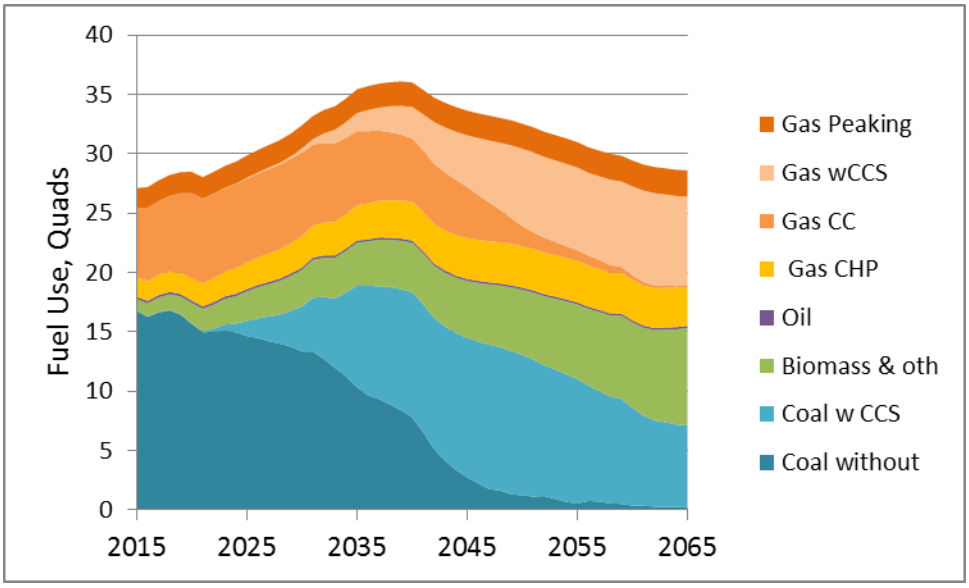

Figure 9. Fuel use by type

The market clearing gas price is shown in Figure 10. In the 2030–2043 period, gas prices rise rapidly to supply gas to replace retiring nuclear units. Post 2043, gas prices continue to rise reaching more than $9.00 per MBtu by 2065. This continued rise in gas prices is necessary despite a gradual decline in gas production, which is shown in Figure 11 by category. Conventional gas is in decline. Shale gas production is still rising. Prices in Figure 10 are "equilibrium" in the sense of achieving a balance for gas demand and production.

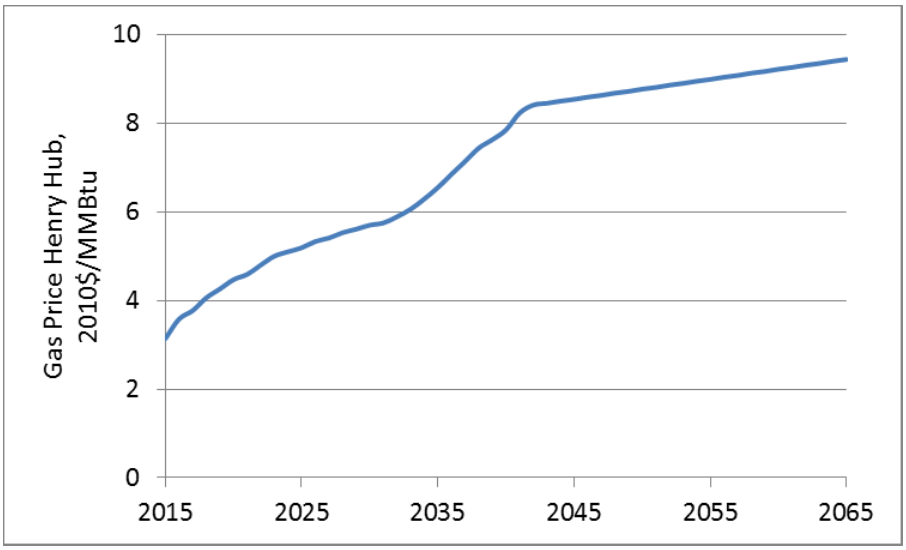

Figure 10. Price of gas, Henry Hub

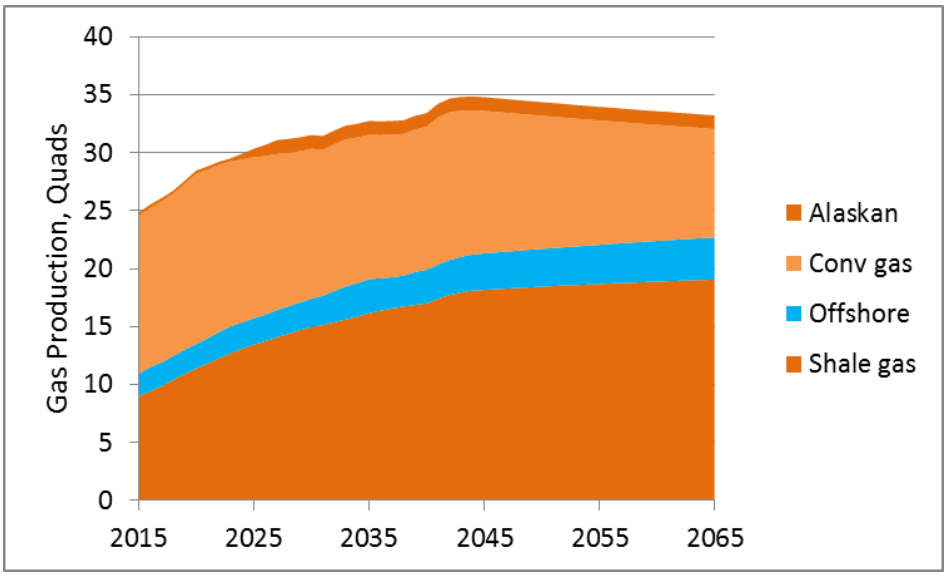

Figure 11. Natural gas production by category in U.S.

Sensitivity cases where gas prices are higher or lower (gas supply shifts to the left or right) show similar patterns due to the overall need to reduce CO_2 emissions.

4. RENEWABLES AND IMPACTS ON THE DISPATCH CURVE

Figure 12 is a summary of all generation presented thus far, plus the growth in intermittent renewables (mainly wind, distributed photovoltaic, and utility-scale solar). This is the total generation needed to meet demand.

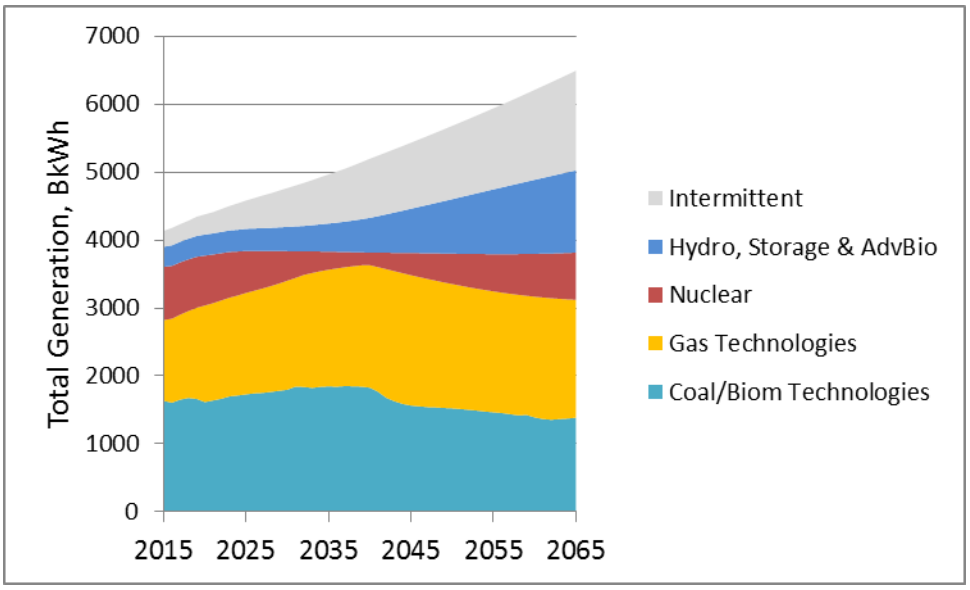

Figure 12. Total generation needed to meet load by technology category

Figure 13 shows the equivalent load duration curve (LDC) in 2035, including a reserve margin exceeding peak demand. Some of the load is met by intermittent renewables, non-dispatchable sources discussed above, or technologies with limited dispatch capability such as hydropower. For these sources, we subtract from the LDC typical hourly generation profiles to arrive at the dispatch curve [4]. Dispatchable units, based on "available" capacity, are stacked on the dispatch curve in order of least variable cost (which could include a CO_2 emissions charge, or a credit for selling CO_2 to EOR, for instance.) This determines the capacity utilization rate (Capacity Factor) for fully dispatchable units. The typical loading order is nuclear, new coal capacity, older less-efficient coal capacity, shoulder units, and peaking units. We see that in 2035, with much intermittent renewables on the system, that the maximum dispatchable load for nuclear units is already less than 100%. The dispatch curve drops off quickly, thereby reducing the utilization of existing coal units. This effect of high intermittent renewables is imposing a power system cost.

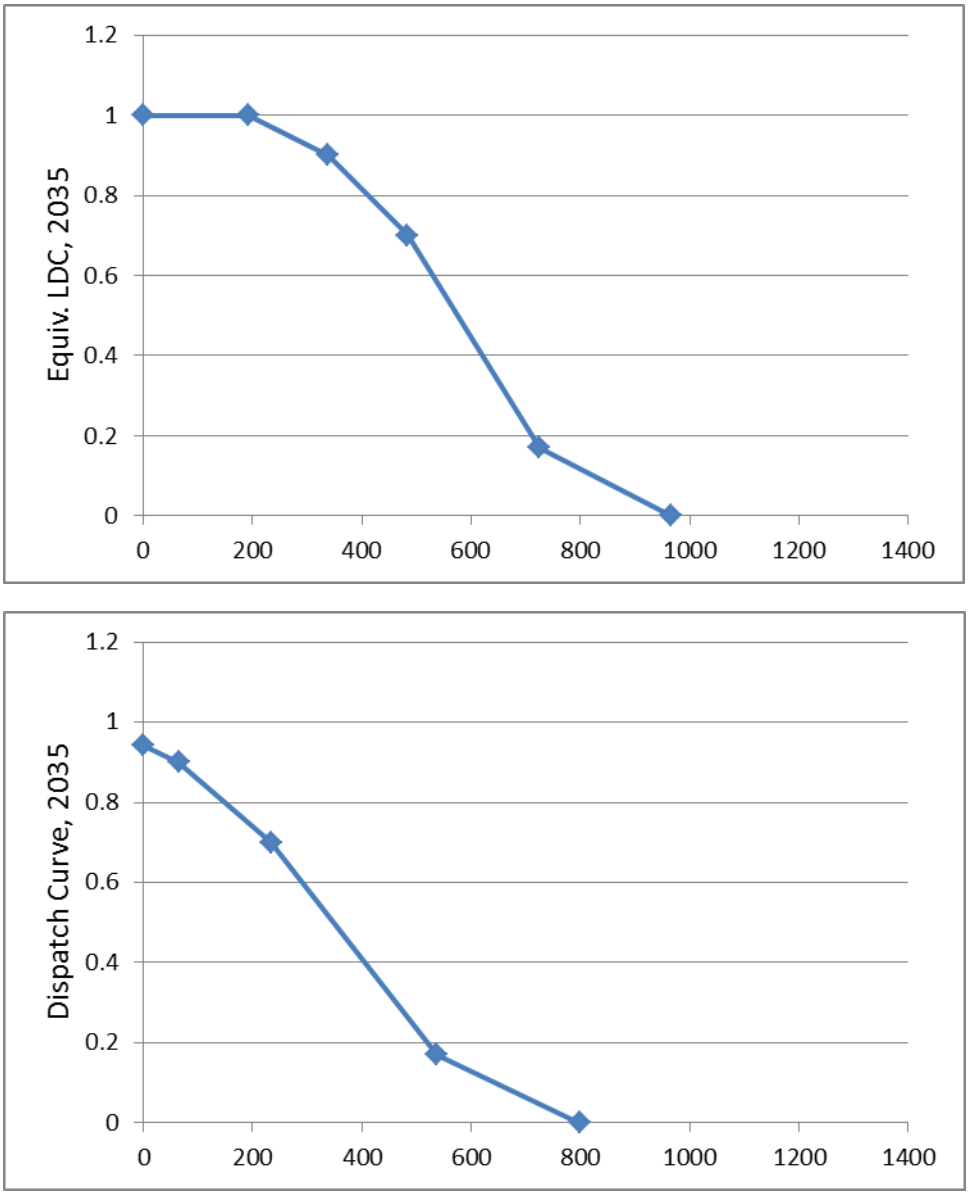

Figure 13. Equivalent LDC and resulting dispatch curve in 2035

Figure 14 shows the progression of less available dispatchable capacity utilization over time as intermittent renewables penetrate. That is, there is less utilization height and more load needed for costly peaking capacity.

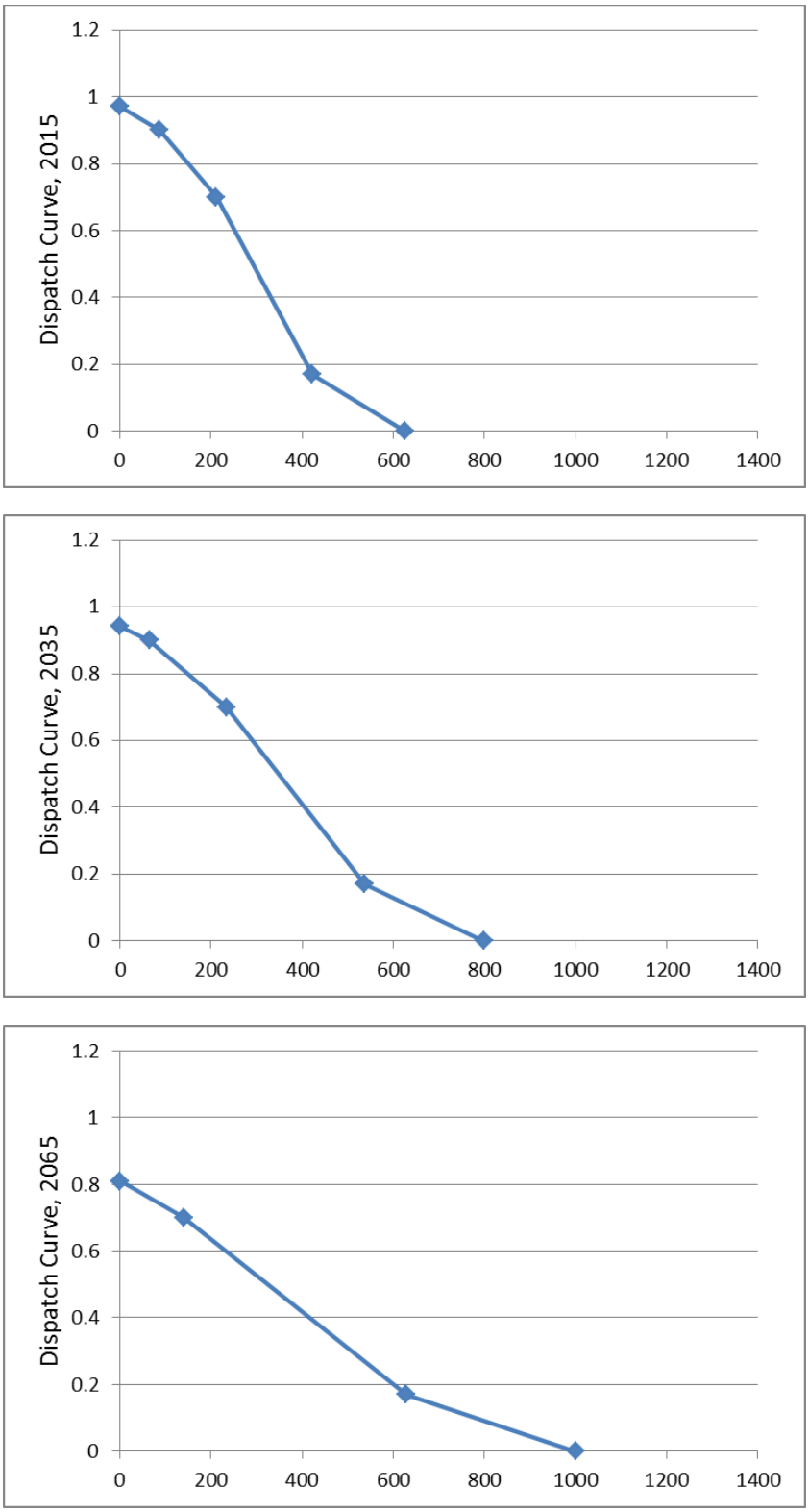

Figure 14. Lowering and spreading out of dispatch curve over time

5. OPERATION OF DISPATCHABLE POWER PLANTS

When existing coal plants are retrofitted with CCS, their variable operating cost increases because of the energy requirement for CO_2 capture and compression. Without giving these units credit for having a lower CO_2 emission rate, their utilization would fall; that is, they would be pushed down the dispatch curve, and most units without CCS would be dispatched at higher capacity factors. This is the opposite of a least-cost solution for reducing CO_2. You want to use fully the plants on which you have installed carbon capture technology. Normally a least-cost solution for achieving an emission reduction includes a shadow price on the emission constraint. This is the price of CO_2. If there is a price on CO_2 emissions, least-cost operations can be achieved because units without CCS would now pay a penalty for their emissions, a variable cost, and they would be pushed down the loading order, letting retrofitted plants operate at higher utilization. In fact, up to one-third of the generation that is lost due to retrofitting a unit with CCS can be made up by operating the unit at a higher capacity factor than units which do not retrofit. This higher utilization provides an additional significant incentive to retrofit existing units.

In our ESIM runs, we used a medium CO_2 emissions charge as a driver to achieve least-cost dispatch order, as shown in Figure 15. Too high a CO_2 price would quickly close down existing power plants without CCS, thus bringing the transition period to a close and creating a shortfall in capacity. Also, the higher the CO_2 price, the greater the likelihood for gas and power market instability/volatility (to be discussed in a later section). In the post-transition (which ends around 2040), some increase in CO_2 price can be allowed, as shown in Figure 15, to stimulate investment in very low CO_2 advanced technologies. A credit for capturing CO_2, such as the selling price of CO_2 for EOR, is almost equivalent to a CO_2 price. Both incentives encourage full utilization of the plant with CCS.

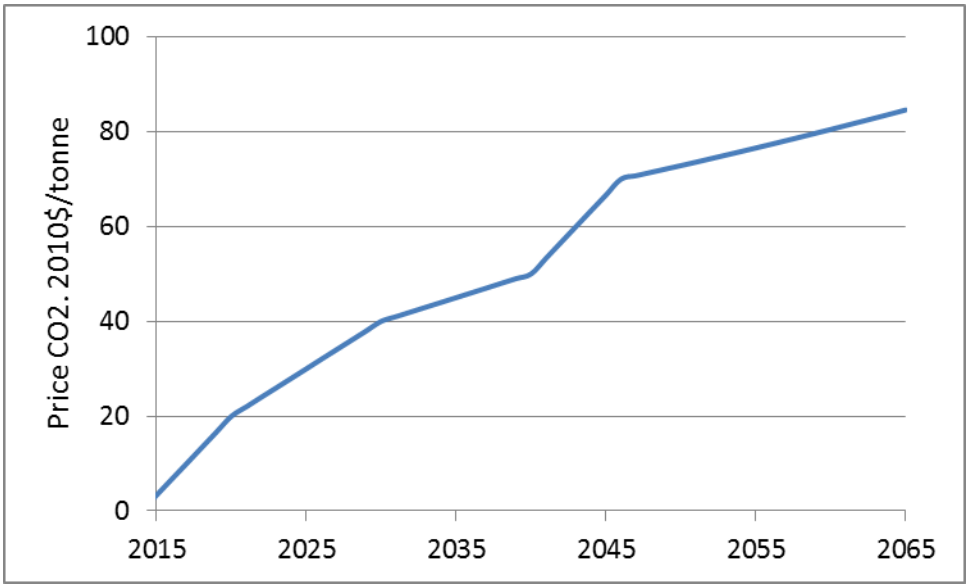

Figure 15. Price of CO_2 which supports the transition period, least-cost unit operations, and advanced technology penetration

6. CAPTIAL REQUIREMENTS AND FINANCING

Figure 16 shows the paths of expenditures for fuel, operating and maintenance (O&M) costs, and capital outlays. Fuel costs and capital outlays are about the same summed over the period, whereas O&M is somewhat less. Figure 17 breaks down capital outlays into technology investments.

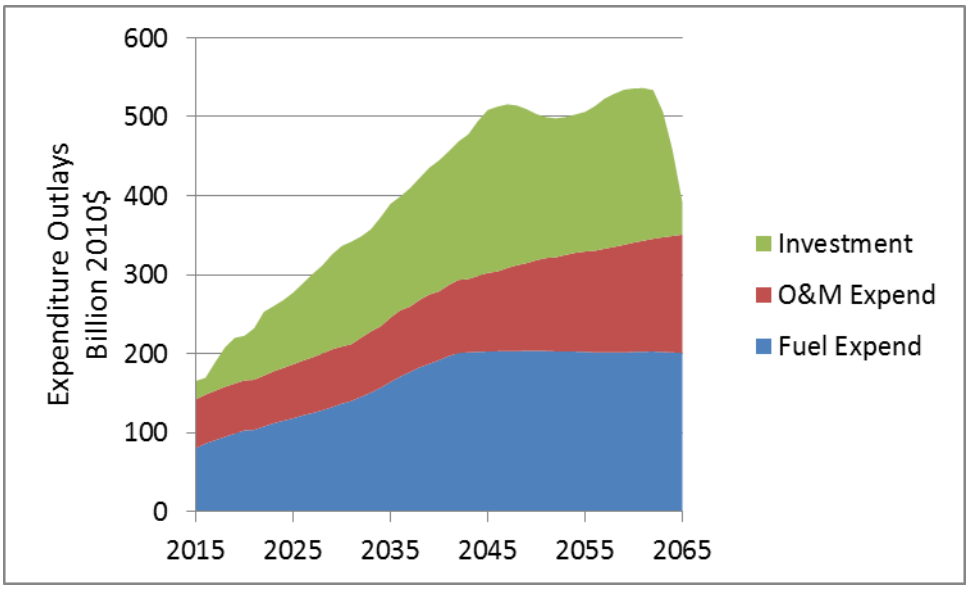

Figure 16. Expenditure outlays for electric power generation in the U.S.

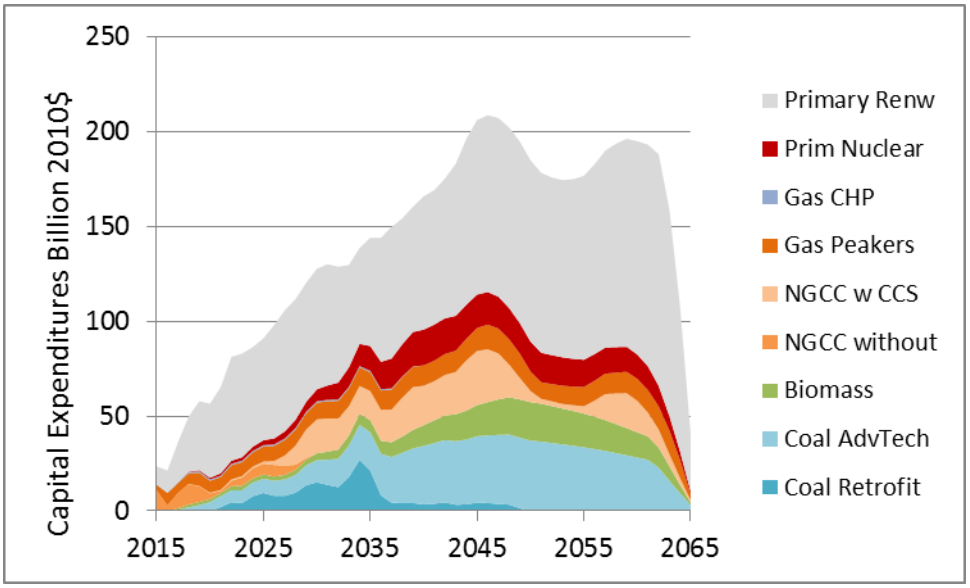

Figure 17. Technology investment requirements

Capital outlays for renewable sources are so high because of very low capacity factors; that is, a lot of capacity is needed to produce a given amount of generation. However, renewables have near zero fuel costs. The objective is to minimize the present value of the future path of total expenditure outlays for electric power generation which meets electricity demand and achieves a CO_2 reduction goal.

Note that the capital expenditure needed to retrofit a significant share of the total existing PC fleet is very small relative to total industry capital requirements.

At the same time, because of the carbon charge shown in Figure 15, the electric power sector is raising considerable tax revenue, as shown in Figure 18. Of course, as CO_2 emissions decline in later years, tax revenue also declines.

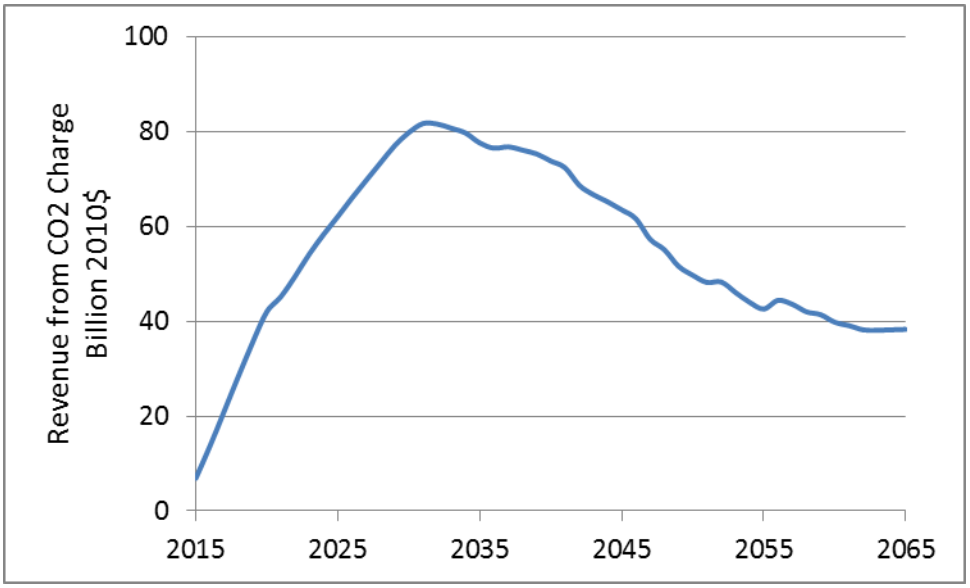

Figure 18. Revenue collected from the CO_2 charge

Some significant findings are:

- CO_2 revenue (undiscounted) is about $2,640 billion.
- CCS retrofit cost (undiscounted) is much less at $230 billion.
- The real levelized economic cost of electricity generation is about 7.5 cents/kWh (excluding transmission and distribution costs and utility taxes). This is higher than today's electric rates but perhaps livable.

Hypothetically, suppose that ¼ of CO_2 revenue is recycled into the electric power sector to incentivize the incremental capital cost of adding CCS. This would lower consumer electric bills. But consumers, in addition to paying for electric power expenditures, would need to pay the remaining ¾ of the CO_2 tax bill. Then the levelized cost to consumers would be about 8.4 cents/kWh, again probably manageable to reduce GHG emissions. Plus, we as a country

could look forward to applying ¾ of the above CO_2 revenue to reducing the national debt and hence stimulate long-run economic growth, relative to the sluggish growth that we now face.

7. GAS AND POWER MARKET STABILITY/VOLATILTY ANALYSIS

The market gas price and production paths shown above are based on least-cost equilibrium. But is this equilibrium stable, or will oscillatory prices and volatility arise in gas and power markets?

Figure 19 shows the upward sloping marginal cost (MC) curve for running existing PC units (corresponding to Figure 2 data). The higher the price on CO_2, the higher is this MC curve. The top horizontal line is the annual owners' cost of new NGCC. Where these two lines cross, determines how much new NGCC capacity is least-cost to be built.

However, after the new NGCC units are built, their capital cost is sunk and becomes irrelevant for the operation of the NGCC capacity. The variable cost of the NGCC unit is the bottom horizontal line. Comparing the variable cost of the NGCC unit with the marginal cost curve for running existing PC units, we see that the new NGCC units now jump over a segment of the existing PC units and push them down the loading order or into retirement. The resulting high capacity utilization of the NGCC units raises gas demand and, hence, gas prices. Under higher gas prices, the original investment in the new NGCC is regretted. This cycle leads to instability/volatility in gas prices and production.

Since the marginal cost of running the existing PC units rises linearly with the price of CO_2, a higher price of CO_2 will induce greater amplitude in oscillatory gas price behavior.

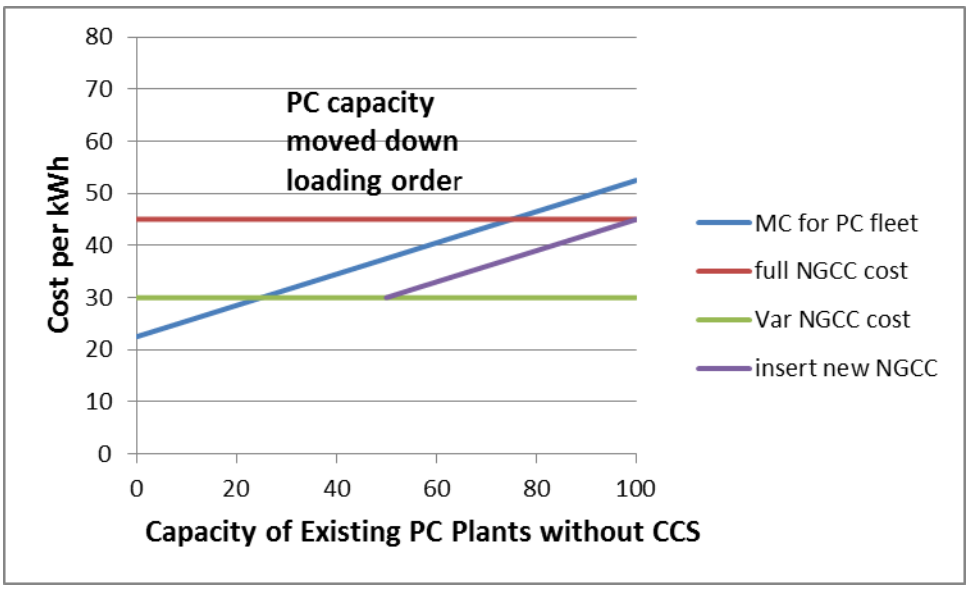

Figure 19. Source of volatility in gas market

8. CONCLUSIONS

- We only have a few potential options: CCS, nuclear, energy storage, and biochemical. We need to fund the RD&D to develop these options.
- The transition from an existing fleet to a new more efficient power generation fleet cannot realistically occur in a few years but would take decades because of planning, financial, and resource (e.g., skilled labor, materials, and manufacturing) constraints.
- Rapid transition scenarios tend to focus on the objective and do not account for maintaining grid reliability and economic impacts on consumers during the transition period.
- Existing PC units are diverse. Market incentives for retrofitting units with CCS are less costly than Command-and-Control regulations.
- In general, the structure of driver policies and the associated behavioral incentives that are induced need to be carefully understood to successfully achieve the goals.
- Some credit for reducing CO_2, or small price on emitting CO_2, will provide an incentive to operated units with CCS with higher utilization than units without capture. This is a cost-effective way to further reduce CO_2.
- Selling CO_2 for EOR adds an incentive to retrofit and reduces a unit's variable cost, thus putting it higher on the loading order and increasing its generation and CO_2 production.
- Electricity prices can be moderated for consumers and businesses if revenue from a modest price on CO_2 is recycled back to help fund investments in advanced generation capacity.
- U.S industry has an opportunity, if investments in RD&D are made, to lead the world in supplying low-carbon technologies to the global market.

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The work shown is preliminary and does not necessarily reflect the views of NETL or Argonne National Laboratory.

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