The cost of displacing fossil fuels: Some evidence from Texas

*Peter R. Hartley**

ABSTRACT

Although technological progress can alter the relative costs of different energy sources, fossil fuels inevitably will be displaced as depletion raises their costs and makes them uncompetitive. They may be displaced sooner if they are taxed to internalize negative externalities. Currently, wind generation or nuclear power, supplemented by bulk electricity storage, are the most feasible alternatives to fossil fuels for electricity generation. The ERCOT ISO in Texas provides a realistic model for examining the costs of replacing fossil fuels by wind generation and storage, and for comparing wind power with generation based on nuclear and storage. ERCOT is relatively isolated from neighboring grids, and wind power was almost a quarter of its total generating capacity at the end of 2016. Using the ERCOT example, we also discuss how the long-run configuration of the electricity supply system affects evolution away from a system dominated by natural gas.

Keywords: Energy transition, wind, nuclear, natural gas, electricity storage

https://doi.org/10.5547/01956574.39.2.phar

1. INTRODUCTION

According to the International Energy Agency (IEA) key world energy statistics, fossil fuels supplied about 81% of the world's primary energy in 2014. Although the growth in renewable energy sources, especially wind generation, has been strong for at least the last 15 years, more than 92% of the non-fossil component of primary energy in 2014 was supplied by nuclear, hydroelectricity and biomass. Most forecasts have fossil fuels continuing to dominate primary energy supply for many decades to come. As emphasized in Hartley and Medlock (2017), technical change in the fossil fuel sector can delay the transition from fossil fuels to their alternatives. However, technical change can also lower the costs of alternative energy sources, while taxes imposed on fossil fuel use to compensate for negative externalities will also hasten their displacement. If nothing else raises the costs of fossil fuels above the costs of the alternative energy sources, depletion ultimately will do so.

The evolution of the power generation part of the overall energy supply system will play a central role in the transition away from fossil fuels. While the transportation sector consumes about one quarter of total final energy (again according to IEA statistics), electricity is the most likely alternative to oil products for ground, if not air, transportation. Electricity can also substitute for fossil

* Department of Economics and James A. Baker III Institute for Public Policy, Rice University and Department of Economics, University of Western Australia. Send correspondence to Department of Economics, MS22 Rice University, 6100 Main Street, Houston, TX, 77005-1892. E-mail: hartley@rice.edu.

fuels in providing heating services. Hence, as argued by Green and Staffell (2016) for example, the electricity sector is at the forefront of any move to displace fossil fuels.[1]

Within the electricity sector, renewable energy supplies, and especially wind power, are seen as critical to allowing power generation without fossil fuels.[2] However, wind generation suffers from the problems that it fluctuates substantially over short intervals, produces no output when wind speeds are too low or too high, cannot be dispatched always and only when needed, and tends to be low during periods of peak demand. Effective electricity storage could solve all of these problems and allow wind to supply 100% of needed generation.

In order to more systematically evaluate the potential of wind generation for this role, the Electricity Reliability Council of Texas (ERCOT) ISO is of particular interest. The more than 18 GW of wind capacity in ERCOT at the end of 2016 was more than 24% of total generation capacity. Wind generators also supplied slightly more than 15% of the ERCOT load in 2016. Furthermore, ERCOT has weak links and little trade in electricity with neighboring systems. Thus, the ERCOT experience can be used to judge how scaling up wind generation to replace fossil fuel generation may affect system costs.

Identifying the technologies that are likely to displace fossil fuels in electricity generation is interesting for a number of reasons. First, the likely long-run configuration of the electricity supply system influences investments in earlier periods back to today. The traditional way to determine the generating investment decision of a private profit-maximizing electricity supplier is to choose the technology with the lowest levelized cost of electricity (LCOE). However, LCOE does not take into account how new generation added later will affect the capacity factors or economic lifespans of each technology. Furthermore, the technologies likely to be added in the immediate future will depend on what those investors believe will happen subsequent to their decision, and so on. In short, in a dynamic optimization framework, the investments made today will depend in part on the expected long-run configuration of the system.

Second, since government can alter private investment decisions using taxes and subsidies, the question arises as to what the *optimal generating mix* should be. A screening curve analysis, which splits the costs of each technology into fixed and variable components and calculates capacity factors so that overall costs of meeting demand are minimized, is traditionally used to answer this question. As with LCOE calculations, however, screening curve analysis does not take into account how new generation added later will affect the costs of each technology. Screening curve analysis also is not suitable for choosing the optimal amount of non-dispatchable supply. Such generation cannot be scheduled to respond to changes in the demand for electricity, while the analysis also does not take into account the need for backup capacity when renewable sources are not generating.

Third, the cost of the long-run alternative energy supply to fossil fuels is especially important. The higher that cost, the longer will fossil fuels remain viable as an energy source. Furthermore, a higher cost of energy at the time of transition implies that more total fossil fuels will have been used by then regardless of the prior trajectory of fossil use. Also, as argued by Hartley et al. (2016), and verified again in Hartley and Medlock (2017), a higher cost of the backstop technology will imply there is more of an "energy crisis" around the transition time. The crisis is characterized by

1. Boßmann and Staffell (2015) point out that using electricity to supply transportation and heating demand will likely change the shape of the load curve. While our analysis is based on actual hourly wind output and load rather than a hypothetical forecast load, it would be of interest to repeat the exercise for a load curve reflecting additional sources of demand.

2. Most of the capacity added under renewable energy mandates mandates, which typically exclude hydroelectricity and nuclear power as "renewable," has been wind. Although the cost of utility-level solar power has been falling, it is still considerably more expensive than wind. Texas has recently encouraged more utility-level solar power projects, but as of the end of 2015 total capacity was under 600MW.

slower economic growth and a drop in the consumption/output ratio as more resources are devoted to investing in energy technologies and procuring energy inputs into final production.

2. RELATED LITERATURE

Our analysis is related to several lines of research. Most directly, it is concerned with the long-run evolution of the energy supply system and what might constitute the "backstop technologies" to replace fossil fuels. A pair of articles by Delucchi and Jacobson (2011) and Jacobson and Delucchi (2011), examine the feasibility and potential cost of satisfying global energy demand using wind, water and solar generation. In order to compensate for the non-dispatchability of most of these sources, they propose supplementing the system with hydropower and battery and hydrogen storage, real time prices to shift demand to when more of the electricity is being generated, and additional transmission lines to reduce correlation in output from renewable generators. They claim that their system would be similar in cost to the predominantly fossil fuel based system in use today.

Trainer (2012) argued that Jacobson and Delucchi did not realistically evaluate the costs of coping with variability in the supply of renewable energy. He noted that wind speeds that are either too high or too low can both reduce wind output almost to zero. He presented data showing that in many electricity systems with substantial wind capacity there can be several successive days with wind generators operating at capacity factors well below 10%. He also questions the claim of Jacobson and Delucchi that a grid harvesting wind from a large geographic area would need little storage. He cites data from Australia showing that for "20% of the time a wind system integrated across 1500 km from Adelaide to Brisbane would be operating at under 8% of peak capacity."

When a large amount of backup capacity is added to the system to cope with low wind output, it tends to operate at a low capacity factor since it is not used when wind output is high. In addition, there is a complementary problem when wind speed is ideal. Too much electricity is generated and discarding it will reduce the overall capacity factor on wind generators. Trainer then argues that the proposals of Jacobson and Delucchi to overcome these problems through storage seriously understate the costs of building and operating bulk electricity storage systems.

Jacobson and Delucchi (2011) ruled out nuclear power as a replacement for fossil fuels on grounds other than economics—primarily that widespread use of nuclear power would increase the proliferation of nuclear weapons. They also claim that nuclear would be less effective than wind at reducing CO_2 emissions. Qvist and Brock (2015) take the opposite view that nuclear power is one of the few base load alternatives to fossil fuel that is currently available and which historical experience has proved can be significantly expanded and scaled up to allow deep cuts in CO_2 emissions. They use data from Sweden's rapid expansion of nuclear power between 1960 and 1990 to demonstrate the ability of nuclear power to reduce CO_2 emissions while simultaneously allowing substantial economic growth. They also claim that the Swedish experience demonstrates that nuclear could replace global fossil fuel generation capacity in around two decades. Using data from France, they increase this estimate to about 34 years.

Grubler (2010) presented data on the French nuclear build-up that leads to less optimistic conclusions. He points out that construction times and costs escalated as the French program proceeded.[3] He suggested that reduced standardization of reactor designs, partly to improve safety, and especially the unsuccessful attempt to introduce a new design toward the end of the scale-up, was mainly responsible. The latter was motivated in part by a political desire to promote greater domes-

3. Nevertheless, the costs he provides for the French program are less than half the capital costs we use in our later calculations. The numbers that we use come from the United States Energy Information Administration (EIA).

tic value added for the nuclear industry and higher export market potential. More recent experience with escalating costs of nuclear plant construction not only in France but also the United Kingdom, Finland and the United States has also raised doubts about the long-term viability of nuclear power.

Green and Staffell (2016) simulate the evolution of the British wholesale electricity market under different scenarios regarding reduced use of fossil fuels. They assume that power stations are added whenever they are expected to be profitable over their expected lifetimes, and are closed when they cannot cover their variable costs. The existing configuration of the system therefore continues to influence its trajectory. A major message in their paper is that coal will be squeezed out of the system under policies that constrain CO_2 emissions. Coal is also having difficulty competing against natural gas in the United States at the moment, given the currently low natural gas prices. In the analysis presented below, the only fossil fuel fired capacity that we consider is natural gas.

In a sense, we are interested in the opposite problem to the one discussed by Green and Staffell. We want to know how conclusions about what type of system may be desirable in the long run affect decisions about investments today and in the near future. Green and Vasilakos (2011) is closer to what we do here. They use data on wind speeds (we have measured data on actual wind generator output in Texas) in the United Kingdom to simulate the effects of different levels of wind penetration on the long-run equilibrium of the system. They calculate the likely effect of wind using the residual load duration curve facing thermal generators after subtracting wind. In contrast to Green and Vasilakos, we are not interested only in the long-run effect of increasing wind penetration. Rather, our main focus is on wind and nuclear power as alternative non-fossil means of generating electricity in the long run. We also use linear programming to examine systems combining either of those technologies with natural gas plants. Our interest is not only in the costs and other characteristics of the different long-run systems, but also how those different systems might affect the type of investments that ought to be made in the intermediate and then short run.

Experience maintaining network stability and power quality in the face of increasing wind generation has emphasized the value of storage. Green and Vasilakos (2012) provide an interesting analysis of Denmark, which has one of the highest levels of installed wind capacity relative to electricity demand.[4] They emphasize the benefits of the connections between Denmark and Norway, Sweden and Finland, which have substantial hydroelectric capacity. In a simplified model, they assume that Denmark has fixed quantities of wind and thermal generation and a limited capacity connection to hydroelectricity plants based on stored water. Their key conclusion is that, in the absence of transmission constraints or binding constraints—high or low—on reservoir storage, wind output should be accepted whenever it is available. Effectively, the resulting variations in water in storage represent a "battery" for the wind generation. Water should then be allocated across periods to equalize the thermal output, and hence thermal marginal cost, in each period. This equilibrated value also represents the shadow value of water. Green and Vasilakos also discuss the implications of the limited transmission capacity and other constraints, but the intuition of the unconstrained case informs their empirical analysis.

Green and Vasilakos find that short-term fluctuations in wind output in Denmark are highly correlated with short-term fluctuations in net exports of electricity to Norway, Sweden and Finland. The ability to trade power with neighbors possessing significant reservoirs for hydroelectricity generation thus allows Denmark to smooth daily or weekly fluctuations in wind output. At an annual timescale, however, Denmark's net exports of electricity are uncorrelated with wind production. Instead, there is a strong correlation between Denmark's annual net exports of electricity and its

4. Ranking countries by the proportion of renewable capacity can be misleading when connections allow substantial trade. The ERCOT system has only weak DC links with its neighbors and operates substantially as a stand alone network.

thermal production, and a negative correlation between those net exports and the level of hydro generation in Nordic countries. Thus, while Denmark uses water storage by its neighbors to offset short-term fluctuations in wind output, the neighbors use Denmark to cope with longer-term fluctuations in hydro power availability.

In contrast to wind generation, nuclear plants are generally operated to produce a very smooth flow of output. Since nuclear plants have high capital and low operating costs, it is generally efficient to operate them at full capacity except when being refueled. They are designed to operate that way in the United States, but in France and Germany nuclear plants have recently been operated in load following mode primarily to accommodate intermittent renewable generation (see Lokhov (2011)). In the United States, it makes more sense to use natural gas-fired plants to accommodate load variation, especially given current natural gas prices.

Even though nuclear power plants are generally operated at full capacity, they also can benefit from electricity storage. Storage allows a higher capacity of nuclear power, since any excess of output over load can then be stored to be used when output is less than load. Trade in electricity can also substitute for storage in supporting nuclear power just as it does for wind. For example, one reason that France can accommodate so much nuclear capacity is that it can trade excess nuclear electricity generated at night to its neighbors.

There is also a substantial literature on electricity storage technologies. Luo et al. (2015) review recent technological developments. They note that pumped hydroelectric storage represents more than 99% of current worldwide bulk storage capacity. It is the most mature technology, and is capable of storing large amounts of energy. Capacities of operating systems range up to more than 3GW. The plants have 70–85% cycle efficiency and a lifetime of more than 40 years.

Rechargeable batteries of many sorts are also widely used, but not much for bulk electricity storage. Most facilities in operation have less than 10MW capacity. The limited lifespan, high self-discharge rate, and high maintenance costs of batteries make them expensive.

Another technology currently used is compressed air storage. Its cycle efficiencies of around 50% are much lower than pumped storage. Some variants that could have higher cycle efficiencies are under development. Some flywheel energy storage systems are also in operation. Cycle efficiencies up to 95% can be achieved in systems using non-contact magnetic bearings. The large inertia in these systems makes them particularly suitable for providing frequency control services, but they have modest storage capacity and store electricity for only short periods. Energy stored in the form of thermal energy is also used for load shifting. However, its cycle efficiency (30–60%) is low. Other technologies that Luo et al. discuss are more experimental.[5]

The United States Department of Energy released a study on grid energy storage in 2013. They focus on the role that energy storage can play in enhancing renewable energy penetration into the network. Its role in smoothing the load on nuclear power plants is only mentioned in passing when discussing the development of energy storage in Japan. The report notes that the 23.4GW of pumped storage capacity in the United States represents about 95% of total storage capacity. The remainder is roughly one third each of thermal storage and compressed air, and one sixth each of batteries and flywheels. They identify four main barriers to more widespread deployment of energy storage: cost, validated performance and safety, unsupportive regulations and industry acceptance.

5. Flow batteries, which use two separate liquid electrolyte tanks, may be suitable for bulk electricity storage of up to several months. The generating capacity of the system, which is determined by the size of the electrodes and the number of reaction cells, is independent of the storage capacity, which depends on the amount of electrolyte and its concentration. Since the electrolytes are stored separately, there is also little self-discharge.

In our analysis, we will take the cost of pumped storage as a realistic estimate of the cost of commercially viable bulk electricity storage systems. In practice, considerable technical progress would be needed to reduce the costs of alternatives to pumped storage to this level.

The importance of hydroelectricity as a complement to wind generation raises the question of how ERCOT can accommodate more than 18GW of wind capacity. ERCOT has almost 700MW of run-of-river hydroelectricity, but, like wind, its output is exogenous to demand or supply from other generators.

Cullen (2013) used 15-minute interval data from ERCOT from 2005–2007 to measure how wind generation affects other generators. He allows the output of each non-wind generator to be a quadratic function of wind production. Noting that the diurnal and seasonal patterns for wind production may be correlated with incentives for production by other generators, he also includes as explanatory variables current and lagged values of aggregate load, temperature, and an indicator for when transmission lines are congested. To capture the effects of start-up and shut-down costs, he also includes the operating state for the generator two hours prior to production. The same lagged operating state variables for all the *other* generators on the grid are also included in each regression to allow for potential strategic interactions between generators. Each regression also includes a set of day by year indicator variables. Before dynamics are accounted for, Cullen finds that each MWh of wind causes an average 0.85MWh reduction from gas generators, 0.18MWh reduction from coal generators and economically insignificant changes from other generators.[6] After dynamic controls are introduced, coal offsets drop to almost zero while gas offsets increase to 0.92MWh, of which 0.53MWh is from combined cycle, 0.32MWh from older steam plants and only 0.07MWh from natural gas turbines.

Cullen's results thus suggest that natural gas generation plays an important role in complementing intermittent wind production in ERCOT. His results are also consistent with our conclusion below that introducing wind generation into an otherwise all natural gas system would primarily displace combined cycle plants.

3. DATA

The main data set we use was prepared by ERCOT for its 2016 *Wind Integration Report*. This gives system load and wind output for every hour of the year. We used only the most recent year because the amount of wind capacity is still growing and we wanted as much wind capacity as possible. Furthermore, until the almost $7 billion Competitive Renewable Energy Zones (CREZ) transmission system upgrade was completed in 2014, transmission capacity was insufficient to get maximum output from wind farms in the west of the state to the main loads in the east, leading to frequent curtailment of wind output at night. Nevertheless, data going back to 2007 shows that the general relationship between wind output and system load has not changed noticeably over the decade.

Figure 1 graphs a kernel density estimate (evaluated at 100 points in each dimension using a Gaussian kernel) of the bivariate probability density function for hourly wind output and total ERCOT system load for 2016. Table 1 gives some summary statistics. Since wind capacity grew by more than 16% from 16.246GW at the beginning of 2016 to 18.923GW at the end, the table also provides statistics on the capacity factor for each hour. The mean capacity factor of more than 35%

6. For 2005–2007, natural gas generators constituted about 65% of ERCOT capacity and provided about 45% or primary energy input into electricity generation.

Figure 1: Bivariate density function for hourly ERCOT load and wind generation

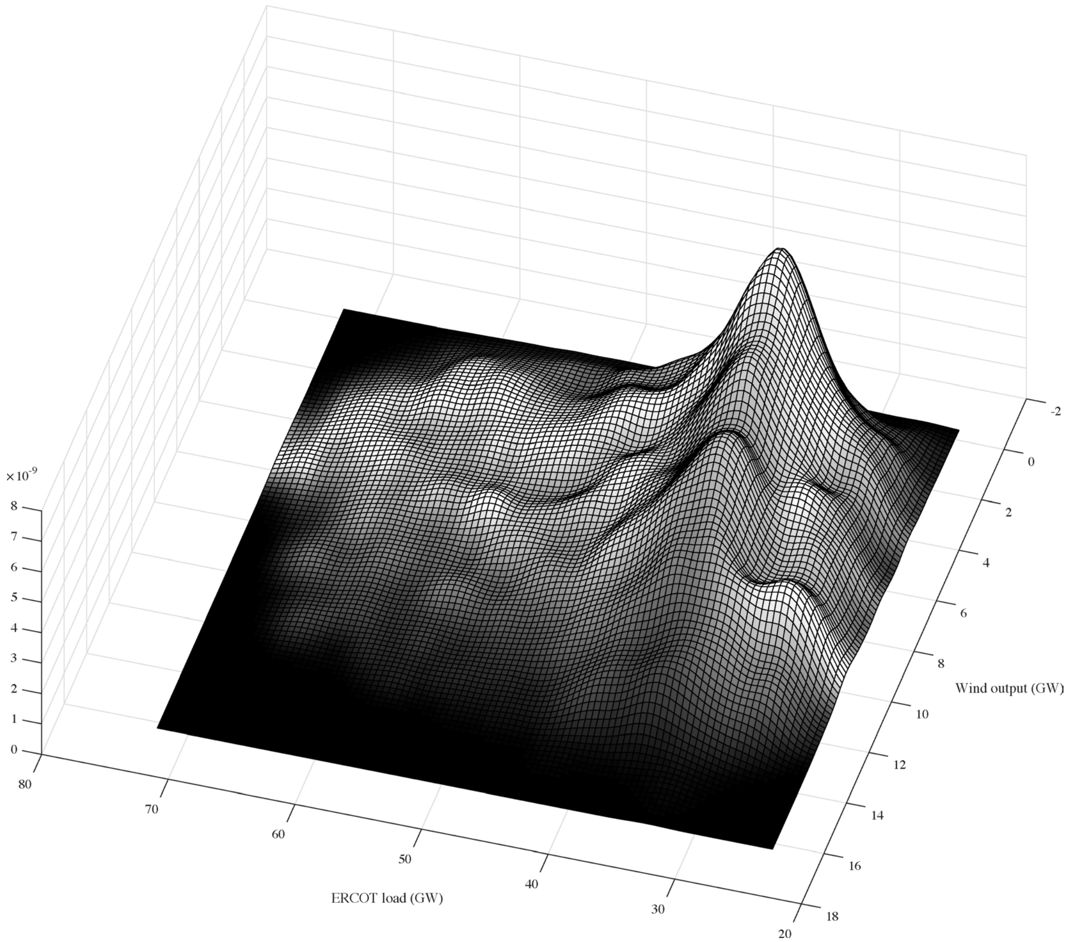


Table 1: Summary hourly statistics for 2016

Statistic	ERCOT load (GW)	Wind output (GW)	Wind capacity factor (%)
min	25.074	0.131	0.79
max	71.243	15.722	86.03
mean	40.0084	6.0742	35.46
median	37.633	5.746	33.66
std. dev.	9.4774	3.3867	19.87
skewness	0.941	0.286	0.275

is quite high by international standards, especially given the inland location of almost all the wind farms.

In an ideal situation, wind output would be highest when system load is highest and vice versa. The “ridge” in Figure 1 would then run from the back right to the front left. In fact, there is a tendency for wind output to be lower when the ERCOT load is highest. The correlation between the two variables is –0.12. At the daily frequency, wind output tends to be largest in late night and early morning hours when ERCOT load is relatively low. Seasonally, wind generation also tends to be

Table 2: Power plant capital and operating costs

Parameter	GT	CC	Wind	Nuclear	Battery storage	Pumped storage
capital cost ($b/GW)	0.678	1.104	1.877	5.945	4.985	5.288
size (MW)	237	429	100	2234	50	250
annual fixed O&M ($b/GW)	0.0068	0.01	0.0397	0.10028	0.1	0.018
variable O&M ($'000/GWh)	10.7	2.0	0	2.3	0	0
fuel ($'000/GWh)	28.35	18.22	0	1.53	0	0
plant life	30	30	25	60	15	50
indicative capacity factor	0.05	0.50	0.355	0.9008	0.12	0.12
fixed/output (¢/kWh)	14.66	2.36	6.69	7.00	63.24	40.48
variable (¢/kWh)	3.90	2.02	0	0.38	0	0
total LCOE (¢/kWh)	18.56	4.38	6.69	7.38	63.24	40.48

higher in spring when demand is relatively low. The variability of wind output is illustrated by the fact the while mean wind output is 15% of the mean ERCOT load, the standard deviation of wind output is more than 35% of the standard deviation of ERCOT load.

The second main data source we use is a 2016 report issued by the Energy Information Administration (EIA) on *Capital Cost Estimates for Utility Scale Electricity Generating Plants*. The cost estimates presented in the report were produced by an external consultant to the EIA using, where possible, data on actual or planned projects in the United States combined with generic assumptions for labor and materials costs. The cost estimates were developed using a common methodology across technologies. They represent the costs of a generic facility in a location that does not have unusual constraints or infrastructure requirements (including needed transmission upgrades). The EIA uses the estimates to develop energy projections and analyses, including forecasting retirements of old plants and the mix of generating capacity additions needed to serve future electricity demand.

We focused on six technologies. For fossil fuels, we examined only natural gas plants on the assumption that the lower emissions from natural gas combustion would make it a preferred technology in the longer-run time horizon that we are interested in. Specifically, we used the costs for "advanced natural gas combined cycle" (CC) and "advanced combustion turbine" (GT) technologies. For technologies that do not emit any CO_2, we used onshore wind and "advanced nuclear". Since the 2016 report gives battery storage as the only electricity storage technology, we also used estimates of costs for pumped storage from the equivalent 2013 report. As noted in the literature survey, pumped storage is currently the lowest cost electricity storage technology and the only one in extensive use.

The critical parameters are summarized in the top half of Table 2.[7] The lower half of Table 2 contains parameters and calculations that do not come from the EIA publication referenced above. The fuel costs for the natural gas plants were developed by combining the heat rate for the plants specified in the EIA data with the (historically very low) average cost of natural gas delivered to power plants in the United States in 2016 ($2.89/MMBTU), which was obtained from EIA natural gas statistics. The fuel cost for the nuclear plant was derived using the average monthly cost of U_2O_8 for 2016 ($26.31/lb, obtained from IMF statistics), an assumption of 180 MMBTU/lb of U_2O_8 and

7. These costs ignore environmental costs associated with the production and combustion of fossil fuels, the mining and disposal of rare earths used in wind turbine magnets, the mining of uranium and handling of nuclear waste, and many other negative externalities.

a heat rate for the plant of 10.452 MMBTU/MWh. The resulting variable cost of 0.38/kWh closely approximates the reported cost of 0.4/kWh for the South Texas Project nuclear plant.

For calculating the LCOE in the lower half of Table 2, the life of the natural gas plants has been taken as 30 years. The National Electric Energy Data System (NEEDS) database v.5.13 shows that the average ages of GT and CC plants in operation in the United States as of 2015 were 26 years and 18 years respectively. Since many of the CC plants were still quite young and likely to be used for many more years, a lifetime of 30 years is likely to be conservative. The NEEDS database also gives retirement ages for the nuclear plants that imply they have a lifetime of 60 years. The average age of the pumped storage plants in the NEEDS database is 40 years, so we conservatively assumed a plant design life of 50 years. The wind turbines in the NEEDS database have been operating for an average of 10 years, but these are among the newest plants. Siemens Wind Power conducted life cycle assessments of wind turbines and suggested that their operating lifetimes are likely to approximate 25 years.[8] With regard to battery technologies, Luo et al. (2015) give ranges of only 5–15 years as a result of chemical deterioration with accumulated operating time. Since the cost of battery storage in Table 2 is so high, in the subsequent analysis, we will use the costs of pumped storage as an estimate of the costs that might eventually be obtained by other mass storage technologies.

The indicative capacity factors for natural gas plants approximate the values calculated endogenously in the subsequent analysis. A *Today in Energy* fact sheet from the EIA published July 8, 2013 indicates that pumped storage in the United States currently operates at about a 12% capacity factor. The wind capacity factor comes from the ERCOT data discussed above, while the capacity factor for nuclear plants is the realized average capacity factor for United States plants in recent years.

The calculations also use a real after-tax weighted average cost of capital (WACC) for electric utilities of 7.5%, but in the analysis below we also consider 5% and 10%. Public utility commissions in the United States allow regulated real equity returns of around 10%. However, utilities often have leverage ratios of 40% with a real return on debt of around 6%.

The relatively low LCOE for CC generators reflects the current low prices for natural gas in the United States. We would expect those prices to rise somewhat as more LNG is exported from the United States, linking prices there to prices in the rest of the world. As argued above, prices worldwide will rise in the long run. In the subsequent analysis we examine the effect of raising the natural gas price substantially above the 2016 average price.

While both wind and nuclear can generate power without emitting CO_2, the LCOE results in the lower half of Table 2 suggest that wind should be preferable to nuclear for replacing fossil fuels. As Joskow (2011) observes, however, and the analysis in the next section also shows, the LCOE calculations can be misleading when one has to ensure supply can always meet the load. The fact that wind output is very variable, not able to be dispatched as needed, and generally not well-correlated with system load can raise the overall cost of a system that includes substantial wind generation.

4. ANALYSIS AND RESULTS

We first use elementary methods to analyze the long-run systems with storage complementing nuclear or wind generation. Subsequently, we examine systems that can include natural gas, wind, nuclear and storage. This requires the use of linear programming.

8. Some wind farms established in Texas after 1995 have already been retired.

4.1 Long-run systems with storage and no fossil fuel

We first consider the case where nuclear and storage are used. We imagine we have nuclear plants (running at 90.08% capacity factor) generating a constant flow of power. When output exceeds the load, the excess electricity is used to pump water into the upper reservoir of pumped storage facilities. Conversely, when the load exceeds the output of the nuclear plants, water is allowed to flow from the upper to the lower reservoir through turbines, which generate sufficient power to make up for the excess demand. The July 8, 2013 *Today in Energy* EIA fact sheet referred to previously indicates that pumped storage in the United States currently operates at about 80% efficiency. In other words, only 80% of the electricity used to pump water up to the higher reservoir is produced when water is allowed to flow back down to the lower reservoir.[9] We thus first calculated a "scaled average" nuclear power output by choosing a multiple k of the 2016 average annual load $\bar{L} = \mathbb{E}L_h =$ 40.0084MW, where L_h is the load in hour h, such that:

$$\sqrt{0.8} \sum_{\{h:L_h<k\bar{L}\}} k\bar{L} - L_h = \frac{1}{\sqrt{0.8}} \sum_{\{h:L_h>k\bar{L}\}} L_h - k\bar{L} \tag{1}$$

The resulting solution for $k = 1.021275$. In other words, to compensate for the electricity lost during storage the amount generated on a constant basis has to be about 2.1% above the average system load. To generate that amount using nuclear plants with an average capacity factor of 0.9008, we would need 45.359GW of nuclear capacity.

Figure 2 graphs $\sqrt{0.8}(L_h - k\bar{L})$ if $L_h < k\bar{L}$ and $(L_h - k\bar{L})/\sqrt{0.8}$ if $L_h > k\bar{L}$ for each hour of 2016. This corresponds to the amount of electricity stored or the amount produced from storage, net of losses. The figure shows both daily and seasonal variations in load. Electricity demand in Texas peaks in the summer months when there is very high demand for air conditioning. The smaller increase in demand from December to February reflects increased use of electricity for heating.

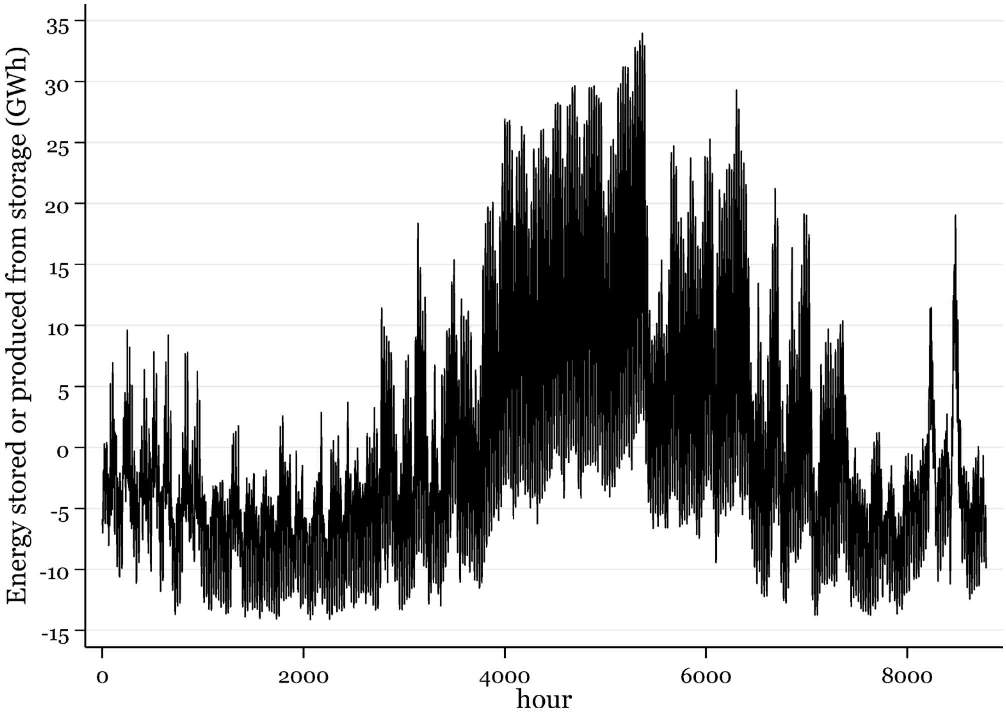
The pumped storage *generating* capacity would be the maximum value graphed in Figure 2 times $\sqrt{0.8}$, which is 30.383GW. Cumulating the amounts graphed in Figure 2, we find that the maximum *stored energy* would be equivalent to about 21.8 days of operation at full generating capacity. The average capacity factor of the pumped storage, measured by generated power divided by capacity times hours in a year would be 11.2%, or slightly less than the capacity factor for pumped storage in the United States as reported above.

Finally, the system as configured would allow the exact distribution of load experienced in 2016 to be satisfied with an average capacity factor for the nuclear plants of 90.08%. This allows for down-time for refueling and other problems. However, we add an additional 10% reserve plant margin to allow for stochastic variation in load and equipment failures, including transmission line outages.[10] The lowest cost way of providing this capacity in a way that also would not involve much combustion of fossil fuels under normal operation is to add GT to the system. Given the maximum hourly load in 2016 of 71.243GW, the annual capital cost of 7.124GW of GT (approximately the existing GT capacity in ERCOT) would be $457m.

9. Natural runoff into the upper reservoir and evaporation from it can affect the energy efficiency of pumped storage. Evaporative loss may be a particular problem in the Texas summer.

10. Costs of providing ancillary services will also include shut-down and start-up costs, but the EIA data does not provide any information about these. Current market prices for providing ancillary services in ERCOT, especially when wind generation is high, suggest that the cost of providing such services is high.

Figure 2: Storage energy flows under nuclear generation



We consider next a system with wind and storage.[11] We need first to allow for the fact that the available wind capacity grew over 2016. We calculated the capacity factor for wind generation in every hour of 2016 and assumed that if the generating capacity had been the full amount available at the end of 2016, the capacity factor would have been the same as the actual one. Let the resulting wind generation in each hour be W_h. In order to calculate the amount of storage capacity, we again need to scale wind capacity and output by a factor ω such that 80% of the cumulative amount of excess generation over load equals[12] the cumulative excess of load over generation over the year. Thus, (1) is modified to:

$$\sqrt{0.8} \sum_{\{h:L_h<\omega W_h\}} \omega W_h - L_h = \frac{1}{\sqrt{0.8}} \sum_{\{h:L_h>\omega W_h\}} L_h - \omega W_h \tag{2}$$

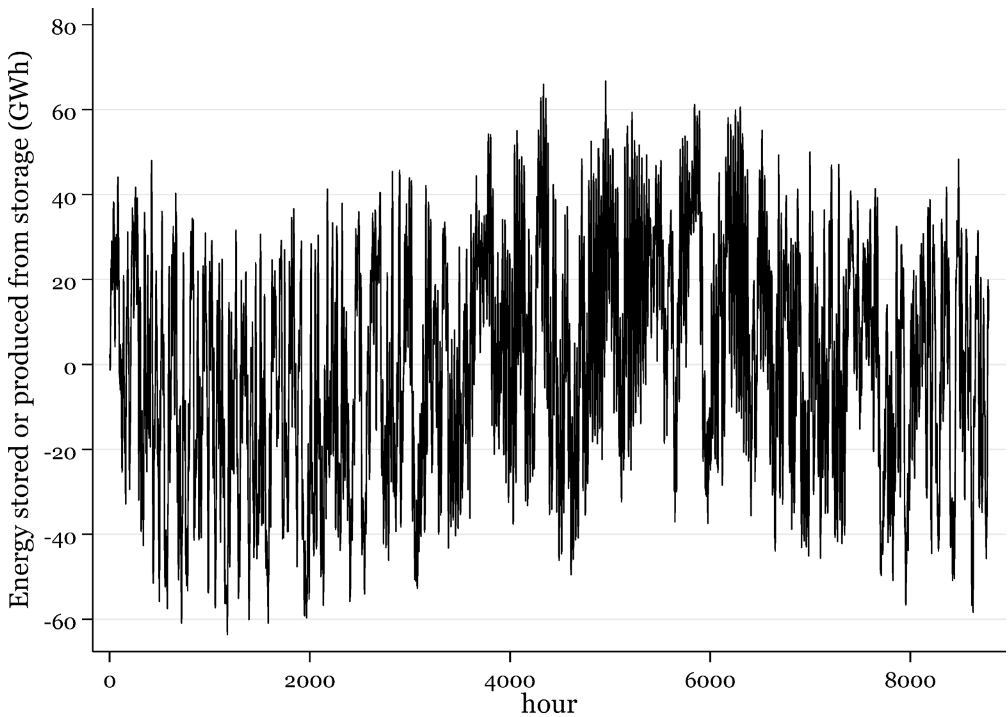
This process implicitly assumes that increasing wind generating capacity by a factor of ω will not change the patten of wind generation or wind capacity factors, and thus will scale wind variability. On the one hand, the average quality of the sites, and thus wind capacity factors, are likely to decline as substantial amounts of wind generation are added.[13] On the other hand, con-

11. As Green and Staffell (2016) observe, there can be problems maintaining network stability with wind turbines since they operate asynchronously and do not provide inertia to stabilize frequency. The actual system we will examine will also have natural gas turbines in addition to hydroelectric plants to help provide ancillary services.

12. This procedure assumes that any excess of wind output over load is stored rather than "spilled." In the next section, we assume that the capacity to store energy is the same as the capacity to generate electricity from stored water. In the solution below, the maximum hourly storage rate is strictly less than the maximum hourly generation from storage. When the constraint on storing energy is never binding, one can show that it will not be optimal to spill generated wind power.

13. Although some of the best locations for generating wind power may not have been viable before the CREZ lines were built, it is likely by now that most of the best sites have been developed. Coastal sites with a lower correlation of output with

Figure 3: Storage energy flows under wind generation



tinuing technical improvement in wind turbines is likely to raise their capacity factors. Proceeding with this assumption, we obtain a solution for $\omega = 6.330453$. Given that the wind capacity in Texas was 18.923GW at the end of 2016, this means that we would require 119.791GW of wind capacity to generate power equal to the cumulated Texas load for 2016 after allowing for a 20% loss when using pumped storage. Once again we can visualize the electricity being stored and produced from pumped storage facilities by graphing $\sqrt{0.8}(L_h - \omega W_h)$ if $L_h < \omega W_h$ and $(L_h - \omega W_h)/\sqrt{0.8}$ if $L_h > \omega W_h$ for each hour of 2016, as in Figure 3.

The higher variance of the fluctuations in Figure 3 compared to Figure 2 reflects the high variability of wind output compared to system load. The mild negative correlation between wind output and load also means that the draw on storage in the summer can be much higher than under the nuclear scenario. In addition, the need to store excess generated power in the "low demand" spring and autumn seasons can be almost as large as the positive excess of load over generation in the summer. The tight daily cycle of demand evident in Figure 2 is also changed in Figure 3 into longer period cycles of excess supply or excess demand.

The pumped storage generating capacity is again the maximum value graphed in Figure 3 times $\sqrt{0.8}$, which in this case is 59.698GW. This is more than 96% higher than in the nuclear case.[14] The extreme variability of wind thus requires much more storage generating capacity. Cumulating the amounts graphed in Figure 3, the maximum storage volume needed in this case would be about 19.4 days of operation at maximum capacity. The average capacity factor of the pumped storage in

the inland sites have recently been developed, but they also have lower average capacity factors. Remaining coastal sites are limited, in part because of concerns about hurricanes and migratory birds.

14. If the average capacity of a storage facility is 250MW as in Table 2, we would need around 122 facilities in the nuclear case and 239 in the wind case.

Table 3: Solutions for costs in the long-run systems

	WACC		
	0.05	**0.075**	**0.10**
Nuclear and storage			
Annual cost ($b)	29.875	39.798	50.286
Average cost (¢/kWh)	11.46	15.27	19.293
Wind and storage			
Annual cost ($b)	39.438	50.789	63.00
Average cost (¢/kWh)	15.13	19.49	24.171

this case would be 16.6%. As with the nuclear case, we also allow for 7.124GW of GT for emergency backup capacity.

Recall that the LCOE in Table 2 were calculated using a real weighted average cost of capital of 7.5%. Table 3 presents the results for this and two other discount rates. The average costs were calculated noting that the total electricity to be supplied is 351.433385TWh.

The cost of wind plus storage exceeds the cost of nuclear plus storage by more than 32% when $r = .05$ to around 25% when $r = 0.10$. This is despite the result in Table 2 that the LCOE for wind is a little over 9.3% below the LCOE for nuclear. Coping with wind output variability almost doubles the amount of expensive storage capacity. Furthermore, while an increase in WACC favors wind over nuclear, it also raises the cost of storage. Hence, even at the unrealistically high (for a utility) real WACC of 10%, the nuclear plus storage system remains less costly.

The difference in cost between the two systems could exceed the values in Table 3 for two reasons. First, the calculations assume that the cost of bulk electricity storage scales linearly with storage generating capacity. However, the number of sites suitable for pumped storage is limited. As more pumped storage sites are exploited, sites that are more expensive to develop, or which are more remote and therefore require additional transmission lines to be built, are likely to be needed. Alternatively, using more expensive methods of bulk electricity storage in place of pumped storage would also raise costs. A partially offsetting factor is that the ratio of stored energy to storage generating capacity is about 12% higher in the nuclear system, possibly because of stronger seasonality in the flows in to and out of storage. This would raise storage costs per unit of generating capacity in the nuclear case.[15] Nevertheless, since the system with wind has almost double the required storage generating capacity, it is likely to incur more than double the storage costs.

The second reason that the values in Table 3 could understate the advantage for nuclear is that the wind resource itself is often distant from markets and requires additional transmission lines to be built. For example, Texas electricity consumers had to finance an almost $7 billion expansion in high voltage transmission lines (in the CREZ project) to facilitate the exploitation of an additional 12GW of wind resources in west Texas. These lines, like the wind generation capacity itself, are used at a low capacity factor and thus are expensive per unit of energy delivered. By contrast, nuclear plants can be built much closer to the main load centers and any new transmission lines required are likely to be much shorter and used at much higher capacity factors.

On the other hand, Table 3 could overstate the advantage for nuclear if Table 2 understates the capital costs for nuclear. As we noted in section 2, increased regulatory constraints and reduced standardization have raised the costs of constructing nuclear plants.

15. According to Schoenung and Hassenzahl (2003), the volume of water V in m^3 needed to store energy E in kWh when the average head in m driving the turbine is h is $V = 400E / h$. For a 250MW generating capacity facility with a head of 300m, a reservoir with 25m water depth would need to cover about $7km^2$ in the nuclear case compared to $6.2km^2$ in the wind case.

Table 4: Long-run system costs with alternative capital costs

	WACC		
	0.05	**0.075**	**0.10**
Nuclear and storage			
Annual cost ($b)	31.299	41.847	52.991
Change relative to Table 3	4.8%	5.1%	5.4%
Wind and storage			
Annual cost ($b)	37.843	48.772	60.524
Change relative to Table 3	–4.0%	–4.0%	–4.1%

It is also possible that further improvements in wind technology may continue to lower the capital costs of wind. However, we argued above that some of these improvements may be needed to ensure that the average load factor of wind plants does not deteriorate as substantial amounts of wind generation are added. If so, technological improvements could actually raise capital costs. For example, longer blades require higher towers. Nevertheless, we examined the effects of reducing the capital cost for wind by 10% while simultaneously raising the capital cost for nuclear by 10%.

The results presented in Table 4 show that the system with nuclear and storage is more sensitive to a change in capital costs than the system with wind and storage. The sensitivity to capital costs also rises with the WACC. The results suggest that, to overturn the conclusion that nuclear plus storage is less costly, relative to the costs in Table 2, the capital costs for nuclear would need to be at least 50% higher, or the capital costs for wind at least 60% lower, or some combination of higher costs of nuclear and lower costs of wind would need to alter the cost ratio by between 50% and 60%.

The result that the wind plus storage system likely has a higher cost than the nuclear plus storage one has an important implication. As noted in the introduction, it is often argued that storage would solve the problems with wind generation—its intermittency, non-dispatchability, and generally negative correlation with system load. Our result implies, however, that far from making highly variable and uncontrollable sources of generation more competitive, storage would in fact better advantage stable and controllable generation. With storage, such sources can be used to continuously and reliably supply the average load at low cost.

The amount of electricity storage required under these two scenarios is extraordinary. It is about 30% more than the current pumped storage capacity in all of the United States in the nuclear case, and more than 2.5 times current United States capacity in the wind case. As we will see in the next sub-section, the need for so much storage will delay the transition to the long-run system.

4.2 Including natural gas generation

Allowing for any combination of natural gas, wind, nuclear and storage results in a more complicated problem that can only be solved using linear programing. The linear program takes as inputs the vectors of hourly wind outputs (scaled to end of year wind generating capacity) W_h and system loads L_h in ERCOT in 2016. The choice variables include a scale multiple ω of the wind capacity (18.923GW) and outputs. The capacities K_C of CC, K_T of GT and K_N of nuclear, and the outputs $GC_h \le K_C, GT_h \le K_T, N_h \le K_N$ from these plants in each hour, also need to be chosen. Finally, the pumped storage capacity, and the electricity used for pumping or the electricity generated from the stored water in every hour, also need to be chosen. As a result of electrical and hydraulic losses, the amount generated is only 80% of the amount of electricity consumed for pumping. We let K_P be the total *generating* capacity of the pumped storage facilities with $PD_h \le K_P$ the electricity generated from storage, and $PU_h \le K_P / 0.8$ the electricity used for pumping, for each hour of the year. In principle, there may also be a constraint on the amount of stored energy.[16] However, since the cost data is presented as a function of generating capacity only, we assume that the stored energy constraint is not binding.

The objective to be minimized is annual system costs:

$$F_C K_C + F_T K_T + 18.923\omega F_W + F_P K_P + F_N K_N + \sum_h V_C GC_h + \sum_h V_T GT_h + \sum_h V_N N_h \tag{3}$$

where $F_i, i \in \{C, T, W, P, N\}$ are the equivalent annual fixed costs per GW of generating capacity of each type of plant and $V_i, i \in \{C, T, N\}$ are variable costs for natural gas and nuclear plants. Denote the capital costs (Table 2 row 1) in \$b/GW of capacity for a plant of type i by p_i and the fixed O&M costs (Table 2 row 3) in \$b/GW by q_i. Also let $A_r^{N_i}$, for plant lifetime N_i and discount rate r, be the annuity factor required to convert the capital costs of p_i to equivalent annual costs. The fixed costs per unit of capacity, measured in \$b/GW, can then be written as

$$F_i = q_i + \frac{p_i}{A_r^{N_i}} \tag{4}$$

Letting $v_i, i \in \{C, T, N\}$ denote the variable O&M costs (Table 2 row 4), and $f_i, i \in \{C, T, N\}$ the fuel costs, of the thermal plants in thousands of dollars, the variable costs in \$b/GWh are

$$V_i = (v_i + f_i) \times 10^{-6} \tag{5}$$

The minimization is subject to a set of demand and storage constraints for each hour that generalize (1) and (2) . In particular, we allow generation to exceed load since it could be optimal to have K_P small and ω large with wind generation "spilled":

$$\begin{gathered} GC_h + GT_h + \omega W_h + N_h + PD_h \ge L_h + PU_h \\ \sqrt{0.8} \sum_h PU_h = \frac{1}{\sqrt{0.8}} \sum_h PD_h \end{gathered} \tag{6}$$

The reserve plant margin constraint requires primarily dispatchable (natural gas, nuclear and pumped storage) capacity to exceed the maximum hourly load for the year by 10%. However, we also allow for a capacity contribution from wind. Specifically, we allowed the minimum wind generation in the 5% of the hours in 2016 with the highest hourly loads, namely 2.717 GW, to scale with ω in contributing to the reserve plant margin constraint:

$$K_C + K_T + 2.717\omega + K_P + K_N \ge 1.1 \max_h L_h \tag{7}$$

Finally, we calculate the total amount of natural gas used over the year (in quads or 10^{15} BTU):

$$E = \sum_h H_C GC_h + \sum_h H_T GT_h \tag{8}$$

where $H_C = 6.3 \times 10^{-6}$ quads/GWh and $H_T = 9.8 \times 10^{-6}$ quads/GWh are the heat rates of the CC and GT plants from the EIA data discussed previously. Initially, we will assume that E is unconstrained

16. Stored energy in hour h, S_h, would evolve according to $S_h = S_{h-1} + \sqrt{0.8} PU_h - PD_h / \sqrt{0.8}$. Storage capacity S_P would be another choice variable with constraint $S_h \le S_P, \forall h$. Storage costs would in general depend on both K_P and S_P.

and we examine the solutions as WACC and p_{NG} vary. Subsequently, we will also examine the effect of quantitative restrictions on the total amount of natural gas used.

Figure 4 graphs the hourly solution for generation in a case where there is substantial output from all generator types.[17] Note the scale differences in the sub-graphs. Apart from the peak summer season, CC output varies to complement load minus wind output. During the peak season, CC plants are run at full capacity during the day, but cycled below capacity at night to accommodate increased wind output. During daylight hours in the peak season, GT compensate for variation in load and wind output. Nuclear output is virtually the same in every hour. The only exceptions occur for some hours in the spring when very high wind output coinciding with a low load results in some curtailment of nuclear output. Even modest costs of cycling nuclear capacity (which are ignored in this analysis) would likely make it preferable to spill the excess wind output in those periods.

Table 5 presents solutions for a range of natural gas prices (measured relative to the average cost of natural gas delivered to power plants in the United States in 2016). The three panels are for the three different WACC values as in Table 3.

The all natural gas system has the lowest cost even as the natural gas price rises substantially. This reflects the fuel-efficiency of natural gas generation and the ability to operate CC at high capacity factors. Nevertheless, higher natural gas prices increase CC and especially GT costs. Reduced GT capacity requires CC to be used in higher demand periods, reducing its capacity factor and further raising its cost. Eventually, the wind or nuclear plants become competitive. Consistent with the results of Cullen (2013) discussed previously, when wind or nuclear are introduced into the system, they displace CC plants more than GT.

The relatively low capital intensity of natural gas generation increases its advantage as the discount rate rises. At a 5% WACC, the natural gas price has to rise by around 140% before nuclear generation can compete. At 7.5% WACC, the gas price has to rise about 215%, and at 10% WACC by about 290%, before alternative generation becomes competitive.

At a WACC of 7.5% or 10%, wind generation displaces natural gas as the natural gas price increases. At a 5% WACC, however, the transition is from natural gas to nuclear even though the LCOE of nuclear exceeds the LCOE of wind generation. This again shows that the LCOE is not a reliable guide to the overall cost of including a generation technology in the system.

Figures 5–7 graph the optimal generating capacities (measured in GW on the left hand axis) for a finer grid of natural gas prices than in Table 5. Each figure also includes two line graphs (measured on the right hand axis). The top positively-sloped line gives minimized system annual cost *as a ratio to* minimized costs when the natural gas price equals the 2016 average (so the line starts at 1). The lower negatively-sloped line gives total fuel used *relative to* the fuel used when the natural gas price equals the 2016 average (so this line also starts at 1). The three figures again correspond to the three different WACC values.

Prior to attaining the level where wind or nuclear displace natural gas, increases in the cost of natural gas have very little effect on the total amount of fuel used.[18] A given percentage increase in the price of natural gas raises costs by around 40 times the percentage that it reduces natural gas use. An implication is that a tax on natural gas use, or on CO_2 emissions, would raise electricity prices

17. Only the CC, GT or nuclear generators are marginal, however, and the multiplier λ_h on the demand constraint in hour h in equals the corresponding LCOE for the capacity that is marginal in hour h. If we let the multiplier on the reserve capacity constraint be μ then $\sum_h \lambda_h L_h + 1.1\mu \max_h L_h$ equals the minimized system cost.

18. In a recent paper, Cullen and Mansur (2017) examine the impact on CO_2 emissions of switching from coal to natural gas generation in response to a CO_2 emissions tax. They similarly find that "when coal holds a sizable cost advantage over natural gas, a marginal change in the cost ratio has no notable effect on emissions."

Figure 4: Hourly outputs and load when r = 0.075, p_{NG} = 9.40

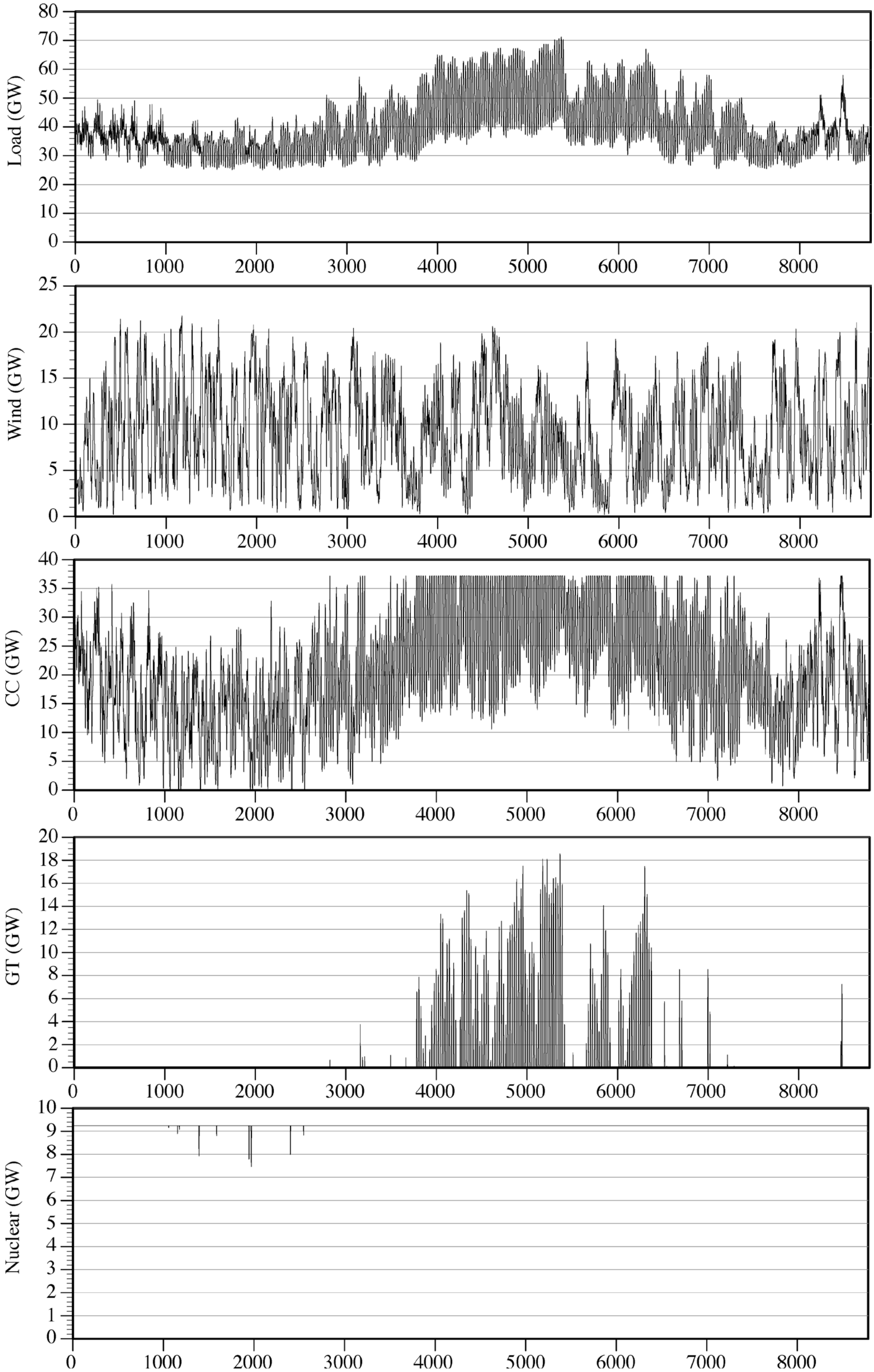


Table 5: LP solutions for different interest rates and natural gas prices

	Natural gas price *relative to* 2016 ($2.89/MMBTU)						
Variable	**1.0**	**2.0**	**2.5**	**3.0**	**3.5**	**4.0**	**4.5**
***r* = .05**							
Annual cost ($b)	12.835	19.337	22.265	23.112	23.707	24.182	24.484
Average cost (¢/kWh)	3.65	5.50	6.34	6.58	6.75	6.88	6.97
CC capacity (GW)	48.078	53.042	27.720	23.575	22.355	17.963	17.503
GT capacity (GW)	30.289	25.325	20.753	18.804	17.548	16.458	15.834
Wind capacity (GW)	0	0	0	0	0	0	0
Nuclear capacity (GW)	0	0	29.895	35.988	38.465	40.020	42.197
Pumped storage capacity (GW)	0	0	0	0	0	1.926	2.833
CC capacity factor (%)	80.05	73.97	45.13	32.87	27.55	19.45	17.89
GT capacity factor (%)	5.03	3.05	2.84	2.45	2.14	1.94	1.76
Nuclear capacity factor (%)			90.01	88.36	87.03	86.64	87.43
Storage capacity factor (%)						44.04	41.44
Fuel used (10^{15} BTU)	2.261	2.238	0.743	0.468	0.373	0.221	0.197
***r* = .075**							
Annual cost ($b)	14.267	20.811	24.058	27.295	29.385	30.183	30.797
Average cost (¢/kWh)	4.06	5.92	6.85	7.77	8.36	8.59	8.76
CC capacity (GW)	45.289	50.175	52.146	53.727	26.436	23.576	22.375
GT capacity (GW)	33.078	28.192	26.221	24.640	20.750	18.903	17.985
Wind capacity (GW)	0	0	0	0	1.806	0	0
Nuclear capacity (GW)	0	0	0	0	30.922	35.888	38.007
Pumped storage capacity (GW)	0	0	0	0	0	0	0
CC capacity factor (%)	83.67	77.41	75.03	73.18	41.82	33.14	28.67
GT capacity factor (%)	6.39	4.14	3.37	2.80	2.74	2.48	2.26
Nuclear capacity factor (%)					89.72	88.41	87.32
Storage capacity factor (%)							
Fuel used (10^{15} BTU)	2.279	2.250	2.241	2.235	0.661	0.473	0.390
***r* = .10**							
Annual cost ($b)	15.806	22.395	25.659	28.911	32.154	34.964	36.669
Average cost (¢/kWh)	4.50	6.37	7.30	8.23	9.15	9.95	10.43
CC capacity (GW)	42.930	47.914	49.686	51.280	52.715	41.770	27.931
GT capacity (GW)	35.437	30.453	28.681	27.087	25.652	30.495	24.129
Wind capacity (GW)	0	0	0	0	0	42.499	17.398
Nuclear capacity (GW)	0	0	0	0	0	0	23.810
Pumped storage capacity (GW)	0	0	0	0	0	0	0
CC capacity factor (%)	86.82	80.26	78.02	76.06	74.36	57.85	43.08
GT capacity factor (%)	7.72	5.10	4.34	3.70	3.16	2.25	2.55
Nuclear capacity factor (%)							88.99
Storage capacity factor (%)							
Fuel used (10^{15} BTU)	2.298	2.262	2.252	2.245	2.239	1.407	0.719

substantially while doing very little to reduce gas use until the tax rate was high enough to trigger the entry of wind, or especially nuclear, generation into the system.[19]

Storage is included in the minimum cost systems in Figures 5–7 only when WACC is 5% and the natural gas price is at least $11.57/MMBTU (4 times the 2016 price).[20] A low WACC is

19. According to EIA data, burning one MMBTU of natural gas emits about 53.07 kg of CO_2. Hence, a tax of $10/metric tonne of CO_2 is equivalent to a tax on natural gas of around 53/MMBTU (18.3% of the 2016 price).

20. For a WACC of 7.5%, increasing p_{NG} by even a factor of 5.5 is insufficient to make storage part of the cost-minimizing solution. Increasing it by a factor of 6, however, produces a minimum cost system with around 2.499 GW of pumped storage.

Figure 5: Optimal capacity mix, minimized cost and fuel use when *r* = 0.05

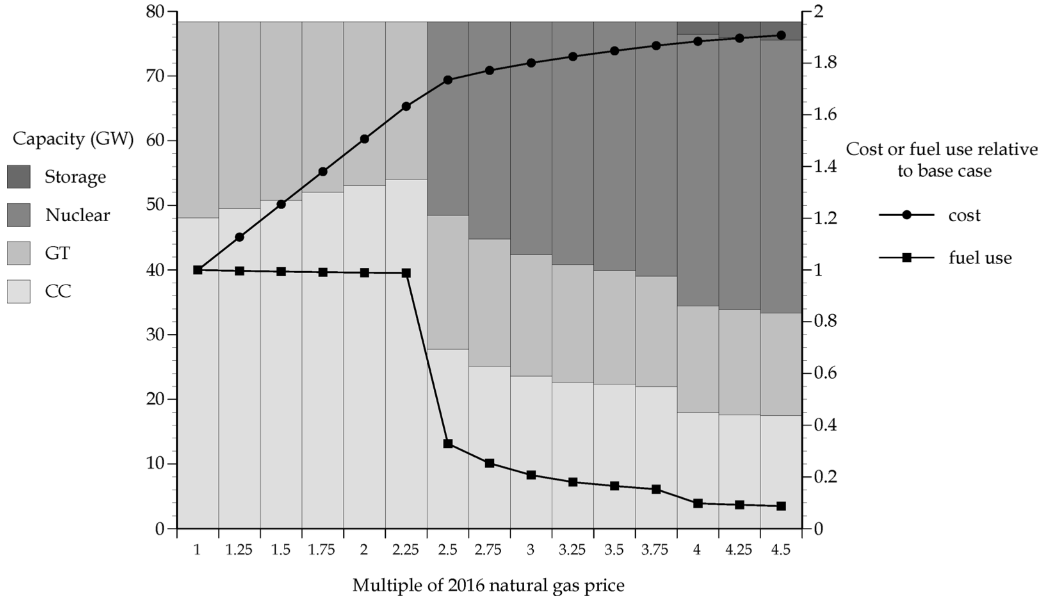
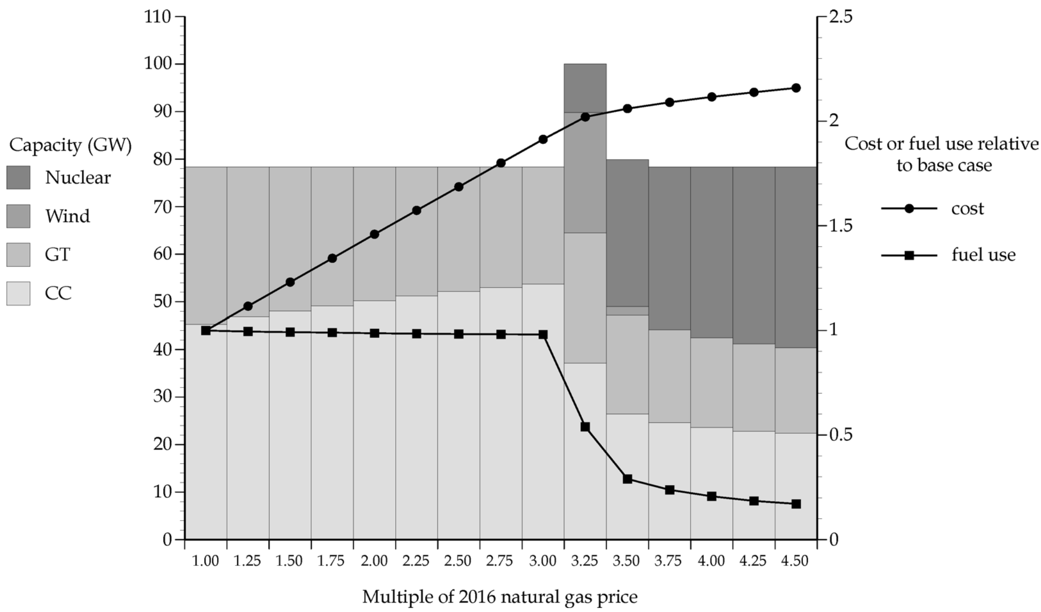


Figure 6: Optimal capacity mix, minimized cost and fuel use when *r* = 0.075



required because storage is capital intensive. A high natural gas price also is needed, for otherwise backup capacity can be provided by GT at much lower cost.[21]

21. For $r = 0.075$ and $p_{NG} = 2.89$, if natural gas is severely constrained to $E \leq 0.5$ while K_N is constrained to zero, 8.561 GW of storage is added. For less severe constraints on E, large amounts of wind capacity are added and a substantial amount of wind generation is "spilled". While this is costly, it is still less expensive than adding storage.

Figure 7: Optimal capacity mix, minimized cost and fuel use when *r* = 0.10

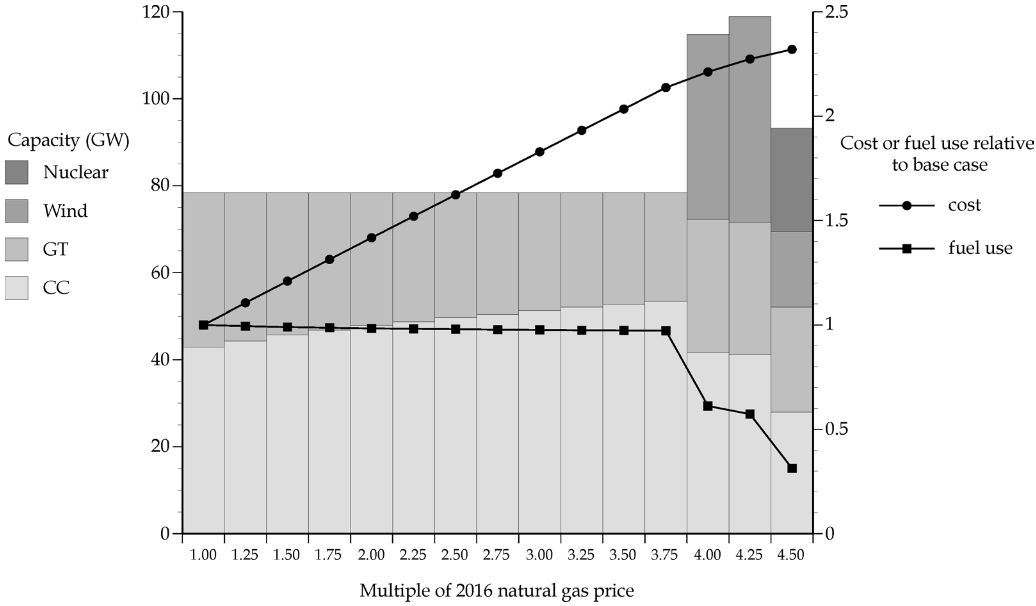
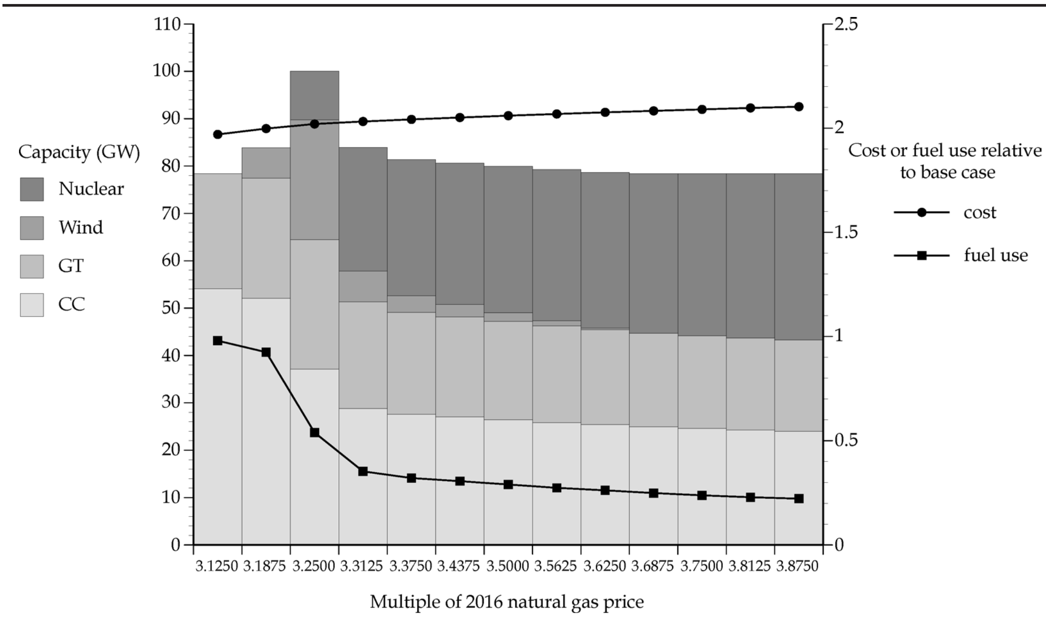


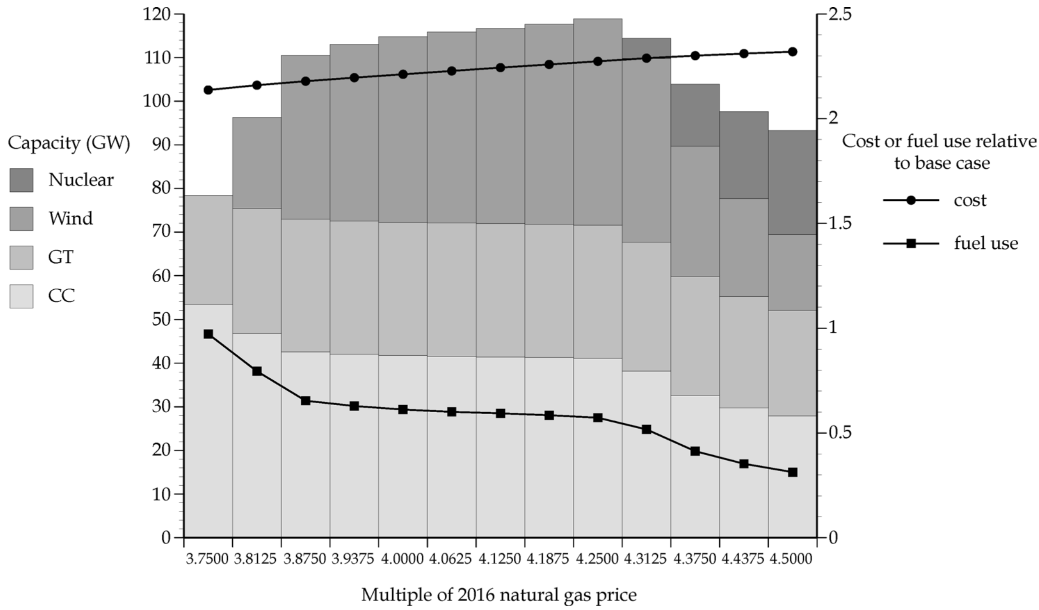
Figure 8: Transition away from natural gas when *r* = 0.075



Figures 8 and 9 focus on the transition away from natural gas as the natural gas price rises for a WACC of 7.5% and 10% respectively. These two figures present results for an even finer grid of natural gas prices, but over smaller ranges, than do the corresponding Figures 6 and 7.

The window of natural gas prices where wind is competitive appears limited, although the total amount of wind capacity included in the minimum cost system can greatly exceed current ERCOT wind capacity. Furthermore, as we show below, reducing wind, and raising nuclear, capital

Figure 9: Transition away from natural gas when *r* = 0.10



costs increases the amount of wind capacity and extends the range of natural gas prices over which wind generation is used.

Where the transition is from natural gas to wind generation, the reduction in natural gas use is much smaller (on the order of 30%) than when nuclear is introduced at higher gas prices (achieving a 50–65% reduction in fuel use). The need to supply backup for wind generation implies that CC and GT capacities and capacity factors tend to be higher when there is wind and no nuclear than when there is nuclear and no wind. Wind therefore has a limited ability to reduce the demand for natural gas. The nuclear plants reduce gas use more effectively since they can reliably displace much more gas plant output. An implication is that, insofar as the negative externalities of electricity production are related to fossil fuel use, wind is far less effective at reducing those externalities than is nuclear.[22]

Table 6 illustrates the effect of constraining natural gas use while keeping WACC = 7.5% and p_{NG} = 2.89/MMBTU. It shows that wind capacity is also part of the minimum cost system for a range of constraints on the amount of natural gas than can be used in the system.[23]

Figure 10 illustrates the effect of reducing the capital cost for wind generation by 10% while simultaneously raising the capital cost for nuclear plants by 10%. Note that in this figure, as in Figures 5–9, the base case represents not only the 2016 natural gas price but also the original EIA capital costs from Table 2. Comparing Figures 8 and 10, we see that the changes in capital costs allow wind to remain competitive over a wider range of natural gas prices. In addition, the maximum amount of wind capacity is much larger than in Figure 8. The system cost increases are also greater,

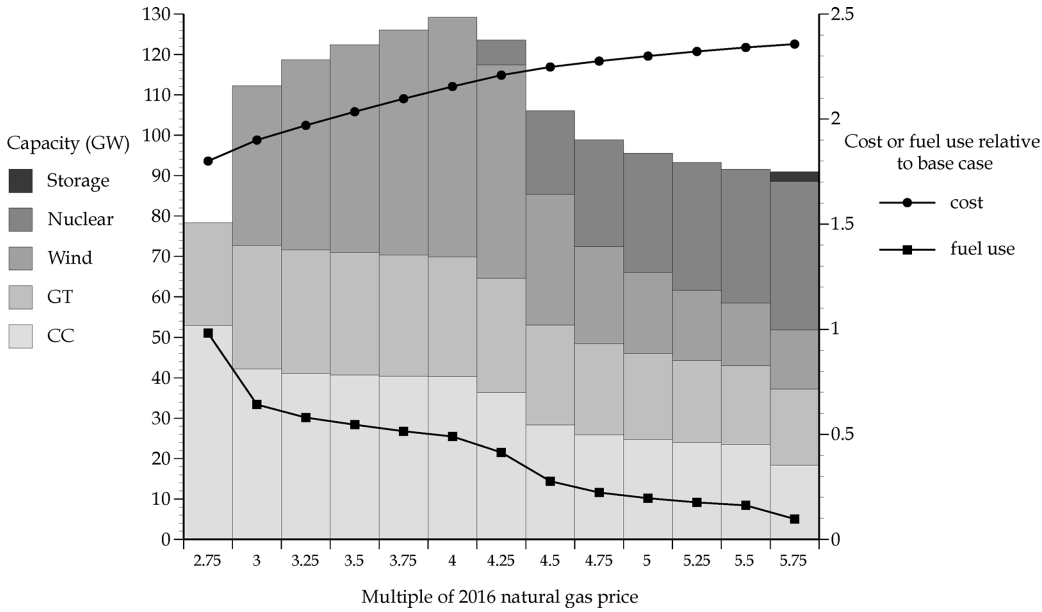
22. Green and Staffell (2016) similarly observe that the 11GW of wind and 30 GW of solar that Germany added to its system between 2008 and 2013 merely offset the emissions from closing 8GW of nuclear stations in 2011.

23. It might be thought that a similar transition with positive wind capacity should occur when $r = 0.05$. However, when $r = 0.05$, $p_{NG} = 2.89$ and $E \leq 2.2$, the cost-minimizing configuration has 0.655 GW of nuclear and no wind. Not until r is almost 7% does the cost-minimizing system when $E \leq 2.2$ include wind, and even then it is just 1.691 GW.

Table 6: Transitions from natural gas with constraints on gas use

$r = .075, p_{NG} = 2.89$	Fuel use constraint (10^{15} BTU) 2.279	2.0	1.5	1.0	0.5
Annual cost ($b)	14.267	15.851	19.066	22.322	25.848
Average cost (¢/kWh)	4.06	4.51	5.43	6.35	7.36
CC capacity (GW)	45.289	50.175	42.599	32.453	23.915
GT capacity (GW)	33.078	26.471	29.031	25.256	19.219
Wind capacity (GW)	0	11.982	32.180	16.515	0
Nuclear capacity (GW)	0	0	2.117	18.287	35.233
Pumped storage capacity (GW)	0	0	0	0	0
CC capacity factor (%)	83.67	69.90	60.90	52.39	34.59
GT capacity factor (%)	6.39	2.59	2.58	2.72	2.56
Nuclear capacity factor (%)			90.08	90.03	88.68

Figure 10: Transition away from natural gas when r = 0.075 and with changed capital costs



while substantial reductions in natural gas use take longer to materialize. Figure 10 also shows that storage is now introduced into the minimum cost system before wind is completely displaced.

For the remainder of this section, we return to the original capital costs as given in Table 2. Although there are reasons to believe that Table 2 understates the capital cost of nuclear and may overstate the capital cost of wind, as we noted while discussing the results in Table 3, there are other reasons to believe that the costs of a system with wind and storage have also been understated.

The analysis of the long-run systems implied that nuclear energy with storage provides the lowest cost long-run alternative to fossil fuels. Wind ended up being much more expensive than nuclear because it requires almost double the storage to make up for its intermittency, non-dispatchability, and generally negative correlation with system load. At a WACC of 7% or above, however, the cost minimizing solution over some range of natural gas prices involves wind and natural gas with no nuclear or storage. These results might appear contradictory. The explanation, however, is that wind needs much more backup capacity than does nuclear. When that backup is expensive stor-

Table 7: Effects from constraining wind capacity to zero

	p_{NG} = 9.22		p_{NG} = 9.40		p_{NG} = 10.12	
***r* = .075**	***ω* free**	***ω* = 0**	***ω* free**	***ω* = 0**	***ω* free**	***ω* = 0**
Annual cost ($b)	28.505	28.507	28.824	28.863	29.385	29.386
Average cost (¢/kWh)	8.11	8.11	8.20	8.21	8.36	8.36
CC capacity (GW)	52.040	54.188	37.144	28.732	26.436	26.202
GT capacity (GW)	25.405	24.179	27.325	21.171	20.750	20.371
Wind capacity (GW)	6.428	0	25.308	0	1.806	0
Nuclear capacity (GW)	0	0	10.265	28.465	30.922	31.794
Pumped storage capacity (GW)	0	0	0	0	0	0
CC capacity factor (%)	71.24	72.65	56.73	47.85	41.82	41.64
GT capacity factor (%)	2.59	2.64	2.63	2.92	2.74	2.80
Nuclear capacity factor (%)			90.05	90.08	89.72	89.72
Fuel used (10^{15} BTU)	2.108	2.234	1.228	0.814	0.661	0.653
	p_{NG} = 11.21		**p_{NG} = 11.57**		**p_{NG} = 12.29**	
***r* = .10**	***ω* free**	***ω* = 0**	***ω* free**	***ω* = 0**	***ω* free**	***ω* = 0**
Annual cost ($b)	34.440	34.580	34.964	35.389	35.950	36.301
Average cost (¢/kWh)	9.80	9.84	9.95	10.07	10.23	10.33
CC capacity (GW)	42.583	53.660	41.770	54.001	41.139	27.147
GT capacity (GW)	30.394	24.707	30.495	24.366	30.437	20.919
Wind capacity (GW)	37.543	0	42.499	0	47.298	0
Nuclear capacity (GW)	0	0	0	0	0	30.301
Pumped storage capacity (GW)	0	0	0	0	0	0
CC capacity factor (%)	60.74	73.26	57.85	72.87	54.93	44.70
GT capacity factor (%)	2.74	2.83	2.65	2.71	2.55	2.92
Nuclear capacity factor (%)						89.97
Fuel used (10^{15} BTU)	1.503	2.236	1.407	2.234	1.317	0.724

age, the system with wind has higher cost, but when it is less costly natural gas plant, the combined system including wind can have lower cost.

In the context of a dynamic optimization model of the transition process, a critical issue is the length of time that natural gas prices would lie in the range where wind is part of the cost-minimizing solution. That would, in turn, depend on the rate of growth in electricity demand, technological progress in fossil fuel production, and the elasticity of the natural gas supply curve. If the time interval during which wind is part of the cost-minimizing solution is shorter than 25 years, the lifetime of the wind generators would be shortened, raising their equivalent annual capital cost. Where additional wind generation would be far from the load centers, required new transmission lines may also be under-utilized or even abandoned once the wind generation is itself later displaced. This also will be costly if the new lines are used only briefly.

Even when wind generation persists for a long time, a large amount of wind capacity may be required for only a shorter time. In that case, a substantial fraction of wind capacity might have a very short life even if some of it is used for 25 years. In making this judgement it is important to note that the demand for wind capacity would depend not only on its *share* in total supply but also on the overall level of demand. Since the growth of Texas has been larger than for the United States as a whole as a result of migration, total demand growth in ERCOT has been relatively strong.

In judging the desirability of including substantial amounts of wind in the system, it is also important to calculate the extent to which wind lowers cost over some ranges of natural gas prices. This issue is examined in Table 7, which contrasts cases where wind capacity is used when WACC is 7.5% or 10% with the outcome when wind capacity is constrained to be zero but r and p_{NG} keep the same values. For $r = 0.075$, $p_{NG} = 9.22$ (3.1875 times the 2016 price), Table 7 shows that, when wind capacity is constrained to zero, the minimum cost system becomes all natural gas. The annual cost rises by only \$2.13 million. When the natural gas price is raised further to \$9.40 (3.25 times the 2016 price), constraining wind capacity to zero now results in a system with much more nuclear and an annual cost that is \$38.75 million higher. Increasing p_{NG} further to \$10.12 (3.5 times the 2016 price), the increase in annual cost from constraining wind capacity to zero falls to just \$1.41 million.

When the WACC is raised to 10%, the lower panel in Table 7 shows that costs are more affected by constraining wind capacity to zero. When $p_{NG} = 11.21$ (3.875 times the 2016 price), they increase by more than \$140 million, when $p_{NG} = 11.57$ (4 times the 2016 price) by almost \$425 million and when $p_{NG} = 12.29$ (4.25 times the 2016 price) by more than \$350 million. Nevertheless, these cost differences are quite small if additional wind capacity requires upgrading or extending the transmission system. Recall that the CREZ lines in Texas cost around \$7 billion.[24]

It might be thought that constraining wind capacity to zero, and increasing the longevity of the all natural gas system, would result in more natural gas use and higher emissions. In the examples in Table 7, using all natural gas instead of wind plus gas when $r = 0.075, p_{NG} = 9.22$ does indeed consume an additional 0.126 quads of natural gas per year. However, the natural gas plus nuclear system when $r = 0.075, p_{NG} = 9.40$ consumes 0.414 fewer quads of natural gas per year. When $r = 0.10$, the increased gas consumption when $p_{NG} = 11.21$ is 0.733 quads and when $p_{NG} = 11.57$, 0.828 quads, but when $p_{NG} = 12.29$, it falls by 0.593 quads.

More to the point, since natural gas is such a clean burning fossil fuel, the main issue that its consumption raises is the emission of CO_2. The externality in this case is, however, a stock one, not a flow one. The gradual accumulation of CO_2 in the atmosphere, not the emissions in any one year, causes surface temperature changes and other effects on climate. In that regard, since the cost of supply increases with depletion, the ultimate consumption of fossil fuel depends mostly on the cost of the non-fossil energy supply system. Greater consumption in years prior to transition to the non-fossil fuel system will lead to more rapid depletion and higher price increases than otherwise. Hence, it will hasten the time when fossil fuels are replaced. In short, prolonging the persistence of an all natural gas system and then hastening the build up of nuclear by constraining the use of wind capacity would likely have only minor effects on the cumulative use of natural gas.

Greater uncertainty about the potential marginal net damage from CO_2 emissions may also favor the use of more nuclear power in the short term by increasing its option value. In particular, if new information reveals a greater urgency to transition away from fossil fuels for environmental reasons, this will be much easier if there is more nuclear and less wind capacity in the system.

5. CONCLUDING REMARKS

The ERCOT ISO in Texas can be used to explore the likely costs of displacing fossil fuels from electricity supply. The ERCOT system has only weak connections with neighboring systems and, except for emergencies, operates essentially as a stand-alone system. It also has a substantial amount of wind capacity operating at a relatively high average capacity factor. Hence, it provides a realistic example of the operation and costs of a system dominated by wind generation.

Combining data from ERCOT with cost estimates of different technologies from the EIA, we calculated the costs of satisfying the 2016 ERCOT load using different combinations of wind, natural gas, and nuclear generation together with pumped storage. We found that, for the long-run system where the 2016 ERCOT load is supplied by either wind or nuclear supplemented with storage, the system with wind is much more costly than the one with nuclear. The main reason is

24. Ancillary service costs could also differ in the two systems since GT capacity is being used differently.

that the system with wind requires almost double the amount of electricity storage, which is very expensive. Even at a real discount rate of 10%, which is close to the real return on equity alone for an electric utility, and which normally would be expected to favor wind over nuclear, the system with wind remained more than 25% more expensive. On the other hand, we also found that for a discount rate of around 7% or higher, and an intermediate range of natural gas prices or moderate quantitative restrictions on annual natural gas use, the wind plus natural gas system was less costly than the nuclear plus natural gas one.

While the two sets of results may appear contradictory, they are actually consistent. The reason is that wind needs much more complementary generating capacity than nuclear as a result of its high variability and slightly negative correlation with system load. When that additional capacity is relatively low cost gas generation, the hybrid system with wind is less expensive when compared to the nuclear plus gas system. When the complementary capacity is high cost storage, however, the wind system becomes much more expensive.

When nuclear power is a better long-run option than wind generation, nuclear might also be a better short-run investment. Additional wind capacity slows the adoption of nuclear as natural gas prices rise. The reason is that wind tends to supply more output in low demand hours, while its high variability increases the variability of the net load on the thermal system. Both factors make it much harder for base load technologies like nuclear to cover their costs.

We also found that in circumstances where wind capacity was part of the cost-minimizing system, constraining it to zero raises costs by only very modest amounts. The use of natural gas alone persists for slightly longer, but the build-up of nuclear capacity occurs more rapidly. The cost savings from allowing wind to displace natural gas or nuclear in the interim are so small that they could easily be exceeded by the cost of building additional transmission capacity to connect remote wind farms with loads. Furthermore, if the period during which wind is part of the minimum cost system is short, wind generators and associated infrastructure might be used for less time than their normal lifespans. If so, this would further raise effective annual costs and make the wind generation less competitive.

Nuclear power has additional value in a world where we desire to limit cumulative CO_2 emissions from fossil fuel use. Since nuclear with storage has lower costs in the long run than wind with storage, the cost of fossil fuel energy, and hence the total amount that is mined, does not have to rise as much before fossil fuels are displaced. Less fossil fuel ultimately will be burned, implying cumulative CO_2emissions also will be lower. Finally, if there is substantial uncertainty about the environmental effects of fossil fuel use, nuclear also has a higher option value than wind. If new information reveals that more drastic reductions in fossil fuel use are required, they can be achieved in a shorter period of time when there is more nuclear capacity in the system.

ACKNOWLEDGMENTS

I thank four referees, Michael Maher in the Center for Energy Studies, James A. Baker III Institute for Public Policy at Rice University, Raúl Bajo-Buenestado of the University of Navarra, Ozgur Inal of *Direct Energy*, Ken Clements at the University of Western Australia and various seminar participants for valuable comments.

REFERENCES

Boßmann, T. and Iain Staffell (2015). "The shape of future electricity demand: Exploring load curves in 2050s Germany and Britain." *Energy*, 90: 1317–1333. https://doi.org/10.1016/j.energy.2015.06.082.

Cullen, Joseph A. (2013). “Measuring the Environmental Benefits of Wind-Generated Electricity.” *American Economic Journal: Economic Policy*, 5(4): 107–133. https://doi.org/10.1257/pol.5.4.107.

Cullen, Joseph A and Erin T. Mansur (2017) “Inferring Carbon Abatement Costs in Electricity Markets: A Revealed Preference Approach using the Shale Revolution.” *American Economic Journal: Economic Policy*, 9(3): 106–133. https://doi.org/10.1257/pol.20150388.

Delucchi, Mark A. and Mark Z. Jacobson (2011). “Providing all global energy with wind, water, and solar power, Part II: Reliability, system and transmission costs, and policies.” *Energy Policy*, 39: 1170–1190. https://doi.org/10.1016/j.enpol.2010.11.045.

Green, Richard and Iain Staffell (2016). “Electricity in Europe: exiting fossil fuels?” *Oxford Review of Economic Policy*, 32(2): 282–303. https://doi.org/10.1093/oxrep/grw003.

Green, Richard and Nicholas Vasilakos (2011). “The Long-term Impact of Wind Power on Electricity Prices and Generating Capacity.” Centre for Competition Policy, University of East Anglia, CCP Working Paper 11–4. https://doi.org/10.1109/PES.2011.6039218.

Green, Richard and Nicholas Vasilakos (2012). “Storing wind for a rainy day: What kind of electricity does Denmark export?” *The Energy Journal*, 33(3): 1–22. https://doi.org/10.5547/01956574.33.3.1.

Grubler, Arnulf (2010). “The costs of the French nuclear scale-up: A case of negative learning by doing.” *Energy Policy*, 38: 5174–5188. https://doi.org/10.1016/j.enpol.2010.05.003.

Hartley, Peter R., Kenneth B. Medlock III, Ted Temzelides and Xinya Zhang (2016). “Energy Sector Innovation and Growth.” *The Energy Journal*, 37 (1): 233–258. https://doi.org/10.5547/01956574.37.1.phar.

Hartley, Peter R. and Kenneth B. Medlock III (2017). “The Valley of Death for New Energy Technologies.” *The Energy Journal*, 38(3): 33–61. https://doi.org/10.5547/01956574.38.3.phar.

Jacobson, Mark Z. and Mark A. Delucchi (2011). “Providing all global energy with wind, water, and solar power, Part I: Technologies, energy resources, quantities and areas of infrastructure, and materials.” *Energy Policy*, 39: 1154–1169. https://doi.org/10.1016/j.enpol.2010.11.040.

Joskow, Paul L. (2011) “Comparing the Costs of Intermittent and Dispatchable Electricity Generating Technologies.” *American Economic Review: Papers & Proceedings*, 100(3): 238–241. https://doi.org/10.1257/aer.101.3.238.

Lokhov, Alexy (2011). “Load-following with nuclear power plants.” *NEA update, NEA News*, Nuclear Energy Agency, 29.2: 18–20.

Luo, Xing, Jihong Wang, Mark Dooner and Jonathan Clarke (2015). “Overview of current development in electrical energy storage technologies and the application potential in power system operation.” *Applied Energy*, 137: 511–536. https://doi.org/10.1016/j.apenergy.2014.09.081.

Qvist, Staffan A. and Barry W. Brock (2015). “Potential for Worldwide Displacement of Fossil-Fuel Electricity by Nuclear Energy in Three Decades Based on Extrapolation of Regional Deployment Data.” *PLoS ONE*, 10(5): e0124074. https://doi.org/10.1371/journal.pone.0124074.

Schoenung, Susan M. and William V. Hassenzahl (2003). “Long- vs. Short-Term Energy Storage Technologies Analysis: A Life-Cycle Cost Study.” A Study for the DOE Energy Storage Systems Program, Sandia National Laboratories *Sandia Report* SAND2003-2783.

Trainer, Ted (2012). “A critique of Jacobson and Delucchi’s proposals for a world renewable energy supply.” *Energy Policy*, 44: 476–481. https://doi.org/10.1016/j.enpol.2011.09.037.