# Holy Grail of Carbon Capture Continues to Elude Coal Industry

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# Executive Summary

Hopes for carbon capture and storage (CCS) technology have been a key policy driver at the U.S. Department of Energy for more than a decade, promoted initially as a way to cut carbon dioxide ($CO_2$) emissions that cause climate change and now, under the Trump administration, as an unabashed means of propping up the declining U.S. coal industry.

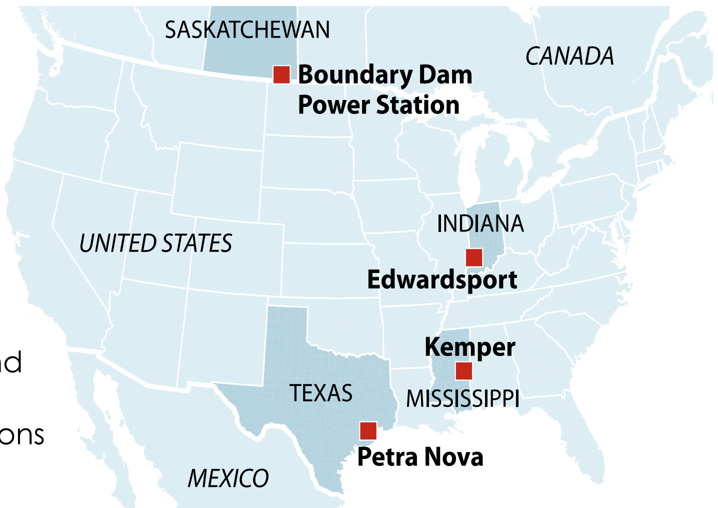
Billions of dollars have been spent for carbon capture research and development in North America, and rosy predictions for CCS have been ritually repeated year in and year out.

However, today, 15 years after CCS development work began in earnest, there remains only one operational coal-fired carbon capture project in the U.S: NRG's experimental Petra Nova project south of Houston. A second North American CCS plant, the Boundary Dam Power Station owned by Saskatchewan Power (SaskPower), is in operation in Canada.

In this report, we examine CCS-related projects at four North American coal-fired power plants.: Petra Nova, Boundary Dam, Southern Company's Kemper project in Mississippi, and Duke Energy's Edwardsport plant in Indiana.

Petra Nova and Boundary Dam involve post-combustion $CO_2$ capture. Kemper, by contrast, was designed originally as a coal gasification unit with pre-combustion removal of $CO_2$, but both its gasification and $CO_2$ capture components have since been dropped. The Edwardsport plant, which was initially promoted for its capability to capture $CO_2$, later abandoned the idea because of its high cost. It is included here for its gasification technology, which is an essential component of pre-combustion $CO_2$ capture.

While Petra Nova and Boundary Dam are operational, both are really only demonstration units. Petra Nova captures just over a third of the flue gas from one of four coal-fired units at the massive W.A. Parish Plant, and it has been an expensive experiment, at a cost of more than $1 billion. Boundary Dam, the smallest of the four projects examined here, has been plagued by operational problems and cost overruns that have pushed its price tag to roughly US$1.1 billion. Further, both Petra Nova and Boundary Dam rely economically on selling their captured carbon for enhanced recovery operations (EOR) in oil fields, an option that is not necessarily available to coal plants elsewhere.




The integrated gasification combined cycle projects at Edwardsport and Kemper have been disasters, as they proven absurdly expensive to build and costly and unreliable to operate.

Widescale use of CCS would require a huge network of pipelines (and associated infrastructure) to transport captured $CO_2$ to sequestration sites, an issue given scant attention in CCS development discussions. Such a network would be enormously costly and extremely time-consuming to permit and build. Further, Capturing $CO_2$, piping it to distant sequestration sites and injecting it into the ground would require an exorbitant amount of water.

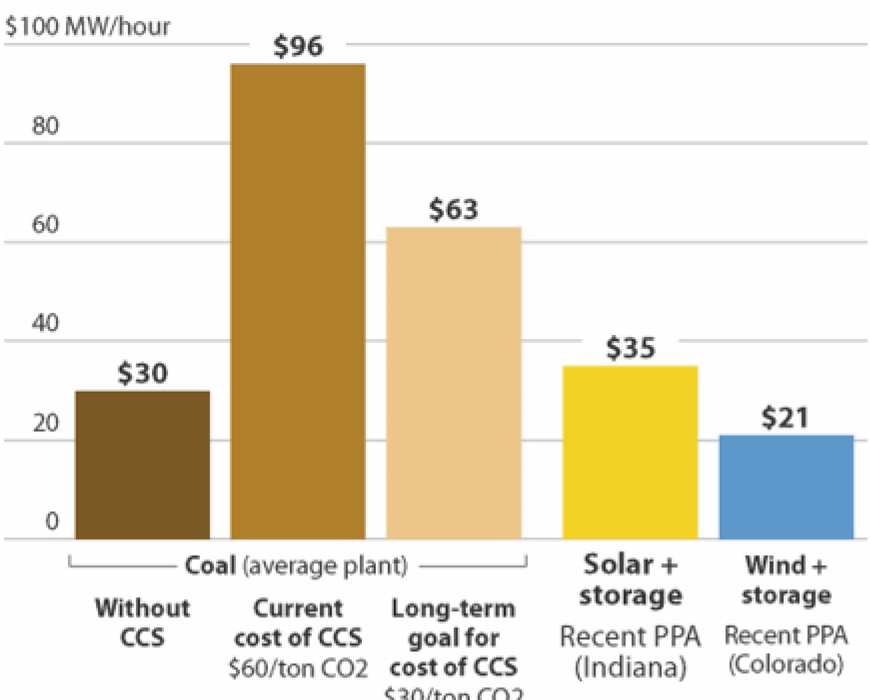
We note also in this report that the aging U.S. coal fleet would require costly upgrades to accommodate CCS retrofits. More than half of the fleet is already more than 40 years old; significant rebuilds would be required for owners to ensure that their facility could operate for the 20-30-year lifespan of any new CCS equipment. This phenomenon is already on display at Boundary Dam, where SaskPower spent more than US$330 million to rebuild the power block at the plant to ensure its operational lifespan would match that of its CCS retrofit. Such investments are site and plant specific, negating any potential economies of scale.

The CCS experiments described here have unfolded against the backdrop of an electricity-sector revolution driven by increasingly low-cost, zero-emission wind and solar and plentiful and relatively low-cost natural gas supplies.

As it is, coal plants without CCS are having an increasingly difficult time competing with wind and solar resources. Adding a $60 per ton cost for CO2 capture, or even the $30 per ton cost that advocates say can be achieved, will further undermine coal's ability to compete.

These larger trends further undermine the economics of CCS retrofits. Adding CCS costs to units that aren't even operating now full time will only lead to increases in per-unit costs, creating a spiral that feeds on itself, rendering plants increasingly uneconomic and turning CCS equipment into stranded assets. The utility industry, well aware of what is occurring in power-generation markets nationally (and internationally) and pushed by consumers big and small to modernize, is now moving rapidly away from baseload coal and toward a cleaner, more distributed-energy future, making carbon capture an increasingly outmoded concept. In short, where high-risk, high-dollar carbon capture investments may have made sense at one time, today they do not— and indeed the high cost of carbon capture will most likely remain prohibitive.

**Figure 1: The high cost of carbon capture**




Source: IEEFA

While this report focuses on U.S. electricity markets, our findings serve as a cautionary tale for any country considering broad adoption of CCS. The technology remains unproven at full commercial scale, it is wildly expensive, there are serious questions regarding the after-capture transport, injection and storage of the captured CO2 and—most important—more reliable and far cheaper power-generation options exist.

# Introduction

When the Bush administration rolled out the initial FutureGen carbon capture project 15 years ago, coal was still king in the U.S., generating more than 50% of the nation's electricity and widely seen as the bulwark on which reliable electricity supplies depended.

The thinking at the time: The U.S. had no choice but to invest in "clean coal" research if it wanted to simultaneously address climate change and keep the lights on.

FutureGen, a roughly $1 billion government-industry partnership, was meant to test both coal gasification and carbon capture, a combination that had never been attempted at a commercially sized power plant. The project was hailed by Energy Secretary Samuel Bodman as "a stepping-stone toward future coal-fired power plants that not only will produce hydrogen and electricity with zero emissions, but will operate with some of the most advanced, cutting-edge technologies."

The project never got past the design phase, and was killed in 2008 after its cost had climbed to $1.8 billion.

A follow-on proposal, FutureGen 2.0, was proposed by the Obama administration in 2010. Although smaller in size than the original experiment, the estimated cost for FutureGen 2.0 was $1 billion. Enthusiasm, as before, remained high, with Energy Secretary Steven Chu predicting that the investment would "open up the over $300 billion market for coal unit repowering and position the country as a leader in an important part of the global clean energy economy."

Like its predecessor, FutureGen 2.0 failed to clear the design phase and was cancelled in 2015 after its cost jumped to $1.65 billion.

Three carbon capture projects have been built in the past decade in North America, however:

- SaskPower's Boundary Dam Unit 3;
- NRG Energy's Petra Nova facility;
- Southern Company's Kemper integrated gasification combined cycle (IGCC) project.

The Kemper plant was completed, but its coal gasification and carbon capture systems were abandoned—after $7.5 billion had been sunk in the effort. Kemper now operates as the world's most expensive natural gas-fired plant.

A fourth plant, Duke Energy Indiana's Edwardsport project, which also uses IGCC technology, was originally promoted for its purported capability to capture $CO_2$. However, the plan to capture $CO_2$ was later abandoned due to concerns over its high cost.[1]

Boundary Dam and Petra Nova— two relatively small projects by industry standards—use post-combustion carbon capture and sequestration (CCS) technology in which $CO_2$ is captured from emissions after coal is burned. Boundary Dam Unit 3 produces just 110 megawatts (MW) of power and Petra Nova captures $CO_2$ from the equivalent of only 240

[1] Indiana Court of Appeals: https://www.citact.org/sites/default/files/AppellantsBrief-signed.pdf

MW of production at the W.A. Parish Unit 8 plant near Houston. Baseload coal-fired units are generally much larger, in the range of 400 to 800 MW.

The U.S. government has pumped more than $5 billion into CCS research since 2010,[2] including significant funding for both Petra Nova and Kemper, but obviously little progress has been made.

Indeed, even as these projects have vividly demonstrated the manifold technical problems and high costs associated with carbon capture, the electricity-generation sector has been swept up in a technology-driven revolution that calls into question the supposed need for coal plant CCS in the first place.

Electricity produced by renewable energy, particularly wind and solar, amounted to little more than a rounding error in the Energy Information Administration's 2003 Annual Energy Review. Today they account for more than 10% of the nation's electricity generation, and both continue to gain market share fast.

Similarly, fracking and related technological advances have vastly improved the outlook for natural gas-fired generation. Supplies have soared and costs have been cut to the point that gas is now the only viable option for developers looking to build new fossil-fuel generation. Further, the utility industry itself, long a source of support for coal in general and specifically for CCS development financing, is now moving quickly away from coal.

High-risk, high-cost CCS investments looked potentially viable a decade ago but are being eclipsed today by less-costly ways to produce electricity while curbing carbon emissions.

# Major North American Carbon-Capture Projects

## Boundary Dam/SaskPower

SaskPower, the state-owned utility in Saskatchewan, has spent C$1.5 billion[3] to retrofit Unit 3 at its Boundary Dam generation station with CCS technology.[4] Of that total, 50%, or roughly C$750 million, went to $CO_2$ capture equipment and C$440 million was spent to upgrade and modernize the aging plant so that it would be able to run long enough to recover the carbon capture investments. SaskPower spent an additional C$293 million on related emission controls and efficiency improvements.[5]

In its 2014 annual report, the company touted the project as "the first commercial-scale post-combustion project of its kind at a coal-fired power station"[6] and one that would be able to capture 1 million metric tons of $CO_2$ annually—roughly 90% of the plant's $CO_2$ output. Much of the captured $CO_2$ was to be used in enhanced oil recovery efforts (EOR) at an oil field in southern Saskatchewan. The rest was to be stored underground.

[2] Congressional Research Service, "Carbon Capture and Sequestration in the U.S.," Peter Folger, Aug. 9, 2018, p.1, https://fas.org/sgp/crs/misc/R44902.pdf.

[3] Using a year-end 2014 exchange rate of .76491, this means the facility cost roughly US$1.147 billion to build.

[4] 2015 SaskPower Annual Report, p. 59.

[5] "Details from the IEAGHG-DOE Report on the SaskPower Boundary Dam Power Station Integrated CCS Project," Carolyn Preston, August 2015, http://www.wyia.org/wp-content/uploads/2017/06/carolyn-preston.pdf

[6] 2014 SaskPower Annual Report, p 8.

Given its first-of-a-kind status, it is no surprise that little has gone well. The project was over budget and behind schedule when it began operating in October 2014. Its overall $CO_2$ capture rate during its first year of operation hovered at about 40%, a dismal performance, as David Jobe, SaskPower's director of carbon capture and chemical services, acknowledged in an interview with The Chemical Engineer in May of this year.

"Let's just say that out of the box, the plant didn't work as designed,"[7] Jobe said.

Nor is the plant working now as promised. Boundary Dam has never hit its $CO_2$ sequestration goal of 1 million metric tons a year, having captured a total of only 2.2 million metric tons in the four years since its carbon capture system came online.[8]

Meanwhile, the utility has had to pay millions of dollars for temporary units that boost the capacity of the system's thermal reclaimer, the unit that purifies the amine solution used to strip $CO_2$ and sulfur dioxide from the plant's flue gases. The amine solution has been degrading faster than anticipated, overwhelming the plant's installed reclaimer and forcing the utility to bring in mobile units.[9] The fix has worked, but according to a report prepared for SaskPower, it is "not economically sustainable."[10]

The amount of $CO_2$ captured at Boundary Dam is not likely to increase anytime soon either, as the entire plant has been online only approximately 50% of the time from August 2015 to August 2018.[11]

Capturing the $CO_2$ from Boundary Dam Unit 3 also is very expensive, averaging about C$60 per metric ton (US$42 per short ton), doubling the overall cost of producing power at the plant.[12]

One reason for this high cost, besides the plant's unreliable operating performance, is that Boundary Dam's carbon-capture equipment is extremely energy intensive, requiring large amounts of electricity that would otherwise go to the company's customers. Although Unit 3 has a gross power rating of 150MW, about 30MW are consumed by the carbon-capture equipment, and an additional 15-16MW are needed to compress the captured $CO_2$ before it is piped offsite.[13]

SaskPower said this summer that its costly experience with Unit 3 prompted it to decide against retrofitting two other units at Boundary Dam with carbon capture technology. Instead, the two 1970s-era units will be shuttered, perhaps as early as next year.

The decision was not a complete surprise, as SaskPower CEO Mike Marsh had said late last year that the company was "extremely unlikely" to recommend going ahead with carbon

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[7] *The Chemical Engineer*, "The Privilege of Being First," A. Duckett, May 1, 2018. https://www.thechemicalengineer.com/features/the-privilege-of-being-first/

[8] https://www.saskpower.com/about-us/our-company/blog/bd3-status-update-august-2018

[9] CBC News, "SaskPower looking for help to fix 'high cost' Boundary Dam carbon capture flaw," Geoff Leo, May 28, 2018, https://www.cbc.ca/news/canada/saskatchewan/saskpower-looking-for-help-to-fix-high-cost-boundary-dam-carbon-capture-flaw-1.4680993

[10] Ibid

[11] SaskPower web site, accessed 7-20-2018

[12] *Regina Leader-Post*, "Sask. Energy Minister says residents already paying carbon tax," D.C. Fraser, May 11,2017, https://leaderpost.com/news/saskatchewan/sask-energy-minister-says-residents-already-paying-carbon-tax

[13] *The New York Times*, "Technology to Make Clean Energy from Coal is Stumbling in Practice," Ian Austen, March 29, 2016, https://www.nytimes.com/2016/03/30/business/energy-environment/technology-to-make-clean-energy-from-coal-is-stumbling-in-practice.html

capture retrofits at the two facilities, in large part due to the current economics of coal with $CO_2$ capture versus cleaner natural gas-fired facilities.

## Petra Nova/NRG Energy

NRG Energy partnered with JX Nippon Oil & Gas Exploration Corp. of Japan to build the Petra Nova carbon capture facility, adding it to Unit 8 of NRG's W.A. Parish generating plant southwest of Houston.

In total, Parish has 3,700MW of capacity; Unit 8 has 650MW of capacity. The Petra Nova project captures $CO_2$ from flue gas from 240MW of the power generated by Unit 8.

Retrofitting the post-combustion carbon capture system cost US$1 billion, or approximately $4,200 per kilowatt. After capture, the plant's $CO_2$ is compressed and piped to an oil field some 80 miles away for use in enhanced oil recovery activities.

The system has been running since early 2017 and its operators have estimated it has captured approximately 1.7 million tons of $CO_2$ during its first 17 months in operation. That total is clearly overstated, however First, the $CO_2$ capture process—much like the one at Boundary Dam— consumes a lot of energy, a problem NRG opted to address by building a dedicated natural gas-fired unit to power the Petra Nova carbon capture equipment. This dedicated natural gas-fired unit emitted approximately 450,000 tons of $CO_2$ from January 2017 to May 2018, the same period during which Petra Nova reportedly captured 1.7 million tons. Thus, the project appears to have captured only a net 1.25 million tons of $CO_2$, not 1.7 million tons.

There's also the question of how to factor in the emissions from the extra oil produced from the injected $CO_2$. NRG, which owns a piece of the West Ranch oil field where the captured $CO_2$ is being injected, says production at the field has climbed from 300 barrels per day to more than 4,000 in the first year of operations, and that output could climb as high as 15,000 barrels per day as a result of the EOR activities. Once oil produced at West Ranch is consumed it will release more $CO_2$ into the atmosphere. So exactly how much $CO_2$ emissions are reduced due to the Petra Nova project depends on how much of the new oil produced through EOR displaces oil produced elsewhere. In sum, there likely is only a small net benefit to the project, and it is possible the Petra Nova project could increase, rather than decrease, global $CO_2$ emissions.

The head of the U.S. Department of Energy's Advanced Fossil Technology Systems program has said that the cost of capturing $CO_2$ at Petra Nova is about $60 per ton.[14][15] This translates into a cost of approximately $60 to $65 per megawatt-hour (MWh), since U.S. coal plants emit, on average, 1.1 tons of $CO_2$ per a net MWh of electricity generated. It remains unclear, however, as to whether the $60 per ton figure represents the full cost of capturing $CO_2$ at Petra Nova, which includes the cost of operating the dedicated natural gas-fired unit and the costs associated with compressing the captured $CO_2$ and transporting it for injection at the oil field.

Petra Nova has been in operation for less than two years, so it impossible to know yet how well the technology will work over the long term and what it will cost as the W.A. Parish plant

[14] IEA Clean Coal Centre, "USA Experts: Coal Plants Must Adapt To New Energy Landscape," Aug. 28, 2018, https://www.iea-coal.org/usa-experts-coal-plants-must-adapt-to-new-energy-landscape/

[15] Other than Kokkinos' comment about the $60 per ton cost of capturing CO2, almost no details have been provided about the actual costs being incurred or the problems being experienced at Petra Nova.

continues to age. Unanticipated problems could cause the cost per ton of capturing the $CO_2$ at Petra Nova to rise. It is also uncertain if the costs at Petra Nova are indicative of what it would cost to capture all the $CO_2$ from a coal-fired plant. The Petra Nova unit captures roughly a third of Unit 8's emissions; scaling up the system to capture $CO_2$ from the entire unit may not create the economies of scale proponents suggest.

## Kemper/Southern Co.

Southern's Kemper IGCC facility, near Meridian, Miss., is the poster child for projects gone wrong.

Initially proposed in 2008, the greenfield project was pegged to cost under $3 billion and to be up and running in 2014. It did not unfold as envisioned, however, and when the IGCC and carbon capture portions of the project were finally cancelled in 2017, the project's overall cost had ballooned to $7.5 billion.

Kemper was designed as a first-of-a-kind plant with a system that produced gasified coal that would be burned in a modified combined cycle power plant and a pre-combustion carbon capture system that would pull the $CO_2$ from the gasified coal before it was burned. The gasification process, dubbed TRIG, for transport integrated gasification, was developed by Southern in cooperation with the engineering and construction company KBR and the Department of Energy. It had been tested on a small scale, mainly at DOE's Wilsonville, Ala., fossil fuels research center, but Kemper was to have been its first commercial-scale test.

The gasification process and associated emissions controls were expected to produce marketable quantities of ammonia and sulfuric acid as well as the captured $CO_2$, which was slated for use in EOR activities.[16] Southern pointed out repeatedly in its discussions of the project that the $CO_2$ capture would bring the plant's emissions down to levels comparable to conventional combined cycle gas-fired generators.

Essentially, the Kemper gasification process turned a relatively straight-forward activity—burning coal to boil water and produce electricity—into a complicated chemical process that produced electricity almost as a by-product.

As aptly explained in a 2017 IEEE Spectrum article about Kemper, "IGCC technology can be thought of as a chemistry set bolted onto what is now a well-established gas-fired power plant. The chemistry set exists to strip out methane from the coal feedstock along with a range of byproducts that can be sold commercially or disposed of."[17]

Running the Kemper on-site equipment, including the coal gasification and carbon capture systems, was expected to consume 30%, or 250MW, of the plant's 830MW gross output, leaving its net output at 582MW. By way of contrast, a typical natural-gas-fired plant consumes just 3-4% of its gross output to run internal plant equipment.

The traditional combined cycle gas units at Kemper appear to have not been a problem. They came online for the first time in late 2013 and were synchronized with the grid in mid-2014. In the end, it was the "bolted-on" chemical processes that did the project in.

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[16] DOE Kemper project fact sheet, https://www.energy.gov/fe/southern-company-kemper-county-mississippi
[17] *IEEE Spectrum*, "The Three Factors That Doomed Kemper County IGCC," David Wagman, June 30, 2017, https://spectrum.ieee.org/energywise/energy/fossil-fuels/the-three-factors-that-doomed-kemper-county-igcc

Testing of the gasifiers, that is, the chemical portion of the project, dragged on for years, with one delay after another announced periodically by Southern or its subsidiary that owns the plant, Mississippi Power. As late as May 2017 (just a month before the utility abandoned the gasification/carbon capture segments of the project), an analysis[18] by the engineering firm URS showed a laundry list of technical milestones that had been promised but had not yet accomplished, including:

- Simultaneous operation of the gasifiers;
- Continuous and reliable coarse- and fine-ash removal;
- Successful running of both combustion turbines on the coal-produced syngas for the minimum time required by Siemens, the turbine vendor, to demonstrate commercial readiness;
- Full power (528MW) operation of the entire-system using 100% syngas for the combustion turbines and the follow-on steam turbine "for a to-be-determined minimum continuous period."

Put another way, three years after the natural gas plant began producing electricity for the grid, the gasification and carbon capture portions of the plant were still not working reliably.

How the project dragged on as long as it did is beyond the scope of this report, but certainly a portion of Southern's commitment to the project can be traced to the company's high hopes for its global use. In 2012, well before construction at Kemper was even complete, Southern and KBR formed a partnership to market the technology worldwide.

"This innovative coal gasification process can provide power companies an efficient means to generate electricity using an abundant, low-cost fuel—low-rank coal[19]—while significantly reducing carbon emissions," the companies said in announcing their partnership.[20]

The TRIG process, they noted, was developed specifically for low-quality coal, which accounts for more than 50% of the world's overall reserves.

Even if the process had worked as promised, however, Southern ultimately would have faced unassailable economic challenges:

- With a forecasted heat rate of 12,000 Btus/KWh, Kemper would have been far less efficient at burning fuel than conventional natural gas-fired plants, which typically have heat rates of around 7,000 Btus/KWh.[21]
- While the plant was being built, its estimated annual non-fuel operational and maintenance expenses skyrocketed from an average of $51 million for each of the plant's first five years in operation to an average of $200 million annually, an increase of 300 percent.

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[18] URS analysis, IM Monthly Report, April 2017, http://www.psc.state.ms.us/executive/pdfs/2017/Kemper/Monthly%20Report%20April%202017%20Executive%20Summary.pdf

[19] Generally meaning lignite or brown coal, which have significantly lower heating values than bituminous coal.

[20] Southern Company press release, Oct. 29, 2012, https://www.reuters.com/article/idUS116576+29-Oct-2012+PRN20121029

[21] https://www.eia.gov/electricity/annual/html/epa_08_02.html

As a result, electricity produced at Kemper using gasified coal was going to be far more expensive than electricity produced at conventional natural-gas-fired units or, for that matter, power produced by wind or solar.

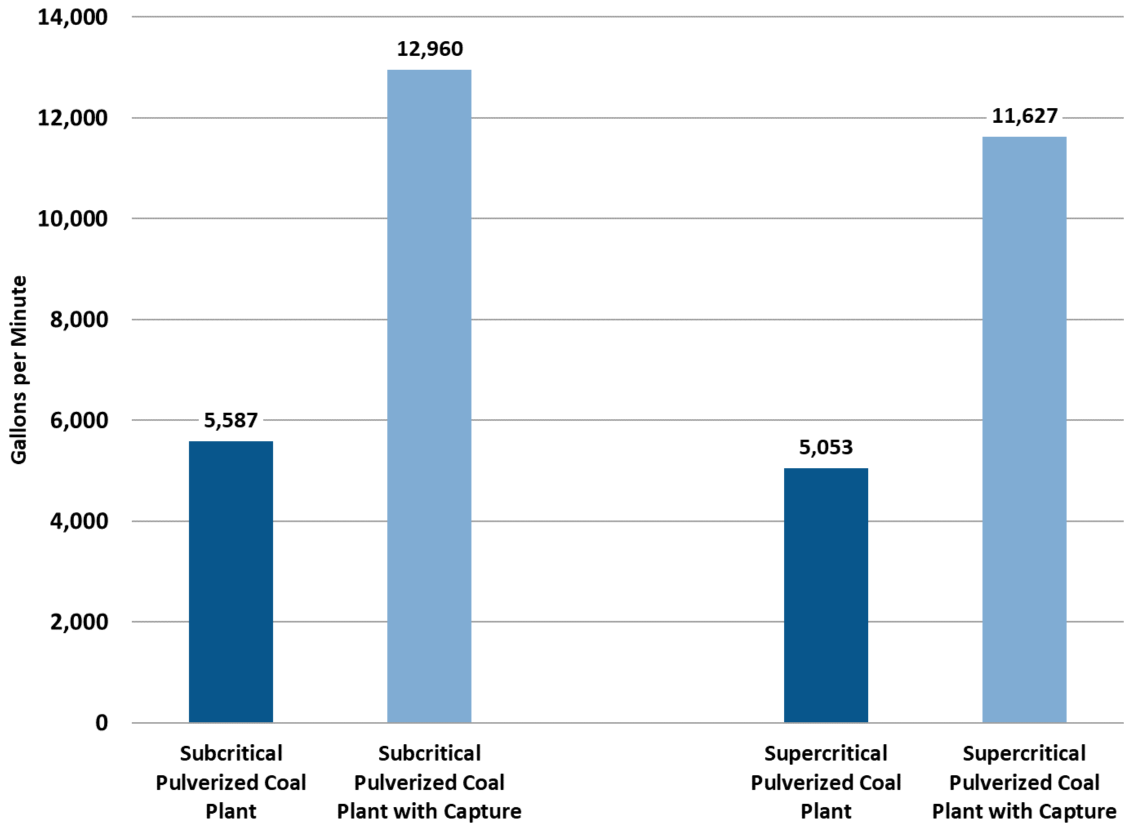
In the spring of 2017, Southern Company abandoned the coal gasification and carbon capture portions of Kemper, admitting that their economic viability had been eroded by low natural gas prices and the higher-than-expected operating costs.

The massive amount of water required to run the coal-gasification process was an additional problem that surfaced during Kemper's construction and early operational testing.

Although the design included a five-million-gallon water storage facility, that reserve proved so insufficient[22] that Southern added a 1.7-million-gallon temporary storage facility "and was considering additional permanent tankage," as URS noted in 2017.

In fact, water requirements are a major stumbling block to CCS, affecting all stages of the process—from cooling the plant to capturing, compressing and injecting the captured $CO_2$.[23] Figure 1 illustrates the magnitude of this problem, showing how $CO_2$ capture technologies at least double water requirements at both subcritical and supercritical coal facilities. For coal facilities in arid regions this is obviously a deal-breaker, and even CCS plants proposed in wetter regions will likely face permitting struggles to secure adequate process water.

**Figure 2: Estimated Increased Coal Plant Water Requirements with CCS**




Source: Sommer Energy

[22] URS, op cit

[23] https://www.netl.doe.gov/research/coal/carbon-storage/water-ccs

## Edwardsport/Duke Energy

The Edwardsport IGCC plant was formally proposed in September 2006 by PSI Energy, which shortly thereafter became part of Duke Energy. The two-unit, 618MW facility was projected to cost $1.985 billion. When the project was completed in 2013, that figure had increased to more than $3.5 billion.

Initially, Duke officials promoted Edwardsport for its potential to capture a significant portion of the plant's carbon emissions. In a presentation before the project was officially proposed, Kay Pashos, president of Cinergy/PSI, said the project offered "future potential to capture $CO_2$ at a significantly lower cost than conventional pulverized coal because $CO_2$ can be separated prior to combustion."[24]

After the plant's completion in 2013, Douglas Esamann, president of Duke Energy Indiana, told Power Engineering magazine that the plan had been to eventually add carbon capture to the facility but that the company did not want to proceed with that effort yet because it was considered still too expensive and was not required.[25]

Even though the plant does not capture $CO_2$, Edwardsport raises important questions about the economic viability of pre-combustion capture because it does burn gasified coal, the same as Kemper was supposed to do. Given how poorly the GE-supplied gasification systems at Edwardsport have performed since coming online, Duke was probably wise to skip the additional carbon capture step.

During the regulatory approval process and as the plant was being built, Duke claimed it would immediately post a capacity factor[26] of roughly 82%—and that it would do so operating entirely on the gasified coal (syngas). But the plant has not operated anywhere near this well.

From the plant's start-up through September 2018, over more than five full years of operation, Edwardsport's average capacity factor was 57% (including the entire time when the plant was using gasified coal or natural gas, not just when it was burning gasified coal). Its gasified-coal-only capacity factor during this period was 41% (Figure 2).[27]

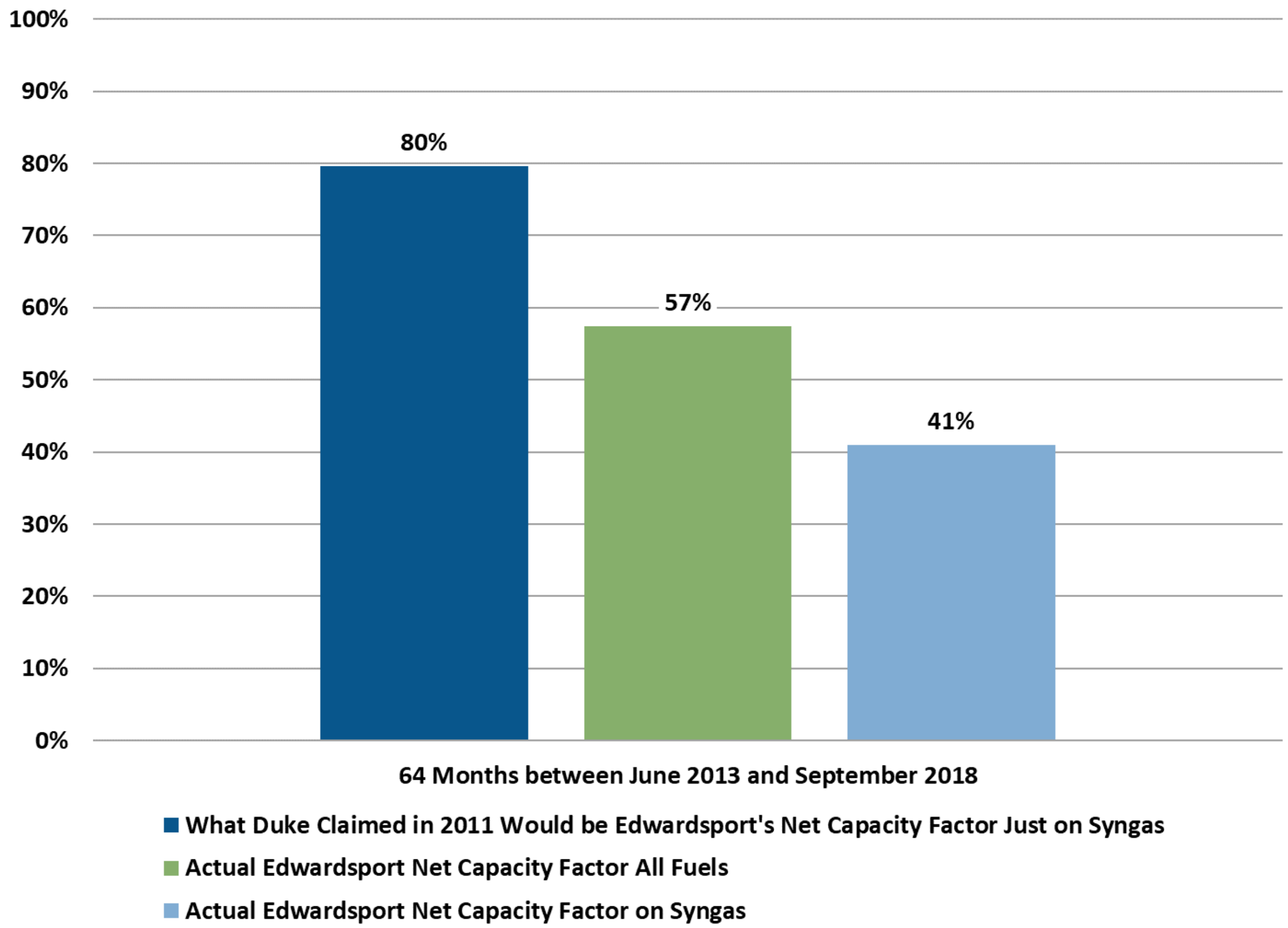
[24] "IGCC—An Important Part of Our Future Generation Mix," Kay Pashos presentation, October 2005, p. 11, https://www.globalsyngas.org/uploads/eventLibrary/02PASH.pdf

[25] *Power Engineering*, "Edwardsport Power Plant Makes History," Nov. 14, 2013, https://www.power-eng.com/articles/print/volume-117/issue-11/departments1/power-plant-profile/edwardsport-power-plant-makes-history.html

[26] A plant's capacity factor is the ratio of the energy it actually produces in a month or year compared to the energy it would have produced if it had operated at full power for all of the hours of the month or year. The higher the capacity factor, the better the plant has performed.

[27] "IEEFA Update: Kemper, Edwardsport, and 'Clean Coal'," David Schlissel, Feb. 28, 2017, http://ieefa.org/ieefa-update-kemper-edwardsport-clean-coal-myth/

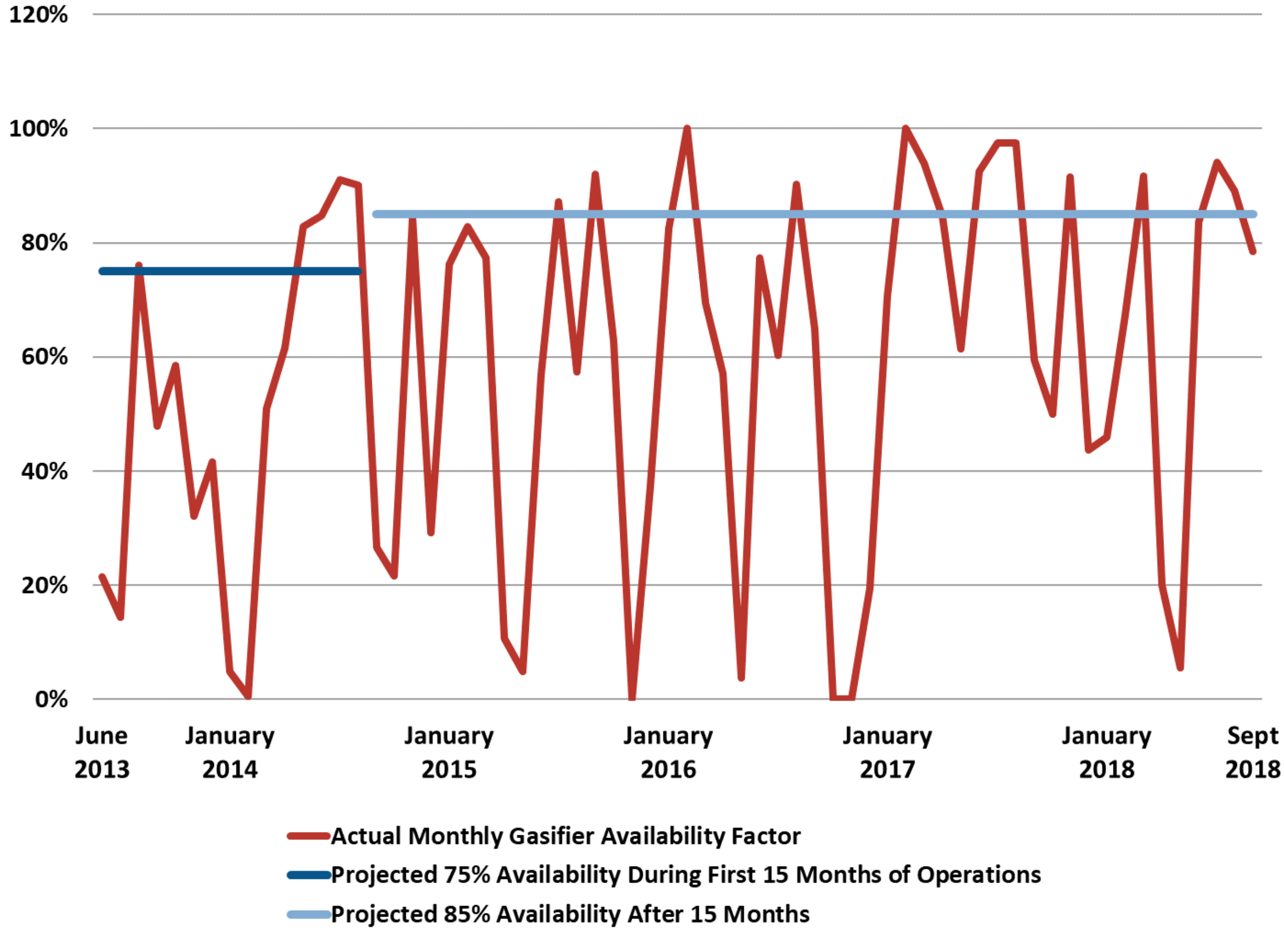
**Figure 3: Edwardsport IGCC Actual vs. Promised Operating Performance**




Source: IEEFA

Figure 3 then shows that Edwardsport's poor operating performance has, in large part, been due to the unreliable operation of its gasifiers, which are crucial components of any pre-combustion carbon capture plant.

**Figure 4: Edwardsport IGCC Monthly Gasifier Availability**




Source: IEEFA

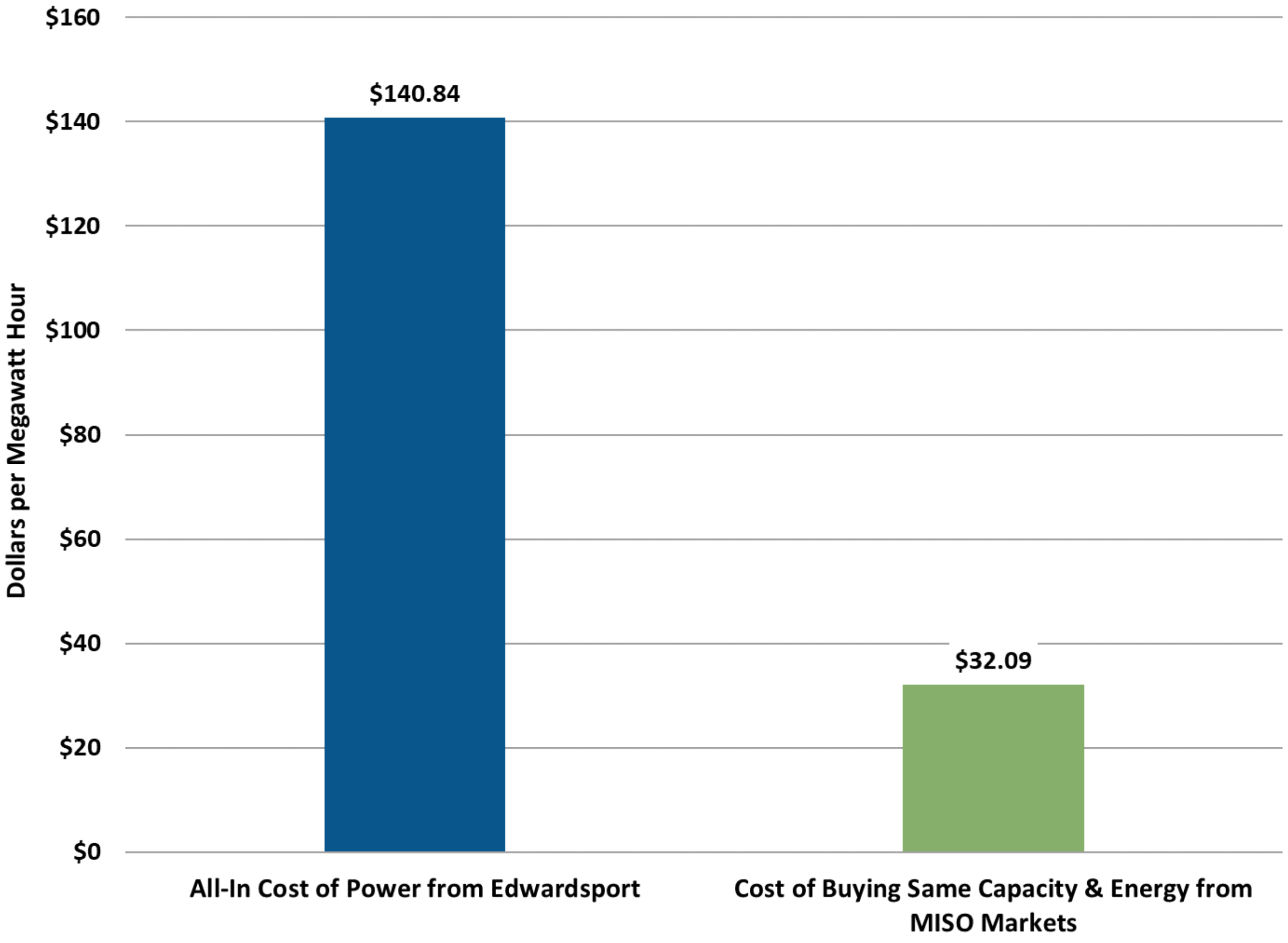
Not surprisingly, Edwardsport's poor operating performance has driven up the cost of the electricity it produces. According to data submitted by Duke Energy to the Federal Energy Regulatory Commission, operations and maintenance costs at the plant averaged nearly $61/MWh through 2017—$20-$30/MWh more than the O&M costs at the five new conventional combined cycle gas plants Duke brought online from 2009-2013 (plants comparable in size and age to Edwardsport).

It is worth noting here that fuel costs at Edwardsport are relatively low, given the inexpensive coal feedstock used in the gasifiers, which is to say that non-fuel-related costs associated with running and maintaining the gasifiers must be extremely high.

Factoring in the plant's construction cost ($3.5 billion for 618MW of capacity) makes the cost of power from Edwardsport much higher. The all-in cost of electricity from Edwardsport averaged $140.84/MWh through September 2018,[28] more than four times the average price of power bought on the wholesale market in the region (Figure 4). Clearly, ratepayers would have been much better off had Duke simply opted to purchase power on the open market.

[28] Settlement Testimony of David A. Schlissel on Behalf of Citizens Action Coalition of Indiana, Inc., Oct. 16, 2018

**Figure 5: Edwardsport IGCC's All-In Cost vs. the Cost of Buying the Same Energy and Capacity from the Competitive Wholesale Markets**




Source: IEEFA

The situation could well worsen in the years ahead. Strong deflationary price trends are sweeping the wind and solar sectors, exerting continued downward pressure on the price of power from these renewable resources.

A similar trend is starting to appear in the energy storage arena, which will make renewables even more cost effective, as well as increasingly dispatchable. As this happens and as additional renewable capacity is added to the grid, overall energy market prices are likely to fall and higher-priced electricity from plants like Edwardsport are likely to be called on for even less generation, further increasing their cost per MWh.

# CCS Also Would Require Extensive New Infrastructure to Compress, Transport and Inject Captured CO2

Boundary Dam and Petra Nova use captured $CO_2$ for enhanced oil recovery (EOR) activities. However, the potential for EOR in general is limited.

If carbon capture is to be used as a mechanism for achieving major reductions in $CO_2$ emissions from coal-fired power plants—regardless of whether EOR is involved—long-term repositories for it will be required. And regardless of the capture technology used, an array of additional infrastructure would be needed to transport and store the captured $CO_2$.

Broadly speaking, captured $CO_2$ would need to be compressed, transported (most likely via pipeline) and then injected at a storage site. At each step along the way, and for many years after injection, monitoring would be required.

As we have seen, progress on capture technology has been minimal, at best, since the failed FutureGen project. But there has been essentially *no* progress on infrastructure issues, a reality that even the National Coal Council underscored in a 2015 report to Energy Secretary Ernest Moniz: "Capture technology is not the most significant stumbling block for the large-scale commercial application of CCS technology. Storage remains the primary hurdle with respect to the commercialization of CCS."[29]

None of the infrastructure that would be required to transport and inject $CO_2$ exists, the council said, and without it, commercialization of the technology was "difficult to imagine."

Transporting and storing a meaningful amount of $CO_2$ in the U.S. essentially would require financing, permitting and construction of a massive new national pipeline system—one on the magnitude of the existing oil and gas pipeline network. Such a system could be built, but the scope and cost of such an undertaking would be enormous. And with growing public opposition to new oil and gas pipeline construction in recent years, permitting and building such an entirely new set of long-distance pipelines would be time consuming, at best.

The scope of the pipeline infrastructure that would need to be added cannot be overstated. The roughly 50 existing $CO_2$ pipelines in the U.S. extend for about 4,500 miles in total and transport approximately 68 million metric tons of $CO_2$ annually.[30] In contrast, according to Environmental Protection Agency data, U.S. coal-generating plants emitted 1.3 billion tons of $CO_2$ (just under 1.2 billion metric tons) in 2017 alone. It would, it goes without saying, require a lot of new pipeline capacity to transport even a small fraction of that total amount of $CO_2$, with enormous associated costs.

A couple of back-of-the-envelope calculations for the required scale of such a network—based on what happened at Kemper—go like this:

First, Denbury, an oil and gas company that specializes in using $CO_2$ in EOR activities, was to have received 70% of the plant's $CO_2$ production, according to its contract with Mississippi

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[29] National Coal Council, "Fossil Forward: Revitalizing CCS Bringing Scale and Speed to CCS Deployment, January 2015, p.95, https://www.nationalcoalcouncil.org/studies/2015/Fossil-Forward-Revitalizing-CCS-NCC-Approved-Study.pdf

[30] DOE, "A Review of the CO2 Pipeline Infrastructure in the U.S.," April 21, 2015, DOE/NETL-2014/1681, https://www.energy.gov/sites/prod/files/2015/04/f22/QER%20Analysis%20-%20A%20Review%20of%20the%20CO2%20Pipeline%20Infrastructure%20in%20the%20U.S_0.pdf

Power. The $CO_2$ compressor at the Kemper plant was designed to handle 11,000 metric tons per day,[31] so Denbury was to have processed about 7,700 metric tons a day, or approximately 2.8 million tons a year. Based on these figures, roughly 428 similarly sized pipelines would be needed to handle all of the U.S. coal sector's annual $CO_2$ emissions.

Second, the pipeline at Kemper, paid for by Mississippi Power, ran for 61 miles and cost $141 million—suggesting that the cost of building a national $CO_2$ pipeline system would run on the order of $60 billion or more.

Beyond plant performance and pipeline network requirements, a host of other practical uncertainties remain:[32]

- Can water requirements be met?
- Who would be responsible (and legally liable) for the long-term performance of storage reservoirs?
- Would proposed storage reservoirs actually be able to hold predicted volumes?

The industry would do well to answer these questions before a major commitment is made to CCS as a significant strategy for reducing $CO_2$ emissions and before such technology is promoted in foreign markets.

# The Changing Electricity-Generation Environment

The record on commercializing coal-based carbon capture projects is poor—the examples to date have been either extremely costly, technically unreliable or both—and that's to say nothing of the extremely limited infrastructure that is in place for piping and injecting the captured carbon.

These problems raise an increasingly nagging question: Given the broad changes reshaping the U.S. electricity generation sector, is CCS even needed?

In this section we discuss five forces that have undercut the rationale for retrofitting existing coal-fired facilities with carbon capture technology:

- The aging of the U.S. coal fleet;
- The technological revolution in the natural gas industry;
- The trend toward significant and continuing cost reductions in renewable energy;
- The evolution of an electric grid-operating paradigm that no longer relies on inflexible baseload generation; and
- Utility, corporate and public pressure for cleaner fuels.

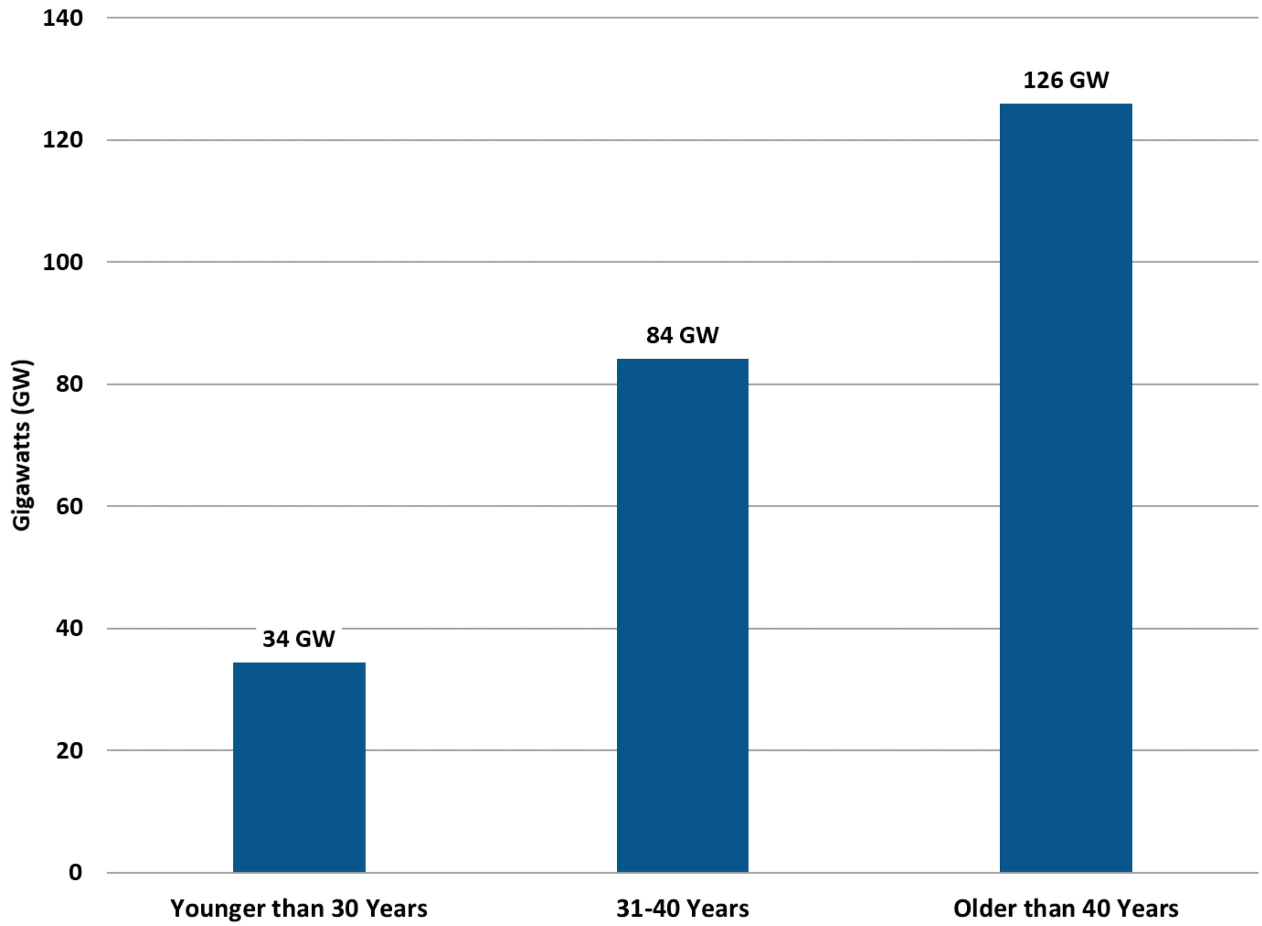
[31] *Power Magazine*, "Kemper County IGCC Project Update," April 1, 2013, https://www.powermag.com/kemper-county-igcc-project-update/?pagenum=4
[32] Sommer Energy LLC, "Carbon Capture and Storage," Anna Sommers, March 2018.

## Coal's Aging-Fleet Problem

Installed coal-fired capacity in the U.S. is old and getting older—and it is not being replaced with new coal-fired generation.

As of the end of 2017, according to data from S&P Global Market Intelligence, the U.S. had 245 gigawatts (GW) of coal-fired generating capacity online. Of that total capacity, only 14%, or about 34GW, was less than 30 years old, and more than 50%, or 126GW, was more than 40 years old (Figure 5).

**Figure 6: Age of U.S. Coal Fleet**




Source: S&P Global Market Intelligence

This aging of the U.S. coal fleet is crucial to any discussion regarding carbon capture because aging affects plant economics in a number of negative ways: declining plant operating performance and reliability; higher heat rates; higher maintenance costs; and the need for significant capital investments in plant refurbishment/equipment renovation before or in conjunction with any decision to install CCS technology.

The International Energy Agency (IEA) noted in a 2015 report summarizing the carbon capture technology retrofit at SaskPower's Boundary Dam Unit 3 that the entire plant essentially would require rebuilding if it were to operate long enough to recover the costs of the CCS equipment.

The IEA report, which refers to the plant as BD3, concluded "In order to support the deployment of [CCS] at BD3, it was a prerequisite to rebuild and upgrade the BD3 power plant both in order to assure an additional 30 years of operation, and to achieve effective integration with the carbon capture system. A thirty-year life of the retrofitted BD3 power unit would be a requirement to attain an acceptable lifecycle cost of electricity to support the business case."[33]

In other words, it makes no economic sense to add CCS technology to an older coal plant with only a limited remaining operating life. This is especially true in cases where plants already face degrading operating performance and rising operating costs.

Decisions to spend hundreds of millions if not billions of dollars to retrofit old coal plants just to add CCS technology will lead to calls for other options that include renewables, energy efficiency, and demand response, all of which are certain to be less costly than a full-blown rebuild and CCS installation.

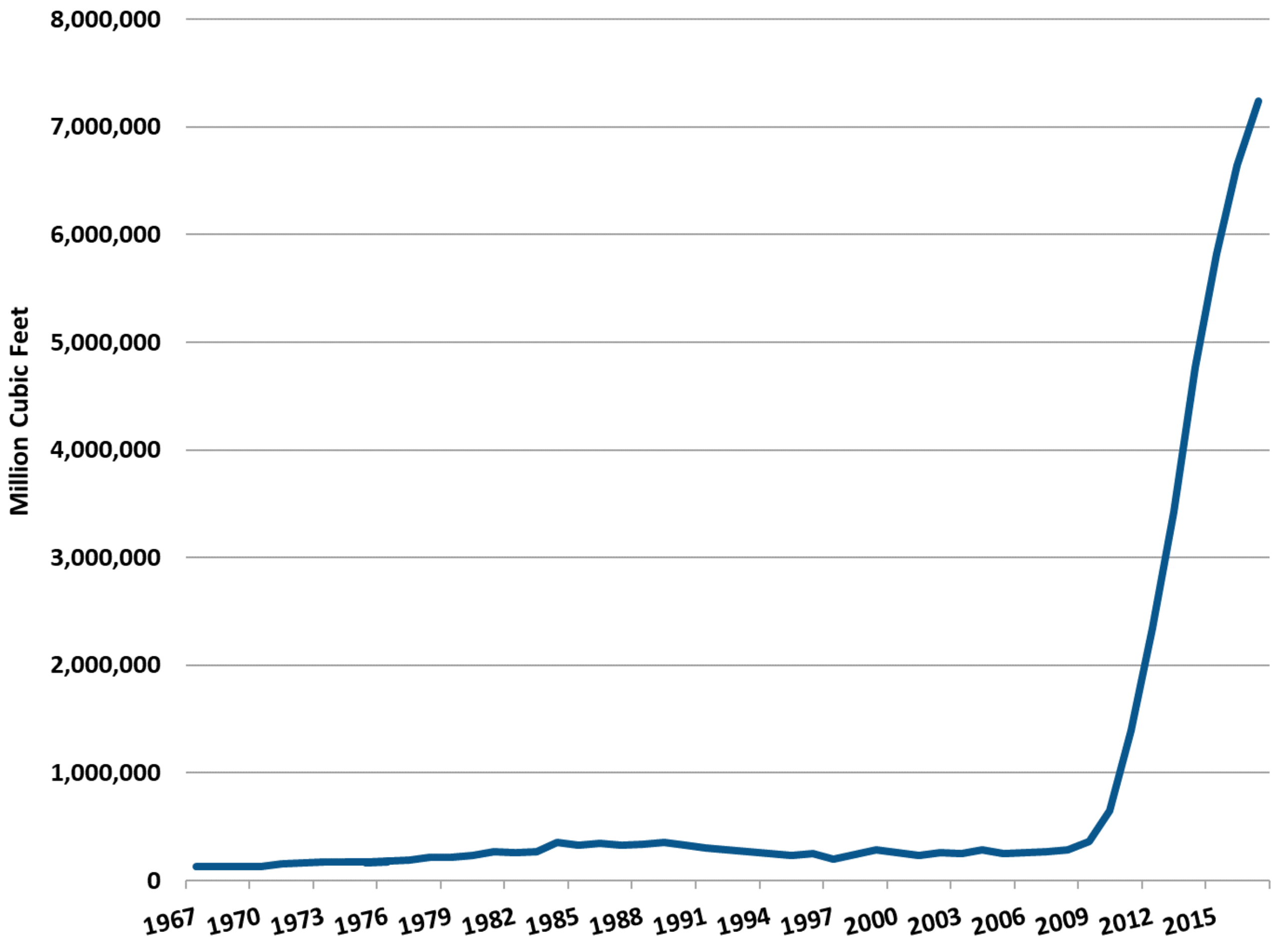
A further hindrance to wider CCS adoption is the fact that the two working CCS units in North America, Boundary Dam and Petra Nova, are essentially pilot project. Before CCS technology is feasible or economically viable at scale—if indeed it ever is—years of additional research and operational experience will be required. By that time, the aging U.S. coal fleet will be even older and less competitive with renewables and natural gas.

## The Surge in Natural Gas-Fired Generation

It is difficult to grasp the scope of change in the past 10 years in the natural gas industry, but Figure 6 gives a good indication of the enormity of the transformation.

[33] IEA, "Integrated Carbon Capture and Storage Project at SaskPower's Boundary Dam Power Station," p. 27, https://ccsknowledge.com/pub/documents/publications/saskpower-boundry-dam/Deploying%20Carbon%20Capture.pdf

Figure 7: Annual Ohio and Pennsylvania Natural Gas Marketed Production




Source: EIA

For all practical purposes, natural gas production in Ohio and Pennsylvania amounted to next to nothing until the late 2000s, when the use of horizontal drilling and fracking technology began to take hold across the industry.

Production soared in formerly unproductive formations such as the Utica and Marcellus Shales, which underlie most of Pennsylvania and much of eastern Ohio. Today these two states account for more than 20% of the nation's annual natural gas production.

The rise of this new regional production, coupled with technology-driven supply increases elsewhere in the U.S., has reshaped the electric power market, producing strong surety of supply and expectations for relatively low and stable long-term prices. This has been a main driver of the decline in coal-fired generation over the past decade or so as developers have rushed to build cleaner and more efficient natural gas-fired generating units.

The EIA said this year that it expects roughly 32GW of new electricity-generation capacity to come online in 2018, of which an estimated 21GW will be gas-fired.

Not surprisingly, about half of this new natural gas capacity is expected to be within the boundaries of the PJM independent operating system, which runs the bulk power market in Ohio, Pennsylvania and all or parts of 11 other states.

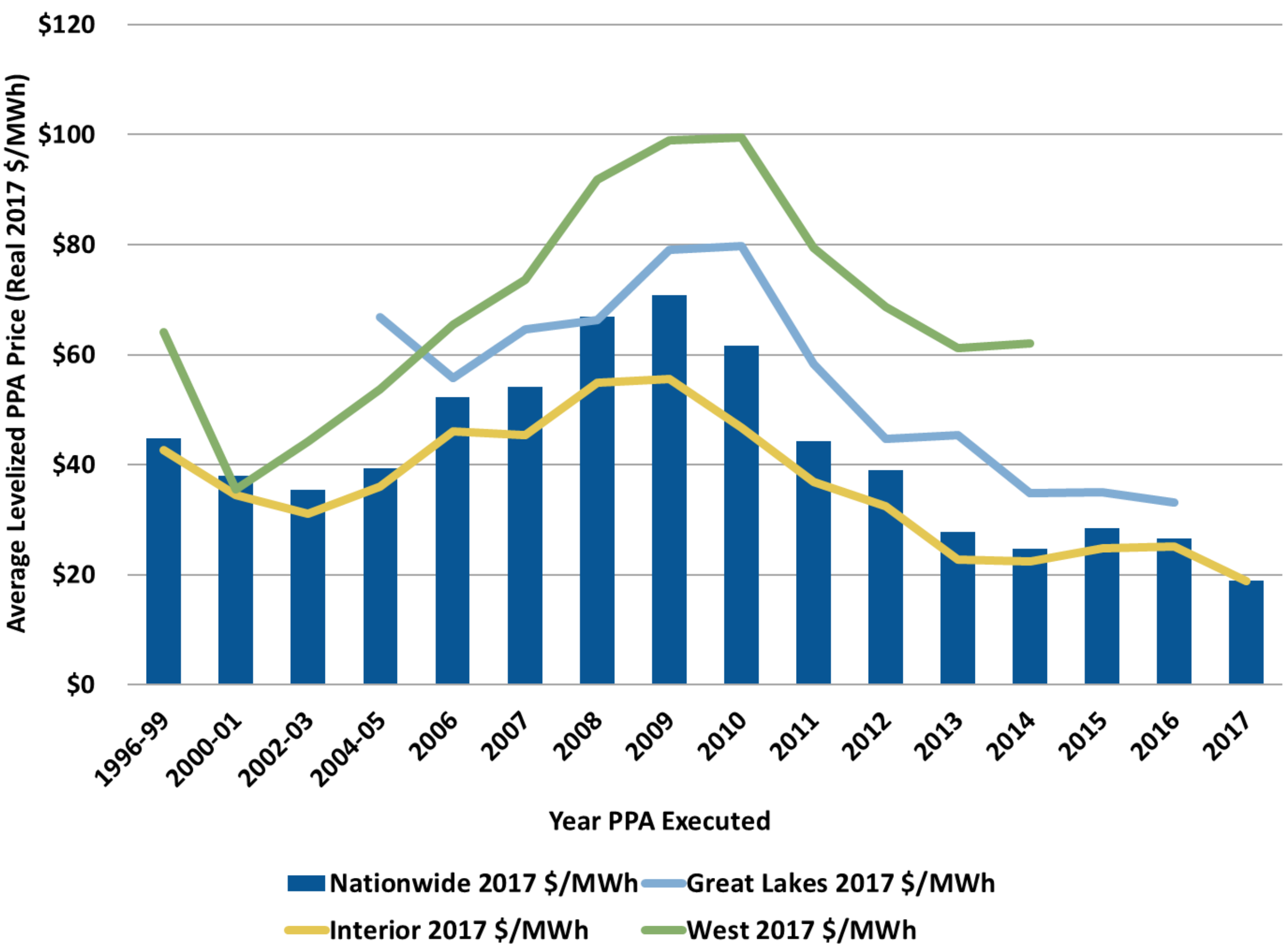
And where formerly companies built mine-mouth coal plants in the region, numerous developers are now building what amount to well-sited gas plants, a strategy that cuts down on transportation costs and helps such projects stay competitive.

## The Rise of Variable Generation

Colossal changes in the natural gas sector have, if anything, been surpassed by recent advances in renewable energy, where declining costs have led to dramatic growth in wind and solar generation alike.

In 2005, only about 6MW of wind generation capacity had been installed in the U.S. That had climbed to more than 90GW by the middle of this year, with enough capacity under construction now to push the total above 100GW in the near future. This uptake has been driven in no small part by falling wind-power prices (Figure 7), particularly in the Midwest, where American wind resources are the most plentiful.

**Figure 8: Declining Wind power purchase agreement (PPA) Prices**

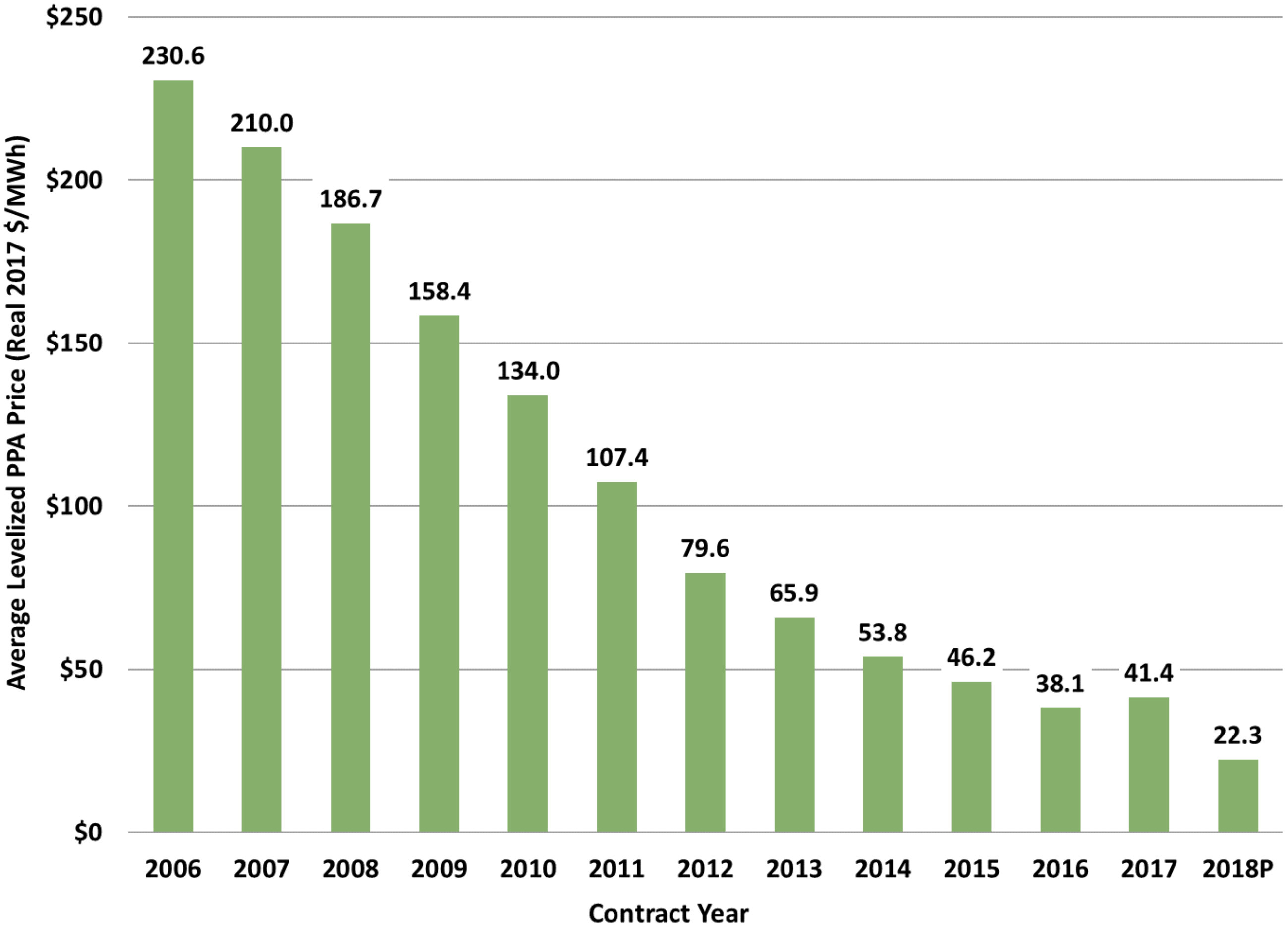



Source: Lawrence Berkeley National Lab

The rise of utility-scale solar generation has been just as dramatic, climbing from essentially zero in 2005 to more than 58GW today, with significant additional capacity under construction,

According to the Solar Energy Industries Association, installed solar capacity will double in the coming five years.[34] As capacity climbs, prices are falling (Figure 8). Power purchase agreement costs, almost off the charts in 2006, have been less than $50/MWh since 2015, with the average falling to about $40/MWh in 2017 (levelized for the full term of the supply contract).

**Figure 9: Declining Solar power purchase agreement (PPA) Prices**

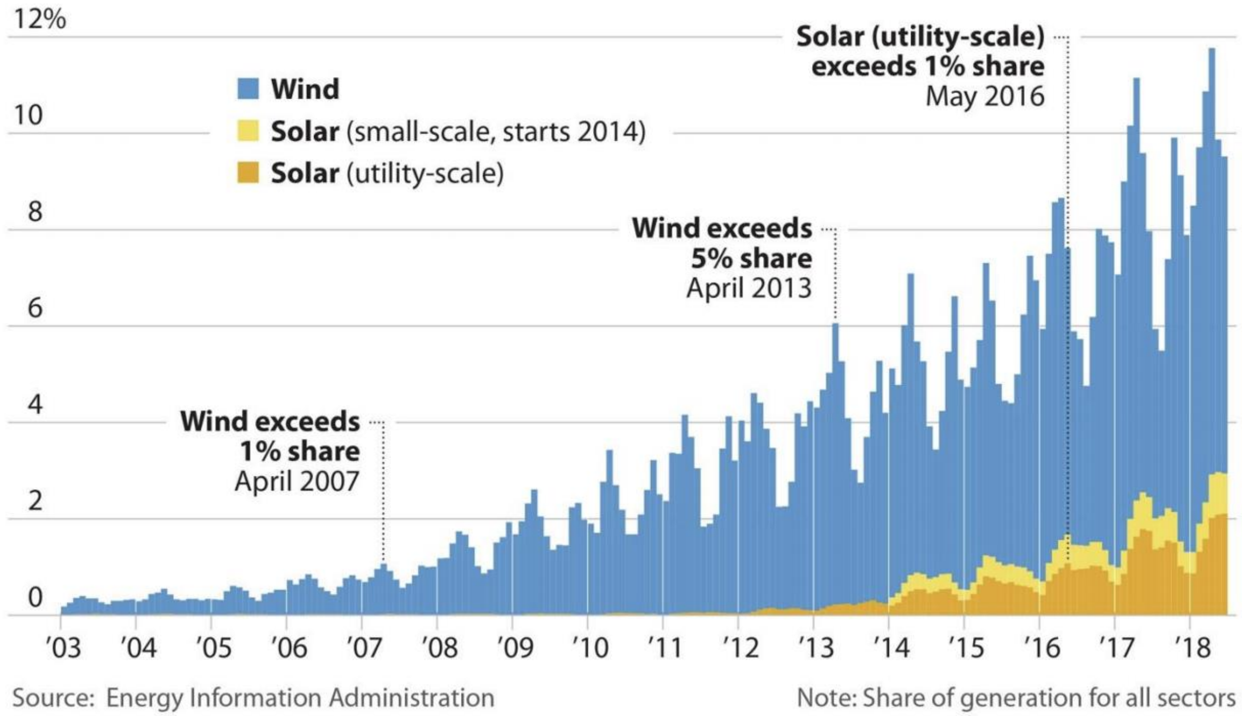



Source: Lawrence Berkeley National Lab

The growth in installed wind and solar capacity, and the lower prices of these resources, has led to a veritable explosion in generation, a development that is certain to continue in coming years as the costs of adding new wind and solar resources decline further. (Figure 9)

34 SEIA website, https://www.seia.org/us-solar-market-insight

**Figure 10: Rising U.S. Generation from Wind and Solar Resources**




The growth of wind and solar stands to be accelerated by the development of the energy storage sector, which is in its nascent stages today but growing quickly.

The promise of energy storage is that it will enable power generators to store variable resources—those like wind and solar that are not always available— for use when they are needed. One example of the likely effect is in the current use of lithium-ion batteries that store solar power produced during lower demand periods (generally late mornings and early afternoons) for power generators or homeowners to use later in the day, when demand and prices are higher.

Similarly, storage will enable wind generators to save energy produced at night for when demand is higher in the daytime.

One major side-effect of storage: a reduction in $CO_2$ emissions through the displacement of generation that would otherwise be produced by fossil-fired plants.

While electricity storage remains largely conceptual across power markets, a number of recent contracts and bids shows that broad uptake is likely soon. Two recent solicitations, one by Xcel Energy in Colorado and the other by NIPSCO (Northern Indiana Public Service Company) are particularly revealing on this point.

In Colorado, Xcel received bids for: 5,097MW of wind-plus-battery storage at a median price of $21 per MWh; 4,048MW of wind-and-solar-plus-battery storage at a median price of $30.60 per MWh; and 10,813MW of solar-plus-battery storage at a median price of $36 per MWh.[35]

[35] "2017 All Source Solicitation 30-Day Report," CPUC Proceeding 16A-0396E, Dec. 28, 2017, p.9, https://assets.documentcloud.org/documents/4340162/Xcel-Solicitation-Report.pdf

This past summer, NIPSCO received bids for 755MW of solar-plus-storage at an average price of $35 per MWh and a capacity charge of $5.90/kilowatt-month for the storage.[36]

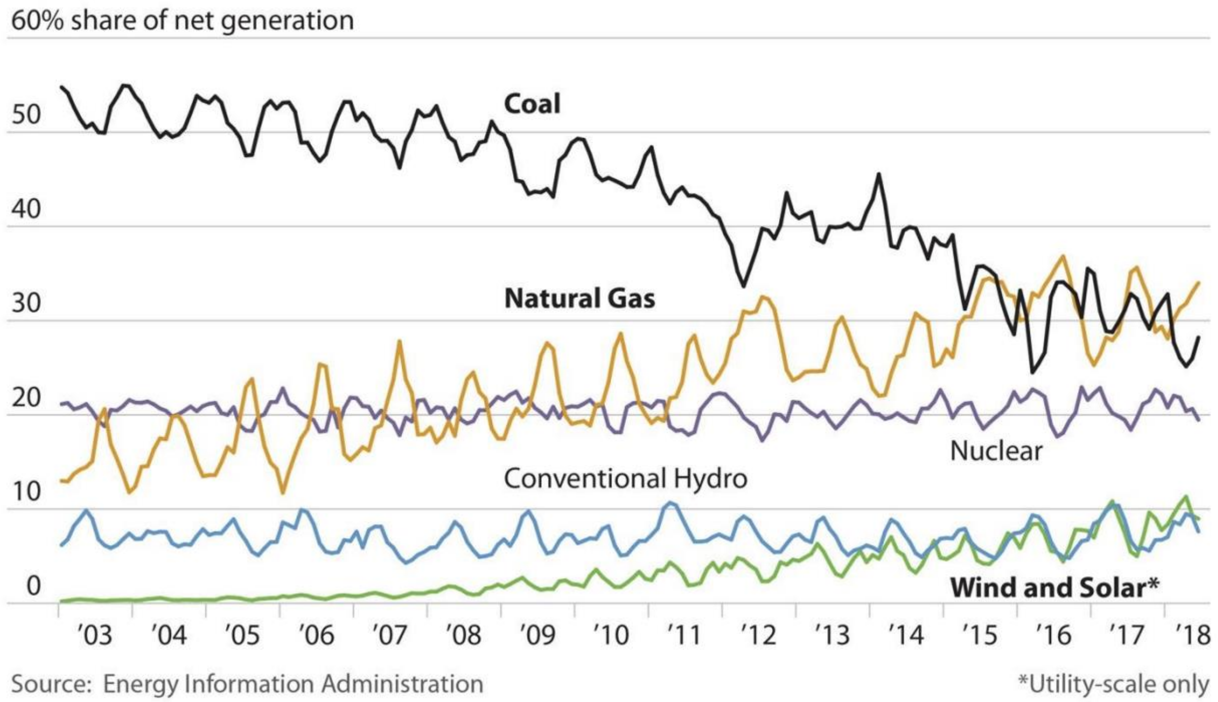
These bids are bad news for a large number of existing coal plants, which cannot compete with such prices. They are also bad news for CCS, which would add at least $60/MWh to the cost of coal-generated electricity. Coal is already being priced out of the market almost everywhere in the U.S., a trend that will only accelerate if and when CCS costs are added.

The solar-plus-storage bids received by NIPSCO are of special note. Installed costs averaged out to $1,151/kilowatt (kW) of capacity. The DOE currently puts the cost of building new supercritical coal units with CCS on the order of $5,000/kW.[37]

And on this front, natural gas is also at risk. A recent report by Bloomberg New Energy Finance (BNEF) indicates that solar-plus-storage is nearing price parity with new gas-fired generation in the U.S. Southwest. The report estimates that a 100MW solar farm with a 25MW storage component that is capable of lasting four hours would be able to sell power into the Arizona market at $36/MWh by 2021.By comparison, a new gas-fired facility would cost $47/MWh.[38]

The decline in coal's share of the U.S. electricity generation is sure to accelerate in coming years.

**Figure 11: Coal's Declining Share of U.S. Electricity Generation**




[36] "NIPSCO Integrated Resource Plan 2018 Update," July 24, 2018, p. 19, https://www.nipsco.com/docs/default-source/about-nipsco-docs/7-24-2018-nipsco-irp-public-advisory-presentation.pdf

[37] National Energy Technology Laboratory, "Post-Combustion Capture Retrofit: Eliminating the Derate," Jeff Hoffmann, et al, Aug. 21, 2017, https://www.netl.doe.gov/File%20Library/Events/2017/co2%20capture/1-Monday/J-Hoffman-NETL-Eliminating-the-De-Rate-Study.pdf.

[38] Bloomberg News, "Solar With Batteries Cheaper Than Gas in Parts of U.S. Southwest," Brian Eckhouse, Sept. 17, 2018, https://www.bloomberg.com/news/articles/2018-09-17/solar-with-batteries-cheaper-than-gas-in-parts-of-u-s-southwest

## Changes in Grid Operations

Gains in market share by renewable resources and flexible natural gas-fired generation are changing how operators run American electric grids.

Because solar and wind have zero fuel costs they are dispatched first—ahead of both gas- and coal-fired generation—when they are available, a practice that is followed because it keeps costs down across the board. And because natural gas units generally have more operational flexibility, they are typically tapped ahead of coal-fire units to match the variability of wind and solar.

These grid-operation changes have put serious economic pressure on older coal-fired units, which are being pushed out of formerly lucrative generation periods. In the wind-heavy Midwest, for example, coal units that once ran all night to meet demand, are often being shut off or ramped down now during that window of time—which is when the region's wind resources generally are at their peak,

As coal units are called on less, their fixed costs must be spread over a smaller number of megawatt-hours sold, raising their overall per MWh operating and maintenance costs and furthering their downward competitive cycle.

## The Two-Pronged Market Push for Cleaner Fuel

A major change in utility and corporate behavior over the past few years will prove just as challenging to coal-fired generation as the ongoing shift to renewables and natural gas.

The FutureGen project first proposed in 2003 had two major, coal-dependent utility sponsors: Southern Co. and American Electric Power. In 2005, when the project officially broke ground, roughly 70% of Southern's electricity generation was coal-fired. Today, coal's share of Southern's generation mix has tumbled to 30%, while natural gas is closing in on 50% and renewables, which accounted for close to zero of the company's generation in the mid to late 2000s, now generate almost 10% of the utility's output. AEP's mix has changed significantly too. A decade ago, coal accounted for 70% of the company's installed capacity; that figure has dropped to 47%, and plans are for further decline.

In fact, a growing number of U.S. electric utilities are planning now to phase out their coal-fired generation completely. Ben Fowke, chairman, CEO and president of Xcel Energy, has said just that, that "coal is on the way out."

"I will tell you, it's not a matter of if we're going to retire our coal fleet in this nation, it's just a matter of when,"[39] Fowke said.

He is hardly the only utility sector executive of that mind. In 2016, Gerald Anderson, chairman of Michigan's DTE Energy said: "I don't know anybody in the country who would build another coal plant."[40]

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[39] Greentech Media, "Xcel CEO Says Retiring the U.S. Coal Fleet "Just a Matter of When'," Julia Pyper, June 8, 2018, https://www.greentechmedia.com/articles/read/xcel-ceo-retiring-coal-fleet#gs.mBCKNSY

[40] mLive Media Group, "Michigan's biggest electric provider phasing out coal, despite Trump's stance," Emily Lawler, Nov. 25, 2016, https://www.mlive.com/news/index.ssf/2016/11/michigans_biggest_electric_pro.html

When companies like these are openly planning their exit from coal, strategies to invest hundreds of millions or billions of dollars on costly plant upgrades and still largely untested carbon capture equipment is not a business plan likely to secure board approval.

Part of this shift stems from the fact that utilities are being pressed hard by many of their largest corporate clients—who in turn are catering to customer preferences— to get out of coal. Led by household-name companies like Apple, Facebook, and Google, U.S. corporations have signed deals for more than 13GW of renewable energy power supplies in the past five years.

Beyond these direct purchases, companies have been pushing utilities to offer green tariffs so that they can buy clean electricity without having to bother with negotiating their own power supply deals. Companies are also beginning to factor the availability, or lack thereof, of renewable energy resources into their expansion and/or relocation plans, a trend that is also pushing utilities toward cleaner generation.

The broad reality is the utility industry, pushed by its customers, is moving on from coal. This trend is undermining outdated rationales for developing expensive carbon capture and storage systems for the aging and shrinking U.S. coal fleet.

# The Economics

The two operational carbon capture projects discussed in this report—Boundary Dam and Petra Nova—share two commonalities: the use of post-combustion technology and the reliance on $CO_2$ sales for use in EOR activities to help make $CO_2$ capture economic.

This is particularly important at the Petra Nova plant, where NRG owns a 25% stake of the King Ranch oil field, which is where the captured $CO_2$ is injected. In an interview last year with E&E News after the facility began commercial operations, David Knox, an NRG spokesman, noted that oil sales are what make the project feasible.

"At $50 [per barrel of oil], we're economically viable, which means that it can pay all the debt, it can pay for the capital cost, it can pay for the operating cost, and it actually makes a bit of money to pay for this," Knox said.[41]

Beyond that, the real money will start rolling in as output at the oil field starts increasing. Initial projections by NRG indicated the $CO_2$ injections could ultimately boost output to 15,000 barrels per day from the pre-project level of about 500 b/d.

"The economics of that are what make this a valuable prospect," Knox said. "It's not selling the $CO_2$."

This is problematic for two reasons. First, if the goal of carbon capture technology is to curb emissions out of concern for climate change, then clearly using it to produce more $CO_2$ from burning another fossil fuel makes no sense. Second, the possibilities around reuse of $CO_2$ in EOR activities are quite limited. When the Petra Nova project was first announced, NRG Chairman David Crane told Reuters that the technology is applicable to only some U.S. coal-fired plants because most are either located too far from oil-producing regions or lack access to pipeline transport.

[41] E&E News, "Carbon capture takes 'huge step' with first U.S. plant," Christa Marshall, Jan. 10, 2017, https://www.eenews.net/energywire/stories/1060048090

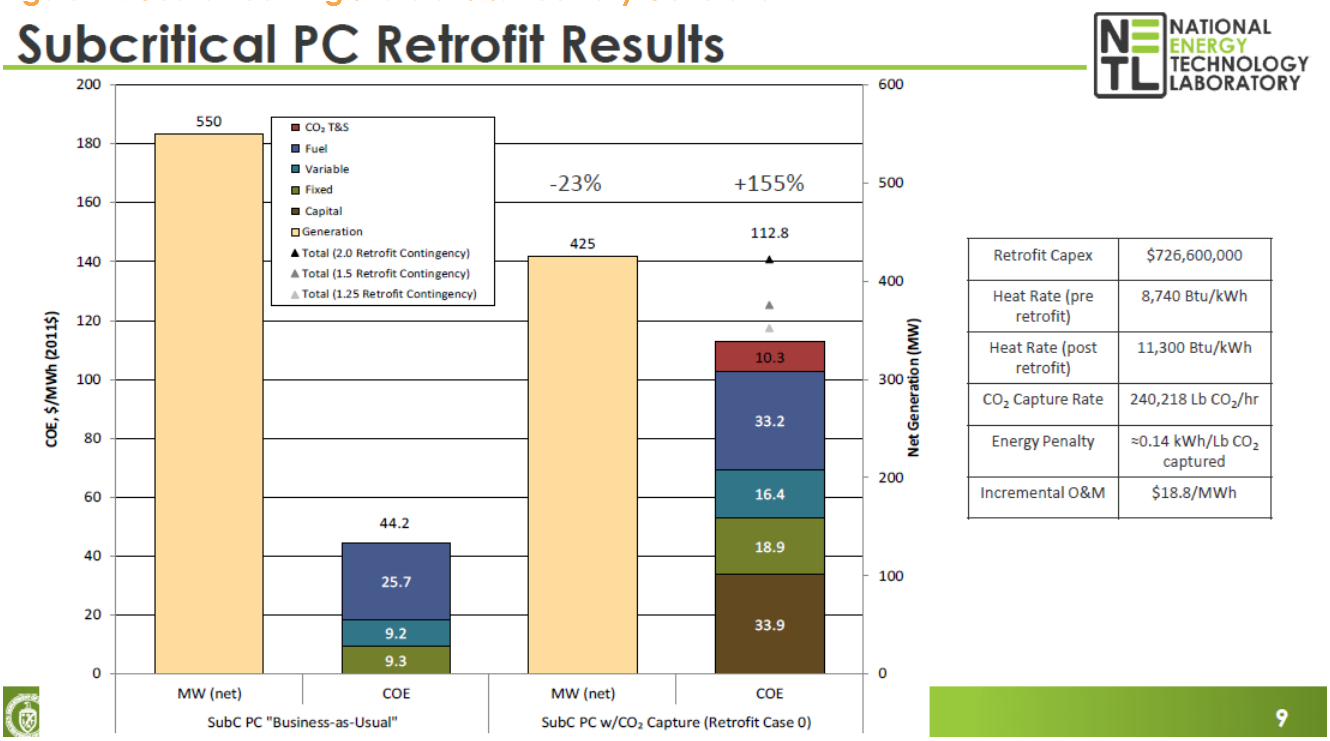
And without EOR, the economics of CCS do not work.

## Problems Posed by Competition

Another CCS project hurdle, especially for plants like Petra Nova located in competitive electricity markets, is the electricity produced will very likely be priced out of the market as cheaper natural gas and renewable energy resources compete for sales. If a plant's output doesn't clear the market, then it isn't selling electricity and it isn't producing $CO_2$ for EOR reuse, a circumstance that can potentially strand the entire investment.

Figure 11, taken from an August 2017 presentation developed by DOE's National Energy Technology Laboratory,[42] **illustrates the exceedingly high economic penalty associated with retrofitting carbon capture technology at coal-fired units without linking the system to any EOR activity.**

Figure 12: Coal's Declining Share of U.S. Electricity Generation




| | |
|---|---|
| Retrofit Capex | $726,600,000 |
| Heat Rate (pre retrofit) | 8,740 Btu/kWh |
| Heat Rate (post retrofit) | 11,300 Btu/kWh |
| $CO_2$ Capture Rate | 240,218 Lb $CO_2$/hr |
| Energy Penalty | ≈0.14 kWh/Lb $CO_2$ captured |
| Incremental O&M | $18.8/MWh |

According to this example, output drops sharply when CCS is added, from 550MW net to 425MW, a decline of 23%. Just as problematic is the fact that costs would jump from just over $44/MWh to more than $112/MWh—a 55% increase. This analysis is based on current cost

[42] NETL, "NETL Carbon Capture Retrofit Analyses," Eric Grol, Aug. 9, 2017, DOE/NETL-2017-21457, https://www.netl.doe.gov/research/energy-analysis/search-publications/vuedetails?id=2405

estimates, meaning that 15 years of development have done nothing to make coal CCS economically viable.

This point was driven home by Howard Herzog, a CCS expert at the Massachusetts Institute of Technology, in a 2015 interview in which Herzog talked about the problems at SaskPower's Boundary Dam project. "It all comes down to economics, it's very simple," Herzog said. "The markets aren't there for CCS."[43]

Even if the markets eventually are "there" for CCS, the technology remains so far from being commercially viable that it seems only fair to doubt that it can ever catch up to rapidly changing electricity markets. Current renewable energy and storage developers are not standing still; indeed, new record-low contract prices have become a staple of utility and energy developer announcements lately. Given this ferocious and ongoing competition, the coal sector today is at a serious disadvantage—and one from which it will not likely recover.

Existing coal-fired facilities already are having a difficult time clearing the market. Adding costly $CO_2$ capture technology would only exacerbate coal's competitive position. While the $1 billion Petra Nova CCS project may be breaking even on the strength of its related oil sales, actual capture costs are running about $60/ton, as previously noted.[44] And, also as noted previously, it remains unclear as to whether this $60/ton is an accurate representation of the full cost of capturing and sequestering the $CO_2$ emissions or whether such a figure can be fairly applied to the capture and sequestration of $CO_2$ at other coal plants. Nor does it reflect what it would cost to build and operate the massive infrastructure that would be needed to transport captured $CO_2$ from coal plants to long-term repositories.

Another way of looking at coal's core economic problems is through the lens of basic business best practices. Jonathan Adelman, a vice president of strategic and resource & business planning at Xcel Energy, noted in a recent interview with Greentech Media that Xcel's aggressive plans to phase out coal-fired generation are driven solely by economics. "In many areas," Adelman said, "the incremental cost of renewable generation is currently less than the embedded cost of existing generation. That is a very important part of this transition. If we can buy a new resource at a lower cost than the existing resource, that is going to advance the transition."[45]

If new renewable generation is currently cheaper than paid-for coal without CCS, the writing is on the wall: Neither utility executives nor merchant plant owners are going to build new coal plants with unproven, balky CCS technology that would prove economically uncompetitive from Day One. And adding the technology to plants that on average are more than 40 years old isn't viable either from a business point of view.

If $CO_2$ reductions are the goal, continuing the build-out of the renewable energy sector is a far better option than trying to make carbon capture technology work. Costs continue to fall for wind and solar generation alike, and the looming competitiveness of storage makes these zero-fuel, zero-emissions resources increasingly dispatchable as well. Such resources can be

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[43] *National Geographic*, "This Plant Set Out to Prove Coal Can Be Clean. Did It Work?," Christina Nunez, Oct. 13, 2015, https://news.nationalgeographic.com/energy/2015/10/151013-boundary-dam-test-for-clean-coal-one-year-later/

[44] IEA Clean Coal Centre, "USA Experts: Coal Plants Must Adapt To New Energy Landscape," Aug. 28, 2018, https://www.iea-coal.org/usa-experts-coal-plants-must-adapt-to-new-energy-landscape/

[45] Greentech Media, "Xcel Resource Planning Executive: We Can Buy New Renewables Cheaper Than Existing Fossil Fuels", Juan Monge, Sept. 11, 2018, https://www.greentechmedia.com/articles/read/an-interview-with-xcels-avp-for-strategic-resource-business-planning-the-re

built today, lowering emissions immediately—and years if not decades before significant reductions from CCS retrofits could be expected to be achieved.

Finally, a note on lessons learned in the course of history around the U.S. nuclear industry, an industry that has been used to support the oft-repeated claims of CCS proponents that costs will go down simply if more CCS plants are built. That certainly has not been the case for nuclear power and there is no indication it will happen for CCS technology either. Adding CCS cannot not, in any sense, be expected to lead to the same magnitudes of cost reductions that have been possible through the standardization and mass production of wind turbines and solar modules.

# Conclusion

Fifteen years into North American CCS development efforts, little or no progress has been made toward truly practical technology or economic viability.

The four CCS initiatives reviewed here can all be categorized as experimental, and none of the experiments have gone well. Two in essence have been abandoned (Edwardsport and Kemper) and two (Boundary Dam and Petra Nova) are only economically viable by selling the captured $CO_2$ for use in EOR which, in turn adds more $CO_2$ to the atmosphere.

Top experts in the field of CCS are acknowledging these failures on several fronts.

Just last year, for example, DOE researchers conceded the following: "Retrofit into existing plant [is] considered technically feasible but carries significant impact to existing plant economic business case."[46]

In October of this year, Steve Winberg, an assistant DOE secretary who oversees the agency's Office of Fossil Energy, underscored the economic concerns in telling industry officials that it is essential to cut CCS costs in half, to $30 per ton, if CCS is to ever be feasible. "We've got to get the cost down so that fossil energy, whether it's coal or natural gas, remains viable," Winberg said.[47]

Yet even this ambition is inadequate. First, as we have shown, carbon capture is not economic at $30/ton, and second, the absence of any clear time frame for achieving such a goal puts CCS in an untenable position competition-wise. Even if CCS gets cheaper, competing resources, particularly renewables, are likely to continue declining in cost as well, retaining their economic advantage. The fact is, with the current, real cost of CCS at $60 per ton, by any measure of common sense, CCS should not even be part of discussions around where electricity-generation markets are going. Investment dollars are far better directed to other, more immediately useful purposes.

The third hurdle to broad uptake of CCS—in addition to its high cost and its growing lag in the race for electricity-generation competitiveness—is that its proponents are seemingly unaware of the huge and ongoing shift in the nation's electricity sector.

[46] NETL, "Eliminating the Derate," op. cit.

[47] S&P Global Market Intelligence, "DOE: Coal must 'evolve with the grid,' lower carbon capture costs," Ellie Potter, Oct. 5, 2018, https://www.snl.com/web/client?auth=inherit#news/article?id=46903210&KeyProductLinkType=6

That shift breaks down as follows:

- Renewables are rapidly declining in price, becoming increasingly efficient and gaining market share; further, with storage, renewables offer the dispatchability and resilience needed for 24/7 operation;
- Technological developments in the natural gas industry have ensured steady supplies that will keep costs low;
- The utility industry itself is moving away from coal and is showing no interest in investing in costly, largely unproven technologies fraught with risks that offer little potential return.
- Societal expectations support the shift, with growing numbers of large corporate energy users seeking their own green energy supplies or pushing supplier utilities to do so. Renewable energy availability is also increasingly a factor in corporate relocation decisions.

Pretending that existing CCS approaches are a good fit for changing markets, or even really a viable option, will not address pressing demands for clean electricity supplies.

Finally, it is worth noting that any decision to add CCS to a significant portion of the U.S. coal generation fleet would result in significantly higher costs for end-users across the board. This is true also of electricity markets outside the U.S. The tens-to-hundreds of billions of dollars required to add and operate CCS equipment at scale, and to upgrade aging existing coal fleets, would certainly lead to huge ratepayer increases and substantial burdens for taxpayers too.

An informed industry discussion about economically justifiable options makes more sense.

# Appendix

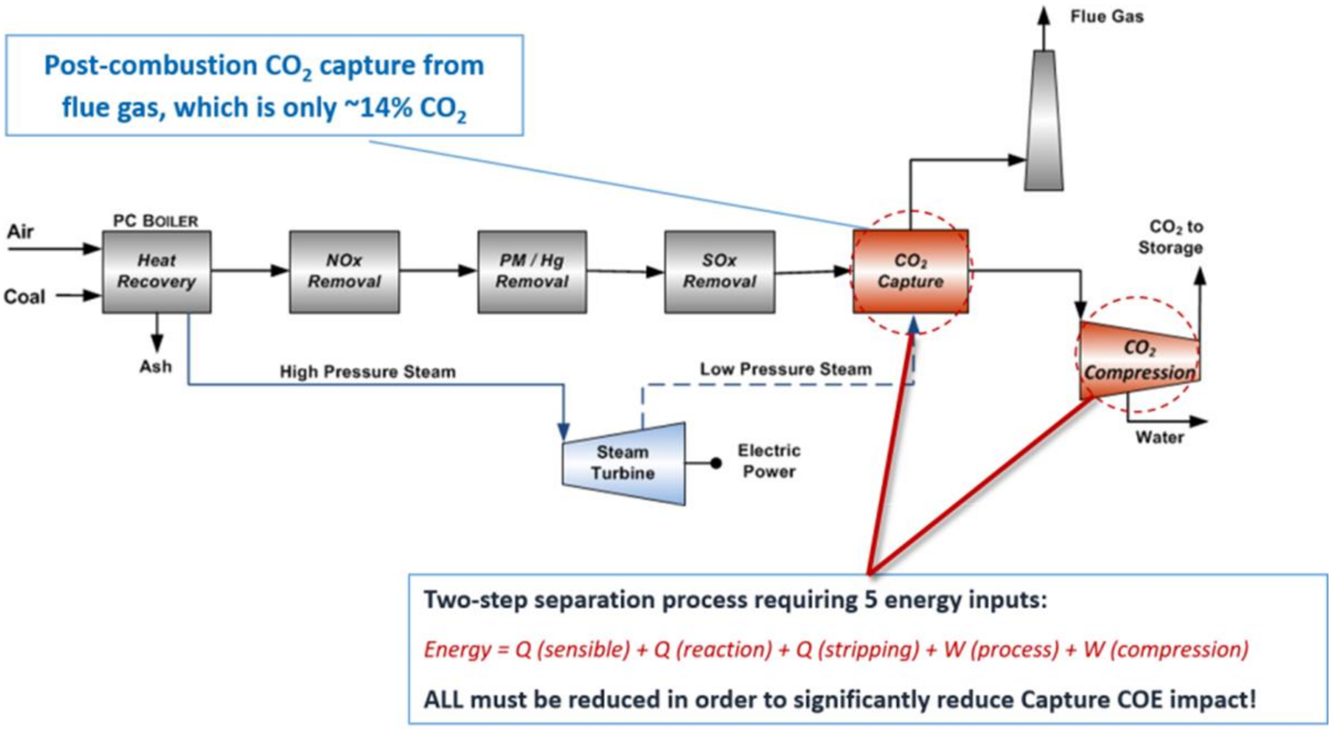
## The Technology Options

In looking to reduce $CO_2$ emissions associated with coal combustion in the utility sector, two basic operations exist, broadly speaking: Removing the $CO_2$ before the coal is combusted or using post-combustion options to pull it out of flue gas before it is vented into the atmosphere.

### Post-Combustion

This approach relies on capturing carbon after combustion, as has been done with other coal-based air pollutants such as $SO_2$, nitrogen oxides and mercury.

The challenges here include dealing with the volume of flue gas and separating the relatively dilute amount of $CO_2$ (about 14%) from the remaining gases, primarily nitrogen.[48]

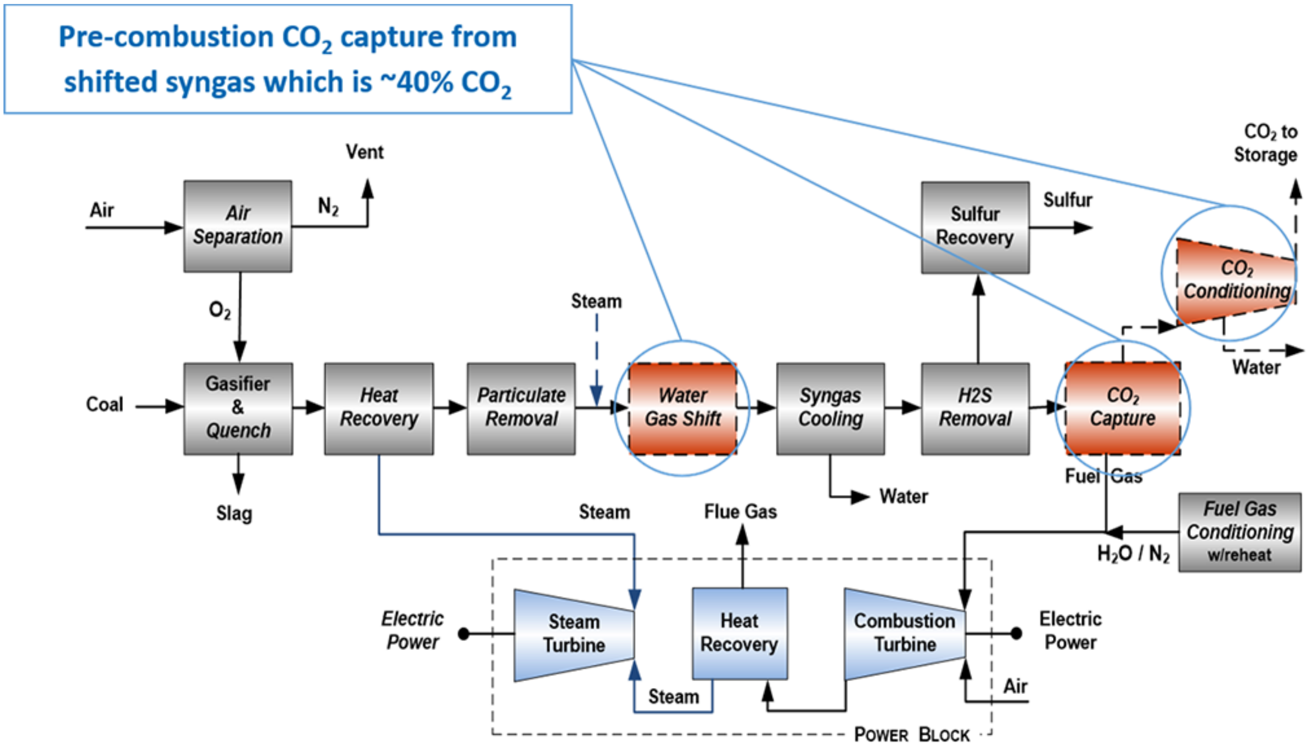



Source: NETL[49]

[48] https://www.netl.doe.gov/research/coal/carbon-capture/post-combustion
[49] Ibid.

## Precombustion

This option uses coal essentially as a feedstock. Coal is gasified, producing a synthetic gas similar to natural gas that is then combusted to drive gas-fired turbines. The premise here is that the gasification process allows for the production of other saleable products while boosting the concentration of $CO_2$, making it easier to capture.



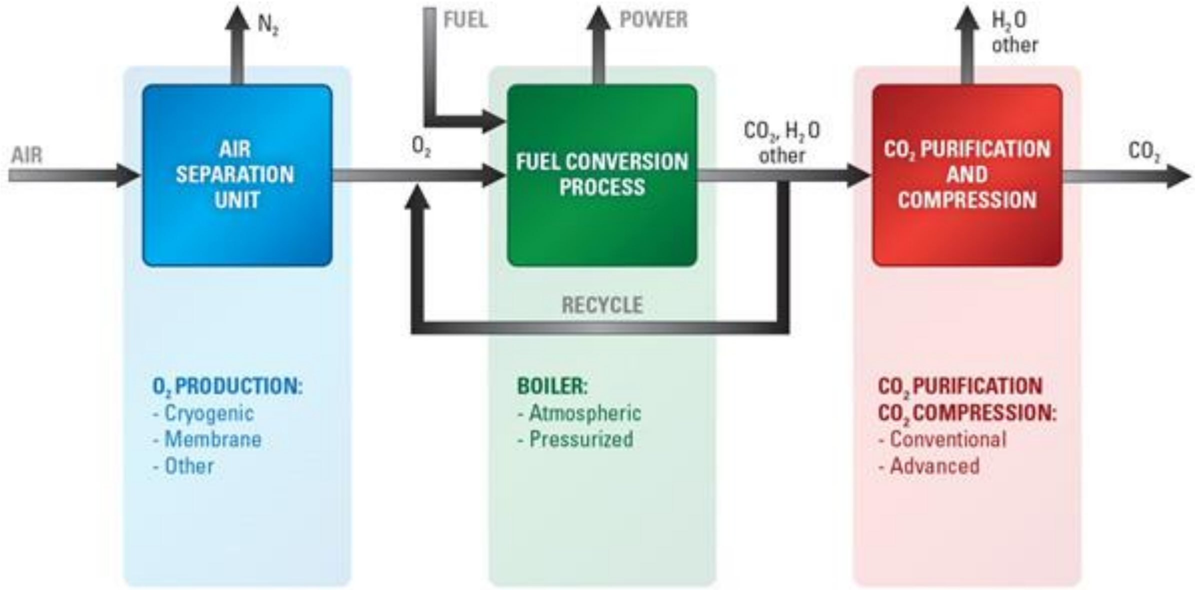

Source: NETL[50]

Economics don't favor this approach in a low-cost natural gas environment like the one that prevails today. Clearly, using coal to produce a synthetic gas requires purchasing coal, as well as paying for the necessary capital equipment and other operating expenses to enable the conversion. At high and sustained natural gas prices, this approach might have been feasible, but in the current low-cost environment, driven by the fracking revolution, the economics of coal-produced syngas don't come close to being competitive.

[50] https://www.netl.doe.gov/research/coal/carbon-capture/pre-combustion

## Oxy Combustion

Oxy combustion, a specific type of pre-combustion control, was to have been demonstrated in the original FutureGen project, using enriched oxygen instead of plain air (which contains significant amounts of nitrogen) for the combustion process. This process was meant to reduce the volume of flue gas, making it easier to capture the carbon dioxide as well as other pollutants such as $SO_2$, NOx and mercury.




Source: NETL[51]

No oxy combustion commercial units are in operation. although research and development on the process continues. According to DOE's National Energy Technology Laboratory, "the capital cost, energy consumption, and operational challenges of oxygen separation are a primary challenge of cost-competitive oxy-combustion systems."[52]

[51] https://www.netl.doe.gov/research/coal/energy-systems/advanced-combustion/oxy-combustion
[52] Ibid.

# Institute for Energy Economics and Financial Analysis

The Institute for Energy Economics and Financial Analysis (IEEFA) conducts research and analyses on financial and economic issues related to energy and the environment. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy and to reduce dependence on coal and other non-renewable energy resources. More can be found at www.ieefa.org.

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# Important Information