

Engineering-Economic Evaluations of Advanced Fossil Fuel Power Plants with Carbon Capture and Storage

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Technical Update, June 2018

EPRI Project Manager

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PRODUCT DESCRIPTION

Background

This 2018 update to an annual report series on recent engineering and economic studies by the Electric Power Research Institute (EPRI) and others provides an overview of the expected costs and performance for new and retrofit fossil fuel power plants with carbon capture and storage (CCS). Power plant types covered in the report include pulverized coal, fluidized-bed combustion, oxy-combustion, integrated gasification combined cycle, and natural gas combined cycle. The report surveys publicly reported technical, cost, and status information for fossil fuel power plants in the United States and elsewhere and reviews the status of carbon dioxide (CO₂) capture technology. Context for cost estimates and technology evaluations is provided through discussion of pilot and demonstration project status, novel power cycle developments, regulatory and energy policy updates, carbon emissions trading market news, and construction cost trends.

Objectives

This report is intended for a variety of users, including engineers, managers, generation planners, and regulatory affairs personnel responsible for initiating or monitoring the development of advanced fossil power plant and CCS technologies; researchers conducting and reporting results from engineering-economic studies of power plants without and with CCS; and engineering-procurement-construction contractors and equipment suppliers involved in the development of advanced coal-based power plants. This report aims to facilitate decision making in future projects to advance the timely deployment of reliable, next-generation units with reduced fuel consumption and emissions.

Approach

This report draws upon commercial and demonstration project data and upon engineering-economic studies by EPRI and others on the expected cost and performance at commercial scale of advanced fossil fuel power generation and environmental control technologies now at pilot scale. EPRI uses its industrial contacts worldwide to interview research peers, technology and equipment suppliers, and engineering firms to gain up-to-date information on the costs of coal and natural gas plant designs, construction, and operation.

Results

Data suggest that coal power plant costs and CO₂ capture costs for any fossil power plant type have become more difficult to predict in North America, Europe, Australia, and in other areas where baseload power demand growth is low, greenhouse gas regulations and/or legal challenges to regulations are impacting generation choices, and the number of government and industry collaborative demonstration projects is shrinking. In contrast, investment in advanced, efficient fossil power plants continues to be strong in Asia, despite the recent slowdown seen in China.

Globally, the number of CCS projects has increased; however, relatively few are large-scale projects for fossil power plants. Thus, cost data on such projects are limited and may not be readily transferrable outside of a given region. Additionally, a larger percentage of coal power projects coming on line incorporate “new technology” elements (for example, higher steam cycle temperatures to improve efficiency, provisions for CO₂ emissions reduction via some degree of CO₂ capture, or pre-investment to ease future CO₂ capture retrofits). These elements tend to increase cost uncertainty. Some countries or subnational jurisdictions have pledged to

discontinue coal-based generation by a certain future date, albeit sometimes with exceptions for plants employing CCS, which can also affect life-cycle economics.

Overall, natural gas prices remain low in North America and they have been moderating in other parts of the world. Accordingly, natural gas power plants remain the predominant choice for new capacity in the United States and Canada and they are gaining market share elsewhere. A growing number of studies are also looking applying CO₂ capture to natural gas combined cycle units or to oxy-combustion units with inherent CO₂ capture. In North America and Europe, the addition of intermittent renewable generation to the grid is affecting the choice of new natural gas power plants, with fast start and flexible operating capability becoming especially important.

Applications, Value, and Use

This document condenses available information to present a current picture of technology, cost, and performance trends for advanced fossil power plants, with and without CCS, by summarizing results from recent studies by EPRI, the U.S. Department of Energy's National Energy Technology Laboratory, the International Energy Agency's Greenhouse Gas Programme, the Global Carbon Capture and Storage Institute, and other sources, and by providing context with discussion of regulatory and economic drivers.

Given its breadth of scope, the report's aim is to inform readers of general trends and expectations for fossil power plant cost and performance. It is not intended to be a cost-estimating or performance-estimating tool for any specific project, even at the conceptual design phase.

Keywords

Carbon capture and storage
Coal-based power generation
Integrated gasification combined cycle
Natural gas combined cycle
Oxy-combustion
Pulverized coal
Ultra-supercritical

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1

INTRODUCTION

Global Energy Projections

In much of the world, policies to reduce greenhouse gas (GHG) emissions and provide greater access and/or security to the electric grid are driving technology innovation in the power industry. Across the world's economies, overall (primary) energy demand continues to increase, with the International Energy Agency (IEA) projecting a rise of 30% between 2016 and 2040.¹ Electricity accounts for 40% of end-use energy growth within this timeframe. As shown in Figure 1-1, the largest increases in energy demand are expected in areas with fast growing economies and large underserved populations, including India, China, Africa, the Middle East, and Southeast Asia.

In 2017, global electricity demand increased by 3.1%, with demand growth in China and India accounting for 70% of the global increase. Global energy intensity improved by 1.7%, compared with an average of 2.3% over the previous three years.² In 2017, global CO₂ emissions from energy use increased by 1.4%, marking the first rise in three years, and hitting a historic high of about 36 billion tons (32.5 gigatonnes).³

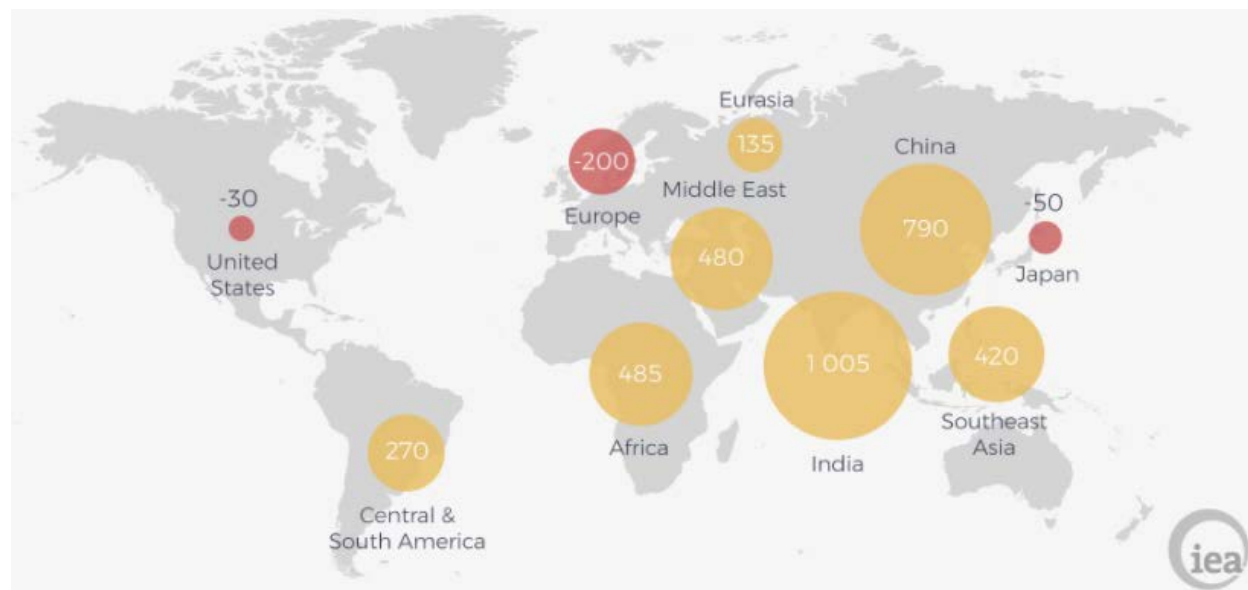


Figure 1-1
IEA WEO2017 Change in Primary Energy Demand, 2016-2040 (Million Tonnes Oil Equivalent)

¹ International Energy Agency (IEA) World Energy Outlook 2017 (WEO2017) <https://www.iea.org/weo2017/>

² International Energy Agency (IEA). *Global Energy & CO₂ Status Report 2017*. March 2018.

³ <https://www.businessgreen.com/bg/news-analysis/3028974/iea-energy-related-co2-emissions-break-three-year-trend-to-rise-in-2017>

Generation Mix Forecasts

The “reference case” in the U.S. Energy Information Administration (EIA) 2017 International Energy Outlook (IEO2017) forecasts renewables (including hydropower) as the fastest-growing sources of electric generation over the period of 2015 to 2040, increasing by an average of 2.8% per year. During that same timespan, natural gas generation is forecast to grow by an average of 2.1% annually and nuclear generation by an average of 1.5% annually. Coal’s share of the electricity generation mix declines from 40% in 2015 to 31% by 2040, but its absolute value of annual generation remains steady. As shown in Figure 1-2, by 2040 renewables will provide the same share of world electricity generation as coal at 31%.⁴

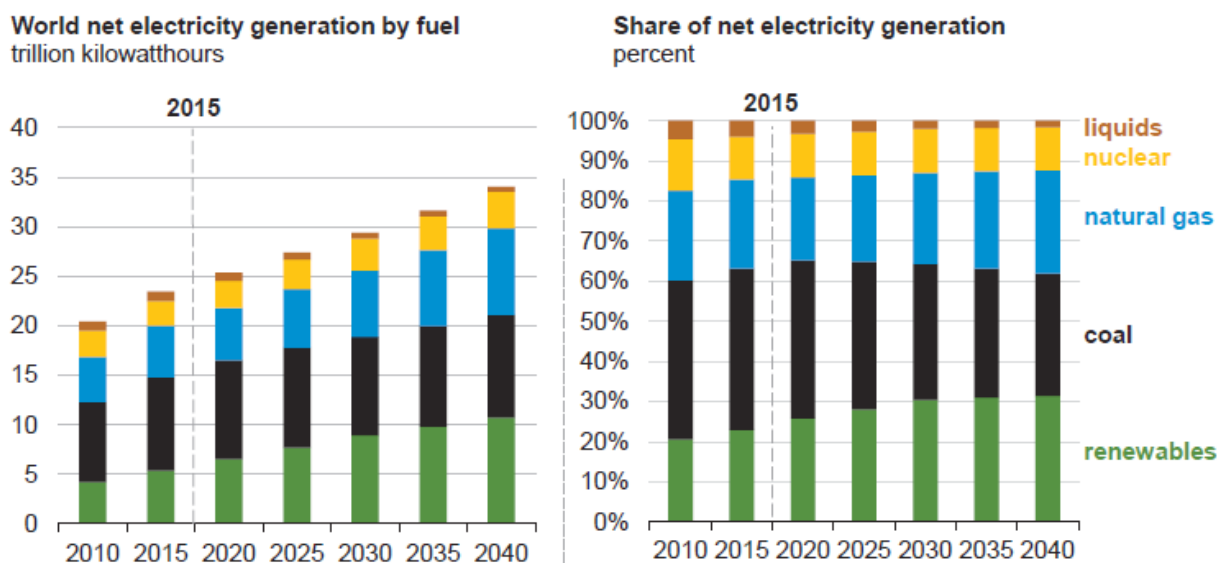


Figure 1-2
IEO2017 OECD and Non-OECD Net Electricity Generation (trillion kWh)

In 2017, natural gas held its position as the most-used fuel for electricity generation in the United States for the third consecutive year, although the absolute quantity of gas consumed fell. Coal-fired electricity generation fell to a lesser extent, marking the first year since 2008 that both natural gas- and coal-fired power production decreased in the same year. Electricity from renewable energy sources, especially wind and solar, continued to increase in 2017. Wind made up 6.3% of 2017 U.S. generation, and utility-scale solar made up 1.3%. These percentages were record shares for both fuels.⁵

In terms of U.S. generating capacity additions and retirements, coal power plants accounted for 6.3 gigawatts (GW) of the 11.2 GW of the generating capacity retired in 2017. For the first year in at least a decade, no new coal-based units began commercial operation in 2017. About 4.0 GW of natural-gas-fired capacity were retired in 2017, primarily steam turbine units. However,

⁴ EIA. International Energy Outlook 2017 (IEO2017).

⁵ EIA. “Electricity generation from fossil fuels declined in 2017 as renewable generation rose.” *Today in Energy*, March 20, 2018.

about 9.3 GW of new gas-fired capacity were added, of which 8.2 GW consisted of combined cycle units.⁶

Although coal consumption by the U.S. power sector has declined, the use of “refined” coal is growing (i.e., dried, beneficiated, and/or otherwise processed to reduce emissions of NO_x, SO₂, and Hg by the amounts prescribed by the Internal Revenue Service for Section 45 tax credits). Figure 1-3 shows coal use by rank (2017 data for January through September) and also the fraction of coal in each rank qualifying as being refined before being used to generate electricity.⁷

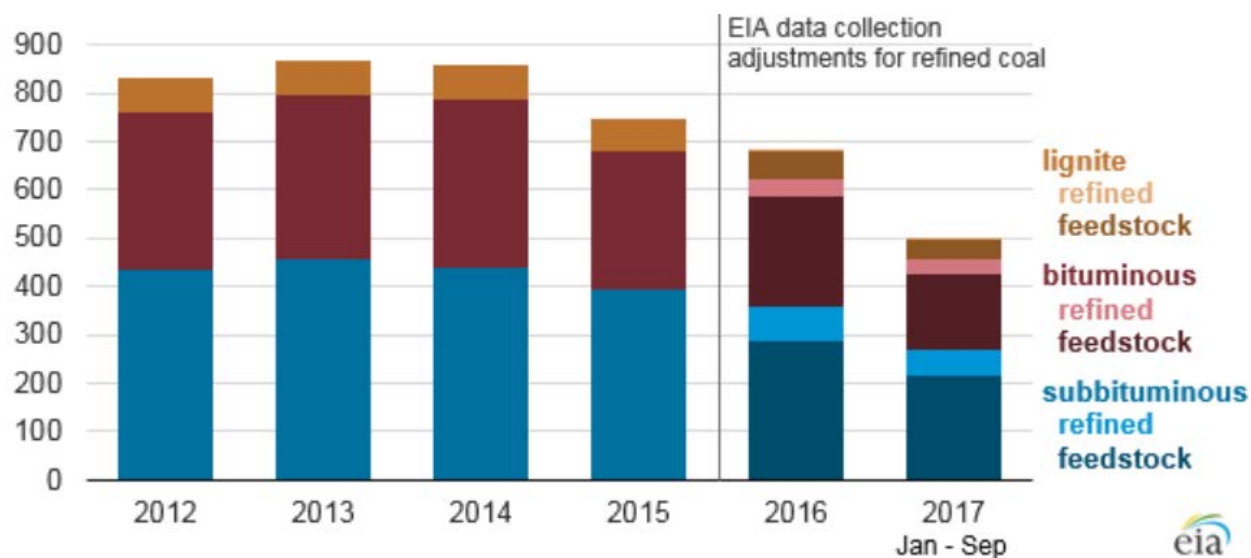


Figure 1-3
U.S. Power Sector Coal Consumption by Type (million short tons)

The addition of carbon capture and storage (CCS) at SaskPower’s Boundary Dam generating station in 2104 and at NRG’s W.A. Parish generating station in 2016 (the Petra Nova project) has demonstrated amine solvent post-combustion capture technologies at first-of-a-kind commercial scales. However, making a business case for next-generation projects still represents a significant challenge.

In the United States, competition from low-cost natural gas affected operating decisions for Mississippi Power’s Kemper County Energy Facility. Kemper would have been the world’s first utility-scale IGCC plant with CO₂ capture. Over the duration of the project development and construction, however, the price of natural gas—a competitor to lignite from the mine adjacent the plant—decreased from about \$10/MBtu (\$9.50/GJ) to about \$3/MBtu (\$2.80/GJ).⁸ The Kemper plant’s startup in 2017 was soon followed by a decision to operate on natural gas instead of lignite-derived syngas. Like Boundary Dam and Petra Nova, sale of the captured CO₂ for

⁶ Ibid.

⁷ EIA. “Refined coal has made up nearly one-fifth of coal-fired power generation so far in 2017.” *Today in Energy*, December 12, 2017.

⁸ <https://www.utilitydive.com/news/after-kemper-new-clean-coal-plants-face-long-odds/446288/>

enhanced oil recovery (EOR) would have been part of the Kemper project, but this revenue could not offset the savings in power production costs from operation on low-cost natural gas.

Commitments to GHG reductions have led several countries to announce target dates by which they intend to close their coal-fired plants (without CCS), particularly in Europe. Accordingly, recent CCS project and funding announcements from Europe have shifted from power plant hosts to industrial sources.^{9,10} Nonetheless, the market for new coal-fired power plants continues in the Balkan states and Poland. In 2015, Turkey announced plans to nearly double its coal-fired capacity by 2020, and ultimately add as many as 80 new plants,¹¹ although it is also adding NGCC plants and renewable power systems.

Coal-fired generation in China is expected to remain flat through 2040. By then, renewables, natural gas, and nuclear power are expected to account for increased shares of the country's growing electricity generation while coal's proportion is forecast to decline from about 70% to 50%.¹²

As part of China's 13th Five-Year Plan (2016–2020), 150 GW of new coal power capacity has been canceled or postponed until at least 2020. Stricter controls on power plant emissions are expected to prompt the retirement of up to 20 GW of older coal-fired units and spur technological upgrades to the remaining 1000 GW of coal power units.¹³ Nonetheless, coal capacity additions continue, with 94 GW in construction.¹⁴ Additionally, Chinese firms are increasingly involved in the financing and development of coal-fired power plants outside China.

India had coal-based generation capacity totaling 192 GW in 2017, which was projected to increase to 330–441 GW by 2040.¹⁵ The central government has mandated that new coal-fired power plants must use supercritical technology, at a minimum, and that some older subcritical plants must undergo efficiency improvements. Capacity additions for January through September 2017 show a shift toward renewables (primarily solar) at 60%, with the balance of capacity additions being 25% thermal, 10% large hydroelectric, and 6% nuclear.¹⁶ Rapidly declining solar tariffs and government incentives, such as land acquisition and new transmission infrastructure, are drivers behind a solar boom focused on large photovoltaic parks (e.g., 2 GW).¹⁷

⁹ <http://bellona.org/news/ccs/2017-10-24057>

¹⁰ <https://pale-blu.com/acorn/>

¹¹ <http://www.powerengineeringint.com/articles/2015/05/turkey-plans-doubling-of-coal-fired-power-capacity-by-2020.html>

¹² EIA. International Energy Outlook 2017 (IEO2017).

¹³ EIA. "Chinese coal-fired electricity generation expected to flatten as mix shifts to renewables." *Today in Energy*, September 27, 2017.

¹⁴ Shearer, Christine, et al. *Boom and Bust 2018: Tracking the Global Coal Plant Pipeline*. CoalSwarm, Greenpeace USA, and Sierra Club. March 2018.

¹⁵ Draft National Energy Policy. Version 27.06.2017. <http://indiaenergy.gov.in/wp-content/uploads/2017/10/Draft-National-Energy-Policy.pdf>

¹⁶ <https://cleantechnica.com/2017/11/24/third-power-capacity-added-india-year-solar/>

¹⁷ <http://www.latimes.com/world/asia/la-fg-india-solar-20180319-story.html>

In Southeast Asia, energy demand increased by more than 60% over the past 15 years.¹⁸ The International Energy Agency (IEA) projects both the regional economy and electricity demand to nearly triple by 2040. To meet the increase in demand, 325 GW of generating capacity is projected to be added between 2017 and 2040. By 2040, renewables are expected to account for the largest share of installed capacity (nearly 40%), but coal will be most prominent in the generation mix (at about 40%). Output from natural gas-fired plants is forecast to rise by 60% in absolute terms, but the share of natural gas in the generation mix is forecast to fall from the current 43% to 28% by 2040.¹⁹

Fuel Production and Pricing

In 2017, the United States became a net exporter of natural gas for the first time since 1957.²⁰ Through advances in horizontal drilling and hydraulic fracturing, U.S. natural gas production has risen from an average 55 billion cubic feet per day (Bcf/d) in 2008 to 73.6 Bcf/d, or about 2.1 billion cubic meters per day, in 2017.²¹

Lower prices for natural gas have accompanied increased supplies. Excepting three relatively brief periods, the monthly average spot price at the Henry Hub in Louisiana has stayed below \$3.00/MBtu (\$2.84/GJ) from January 2015 through June 2018.²²

The combination of the increase in natural gas supply and low gas prices have tipped the generation fuel mix in the United States from coal to natural gas. For 2017, the fuels used for power generation as a percentage of the total U.S. generation mix were: 31.7% natural gas, 30.1% coal, 20% nuclear, and 17.1% renewables including hydropower.²³ In contrast, the 2017 generation fuel mix in the European Union consisted of 30% renewables (solar, wind, biomass, and hydropower), 25.6% nuclear, 20.6% coal, and 19.7% natural gas.²⁴

Constraints on natural gas pipelines and capacity limits on liquefied natural gas (LNG) infrastructure have created regional markets around the world with different natural gas prices (see Figure 1-4).²⁵ A recent expansion in LNG facilities has increased supplies, which has been matched by rising demand, resulting in record levels of LNG trade. China, in particular, represents a growth market. On the supply side, significant expansion is under way in Australia, while two LNG projects in the United States—Sabine Pass in Louisiana and Cove Point in Maryland—have increased U.S. export capacity from 0.5 Bcf/d in 2016 to 1.9 Bcf/d, or about 54 million cubic meters per day, in 2017.²⁶ This accounts for just over 4% of global LNG supply.

¹⁸ International Energy Agency. *Southeast Asia Energy Outlook 2017*.

¹⁹ Ibid.

²⁰ EIA. "The United States exported more natural gas than it imported in 2017." *Today in Energy*, March 19, 2018.

²¹ <http://www.powermag.com/future-looks-bright-for-gas-fired-generation/>

²² <https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm>

²³ <https://www.eia.gov/tools/faqs/faq.php?id=427&t=3>

²⁴ <https://sandbag.org.uk/wp-content/uploads/2018/01/EU-power-sector-report-2017.pdf>

²⁵ <http://www.ferc.gov/market-oversight/mkt-gas/overview/ngas-ovr-lng-wld-pr-est.pdf>

²⁶ <http://www.worldoil.com/news/2018/3/27/eia-us-lng-exports-quadrupled-in-2017>

Several more U.S. LNG projects are expected to come on line in 2018–19, bringing total capacity to roughly 9.6 Bcf/d, or about 270 million cubic meters per day. This would place the United States behind only Qatar and Australia in liquefaction capacity.²⁷ EIA projects global annual LNG trade to increase from 12 trillion ft³ (340 billion m³) to 31 trillion ft³ (880 billion m³) between 2015 and 2040.²⁸



Figure 1-4
World Liquefied Natural Gas Estimated March 2018 Landed Prices (\$ per million Btu)

Natural gas pipeline expansions within the United States from shale-producing formations, such as the Marcellus, are helping to diminish some regional price differences and seasonal price swings. EIA noted that natural gas prices in 2017 at key regional trading hubs were less volatile than in previous years, as pipelines that came on line throughout the year eased infrastructure constraints that historically affected regional prices.²⁹

Global demand for coal, which had fallen in 2015–16, increased about 1% in 2017.³⁰ The price of Central Appalachian coal, driven by strong international demand, rose 29%. Powder River Basin and Northern Appalachian steam coal spot prices increased 4% and 10%, respectively. In contrast, Rocky Mountain region coal prices remained flat, and Illinois Basin coal prices fell by

²⁷ <http://www.northstarindustries.com/natural-gas-2016-2017-prices-production-and-exports/>

²⁸ EIA. International Energy Outlook 2017 (IEO2017).

²⁹ <http://www.powermag.com/future-looks-bright-for-gas-fired-generation/?pagenum=3>

³⁰ <https://www.iea.org/geco/coal/>

7%.³¹ The increase in exports more than offset a slight decline in domestic consumption, contributing to higher coal production in 2017.

EIA's reference case for IEO2017 shows global coal use remaining essentially flat from 2015 through 2040. Declines in coal use in OECD regions and China are expected to be offset by growth in India and other non-OECD nations.³²

Capital and Construction Cost Indices

Continuing an upward trend that started in 2016, U.S. construction costs rose modestly in 2017 and early 2018, as shown in Figure 1-5, which plots the Chemical Engineering Plant Cost Index (CEPCI). In general, prices have been more stable since 2012 than they were in the preceding period of the 2008 oil price boom/bust cycle and subsequent "great recession."

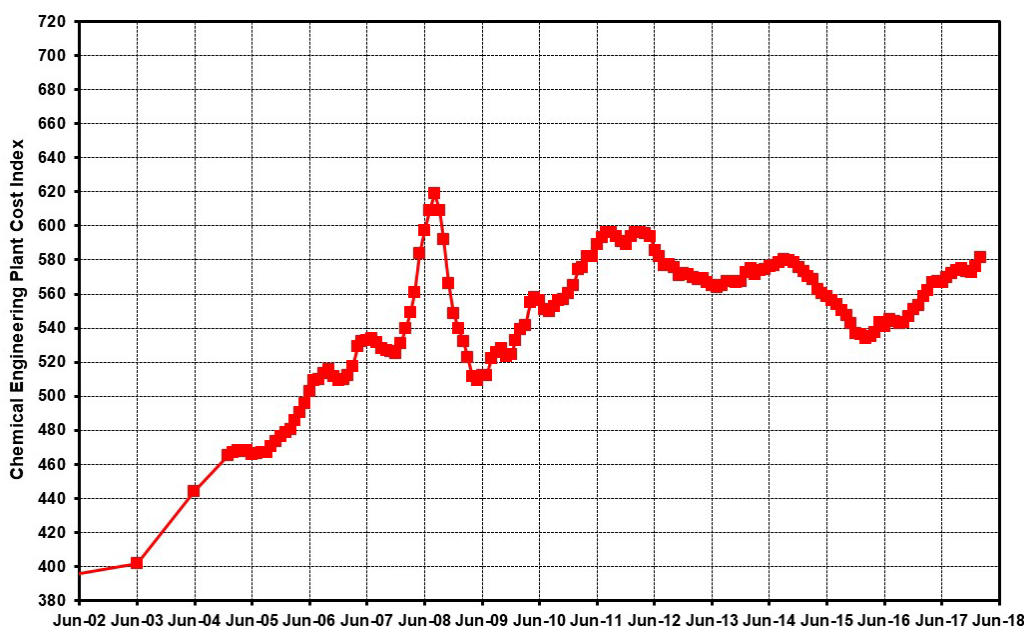


Figure 1-5
CEPCI Index, 2002 to 2018

In the late 2000s, EPRI began to observe a discrepancy between power plant cost estimates derived using indices or from engineering-economic studies versus the values reported for projects then recently completed or under construction.³³ An initial survey by EPRI of construction costs for large fossil fuel plants found that many experienced delays in regulatory approval or from legal challenges. Other issues included costly changes in the midst of construction due to adjustments to initial designs, underestimates of bulk material requirements, or unanticipated conditions that arose from integrating new technologies into the plants. Inexperience with new technology translated to added engineering and construction labor effort

³¹ EIA. "U.S. coal production, exports, and prices increased in 2017." *Today in Energy*, February 16, 2018.

³² Ibid.

³³ For example, see Section 1 of EPRI report 1019659, September 2010.

as projects progressed. Labor issues (shortages, lower productivity, etc.) and delays caused by site conditions were also common.

Regulatory and Energy Policy Drivers

The Paris Agreement

In December 2015, 191 parties adopted the Paris Agreement, which consists of pledges from individual countries aimed at lowering GHG emissions to 26–28% below 2005 levels by 2025. The Agreement was ratified and took effect in November 2016. The stated goal is to limit global average temperature rise to well below the 3.6°F (2°C) goal, although the current pledges by countries are insufficient to achieve this target.³⁴ The Agreement includes five-year “check-ins,” points at which countries are encouraged to resubmit and strengthen their commitments.

Following the Paris Agreement, several countries either announced plans to end domestic coal-fired generation or set in place emissions reductions targets that would effectively require an end to use of unabated coal power plants: France by 2023, the United Kingdom and Austria by 2025, Canada and the Netherlands by 2030, and Germany by 2050.³⁵

The Canadian government’s announcement, issued in November 2016, was followed by an “equivalency agreement” between the federal government and the province of Saskatchewan. The agreement, which has still to be finalized, will allow the province to continue operating coal-fired power plants after 2030 provided it achieves equivalent emission-reduction outcomes on an electricity systemwide basis.³⁶ Thus, SaskPower’s investment in CCS technology at Boundary Dam protects Unit 3 from closure. CCS could potentially be undertaken to extend the lives of additional coal-fired units throughout the province.

The Trump administration notified the United Nations in August 2017 that the United States will withdraw from the Paris Agreement to protect U.S. economic interests. The Agreement had been signed under the previous Obama administration. The terms of the Paris Agreement state that the United States cannot formally notify the United Nations of its withdrawal until 2019, and actual withdrawal may not occur until November 4, 2020. No other countries have announced an intention to withdraw from the Paris Agreement.

European Union Pollutant Regulations

Stricter emissions standards for NO_x, SO₂, particulates, and mercury were adopted by the European Commission in 2017 for a range of fuels. The new standards, which apply different allowable emission levels to new and existing facilities, depending on size, will have to be met by 2021. Several countries that rely heavily on coal for power generation, such as Poland, Bulgaria, Germany, and the Czech Republic, opposed the new standards.³⁷

³⁴ *Sustainable Energy in America 2016 Factbook*. Bloomberg New Energy Finance. February 2016.

³⁵ <https://electrek.co/2016/11/25/6-major-countries-phase-out-coal/>

³⁶ http://www.powermag.com/98436-2/?hq_e=el&hq_m=3313054&hq_l=10&hq_v=0b00445e3d

³⁷ <https://www.reuters.com/article/us-eu-coal-pollutants/eu-states-approve-plans-for-stricter-limits-on-pollutants-from-power-plants-idUSKBN17U1ZO>

U.S. Tax Credits for CCS

The Bipartisan Budget Act of 2018 increased the Section 45Q tax credits for geologic CO₂ sequestration in saline formations and in conjunction with CO₂-EOR. Additional significant changes, as listed in Table 1-1,³⁸ include lifting the aggregate credit ceiling of 75 million tons, which applied to all projects, both sequestration and EOR. Since the original Section 45Q tax credit was initially enacted as part of the Energy Improvement and Extension Act of 2008, more than two-thirds of the available credits had been claimed. Construction of the CO₂ capture system must begin before January 2024.

Table 1-1
2018 Changes in IRS Section 45Q Tax Credits

	Original 45Q Credit (2008)	Expanded 45Q Credit (2018)
EOR, Other Industrial Utilization (e.g., photosynthesis, chemosynthesis, chemical conversion into a material or chemical compound for which a commercial market exists as determined by the Secretary of the Treasury)	\$10/ton plus inflation	\$12.83/ton to \$35/ton plus inflation (linear increase through 2026; inflation adjustment thereafter)
	75-million-ton limit (applies to all projects, whether EOR or storage)	Credit applies for 12 years beginning on date equipment is placed in service
Sequestration	\$20/ton plus inflation	\$22.66/ton to \$50/ton plus inflation (linear increase through 2026; inflation adjustment thereafter)
	75 million ton limit (applies to all projects, whether EOR or storage)	Credit applies for 12 years beginning on date equipment is placed in service

EPA's Clean Power Plan

Following finalization in August 2015 of EPA's Clean Power Plan (CPP) rule for existing generating units, 24 states sued EPA in the federal Court of Appeals in Washington, D.C.³⁹ In February 2016, the U.S. Supreme Court stayed CPP implementation pending judicial review. The D.C. Court of Appeals announced in May 2016 that the full court would hear arguments on the CPP, rather than a panel of three judges. The hearing was held in September 2016. No decision has been announced, and the litigation has been held in abeyance since April 2017. However, August 2017, the court stated that EPA has an "affirmative statutory obligation to regulate greenhouse gases." In October 2017, the Trump administration proposed a rule to repeal the CPP and reinterpret Section 111(d) of the Clean Air Act (the clause used by the Obama administration to promulgate the rule). The public comment period for the proposed rule closed

³⁸ <https://www.huntonnickelreportblog.com/2018/02/section-45q-tax-credit-enhancements-could-boost-ccs/#page=1>

³⁹ The lawsuit is a consolidation of 38 separate cases and also includes cases by utilities and coal companies.

in April 2018. EPA is expected to propose some type of replacement rule, potentially by year-end 2018, to reduce its legal vulnerability regarding the CPP repeal.⁴⁰

Regardless of the future of the Clean Power Plan, analysis of its implementation provides insight into the potential measures that 47 states could use to meet various CO₂ emission reduction targets.⁴¹ In developing the CPP under the Obama administration, EPA used a best system of emissions reduction (BSER) approach consisting of three “building blocks:”⁴²

- Building Block 1 – Reducing the carbon intensity of electricity generation by improving the heat rate of existing coal-fired power plants.
- Building Block 2 – Substituting increased electricity generation from lower-emitting existing natural gas plants for reduced generation from higher-emitting coal-fired power plants.
- Building Block 3 – Substituting increased electricity generation from new zero-emitting renewable energy sources (e.g., wind and solar) for reduced generation from existing coal-fired power plants.

EPA applied the building blocks to all coal, oil, and natural gas power plants in each of the nation’s three major power grids—the Western interconnection, the Eastern interconnection, and the Electricity Reliability Council of Texas. EPA then used the results with all affected sources in each state to arrive at individual statewide rate-based and mass-based goals. States were then to develop plans ensuring that their power plants—either individually, together, or in combination with measures “outside the fence”—achieved the equivalent, in terms of either rate or mass, of an interim CO₂ performance rate between 2022 and 2029 and a final CO₂ emission performance rate for their state by 2030. The CPP allowed for emissions trading among states.

Other EPA Rulemakings

In June 2015, EPA issued a final rule⁴³ directing 36 states to remove provisions from their State Implementation Plans (SIP) allowing exemptions from emissions limitations during the startup, shutdown, or malfunction (SSM) events at regulated sources. The rule rolls back a previous policy that provided utilities an “affirmative defense” against enforcement actions and exemption from emission standards during SSM events. The 36 states directed to change their policies to prohibit exemptions for SSM events were scheduled to comply by November 22, 2016. The State of Texas has objected and challenged the legality of the SSM SIP call. However, in 2017 the EPA (under the Trump administration) announced it would review its prior rule and requested that the Texas challenge be held in abeyance.⁴⁴

EPA’s Mercury and Air Toxics Standards (MATS) rule, adopted in 2012, also faced court challenges. The U.S. Supreme Court determined that EPA had failed to consider the costs of

⁴⁰ <https://www.scientificamerican.com/article/will-the-clean-power-plan-repeal-come-with-a-replacement/>

⁴¹ Vermont and Washington D.C. do not have large fossil fuel power plants and are therefore exempt. Due to the uniqueness of their grids, Alaska and Hawaii will be subject to regulation at a later date.

⁴² 80 FR 64662, October 23, 2015. “Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.”

⁴³ 80 FR 33840, June 12, 2105.

⁴⁴ <https://www.huntonnickelreportblog.com/2017/09/limits-timing-administrative-reviewreconsideration-review-several-recent-cases/>

compliance, but legal efforts to stay the rule while EPA made changes were unsuccessful. About 87 GW of coal power plants installed new pollution controls in 2015–16, while significantly more plants are presumed to already be in compliance. Nearly 20 GW of coal capacity were retired rather than invest in new equipment.⁴⁵ In 2016, EPA issued a decision to uphold the MATS rule, which was met with a new lawsuit. In April 2017, EPA under the Trump administration requested, and was granted, a delay from a D.C. circuit court in order to review the MATS rule.⁴⁶ EPA’s review was still ongoing as of April 2018.⁴⁷

In March 2018, EPA proposed the first of two rules to amend the 2015 final rule for Disposal of Coal Combustion Residuals from Electric Utilities, with the expectation its changes would significantly reduce the cost of compliance by utilities.⁴⁸

Joint International CCS Research

The climate agreement between the United States and China in November 2014, set forth each country’s goals, which became part of the Paris Agreement. The United States pledged to reduce its GHG emissions by 26–28% from 2005 levels by 2025, while China pledged to curtail its GHG emissions to peak around 2030, and to increase its use of non-fossil energy to about 20% by 2030.⁴⁹ The two countries agreed to a suite of joint research and technology development efforts to support GHG emissions reductions, including projects for CCUS.⁵⁰

In June 2017, a new collaboration between China and the United Kingdom to pursue CCS research and two-way knowledge transfer was announced. At the heart of this initiative are the ACORN CCS project in Scotland targeting CO₂ capture from a natural gas processing unit and the Guangdong Offshore CCUS project in China targeting CO₂ capture from a power plant.⁵¹

The ACORN project received funding from the Accelerating CCS Technologies (ACT) initiative⁵², which involves Germany, Greece, The Netherlands, Norway, Romania, Spain, Switzerland, Turkey, and the United Kingdom. The initial round of funding in 2017 provided €38 million to eight projects (about \$45 million at a June 2018 exchange rate). In May 2018, the United States reportedly announced its intention to join the initiative.⁵³

Emissions Performance Standards

In August 2015, EPA released its final “Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility

⁴⁵ <https://www.utilitydive.com/news/a-complicated-calculus-keeps-the-remaining-coal-fleet-alive/519076/>

⁴⁶ <https://www.utilitydive.com/news/updated-dc-circuit-grants-trump-request-to-delay-hearing-on-mats-rule/441529/>

⁴⁷ <https://www.eenews.net/stories/1060079569>

⁴⁸ <https://www.epa.gov/newsreleases/epa-proposes-first-two-rules-amend-coal-ash-disposal-regulations-saving-100m-year>

⁴⁹ <http://www.whitehouse.gov/the-press-office/2014/11/11/fact-sheet-us-china-joint-announcement-climate-change-and-clean-energy-c>

⁵⁰ <https://2009-2017.state.gov/e/oes/rls/rpts/258282.htm>

⁵¹ http://www.gdccus.org/en/nd.jsp?id=499#_np=2_364

⁵² <http://www.act-ccs.eu/>

⁵³ Dixon, Tim. “US-Norway Collaboration Meeting.” IEAGHG Blog. May 2, 2018.

Generating Units.”⁵⁴ The standard for new coal power plants is 1400 lb (635 kg) of CO₂ per MWh, gross basis. This is relaxed from the standard proposed by EPA in January 2014, which was 1100 lb (500 kg) of CO₂ per MWh, gross basis. According to EPA, a highly efficient supercritical PC unit would need to capture about 20% of its CO₂ emissions to meet the final standard. The standard for new NGCC units is 1000 lb (454 kg) of CO₂ per MWh, gross basis, or about 1030 lb (468 kg) of CO₂ per MWh, net basis, for a 12-month average.

China’s “Action Plan of Upgrade and Renovation of Coal Power for Energy Conservation and Emission Reduction,” issued in 2014, sets a standard based on net power output with specified limits on fuel consumption for new power plants. Mass-based limits for bituminous coal are 620 lb (282 kg) of fuel per MWh for 1000 MW power plants and 630 lb (285 kg) of fuel per MWh for 600 MW power plants. If a typical coal in China has a carbon content similar to that of Pittsburgh #8, then China’s fuel consumption limit for 1000 MW power plants is equivalent to a rate of 1680 lb (763 kg) of CO₂ per MWh.⁵⁵

The United Kingdom’s Energy Act 2013 set a standard for new fossil generation of 992 lb (450 kg) of CO₂ per MWh (net basis), which will apply until 2045.

Canada passed an emission performance standard in 2012 for coal-fired power plants at an annual average emissions rate of 925 lb (420 kg) of CO₂ per MWh, on a net basis, excluding energy for CO₂ compression. The standard applied to new units—those that begin producing power commercially after July 1, 2015—and to old units, generally defined as having reached an age of 50 years since starting to produce electricity commercially.⁵⁶ The government’s announced plans in November 2016 to phase out traditional coal-fired electricity by 2030 will accelerate the decision-making for the fate of older units that would have had later cutoff dates under the 2012 EPS 50-year timeframe. Proposed amendments to the 2012 standard would replace the 50-year timeframe by requiring all units to meet the performance standard after December 31, 2029, or be retired.⁵⁷

In 2006, California set a CO₂ emission performance standard for long-term baseload power contracts at no greater than 1100 lb (500 kg) of CO₂ per MWh. Maine and Washington subsequently adopted standards for power plants similar to California’s standard. New York adopted an output-based CO₂ emission limit of 925 lb (420 kg) of CO₂ per MWh or an input-based limit of 120 lb-CO₂/MBtu (52 kg-CO₂/GJ) for most new or expanded baseload fossil fuel-fired plants.⁵⁸

⁵⁴ 80 FR 64509, October 23, 2015.

⁵⁵ *Can Future Coal Power Plants Meet CO₂ Emission Standards Without Carbon Capture & Storage?* EPRI. 3002006770. October 2015.

⁵⁶ <http://www.powermag.com/POWERnews/4942.html>

⁵⁷ “Announced regulatory action on coal and natural gas fired electricity production.” Environment and Climate Change Canada, Electricity and Combustion Division, March 2016.

⁵⁸ <http://www.dec.ny.gov/press/83269.html>

Carbon Pricing

The World Bank reports that over 65 jurisdictions have put a price on carbon or are in the process of doing so (Figure 1-6). Together, these carbon pricing instruments cover about 8 gigatonnes of CO₂ equivalent annually, or about 15% of global GHG emissions.⁵⁹

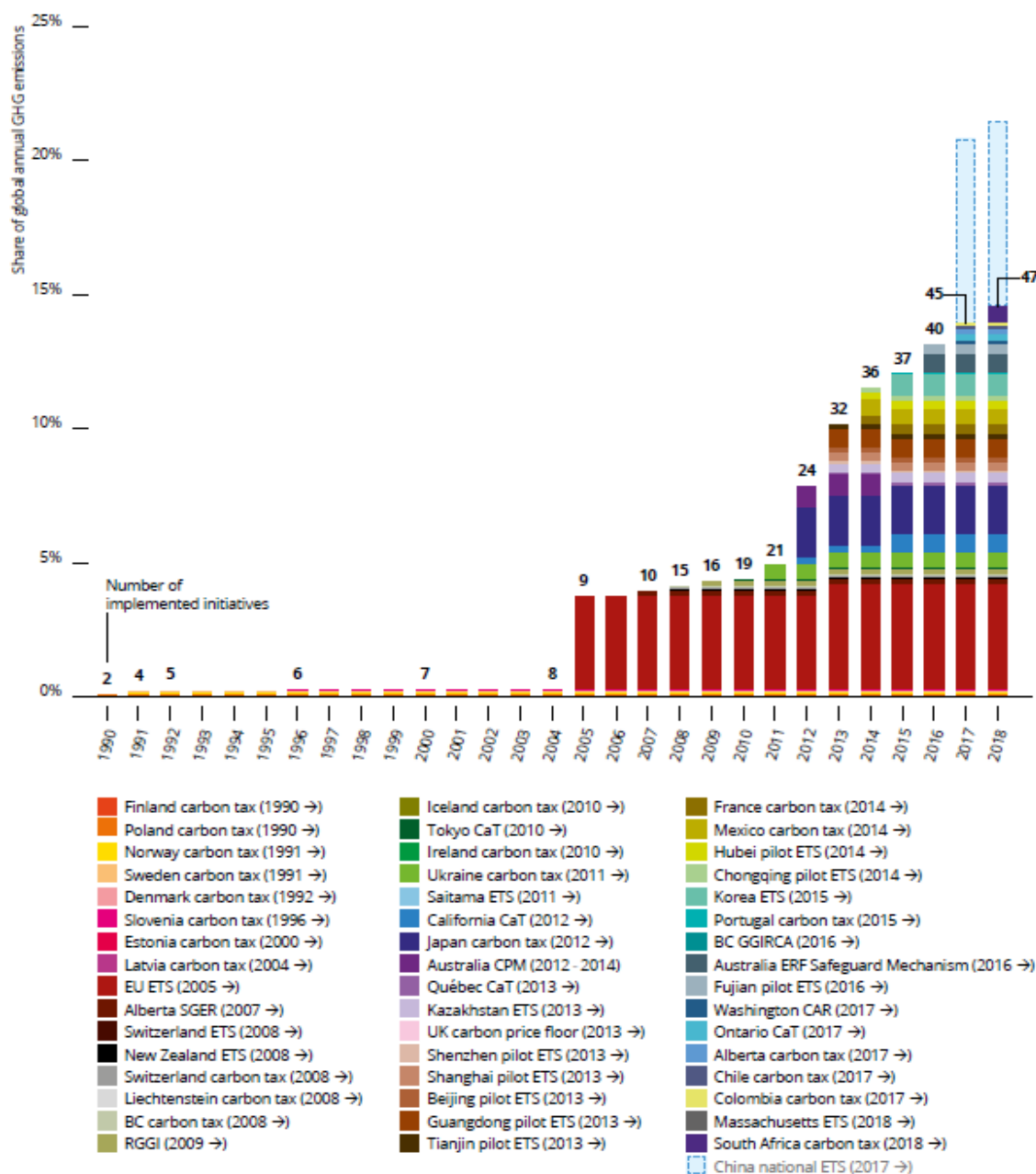


Figure 1-6
World Bank Overview of Status of Regional, National, and Subnational Carbon Pricing Schemes

⁵⁹ Carbon Pricing Watch 2017, An advance brief from the State and Trends of Carbon Pricing 2017 report. World Bank Group.

Carbon pricing developments in 2017 included:

- A carbon tax in Alberta, covering all GHG emissions from combustion that are not covered by its existing carbon pricing initiative for large emitters (e.g., transportation and heating emissions)
- An ETS in Ontario, covering GHG emissions from industry, electricity generators and importers, natural gas distributors, and fuel suppliers (with linkage to the California-Quebec cap-and-trade program in 2018)
- A carbon tax in Chile, which applies to CO₂ emissions from large emitters in the power and industrial sectors
- An economy-wide carbon tax in Colombia on all liquid and gaseous fossil fuels used for combustion
- The Clean Air Rule in Washington, which established a state baseline-and-credit system, initially covering fuel distributors and industrial companies not considered to be energy-intensive or trade-exposed.⁶⁰ A court decision subsequently voided parts of this rule, clarifying that the Washington Department of Ecology has the authority to regulate direct carbon emitters but not suppliers of products.⁶¹

European Union ETS

Launched in 2005, the European Union's Emissions Trading Scheme (EU ETS) is approaching the end of its third phase, spanning 2013 to 2020. The market has a binding target to reduce overall GHG emissions by at least 40% below 1990 levels by 2030. The world's largest carbon emission allowance trading market, the EU ETS covers more than 11,000 regulated sources representing roughly 45% of total GHG emissions in 31 countries (28 EU member states plus Iceland, Liechtenstein, and Norway).

Modifications made to Phase 3 included:

- Institution of a single EU-wide cap in place of the previous system of national caps
- Tightening of limits on the banking of allowances and use of offsets
- Extension of coverage to N₂O and perfluorocarbons
- Extension of coverage to include CCS installations, as well as the production of petrochemicals, ammonia, aluminum/nonferrous metals, gypsum, and nitric, adipic, and glyoxylic acids

Faced with a surplus of over 2 billion allowances in 2013, which was attributed to the recession and high imports of international carbon credits, the European Commission opted to postpone the auctioning of 900 million allowances until 2019–2020 to allow demand to pick up. The creation of a market stability reserve, into which the excess allowances can be transferred, represented a longer-term solution. The reserve will become operational in January 2019.⁶²

⁶⁰ Ibid.

⁶¹ <http://thelens.news/2017/12/19/court-says-ecology-overreached-clean-air-rule/>

⁶² https://ec.europa.eu/clima/policies/ets/reform_en

The corrective measures appear to have an impact: prices have climbed from about €6 per tonne of CO₂ in mid-2017 (about \$7/tonne using a June 2018 exchange rate) to about €15 per tonne (about \$18/tonne) in June 2018.⁶³

Market reforms for the post-2020 period include:

- An annual reduction of 2.2% in the cap on the total volume of emissions
- A temporary doubling of allowances to be placed in the market stability reserve, until the end of 2023
- A new mechanism to limit the validity of allowances in the market stability reserve above a certain level, operational from 2023⁶⁴

United Kingdom

In 2013, the UK government introduced a carbon floor price, which is a tax on fuels used to generate electricity. The floor price consists of the EU ETS carbon price and an added UK-only carbon price support rate. Fuels with higher carbon intensity values face higher price support (tax) rates. In 2014, the UK government froze maximum price support rates at 2015 levels at £18/tonne of CO₂ (about \$22/ton or \$24/tonne at a June 2018 exchange rate) until 2020, which was subsequently extended to 2021.⁶⁵ The freeze was intended to reduce the gap between low EU ETS allowance prices and the prices that would have resulted under a rising UK carbon floor price trajectory as initially conceived. However, even at the £18/tonne rate, the impact on fuel choice for power generation has been significant. The carbon price support coupled with low natural gas prices, policies promoting renewable energy, and the government's announced phase out of coal power by 2025 created a surge in natural gas use while coal power generation declined and now accounts for less than 7% of total electricity supply. In 2017, natural gas generation also declined, while wind and solar set new records.⁶⁶

RGGI

The Regional Greenhouse Gas Initiative (RGGI), the first mandatory GHG market-based program in the United States, was established in 2005. RGGI covers CO₂ emissions from the power sector in Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. New Jersey, which had been an original member but withdrew in 2012, had its new governor direct state agencies to negotiate how to rejoin.⁶⁷ Virginia is taking actions to align its policies with RGGI, with a vision of ultimately joining.⁶⁸ Auction prices had generally increased since December 2012, around the time RGGI announced the intention to reduce CO₂ emissions caps by 45% by 2014. Since the announced cap reduction,

⁶³ <http://markets.businessinsider.com/commodities/co2-emissionsrechte>

⁶⁴ <http://sdg.iisd.org/news/carbon-pricing-and-markets-update-eu-ets-post-2020-reform-adopted/>

⁶⁵ <http://researchbriefings.files.parliament.uk/documents/SN05927/SN05927.pdf>

⁶⁶ <https://www.theguardian.com/business/2018/jan/05/uk-coal-fired-power-plants-close-2025>

⁶⁷ <https://www.utilitydive.com/news/new-jersey-to-rejoin-rggi-in-new-executive-order/515802/>

⁶⁸ <http://ideastations.org/radio/news/public-comment-winds-virginia-proposal-join-regional-greenhouse-gas-initiative>

the auctions have tended to sell all allowances offered.⁶⁹ As shown in Figure 1-7,⁷⁰ RGGI allowance prices began to drop in early 2016 when the U.S. Supreme Court stayed implementation of the Clean Power Plan.

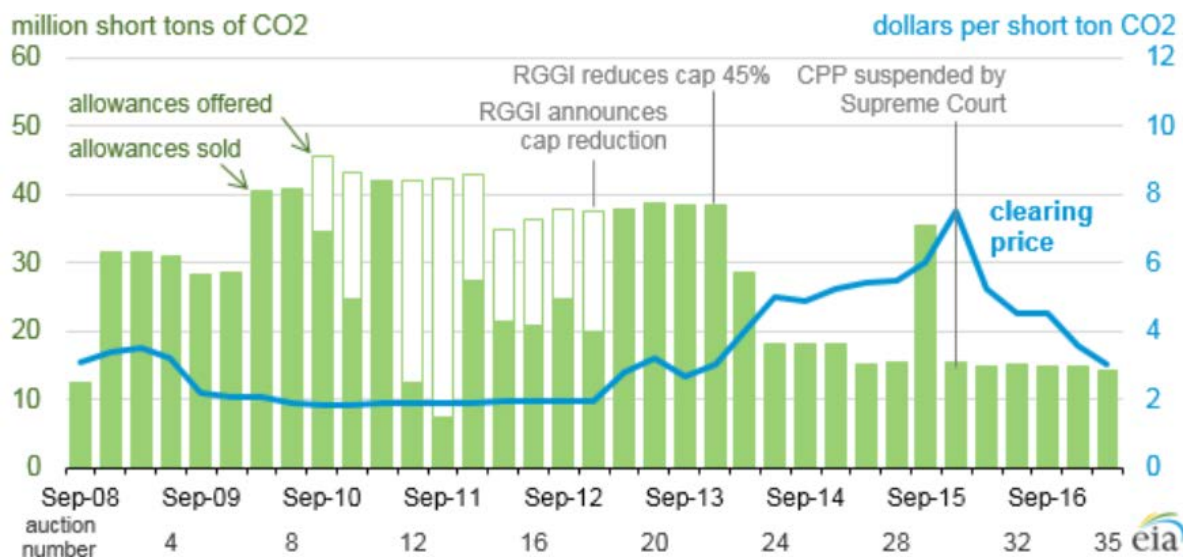


Figure 1-7
RGGI Auction Allowances and Prices

California-Quebec-Ontario

California and Quebec have run joint cap-and-trade emission allowance auctions since 2014. The floor price has risen gradually from \$10/tonne (then CAD\$10.75/tonne) to a May 2018 value of \$14.65/tonne (about CAD\$19/tonne). There is no ceiling price. Ontario joined the market on January 1, 2018, and participated in the February and May auctions, in which all available current-vintage allowances were sold.⁷¹

Canada

Canadian provinces and territories have until September 1, 2018, to propose carbon pricing schemes consistent with the Pan-Canadian Framework on Clean Growth and Climate Change. If provincial plans are not forthcoming or deemed by the federal government not to satisfy the federal standard, a federal pricing plan would go into effect on January 1, 2019 (in lieu of or in addition to the provincial or territorial plan), with a starting price of CAD\$20 per tonne of CO₂ (about \$14/ton or \$16/tonne at a June 2018 exchange rate). For provinces or territories electing a “carbon tax” type approach, as opposed to an emissions trading system, the tax would need to climb by CAD\$10 per year to reach a value of CAD\$50 per tonne of CO₂ by 2022 (about \$35/ton or \$39/tonne at a June 2018 exchange rate).⁷² For provinces instituting a cap-and-trade

⁶⁹ <https://www.rggi.org/auctions/auction-results>

⁷⁰ EIA. “Regional Greenhouse Gas Initiative auction prices are the lowest since 2014.” *Today in Energy*, May 31, 2017.

⁷¹ https://www.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf

⁷² <https://icapcarbonaction.com/fr/news-archive/502-canada-announces-new-timeline-for-federal-carbon-pricing>

type system, the cap on available allowances must be set to yield a result matching or surpassing Canada's national target (i.e., Paris Agreement commitment) to cut GHG emissions by 30% below 2005 levels by 2030. Provinces would also need to ensure that their annual caps for the initial years, through 2022, match the estimated emissions cuts that would be seen under a carbon tax approach. As of year-end 2017, four provinces had CO₂ emissions pricing schemes (two market-based, one tax-based, and one mixed approach) and four other provinces had proposed pricing systems.

China

In December 2017, China launched a national carbon market, although setup is expected to take a couple of years, with actual trading to begin in 2020.⁷³ In its first phase, the market will cover power generation only, but this alone accounts for more than 3.5 gigatonnes of annual CO₂ emissions, making it nearly double the size of the EU ETS.⁷⁴ China already has in place eight pilot CO₂ emissions trading markets, covering 1.3 gigatonnes of CO₂ equivalent.

South Korea

In January 2015, South Korea launched a carbon market covering 525 businesses and institutions, of which 10 large entities are responsible for an estimated 76% of the covered emissions.⁷⁵ The market saw limited liquidity in its first phase (2015–2017), and the central government has taken measures to encourage more trading, including releasing additional allowances from the reserve onto the market through auctions and approving the use of certain international credits for compliance starting from the second phase of the KETS (2018–2020), instead of the third phase (2021–2025). Initially, only international certified emissions reductions (CERs) generated by Korean businesses were eligible for compliance.

Also in the second phase, fewer free allowances will be distributed in 2018 to companies that have banked allowances from the first phase exceeding a certain amount, and the amount of emission allowances that companies can borrow will be gradually reduced again. The second phase will include the start of allowance auctions, with the auction share in 2018 set to be 3%, increasing to at least 10% in 2021.

The price of carbon credits per ton has risen from 16,600 won per tonne in June 2016 to a high of 28,000 won per tonne in November 2017 (about \$24/ton or \$26 per tonne at a June 2018 exchange rate).⁷⁶

CCS Regulatory Development

Some 13 U.S. states have passed CCS legislation covering issues such as site permitting, property rights, long-term stewardship, EOR, and tax incentives.⁷⁷

⁷³ <https://www.vox.com/energy-and-environment/2017/12/22/16804594/china-carbon-trading-system>

⁷⁴ <https://www.forbes.com/sites/energyinnovation/2017/12/19/the-china-carbon-market-just-launched-and-its-the-worlds-largest-heres-how-it-can-succeed/#444a23a77ce6>

⁷⁵ <http://www.ecosystemmarketplace.com/articles/standoff-continues-in-south-korea-s-new-carbon-markets/>

⁷⁶ <http://english.yonhapnews.co.kr/news/2017/11/29/0200000000AEN20171129006100320.html>

⁷⁷ <http://www.ccsreg.org/bills.php>

EPA issued its first Class VI geologic sequestration permits in August 2014 to the FutureGen 2.0 project in Illinois, which was later cancelled. Over a 20-year timeframe, four horizontal wells would have injected approximately 24 million tons (22 million tonnes) of CO₂ into the Mt. Simon Sandstone from a unit retrofit from oil firing to coal oxy-combustion.⁷⁸

In September 2014, EPA issued a Class VI permit to the Archer Daniels Midland (ADM) Illinois Industrial CCS Project (Ill-ICCS). The project intends to inject approximately 1.1 million tons (1.0 million tonnes) of CO₂ per year for five years. The CO₂ is captured at ADM's ethanol plant using Alstom's advanced amine process. Injection operations began in April 2017.⁷⁹

In January 2018, EPA issued an implementation guide to administrators of UIC Class VI programs.⁸⁰ In April 2018, North Dakota became the first state to be granted primacy by EPA for implementing and enforcing its own Class VI UIC program.⁸¹

Power Plant Contracting Strategies

Around the world, fewer fossil power plants are being built, with a greater fraction employing new technology to improve efficiency, reduce emissions, manufacture co-products, or save water. Coal-fired power plants in particular are more complex and have longer development, permitting, and construction times. Financing is often more complex as well. These factors translate to higher risk. In response, new approaches for contracting major projects are emerging.

In the traditional approach, the lender and owner require an EPC contractor to minimize risk exposure and provide a predictable outcome covered by performance guarantees. The contractor utilizes its experience and applies reasonable values for the cost and lead time for equipment, bulk material quantities, craft labor hours and productivity factors, risk money and contingencies, escalation, and fee.

EPC contractors are either no longer providing lump-sum-turnkey contracts, or pricing them at a high premium, especially for advanced coal power plants. [EPC contracts for NGCC and reciprocating engine power plants are more likely to be available under traditional terms.]

In the wake of 2008's boom-bust cycle in oil prices, a modified EPC approach has emerged in which the project participants share risks. Before the risks are allocated to the appropriate party, a comprehensive risk assessment is performed collaboratively. All major risks are identified and the impacts on the project are quantified, along with proposals for how risks can be minimized, avoided, or mitigated. The project participants work as a team to address the lack of predictability. Each party (e.g., owner, lender, EPC contractor, or major equipment supplier) assumes the risk for areas over which they have control. A risk sharing approach may include the following steps:

- Develop proper front-end engineering design – this critical package will help quantify unknowns and can be used as the basis for producing a solid cost estimate

⁷⁸ <https://www.bna.com/doe-suspends-billion-n17179922773/>

⁷⁹ <https://www.energy.gov/fe/articles/doe-announces-major-milestone-reached-illinois-industrial-ccs-project>

⁸⁰ https://www.epa.gov/sites/production/files/2018-01/documents/implementation_manual_508_010318.pdf

⁸¹ <https://www.usnews.com/news/best-states/north-dakota/articles/2017-05-09/epa-signs-off-on-north-dakota-regulation-of-co2-wells>

- Assign performance guarantees – the major suppliers will provide the guarantees
- Obtain early commitments for major equipment to help mitigate schedule delays
- Negotiate with bulk suppliers (fix unit costs with indexing) – this will help mitigate commodity price increases
- Negotiate project labor agreements – this will help mitigate construction cost overruns

Understanding Cost Differences between Technology Assessment Studies and Commercial Projects

The actual costs for U.S. coal-based power plants recently completed or under construction have been considerably higher than the engineering-economic cost estimates of similar plants by EPRI, DOE, and others. In some cases, the actual costs have also been much higher than initial estimates by the project developers, leading to adverse publicity and regulatory rulings precluding full cost recovery through rates. A closer examination finds these situations to be more complex than news reports. Systematic attempts by EPRI and others to reconcile cost differences have found considerable discrepancies in “system boundaries” and different approaches to handling such cost elements. Areas of significant uncertainty include:

- Escalation
- First-of-a-kind technology premiums (e.g., second-generation IGCC, comprehensive boiler repowering, integration of CO₂ capture and compression)
- Site-specific conditions (e.g., access for fuel, reagents, product sales, transmission lines, etc.)
- Project-specific conditions (e.g., owner’s costs, cost of financing)
- Regional differences in labor and material costs
- Varying definitions of total plant cost, total resource cost, allowance for funds used during construction, etc.

For similar reasons, it can sometimes be difficult to compare cost estimates between engineering-economic studies by different organizations.

Levelized Cost Metrics for Power Plants with CO₂ Capture and Storage

Engineering-economic studies aim to estimate the cost of CO₂ capture and storage for various types of fossil power plants by comparing the life-cycle cost of plants with capture to “base case” plants without capture. Results are typically expressed as the difference in the levelized cost of electricity (\$/MWh) or as a levelized cost divided by the tons of CO₂ not emitted (\$/ton-CO₂). Although the latter metric seems straight-forward, analysis by EPRI and an international task force (including IEA, DOE, GCCSI, Carnegie-Mellon, and Vattenfall) found that differences in conventions for nomenclature and cost accounting can lead to significant differences in results.⁸²

The simplest distinction involves the system boundary. The “cost of CO₂ captured” often looks only within the plant battery limit, and thus would include the costs of CO₂ capture and compression, but not the cost of CO₂ transportation and storage. However, some studies where

⁸² *Toward a Common Method of Cost Estimation for CO₂ Capture and Storage at Fossil Fuel Power Plants: A White Paper*, EPRI. 3002000176, March 2013.

CO₂ is sold for EOR will include the cost of pipeline transportation to the oilfield. This metric is most often used to assess the economics of providing CO₂ for sale as an industrial commodity (e.g., for food and beverage industry or for enhanced oil recovery). The equation for the cost of CO₂ captured is:

$$\text{Cost of CO}_2 \text{ Captured (\$/tCO}_2\text{)} = (\text{COE})_{\text{cc}} - (\text{COE})_{\text{ref}} / (\text{tCO}_2/\text{MWh})_{\text{captured}}$$

where $(\text{tCO}_2/\text{MWh})_{\text{captured}}$ = total mass of CO₂ captured per net MWh for the plant with capture (equal to CO₂ produced minus emitted), and COE is the cost of electricity; the reference plant is the same type as the capture plant, and the COE with capture, $(\text{COE})_{\text{cc}}$, excludes the costs of CO₂ transport and storage.⁸³

Alternatively, the “cost of CO₂ avoided” includes the full-chain cost of keeping CO₂ away from the atmosphere and accounts for the cost of CO₂ transportation, injection into a storage reservoir, periodic well integrity testing, and subsurface monitoring. This metric is the appropriate measure for determining the true cost of greenhouse gas mitigation and for comparing the cost of building and operating fossil power plants with CCS against the cost of building and operating fossil plants without CCS and paying a carbon tax. The equation for the cost of CO₂ avoided is:

$$\text{Cost of CO}_2 \text{ Avoided (\$/tCO}_2\text{)} = (\text{COE})_{\text{ccs}} - (\text{COE})_{\text{ref}} / (\text{tCO}_2/\text{MWh})_{\text{ref}} - (\text{tCO}_2/\text{MWh})_{\text{ccs}}$$

where COE = cost of electricity generation (\$/MWh), tCO₂/MWh = CO₂ mass emission rate to the atmosphere in tons per MWh (based on the net capacity of each power plant), and the subscripts “ccs” and “ref” refer to plants with and without CCS, respectively; most commonly, the reference plant is assumed to be one that is identical or similar to the plant with CCS.⁸⁴

Comparisons for adding CCS to power plant technologies with significantly different capital cost vs. operating cost structures (e.g., IGCC or PC vs. NGCC) will be very dependent on assumptions for capacity factor, financing parameters, and the discount rate.

The international task force recognized that some of the details and assumptions required for a CCS cost estimate cannot be standardized. Thus, a clear and full reporting of all major assumptions is a critical step in transparent CCS costing, especially for project scope definition and design parameters, financial and economic parameters, methods of quantifying various cost elements, and reference cases when calculating overall cost values such as the increased cost of electricity and the cost of CO₂ avoided. The task force developed “checklists” of recommended information that should be conveyed in technical reports, journal articles, and conference presentations.⁸⁵

Alternative Cost Metrics: System LCOE and Energy-Economy Modeling

As a technology selection guide, EPRI, IEA, and Australia’s National Electricity Market have begun evaluating proposed power plant projects in terms of their systemwide value rather than

⁸³ Edward Rubin, “Understanding the pitfalls of CCS cost estimates,” *International Journal of Greenhouse Gas Control*, Vol. 10, p.181–190, 2012.

⁸⁴ Ibid.

⁸⁵ *Toward a Common Method of Cost Estimation for CO₂ Capture and Storage at Fossil Fuel Power Plants: A White Paper*, EPRI. 3002000176, March 2013.

just their traditional LCOE values. Success in such an approach requires considerably more modeling to look at the impact of different plant types in specific grid systems or regions and, in some cases, the underlying regional economies.

System LCOE models aim to calculate the economic impact that the proposed power plant would have on the existing load and generating resources. The change in system costs can be assigned to the incremental generating unit as an integration cost in order to compare options of different sizes and operating profiles. The cost of a power plant project becomes the sum of its LCOE and its impact on the electrical system in which it will operate.

For the United States, EPRI uses its US-REGEN energy-economy model to look at the potential reduction in total system cost that results from integration of a given power generation technology.⁸⁶

EPRI and others have undertaken to identify more comprehensive economic metrics for power plants that address some of the following limitations of traditional LCOE economics:

- **Technology Category:** The operating characteristics of distinct technologies, such as dispatchability, variable O&M, and output profile drastically affect a power plant's value. For example, a plant with low operating costs may produce energy in a baseload mode, which includes many periods with low values of energy and capacity as well as high-value periods. Another technology may operate fewer hours, albeit at higher cost, but flexibly during periods of high energy and capacity value. Even generating technologies of the same type may have characteristics that are distinctive enough to make LCOE comparisons less meaningful.
- **Resource Mix:** In general, the value of a power plant type declines as its systemwide penetration increases. For dispatchable resources, the frequency that the incremental resource is needed will decline. Increases in the penetration of variable energy resources shift the timing of the net load peak. This is especially pronounced in areas with high rates of solar photovoltaic (PV) penetration. In regions with projected net load peaks occurring after 6:00 p.m., PV doesn't provide much capacity value. The underlying conventional resources can also affect value. Renewable technologies will have different value profiles in regions with predominantly inflexible baseload fleets compared with regions with fast-ramping or cycling-capable fleets.
- **Installed Reserve Margin:** Regions with similar percentages of power plant types can have different market cost profiles due to the level of installed reserves. For example, in a region with low reserves, incremental renewables will offset high-cost peaking resources more often than in a region with high reserves. This can also affect the mix of energy and capacity value offered by an incremental generating unit.

Integration Costs: Intermittent renewables often trigger a shift in the operational practices of fossil power units, including increasing planned ancillary services to accommodate the variability and volatility of their intermittent generation. In addition, the uncertainty of the output of renewables plants can result in significant deviations from expected net load and associated inefficient commitment and dispatch. Ramping units up and down to match volatile net load

⁸⁶ <https://www.epri.com/#/pages/product/3002010956/?lang=en>

profiles also adds to costs. In system analyses, these costs should accrue to the incremental renewable energy resource but are not captured in LCOE calculations.

2

COMPARISON STUDIES ACROSS GENERATING TECHNOLOGIES

EPRI assesses the cost competitiveness of advanced fossil power plants, without and with CO₂ capture, by reviewing results from broad-based engineering-economic studies by industry, government, and non-governmental research organizations around the world.

EPRI Engineering-Economic Evaluations of Fossil Plants, Without and With CO₂ Capture

In 2018, EPRI updated the average value and range of LCOE estimates from earlier EPRI studies of fossil fuel generation options, without and with CCS. The “Integrated Generation Technology Options” report⁸⁷ provides an executive-level overview of current (2016) and longer-term (2025) electricity generation technology costs and performance.

Cost estimates reported in terms of the total capital requirement (TCR) are based on overnight capital or “all-in” costs and include:

- Total plant cost (TPC) – all process and support facilities, fuel handling and storage; water intake structures and wastewater treatment; offices, maintenance shops, and warehouses; step-up transformer
- Owner’s costs – startup costs, working capital, land, license fees
- Interest during construction – interest expenses accumulated during power plant construction

TCR does not include production tax credits, investment tax credits, loan guarantees, or other incentive programs. LCOE is based on a constant-dollar (December 2016) basis, and no inflation/escalation for fuel, capital cost, and O&M is assumed. For the results shown in Table 2-1 and Table 2-2, the following assumptions were made:

- Generic U.S. location
- 80% capacity factor
- 30-year book life
- No site-specific assumptions
- Mercury, SO_x/H₂S, NO_x, and PM removal are included for PC and IGCC technologies; NO_x removal is included for NGCC technology
- All technologies use a closed-cycle wet cooling tower
- Construction with and without CCS is 4 years for PC and IGCC plants, 3 years for NGCC plants
- For options with CCS, the LCOE value includes a CO₂ transportation and storage cost of \$9/ton (\$10/tonne)

⁸⁷ *Program on Technology Innovation: Integrated Generation Technology Options 2017*. EPRI, Palo Alto, CA: 2018. 3002011806.

- Cost ranges represent potential plant configurations and equipment types; mature technologies are assumed
- For 2025 results, it is assumed that established R&D objectives are achieved and technology development is successful. Estimated cost reductions are based on an assessment of potential technology improvements.

Table 2-1
EPRI Representative Cost and Performance of Fossil Fuel Generation Options (2016 Technology)

Technology	Nominal Plant Capacity (MW)	Net HHV Heat Rate, Btu/kWh	CO ₂ Emissions, lb/MWh (net)	TPC, \$/kW	TCR, \$/kW	Fixed O&M, \$/kW-yr	Variable O&M, \$/MWh	Fuel Price, \$/MBtu	LCOE, \$/MWh
PC	800	8900	1870	2,500–3,200	2,900–3,740	54	3	2–3	60–78
IGCC	600	8900	1870	3,300–4,100	4,000–4,900	76	4	2–3	73–93
NGCC	720	6600	770	1,000–1,230	1,160–1,440	15–17	2–3	3–6	37–60

For heat rates in kJ/kWh, multiply the Btu/kWh values by 1.055. For emissions rates in kg/MWh, multiply the lb/MWh values by 0.4536.

Table 2-2
EPRI Representative Cost and Performance of Fossil Fuel Generation Options (2025 Technology)

Technology	Nominal Plant Capacity (MW)	Net HHV Heat Rate, Btu/kWh	CO ₂ Emissions, lb/MWh (net)	TPC, \$/kW	TCR, \$/kW	Fixed O&M, \$/kW-yr	Variable O&M, \$/MWh	Fuel Price, \$/MBtu	LCOE, \$/MWh
PC with CCS	500	9840–12,450	200–260	3,700–4,500	4,300–5,300	95	6	2–3	92–124
IGCC with CCS	500	9100–11,400	200–330	4,500–5,500	5,400–6,600	104	6.3	2–3	101–132
NGCC	1100	6100	710	1,090–1,340	1,270–1,570	15–17	2–3	3–6	36–59
NGCC with CCS	970	7500	90	1,800–2,300	2,100–2,680	27	3–5	3–6	55–87

For heat rates in kJ/kWh, multiply the Btu/kWh values by 1.055. For emissions rates in kg/MWh, multiply the lb/MWh values by 0.4536.

In 2018, EPRI also published a study⁸⁸ valuing enhanced flexibility in fossil fuel power plants through lower minimum load levels. Understanding the limits, value, and wear-and-tear impacts of flexible operations provide key economic inputs to generation system and fossil power plant operators as they plan dispatch schedules to meet grid needs and participate in ancillary service markets. Units that historically operated in baseload or near-baseload modes are now being used in flexible operating modes that entail greater cycling, lower utilization, and increasing relative costs of generation (especially as fixed costs are spread across fewer MWh of output).

The study modeled the economic value of lowering a unit's turndown limit for asset owners/operators across different regions, generation asset types, and market environments (e.g., level of renewable deployment). Five scenarios were developed:

1. Reference: Assumes on-the-books state and federal policies and incentives only.
2. Tax: Assumes a \$16/ton CO₂ tax in 2035, a situation roughly comparable to forecasts under the Obama administration's proposed Clean Power Plan.
3. 50% RPS (Wind): Assumes that half of in-region demand must be met with either onshore or offshore wind generation technologies.
4. 50% RPS (Solar): Assumes that half of in-region demand must be met with solar generation technologies.
5. 50% RPS (Both): Assumes that half of in-region demand must be met with even shares of wind and solar generation technologies.

For each region and scenario, the analysis examined changes in operations and revenues for three asset types: existing coal units, new NGCC units, and existing NGCC units. Parametric sensitivities for minimum loads and startup costs were conducted.

Figure 2-1 shows the "reference" policy conditions for 2035. Regional grid sizes and compositions vary significantly, showing, for example, the economic competitiveness of wind in Texas and Mountain-North even without policy support.

⁸⁸ *Economic Value of Increased Operational Flexibility for Fossil-Fired Generation Assets*. EPRI, Palo Alto, CA: 2018. 3002013735.

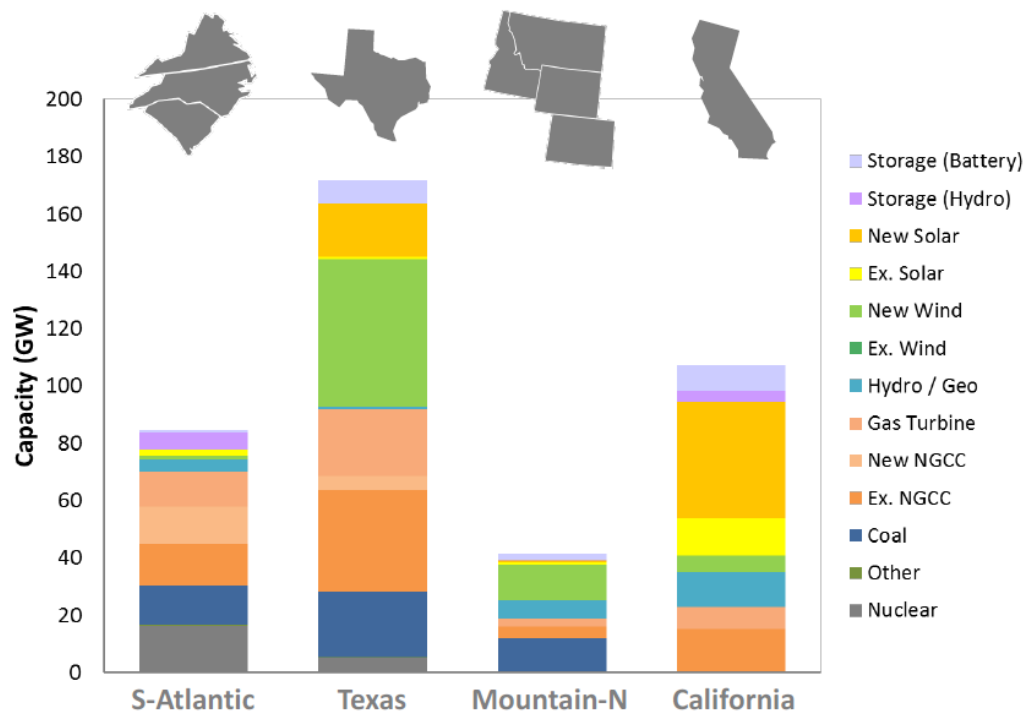


Figure 2-1
Capacity by Technology under Reference Policy Conditions in Four U.S. Regions in 2035

Figure 2-2 indicates that lower minimum load capability can alter net revenues even for units in grids without significant variable renewable penetration. Lower turndown levels are most valuable (on average) under a CO₂ tax scenario, especially as more coal units switch to mid-merit dispatch (as shown in Figure 2-3). Depending on greenhouse gas policy stringency and timing, carbon pricing alters retirement and dispatch decisions for power generators. The \$16/ton-CO₂ tax scenario is not high enough to induce retirements for many coal power plants, but the tax increases dispatch costs and consequently increases the frequency of cycling and hours with negative operating margins, which significantly increases the value of being able to turn down to lower minimum loads. Net profitability impacts are similar across the three 50% RPS scenarios, and higher renewables deployment induces seasonal layups (especially during spring and fall with lower load and higher renewable output), which lowers the value of flexibility.

The relative value of better turndown capability depends on changes in net revenues compared with baseline net revenues when the unit has a higher minimum load. Although operational changes are more significant in absolute terms, differences in net revenues are small in relative terms for many units but may be more significant for lower-profitability assets that are struggling to cover fixed costs. Under scenarios where lower minimum load capability alters dispatch, net revenues generally do not change much because the difference in revenues is largely offset by cost changes. Additionally, startup costs represent a small fraction of total operating costs for many units, meaning that avoiding these events through better turndown capability may not markedly change profitability.

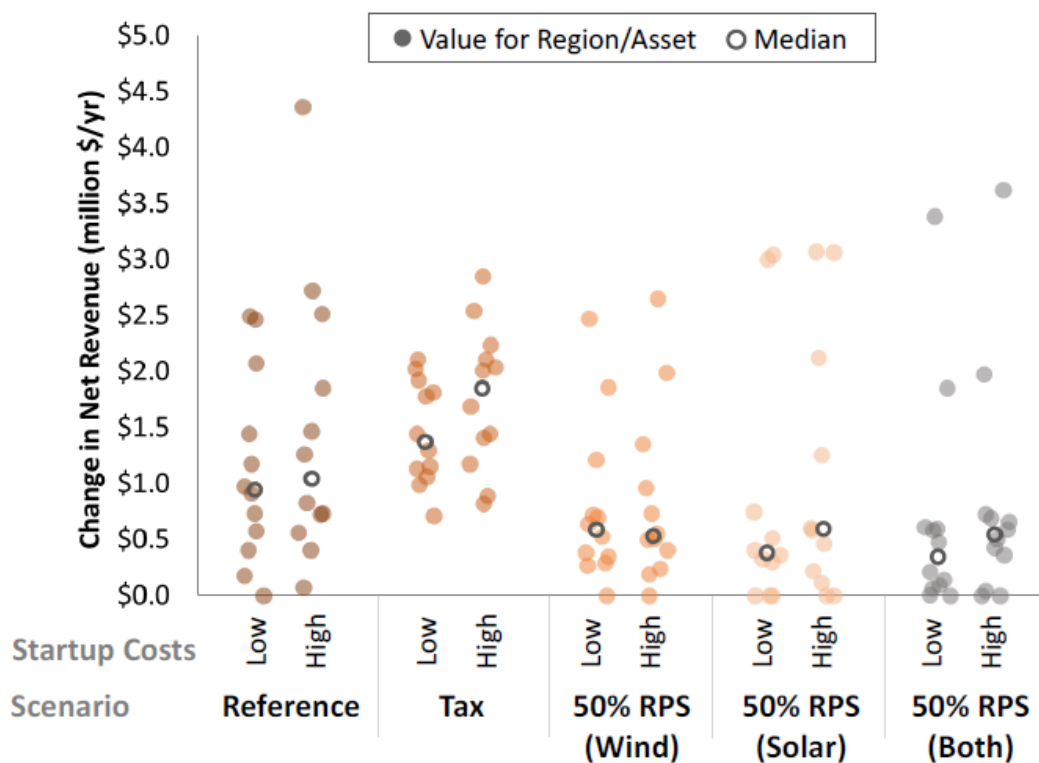


Figure 2-2
Changes in Net Revenue with Lower Minimum Loads for Different Market Environments and Startup Cost Profiles (horizontal axis) for Specific Regions and Plants (dots)

Figure 2-3 shows changes in net revenue for three plant types: existing coal, new NGCC, and existing NGCC. Lower minimum load capability is more valuable for new NGCC units than for existing NGCC units because new NGCC units have lower heat rates (i.e., higher efficiencies and lower short-run marginal costs) and are ranked closer to mid-merit for the regions and scenarios examined. Capacity factors are lower for existing NGCC units due to their higher dispatch costs. Wider coal variation reflects different dispatch patterns across regions and different fleet capacity mixes, resources, policies, and transmission constraints. As noted, changes in net revenue attributable to lower minimum load capability are often higher in regions without seasonal layups.

Figure 2-2 and Figure 2-3 show that the capability to run at lower minimum loads typically is more valuable when startup costs are high, but only by a modest amount. Higher startup costs have countervailing effects when minimum generation is lower. On one hand, when a unit is already online, it may spend more hours at these minimum generation levels to avoid costly startups. On the other hand, when a unit is offline, the higher opportunity cost of commitment may prevent startups.

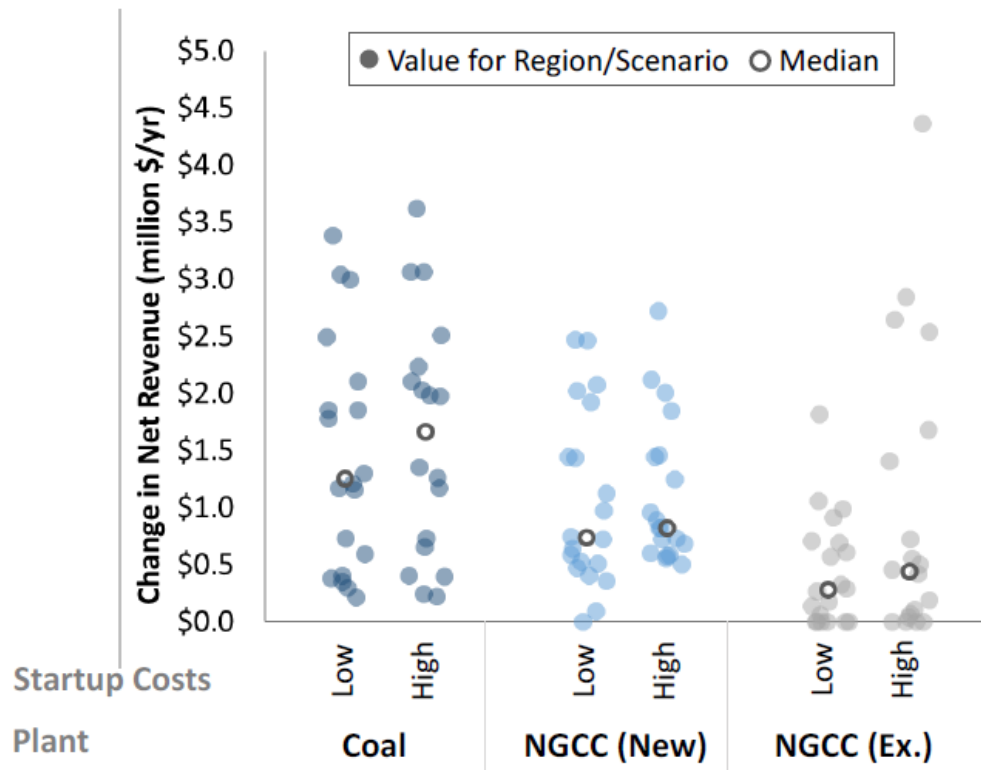


Figure 2-3
Changes in Net Revenue with Lower Minimum Loads for Different Plant Types and Startup Cost Profiles (horizontal axis) for Specific Regions and Scenarios (dots)

The study results suggest that lower minimum load capability is most valuable when policies rearrange the merit order, mid-merit units are considered, regions/scenarios do not force seasonal layup, and units are more flexible than other comparable generators. If a majority of similar units in a region can improve their turndown capability, the value of flexibility would be less for any single unit.

EPRI has also examined the potential for flexibility in coal plants with CO₂ capture. A 2010 study found that CO₂ capture and compression equipment capable of flexible operation can yield added revenue through participation in ancillary services markets.⁸⁹ EPRI examined plant outputs and operating modes in the context of varying power market conditions—for real power and for reserve and regulation services. These approaches were applied to new IGCC and PC units as well as to PC plants with CCS retrofits, assuming the plants were designed with the option to boost output during favorable market conditions by bypassing CCS and venting CO₂ to the atmosphere. Because CO₂ is not vented unless reserves are called, the average CO₂ intensity remained below that of NGCC plants. To facilitate operating flexibility, EPRI recommends the following design approaches:⁹⁰

⁸⁹ *Valuing the Flexibility of Providing System Services for Coal Plants with Carbon Capture Capability*. EPRI, Palo Alto, CA: December 2010. 1021203.

⁹⁰ *Valuing Operating Flexibility in Advanced Coal Plants*. EPRI, Palo Alto, CA: 2009. 1017498.

- Provision of multiple parallel components that perform the same operation, providing reliability and turndown capability
- Shutting down CO₂ capture systems during peak demand periods
- Over-sizing processing components and storing intermediate “products” from/for off-peak processing (e.g., liquid O₂, liquid N₂, or CO₂-lean/rich/lean sorbent)

Over the last decade, EPRI has worked with engineering contractors and technology suppliers to improve the scope and sophistication of its engineering-economic evaluations of fossil power generation technologies and CO₂ capture and compression systems. These studies, described in subsequent chapters of this report, have examined scenarios for a variety of IGCC, PC, CFB, oxy-combustion, and NGCC plant configurations, without and with CO₂ capture at varying levels, installed as new-build construction or retrofit.

IEAGHG Studies

A 2018 study by the International Energy Agency’s Greenhouse Gas Programme (IEAGHG) examined the impact of location-specific factors on the cost of CO₂ capture for SCPC and NGCC power plants in various countries: Brazil, Canada, Chile, China, Egypt, India, Indonesia, Japan, Poland, South Africa, and the United States (Wisconsin and Wyoming).⁹¹ Table 2-5 lists the design parameters that were considered. In total, 19 case studies for SCPC plants in 11 countries and 17 case studies for NGCC plants in 12 countries were developed.

The costs of plants in each location were estimated using country-specific economic parameters, including equipment and materials costs and construction labor productivity and costs. For the NGCC cases, the cost of vendor packages (e.g., the gas turbine) were sourced from the international market and no material costs were applied to this equipment. The project contingency for most locations was 10%, but in some locales it was adjusted to account for potential execution risks: 15% for India, China, and Southeast Asia; 20% for South America and the Middle East.

A nominal 90% CO₂ capture rate using the Shell Cansolv process was assumed for both the SCPC and NGCC cases with CCS. The SCPC plants had steam conditions of 3915 psi/1112°F/1148°F (27 MPa/600°C/620°C). Net power output without CO₂ capture was about 1000 MW for the reference plant in the Netherlands. Plant thermal capacity (LHV basis) was kept constant for all of the case studies. The SCPC plants with CO₂ capture were based on boilers with the same thermal capacity as the related cases without CCS. Alstom wet limestone scrubbing was used for FGD.

The NGCC plant capacity, both with and without CCS, was selected to fully load two heavy-frame H-class gas turbines and one steam turbine.

⁹¹ IEAGHG. *Effects of Plant Location on the Costs of CO₂ Capture*, 2018-04, April 2018.

Table 2-3
Design Parameters Affected by Plant Location

	Design Parameter	Impact on Plant Design
Coal Analysis	• Moisture content • Sulfur content • Ash content • Heating value • Specific carbon content (kg of C/GJ)	Boiler Case • Coal flowrate, feedstock handling, and storage capacity • Combustion efficiency decreases with moisture, ash, and sulfur content, and from subbituminous coal to anthracite • Ash handling capacity and amount of solids to be disposed of • Capacity and performance of flue gas treatment units, i.e., capture unit and de-SO_x
Ambient Conditions	• Ambient air temperature • Ambient pressure/site elevation • Ambient air humidity • Sea water temperature	• Gas turbine performance and downstream system capacity (NGCC) • Cooling system temperature level, in particular condensing conditions • Flue gas temperature profile, including decarbonized gas temperature (and water content) and CO₂ delivery conditions
	• Access to raw water/ sea water	• Cooling system type: mechanical or natural draft cooling tower, dry air cooling, once-through sea water cooling • Liquid waste handling and wastewater treatment design • Cooling tower make-up: sweet or sea water • Condenser type
County/Site Location	• Local regulation/emissions targets	Boiler Case • De-SO_x and de-NO_x design performance, limestone handling facilities capacity • Consumption of limestone and ammonia and related operating costs
	• Grid frequency (50 Hz/60 Hz)	NGCC Case • Gas turbine type and capacity

The study yielded the following results and observations:

- Net base plant efficiency ranges and the penalties for adding CO₂ capture:
 - For the SCPC cases without capture, LHV efficiencies ranged from 41.1% to 44.5%; with capture, the range dropped to 31.9% to 35.4%. Thus, the efficiency penalties for adding CCS to the SCPC plants were 8.7 to 9.9 percentage points. The highest penalties were for locations where coals had high carbon content or where ambient conditions led to a high cooling temperature.
 - For the NGCC cases without capture, LHV efficiencies ranged from 59.4% to 61.7%, and with capture, the efficiencies ranged from 52.6% to 54.6%. Thus, the efficiency penalties

for adding CCS to the NGCC plants were 6.5 to 7.3 percentage points. The highest penalties were associated with locations having the lowest condenser operating temperatures.

Major conclusions on the impacts on plant designs included:

- For SCPC cases, coal type significantly affected the capacity of a unit and its physical footprint, particularly the solid handling and storage systems. Fuel carbon content and moisture content are the main parameters affecting the boiler and flue gas treatment system design (including the CO₂ capture unit) in terms of capacity, combustion efficiency, and auxiliary power consumption. Where low-rank coals were used, additional drying units and modifications of boiler were considered in the design.
- For NGCC cases, the grid frequency (50 Hz or 60 Hz) significantly affected the plant capacity and performance because each system frequency uses a different set of gas turbines. Unit output and efficiency, as well as the flue gas flow rate and temperature, depend on location-specific ambient conditions.
- Different emission limits in the various locations define the performance required of the FGD and NO_x control systems for the SCPC cases, and the consumption rate and cost of limestone and ammonia. For the NGCC cases, emissions mainly depend on the gas turbine performance, which was the same for all cases, regardless of location.
- The cooling system type impacts the selection of steam turbine condenser design and operating conditions.
- The design of the wastewater treatment system is affected by the cooling system type as well as access to raw water or seawater. In general, for the cases with cooling towers, recovered water is recycled back to the cooling tower basin. If other cooling media are selected, different approaches may be considered. For the seawater-cooled cases, water can be recovered or discharged after treatment, depending on the demand for and access to raw water. In locations where air cooling is required, water recovery is maximized to reduce the need for raw water makeup, with a “zero water discharge,” design for wastewater treatment. In a plant with CO₂ capture, part of the water in the flue gas is condensed in the capture units, potentially allowing achievement of “zero water intake” without modification to the wastewater treatment design.

TPC cost results for SCPC plants with CO₂ capture are shown in Figure 2-4; results for NGCC plants are shown in Figure 2-5 for NGCC. Observations include:

- The addition of post-combustion CO₂ capture on either an SCPC or NGCC plant increased total plant costs by 90–110%.
- The TPC of SCPC plants varied between €1.34 billion and €1.62 billion for plants without CO₂ capture and between €2.0 billion and €2.5 billion for plants with capture, suggesting that the impact of the various design differences accounts for about 20% of the difference in total capital cost among the locations. The most significant variations were for cooling system modifications, solids handling and storage, and flue gas desulfurization, due largely to the variability in coal ash, moisture, and sulfur content.
- The specific plant costs show a wider range of variation: from €1,280/kW to €1,620/kW for SCPC plants without capture and from €2,430/kW to €3,140/kW for plants with capture, corresponding to a 25% variation related to design changes.

- For NGCC plants, the grid frequency and consequently the gas turbine size have a major impact on the overall plant capacity, with NGCC plants located in 60 Hz grids being roughly 35–40% smaller than plants located in 50 Hz grids.
- The TPC of NGCC plants at locations in 50 Hz grids ranged from €655 million to €810 million for plants without CO₂ capture and from €1,160 million to €1.45 billion for plants with capture.
- The TPC of NGCC plants at locations in 60 Hz grids ranged from €490 million to €565 million for plants without CO₂ capture and from €890 million to €1.2 billion for plants with capture.
- For both SCPC and NGCC plants, the selection of different design bases accounted for about 10–15% of the difference in TPC.
- The specific plant costs for NGCC plants varied from €600/kW to €750/kW for plants without capture and from €1,200/kW to €1,560/kW for plants with capture, corresponding to a 25% variation related to design change modifications (including changes due to differences in grid frequency).

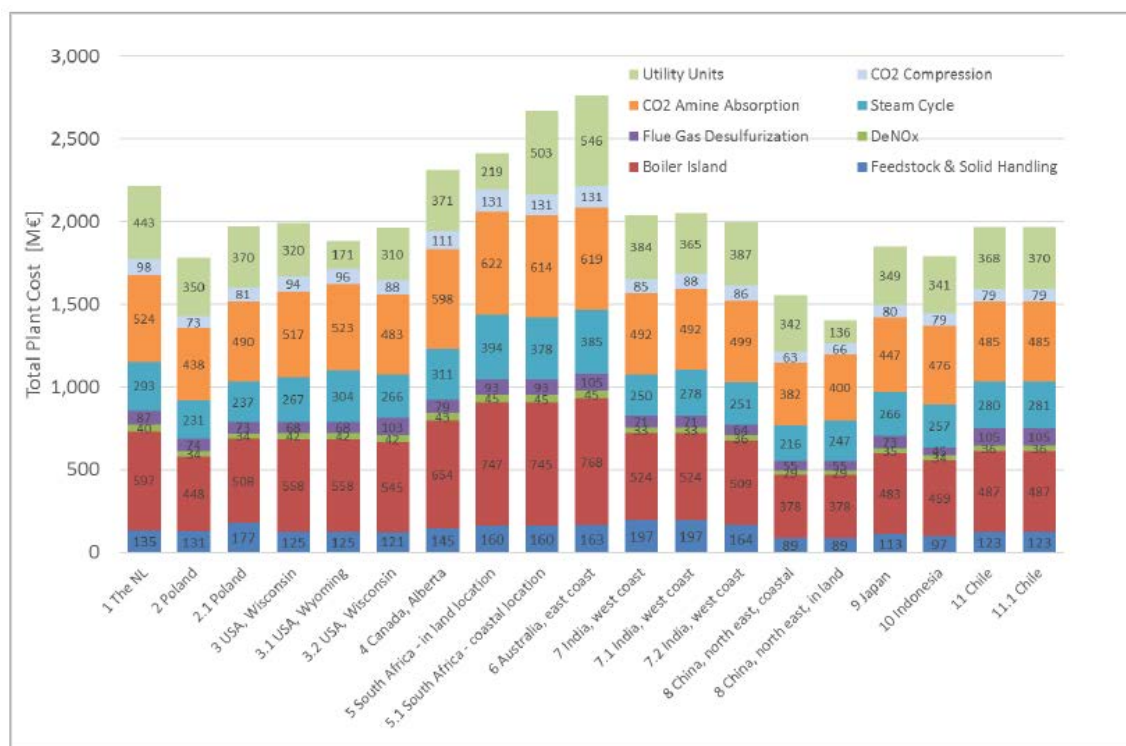


Figure 2-4
IEAGHG Total Plant Costs for SCPC Cases with CO₂ Capture

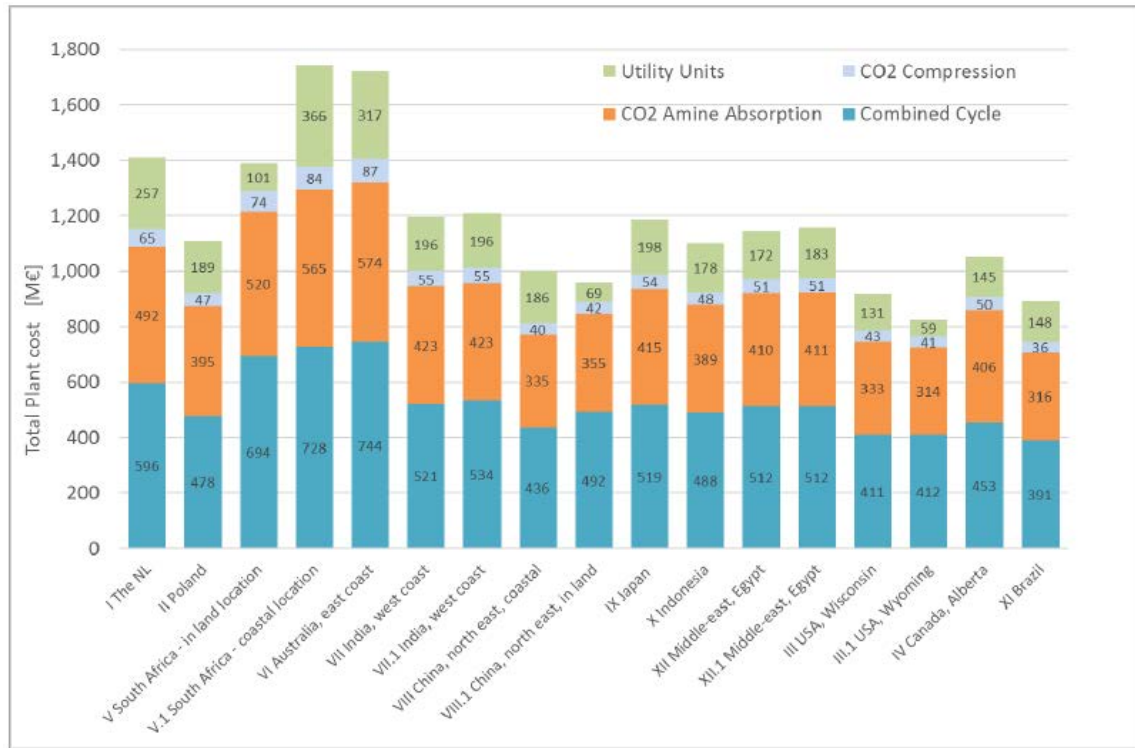


Figure 2-5
IEAGHG Total Plant Costs for NGCC Cases with CO₂ Capture

Figure 2-6 illustrates the cost impact of various cooling systems on SCPC plants, where air cooling presents the lowest cost option (but also the lowest plant efficiency). A similar impact was seen in NGCC plants). Figure 2-7 illustrates the impact of coal type on the boiler island, including flue gas treatment and solids handling facilities (blue-dashed line is for high-moisture subbituminous coal and lignite and red-dashed line is for high ash coal). The sulfur content of coal types also significantly affects TPC due to the requirement for flue gas treatment.

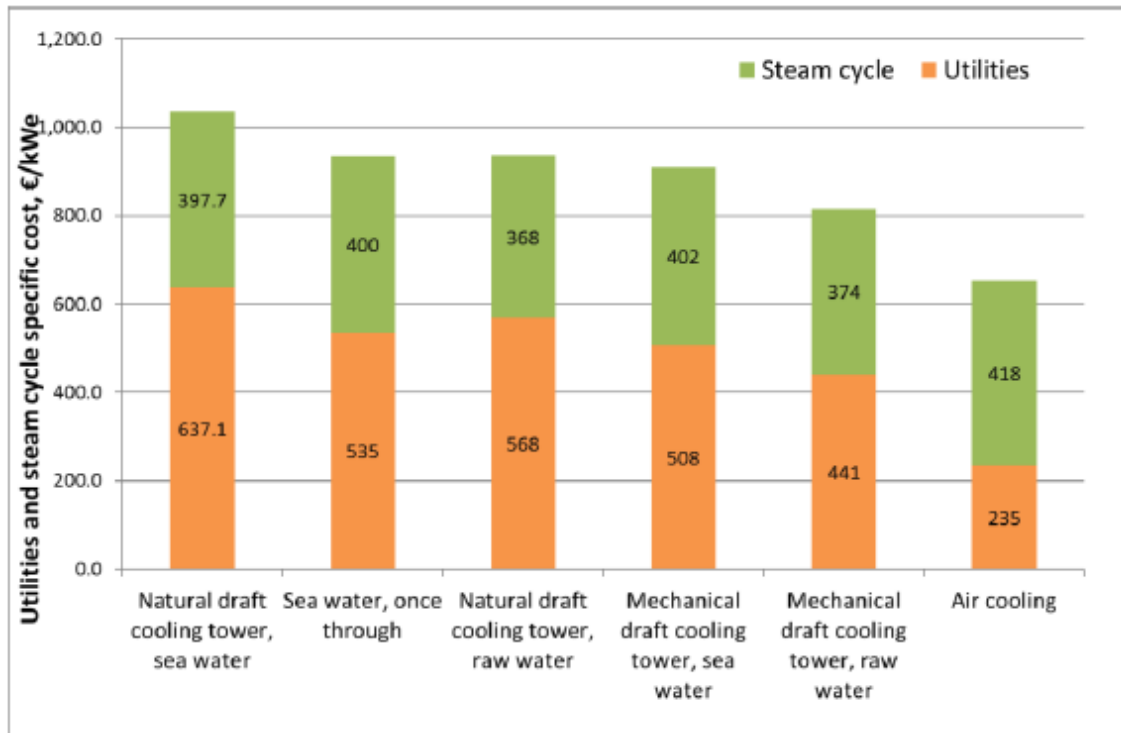


Figure 2-6
IEAGHG Utilities and Steam Cycle Costs for SCPC Plants with CCS

Figure 2-7 illustrates how the cost of the boiler island, including flue gas treatment and solids handling facilities, is dependent on the carbon content of the coal. Generally, higher carbon content lowers the cost. However, the impacts of high moisture (blue dashed line) or high ash (red dashed line) also exert an influence. Higher sulfur content adds to the capital cost of the FGD system.

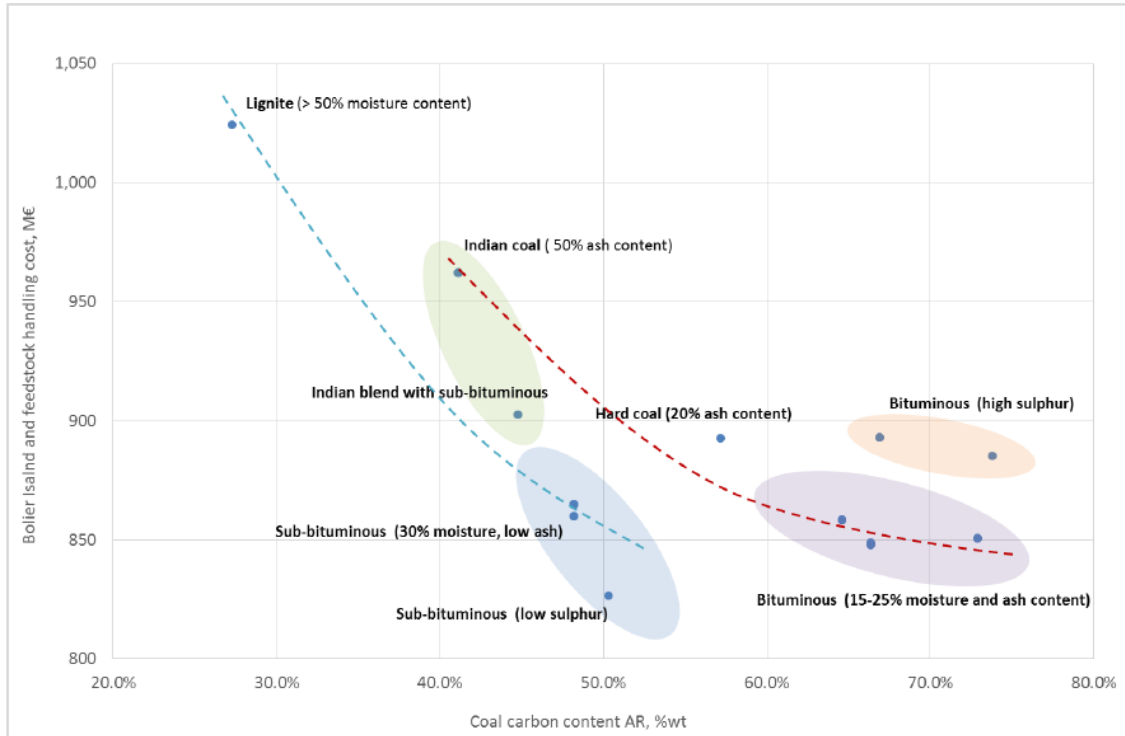


Figure 2-7
IEAGHG Boiler Island Costs by Coal Type and Carbon Content

The FlexEVAL study⁹² by IEAGHG examined the value of flexible CCS-equipped power plants in the UK electricity system from 2015 to 2050, as the level of intermittent renewable power grows. Flexibility enhancing options for CCS technologies are shown in Table 2-4.

Table 2-4
Engineering Requirements and Effects of Flexibility Increasing Process Adjustments for CCS Power Plants

CCS Option	Bypass Integration	Storage Integration
Pre-combustion	- Gasification process remains main source of energy penalty - Solvent regeneration and compressor work reduced	Hydrogen storage to decouple gasification and capture from power generation
Oxy-combustion	- Compressor work can be saved - Plant can run on air instead of oxygen	ASU must operate continuously
Post-combustion	Reduced energy consumption in heat exchanger and stripper	- Large quantities of rich and lean solvent needed - Steam turbine, stripper, and compressor must be sized accordingly

⁹² IEAGHG. *Valuing Flexibility in CCS Power Plants*. 2017/09, December 2017.

The FlexEVAL study defined the “system value” of a particular technology as the marginal change in total electricity generation cost (capital, energy, ancillary services) from integrating an additional unit of that technology into the grid. The relative system value is specified as reduction in annual total system cost (TSC) per unit of installed capacity on a £/kW basis. The first-of-a-kind (FOAK) capacity unit of a certain technology in a given capacity mix has a different value than the n^{th} -of-a-kind (NOAK) unit. Findings of the study include:

- All of the CCS technologies in the study provided value to the 2030 and 2050 UK electricity systems because they reduce the total system cost when deployed in a mix of power generating capacity.
- A cost-optimal future electricity system contains large amounts of intermittent renewable capacity. To integrate the intermittent power generation, thermal power plants must increase cyclic operation.
- Scenarios without restrictions on the amount of capacity that can be installed indicate that NGCC with post-combustion capture, in combination with onshore wind power, is part of the economically and environmentally optimal solution for the 2030 and 2050 conditions.
- Flexible CCS technologies provide additional value in being able to accommodate higher levels of intermittent renewable capacity, reducing total system cost through increased electricity dispatch from intermittent renewables with low operational cost.
- Non-flexible and flexible fossil power plants with CCS show different optimal operational strategies. Under the conditions forecast for 2030, flexible power plants with CCS show more frequent startups/shutdowns than non-flexible power plant with CCS in order to enable intermittent renewable power generation. Under the conditions expected in 2050, with larger amounts of renewable and CCS capacity, non-flexible power plants with CCS are forced into cyclic operation due to their tighter operating envelope (i.e., higher minimum stable generation, longer startup times, etc.) causing higher startup costs.
- Non-flexible fossil power plants with CCS show a higher utilization than flexible power plants with CCS in terms of absolute power output, but a lower utilization in terms of running times.
- In 2030, the level of economically optimal deployment for the different CCS options is: 28 GW for coal (post-combustion), 29 GW for coal (oxy-combustion), 26 GW for IGCC (pre-combustion), and 40.5 GW for NGCC (post-combustion).
- In 2050, the level of economically optimal deployment for the different CCS options under the business-as-usual electricity demand scenario is 21 GW for coal (post-combustion) and 31.5 GW for NGCC (post-combustion). Under the extreme peak electricity demand scenario, it is 23 GW for coal (post-combustion) and 33 GW for NGCC (post-combustion).
- The relative system value for the different CCS options indicates the generated reduction in TSC per installed capacity unit is a function of system conditions and amount of capacity deployment. It ranges from £500-800/kW at maximum deployment rates and illustrates clearly the value difference between FOAK and NOAK power plants.

The LCOE metric assumes that generated electricity is a “homogeneous” product. However, intermittent technologies necessitate back-up or energy storage capacity in order to provide electricity with the same reliability as conventional power plants. The traditional LCOE is also lacking a systemic perspective when comparing electricity generation costs of different

technologies. Omission of the additional costs to accommodate intermittent sources can lead to suboptimal results.

The FlexEVAL study found that both flexible and non-flexible options reduced total system cost, but that the flexible CCS power plants exhibited a greater operating range. They could turn down further and load-follow more quickly than the non-flexible cases. However, these capabilities came at higher cost and with higher emissions.

In a 2014 study, IEAGHG worked with Foster Wheeler to assess CO₂ capture at coal-based power and hydrogen plants.⁹³ The study assumed a 90% CO₂ capture option via the following cases:

- Reference Case: ~1000 MW (net) supercritical PC plant, without CO₂ capture, Alstom wet FGD
- Supercritical PC with the Shell Cansolv advanced amine CO₂ capture system
- Supercritical PC with oxy-combustion: FW Energie circulating fluid bed scrubber FGD technology and Air Products cryogenic purification unit
- IGCC – General Electric, radiant syngas cooler; UOP Selexol solvent scrubbing; 2 F-class gas turbines (~275 MW equivalent on natural gas)
- IGCC – Shell Coal Gasification Process with syngas cooler; UOP Selexol solvent scrubbing; 2 F-class gas turbines (~275 MW equivalent on natural gas)
- IGCC – MHI, air-blown two-stage entrained-bed gasifier; UOP Selexol solvent scrubbing; 2 MHI 701 F4 gas turbines

Cost estimates were generally derived in accordance with the standards developed by the international CCS task force.⁹⁴ Base case assumptions for the study include:

- Greenfield site, Netherlands coastal location
- 48°F (9°C) ambient temperature
- Natural draft cooling towers
- Eastern Australian internationally traded bituminous coal, 0.86% sulfur as-received, 11,120 Btu/lb (25.87 MJ/kg), LHV basis
- Coal price: ~\$3.06/MBtu (€2.50/GJ), LHV basis, which is equivalent to ~\$2.92/MBtu (€2.39/GJ), HHV basis
- 2Q 2013 cost basis
- Discount rate: 8% (constant money values)
- Operating life: 25 years
- Construction time: PC plants – 3 years; IGCC plants – 4 years
- Capacity factor: 90% for PC plants; 85% for IGCC plants

⁹³ IEAGHG. *CO₂ Capture at Coal Based Power and Hydrogen Plants*. 2014/3, June 2014.

⁹⁴ *Toward a common method of cost estimation for CO₂ capture and storage at fossil fuel power plants*, IEAGHG Technical Review 2013/TR2, March 2013.

- CO₂ transport and storage cost: ~\$10.50/ton (€10/tonne)

Table 2-5 lists the performance results for the cases, while Table 2-6 shows the cost results.

Table 2-5
IEAGHG Plant Performance Summary

Case	Net Power Output, MW	CO ₂ Captured, kg/MWh	CO ₂ Emissions, kg/MWh	Efficiency		Efficiency Penalty for Capture (LHV) % points
				HHV, %	LHV, %	
PC Reference Plant	1030		746	42.2	44.1	
PCC - Cansolv	822	840	93	33.6	35.2	8.9
Oxy-Combustion	833	823	92	34.1	35.7	8.4
Shell IGCC, oxygen-blown	804	837	93	33.9	35.5	8.6
GE IGCC, oxygen-blown	874	844	94	33.3	34.9	9.2
MHI IGCC, air-blown	863	842	104	33.2	34.8	9.3

Table 2-6
IEAGHG Plant Costs, LCOE, and CO₂ Avoidance Cost

Case	Total Plant Cost (TPC) - €/kW	Total Capital Requirement - €/kW	% TPC Increase Compared to Reference Plant	LCOE (€/MWh)	% LCOE Increase Compared to Reference Plant	CO ₂ Avoidance Cost (€/tonne)
PC – no capture	1447	1887		52.0		
PCC - Cansolv	2771	3600	91	94.7	82	65.4
Oxy-combustion	2761	3583	91	91.6	76	60.8
Shell IGCC	3157	4350	118	116.5	124	98.9
GE IGCC	3074	4238	112	114.4	120	95.8
MHI IGCC	3046	4200	110	114.5	120	97.4

The study shows that CO₂ capture increases the specific cost per kW of the PC cases by about 90% compared with the reference plant. There is no significant difference between the specific capital costs of the post-combustion capture and oxy-combustion plants. Additional costs for oxy-combustion are attributable to the air separation unit and to higher CO₂ compression and purification costs.

The specific capital costs of the three IGCC plants with capture are 110–118% higher than the cost of the PC reference plant. The MHI air blown gasifier plant has higher costs for gasification, syngas treatment, and acid gas removal, due to the higher volume of the fuel gas, but it avoids the cost of a large air separation unit (MHI includes a small air separation unit to produce nitrogen for coal feeding in its cost for the gasification unit).

Additional facets of the IEAGHG study considered cases for (1) achieving 98% CO₂ capture in a PC plant with post-combustion CO₂ capture (using biomass), an oxy-combustion plant, and an IGCC plant, (2) different hydrogen and power co-production cases, and (3) sensitivity cases for once-through seawater cooling and dry (air) cooling compared to a reference case with a wet cooling tower. Net electrical efficiency increases of about 0.6 percentage point were seen for the seawater cooling, due to the higher gross power production as a result of lower condenser operating pressure and the lower plant auxiliary power demand. The air cooled condenser resulted in net electrical efficiency decreases of about 0.6 percentage point, due to the lower gross power production as a result of higher condenser operating pressure.

GCCSI Review of Costs of CCS and Other Low-Carbon Technologies

In 2017, the Global CCS Institute (GCCSI) published costs for CCS on numerous facilities in fourteen countries.⁹⁵ The study observed that the deployment of NOAK can reduce the future cost of applying CCS by up to approximately 30% in power plants. Table 2-7 shows results for fossil power plant types based on a U.S. Midwest reference location.

Table 2-7
GCCSI Costs of CCS for Power Plants

	PC Supercritical	Oxy-Comb. Supercritical	IGCC	NGCC
Levelized Cost	US\$/MWh	US\$/MWh	US\$/MWh	US\$/MWh
Without CCS	75–77	–	95	49
With CCS FOAK	124–133	118–129	141	78
With CCS NOAK	108	107	102	62
Increase for FOAK w. CCS	60–70%	51–64%	45%	57%
% Decrease FOAK to NOAK	-13 to -19%	-9 to -16%	-28%	-21%
Cost of CO₂ Avoided (US\$/tonne CO₂)				
FOAK	74–83	66–75	97	89
NOAK	55	52	46	43

⁹⁵ Irlam, Lawrence. *Global Costs of Carbon Capture and Storage – 2017 Update*. Global CCS Institute. June 2017.

A GCCSI 2015 technology report⁹⁶ drew on cost and performance data from seven recent studies⁹⁷ to produce cost ranges for major low- and zero-emissions technologies, including coal and natural gas generation with CCS, wind, nuclear, solar thermal, and solar PV. Table 2-8 lists some of the parameters in the GCCSI comparison, while Figure 2-8 graphs the range of results in terms of LCOE (in 2014 U.S. dollars). For the fuel cost and other parameters used in the GCCSI comparison, NGCC with CCS had a lower LCOE than coal plants with CCS.

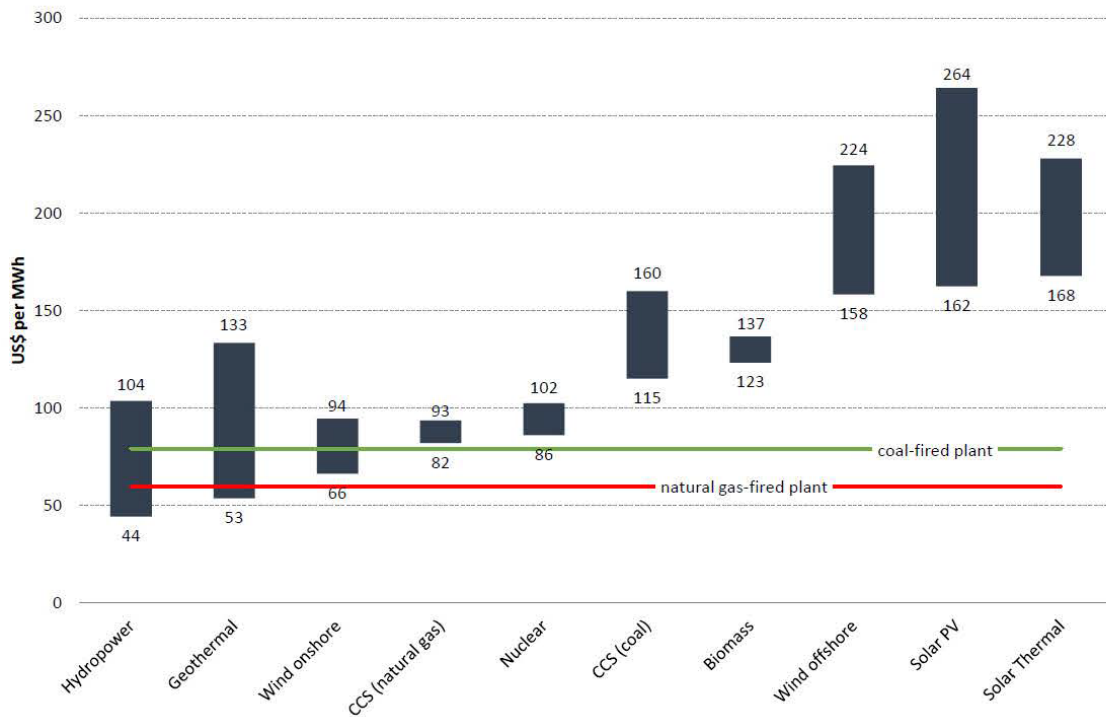
⁹⁶ *The Costs of CCS and Other Low-Carbon Technologies – 2015 Update*. Global CCS Institute. July 2015.

⁹⁷ Including: *Program on Technology Innovation: Integrated Generation Technology Options 2012*. EPRI, Palo Alto, CA: 2013. 1026656.

Table 2-8
GCCSI Low-Carbon Technology Assessment Parameters

Source	Gas	Gas with CCS	Coal	Coal with CCS	Onshore wind	Offshore wind	Hydro	Biomass	Solar PV	Solar Thermal	Geothermal	Nuclear
Plant Life, years	28	30	35	36	23	23	50	30	30	27	27	44
Construction Time, years	3	3	5	5	2	2	4	4	1	2	3	6
Capacity Factor, %	66	69	76	75	33	40	60	69	19	38	81	85
Thermal efficiency, %	49-57	37-54	38-47	28-39	-	-	-	24-31	-	-	-	33-36
Fuel cost, (\$/MBtu)	4.98	4.98	2.36	2.36	-	-	-	3.00	-	-	-	0.71

Note: A discount rate of 8% is used for all case. Plant life, construction times, and plant capacity factors were calculated by averaging values from seven studies. For fuel costs in \$/GJ, multiply \$/MBtu values by 0.9478.



Source: Global Carbon Capture and Storage Institute

Figure 2-8
GCCSI Levelized Cost of Electricity for Low Carbon Power Generation Technologies

The Global Carbon Capture and Storage Institute report concluded:

- CCS is a cost-competitive power sector emissions reduction tool when considered among the range of available low and zero emissions technologies. Although CCS adds costs to traditional fossil power generation, the underlying coal and gas generation technology and fuel sources are competitive. CCS has higher rates of utilization than some renewables technologies.
- Nuclear, hydro, and geothermal generation can be cost-competitive in some markets given their capacity factors of up to 80 to 90%. The relative costs of solar and wind generation technologies are affected by lower capacity factors (up to 40% availability).
- Hydropower and onshore wind technologies are among the least expensive greenhouse gas emissions reduction technologies.
- Offshore wind, solar PV, and solar thermal are the most expensive technologies for displacing greenhouse gas emissions from fossil fuel combustion, highlighting the importance of expected cost reductions and technical improvements for these technologies.
- Significant cost reductions are also expected for CCS technologies as deployment increases. Although CO₂ capture technology is currently deployed at pilot and demonstration scale in the power sector, integrated CCS at commercial scale in the power sector is still in an early and high cost stage of deployment.

- Using data from current studies, coal-fired generators with CCS capability would be on par with traditional (unabated) coal and gas generation if CO₂ emissions were priced at \$44 to \$100 per ton (\$48 to \$109 per tonne).

Australian Power Generation Technology Study

EPRI teamed with Australian organizations to develop the 2016 Australian Power Generation Technology Report.⁹⁸ The study compared technology options for power generation and assembled cost and performance data for new-build power plants in 2015 and 2030. The following assumptions undergirded the study:

- The estimates represent a complete power plant on a generic site. Site-specific considerations, such as unusual soil conditions, special seismic zone requirements, or unique local conditions (accessibility, local regulatory requirements, etc.) were not considered.
- The boundary for the cost estimate is defined as the total plant facility within the fence line, including coal yards and receiving equipment but terminating at the high-voltage side of the main power transformers. Where CO₂ is captured, costs beyond the fence are not included (e.g., transport pipeline, booster pumps, and geologic injection and storage monitoring equipment).
- The reference site is characterized as a generic Hunter Valley location in New South Wales. For the brown coal (lignite) cases, a Victoria minemouth location is assumed.
- Labor costs are based on Hunter Valley or Victorian wage rates and productivities in a competitive bidding environment.

Fuel assumptions for the 2015 cases are:

- Black coal: A\$2.00–A\$4.00 (\$1.50–\$3.00 using a June 2018 exchange rate)
- Natural gas: A\$5.00–A\$8.00 (\$3.80–\$6.00 using a June 2018 exchange rate)

The estimates for 2015 “overnight” capital costs are based on operation in the first half of 2015. Other economic assumptions include:

- Nominal cost of equity: 11.5% per year
- Nominal cost of debt: 8.0% per year
- Debt financing fraction: 70%
- Inflation: 2.5% per year
- Company (income) tax rate: 30% per year
- Property tax / insurance rate: 2.0% per year
- Asset tax life: 30 years

Other design and operating assumptions include:

- Dry cooling and dry ash handling systems
- An 85% capacity factor for supercritical, ultra-supercritical, oxy-combustion, and combined cycle cases

⁹⁸ http://www.co2crc.com.au/wp-content/uploads/2016/04/LCOE_Report_final_web.pdf

- An 80% capacity factor for IGCC cases

Table 2-9 Shows the performance and cost results for the fossil power plant cases with and without CCS for bituminous coal (black coal). The study contains similar cases for lignite (brown coal), with the exception of oxy-combustion technology.

Table 2-9
Performance and Economic Results for Australian Fossil Fuel Power Plant Cases with and without CCS (A\$ 2015)

	Supercritical		Ultra-Supercritical		IGCC		Oxy-Fuel	Combined Cycle	
	No CCS	With CCS	No CCS	With CCS	No CCS	With CCS		No CCS	With CCS
Gross Power (kW)	401,091	343,275	695,225	595,010	474,683	448,391	542,797	451,468	417,307
Total Aux. Power (kW)	26,091	72,658	45,225	133,610	93,113	139,672	167,795	9,467	48,393
Net Power (kW)	375,000	270,617	650,000	461,400	381,570	308,720	375,003	442,002	368,915
Net Heat Rate (kJ/kWh, HHV)	9000	12,400	8800	12,000	9000	12,400	12,000	7200	8600
Net Plant Efficiency (% HHV)	40	29	41	30	40	29	30	50	42
Fixed O&M (A\$/kW-yr)	\$45.00	\$55.00	\$45.00	\$55.00	\$50.00	\$60.00	\$55.00	\$20.00	\$35.00
Variable O&M (A\$/MWh)	\$2.50	\$10.00	\$2.50	\$9.00	\$8.00	\$10.00	\$12.00	\$1.50	\$12.00
Bare Erected Cost (A\$/kW)	\$2,524	\$5,570	\$2,536	\$5,731	\$4,120	\$6,435	\$5,489	\$1,317	\$2,571
Total Plant Cost (A\$/kW-net)	\$3,000	\$6,750	\$3,100	\$7,000	\$5,000	\$7,800	\$6,750	\$1,450	\$3,050
Average LCOE (A\$/MWh)*	\$79	\$168	\$80	\$169	\$122	\$195	\$169	\$78	\$136

* LCOE values for CCS cases include a CO₂ transportation and storage cost of A\$15/tonne (about \$10.30/ton).

Note: Coal-fired plant data are for bituminous (black) coal. For costs in US\$, multiply costs in A\$ by approximately 0.76. For heat rate values in Btu/kWh, multiply kJ/kWh values by 0.9478.

*Retrofitting CCS to Coal – Enhancing Australia’s Energy Security*⁹⁹ is a supplementary report to the *Australian Power Generation Technology Report*, and uses the same design basis, capital cost estimating basis, and LCOE methodologies.

Table 2-10 shows the supplementary report’s total plant costs on a \$/kW basis for various lignite retrofit scenarios, alongside the costs of a new-build supercritical plant with and without post-combustion CO₂ capture. All of the retrofit cases assume wet cooling is available and that the existing base PC plants without CO₂ capture are fully amortized, in good condition, and have suitably long remaining lives. No base plant upgrades are included in the analysis.

The base case post-combustion capture (PCC) system for the lignite plant retrofit is a fully integrated monoethanolamine (MEA) solvent process. The gross power output following the addition of CO₂ capture drops significantly due to the extraction of steam from the power cycle for CO₂ capture solvent regeneration. The auxiliary load also increases from the base PC plant case because of the power demand for CO₂ compression as well as the capture system’s pumps and fans. The advanced solvent case benefits from reduced steam demand for solvent regeneration and other reductions in auxiliary loads. Although not proven at scale, EPRI believes these advances should be commercially available in the near term. The lignite properties in the study are from U.S. lignites, which differ considerably in properties from the lignite of Australia’s Latrobe Valley.¹⁰⁰ Given the lower levels of sulfur in Latrobe Valley lignite, it is likely that the resulting lower levels of SO_x (and also NO_x) in the flue gas could allow a reduction in the size of FGD and SCR equipment and reagent usage. These savings are reflected in the “minimal FGD/SCR” case.

Table 2-10
Cost and Performance Estimates for Australian Lignite Plants with and without CO₂ Capture (A\$ 2015)

	New Supercritical Brown Coal		Brown Coal Retrofit		
	No PCC	With PCC	Base Case	Advanced Solvent	Minimal FGD/SCR
Total plant cost (A\$/kW sent out)	3850	8250	4900	4700	3900
Fixed O&M (A\$/kW-year)	55	65	70	65	60
Variable (A\$/MWh)	3.0	12	14	14	12
Efficiency (% HHV)	36	25	-11.5	-9.5	-9.5

Note: For costs in US\$, multiply costs in A\$ by 0.76.

⁹⁹ http://www.co2crc.com.au/wp-content/uploads/2017/03/Retrofit_ccs_report_web.pdf

¹⁰⁰ *A Summary of EPRI’s Pulverized Coal (PC) and Circulating Fluidized Bed (CFB) Post Combustion CO₂ Capture Retrofit Studies: The Five North American Plant Retrofit PCC Cases*. EPRI, Palo Alto, CA: 2012.1026864.

U.S. Energy Information Administration Cost Data

EIA generating technology cost and performance estimates from 2016–17 are shown in Table 2-11.^{101,102}

Table 2-11

EIA –Estimated Power Plant Capital and Operating Costs – 2016-17 Update

	Nominal Capacity (MW)	Heat Rate (Btu/kWh)	Capital Cost (\$/kW, overnight basis)	Fixed O&M Cost (\$/kW-yr)	Variable O&M Costs (\$/MWh)
USC	650	8,800	\$3,636	\$42.10	\$4.60
USC with 90% CCS	650	11,650	\$5,569	\$80.53	\$9.51
USC with 30% CCS	650	9750	\$5,084	\$70.00	\$7.10
IGCC	618	8600	\$4,908	\$65.40	\$5.00
PC conversion to natural gas	300	10,300	\$226	\$22.00	\$1.30
PC greenfield with 10-15% biomass	300	8960	\$4,620	\$50.90	\$5.00
PC conversion to 10% biomass	300	10,360	\$537	\$50.90	\$5.00
NGCC	702	6600	\$978	\$11.00	\$3.50
Advanced NGCC	429	6300	\$1,104	\$10.00	\$2.00
Combustion Turbine	100	10,000	\$1,101	\$17.50	\$3.50
Advanced Combustion Turbine	237	9800	\$678	\$6.80	\$10.70
Reciprocating Internal Combustion Engine	85	8500	\$1,342	\$6.90	\$5.85

¹⁰¹ *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants*, U.S. Energy Information Administration, November 22, 2016.

¹⁰² *Addendum: Capital Cost Estimates for Additional Utility Scale Electric Generation Plants*, U.S. Energy Information Administration, April 2017.

DOE NETL Technology Comparison Studies

NETL reports that an update (Version 4) of its “baseline studies” for bituminous coal and natural gas power plants is under way.

In 2016, DOE NETL presented results from a study evaluating the cost and performance of non-CCS compliance options to meet EPA’s Section 111 (b) New Source Performance Standard (NSPS) for greenhouse gas emissions. Figure 2-9¹⁰³ shows results for natural gas cofiring for SCPC, A-USC, and IGCC plants. Three different target CO₂ emission levels were examined for each technology: 1400 lb (635 kg) per MWh (gross), the NSPS standard, and two lower thresholds of 1350 lb (612 kg) per MWh (gross) and 1300 lb (589 kg) per MWh (gross), which would allow power producers some “cushion” in the event that their plants experience a period of noncompliance.

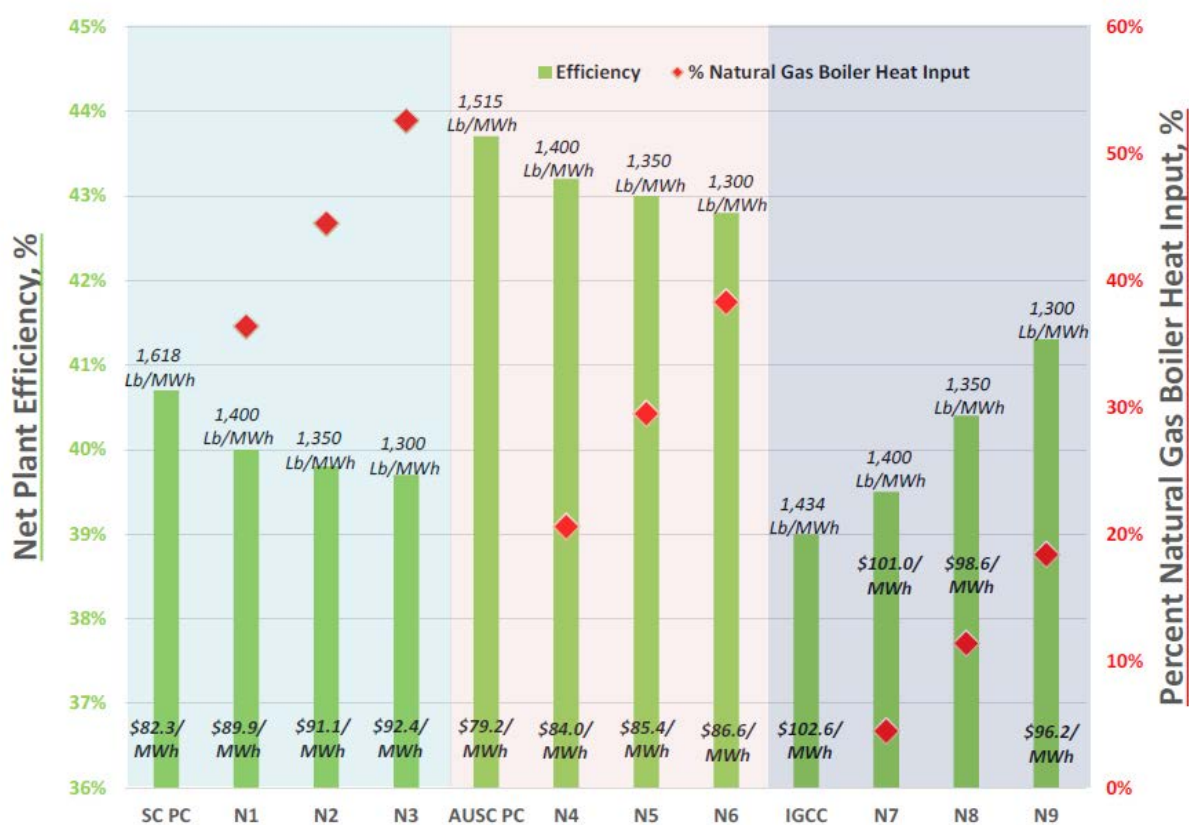


Figure 2-9
NETL Natural Gas Cofiring Cost and Performance

Alternatively, a combined heat and power (CHP) option was examined. Coal power plants that sell a portion of their low-grade thermal energy (e.g., low-pressure steam or hot water) to industrial customers are allowed to count that energy toward their total gross power, which

¹⁰³ Fout, Timothy and Eric Grol. “Update on CO₂ Capture Related Systems Analysis Activities,” presentation at 2016 NETL CO₂ Capture Technology Meeting, August 9, 2016.

results in a lower GHG emissions factor. Figure 2-10¹⁰⁴ shows how the three technologies (SCPC, A-USC, and IGGC) perform for four different CO₂ emissions targets. In all cases, net electricity efficiency drops but the efficiency gained from the thermal energy sales more than compensates for the efficiency reduction. Moreover, the cost per MWh of exporting more heat to achieve the lower emissions targets is the same or only slightly higher than the cost of achieving the emissions performance standard of 1400 lb (635 kg) per MWh (gross).

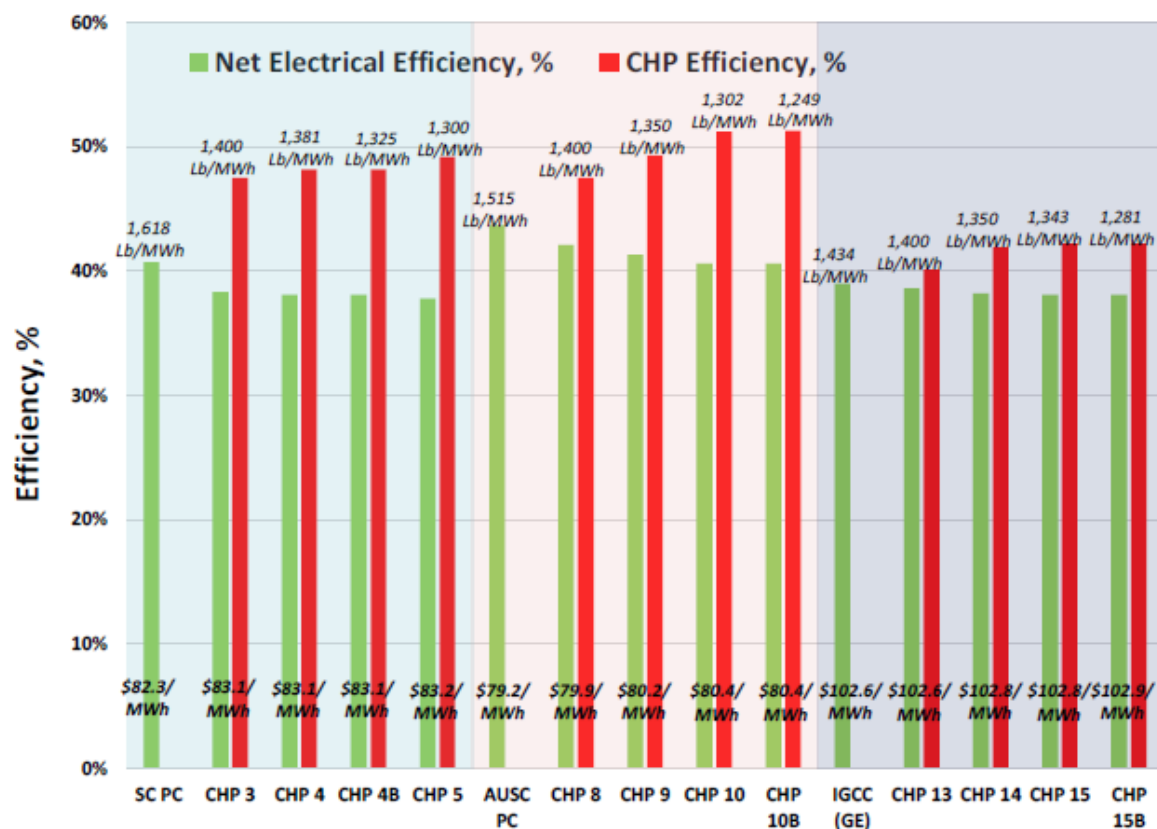


Figure 2-10
NETL Combined Heat and Power Cost and Performance

NETL continues to update its “baseline” cost and performance reports for coal power systems firing bituminous and low-rank coals as well as for NGCC plants in comparable locations. NETL has also published new and updated evaluations of post-combustion CO₂ capture and oxy-combustion technologies and life-cycle GHG analyses for fossil-fuel power plants. Also updated are cost reduction targets for “second generation” and “transformational” advanced coal technologies with CCS.¹⁰⁵

NETL’s goals for technologies expected to be available by 2025 call for a first-year cost-of-electricity reduction of 20% relative to today’s technologies for PC and IGGC plants with capture, bringing the cost of CO₂ captured to about \$40/ton (\$44/tonne), excluding the costs for

¹⁰⁴ Ibid.

¹⁰⁵ Kristin Gerdes, “New Coal Power R&D Goals: Enabling Coal with CCS to be an Affordable, Competitive Option,” presentation at 2013 NETL CO₂ Capture Technology Meeting, Pittsburgh, PA. July 8, 2013.

CO₂ transportation, injection, and monitoring. Revenue from CO₂ sales for EOR may then make such plants economically viable and competitive with natural gas or nuclear power plants. Transformational technologies for a 2035 timeframe include chemical looping, supercritical CO₂ cycles, transformational CO₂ capture processes, integrated gasification fuel cells, and pressurized oxy-combustion. The envisioned advances would bring further cost reductions and competitive advantage.

NETL's 2015 baseline study update for PC and NGCC plants—Revision 3¹⁰⁶—shows that greater efficiencies for the baseline plants are now achievable (see Figure 2-11). The use of an advanced amine solvent in place of MEA helps reduce the steam requirements for CO₂ solvent regeneration, resulting in an overall regeneration energy of 0.13 kWh (net) per pound of CO₂ captured (0.29 kWh-net/kg-CO₂) compared with a value of 0.17 kWh (net) per pound of CO₂ captured (0.37 kWh-net/kg-CO₂) from Revision 2.¹⁰⁷ The higher efficiencies result in lower cost-of-electricity values as shown in Figure 2-12, which also shows a slight increase in \$/ton-CO₂-captured values—a reflection of the lower base plant CO₂ emissions due to efficiency gains.

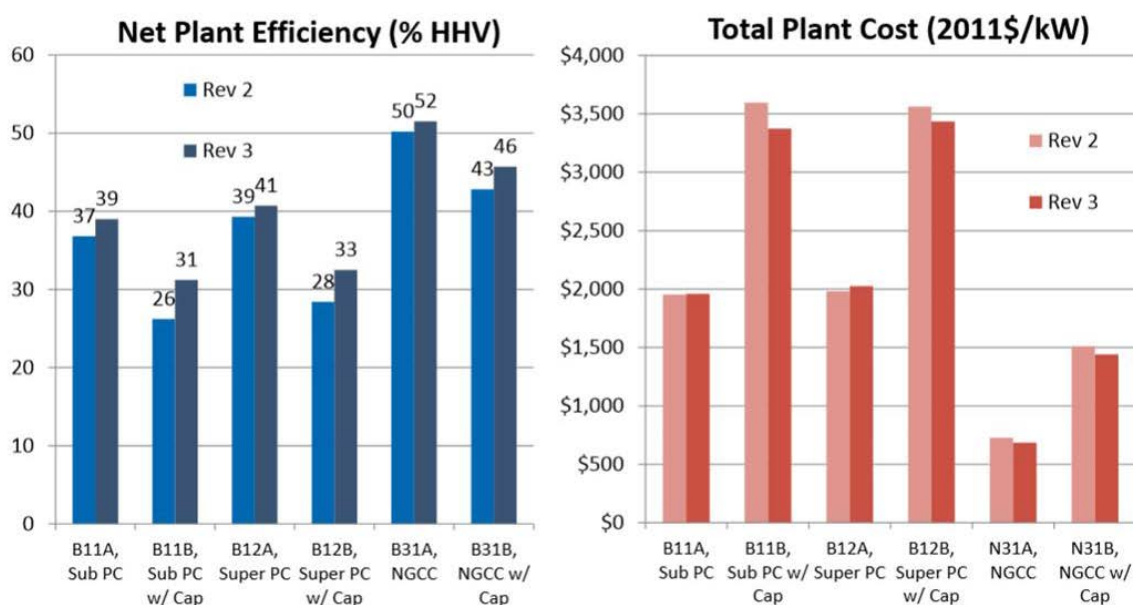


Figure 2-11
NETL Plant Efficiencies and Cost for State-of-the-Art Advanced Post-Combustion Capture

¹⁰⁶ *Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3*. DOE/NETL-2015/1723, July 6, 2015.

¹⁰⁷ Kristin Gerdes, “Techno-economic Evaluation of State-of-the-Art and Advanced Post-Combustion Capture Plants,” presentation at 2014 NETL CO₂ Capture Technology Meeting, Pittsburgh, PA, July 29, 2014.

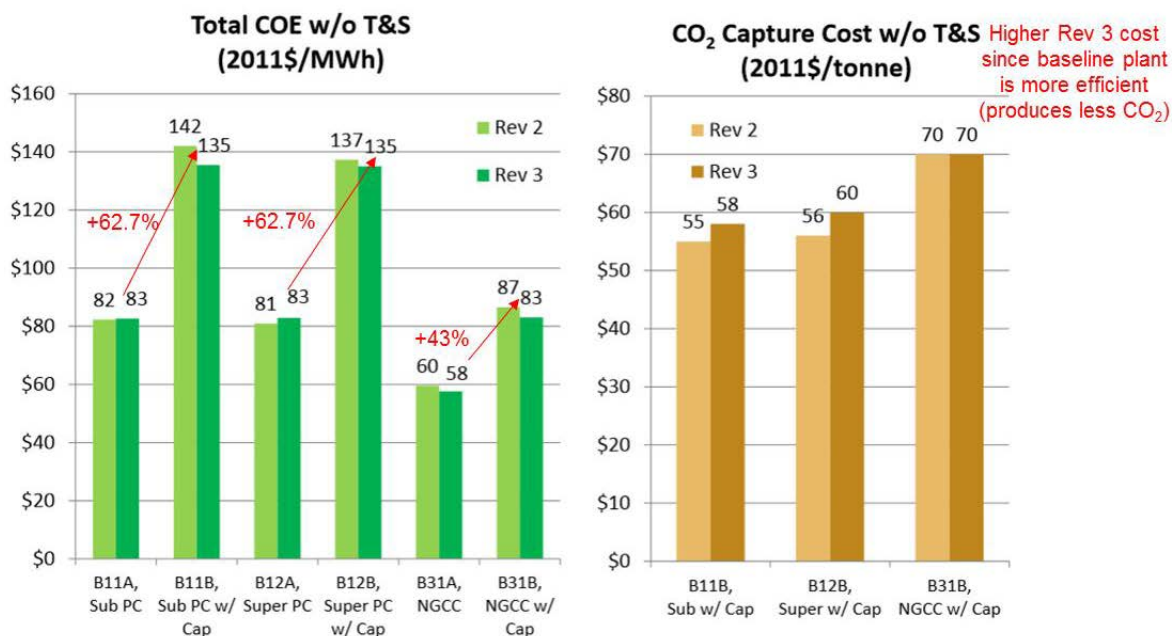


Figure 2-12
CO₂ Capture Costs for State-of-the-Art Advanced Post-Combustion Technologies (NETL)¹⁰⁸

Table 2-12 contains performance and economic results for the study.¹⁰⁹ The cases without capture use conventional financing, whereas the cases with CO₂ capture use high-risk financial assumptions, consistent with NETL's methodology.¹¹⁰

Assumed fuel prices are \$2.94/MBtu (\$2.78/GJ) for Illinois No. 6 coal and \$6.13/MBtu (\$5.81/GJ) for natural gas, both on an HHV basis, delivered to the Midwest, in 2011 U.S. dollars.

All plant configurations were evaluated based on installation at a greenfield site. An 85% capacity factor is assumed for all cases; CO₂ capture cases are based on 90% capture using Shell Cansolv technology. A transport and storage charge of \$10 per ton (\$11/tonne) of CO₂ is added to the cost-of-electricity value, which represents an approximately 62-mile (100 km) pipeline and storage in a deep saline formation in the Midwest.

The nominal net plant output for this study targets 550 MW. The actual net output varies between technologies because the combustion turbines in the NGCC cases are manufactured in discrete sizes, but the boilers and steam turbines in the PC cases are readily available in a range of capacities. Thus, the PC cases have a net output of 550 MW, while the NGCC cases have a net output of 559 MW with CO₂ capture and 630 MW without capture.

Environmental emission requirements are based on the mercury and hydrochloric acid limits, set by the March 2013 update to the Utility Mercury and Air Toxics Standards (MATS), and

¹⁰⁸ Ibid.

¹⁰⁹ Tim Fout et al. "Update to Cost Performance Baselines for Fossil Energy Plants: Bituminous Coal and Natural Gas to Electricity," Pittsburgh Coal Conference, October 8, 2014.

¹¹⁰ *Quality Guidelines for Energy System Studies: Cost Estimation Methodology for NETL Assessments of Power Plant Performance*. DOE/NETL-2011/1455. 2011.

particulate matter (PM), SO₂, and NO_x limits, set by the February 2013 update to the New Source Performance Standards.

Mercury, SO₂, NO_x, and PM are actively controlled in all PC cases with dry sorbent injection and activated carbon injection, wet FGD, low NO_x burners with overfire air and SCR, and a baghouse, respectively. NO_x is controlled in both NGCC cases with low-NO_x burners and an SCR.

Table 2-12
DOE NETL Revision 3 – PC and NGCC Performance and Economic Results¹¹¹

	Subcritical		Supercritical		NGCC	
Case	B11A	B11B	B12A	B12B	B31A	B31B
CO ₂ Capture	No	Yes	No	Yes	No	Yes
Gross Power (MW)	581	644	580	642	641	601
Total Aux. Power (MW)	31	94	30	91	11	42
Net Power (MW)	550	550	550	550	630	559
Net Heat Rate (Btu/kWh)	8740	10,953	8379	10,508	6629	7466
Net Plant HHV Efficiency, (%)	39.0	31.2	40.7	32.5	51.5	45.7
Energy Penalty*	-	8	-	8	-	6
Cost (2011 USD basis)						
Total Plant Cost (\$/kW)	1,960	3,467	2,026	3,524	685	1,481
Total Overnight Cost (\$ million)	1,336	2,346	1,379	2,384	528	1,008
Total Overnight Cost (\$/kW)	2,429	4,267	2,507	4,333	838	1,804
Total As-Spent Cost (\$/kW)	2,755	4,865	2,842	4,940	901	1,945
Cost of Electricity, \$/MWh (2011 USD basis)						
Capital	37.8	71.0	39.0	72.2	11.8	26.9
Fixed	9.3	15.1	9.6	15.4	3.4	6.6
Variable	9.2	15.1	9.1	14.7	1.7	4.0
Fuel	25.7	32.2	24.6	30.9	40.7	45.9
CO ₂ T&S	-	10.0	-	9.6	-	4.0
Total	82.0	143.5	82.3	142.8	57.6	87.3
CO ₂ Capture (2011 USD basis)						

¹¹¹ *Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3.* DOE/NETL-2015/1723, July 6, 2015.

NETL used data from its 2015 report, *Cost and Performance Baseline for Fossil Energy Plants, Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3*, to conduct LCOE “breakeven analyses” to determine which of four baseload generating technologies was economically preferred for various combinations of delivered natural gas price and compressed CO₂ sales price. The price of coal was held constant in the analyses at \$2.94/MBtu (\$2.79/GJ), delivered, for Illinois #6. The four competing technologies were:

- NGCC without CO₂ capture
- Bituminous SCPC without CO₂ capture
- NGCC with CCS
- Bituminous SCPC with CCS

The analyses established the lines of equivalence, or parity, for the LCOEs between the top two technologies for NG price and CO₂ price combinations, resulting in preferred technology “regions” on an x-y plot (see Figure 2-14). For the coal and NGCC plants with CCS, the post-combustion CO₂ capture technology was the Cansolv advanced amine process operating at 90% capture. As shown in Figure 2-14, the CO₂ price needs to be about \$50/ton (\$55/tonne) before the cost of adding CCS becomes economical. Below that price, an uncontrolled SCPC or NGCC plant purchasing emission allowances (or paying a tax) would be more economical, with the choice between the two plant types being based on the price of natural gas relative to the price of coal. For a CO₂ price above \$63/ton (\$70/tonne), either the SCPC with CCS or NGCC plant with CCS would be preferred relative to purchasing emission allowances (or paying a tax), with the choice between the two plant types being based chiefly on the price of natural gas relative to the price of coal, but also on the sales price for CO₂. In this the region of the x-y plot where CO₂ capture is economically justified, the SCPC plant becomes more competitive with NGCC not only as natural gas prices increase, but also as the CO₂ sales price increases.

Using the long-term forecasted average price of natural gas in the 2015 NETL baseline study, which was \$6.13/MBtu (\$5.81/GJ), the NGCC-CCS plant is economically preferred at CO₂ prices of \$63–81/ton (\$70–90/tonne) and the SCPC plant with CCS is preferred at CO₂ prices higher than \$81/ton (\$90/tonne). If 2018 wholesale spot market prices for natural gas remain below \$3.00/MBtu (\$2.84/GJ), the breakeven CO₂ price for the SCPC plant with CCS would be in excess of \$108/ton (\$120/tonne). If the May 2018 CO₂ emission allowance price in the California-Quebec-Ontario cap-and-trade auction of \$13.30/ton (\$14.65/tonne) were to persist (which it will, given the auction’s use of a floor price), the preferred generating technology would be NGCC without CO₂ capture and the breakeven natural gas price for SCPC without CO₂ capture would be roughly \$9.80/MBtu (\$9.30/GJ).

The example is illustrative of the impact of low natural gas prices on the competitiveness of coal versus gas and fossil plants with CO₂ capture versus those without, but EIA does not expect natural gas prices to remain this low. In the AEO2018 reference case, the price forecast for natural gas (at the Henry Hub) climbs by 3.9% annually from \$3.18/MBtu (\$3.01/GJ) in 2018 to \$10/MBtu (\$9.50/GJ) by 2048.

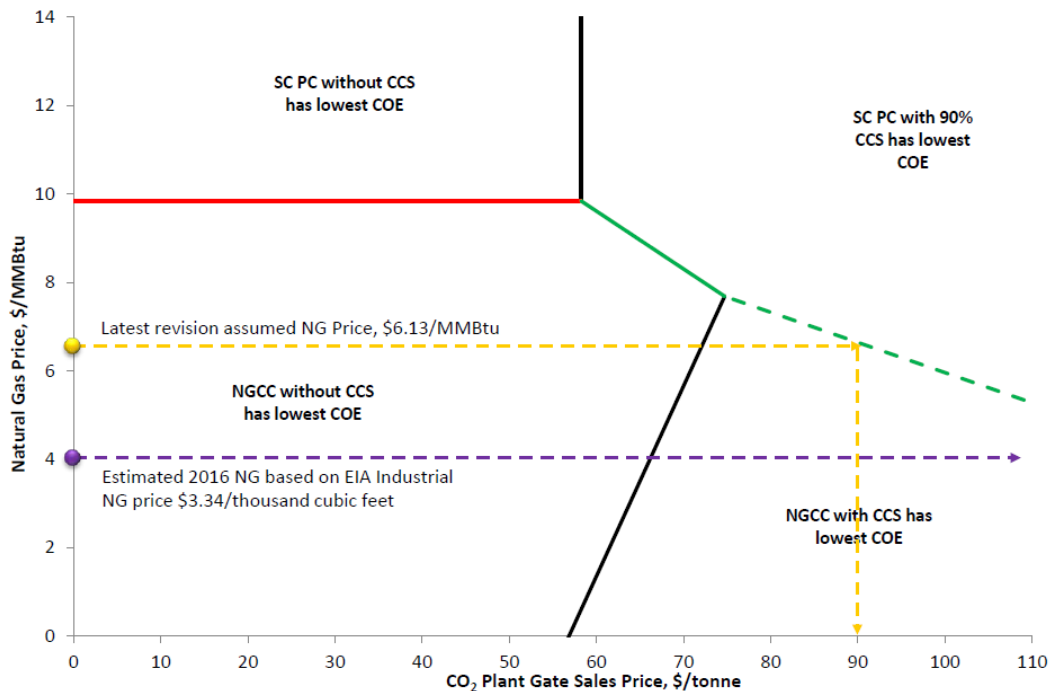


Figure 2-14
NETL Cost and Performance Baseline COE Parity Map for Fossil Power Technologies without and with CCS

[Note: EPRI conducted a similar analysis of the levelized cost of electricity and breakeven natural gas cost for post-combustion partial CO₂ capture on a new USC PC unit to meet EPA's early proposal for a Section 111(b) NSPS of 1100 lb (500 kg) of CO₂ per MWh (gross). It found that 37% CO₂ capture was sufficient to meet the standard. Using MEA post-combustion capture technology on a PRB-firing unit with nominal steam conditions of 1112°F (600°C), the LCOE increased from \$70/MWh to about \$90/MWh. The price of natural gas that yields a breakeven LCOE in an NGCC unit without capture increased from about \$6/MMBtu (\$5.70/GJ) to about \$9/MMBtu (\$8.50/GJ), meaning the NGCC unit would be economically preferred at long-term gas prices below \$9/MMBtu (\$8.50/GJ) and the USC PC with post-combustion MEA capture would be economically preferred at long-term gas prices higher than \$9/MMBtu (\$8.50/GJ), assuming that both dispatched at an 80% capacity factor. EPRI then examined the effect of theoretical improvements to the post-combustion capture process and the effect of CO₂ sales for enhanced oil recovery or another industrial process with inherent sequestration. Each had roughly the same effect, reducing the levelized COE premium for CO₂ capture by up to about \$15/MWh (albeit prior to the depressed oil prices of 2015–17) and reducing the breakeven natural gas price by up to about \$2/MMBtu (\$1.90/GJ). If both could be accomplished, the levelized COE and breakeven natural gas price would be lower than the new USC PC plant without CO₂ capture.]

In June 2015, DOE NETL published *Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO₂ Capture Rate in Coal-Fired Power Plants*.¹¹³ The study examined partial CO₂ capture for both PC and IGCC plants. For supercritical PC plants, the CO₂ capture rate ranged from 16% to 90%; for IGCC plants, the capture rate ranged from 22% to 90%.

Case B12B (Table 2-13) from the NETL's "Cost and Performance Baseline for Fossil Energy Plants, Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3" served as the base case for the supercritical PC plant designs. The only difference lay in the addition of the CO₂ capture system bypass flue gas stream, downstream of the FGD, which can be tuned to meet the desired CO₂ emission level. The basis for the cost and performance of all partial capture cases is the Shell Cansolv advanced amine process operating at 90% capture. No performance penalties were assessed due to the potential operation of the capture system at a scale smaller than its rated design point; accordingly, its auxiliary load was computed directly based on the CO₂ product flow rate. A power law with an exponent of 0.6 was assumed to scale 40% of the cost of the CO₂ capture system based on the inlet gas volumetric flow to the process, and the remaining 60% of the cost scaled based upon the captured CO₂ mass flow rate in accordance with Quality Guidelines for Energy System Studies procedures.¹¹⁴

The costs for controlling and monitoring the CO₂ capture system bypass flow were assumed to be negligible. Although partial bypass of the capture system results in slightly higher SO₂ emissions than in Case B12B, the emission levels will be lower than the values for Case B12A (no CCS), which is tantamount to a special subset of the modified system where all the flue gas flow bypasses the CO₂ capture system.

The supercritical PC plants are evaluated at a rated net power of 550 MW with an assumed capacity factor of 85% percent. A high-risk financial structure resulting in a capital charge factor of 0.124 is used to evaluate the costs of all cases with CO₂ capture. [The no-capture case uses a conventional financial structure with a capital charge factor of 0.116.] All other process parameters and cost assumptions are identical to Case B12B.

Case B5B (GE Energy gasifier) from NETL's "Cost and Performance Baseline for Fossil Energy Plants, Volume 1b: Bituminous Coal (IGCC) to Electricity, Revision 2b"¹¹⁵ served as the base case for the IGCC plants, with a modification to bypass (either partially or entirely) the catalytic water-gas shift reactors, which reduces the amount of CO₂ captured in the Selexol process. The bypass includes a COS hydrolysis reactor. Two partial capture cases were evaluated: one with a partial bypass of the water-gas shift reactor, achieving 37% capture, and one with the water-gas shift reactor bypassed completely, which yielded 22% capture.

The 37% capture case, resulting in 1129 lb (512 kg) per MWh-net or 900 lb (408 kg) per MWh-gross, requires only 17% of the syngas to be sent to the catalytic water-gas shift reactors. The

¹¹³ *Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO₂ Capture Rate in Coal-Fired Power Plants*, DOE/NETL-2015/1720, June 22, 2015.

¹¹⁴ *Quality Guidelines for Energy System Studies: Capital Cost Scaling Methodology*, DOE/NETL-341/013113, January 2013.

¹¹⁵ *Cost and Performance Baseline for Fossil Energy Plants Volume 1b: Bituminous Coal (IGCC) to Electricity, Revision 2b – Year Dollar Update*. DOE/NETL-2015/1727, July 31, 2015.

22% capture case, resulting in about 1360 lb (615 kg) per MWh-net or 1100 lb (500 kg) per MWh-gross, can be processed without including water-gas shift, so the entire gasifier exit stream is processed through a COS hydrolysis reactor instead. The reduced flow through the water-gas shift reactor also reduces the amount of shift steam that needs to be extracted from the steam cycle from about 286,000 lb/hr of 800 psia, 550°F steam (130,000 kg/hr, 55 bar, 290°C) for the reference 90% capture case to about 46,000 lb/hr (21,000 kg/hr) in the 37% capture case, and zero in the 22% capture case. This lower steam extraction requirement results in higher gross power output from the steam cycle for the partial capture cases.

A power law with an exponent of 0.8 was assumed to scale the cost of the water-gas shift and COS hydrolysis reactors based on catalyst volume in accordance with NETL costing procedures.

The amount of hydrogen recovered from the syngas stream is dependent on the Selexol process design conditions. NETL assumes a hydrogen recovery of 99.4%. The minimal hydrogen slip to the CO₂ storage stream maximizes the overall plant efficiency. The Selexol plant cost estimates are based on a plant designed to recover such a high percentage of hydrogen.

The two-stage Selexol system is designed to capture 93% of the CO₂ in the feed for both of the cases that require catalytic water-gas shift. For the lowest capture case with no water-gas shift, the system only needs to capture 78% of the CO₂ in the feed to meet the proposed limit, so the cost estimates were modified to reflect the reduced capture requirement, while the performance continues to be scaled on the amount of CO₂ captured.

Because the Selexol system has components for sulfur capture as well as CO₂ capture, a combined approach to cost scaling was utilized. A power law with an exponent of 0.79 was assumed to scale 40% of the cost of the two-stage Selexol system based on the inlet gas volumetric flow to the process while a power law with an exponent of 0.61 was used to scale the remaining 60% of the cost based upon the captured CO₂ flow rate in accordance with NETL costing procedures.

The IGCC plants are evaluated with an assumed capacity factor of 80%. A high-risk financial structure resulting in a capital charge rate of 0.124 is used to evaluate the costs.

Table 2-13 shows NETL's partial capture study results. The SCPC cases include up-to-date cost and performance information from recent vendor quotes, whereas the IGCC performance and cost are based upon the older quotes used in the Revision 2 report, with standard adjustments to update the cost basis to 2011 dollars.

Table 2-13
NETL Partial CO₂ Capture Cost and Performance Results for SCPC and IGCC (Bituminous Coal)

Plant Type	CO ₂ Emission Level		CO ₂ Capture Rate	HHV Efficiency	COE (excl. T&S)*	Cost of Captured CO ₂	Cost of Avoided CO ₂
	lb/MWh (gross)	lb/MWh (net)	%	%	\$/MWh	\$/tonne CO ₂	\$/tonne CO ₂
SCPC	1618	1705	0	40.7	82.30	-	-
	1400	1498	16	39.2	97.80	123.90	178.70
	1300	1400	22	38.6	101.40	105.30	152.60
	1200	1302	29	38.0	104.80	94.20	137.40
	1100	1201	35	37.4	108.10	86.70	127.20
	1050	1151	39	37.1	109.70	83.70	123.20
	1,000	1100	42	36.8	111.30	81.20	119.70
	900	997	48	36.3	114.40	76.90	114.00
	700	786	60	35.1	121.20	72.00	107.50
	500	570	72	34.1	127.20	67.40	101.40
	183	214	90	32.5	133.20	58.20	89.40
	1434	1724	0	39.0	102.60	-	-
IGCC	1100	1356	22	38.5	109.30	154.70	182.40
	900	1129	37	37.4	114.20	105.70	134.80
	152	206	90	32.6	135.40	63.20	91.70

Note: For emission levels in kg/MWh, multiply the listed lb/MWh emission rates by 0.4536. For costs of CO₂ captured or avoided in \$/ton (short), multiply the listed \$/tonne values by 0.907.

The cost estimates for plant designs that include technologies that are not yet fully mature (e.g., IGCC and any plant with CO₂ capture) use the same cost estimating methodology as for the mature plant designs, which does not fully account for the unique cost premiums associated with the initial, complex integrations of emerging technologies in a commercial application. Thus, initial deployments of new technologies may incur costs higher than those reflected in the NETL comparative analyses.

NETL's western coal baseline studies were published in several volumes:

Volume 3a provides cases for minemouth IGCC plants fed with Rosebud (Montana) Powder River Basin subbituminous coal and North Dakota lignite.¹¹⁶

¹¹⁶ *Cost and Performance Baseline for Fossil Energy Plant—Volume 3a: Low Rank Coal to Electricity: IGCC Cases*. DOE/NETL-2010/1399. May 2011.

Volume 3b provides cases for minemouth PC and CFB plants firing Rosebud (Montana) Powder River Basin subbituminous coal and North Dakota lignite.¹¹⁷

Volume 3c provides cases for NGCC plants at the same site elevation as the minemouth coal plants.¹¹⁸

The studies use first-year costs of \$1.80/MBtu (\$1.71/GJ) for Illinois #6 coal and \$6.75/MBtu (\$6.40/GJ) for natural gas, both HHV basis and in 2007 dollars. The low rank coal baseline reports address plants located at higher (minemouth) elevations, as does a corresponding report for NGCC plants.¹¹⁹

The results for the western coals baseline studies are shown in Table 2-14 and Table 2-15.

The design location for the PRB studies was a greenfield site in Montana, at 3400 feet (1040 m) in elevation, with a design ambient dry-bulb temperature of 42°F (6°C) and a design ambient relative humidity of 62%. The location assumed for the lignite studies was a greenfield site in North Dakota, at 1900 feet (580 m) in elevation, with a design ambient dry-bulb temperature of 40°F (4°C) and a design ambient relative humidity of 68%. To account for the dry climate, use of a parallel-path cooling system was assumed, with cooling load split 50:50 between an air-cooled condenser and a wet cooling tower.

The total plant cost estimates were current for mid-2007. An 80% capacity factor is used for IGCC; 85% for PC and CFB. The study used fuel costs \$0.89/MBtu (\$0.84/GJ) for Rosebud PRB coal, \$0.83/MBtu (\$0.79/GJ) for North Dakota lignite, and \$7.13/MBtu (\$6.76/GJ) for natural gas.

¹¹⁷ *Cost and Performance Baseline for Fossil Energy Plants, Volume 3b: Low Rank Coal to Electricity: Combustion Cases*. DOE/NETL-2011/1463. March 2011.

¹¹⁸ *Cost and Performance Baseline for Fossil Energy Plants, Volume 3c: Natural Gas Combined Cycle at Elevation*. DOE/NETL-2010/1396. March 2011.

¹¹⁹ DOE/NETL-2010/1396. Op. cit.

Table 2-14**NETL Western Coal Baseline Study – Results for PRB Coal and NGCC Cases, Montana Minemouth Site**

Study Case	S1A Shell SCGP	S1B Shell SCGP	S2A TRIG	S2B TRIG	S3A Siemens SFG	S3B Siemens SFG	S4A E- Gas	S4B E-Gas	S12A SCPC	S12B SCPC	S13A USC PC	S13B USC PC	S22A SC CFB	S22B SC CFB	NGCC Adv. F- Class	NGCC Adv. F- Class
CO ₂ Capture Technology, Efficiency	NA	Selexol 90%	NA	Selexol 90%	NA	Selexol 90%	NA	Selexol 90%	NA	Amine 90%	NA	Amine 90%	NA	Amine 90%	NA	Amine 90%
Gross MW	696.7	663.4	652.7	621.3	622.2	634.7	738.3	727.2	582.7	673.0	581.5	665.4	578.4	664.0	522.1	470.0
Net MW	572.7	471.6	545.4	460.9	504.7	445.3	604.8	515.1	550.0	550.1	550.1	550.1	550.1	550.0	512.4	435.1
Net Efficiency, % HHV	42.0	32.1	39.9	31.8	37.9	30.6	36.7	30.4	38.7	27.0	39.9	28.7	38.9	27.3	50.5	42.9
TPC, \$/kW	2506	3480	2236	3019	2610	3533	2265	3144	1879	3268	1972	3322	1932	3295	666	1315
LCOE, \$/MWh	105.40	151.80	94.50	133.30	110.00	154.30	99.80	142.40	73.30	136.30	78.80	136.50	78.00	136.90	81.70	117.80
CO ₂ Emissions, lb/MWh (net)	1735	233	1803	386	1927	246	1977	245	1892	271	1836	255	1866	265	799	94

Note: For CO₂ emission levels in kg/MWh, multiply the listed lb/MWh emission rates by 0.4536.

Table 2-15**NETL Western Coal Baseline Study – Results for Lignite and NGCC Cases, North Dakota Minemouth Site**

Study Case	Case L1A Shell SCGP	Case L1B Shell SCGP	Case L3A Siemens SFG	Case L3B Siemens SFG	L12A SCPC	L12B SCPC	L13A USC PC	L13B USC PC	L22A SC CFB	L22B SC CFB	NGCC Adv. F- Class	NGCC Adv. F- Class
CO ₂ Capture Technology, Efficiency	NA	Selexol 90%	NA	Selexol 90%	NA	Amine 90%	NA	Amine 90%	NA	Amine 90%	NA	Amine 90%
Gross MW	752.6	713.3	678.8	676.9	584.7	683.9	583.2	675.2	578.7	672.9	557.0	501.6
Net MW	616.7	500.1	543.1	466.5	550.1	550.1	550.0	550.0	550.0	550.1	547.0	464.6
Net Efficiency, % HHV	41.8	31.7	37.6	30.0	37.5	25.5	38.8	27.2	38.0	25.9	50.6	43.0
TPC, \$/kW	2539	3584	2656	3626	2041	3560	2156	3588	2042	3533	637	1267
LCOE, \$/MWh	105.80	154.50	110.70	156.90	78.80	147.50	85.30	146.30	81.90	146.00	80.60	115.80
CO ₂ Emissions, lb/MWh (net)	1783	242	1981	255	1996	293	1820	225	1865	236	783	87

Note: For CO₂ emission levels in kg/MWh, multiply the listed lb/MWh emission rates by 0.4536.

IPCC Special Report Cost Update and Comparisons

In 2016, updated costs from the 2005 IPCC Special Report on Carbon Dioxide Capture and Storage (SRCCS) were presented at the CCS Cost Network Workshop organized by the IEA Greenhouse Gas Programme. In the new study, lead authors for the cost sections of the original SRCCS assembled and reviewed costs ranges from 16 recent engineering-economic studies, which were then compared to the costs from the SRCCS escalated to a 2013 cost basis.¹²⁰ The study found that current capital cost estimates were generally higher than the escalated SRCCS costs. For example, a reference pulverized coal plant with supercritical steam conditions (SCPC) firing bituminous coal, without CO₂ capture, had a 28% higher cost than the corresponding escalated SRCCS cost. For a similar plant with CO₂ capture, the current cost was 37% higher than the corresponding escalated SRCCS cost.

In contrast, comparison of current-study LCOE values with escalated SRCCS LCOE values showed little difference (despite the higher capital cost in current studies), which was attributed to the more recent studies using assumptions that lowered LCOE. Such assumptions included:

- Average power plant sizes without CCS about 10% to 25% larger than those in the SRCCS studies
- Higher capacity factors than those in the SRCCS studies: by about 10 percentage points for PC plants, 2 percentage points for IGCC plants, and 8 percentage points for NGCC plants
- Lower fixed charge factors (which in part could reflect today's lower interest rates): by about 30% for SCPC plants, 20% for IGCC plants, and 10% for NGCC plants

Table 2-16 shows the LCOE comparisons for NGCC, SCPC, and IGCC, including transport and storage, with all values in constant 2013 dollars.¹²¹

Table 2-16
Fossil Power Plant with CCS LCOE Comparison for Recent Studies and Escalated 2005 IPCC Study

Case	NGCC with post-combustion capture	SCPC with post-combustion capture	IGCC with pre-combustion capture
Without EOR			
SRCCS (adjusted)	56–110	94–163	92–150
Recent Studies	63–122	95–150	112–148
With EOR Credits			
SRCCS (adjusted)	48–100	76–139	77–128
Recent Studies	48–112	61–121	83–123

¹²⁰ Rubin E.S., et al. "The Cost of CO₂ Capture and Storage," *International Journal of Greenhouse Gas Control* 1750-5836/2005.

¹²¹ Rubin, Edward S. "The Cost of CCS: A Review of Recent Studies," presentation at the CCS Cost Network Workshop in Cambridge, MA. March 22, 2016.

Other study assumption trends and economic data changes between 2002 and 2013 that affected cost study results include:

- Escalation of capital costs
Capital costs rose primarily due to significant increases in the cost of commodities and industrial equipment. The study used the IHS North American Power Capital Costs Index to escalate the capital cost for power plants from 2002 to 2013 U.S. dollars and the Chemical Engineering Plant Cost Index to adjust CO₂ transportation and storage costs. Increases in these two indices were 64% and 44 %, respectively.
- Escalation of fuel costs
Over the selected timeframe, coal prices roughly doubled, while natural gas prices in the United States rose sharply in 2004–08 before declining to roughly 2002 levels. In Europe, natural gas prices continued to rise but have recently moderated.
- Experience gained from pilot plants and demonstrations
FEED studies confirm the anticipated high FOAK costs associated with CCS projects compared to NOAK projects. However, the magnitude of cost differences is difficult to predict for a particular technology.
- There is greater consistency in recent CCS cost studies than in studies from the 2000s; however, a major exception is the difference in reporting between current versus constant dollars, and whether the basis is even clearly specified.

Other Comparative Analyses of Generating Technologies

A 2017 analysis of capital and levelized costs by Lazard spanned multiple alternative and conventional power generation technologies.¹²² Certain assumptions were identical for all technologies, including required debt and equity returns, capital structure, and economic life, in order to isolate the effects of key differentiated inputs such as investment costs, capacity factors, operating costs, and fuel costs (where relevant). These inputs were developed in tandem with a leading consulting and engineering firm and augmented by Lazard’s commercial experience. Input from a wide variety of industry participants. The 2017 analysis assumed:

- 60% debt at 6% interest rate and 40% equity at 10% cost for conventional and alternative energy generation technologies
- Average coal price of \$1.47/MBtu (\$1.39/GJ) based on Northern Appalachian Upper Ohio River barge-delivered coal and Pittsburgh Seam rail-delivered coal
- A range of \$0.65–\$1.33/MBtu (\$0.62–\$1.26/GJ) based on Illinois Basin rail-delivered coal for IGCC
- Natural gas price of \$3.45/MBtu (\$3.27/GJ).

Lazard results compare capital costs and LCOE with and without available subsidies. However, as shown in Table 2-17, the cost range for fossil power technologies is broad, suggesting that project-specific factors have a major influence on plant costs. Developers of U.S. coal power projects with partial (or full) CO₂ capture may face in a challenge in narrowing uncertainty when estimating total capital requirements and LCOE.

¹²² Lazard’s *Levelized Cost of Energy Analysis—Version 11.0*. November 2017.

Table 2-17
Lazard Unsubsidized LCOE Estimates for Fossil Generation Technologies (\$/MWh)

Technology	LCOE (\$/MWh)
Diesel Reciprocating Engine	197–281
Natural Gas Reciprocating Engine	68–106
Natural Gas Simple Cycle (Peaking Duty)	156–210
NGCC	42–78
IGCC*	96–231
Pulverized Coal**	60–78

* The high end of the range includes 90% CO₂ capture, but not CO₂ transportation and storage costs. Incorporates recent U.S. IGCC experience.

** The high end of the range includes 90% CO₂ capture, but not CO₂ transportation and storage costs.

3

PULVERIZED COAL AND FLUIDIZED-BED COMBUSTION PLANTS

Supercritical steam conditions have become the norm for new PC units around the world, and a growing fraction are employing ultra-supercritical steam conditions, with main steam temperatures up to 1120°F (605°C) and reheat temperatures up to 1150°F (620°C).¹²³ European units have emphasized higher main steam pressures as well as temperatures, reaching 4420 psi (305 bar), but the design trend in countries with significant intermittent renewables, where coal plants may need to load-follow and cycle more often, has been toward thinner-walled main steam piping (by lowering pressure or using stronger high-temperature materials) to accommodate faster load ramping. In North America, steam conditions of 3500 psig/1050°F/1050°F (241 bar/566°C/566°C) now seem to be a minimum. AEP/SWEPCO's 600 MW John W. Turk, Jr., plant was the first modern unit to use USC steam conditions, with main and reheat temperatures of 1110°F (599°C) and 1125°F (607°C), respectively. With currently available ferritic/martensitic steels, the maximum sustainable steam temperature is believed to be about 1160°F (630°C).

Advanced ultra-supercritical (A-USC) steam cycles, with steam temperatures up to 1400°F (760°C), allow for substantial efficiency gains but entail use of expensive, nickel-based alloys for the hottest portions of the steam cycle. Although such alloys are not in commercial use in steam generators, a consortium of researchers and suppliers have been assembling and submitting data to support approval by engineering codes and standards bodies.

PC Market Activity

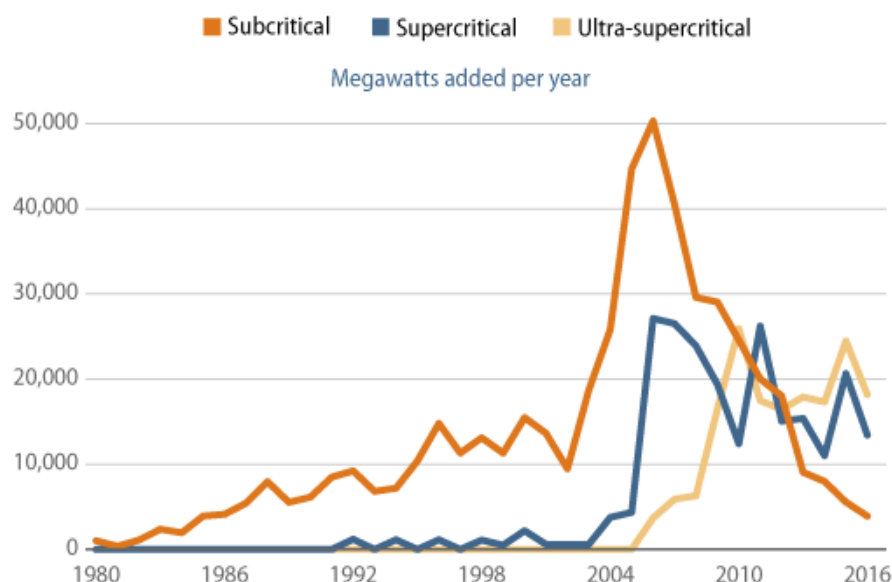
Worldwide, the number of PC plants in the planning and construction phases has shrunk in recent years, although significant activity continues in China, India, and emerging economy nations. From 2010 to 2015, China added nearly 300 GW of new PC generation, with many of these plants employing USC steam conditions. Figure 3-1 charts China's shift toward more efficient power plant technology.¹²⁴

In 2016–17, restrictions on new coal plants were enacted by China's National Energy Administration in response to increasingly low utilization rates: 150 GW of coal projects that were once in development have been terminated or placed on hold until after 2020.¹²⁵ Nonetheless, 94 GW of coal plants were under construction in 2018.

¹²³ A.J. Bennett et al. *Successful Operation of Jinzhushan 3, the World's First PC-Fired Low Mass Flux Vertical Tube Supercritical Boiler*. Presented to Power Gen Asia: November 2010. Babcock & Wilcox Power Generation Group, Technical Paper BR-1849.

¹²⁴ Hart, Melanie, et al. "Everything You Think You Know About Coal in China Is Wrong." Center for American Progress. May 15, 2017.

¹²⁵ EIA. "Chinese coal-fired electricity generation expected to flatten as mix shifts to renewables." *Today in Energy*, September 27, 2017.



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Figure 3-1
China's Coal-Fired Capacity Additions by Steam Cycle Conditions

India has over 214 GW of coal-fired power plants, which account for about 60% of the country's installed generating capacity. Coal plants totaling over 43 GW are reported to be in the construction phase.¹²⁶ Until 2010, all new power plants in India were built with subcritical steam cycle technology, but many of the new units use supercritical steam conditions, including the Ultra Mega Power Projects (UMPP). The government's UMPP initiative of 2005–06 called for the development of 16 supercritical coal-based UMPP of nominally 4000 MW each. The UMPP could be located either at the minemouth for domestic coal or at coastal locations for imported coal. Thus far, two UMPPs have been completed and put into service: the Mundra plant in Gujarat and the Sasan plant in Madhya Pradesh.¹²⁷

In Bangladesh, plans to build 19 new coal-fired units are running considerably behind schedule (for a variety of reasons), with reportedly only one coming on-line in accordance with a government timetable.¹²⁸

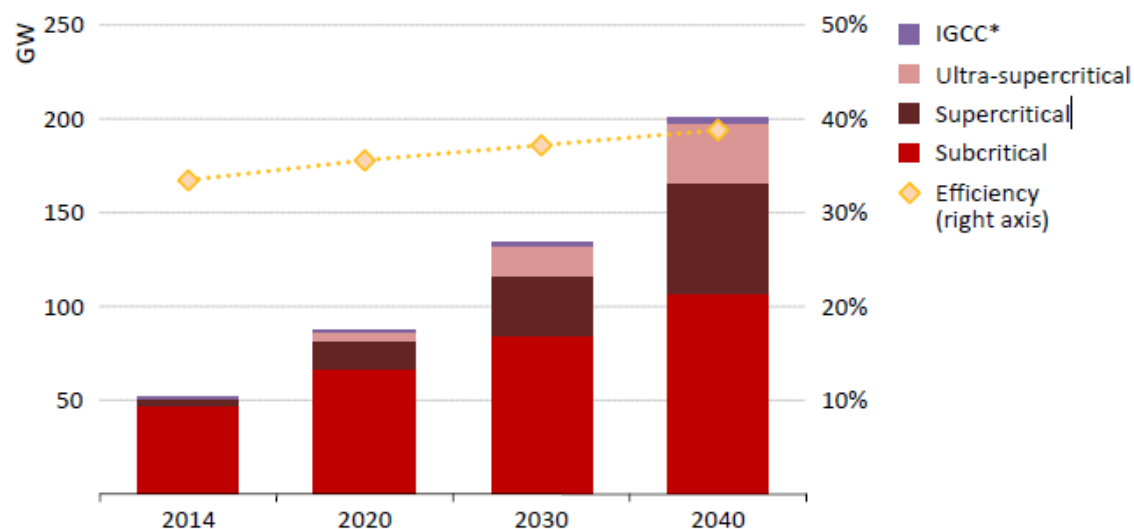
In Southeast Asia, as shown in Figure 3-2, IEA anticipates heavy growth in subcritical units with a shift toward supercritical and ultra-supercritical technologies (and some IGCC) in later years.¹²⁹ Table 3-1 features select activity for new USC power plants in Southeast Asia, as well as South Korea, United Arab Emirates, and Bangladesh.

¹²⁶ https://docs.google.com/spreadsheets/d/1W-gobEQugqTR_PP0iczJCrdaR-vYkJOdzstSsCJXuKw/edit#gid=0

¹²⁷ *Combustion Technology Status: 2017 Update*. EPRI, Palo Alto, CA: 2017. 3002011209.

¹²⁸ <https://www.dhakatribune.com/business/2018/01/21/little-progress-large-coal-fired-power-plant-projects/>

¹²⁹ *Southeast Asia Energy Outlook 2015*, International Energy Agency.



*Integrated gasification combined-cycle.

Figure 3-2
Projected Installed Coal-Based Capacity by Technology Type and Fleet Efficiency (HHV Basis) in Southeast Asia, 2014–2040

Table 3-1
Select USC Power Plants

Plant, Location	Company	MW	Startup Year	Notes
Manjung 4, Janamanjung Power Station, Perak, Malaysia	Tenaga Nasional BHD (TNB)	1000 (net)	2015	Reported cost \$1.5 billion; 15 different coals specified. Boiler by Wuhan Boiler Company. ST by GE/Alstom.
Manjung 5, Janamanjung Power Station, Perak, Malaysia	Tenaga Nasional BHD (TNB)	1000	2017	Reported cost \$1.5 billion. EPC by Sumitomo Corporation and Daelim Industrial Co. Ltd.
Tanjung Bin Energy Power Plant (T4), Johor, Malaysia	Malakoff Power BHD (MPB)	1000	2016	Alstom/GE-led EPC team and technology.
Jimah East Power Station, Mukim Jimah, Malaysia	Jimah East Power	2 x 1000	2019–20	Boilers by IHI Corporation; total project cost ~\$3 billion (2018)
Lontar Power Station Unit 4, Indonesia	PT.PLN (Persero)	315	2020	Construction start in 2016. Estimated cost \$485 million. Boilers supplied by IHI; ST by Toshiba.
Taeon Thermal Power Plant, Units 9 and 10, South Korea	Korea Western Power Co., Ltd.	2 x 1025 (net)	2016–17	Daelim-led consortium. Hitachi boilers and STs.

Plant, Location	Company	MW	Startup Year	Notes
Hassyan Coal Power Project, Dubai, United Arab Emirates	Hassyan Energy Company	4 x 600 (gross)	2020 through 2023	Construction started in 2016; estimated cost \$3.4 billion; GE boiler and ST; EPC contract for the first two units awarded to Harbin Electric International and GE.
Matarbari Power Plant, Cox's Bazar District, Bangladesh	Coal Power Generation Company Bangladesh	2 x 600 (gross)	2024	Estimated cost \$4 billion*; subbituminous coal; EPC by IHI, Sumitomo, and Toshiba.
Payra Thermal Power Plant, Bangladesh	Bangladesh-China Power Company Limited (BCPCL)	2 x 660 (gross)	2019	Estimated cost: \$2 billion. BCPCL is a joint venture by Bangladesh's North-West Power Generation Co. and China National Machinery Import and Export Company (CMC). EPC by two Chinese firms.
Talin Power Station, Taiwan	Taipower	2 x 800	2018	EPC by IHI, CTCI Corp, Sumitomo, and Toshiba; new units will replace older units 1 and 2.

*The higher estimated cost of the Matarbari project (relative to other USC projects in Bangladesh) has been attributed to additional components: river dredging, transmission, land acquisition, and a port capable of receiving and unloading large ships.

From 2007 through 2014, a dozen SCPC units and one USC PC unit, totaling more than 10,300 MW, entered service in the United States. This appears to be the last group of new PC units in the United States for the foreseeable future. This hiatus, which EIA forecasts could last for up to two decades, is the combined effect of uncertainty over baseload power demand growth, competition from natural gas-fired units and renewable generation capacity additions, and EPA regulations for CO₂ and air emissions, effluent discharge, and coal ash storage/disposal.

In 2018, DOE announced that it is seeking to develop two designs for small modular coal-fired power plants without CO₂ capture by 2022.¹³⁰

In Canada, the government announced the phase out most traditional coal-fired electricity by 2030. An “equivalency agreement” was subsequently reached, but not finalized, that would include CCS technology as a viable mitigation option. SaskPower anticipates making a decision in 2018 on whether to expand its carbon capture program on Boundary Dam Unit 3 to include Units 4 and 5.¹³¹

Although few in number, EPRI tabulated reported capital costs for PC and CFB plants in the United States and Canada from 2007 through 2013 in Table 3-2 (there have been no new startups since then). In general, costs appear to be higher than those estimated by using actual cost data

¹³⁰ <https://www.utilitydive.com/news/doe-pushing-small-modular-coal-plant-development/518668/>

¹³¹ <http://www.estevanmercury.ca/news/local-news/saskpower-president-responds-to-latest-government-edict-1.3423176>

from a period when more new plants were being built and escalating those values to the present using published construction cost indices.

EPRI cautions against trying to “over-interpret” cost differences between specific projects in Table 3-2. It is often unclear precisely which project costs are included in publicly reported estimates. For example, each company tends to use its own definition of owner’s costs. In many cases, the numbers quoted appear most similar to what EPRI defines as Total Capital Requirement (TCR) minus Allowance for Funds Used During Construction (AFUDC).

Table 3-2
Published Estimates of PC and CFB Plant Capital Costs in North America

Developer / Owner; Plant Name; Location	Net MW	Technology/ Coal	EPC (Major Partner)	Boiler/ Turbine Vendor	Estimate Date	Reported Capital Cost, \$Million ~TPC/~TCR	Reported Capital Cost, \$/kW ~TPC/~TCR	Status
EPRI EEE estimates	750	SCPC / Bit (P8 or I6)			2/2015		1,962/2,546	EPRI standard criteria, Kenosha, WI location.
EPRI EEE estimates	750	USC PC / PRB			2/2015		2,062/2,665	EPRI standard criteria, Kenosha, WI location.
MidAmerican Energy Company, Walter Scott, Jr. Energy Center, Council Bluffs, IA	790	SCPC / PRB	Mitsui	Hitachi/ Hitachi	8/2007	- / 1,200	- /1,520	Startup June 2007.
Wisconsin Public Service Corp., Weston Unit 4, Wausau, WI	545	SCPC / PRB	Black & Veatch	Babcock & Wilcox/ Toshiba	8/2008	- / 773.7	- /1,420	Startup June 2008.
GenPower, Longview PGF Maidsville, Monongalia County, WV	695	SCPC / Bituminous (minemouth)			2/2011	2,000/ -	2,880/ -	Startup 2011.
Peabody Energy + 8 Municipals, Prairie State Energy Campus, Washington County, IL	2 x 800	SCPC / Bituminous (minemouth)			7/2010	~4,000/4,400	2,500/2,750	Unit 1 online Q4 2011; Unit 2 Q3 2012.

Developer / Owner; Plant Name; Location	Net MW	Technology/ Coal	EPC (Major Partner)	Boiler/ Turbine Vendor	Estimate Date	Reported Capital Cost, \$Million ~TPC/~TCR	Reported Capital Cost, \$/kW ~TPC/~TCR	Status
Duke Energy Cliffside Unit 6, NC (Rutherford / Cleveland County line)	800	SCPC / Bituminous			2013	1,800	2,250	Commercial in Dec. 2012. ¹³² Some references suggest that these values include FGD for Unit 5.
Dominion Virginia Power Virginia City Hybrid Energy Center	585	Subcr. CFB / coal, waste coal and biomass			7/2012	1,800 ¹³³	3,077	July 2012 startup. 2 x 334 MWe CFB boiler; air-cooled condenser.
AEP SWEPCO John W. Turk, Jr., Hempstead County, AR	600	USC PC / PRB	Shaw Group	B&W/ Alstom	2013	~1,800	~3,000	Commercial op Dec 2012. ¹³⁴
Xcel Energy, Comanche Unit 3, Pueblo, CO	750	SCPC / PRB, Air-Cooled Condenser	Shaw Group	Alstom/ MHI	2004	1,300	1,733	Startup July 2010.
Luminant, Oak Grove, Units 1* and 2*, Bremond, TX	2 x 800	SCPC / Lignite	Fluor	Alstom*/ GE B&W*/ GE	8/2010	3,250 (incl Sandow 5)		Unit 1 startup Dec 2009; Unit 2 startup May 2010.
Luminant, Sandow 5, Rockdale, TX	565	CFB / Lignite						Startup Sept 2009.
We Energies, Elm Road Units 1 and 2, Oak Creek, WI	2 x 600	SCPC / Bit.	Bechtel	Hitachi / Hitachi	10/2010	2,300/ -	1,917	Unit 1 startup Feb 2010; Unit 2 startup Jan 2011.

¹³² *Cliffside Steam Station*. Duke Energy Brochure. Revised April 2013.

¹³³ R. Peltier. "TOP PLANT: Virginia City Hybrid Energy Center, Virginia City, Virginia." *POWER*. October 1, 2012.

¹³⁴ R. Peltier. "AEP's John W. Turk, Jr. Power Plant Earns *POWER*'s Highest Honor." *POWER*. August 1, 2013.

Developer / Owner; Plant Name; Location	Net MW	Technology/ Coal	EPC (Major Partner)	Boiler/ Turbine Vendor	Estimate Date	Reported Capital Cost, \$Million ~TPC/~TCR	Reported Capital Cost, \$/kW ~TPC/~TCR	Status
Louisville Gas & Electric, Trimble County Unit 2, Louisville, KY	750	SCPC / Bit.	Bechtel	Doosan Babcock / -		1,200 /	1,600	Startup 2010.
Kansas City Power & Light, Iatan Unit 2, Weston, MO	850	SCPC / PRB	Burns & McDonnell	Alstom/ Toshiba	2011	~2,000 ¹³⁵ /	~2,350	Startup Aug 2010.
TransAlta/Capital Power, Keephills 3, Lake Wabamun, Alberta	450	SCPC / Local Subbit.	Capital Power; Hitachi	Babcock- Hitachi K.K./ Hitachi	9/2011	1,980 CDN (est.)	4,400	Startup Sept 2011.

* Equipment originally purchased in the 1970s and stored.

¹³⁵ R. Peltier. "Plant of the Year: KCPL's Iatan 2 Earns *POWER*'s Highest Honor." *POWER*. August 1, 2011.

In Europe, the number of new coal power projects remains small, and in some areas development activity has halted. In Germany, Uniper's 1100 MW (gross) Datteln 4 unit, scheduled for commissioning in 2020, could be Germany's last coal-fired power plant.¹³⁶ This turnabout comes after Germany added over 7000 MW of coal-fired capacity between late 2013 and early 2015,¹³⁷ although in many instances, the new units allowed for older units to be retired. Recently, there is concern that cost recovery for the new units may prove difficult due to competition from renewables and the decrease in electricity market prices since the coal power projects were conceived.¹³⁸ This dynamic has impacted the prospects of Unit D at RWE Power's Westfalen power plant. Startup was delayed due to boiler leaks. Low electricity prices and escalating cost estimates for repairs led RWE to cancel the unit's completion in December 2015.¹³⁹

Coal-fired power plants in the Netherlands have also been struggling to remain economically viable due to weak electricity demand and competition from renewables.¹⁴⁰

Table 3-3 contains a selection of recent and planned European plants. All are USC plants, typically with steam conditions of 4133 psia/1112°F (285 bara/600°C). The RDK 8 unit at Karlsruhe is reported to have achieved 47.5% net thermal efficiency (LHV basis) while producing 912 MW of electricity. The unit serves district heating loads as well as generating electricity, which boosts fuel utilization efficiency to over 60%.¹⁴¹

Market activity for new coal power plants in Europe is currently concentrated in Poland and the Balkan states, which have existing coal reserves and growing economies. Poland inaugurated Europe's largest coal-fired unit, a 1075 MW unit provided by Mitsubishi Hitachi Power Systems, at the Kozienice power plant in December 2017.¹⁴² The designed net efficiency rate is 45.59% (LHV) with steam conditions of 4350 psi/1112°F/1150°F (300 bar/600°C/620°C). Poland has large reserves of lignite and hard coal, however, it is estimated that about 80% of Polish coal mines have become unprofitable with annual losses climbing to over €1 billion a year. Missed quotas from mines resulted in increased imports of more expensive coal or natural gas. Modernizing plans to unlock deep reserves and develop new deposits were approved in January 2018.¹⁴³

About a quarter of Turkey's electricity comes from coal, and the government is backing an expansion of its fleet to meet rising energy demand with domestic lignite supplies and minimize

¹³⁶ <https://www.platts.com/latest-news/electric-power/london/german-year-ahead-coal-fired-power-generation-26802799>

¹³⁷ <http://www.platts.com/latest-news/coal/london/vattenfall-to-start-new-800-mw-german-coal-unit-26022006>

¹³⁸ <http://www.bloomberg.com/news/articles/2014-06-26/germany-s-new-coal-plants-push-power-glut-to-4-year-high>

¹³⁹ <http://www.industcards.com/st-coal-germany-nw-n-w.htm>

¹⁴⁰ <http://www.climatechangenews.com/2016/11/30/brand-new-dutch-coal-plants-are-crashing-in-value/>

¹⁴¹ <http://www.power-technology.com/features/features/supercritical-mass-inside-the-new-generation-of-coal-fired-power-plants-4872235/>

¹⁴² <https://www.power-technology.com/projects/kozienice-coal-fired-power-station-unit-11/>

¹⁴³ <http://www.powermag.com/king-coal-is-alive-and-kicking-in-poland/?pagenum=1>

reliance on natural gas imports. The government has also launched a privatization campaign for state-owned thermal power plants and coal reserves.¹⁴⁴

Table 3-3
Select New Pulverized Coal Units in Europe

Plant, Location	Company	Net MW	Startup Year	Notes
Germany				
Datteln 4, Datteln*	Uniper (formerly E.ON)	1055	Planned for late 2020	Construction complete; Emissions control permit issued January 2017; estimated cost €1.4 billion (2017)
Lünen, Stummhafen*	Trianel	700	2013	Reported cost: \$1.5 billion
Mannheim 9, Neckarau*	Grosskraftwerk Mannheim	843	2015	Commissioning commenced ahead of schedule in February 2015.
Moorburg A & B, Hamburg*	Vattenfall Europe	2 x 760	2014	Estimated cost: \$3.8 billion
Rheinhafen Power Station RDK 8, Karlsruhe*	EnBW Kraftwerke	842	2013	Estimated cost: €1.0 billion (2010)
Walsum 10, Duisburg	STEAG/EVN	725	2013	Reported cost: €820 million (2011)
Westfalen D & E, Hamm**	RWE Power	2 x 765	2014	Startup for Unit E only; Unit D delayed by boiler leaks; completion discontinued in December 2015.
Wilhelmshaven, Lower Saxony	GDF SUEZ	731	2014	
The Netherlands				
Eemshafen 1 & 2, Eemshafen	Essent/RWE	2 x 800	2015	Reported cost €3 billion (2015)
Maasvlakte, Rotterdam	Electrabel/GDF SUEZ	800	2013	Estimated cost: €1.2 billion (2009); cofiring biomass
Maasvlakte 3, Rotterdam**	E.ON	1050	2013	Cofiring biomass
Poland				
Opole Power Station 5 & 6, Opole	PGE	2 x 900	2018-19	Estimated cost: \$3.7 billion (2014)

¹⁴⁴ <https://www.lexology.com/library/detail.aspx?g=2dc06d1f-3efc-495e-ae3d-4748e01a74e8>

Plant, Location	Company	Net MW	Startup Year	Notes
Kozienice 11, Świerże Górne	Enea Wytwarzanie/Elektrownia Kozienice	1075	2017	Reported cost: €1.5 billion
Ostroleka C, Ostroleka	Energa and Enea	1000 (gross?)	2023	~\$1.8 billion (2018) bid by GE/Alstom ¹⁴⁵
Slovenia				
Sostanj Power Station 6, Savinjska	Termoelektrarna Sostanj	600	2014	Reported cost: €1.4 billion (2016)
* Combined heat and power ** Capture ready				

As of early 2018, seven of Japan's nuclear reactors have restarted under the new safety standards developed in the wake of the 2011 Fukushima-Daiichi failure. To address the country's generation shortfall while the nuclear fleet was shut down, Japanese power companies stepped up deployment of other generation types. About a dozen new NGCC plants have come on-line or will soon. Additionally, a 600 MW and a 1000 MW USC PC unit, both with 3553 psia/1112°F/1112°F (245 bar/600°C/600°C) steam conditions, started up in 2013. This makes for a total of 24 USC PC units with a combined capacity of nearly 20 GW, as of 2015.¹⁴⁶ Construction is also under way for two 540 MW (gross) IGCC units to be built in the Fukushima prefecture.¹⁴⁷

South Africa's state-owned utility, Eskom, currently has two six-unit SCPC power plants, totaling about 4800 MW (gross) each, under construction: Medupi and Kusile. Medupi's first 800 MW unit commenced operation in 2015 and two additional units entered commercial service in 2017. Full completion of the plant is scheduled for 2019–20. The first units at Kusile began commercial service in 2017 and another is scheduled to come on-line in 2018. Medupi and Kusile will be the world's largest dry-cooled coal power plants. The projects help Eskom address reserve shortfalls and improve system reliability.

CFB Market Activity

Coal-fired CFB technology has advanced as well, with larger unit sizes and with efficiencies approaching those of all but the newest PC boilers. The first supercritical CFB unit, the 439 MW (net) unit at the Lagisza Power Station in Poland, with an HHV efficiency >41%, has now been in service for nine years. Among the more recent additions to the global supercritical CFB fleet is the 312 MW (net) unit at the Novocherkasskaya plant in Russia, which entered commercial service in mid-2016.¹⁴⁸ The Samcheok Green Power Plant in South Korea uses four USC CFB

¹⁴⁵ <https://www.reuters.com/article/us-energa-ostroleka/three-groups-offer-to-build-polish-coal-fired-power-plant-idUSKBN1EM14K>

¹⁴⁶ *Combustion Technology Status: 2015 Update*. EPRI, Palo Alto, CA: 2015. 3002007200.

¹⁴⁷ <https://www.mhps.com/en/news/20140912.html>

¹⁴⁸ Peltier, R. "Advanced CFB Technology Gains Global Market Share." *Power Magazine*, November 2016.

550 MW boilers powering two 1000 MW (net) steam turbines. The plant sources high-moisture Indonesian coal and biomass as fuel, which is expected to save millions of dollars in fuel costs over the plant's life, relative to higher ranked fuels. Steam conditions are 3728 psi/1117°F/1117°F (257 bar/603°C/603°C).¹⁴⁹ The project's cost is reportedly \$3 billion.¹⁵⁰

The world's largest single fluidized-bed boiler to date is China's 600 MW Neijiang Baima Unit 5, completed in 2013.¹⁵¹

Advanced CFB units retain their ability to burn high-ash and slagging/fouling fuels that might be problematic for PC boilers. SO₂ capture rates of 91–95% can be achieved with in situ limestone addition to the combustion bed, and firing temperatures remain low enough to limit NO_x formation. Where lower emissions are required, CFB designs include polishing FGD and selective noncatalytic reduction (SNCR) or SCR. Recent CFB boiler designs with polishing dry FGD units have boosted overall SO₂ capture to more than 98%.¹⁵²

Materials Development and Testing for Advanced USC Steam Conditions

The pursuit of high-strength, high-temperature materials and fabrication processes to enable A-USC steam temperatures of nominally 1300°F (700°C) or greater has been an RD&D focus since the 1990s, with major initiatives in Europe, Japan, and the United States. The U.S. program, funded chiefly by DOE, the Ohio Coal Development Office, and major boiler and turbine equipment manufacturers, and with technical participation by EPRI and others, began a pre-competitive R&D project more than a decade ago with the aim of achieving A-USC steam conditions of 1400°F (760°C) and 5000 psia (345 bar).¹⁵³ A PC unit operating at these conditions could achieve an efficiency as high as 47–48% (HHV basis) firing bituminous coal.

Candidate materials were identified for the highest temperature sections of the boiler and steam turbine. Material samples have been subjected to certification testing to validate fabrication procedures and to confirm that the material properties and aging behavior of fabricated components are suitable for the intended boiler and steam turbine uses. From 2012–14, steamside and fireside corrosion testing was conducted at Southern Company's Plant Barry Unit 4 on a reheat steam loop containing 94 specimens made of eight different superalloys with three different surface coatings.¹⁵⁴ Among the boiler alloys tested were Super 304H, HR6(7)W, Haynes 230, Inconel 617, Haynes 282, and Inconel 740(H). This was the first steam loop in the world operating with a maximum temperature of 1400°F (760°C), achieving over 5000 hours at or above that temperature. [A steam loop at E.ON's Scholven plant in Germany had previously operated at 1300°F (700°C).]

¹⁴⁹ <http://www.powermag.com/advanced-boiler-and-hrsg-designs-offer-improved-performance/>

¹⁵⁰ Peltier, R. "Advanced CFB Technology Gains Global Market Share." Power Magazine, November 2016.

¹⁵¹ Ibid.

¹⁵² *Developments in Circulating Fluidized-Bed Combustion Technology*, EPRI, Palo Alto, CA: 2009. 1015695.

¹⁵³ *Boiler Materials for Ultrasupercritical Coal Power Plants*. EPRI, Palo Alto, CA; U.S. Department of Energy (DOE), Washington, DC; and Energy Industries of Ohio (EIO), Independence, OH: 2011. 1022037.

¹⁵⁴ *Progress Report on Advanced Ultra-Supercritical Technology Development*. EPRI, Palo Alto, CA: 2013. 3002001343.

Following the successful test of the steam loop at Plant Barry Unit 4, the U.S. consortium began work on a Component Test (ComTest) program to build a prototype R&D-scale A-USC steam turbine and other A-USC plant components. The consortium, for which EPRI serves as the technical lead, completed a pre-FEED and produced a ComTest configuration. The steam flow rate from the host plant, Alabama Power’s Plant Gaston, will be 120,000 lb/hr (15.2 kg/s).¹⁵⁵

The project plan calls for a manufacturing demonstration of full-size turbine (825 MW IPT) components including a rotor forging and a “nozzle carrier” (inner casing) casting. The manufacture and operational testing of the main steam control valve falls under a related DOE program.

The consortium’s economic study found that an A-USC steam turbine train was approximately twice the cost of a comparable state-of-the-art USC turbine train, chiefly due to the necessary use of nickel-based alloys in select components of the high pressure (HP) and intermediate pressure (IP) turbines. The study found an even more significant cost increase in the long main and reheat steam piping lines, which would also need to be fabricated from nickel-based alloys for the A-USC plant. However, the study was based on a traditional boiler design and turbine arrangement. Follow-on investigations examined innovative boiler/turbine configurations—including Babcock & Wilcox’s downdraft inverted tower (discussed later)—that minimized the quantity of nickel piping in order to reduce costs.

Notably, when USC and A-USC are compared based on partial CO₂ capture, the higher efficiency of the A-USC plant, even with a traditional boiler/turbine configuration, delivers a lower LCOE because it can process less flue gas than the USC plant to reach a given output emissions rate (see Table 3-22.)

In addition to materials development programs for A-USC in the United States, Europe, and Japan, initiatives are under way in China and India, with demonstrations announced for both countries in the 2020 timeframe.¹⁵⁶ The Chinese National Innovation Alliance of 700°C USC Coal-Fired Electricity Generation Technology was established in 2010 and several Chinese organizations are working to optimize the physical arrangements between the boiler and steam turbine, which is applicable to both USC and A-USC plants.¹⁵⁷

Post-Combustion CO₂ Capture

Post-combustion capture using an amine-based liquid sorbent (or “solvent”) in a chemical absorption and thermal regeneration cycle is the most mature option for CO₂ separation from PC, CFB, and NGCC flue gases. Aqueous monoethanolamine has the longest commercial history, and significant effort has gone into various additives and other modifications to MEA chemistry to enable higher concentrations in solution with reduced corrosion. Many other formulations of “advanced amines” and amines mixed with other chemicals have been (and continue to be)

¹⁵⁵ *Combustion Technology Status: 2017 Update*. EPRI, Palo Alto, CA: 2017. 3002011209.

¹⁵⁶ *Coal Technologies with CO₂ Capture - Status, Risks, and Markets: 2013 Update*, EPRI, Palo Alto, CA: 2013. 3002000435.

¹⁵⁷ *Combustion Technology Status: 2017 Update*. EPRI, Palo Alto, CA: 2017. 3002011209.

developed with the aim of reducing regeneration energy requirements and providing other operational advantages.

Figure 3-3 illustrates a generic two-stage amine-based CO₂ absorption process. The flue gas first passes through an absorption column where the solvent, flowing counter-current to the gas, removes the majority of the CO₂ by chemical absorption. The “CO₂ rich” solvent then passes to a stripping column where it is heated with steam (through a heat exchanger known as a reboiler), causing it to release the CO₂, which regenerates the solvent for return to the absorber to capture more CO₂. This process has demonstrated CO₂ capture rates exceeding 90% with CO₂ purity exceeding 99.5%.

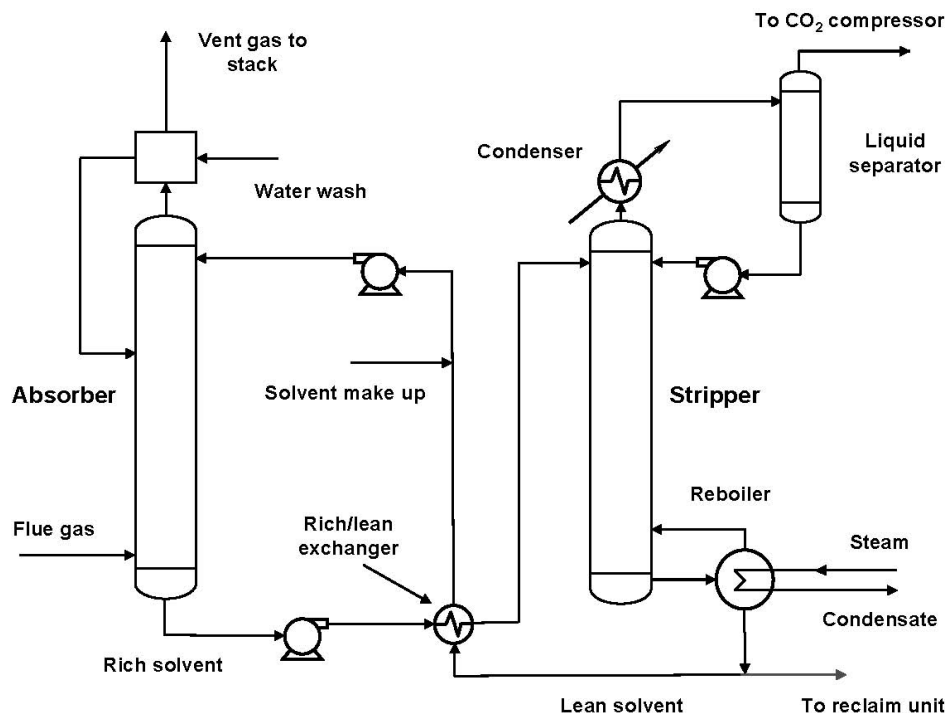


Figure 3-3
Process Flow Diagram for a Generic CO₂ Capture Process Using a Regenerable Solvent

Current R&D seeks to reduce the size, expense, and energy use of absorption and stripping equipment to both reduce costs and enable retrofits within the space available at existing power plants. Complementary R&D aims to reduce the equipment size and auxiliary power and cooling loads for compressing and dehydrating captured CO₂ to the dense phase desired for pipeline transport. Solvent maintenance and makeup can also be a significant cost. Managing solvent carryover and fugitive emissions is also a challenge.

Other CO₂ “solvent type” capture technologies now in the scale-up and demonstration phases use ammonia/ammonium carbonate, potassium carbonate, amino-acid salts, or enzymes. Researchers have tested hundreds of solvent formulations that vary the solution strength of single or multiple sorbent compounds and incorporate additives that promote the reaction mechanisms or perform other functions such as reducing corrosion or solvent degradation. At least one technology uses a phase-separating solvent. Researchers are also investigating ionic liquids that could replace the water and improve the thermal efficiency of the absorption and regeneration processes.

Alternative candidate technologies for post-combustion CO₂ capture include solid sorbent processes, membrane separation processes, mineral and biological fixation processes, and cryogenic separation processes.

Adding current post-combustion CO₂ capture and compression equipment to an existing coal plant to capture 90% of its CO₂ will reduce net electrical output by roughly 20–35% (assuming steam extraction from the power cycle for CO₂ solvent regeneration). O&M costs will increase as well. Yet in an era of high capital costs and difficult permitting for new construction, a CO₂ capture retrofit to an existing plant may be more economical than building a new coal plant with integral CO₂ capture, even if the capture process is a bit more efficient. The economically preferred approach will depend on the actual differences in capital cost (which in turn will depend on the capability of emissions control equipment in the existing plant), the degree to which the existing plant is fully amortized but has a long remaining life, the relative differences in efficiency and fuel cost, and the market for additional baseload power.

The plants considered the most likely candidates for retrofit would have the following characteristics:

- Major components in sufficient condition to justify operation for another 20–30 years
- Dispatch at a high capacity factor
- Have enough space on site to accommodate the CO₂ capture, compression, and cooling equipment, and associated construction access
- Have access to additional cooling water
- Have FGD, SCR, and Hg removal systems in place
- Have an identified site for CO₂ sequestration (or pipeline for CO₂ sale) within a reasonable distance of the plant

Other considerations include the suitability of the steam turbine or turbine crossover extraction points for supplying steam to the stripper reboiler and the ability to obtain replacement power, if needed.

CO₂ Capture Project Updates and Results

Small-scale commercial CO₂ capture systems have been in service on coal-fired units in the United States since as early as 1978. The late 2000s and early 2010s saw the startup of several slipstream capture pilots at PC (and industrial) plants, as well as the first tests of geologic sequestration using CO₂ from coal-fired plants. Some project demonstrated the full integrated CCS chain: CO₂ capture and compression, pipeline transport, and geologic storage.

Beginning in the mid-2010s, two large-scale post-combustion CO₂ capture projects on coal plants entered the stage of early commercial application (one in Canada, one in the United States). Other large-scale projects in OECD countries proceeded through front-end engineering and permitting phases, but did not receive anticipated government or other funding to proceed. Table 3-4 shows that large-scale post-combustion CO₂ capture projects are now also occurring in China.

Table 3-4
Select Large Post-Combustion CO₂ Capture Projects at Coal Power Plants

Project; Location	MWe Equivalent (plant rating)	Mt per Year	Technology	Notes
SaskPower Boundary Dam Unit 3; Saskatchewan, Canada	110	>1.0M (~90%)	Shell Cansolv DC-103™ amine; SNC Lavalin EPC; Hitachi turbine; EOR & saline formation storage; 100% SO ₂ capture with integrated Cansolv DS & H ₂ SO ₄ plant	Construction start 2011; 2014 startup; federal and provincial support.
Petra Nova (NRG, W.A. Parish Gen. Station Unit 8); Thompsons, Texas	240 (617)	~1.5M	MHI KM-CDR (>90% capture); EOR; SO _x trim removal; regen steam from NGCC-cogen	~\$1 billion TPC; \$167M CCPI-3 award; startup year-end 2016.
Uniper Maasvlakte; Rotterdam Capture and Storage Demonstration (ROAD), Netherlands	250 (1100 USC PC)	1.1M	Fluor; 90% capture. New, capture-ready USC PC unit started 2013, offshore gas field storage (potentially enhanced hydrocarbon recovery)	€180M EEPR award; €150M Dutch government; project terminated in 2017.
Shengli Oil Field, China; Sinopec Group	220	1.1M	Modified MEA / 90% for EOR	CFB retrofit; (a 100 tpd pilot has been operating since 2010). Startup unknown.
Shidongkou, China; Huaneng Group	350	1.1M	TPRI amine / 90% capture for EOR	Scale-up from pilot project. Startup unknown.
Guangdong CCUS Offshore Project – China Resources Power’s Haifeng Power Plant; Guangdong Province, China	250	1.1M	TBD – testing 5 candidates; 2 amine absorption carbon capture technologies, a pressure-driven membrane carbon separation technology, a vacuum membrane carbon separation technology and a physical adsorption technology. ¹⁵⁸	Pilot-scale testing planned prior to full-scale project.

Scale-up R&D and pilot-scale demonstrations are also under way on capture technologies promising lower parasitic loads and costs. For example, a 66,000 ton (60,000 tonne) per year CO₂ capture project on a 10 MW coal-fired power plant in India was announced in 2016 based on a solvent developed by Carbon Clean Solutions Limited. The process was tested for 3500

¹⁵⁸ http://www.gdccus.org/en/nd.jsp?id=560#_np=2_364

hours at Technology Centre Mongstad, capturing 25,000 tons of CO₂. Its projected commercial-scale cost is \$27/ton (\$30/tonne) of CO₂ captured with sale of the CO₂ for soda ash production.

DOE awarded \$44 million in February 2018 to seven projects for “next generation” CO₂ capture on fossil power plants. Projects include (1) engineering-scale testing of transformational solvent- or membrane-based CO₂ capture technologies, or (2) designing a commercial-scale, post-combustion CO₂ capture system at an existing coal-fueled generating unit. In the latter category, an EPRI-led team will develop an initial engineering design for a membrane-based post-combustion capture retrofit for Duke Energy’s East Bend Station in Kentucky.¹⁵⁹

Boundary Dam Unit 3

The world’s first commercial-scale post-combustion CO₂ capture project, the retrofit of Unit 3 at SaskPower’s Boundary Dam Power Station in Saskatchewan, has captured a cumulative 2.2 million tons of CO₂ (2.0 million tonnes) as of March 2018.¹⁶⁰

The retrofit of Unit 3 began in 2011 and was completed in October 2014. Total project cost was about CAD\$1.5 billion (about \$1.1 billion using a June 2018 exchange rate), which was CAD\$260M more than the original budget due to higher than expected execution costs for construction in the power island (including in part the reported need to remove asbestos and lead paint from the boiler and other equipment).¹⁶¹ A general apportionment of the capital costs for the project shows 50% for CO₂ capture, 30% for plant refurbishment, and 20% for emission controls and efficiency upgrades.¹⁶² SaskPower placed an emphasis on maximizing power output, which led to higher capital cost.¹⁶³ Costs for the Shell Cansolv capture system, which is used for both CO₂ and SO₂ removal, are divided accordingly with the SO₂ portion counted under emissions controls. According to SaskPower, the CO₂ capture plant was completed slightly under budget.

SaskPower achievements during the first three years of operation include:

- Showed capability to reduce CO₂ emissions to 312 lb /MWh (142 kg/MWh), substantially below the required Canadian standard,¹⁶⁴ although current operation is not at this level
- CO₂ quality of >99% has been consistently achieved during operation, and the product CO₂ stream has had oxygen levels well below the pipeline specifications
- Particulate emissions have been significantly reduced compared to operation without CO₂ capture

¹⁵⁹ <https://www.energy.gov/articles/energy-department-invests-44m-advanced-carbon-capture-technologies-projects>

¹⁶⁰ <https://globalnews.ca/news/4077598/saskpower-two-million-tonnes-carbon-captured-storage-ccs-boundary-dam/>

¹⁶¹ <http://www.leaderpost.com/business/energy/SaskPower+says+ICCS+project+115M+over+budget/9055206/story.html>.

¹⁶² *Integrated Carbon Capture and Storage Project at SaskPower’s Boundary Dam Power Station*, IEAGHG, 2015/06, August 2015.

¹⁶³ Proceedings of the CCS Cost Network 2016 Workshop, IEA Greenhouse Gas Programme. DRAFT. May 2016.

¹⁶⁴ “Integrated Carbon Capture and Storage Project at SaskPower’s Boundary Dam Power Station,” IEAGHG, August 2015.

- Heat recovery from the flue gas cooler is sufficient allow operation on only four of six feedwater heaters when the CO₂ capture plant is running
- When maximum output to the grid or grid support services are needed, the CO₂ capture and compression system can go off-line and the unit can operate in automatic generation control mode.

The captured CO₂ is being supplied to Whitecap Resources for EOR in the Weyburn-Midale oilfields, with a small amount being provided to the nearby Aquistore project demonstrating geologic storage in a saline formation.

In 2016, higher than expected amine degradation and foaming issues added CAD\$8–9 million to the plant’s annual operating budget (about \$6–7 million using a June 2018 exchange rate). SaskPower has subsequently added activated carbon filtration of the amine solution to reduce foaming and degradation from heat and coal particulates; it expects to take further actions to reduce amine makeup costs pending the findings of an ongoing root cause investigation.

Boundary Dam Unit 3 was originally commissioned in 1969 with a gross output of 150 MWe. For the retrofit, the boiler was upgraded from 1000°F (538°C) to 1050°F (566°C), with significantly more surface area to increase the efficiency. The boiler’s internal heat transfer components were removed to effectively rebuild the new boiler. The additional weight of the upgraded boiler required reinforcement of the support columns from the top of the building to the footings.

The original turbine was replaced with a modern Hitachi, dual-mode turbine with improved steam and thermal integration, as well as the capability to handle power upstream or downstream of the CO₂ capture plant.¹⁶⁵ The unit’s output in non-capture mode was increased by 11.1 MW (7.4%) over the original retrofit design as a result of the combined improvements in the boiler and the turbine. The resulting 161 MW gross unit produces 112 MW net with the following losses when operating in capture mode: 11 MW existing parasitic load; 23 MW CO₂ capture, including amine and heat regeneration; and 15 MW for compression.¹⁶⁶

Flue gas cooling operation was improved by adding a polymer heat exchanger to recover heat from the cooling process. The captured heat could then be used to pre-heat the condenser water used for steam generation in the power plant, which improved the efficiency of power generation by about 3.5 MW through reduction of the demand on low pressure feed-water heaters during capture plant operation.¹⁶⁷

A flue-gas diverter was installed to divert flue gas to the pre-existing stack when the capture plant was not in operation, which would occur whenever the power plant was operating at less than 50% load. The diverter dampers were designed to allow incremental adjustment between fully open to the carbon capture plant, and fully open to the stack. This adjustability allowed for

¹⁶⁵ *Integrated Carbon Capture and Storage Project at SaskPower’s Boundary Dam Power Station*, IEAGHG, 2015/06, August 2015.

¹⁶⁶ Ibid.

¹⁶⁷ Ibid.

smoother startup and shutdown, and enabled the capture plant to be run at partial capacity independent of the power plant.

As shown in Figure 3-4, the Boundary Dam Unit 3 repowering also included a new sulfuric acid plant to convert captured SO_2 to a salable commodity, which can be shipped via an onsite truck-loading facility. Early operational issues with the sulfuric acid plant were reported as largely addressed by late 2017.



Used with permission from SaskPower and Shell Cansolv.

Figure 3-4
Photo of the Boundary Dam Integrated CCS Demonstration Project

SaskPower was considering the addition of CCS to Boundary Dam Units 4 and 5, which are similar in size to Unit 3. In November 2017, the company said it was not likely to proceed with further CCS retrofits on the basis of costs (although a final decision has yet to be made).²¹⁶ With the prevailing low price of natural gas, NGCC units may be more economical than coal units retrofit with CCS, even with revenue from CO_2 sales to oil producers. Alternatively, adding CCS to Shand power station may cost less than further retrofits at Boundary Dam. For the 300 MW Boundary Dam Unit 6, SaskPower has until 2028 to comply with greenhouse gas regulations.

Petra Nova

The world's largest commercial-scale post-combustion CO_2 capture project at NRG Energy's W.A. Parish generating station near Thompsons, Texas, came on-line in late 2016. A 75 MW natural gas cogeneration unit that started in 2013 provides heat and power for the Mitsubishi Heavy Industries (MHI) KM-CDR® CO_2 capture process on a slipstream of 240 MW equivalent from coal-fired Unit 8. The post-combustion capture and compression processes consume about 45 MW of the power from the cogeneration unit, while the remainder is sold to the grid.

Thus, the steam cycle and output of Unit 8 have not been impacted by the addition of CO_2 capture. The cogeneration plant was specifically designed to support the CO_2 capture and compression system, resulting in greater efficiency and flexibility. Also, because the

uncontrolled CO₂ emissions rate of the cogeneration unit is lower than that of the base coal unit, the net CO₂ per MWh will be lower. This arrangement results in the CO₂ capture operations being tied to the price and supply reliability of natural gas. Also, the cogeneration unit can no longer run independently of the CO₂ capture plant as there is no home for the steam if the capture plant is not operating.¹⁶⁸

Figure 3-5 illustrates the placement of the Petra Nova cogeneration plant and CO₂ capture facilities at the W.A. Parish power plant.



Used with permission from Petra Nova and NRG Energy.

Figure 3-5
Aerial View of Post-Combustion CO₂ Capture Unit at NRG's W.A. Parish Unit 8

CO₂ emissions from the natural gas unit will be about 785,000 tons (712,000 tonnes) per year. CO₂ capture from the coal-fired unit will be about 1.6 million tons (1.5 million tonnes) per year,

¹⁶⁸ *Combustion Technology Status: 2017 Update*. EPRI, Palo Alto, CA: 2017. 3002011209.

which will be sold for EOR. Thus, the project as a whole should result in a net removal of about 815,000 tons (740,000 tonnes) of CO₂ per year. Construction took about two years. The CO₂ is transported by pipeline about 80 miles (130 km) to the Hilcorp West Ranch oilfield. It is expected that CO₂ injection for enhanced oil recovery will increase oil production from about 300–500 barrels per day to 15,000 barrels per day, although it will take 3–4 years to reach full-scale oil production.¹⁶⁹ NRG has stated that the revenue stream from EOR pays for the entire project and that there has been no impact on the power plant or its costs. When the CCS system operates, Parish Unit 8 has about the same CO₂ emissions rate per MWh as an NGCC plant.¹⁷⁰

Total capital cost for the project has been reported at nominally \$1 billion, of which about \$635 million was for the CO₂ capture and compression plant and the cogeneration facility (inclusive of owner's costs).¹⁷¹ Project ownership is a 50:50 joint venture between Petra Nova (NRG Energy and JX Nippon Oil & Gas Exploration) and Hilcorp Energy, which operates the oilfield. DOE provided up to \$190 million in total cost share with \$167 million in financial assistance through the original CCPI Round 3, which included American Recovery and Reinvestment Act (ARRA) funding plus and an additional \$23 million.¹⁷²

Maasvlakte (ROAD)

Uniper's¹⁷³ Maasvlakte Unit 3, in Rotterdam, South Holland, in the Netherlands, is a 1070 MW "capture ready" USC design with steam conditions of 1112–1148°F (600–620°C), 4133 psia (285 bar) that enable the unit to achieve 47% net efficiency (LHV). It began commercial operation in 2015.¹⁷⁴ For the proposed ROAD (Rotterdam Opslag en Afvang Demonstratie) project, CO₂ capture was to be added to a 250 MW equivalent slipstream from Unit 3, capturing 1.1 million tons (1.0 million tonnes) of CO₂ per year, about 23% of the unit's output.

In June 2017, Uniper and Engie announced that they were terminating their participation in the ROAD project, chiefly for financial reasons. The design of the Fluor CO₂ capture plant was complete. The project had obtained all of the necessary permits for capture, transportation, and storage, but full financial closure remained elusive. The EU ETS did not provide a sufficient economic incentive for CCS. Many utilities in EU states have seen their coal and NGCC power plants lose market share in the wake of depressed energy prices spurred by renewables additions.

Haifeng

China Resources Power's coal-fired Haifeng Power Plant located in Shanwei City in the Guangdong Province plans to have 4x1000-MW SC units, and possibly also 4x1000-MW USC

¹⁶⁹ <http://www.nrg.com/generation/projects/petra-nova/>

¹⁷⁰ IEAGHG 5th CCS Cost Network Workshop, September 2017.

¹⁷¹ *Combustion Technology Status: 2017 Update*. EPRI, Palo Alto, CA: 2017. 3002011209.

¹⁷² <https://energy.gov/fe/petra-nova-wa-parish-project>

¹⁷³ Uniper, a wholly owned subsidiary of E.ON, began operations in January 2016. E.ON has transferred its conventional power generation (hydro, natural gas, and coal) to Uniper.

¹⁷⁴ http://www.mega-project.eu/assets/exp/resources/Aris_Blankenspoor_MPP3_theory_versus_practice_rev_20150410_sv.pdf

units, at the site. Units 1 and 2 began operating in December 2014 and April 2015, respectively. Units 3 and 4 are planned to be built by 2019.

Units 3 and 4 are proposed to have a slipstream PCC CCS demonstration project of 1.1 million tons (1 million tonnes) of CO₂ captured annually to be stored in saline formations about 75 miles (120 km) away. To test candidate technologies for this demonstration, two pilot-scale test platforms at 11–55 tons (10–50 tonnes) of CO₂ per day scale will be built to treat flue gas from Unit 1.

Five CO₂ capture technologies were selected as candidates to be tested in the two test platforms: two amine absorption processes, a pressure-driven membrane technology, a vacuum membrane technology, and a physical adsorption technology. Each supplier will conduct a 6- to 12-month campaign in one of the test platforms, with two in an initial phase and three in a second phase.¹⁷⁵

The University of Edinburgh, the Clean Fossil Energy Development Institute, and Guangdong Electricity Power Design Institute developed the CCS test platform design.¹⁷⁶ An EPC contract for detailed engineering was finalized in September 2017. Construction completion is scheduled for year-end 2018.¹⁷⁷ With the test platform at Haifeng, the development team aims to serve as the world's third open-access CO₂ capture technology test center, along with TCM and NCCC.

EIA Capital Cost Update for a USC PC Plant with CCS

In 2017, EIA published updated U.S. cost and performance estimates for a USC PC plant with 90% CO₂ capture using an MEA solvent (see Table 3-5), and also for other select types of power plants.¹⁷⁸ Although the bituminous coal seam isn't named, its heating value is 12,000 Btu/lb (28 MJ/kg) and its sulfur content is 3%. Table 3-6 provides EIA's capital cost breakdown.

¹⁷⁵ <https://www.globalccsinstitute.com/news/institute-updates/haifeng-co2-capture-testing-platform-contract-signed-project-enters-engineering-stage>.

¹⁷⁶ “China Resources Haifeng Power Plant 2 x 1000MW USCPC Project CCUS Demonstration Plan,” 8th Annual European Carbon Capture and Storage Conference, February 2014.

¹⁷⁷ <https://www.globalccsinstitute.com/news/institute-updates/haifeng-co2-capture-testing-platform-contract-signed-project-enters-engineering-stage>.

¹⁷⁸ https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/eiatasks_10388_10687addendum.pdf

Table 3-5
Parameters for USC PC with Post-Combustion CO₂ Capture from U.S. EIA Generating Cost Study (2017)

Parameter	
Unit size, MWe (net)	650
Heat Rate (Btu/kWh, HHV)	11,650
Capital Cost, \$/kW (net)	4,640 EPC 5,569 TPC
Fixed O&M (\$/kW-yr)	80.53
Variable O&M (\$/MWh net)	9.51
SO ₂ , lb/MBtu HHV	0.02
NO _x , lb/MBtu HHV	0.06
CO ₂ , lb/MBtu HHV	20.6

TPC = “overnight cost” including owners costs less financing. Costs are in August 2016 U.S. dollars.

For heat rate in kJ/kWh, multiply the Btu/kWh value by 1.055. For approximate emission values in mg/Nm³, multiply values in lb/MBtu by 100.

Table 3-6
EIA Capital Cost Breakdown for USC PC with Post-Combustion CO₂ Capture

Capital Cost Category	\$(000), August 2016\$
Civil Structural Material and Installation	328,347
Mechanical Equipment Supply and Installation	1,548,824
Electrical / I&C Supply and Installation	235,801
Project Indirects (incl. engineering, distributable costs, scaffolding, construction management, and startup)	601,931
EPC Cost before Contingency and Fee	2,714,903
Fee and Contingency	301,389
Total Project EPC	2,527,608
Owner Costs (excluding project finance)	603,258
Total Project Cost (excluding finance)	3,619,550
Total Project EPC Cost, \$/kW	4,640
Owner Costs 20% (excluding project finance), \$/kW	928
Total Project Cost (excluding project finance), \$/kW	5,569

DOE NETL Studies for PC and CFB Units

In 2017, DOE NETL released updates for its study, *Eliminating the Derate of Carbon Capture Retrofits*.¹⁷⁹

For a subcritical coal plant retrofit, the study considered a “Petra Nova approach” whereby power and steam requirements for a CO₂ capture and compression plant are supplied by a new cogeneration, or combined heat and power (CHP), unit instead of extracting steam from the base plant and adding auxiliary electrical loads. Table 3-7 lists the three cases and Table 3-8 summarizes the results of the comparison as well as providing reference costs for new-build SCPC and NGCC units. Costs are provided in terms of 2011 dollars to facilitate comparison with previous NETL studies.

Table 3-7
Cases for NETL Subcritical PC Retrofit – Derate Mitigation Options Study

Case	Description	Capture Plant Steam Supply	Utility Power Supply	Aux Plant Design Considerations
0	Fully integrated with existing plant	Extraction from existing plant steam cycle	Deduct from plant export power	N/A – retrofit baseline for comparison
1	Simple cycle CHP	Aux plant HRSG	Aux plant combined turbine	Capture plant steam demand drives CT sizing (sized to provide sufficient exhaust flow to HRSG)
2	Combined cycle CHP	Aux plant steam turbine bottom cycle	Aux plant combined cycle	Capture plant steam demand drives new ST sizing designed for steam extraction

¹⁷⁹ Hoffman, Jeff et al. U.S. DOE/NETL. “Post-Combustion Capture Retrofit: Eliminating the Derate.” Presented at NETL CO₂ Capture Technology Project Review Meeting. August 21, 2017.

Table 3-8
Preliminary Cost Results from NETL Derate Mitigation Options Study for a Subcritical PC Plant

	Pre-Retrofit¹	Case 0	Case 1	Case 2	New SCPC w/CCS¹	New NGCC¹
Total Plant Cost (2011\$/kW)	N/A	1709	1191	983	3524	685
Bare Erected Cost	N/A	1214	833	735	2716	561
Home Office Expenses	N/A	111	79	66	263	51
Project Contingency	N/A	251	77	53	430	73
Process Contingency	N/A	132	164	129	115	0
Total Overnight Cost (2011\$MM)	N/A	880	1056	1268	2384	528
Total Overnight Cost (2011\$/kW)	N/A	2069	1447	1195	4333	838
Owners Costs	N/A	360	256	213	809	154
Total As-Spent Cost (2011\$/kW)	N/A	2231	1560	1289	4940	901
COE (\$/MWh)	44.2	112.8	90.6	77.7	142.8	57.6
Capital Costs	N/A	33.9	23.7	19.6	72.2	11.8
Fixed O&M	9.3	18.9	12.2	9.1	15.4	3.4
Variable O&M	9.2	16.4	10.1	7.4	14.7	1.7
Fuel ²	25.7	33.2	38.5	37.5	30.9	40.7
CO ₂ T&S	N/A	10.3	6.0	4.1	9.6	N/A

¹ All comparison cases from Bituminous Baseline Volume 1a Revision 3 (NETL “Cost and Performance Baseline for Fossil Energy Plants, Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3,” U.S. Department of Energy, Pittsburgh, PA 2015). Pre-Retrofit (Case B11A excluding CAPEX), New SCPC w/CCS (Case B12B), New IGCC (Case B31A)

² Assumed delivered fuel prices: coal \$2.94/MBtu (\$2.79/GJ); NG \$6.13/MBtu (\$5.81/GJ)

In 2017, DOE NETL presented results from its study of the feasibility and potential benefits of retrofitting subcritical PC plants to operate at either supercritical or A-USC steam conditions.¹⁸⁰ The five cases are listed below followed by a summary of performance results in Table 3-9 and cost results in Table 3-10.

- B11A – Reference subcritical plant from “Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3” (Bituminous Baseline).
- B12A – Reference supercritical plant from the Bituminous Baseline.

¹⁸⁰ Turner, Marc. U.S. DOE/NETL. “Final Presentation: Retrofitting the Steam Cycle of a Subcritical Pulverized Coal Plant.”

- 1 – Reference advanced USC plant from “Development of Advanced Ultra-Supercritical (A-USC) Pulverized Coal (PC) Plants”
- Ret-SC – Retrofitted supercritical plant
- Ret-A-USC – Retrofitted A-USC plant

Table 3-9
Summary of NETL Subcritical PC Retrofit Performance Results

Case	Ret-SC ¹	B12A	Ret-A-USC ²	1
Performance				
Heat Rate, Btu/kWh	8379	8379	7814	7814
Net Plant Efficiency, %	40.7	40.7	43.7	43.7
Total Gross Power, MWe	580	580	578	578
Total Auxiliaries, MWe	30	30	27	27
Total Net Power, MWe	550	550	550	550
As Received Coal Feed Rate, lb/hr	395,053	395,053	368,475	368,475
Cost				
Total Plant Cost, \$/kW	1069	2026	1221	1986
Total Plant cost, \$/1000	587,800	1,114,361	671,602	1,092,444
Total Overnight Cost, \$/kW	1303	2507	1486	2455
Total Overnight Cost, \$/1000	716,846	1,378,634	817,655	1,350,301
Total As-Spent Cost, \$/kW	1358	2842	1549	2784
Total As-Spent Cost, \$/1000	746,953	1,563,371	851,996	1,531,241

¹Performance for Case Ret-SC is identical to that of Case B12A.

²Performance for Case Ret-A-USC is identical to that of Case 1.

For heat rate in kJ/kWh, multiply the Btu/kWh value by 1.055. For coal flow in kg/hr, multiply the lb/hr value by 0.4536.

Table 3-10
Summary of NETL Subcritical PC Retrofit Cost Results

Case	B11A ¹	Ret-SC	B12A ²	Ret-A-USC	1 ³
Capital, \$/MWh	0.0	17.9	39.0	20.4	38.2
Fixed, \$/MWh	13.5	10.1	9.6	10.3	9.5
Variable, \$/MWh	12.2	9.2	9.1	8.7	8.6
Fuel, \$/MWh	32.1	24.6	24.6	23.0	23.0
Total (w/o Loss of Revenue), \$/MWh	57.8	61.8	82.3	62.3	79.2
Loss of Revenue, \$/MWh	N/A	6.4	N/A	6.4	N/A
Total (w/ Loss of Revenue), \$/MWh	N/A	68.2	N/A	68.8	N/A

¹ The subcritical plant is equivalent to Case B11A from the Bituminous Baseline, except all capital costs have been repaid and the plant is operating at a capacity factor of 58.4%. Additionally, the performance and O&M costs of this subcritical plant were linearly scaled to the fleet average heating value of 10,921 Btu/kWh (11,520 kJ/kWh).

² The price of electricity is calculated based on annual average retail price of electricity, reported by EIA. The raw data is provided by state, which has been matched with the list of plants generated from the initial repowering retrofit cost reduction case (25% cost reduction case). This price was then adjusted based on the pre-retrofit variable, fuel, and fixed operating costs, reported by Energy Velocity. Only the labor portion of the fixed costs is removed. The remaining cost is then multiplied by 0.5, to account for the distribution costs. The remaining costs are then averaged to obtain the price of electricity used in these calculations (\$46/MWh).

³ Case B12A, Case 1, Ret-SC, and Ret-A-USC all use a capacity factor of 85%.

The study's assumptions included:

- The existing plant is assumed to include all required emission control technology.
- While it has been determined that a retrofit of this type would trigger New Source Review, the costs of retrofitting/adding environmental controls have not been included in this analysis.
- No additional feedwater heater is selected (beyond typical design), as a topping cycle was not selected to be included. [DOE noted that EPRI had thought it unlikely that a reheat loop between a topping turbine and the existing subcritical turbine could be implemented effectively, based on limitations imposed by the steam temperature and pressure of the existing turbine that limit the reheat loop to a small enthalpy increase, as well as the cost of the additional reheat offsetting the modest efficiency increase. Further, Babcock & Wilcox stated it would be unlikely that plants would have sufficient available space to perform new construction.] However, it was assumed that sufficient space was available for the typical configuration of either an A-USC or supercritical steam cycle, which includes one more high temperature feedwater heater than a subcritical configuration.
- For A-USC, the coal feed reduction resulting from the higher steam cycle efficiency and maintaining a constant power output will be within tolerance (11% decrease) and will have a negligible impact on downstream equipment performance.
- For SCPC, the coal feed reduction resulting from the higher steam cycle efficiency and maintaining a constant power output will be minor and will have a negligible impact on downstream equipment performance.

- An external natural gas reheater/superheater is not used as it would require additional space, would not eliminate the need to upgrade the boiler as the pressure still increases, and due to the exhaust gas being approximately 800°F (430°C), it would significantly reduce plant efficiency.

Additionally, for the conversion to SC steam conditions:

- Nearly the entire boiler and steam turbine would need to be demolished, with the exception of:
 - Some top steel for support
 - Fuel prep system
 - Fans, flues, and ducts
 - Foundation
- The fireside of the boiler would need to be demolished to make room for other pressure vessels, bypass valves, flash tanks, etc.
- Access to subcritical units will be a serious challenge as space is significantly limited
- It would be unlikely that sufficient space would be available to install a topping cycle

The retrofit A-USC using the inverted tower design requires the following additional equipment to be replaced:

- Steam generator foundation
- Coal conveyors
- Ash transport and feed equipment (bottom ash only)

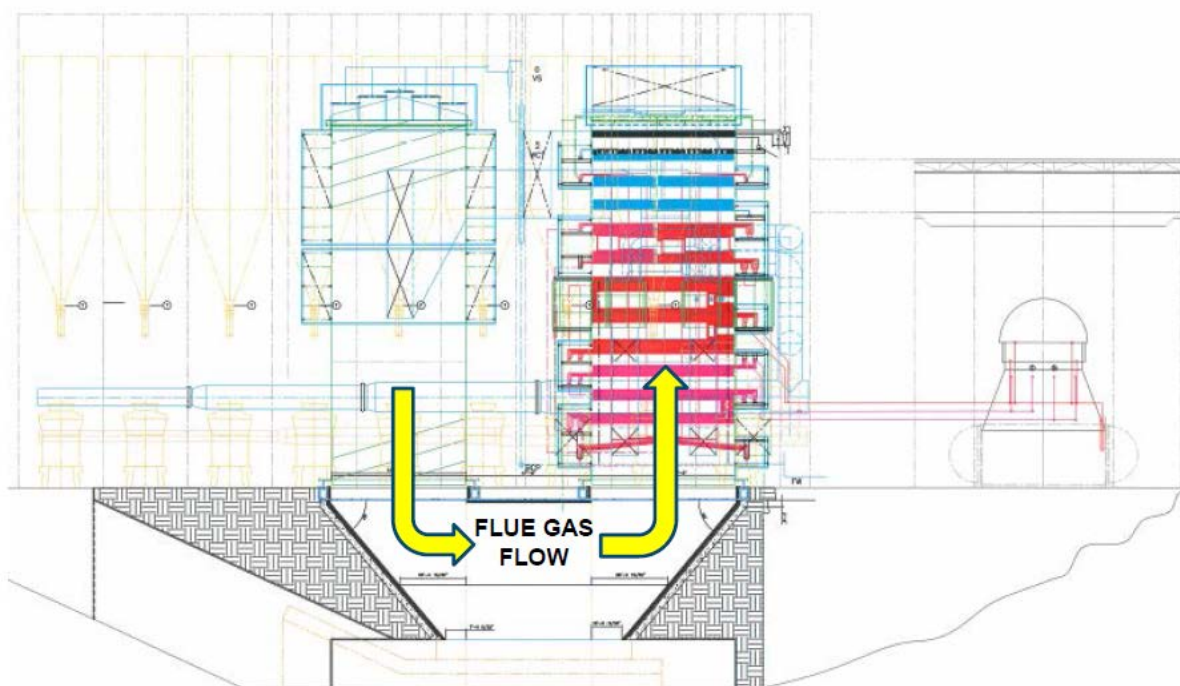
An additional 25% contingency was added to the demolition costs of the A-USC boiler, compared with an SC boiler, to account for the additional equipment.

The study's conclusions were as follows:

- Loss of revenue can be a potentially significant contributor to the cost of retrofit, representing a 10% increase in the cost of electricity (based on current assumptions).
- The duration of the retrofit has the greatest impact on the loss of revenue, with costs ranging from \$65 million to \$518 million.
- The portion of the boiler replaced during retrofit and the retrofit difficulty factor have the greatest potential impact on the capital costs.
- The use of an inverted tower in a retrofit application results in a net increase in capital costs of approximately \$24 million, relative to a traditional configured tower:
 - \$48 million increase due to additional deconstruction (e.g., foundation) and construction (e.g., flue gas and air ducts)
 - \$24 million decrease due to reduced lead length

Also in 2017, DOE NETL presented results from a study of A-USC new-build and retrofit options for SCPC plants.¹⁸¹ The performance evaluation referenced the NETL cases shown in Table 3-13: Baseline PC cases B11A (no CCS) and B11B (with CCS), and Baseline SCPC cases B12A (no CCS) and B12B (with CCS).

A-USC cases all reflect the steam turbine stage efficiencies extracted from steam flow diagrams provided by the A-USC Consortium literature instead of the “baseline report” for bituminous coal. Boiler and steam piping costs reflect the conceptual Babcock & Wilcox inverted tower boiler design, shown in Figure 3-6, which reduces steam lead length from 450 feet (137 m) for a conventional boiler to 150 feet (46 m).



Used with permission from Babcock & Wilcox.

Figure 3-6
Babcock & Wilcox Downdraft Inverted Tower Design

According to Babcock & Wilcox, retrofitting a subcritical PC plant to supercritical would require replacing nearly the entire boiler and steam turbine systems. Additional requirements for a retrofit to A-USC would be the replacement of the steam generator foundation, coal conveyors, and ash transport and bottom ash feed equipment. An additional 25% contingency was added to the demolition costs of the A-USC boiler case compared with the SC boiler case to account for the additional equipment.

Three different A-USC steam pressures, as shown in Table 3-11, were assessed with and without CO₂ capture.

¹⁸¹ Shultz, Travis. U.S. DOE/NETL. “Evaluating AUSC New Build and Retrofit Options for Existing Coal Plants.” EPRI Generation Sector Program Advisory Meeting, Atlanta, GA. September 2017.

Table 3-11
NETL Cases for A-USC Steam Conditions

Case	Steam Conditions	Capacity (MW-net)	CO ₂ Capture (Cansolv)	CO ₂ Capture Heat Integration
1	3500 psig / 1350°F / 1400°F	550	0%	–
2	3500 psig / 1350°F / 1400°F	550	90%	No
3	4250 psig / 1350°F / 1400°F	550	0%	–
4	4250 psig / 1350°F / 1400°F	550	90%	No
5	5000 psig / 1350°F / 1400°F	550	0%	–
6	5000 psig / 1350°F / 1400°F	550	90%	No

The cost results are shown in Table 3-12. The study drew the following conclusions, some of which match the subcritical PC retrofit study:

- Loss of revenue can potentially be a significant contributor to the cost of the retrofit, accounting for a 10% increase in COE (based on the study's assumptions)
- The duration of the retrofit has the greatest impact on the loss of revenue, with costs ranging from \$65 million to \$518 million
- The estimated cost for a supercritical or A-USC retrofit is approximately 53–63% of the cost for greenfield construction
- The portion of the boiler replaced and the retrofit difficulty factor have the greatest potential impact on capital costs
- The use of an inverted tower in a retrofit application results in a net increase in capital costs of approximately \$24 million, relative to a traditionally configured tower
 - \$48 million increase due to additional deconstruction (e.g., the foundation) and construction (e.g., flue gas and air ducts)
 - \$24 million decrease due to reduced steam lead length
- For A-USC cases
 - A COE decrease of 3.8% for non-capture, and a 6.8% decrease for capture plants, as the temperature increases from SC to A-USC conditions at 3500 psig (241 bar)
 - COE penalty for all CO₂ capture cases is ~68%

Table 3-12
NETL A-USC Cost Summary

	PC Supercritical		PC A-USC					
Case Name	B12A	B12B	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
COST								
Total Plant Cost (2011\$/kW)	2026	3524	1986	3447	1977	3429	1972	3417
Bare Erected Cost	1646	2716	1614	2660	1607	2646	1603	2636
Home Office Expenses	165	263	161	258	161	256	160	256
Project Contingency	216	430	210	419	209	417	209	416
Process Contingency	0	115	0	111	0	110	0	110
Total Overnight Cost (2011\$M)	1379	2384	1350	2329	1345	2316	1341	2308
Total Overnight Cost (2011\$/kW)	2507	4333	2455	4236	2444	4214	2437	4199
Owner's Costs	480	809	469	789	467	785	465	782
Total As-Spent Cost (2011\$/kW)	2842	4940	2784	4829	2772	4804	2764	4787
COE (\$/MWh) (excluding T&S)	82.3	133.2	79.2	124.1	78.9	123.3	78.6	122.8
Capital Costs	39.0	72.2	38.2	66.0	38.1	65.6	38.0	65.4
Fixed Costs	9.6	15.4	9.5	15.2	9.5	15.2	9.4	15.1
Variable Costs	9.1	14.7	8.6	14.0	8.5	13.9	8.5	13.9
Fuel Costs	24.6	30.9	23.0	28.9	22.8	28.6	22.7	28.4
COE (\$/MWh) (including T&S)	82.3	142.8	79.2	133.1	78.9	132.2	78.6	131.7
CO ₂ T&S Costs	0.0	9.6	0.0	9.0	0.0	8.9	0.0	8.9
CO ₂ Captured Cost (excluding T&S), \$/tonne	N/A	58.2	N/A	51.1	N/A	50.7	N/A	50.4
CO ₂ Captured Cost (including T&S), \$/tonne	N/A	89.4	N/A	74.3	N/A	73.0	N/A	72.2

DOE NETL “fossil baseline” studies from 2007 to 2012 evaluated state-of-the-art fossil plant designs with and without CO₂ capture and storage. Notable reports included *Techno-Economic Analysis of CO₂ Capture-Ready Coal-Fired Power Plants*, which evaluated various scenarios in which post-combustion CO₂ capture retrofits are made to plants with different levels of “capture ready” pre-investment.¹⁸² Two reports focused specifically on options for reducing the cost and energy penalty for adding post-combustion capture to coal power plants.^{183,184}

NETL’s coal plant retrofit studies include a detailed evaluation of the logistics and cost of a post-combustion CO₂ capture retrofit to an existing plant¹⁸⁵ and the use of satellite imagery to survey 738 coal-fired units in 328 plants in the United States for key characteristics related to CCS retrofit feasibility and cost.¹⁸⁶

DOE NETL’s bituminous baseline report uses standard conditions for a U.S. Midwest location as a design basis for performing engineering-economic evaluations of subcritical and supercritical PC plant designs, without and with CO₂ capture and storage.¹⁸⁷ NETL’s western (low rank) coal baseline reports, published in 2011, addresses designs for minemouth supercritical PC, USC PC, and supercritical CFB plants located at higher elevations.¹⁸⁸

Table 3-13 summarizes results for the bituminous baseline studies of a subcritical PC with steam conditions of 2400 psig/1050°F/1050°F (166 bar/565°C/565°C) and a supercritical PC with steam conditions of 3500 psig/1100°F/1100°F (241 bar/593°C/593°C).¹⁸⁹ These studies were based on Illinois #6 coal. The latest study uses the Cansolv advanced amine post-combustion CO₂ capture technology. The location for the bituminous baseline studies was a greenfield site in the Midwest, at 600 feet (180 m) in elevation, with design ambient dry-bulb temperature of 42°F (6°C) and design ambient relative humidity of 60%.

¹⁸² *Techno-Economic Analysis of CO₂ Capture-Ready Coal-Fired Power Plants*. NETL/DOE-2012/1581. August 2012.

¹⁸³ *Eliminating the Derate of Carbon Capture Retrofits*. DOE/NETL-401/091211. September 2011.

¹⁸⁴ *Fossil Energy RD&D: Reducing the Cost of CCUS for Coal Power Plants*. DOE/NETL-2012/1550 Revision 1, January 2012.

¹⁸⁵ *Carbon Dioxide Capture from Existing Coal-Fired Power Plants (Conesville Study)*. DOE/NETL-401/110907. November 2007.

¹⁸⁶ *Coal-Fired Power Plants in the United States: Examination of the Costs of Retrofitting with CO₂ Capture Technology, Revision 3*. DOE/NETL-402/102309. January 2011.

¹⁸⁷ *Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity*. DOE/NETL-2010/1397. Revision 2, November 2010. Revision 2 incorporates new data from technology vendors, modifies some of analysis methods, lists owner’s costs, and provides supplemental information beyond the scope of the original report.

¹⁸⁸ *Cost and Performance Baseline for Fossil Energy Plants, Volume 3b: Low Rank Coal to Electricity: Combustion Cases*. DOE/NETL-2011/1463. March 2011.

¹⁸⁹ Updated per Table ES-2 and Table ES-4 of *Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3*. DOE/NETL-2015/1723; July 6, 2015.

Table 3-13
DOE NETL Revision 3 Bituminous (Illinois #6) Coal Baseline Study

Technology	PC			
	Subcritical		Supercritical	
Case # (old case number)	B11A (9)	B11B (10)	B12A (11)	B12B (12)
CO ₂ Capture, %	0	90	0	90
Gross MW	581	644	580	642
Net MW	550	550	550	550
Net Efficiency, % HHV	39.0	31.2	40.7	32.5
TPC \$/kW-net	1,960	3,467	2,026	3,524
LCOE \$/MWh*	82.1	143.5	82.3	142.8
CO ₂ Emissions lb/MWh-net	1779	223	1705	214

Note: Based on Illinois #6 Coal at \$2.94/MBtu (\$2.78/GJ); capacity factor 85%; 2011 dollars.

* Includes CO₂ transport and storage.

The western coal baseline study evaluated SCPC designs with steam conditions of 3500 psig/1100°F/1100°F (241 bar/593°C/593°C), USC PC designs with steam conditions of 4200 psig/1200°F/1200°F (290 bar/649°C/649°C), and supercritical CFB technologies with steam conditions of 3500 psig/1100°F/1100°F (241 bar/593°C/593°C).^{190,191} The PC and CFB designs with post-combustion capture (Fluor Econamine FG) are much larger so that net output is same as the designs without capture.

The design location for the PRB studies was a greenfield site in Montana, at 3400 feet (1040 m) in elevation, with a design ambient dry-bulb temperature of 42°F (6°C) and design ambient relative humidity 62%. The location assumed for the lignite studies was a greenfield site in North Dakota, at 1900 feet (580 m) in elevation, with a design ambient dry-bulb temperature of 40°F (4°C) and design ambient relative humidity of 68%. To account for the dry climate, use of a parallel-path cooling system was assumed, with cooling load split 50:50 between an air-cooled condenser and a wet cooling tower. The TPC estimates were current for June 2007. An 85% capacity factor is used for the PC and CFB cases.

As shown in Table 3-14, the SC-CFB plants have a small efficiency advantage in all cases. The SCPC plants have lower capital cost and LCOE for the PRB cases and lower capital cost for the North Dakota lignite case without CCS. However, the higher efficiency gave the SC-CFB plants with CCS a lower cost of CO₂ avoided with PRB and lignite.

¹⁹⁰ *Cost and Performance Baseline for Fossil Energy Plants Volume 3b: Low Rank Coal to Electricity: Combustion Cases*. DOE/NETL-2011/1463. March 2011.

¹⁹¹ *Cost and Performance Baseline for Fossil Energy Plants, Volume 3 Executive Summary: Low Rank Coal and Natural Gas to Electricity*. DOE/NETL-2010/1399. September 2011.

Table 3-14
DOE NETL Comparison of 1100°F Supercritical 550 MW CFB and PC Plants for Low-Rank Coals

Technology	SCPC	SC CFB	SCPC w/ CCS	SC CFB w/ CCS	SCPC	SC CFBC	SCPC w/ CCS	SC CFB w/ CCS
Fuel	PRB	PRB	PRB	PRB	ND Lignite	ND Lignite	ND Lignite	ND Lignite
Gross MW	582.7	578.4	673.0	664.0	584.7	578.7	683.9	672.9
Net MW	550.0	550.1	550.1	550.0	550.1	550.0	550.1	550.1
Efficiency (% HHV)	38.7	38.9	27.0	27.3	37.5	38.0	25.5	25.9
Efficiency vs. SCPC		1.005		1.011		1.013		1.016
Total Plant Cost TPC (\$/kW)	1,879	1,932	3,268	3,295	2,041	2,042	3,560	3,533
TPC vs. SCPC		1.028		1.008		1.000		0.992
Total LCOE \$/MWh*	73.3	78.0	136.3	136.9	78.8	81.9	147.5	146.0
LCOE vs. SCPC		1.064		1.004		1.039		0.990
1 st Year Cost of CO ₂ Avoided (\$/ton)			61.3	58.1			63.7	60.9
1 st Year Cost of CO ₂ Avoided vs. SCPC w/o capture				61.7				62.0

* Note: Based on Powder River Basin coal at \$0.89/MBtu (\$0.84/GJ) HHV and North Dakota Lignite at \$0.83/MBtu (\$0.79/GJ) HHV. Capacity factor is 85% for PC and CFB cases. Costs are in June 2007 dollars.

NETL's "GIS Retrofit Study"¹⁹² developed rough estimates of the difficulty and costs of applying post-combustion capture retrofits to PC units in the United States. The study scaled plot-space requirements and cost estimates from the 2006–07 "Conesville Study,"¹⁹³ and used geographic information system (GIS) technology and aerial and satellite photos to evaluate available plot space and construction difficulty. Along with water availability information from the U.S. Geological Survey and EIA Electricity Market Module information, these data were applied to a quantitative "Carbon Capture Model."

NETL also examined historical operating efficiency and estimated that refurbishments could increase the output of U.S. existing plants by about 13% (almost 38 GW, assuming 85% capacity

¹⁹² *Coal Fired Power Plants in the United States: Examination of the Costs of Retrofitting with CO₂ Capture Technology and the Potential for Improvements in Efficiency*. DOE/NETL- 402/102309, Final Report, January 2010.

¹⁹³ *Carbon Dioxide Capture from Existing Coal-Fired Power Plants (Conesville Study)*. DOE/NETL-401/110907: December 2006 (Revised November 2007).

factors) if the average efficiency of all units, relative to nameplate rating, were increased to the average efficiency of the top 10 percent of units. For many units, this refurbishment could offset one-third or more of the output reduction from addition of CO₂ capture and compression. For a fully amortized plant, the refurbish-then-retrofit approach would be less expensive than a new build SCPC plant with CCS.

In further analysis, NETL estimated that the 10th percentile of the analyzed population (28 GW) would have a levelized CO₂ capture cost of about \$30 per ton (\$34/tonne) or less and a mitigation cost of about \$66 per ton (\$73/tonne) of CO₂ avoided or less (including replacement power). The 50th percentile values (137 GW) had a capture cost of about \$37 per ton (\$41/tonne) and a mitigation cost of about \$86 per ton (\$95/tonne) of CO₂ avoided. Ninety percent of the study population would have capture costs of \$52 per ton (\$57/tonne) or less and a cost of CO₂ avoided of \$97 per ton (\$107/tonne) or less.¹⁹⁴

NETL also examined power replacement options and technology configurations with the potential to reduce the efficiency loss and other disruption to operations from a post-combustion CO₂ capture retrofit.¹⁹⁵ This entailed use of a simple-cycle gas turbine to make up the power loss from the retrofit. The gas turbine flue gas is routed to the CO₂ capture system via a HRSG that provides steam for amine regeneration but not for a steam power cycle. Net power output was limited to 110% of the pre-retrofit plant to accommodate potential transmission limitations. The economic analysis (2007 cost basis) assumed that the Midwest plant fired Illinois #6 coal. The two simple cycle gas turbine models examined were GE 6FA and GE 7FA.

With the assumption that the PC plant was fully amortized prior to the retrofit, the total overnight cost of the base case was the lowest of the three cases, whereas the smaller of the two simple cycle gas turbine augmentation cases had the highest capital cost. On a \$/kW basis, the larger 7FA simple cycle gas turbine case had the lowest cost, whereas the base case had the highest. The base case had the lowest COE and the 7FA case had the highest COE, which in part may be due to fuel price assumptions.¹⁹⁶ The study concluded that installing an on-site simple cycle gas turbine appears to be a viable approach for providing steam and auxiliary power for a post-combustion CO₂ capture retrofit at a PC plant, recognizing that there may be potential optimization measures not addressed in this study.

DOE report NETL-2012/1550¹⁹⁷ summarizes options for reducing costs of coal power plants with CCS, based on expected improvements from ongoing DOE Office of Fossil Energy research. The coal combustion pathway analysis is shown in Table 3-15.¹⁹⁸

¹⁹⁴ *Coal Fired Power Plants in the United States: Examination of the Costs of Retrofitting with CO₂ Capture Technology, Revision 3.* DOE/NETL- 402/102309, January 2011.

¹⁹⁵ *Eliminating the Derate of Carbon Capture Retrofits.* DOE/NETL-401/091211. September 2011.

¹⁹⁶ With a final delivered cost \$38.18/ton (\$42.09/tonne) for Illinois No. 6 coal, the first year price of coal was \$1.64/MBtu (\$1.55/GJ). A natural gas cost of \$6.55/MBtu (\$6.21/GJ) was used.

¹⁹⁷ *Fossil Energy RD&D: Reducing the Cost of CCUS for Coal Power Plants.* DOE/NETL-2012/1550 Revision 1, January 2012.

¹⁹⁸ Adapted from Table 2 and Table 3 of DOE/NETL-2012/1550.

Table 3-15
DOE NETL Coal Combustion Pathway Analysis for Reducing Costs of Coal Power Systems with CCUS

Type of Power Plant*	Current (2012) SCPC	A-USC PC	Current SCPC with CCUS	A-USC PC with CCUS	Advanced Oxy-Fuel PC with CCUS
Efficiency, % HHV	39.3	42.5	28.4	36.5	39.7
Increase from 2012 Baseline		8%		28%	40%
CO ₂ Emissions, lb/MW-net	1,769	1,635	244	188	18
First-Year COE, \$/MWh-net	59	55	107	82	76
LCOE, \$/MWh-net	75	70	135	104	96
Reduction from 2012 Baseline		7%		23%	29%
Total Overnight Capital, \$/kW-net	2,024	1,902	3,570	2,891	2,747
Reduction from 2012 Baseline		6%		19%	23%
Cost of CO ₂ Avoided, \$/tonne			69	32	21
Reduction from 2012 Baseline				54%	70%
Cost of CO ₂ Captured, \$/tonne			42	24	16
Reduction from 2012 Baseline				43%	62%

Note: Costs are in 2007 dollars for an nth-of-a-kind plant commissioned in 2012 that entered construction in 2007.

The “coal combustion pathway” assumes the following technologies:

- Current supercritical pulverized coal technology, as evaluated in the bituminous baseline reports,¹⁹⁹ with steam conditions of 3500 psig/1100°F/1100°F (241 bar/593°C/593°C) and CO₂ capture technology equivalent to Fluor Econamine FG Plus and conventional CO₂ compression.
- A-USC PC technology with steam conditions of 5000 psig/1350°F/1400°F (345 bar/732°C/760°C). The capture cases are assumed to use advanced CO₂ separation and advanced CO₂ compression.
- Advanced oxy-fuel PC technology with A-USC steam conditions, advanced oxygen separation, CO₂/SO₂ co-sequestration, and advanced CO₂ compression.

DOE report NETL-2012/1581, published in 2012, evaluates scenarios in which plants constructed with different approaches to “capture ready” pre-investment are retrofit with post-combustion CO₂ capture.²⁰⁰ All scenarios are designed to achieve 30-year average CO₂

¹⁹⁹ *Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity*. DOE/NETL-2010/1397. Revision 2, November 2010.

²⁰⁰ *Techno-Economic Analysis of CO₂ Capture-Ready Coal-Fired Power Plants*. NETL/DOE-2012/1581. August 2012.

emissions of 1000 lb (454 kg) per MWh (gross). Performance and cost results for the scenarios are summarized in Table 3-16.²⁰¹

Case 2B-11, using a pre-investment approach that maximizes the efficiency and output of the post-retrofit plant—and has the highest capital cost—achieves the lowest 30-year LCOE. Delaying the retrofit and output derate to Year 11 gives a slight LCOE advantage over a retrofit that is phased in over two years. The phased retrofit has a lower total overnight cost and also provides some advantage in experience gained during the phase-in period.

Case 2B-11 achieves cost parity with NGCC at a natural gas cost of about \$12/MBtu (\$11.40/GJ). Price parity with natural gas at \$10/MBtu (\$9.50/GJ) can be achieved with an alternative approach that takes advantage of both “second generation” CO₂ capture technology²⁰² and revenue of \$25/ton (\$28/tonne) from sale of CO₂ for EOR. With revenue of \$75 per ton (\$83/tonne) of CO₂, parity can be achieved at a natural gas cost of about \$8/MBtu (\$7.60/GJ). A comparison with LCOE cost estimates for nuclear generation suggested a capital savings of 50–60% for the CO₂ capture-ready SCPC plant.

²⁰¹ Data Source: NETL/DOE-2012/1581. Op. Cit.

²⁰² “Second generation” capture technology is assumed to reduce post-combustion CO₂ capture capital cost by 30% compared to current amine technology. Savings in parasitic energy losses included a 25% reduction in auxiliary power load and a 20% reduction in steam quality required for solvent regeneration.

Table 3-16
Summary of DOE NETL “Capture Ready” Study Results

Case	Base Case	1A-11	1B-9			1B-11	2B-9			2B-11	2B-11 + 2nd gen CCS
Retrofit Year		2011	2009			2011	2009			2011	2011
Case Definition	SCPC	Not Capture Ready, No Ramp-Up	Capture Ready, Min. Capital Cost, 2 Year Ramp-Up			Capture ready, Min. Cap. Cost, No Ramp-Up	Capture Ready, Min. Heat Rate Penalty, 2 Year Ramp-Up			Capture Ready, Min. HR Penalty, No Ramp-Up	Capture Ready, Min. HR Penalty, No Ramp-Up
Year of Operation	Pre-Retrofit	11+	9	10	11+	11+	9	10	11+	11+	
% Capture	-	70	20	40	69	70	20	40	63	65	
Net Output (MWe)	550.0	365.7	443.8	412.5	367.6	365.7	514.4	480.5	441.5	438.0	
CO ₂ emissions (lb/MWh-gross)	1,675	663	1,598	1,246	689	663	1,397	1,089	704	669	
Steam Turbine, MWe	580.4	440.1	487.4	468.6	441.6	440.1	550.4	522.0	489.3	486.5	
Letdown ST, MWe						NA	71.0	14.1	22.2	22.9	
Gross Power, MWe	580.4	440.1	487.4	468.6	441.6	44.1	557.5	536.1	511.5	509.4	
Auxiliary Load, MWe	30.4	74.8	43.6	56.1	74.0	74.8	43.1	55.6	70.1	71.4	
Net Efficiency (% HHV)	39.3	26.1	31.7	29.4	26.2	26.1	36.7	34.3	31.5	31.2	
Net Heat Rate Btu/kWh-HHV	8,687	13,079	10,778	11,594	13,012	13,079	9,298	9,954	10,835	10,919	
Total Overnight Cost (\$/kW)											
Plant Before Retrofit	2,449	2,449	2,511			2,513	2,558			2,557	2,557
Cost of PCC Retrofit	NA	3,077	2,766			2,798	2,011			2,055	1,796
Total with Retrofit	2,449	5,526	5,277			5,311	4,569			4,612	4,353

Case	Base Case	1A-11	1B-9	1B-11	2B-9	2B-11	2B-11 + 2nd gen CCS
30-Year LCOE (\$/MWh)		139.5	143.2	138.5	131.4	128.6	113.6*

Note: Cost analysis uses June 2011 basis; 80% capacity factor

* LCOE value assumes \$25/ton in revenue from CO₂ sales for EOR.

For heat rate in kJ/kWh, multiply the Btu/kWh value by 1.055.

EPRI Engineering-Economic Evaluations of PC and CFB Units

From 2008 through 2010, EPRI evaluated the performance and economics of a state-of-the-art nominal 1100°F (600°C) USC PC “reference plant,” configured for representative North American design conditions (see Appendix A), before and after retrofit of an advanced amine post-combustion CO₂ capture system. EPRI then conducted subsequent studies evaluating a comparable reference plant design for future nominal 1300°F (700°C) and 1400°F (760°C) main and reheat steam temperatures. The CO₂ capture system for the 1100°F (600°C) USC PC study also served as the basis for EPRI’s post-combustion CO₂ capture retrofit study, which examined four PC plants and one CFB unit to understand the costs and plant-specific issues involved with CO₂ capture retrofits.

EPRI’s initial report 1014924 established the design basis and costs for the base USC PC plant without CO₂ capture. It also provided a preliminary assessment of the process interface and heat integration approach for incorporating MEA-based post-combustion capture.²⁰³ EPRI report 1017515 expanded those results with the development and evaluation of retrofit and new-build designs for a USC PC plant with an optimized MEA process and, alternatively, with MHI’s KM-CDR® process using KS-1 solvent.²⁰⁴ Subsequent studies of advanced USC and oxy-fuel USC designs and plant-specific post-combustion capture retrofits build on the design bases and results established in report 1017515.

The USC PC study assumes a 750 MW net greenfield base plant design firing PRB coal with a higher heating value of 8340 Btu/lb (19.4 MJ/kg) and sulfur content of 0.37% (wt). Steam conditions are 4200 psia/1110°F/1150°F (290 bar/599°C/621°C). A near-zero-emissions environmental design, selected to minimize solvent degradation, included low-NO_x burners, SCR, a baghouse, wet FGD, a wet ESP, and brominated activated carbon injection ahead of the fabric filter for mercury capture. A mechanical-draft wet cooling tower was used for steam cycle and auxiliary cooling. Site conditions were assumed to be those for EPRI’s reference location of Kenosha, Wisconsin. The design efficiency of the PRB-fired USC PC boiler is 85%, HHV basis, or 92%, LHV basis. A 90% capacity factor was assumed.

EPRI’s USC PC study investigated various cost reduction options and identified modifications that may be necessary for the base case plant to accommodate the 30% MEA-based post-combustion capture system.²⁰⁵ The analysis further examined design options to optimize the overall efficiency and cost of the retrofitted plant, resulting in new performance and cost estimates for a USC PC plant with an optimized 30% MEA post-combustion capture system. EPRI also developed and analyzed retrofit and new-build design for fully integrated capture plants based on MHI’s KS-1 solvent. The “Projected New Build” case, examined in report 1017515, further evaluates optimizations that might be possible with a future “nth plant” design.

²⁰³ *An Engineering and Economic Assessment of Post-Combustion CO₂ Capture for 1100°F Series Ultra-Supercritical Pulverized Coal Power Plant Applications: Phase I Report, Tasks 1 and 2*. EPRI, Palo Alto, CA: March 2008. 1014924.

²⁰⁴ *An Engineering and Economic Assessment of Post-Combustion CO₂ Capture for 1100°F Ultra-Supercritical Pulverized Coal Power Plant Applications: Phase II Task 3 Final Report*. EPRI, Palo Alto, CA: October 2010. 1017515.

²⁰⁵ EPRI Report 1014924, p. 4-2.

The retrofit evaluations assumed no capture-ready pre-investment. For a new-build plant optimized for post-combustion capture based on the KS-1 solvent, EPRI estimated the following performance gains:

- Plant efficiency increases by about 1 percentage point to 28.7% HHV
- Net output increases by 20 MW to 561 MW
- Power loss decreases by 3 percentage points to 25%

The “Projected New Build” design further increases efficiency by 2 percentage points and increases net output by 40 MW.

Preliminary Assessment of NGCC-Powered PCC Island

EPRI has generated preliminary costs for CO₂ solvent absorption CO₂ capture using an NGCC-powered PCC island—the approach taken by the Petra Nova project.²⁰⁶ However, EPRI is examining the scenario at a scale that will be relevant if legislation dictates that new coal-fired power plants achieve natural gas equivalency for CO₂ emissions. Under such a scenario, the economics of deploying a separate NGCC island as a power source for the CO₂ solvent absorption process may prove to be cost-effective.

Potential limiting factors to this approach include the plot space needed to house a new NGCC plant and the added emissions from the plant, which would constitute a second source of CO₂ and air emissions release. The CO₂ capture process would also be coupled to natural gas for the life of the power plant, which could be a drawback if natural gas prices became prohibitively high.

Table 3-17 contains a comparison of the estimated costs and performance of a state-of-the-art PC plant with 90% CO₂ capture to the same coal plant using a standalone NGCC plant to achieve 60% CO₂ capture. Figure 3-7 illustrates the LCOE and replacement power estimates. The PCC + NGCC island case generates more power than the PCC with 90% capture case and avoids the considerable derate of the latter. Instead, the PCC + NGCC plant would be in a position to export additional electricity back to the grid.

The capital costs for both the 90% capture and the 60% capture cases are similar (\$2.6 billion and \$2.4 billion, respectively). The considerable cost of the NGCC plant is balanced by savings from smaller CO₂ capture equipment to realize the 60% capture rate. Also, with the NGCC island there are no costs for steam turbine modifications to the base plant.

The total plant cost on a \$/kW basis is lower for the PCC+NGCC island case due to the additional MW generated from the NGCC case. Although the fuel costs of the PCC + NGCC Island case are significantly higher than PCC capture case in terms of actual dollars, the additional power from the NGCC brings the fuel cost in \$/kW back in line.

Adding 60% CO₂ capture to a baseline coal plant by using an NGCC powered PCC island results in a 47% increase in LCOE with no derate of the original plant. In comparison, a 114% increase

²⁰⁶ *Flexible Operation of Current and Next-Generation Fossil Plants With and Without Carbon Capture*. EPRI, Palo Alto, CA: 2016. 3002006388.

in LCOE is estimated from deploying 90% capture on the same baseline coal plant and using the base plant to supply the steam for capture, which incurs a substantial derate.

Table 3-17
Standalone NGCC-Powered Island: Preliminary EPRI Power Use and Cost Estimates

	USC No Capture	PCC 90% Capture	PCC + NGCC Island 60% Capture
Gross Power Output (MWe)	815.2	704.9	1017.0
Aux power plant	65.0	-65	-65
Aux PCC Plant	0.0	-100.7	-45
Aux NGCC	0.0	0.0	-5
Total Auxiliary Power (MWe)	65.2	165.7	115.0
Net Power Output (MWe)	750.0	539.2	902.0
Replacement Power (MWe)	–	210.8	0
% Drop in replacement power required	–	–	100
Power plant cost (\$x1000)	1,695,000	1,695,000	1,695,000
PCC cost (\$x1000)	–	913,000	543,667
NGCC cost (\$x1000)	–	–	250,000
Total Plant Cost (\$x1000)	1,695,000	2,608,000	2,488,667
Total Plant Cost (\$/kW)	2,260	4,837	2,759
Fuel and Total O&M Cost (\$/MWh)	28.04	49.38	45.70
CO ₂ T&S Cost (\$/MWh)	0.00	10.71	4.27
Capital Cost (\$/MWh)	35.80	76.69	43.74
Constant Dollar LCOE (\$/MWh)	63.9	136.8	93.7
% Increase in LCOE with capture	–	114	47
CO ₂ Captured (lb/hr)	–	1,273,667	849,111
CO ₂ Avoided Cost (\$/ton)	–	89.8	61.7
% Drop in CO ₂ Avoided Cost	–	–	31

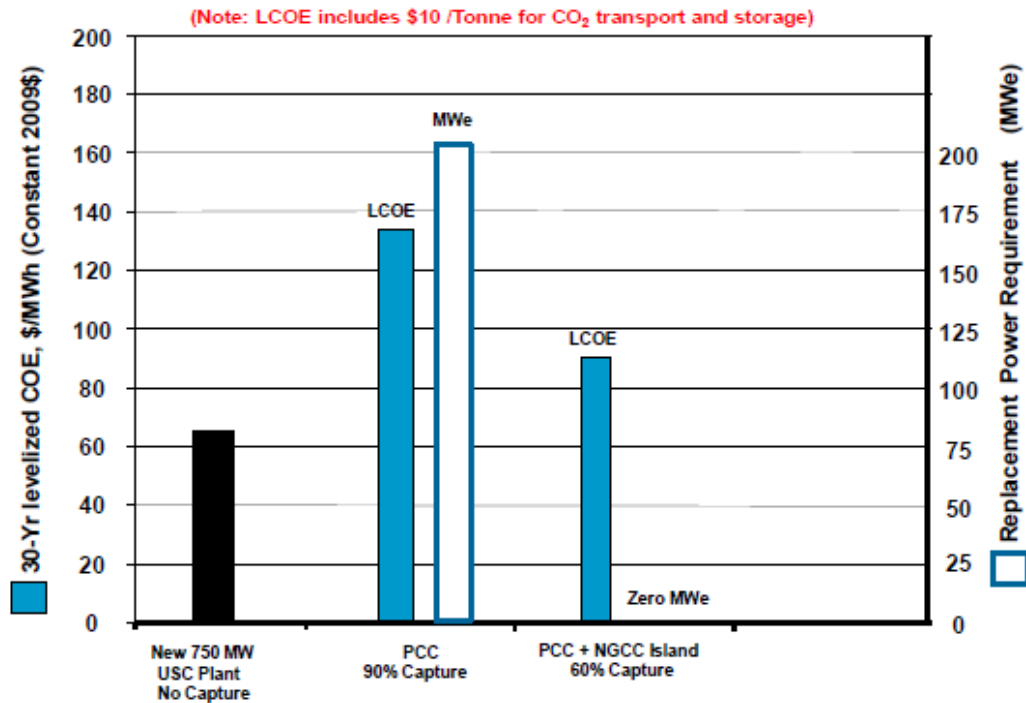


Figure 3-7
Standalone NGCC-Powered PCC Island: EPRI LCOE and Replacement Power Estimates

In addition to the NGCC island case, EPRI is examining other power sources for CO₂ solvent absorption technology including renewable geothermal and solar options, as well as a combination of these two.

Ultra-Supercritical PC with Partial CO₂ Capture

EPRI worked with Amec Foster Wheeler to update the design performance, capital cost, and economics of state-of-the-art USC plants to meet the CO₂ capture requirements for EPA's proposed New Source Performance Standards.²⁰⁷ [The standard has since been finalized by EPA at 1400 lb (635 kg) of CO₂ per MWh-gross.] For the CO₂ capture cases in the Amec Foster Wheeler analysis, power plant emission intensity was set to a maximum of 1100 lb (500 kg) of CO₂ per MWh-gross, considered as an annual average emission, including emissions during normal startup and part-load operation, with the plant assumed to operate at baseload.

Four USC configurations were considered:

- Case 1 – Pittsburgh #8, ~750 MWe (net) without CO₂ capture
- Case 2 – Pittsburgh #8, same boiler thermal input as Case 1 with capture to meet 1100 lb (500 kg) of CO₂ per MWh, gross basis
- Case 3 – Powder River Basin (PRB), ~750 MWe (net) without CO₂ capture

²⁰⁷ *Ultrasupercritical Pulverized Coal Power Plants with Partial Carbon Dioxide Capture: 2015 Detailed Feasibility Study*. EPRI, Palo Alto, CA: 2015. 3002005911.

- Case 4 – PRB, same boiler thermal input as Case 3 with capture to meet 1100 lb (500 kg) of CO₂ per MWh, gross basis

The study design basis was EPRI's Kenosha, Wisconsin, site. Environmental controls include low-NO_x burners, overfire air, SCR, wet FGD, fabric filter, and activated carbon. The steam turbine is designed to operate in normal conditions with an exhaust steam condensing pressure of 2 inches-Hg (0.0677 bara), corresponding to 101°F (38°C). The boiler and steam cycle units are based on the following state-of-the art USC steam conditions:

- PRB – main steam, 1110°F/4200 psia (599°C/290 bara); reheat steam, 1125°F (607°C)
- Pittsburgh #8 – main steam, 1100°F/4200 psia (593°C/290 bara); reheat steam, 1100°F (593°C)

Table 3-18 shows the performance and summary-level cost data for the four cases. Figure 3-8 shows the capital cost breakdown.

Table 3-18
Plant Performance and Cost Summary for USC-PC with Partial CO₂ Capture

Case	1	2	3	4
Coal	Pitt #8	Pitt #8	PRB	PRB
Gross Power (MW)	792.2	761.0	795.1	757.0
Auxiliary Power (MW)	39.7	67.8	43.2	80.3
Net Power (MW)	752.5	693.2	751.9	676.7
Net Efficiency (HHV), %	41.2	38.0	38.8	34.9
Net Heat Rate, Btu/kWh	8280	8980	8790	9780
CO ₂ Capture, %	–	34.7	–	40.6
CO ₂ Emissions, lb/MWh-gross	1614	1100	1758	1100
CO ₂ Emissions, lb/MWh-net	1699	1208	1859	1231
Total Plant Cost (\$ million)	\$1,472	\$1,795	\$1,546	\$1,922
\$/kW (net)	\$1,962	\$2,598	\$2,062	\$2,849
Total Capital Requirement (\$ million)	\$1,910	\$2,324	\$1,997	\$2,474
\$/kW (net)	\$2,546	\$3,363	\$2,665	\$3,667

Note: For heat rate values in kJ/kWh, multiply Btu/kWh values by 1.055. For CO₂ emission levels in kg/MWh, multiply lb/MWh emission rates by 0.4536.

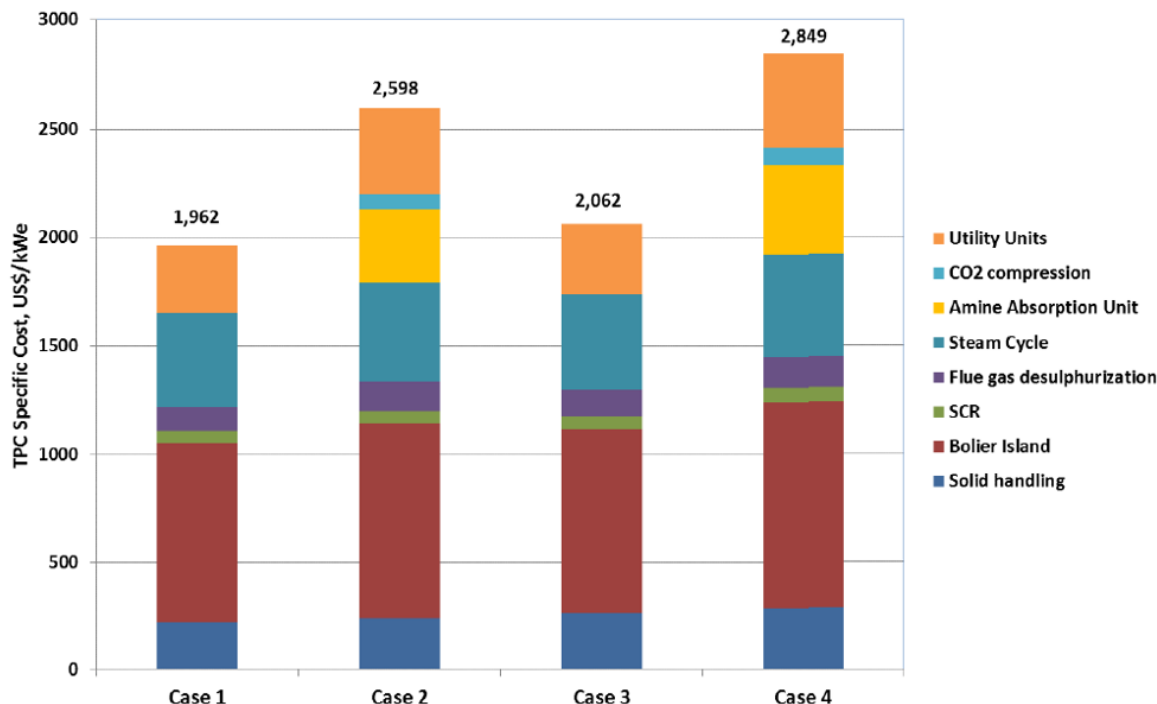


Figure 3-8
Capital Cost Breakdown for USC PC Partial Capture Cases

Observations from the study include:

- The coal feed rates are different in the Pittsburgh #8 and PRB cases, mainly because of the differences in the heating value of the feedstock, as both plants were designed to produce about 750 MWe (net) without CO₂ capture. For the partial CO₂ capture cases, the coal thermal inputs were left unchanged.
- The cases based on Pittsburgh #8 coal are more efficient than the corresponding PRB cases, both in terms of gross and net electrical efficiency. This is mainly due to the higher boiler efficiency and the higher heating value of the coal, which led to a reduction of the electrical load for the plant process units and auxiliaries.
- The addition of the partial CO₂ capture leads to an efficiency penalty of about 8% and 10%, respectively, for the Pittsburgh #8 and PRB cases, which corresponding to a 3.2 and 3.9 percentage point drop, respectively, in overall efficiency.
- The higher efficiency penalty for the PRB case with partial CO₂ capture (Case 4) is a result of the higher CO₂ capture necessary to meet the limit of 1100 lb (500 kg) of CO₂ per MWh-gross (41% versus 35% of the Pittsburgh #8 case).

Post-Combustion CO₂ Capture Using Membranes

EPRI report 3002001327 compares post-combustion capture using MEA to two types of membrane separation.²⁰⁸ A key advantage to membrane technology is that the systems require

²⁰⁸ *Engineering and Economic Analysis of 1300F Series Advanced Ultra-Supercritical Plant with Post-Combustion CO₂ Capture Using Membranes*. EPRI, Palo Alto, CA: 2014. 3002001327.

little or no steam extraction from the LP turbine, thus alleviating a significant parasitic power disadvantage for solvent-based systems. Membrane separation processes require several large pieces of rotating equipment—compressors and vacuum pumps—with large auxiliary loads (~20 MW), but with energy recovery through expanders, these loads are less than the gain in turbine output from avoiding steam extraction.

The CO₂ capture target for the study used EPA's March 2012 proposed New Source Performance Standard, wherein new fossil-fuel power plants would be limited to emissions of 1000 lb (454 kg) of CO₂ per MWh on a gross output basis. This standard was re-issued in September 2013 and again in August 2015, ultimately with a limit for coal-fired units of 1400 lb (635 kg) of CO₂ per MWh, gross basis. The EPRI study, already under way, adhered to the limits in the first proposal for its design basis. Four cases were evaluated, as described below.

Base Case: An 850 MW gross A-USC power plant without CO₂ capture. The steam conditions are 5000 psia/1300°F/1340°F (345 bar/704°C/727°C).

30-wt% MEA PCC System: This system, using two post-combustion capture trains, was described in Appendix D of EPRI report 1017515.²⁰⁹ Because less than half of the flue gas is treated to meet the EPA performance standard, it is assumed that only one PCC train is necessary. For scaling purposes, the cost of the system is proportional to the CO₂ flow entering the absorber column. The CO₂ product flow rate exiting the compression system can be used to scale the cost of the CO₂ compression system. A “retrofit” cost is added to incorporate the required modifications to ductwork, steam system, controls, etc., to accommodate the PCC system. The costs necessary to incorporate the heat integration scheme are included as well. Costs from the earlier study were updated from mid-2009 to December 2012 using the Marshall and Swift Index.

The following assumptions were made for the MEA system:

- The number of plant operators is increased from 18 to 22 per shift
- The number of administration personnel is increased from 22 to 25 to accommodate additional lab personnel
- A variable cost of \$1.85/yr x (hr/lb) or \$4.08/yr x (hr/kg), multiplied by the MEA circulation rate, is added to account for the annual costs associated with MEA solvent replacement and disposal
- A CO₂ transportation and storage cost of \$9/ton (\$10/tonne) is added

Case 1 – Cross-current membranes: The flue gas from the FGD is compressed and cooled in a quench column to reduce its water content. The flue gas then flows through the first cross-current membrane (primary membrane) where CO₂ is separated and concentrated in the permeate flow. The remaining residual gas flows from the membrane to an expander to recover some of the compression energy before exiting the stack.

The permeate from the primary membrane contains water vapor as well as oxygen, nitrogen, and other gases. This flow is compressed and passed to a molecular sieve dehydration bed for the

²⁰⁹ *An Engineering and Economic Assessment of Post-Combustion CO₂ Capture for 1100°F Ultra-Supercritical Pulverized Coal Power Plant Applications: Phase II Task 3 Final Report*. EPRI, Palo Alto, CA: 2010, 1017515.

removal of water vapor before the flue gas enters the cryogenic separation column, where the gas is cooled until the CO₂ is condensed and purified to meet pipeline specifications.

The overhead gas from the cryogenic separation column has a significant concentration of CO₂ at high pressure, so this flows through a secondary membrane (also cross-current) and the permeate is recycled back to the CO₂ compressor. The residual gas from the membrane is expanded to recover some of the compression energy and recycled back to the quench column. The residual stream leaving the primary membrane passes to the stack with CO₂ emissions of 1000 lb/MWh (454 kg/MWh) on a gross basis. This emission level is controlled by adjusting the flue gas bypass flow.

The following assumptions were made for the membrane system:

- The number of plant operators increases from 18 to 20 per shift
- A membrane replacement cost of \$5,000 per operating day is added
- A CO₂ transportation and storage cost of \$9/ton (\$10/tonne) is added

Case 2 – Cross-current and counter-current membranes: One way to improve the performance of a CO₂ separation membrane is to increase the inlet CO₂ concentration. Case 2 evaluates using a counter-current membrane swept with air from the forced-draft fan to remove CO₂ from the residual gas leaving the primary membrane and recycle it to the boiler. This effectively increases the CO₂ concentration exiting the boiler, and increases the performance of the first CO₂ cross-current membrane. This also affects the combustion and heat transfer characteristics of the boiler, which may require some adjustments to the heat transfer area.

In both membrane cases, gross power is increased from the base case plant without capture because of the addition of two turbo-expanders. In Case 2, however, there is less flue gas entering the post-combustion CO₂ capture system and therefore less power is generated by the two expanders. With the steam turbine gross power held constant for both cases, the total gross power for Case 2 is about 8 MW lower than for Case 1.

Because the emission limit is determined on a gross output basis, Case 2 is required to remove additional CO₂ from the flue gas due to its lower power output. This increases the load on the refrigeration system and the CO₂ pump. In Case 1, 59% of the CO₂ is separated from the flue gas in the primary membrane. In Case 2, 65.6% of the CO₂ is separated from the flue gas.

The COE includes the fuel costs, variable and fixed operating costs, as well as the capital cost annual “carrying charge.”

The costs are based on the following assumptions:

- Annual capacity factor – 80%
- Coal cost – \$1.80/MBtu (\$1.71/GJ)
- Annual Capital Carrying Charge – 12.1% of the Total Plant Cost
- Operator Cost – \$48.12/hour, 18 operators per shift
- Administration/Overhead Cost – \$53.13/hour, 22 personnel
- Maintenance labor – 2% of the Total Plant Cost per year
- Maintenance materials – 1% of the Total Plant Cost per year

- Ammonia for SCR – \$520/ton (\$573/tonne)
- FGD reagent cost – \$17/ton (\$19/tonne)
- FGD solids disposal costs – \$12/ton (\$13/tonne)
- Ash disposal costs – \$17/ton (\$19/tonne)
- Other miscellaneous variable costs – 1% of the Total Plant Cost per year

To adjust the COE to incorporate CO₂ removal, the following changes to the aforementioned assumptions are made for the MEA system:

- The number of plant operators is increased from 18 to 22 per shift
- The number of administration personnel is increased from 22 to 25 to accommodate additional lab personnel
- A variable cost of \$1.85/yr x (hr/lb) or \$4.08/yr x (hr/kg), multiplied by the MEA circulation rate, is added to account for the annual costs associated with the MEA solvent (replacement and disposal)
- A CO₂ transportation and storage cost of \$9/ton (\$10/tonne) is added

To adjust the COE to incorporate CO₂ removal, the following changes to the aforementioned assumptions are made for the membrane system:

- The number of plant operators increases from 18 to 20 per shift
- A membrane replacement cost of \$5,000 per operating day is added
- A CO₂ transportation and storage cost of \$9/ton (\$10/tonne) is added

Table 3-19 shows results for all cases. The capital costs for the membrane cases are approximately 8% higher than the equivalent MEA-based PCC system. Because of the lower net power, the capital cost is about 10% higher than the MEA system on a \$/kW basis. Similarly, the COE averaged about 7% higher.

Table 3-19
COE Comparison of All Cases

	Base Plant, No PCC	MEA PCC	Case 1 – Cross Current Membranes	Case 2 – Cross-current & Counter-current Membranes
Capital Cost, \$ million/yr	254.1	283.0	306.6	302.6
Coal Costs, \$ million /yr	78.3	78.3	78.3	78.3
Fixed Operating Costs, \$ million/yr	72.9	81.8	86.8	85.8
Variable Operating Costs, \$ million/yr	24.9	55.9	44.9	44.8
Total Operating Costs, \$ million/yr	430.3	498.0	516.6	511.6
Cost of Electricity, \$/MWh	79.63	100.60	107.10	106.20

The counter-current model is not required to meet the EPA limit, but for higher CO₂ removal, it is unlikely that the CO₂ can be removed with a single membrane economically. Case 2 has a capital cost slightly lower than Case 1 (by about 1%), and the COE for Case 2 is also about 1% lower than for Case 1. However, Case 2 has the disadvantage that the counter-current module is integrated into the boiler's air system, which likely complicates operation and decreases plant flexibility.

A pressure ratio of approximately three across the primary membrane reduces the membrane area and membrane costs. However, this arrangement requires more compression energy. Specifically, the auxiliary load of the flue gas compressor decreases net power and increases capital cost on a \$/kW basis, and subsequently increases COE.

Alternatively, the primary membrane area is tripled and the inlet pressure adjusted so that the separation is the same as Case 1. This has the effect of making no significant changes downstream of the primary membrane, but decreases the flue gas compressor output pressure from 29 psia (2 bar) to 17.5 psia (1.2 bar). This adjustment reduces the compressor power requirements by almost 75% and increases net power to almost 724 MW. Although the membrane capital cost is tripled, the cost of the flue gas compressor decreases such that the total plant cost drops from \$434 million to \$397 million. In combination, these two changes decrease the capital cost from \$3,680/kW to \$3,450/kW and the COE from \$107.10/MWh to \$100.70/MWh, which equals the COE for the MEA system.

The study notes that using membrane systems to remove CO₂ from flue gas is a relatively new technology. Near-term plans to demonstrate the technology at a 1 MW scale should help optimize the flow sheet, improving both net power and capital cost.

Advanced USC PC Studies

EPRI has conducted a series of studies evaluating design options, performance, and costs for A-USC PC units with and without CO₂ capture. The capture systems in these studies build upon the post-combustion capture system design for nominally 1100°F (600°C) USC PC plants. For example, EPRI report 1026645²¹⁰ used information from the 30% MEA process described in EPRI report 1017515 and applied it to the nominal 1300°F (700°C) A-USC plant described in EPRI report 1015699 (750 MW, PRB). EPRI report 1022040²¹¹ describes the equipment changes and performance impacts involved in implementing post-combustion capture on the 1300°F (700°C) A-USC design using the same 30% MEA post-combustion capture system.

EPRI report 1026644 updates an EPRI study²¹² of a “demonstration sized” A-USC unit having a net power of 350–400 MW after the addition of a 30% (by weight) MEA post-combustion capture system. Instead of 90% CO₂ capture, this plant will have CO₂ stack emissions of 800 lb (363 kg) per MWh, which is roughly equivalent to the CO₂ emissions of a modern natural gas combined cycle unit.²¹³

Advanced USC PC study results are summarized in Table 3-20 along with the following design cases from EPRI report 1015699:

- Subcritical at 2600 psia/1005°F/1005°F (179 bar/541°C/541°C)
- Supercritical at 3800 psia/1080°F/1080°F (262 bar/582°C/582°C)
- Ultra-supercritical at 4000 psia/1120°F/1120°F (276 bar/604°C/604°C)
- Advanced ultra-supercritical at 5100 psia/1400°F/1400°F (352 bar/760°C/760°C)

The 750 MW (net), A-USC steam generator is designed for baseload operation with vertical-tube Benson boiler technology and sliding pressure control. The steam turbine throttle conditions are 5100 psia/1256°F/1292°F (352 bar/680°C/700°C).

For the chosen design conditions, and use of a cooling tower instead of once-through cooling, a single reheat steam cycle was determined to be more cost-effective than double reheat. Other features to optimize steam cycle efficiency include a quad-sector regenerative air heater with a design outlet flue gas temperature of 250°F (120°C) with a shell-and-tube secondary air heater (using feedwater system steam) between the forced-draft fan and the air heater to prevent cold-end from reaching acid dewpoint temperature. The steam turbine exhausts to a dual-pressure wet condenser at 1.23/1.39 inch-Hg (4.17/4.61 kPa). Cooling water is supplied by a mechanical-draft wet cooling tower with a 12°F (7°C) approach to wet bulb temperature and has a 15.3°F (8.5°C) rise in the condenser.

²¹⁰ *Engineering and Economic Analysis of 1300F Series Ultra-Supercritical Plant with Post-Combustion Capture*, EPRI, Palo Alto, CA: 2012. 1026645.

²¹¹ *Engineering and Economic Analysis of 1300F Series Ultra-Supercritical Plant with Post-Combustion Capture: Engineering*, EPRI, Palo Alto, CA: 2011. 1022040.

²¹² *Engineering and Economic Analysis of a 1300F Series USC Demonstration Plant with Natural Gas Equivalency Post-Combustion Capture: Engineering*, EPRI, Palo Alto, CA: 2011. 1023621.

²¹³ *Engineering and Economic Analysis of a 1300°F (704°C) Series Advanced Ultra-Supercritical Demonstration Plant with Natural Gas Equivalency Post-Combustion Capture*, EPRI, Palo Alto, CA: 2013. 1026644.

Table 3-20
EPRI 1300°F (700°C) USC PC Study – Summary of Cases for PRB Coal

Technology	SubCr PC	1080F SCPC	1120F USC	1300F A- USC	1300F A-USC 90% PCC	1400F A- USC**	1300F A- USC ²¹⁴	1300F A-USC NGCC-eq
Gross MW				830.5	703.4		511.2	463.3
Net MW	750	750	750	750	533.4	750	463.2	380.2
Total Plant Cost TPC \$/kW	1,780	1,800	1,840	1,990		2,020	3,016	
Net Plant Heat Rate, HHV, Btu/kWh (kJ/kWh)	9430 (9950)	8860 (9350)	8700 (9180)	7990 (8430)	11,230 (11,845)	7630 (8050)	8103 (8549)	9870 (10,413)
Efficiency (% HHV)	36.5	38.5	39.2	42.7	30.4	44.7	42.1	34.6
CO ₂ Emissions, lb/MWh (kg/MWh)	1985 (900)	1877 (851)	1843 (836)	1682 (763)	236 (107)	1617 (733)	1703 (772)	800 (363)
Economic Analysis with Fuel Cost of \$1.80/MBtu (\$1.71/GJ) HHV								
Capital, \$/MWh	28.90	29.30	29.90	32.30		32.80		
O&M, \$/MWh	8.10	8.10	8.20	8.60		8.70		
Fuel, \$/MWh	17.00	15.90	15.70	14.40		13.80		
30-year LCOE \$/MWh	54	53.30	53.70	55.30		55.30	84.00	128.00
Dispatch Cost, \$/MWh (Fuel + Variable O&M)	18.60	17.40	17.10	15.70		15.10	32.00	54.00
Cost of CO ₂ Avoided, \$/ton (\$/tonne)	N/A	Base	23.60 (26.00)	20.40 (22.50)		15.30 (16.90)		
CO ₂ Adder, \$/MWh, w/ \$25/ton tax (\$27.60/mt)	24.80	23.50	23.00	21.00				
LCOE w/ \$25/ton-CO ₂ (\$27.60/mt) adder	78.80	76.70	76.80	76.40				

²¹⁴ EPRI report 1023621, op. cit. Tables 6-3, 6-4.

Technology	SubCr PC	1080F SCPC	1120F USC	1300F A- USC	1300F A-USC 90% PCC	1400F A- USC**	1300F A- USC ²¹⁴	1300F A-USC NGCC-eq
Economic Analysis with Fuel Cost of \$3.60/MBtu (\$3.42/GJ) HHV								
Fuel, \$/MWh	33.90	31.90	31.30	28.80				
Total 30-year Levelized COE \$/MWh	71.00	69.20	69.40	69.70				
Dispatch Cost, \$/MWh (Fuel + Variable O&M)	42.00	40.00	39.50	37.40				
Cost of CO ₂ Avoided, \$/ton (\$/tonne)								
LCOE w/ \$25/ton-CO ₂ (\$27.60/tonne) adder	95.80	92.70	92.40	90.70				

* Costs in mid-2007 reference year dollars, 30-year book life, carrying charge 0.121, capacity factor 85%

** Projected values assuming LCOE the same as for the 1300°F (700°C) design²¹⁵

The environmental design for the 750 MW system includes low-NO_x axial-swirl burners with overfire air and SCR to control NO_x to 0.03 lb/MBtu (~30 mg/Nm³), an ESP, and wet FGD. Halogen injection in the boiler is used to promote mercury oxidation over the SCR catalyst allowing for co-capture in the FGD absorber. The design also allows supplemental injection of activated carbon, ahead of the ESP, if desired.

The A-USC steam generator for the NGCC-equivalent case has steam conditions of 4000 psia/1290°F/1330°F (276 bar/699°C/721°C). The CO₂ capture system is sized to achieve NGCC equivalent stack emissions of 800 lb/MWh (363 kg/MWh) while removing 90% of CO₂ from flue gas passing through the absorber. The remaining portion of flue gas bypasses the absorber and is recombined with the CO₂-lean flue gas between the absorber exit and the stack. Heat integration is improved through use of heat reboiler condensate to heat boiler feedwater, thereby offsetting some of the steam removed from the IP/LP crossover for the CO₂ stripper reboiler.

The costs for EPRI's A-USC study cases are presented on a first-of-a-kind basis and include process contingencies for the boiler and steam turbine because they entail the first application of high-nickel alloy. The construction management and project contingencies were also higher because of the new materials and the potential need for more frequent weld inspection. To present the capital costs for the A-USC units on an nth-of-a-kind basis, Table 3-20 shows values without process contingencies or first-of-a-kind contingencies.

The study reached the following conclusions:

- Implementing advanced 1300°F (700°C) USC technology increases LCOE by about 3.7%, compared to the 1080°F (582°C) SCPC case and reduces CO₂ emissions by ~10%

²¹⁵ G. Booras (EPRI). 2009 EPRI Engineering-Economic Evaluations and Comparison with the Australian (GCCSI and DRET) Economics Reports. Presentation to EPRI CoalFleet Meeting. Charlotte, North Carolina. December 16, 2009.

- The effective “cost” of achieving this reduction in CO₂ emissions is \$20.40 per ton (\$22.50/tonne) avoided, which is substantially lower than the \$62 per ton (\$68.30/tonne) cost of CO₂ avoided for SCPC with post-combustion capture in DOE NETL’s fossil baseline study (2010, Revision 2).²¹⁶
- Advancing to a 1400°F (760°C) A-USC design is expected to further reduce the cost of CO₂ avoided

Although coal prices generally softened in the latter half of 2015, the rate of Chinese imports had been placing pressure on world coal prices, leading to a price sensitivity cases for PRB coal at a delivered price of \$3.60/MBtu (\$3.41/GJ). Previously, Peabody Coal analysts had projected that Chinese demand could support a price premium of \$12/ton (~\$13/tonne) over prices that U.S. utilities were paying for PRB coal.²¹⁷

A-USC Steam Boiler and Turbine Consortium Study

On behalf of the U.S. DOE/Ohio Coal Development Office-led A-USC Steam Boiler and Turbine Consortium, EPRI and General Electric headed up a study to evaluate the economics and performance of A-USC PC power plants.²¹⁸ Three stream pressures were evaluated: 3500, 4250, and 5000 psig (241, 293, 345 barg), with 3500 psig (241 barg) chosen as the most economic option. General Electric provided the steam cycle analysis, as well as the steam turbine design and cost estimating. EPRI performed integrated plant performance analysis using EPRI’s PC Cost model.

Two A-USC cases were developed:

- Case 1 – a conventionally configured A-USC PC power plant with superior emission controls, but without CO₂ removal. EPRI’s reference site conditions for Kenosha, Wisconsin, (see Appendix A) were used as the design basis.
- Case 2 – adds a near-term “advanced” PCC removal system to Case 1, using the design and heat integration strategies from EPRI’s 2015 report, “Best Integrated Coal Plant.”²¹⁹ The capture design basis for this case is “partial,” to meet EPA’s proposed New Source Performance Standard, which was 1100 lb (500 kg) of CO₂ per MWh, gross basis.

Study assumptions included:

- Coal costs of \$1.85/MBtu (\$1.75/GJ) for PRB
- 80% capacity factor
- Nominally 750 MW, net A-USC boiler
- Low-NO_x axial-swirl burners with overfired air and SCR for NO_x control

²¹⁶ *Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity Final Report*, DOE/NETL-2010/1397. Revision 2, November 2010.

²¹⁷ “Peabody projections show lucrative Chinese Market for PRB Coal.” *Platts Energy Week*. December 6, 2010.

²¹⁸ George Booras and John Shingledecker, “Economic Analysis of an Advanced Ultrasupercritical Pulverized Coal-Fired Power Plant with and without Carbon Dioxide Capture.” Coal-Gen Conference, Las Vegas, NV, December 8-10, 2015.

²¹⁹ *EPRI’s Best Integrated Coal Plant with Post-Combustion Capture Case Study*. EPRI, Palo Alto, CA: 2015. 3002003740.

- ESP for particulate control
- Wet limestone flue gas desulfurization for sulfur control
- Halogen injection to promote mercury oxidation in SCR with co-capture in FGD
- Steam conditions of 3500 psig/1350°F/1400°F (241 barg/732°C/760°C)
- Steam turbine sized for 825 MW (gross)
- Condenser pressure: 2.0 inch Hga (6.78 kPa)
- CO₂ transportation and storage cost is assumed to be \$9/ton (\$10/tonne)
- Cost of CO₂ captured excludes CO₂ transportation and storage cost

Capital and operating cost results for are shown in Table 3-21.

Table 3-21
Capital and Operating Costs for A-USC without and with PCC

Cost Category	Case 1: A-USC Plant without PCC		Case 2: A-USC Plant with PCC	
	Annual Cost, \$(000)/yr	\$/MWh (754.2 MW net)	Annual Cost, \$(000)/yr	\$/MWh (708.3 MW net)
Capital Cost	267,652	50.60	287,859	58.00
Fuel Costs	78,433	14.80	78,433	15.80
Fixed Operating Costs	76,287	14.40	83,632	16.90
Variable Operating Costs	26,038	4.90	34,032	6.90
CO ₂ Transportation & Storage			12,800	2.60
Total	448,410	84.70	498,067	100.20
Cost of CO ₂ Avoided \$/tonne			65.84	
Cost of CO ₂ Capture, \$/tonne			45.01	

For a PC plant, EPA defines gross power as the steam turbine gross output minus the boiler feedwater pump power. Analyses conducted using the Case 1 base plant performance values showed that the gross steam turbine power was 825,000 kW and the boiler feedwater pump power was about 21,300 kW. Thus, for Case 2, the gross power as defined by EPA would be about 804,000 kW. To meet the EPA Section 111(b) NSPS limit as originally proposed, the unit would be allowed to emit approximately 884,000 lb/hr (401,000 kg/hr) of CO₂. The CO₂ emitted from the Case 1 plant was 1,313,000 lb/hr (596,000 kg/hr), which meant that 34% of the flue gas had to be treated to meet the proposed 111(b) limit. (Note that preliminary analyses suggest that about 15% of the CO₂ would have to be removed from the flue gas to meet EPA's final Section 111(b) NSPS limit.)

Steam was required to regenerate the solvent, but due to the high efficiency and the advanced solvent, the steam flow was dramatically reduced compared to past studies on USC power plants using MEA as the solvent. Gross power decreased by 16 MW (about 2%), while auxiliary load increased nearly 30 MW, with 21 of the 30 MW associated with CO₂ compression.

The capital cost of the CO₂ removal system was \$178 million, approximately 8% more than the base plant cost. However, when divided by the net power, the cost increased \$440/kW (about 15%) due to a combination of the increased capital and lost generation. The LCOE increased about 18% due to the increased capital, lost generation, and increased operating costs associated with the carbon capture system.

Table 3-22 presents results from a comparison of USC to A-USC without and with PCC. The base A-USC plant efficiency is 2.6 percentage points higher than USC. This reduces the portion of flue gas to PCC system from 45% to 34%, and the capture penalty for adding PCC from 3.9 to 2.5 percentage points. LCOE increase over base plant is 36% for USC and 18% for the A-USC case.

Table 3-22
Performance and Cost Comparisons for USC versus A-USC without and with PCC

	USC Plant		A-USC Plant	
	without PCC	with PCC	without PCC	with PCC
Net Power Output, MW	749.6	674.6	754.2	708.3
Net Efficiency, % (HHV)	38.8	34.9	41.4	38.9
% of Flue Gas to Capture		45		34
Capture Penalty, % points		3.9		2.5
Total Plant Cost, \$/kW	2,637	3,643	2,933	3,370
Increase in Capital Cost, %		38.2		14.9
LCOE, \$/MWh (including CO ₂ T&S cost)	80.0	108.8	84.7	100.2
Increase in LCOE, %		36.0		18.3
Cost of CO ₂ Avoided, \$/tonne		100		66
Cost of CO ₂ Captured, \$/tonne		66		45
Cost of CO ₂ Avoided, \$/tonne (relative to USC w/o PCC)			84	69
Cost of CO ₂ Captured, \$/tonne (relative to USC w/o PCC)				61

PCC to meet EPA's formerly proposed NSPS emission limit of 1100 lb (500 kg) of CO₂ per MWh, gross basis.

Coal costs are assumed to be \$1.85/MBtu (\$1.75/GJ) for PRB

80% capacity factor for all cases

Transportation & storage cost is assumed to be \$9/ton (\$10/tonne) CO₂. Cost of CO₂ captured excludes CO₂ transportation and storage cost.

CFB Cost and Performance Studies

EPRI published results of a retrofit study for post-combustion CO₂ capture addition to a combined heat and power unit with a CFB boiler, but it has not yet conducted a full engineering-economic analysis of a large-scale CFB unit. Table 3-23 from EPRI report 1015695 compares

the estimated costs and heat rates for 500 MW CFB power plants with different design fuels as ratios to the corresponding values for a 500 MW PC plant fired with PRB coal.²²⁰

Table 3-23
Relative Capital Costs and Heat Rates for 500 MW CFB Plant vs. 500 MW PRB-Fired PC Plant

CFB Fuel	Capital Cost	Net Heat Rate
PRB Coal	0.98	1.02
Petroleum coke	1.03	0.95
Culm with 40% ash	1.10	1.00
Culm with 60% ash	1.36	1.07

The values in the table assume CFB technology has reached commercial maturity for a single 500 MW-scale subcritical CFB boiler. To date, a number of units have been commissioned using two subcritical CFB boilers to provide steam for a single 600–700 MW steam turbine generator, but only one CFB boiler close to 500 MW size has been built—the 460 MW gross supercritical CFB unit in Poland. However, vendors claim to have enough confidence in their technology to offer commercial supercritical CFB boilers in the 600–800 MW range.

EPRI modeling suggests that the capital cost for a 500 MW PRB-fired CFB plant may be slightly lower than that for a PC plant. The heat rate of the CFB unit is slightly higher because of higher forced-draft fan duty to fluidize the solids, probably resulting in very similar costs of electricity for the two designs. Fixed operation and maintenance costs for CFB units are comparable to PC units, and CFB boiler availabilities in excess of 90% are comparable to those achieved by PC boilers. Variable O&M costs for CFB units tend to be higher, reflecting the higher rates of limestone feed and ash removal, although the difference is less significant for low-sulfur fuels. Further, any difference in variable O&M costs may be offset by utilizing the fuel flexibility of the technology to burn a wider range of low-cost fuels than is possible with a PC boiler.

Although operating experience on supercritical CFB units is minimal, some benefit is expected from more even temperature distribution in the furnace compared to a PC unit.

Table 3-23 also indicates that the capital cost for a CFB unit fired with petroleum coke is slightly more expensive than for the PRB-fired PC, mainly because of the higher sorbent feed rates (and ash removal rates) arising from the higher sulfur content of petroleum coke. The heat rate is lower because of the higher calorific value of the fuel. Although the capital cost for waste coal-fired CFB units can be much higher than for a PRB-fired PC, mainly because of the higher feed rates and ash removal rates, the lower price of fuel could make the cost of electricity competitive.

EPRI's CO₂ Capture Retrofit Study (North America)

EPRI's CO₂ Capture Retrofit Study²²¹ has evaluated the design requirements, performance impacts, and costs for post-combustion capture retrofits to existing coal-fired power plants with

²²⁰ *Developments in Circulating Fluidized-Bed Combustion Technology*, EPRI, Palo Alto, CA: 2009. 1015695.

²²¹ *A Summary of EPRI's Pulverized Coal (PC) and Circulating Fluidized Bed (CFB) Post Combustion CO₂ Capture Retrofit Studies: The Five North American Plant Retrofit PCC Cases*. EPRI, Palo Alto, CA: 2012.1026864.

different owners and diverse factors related to steam cycle design, emissions controls, and location. The study cases examine five plants that are representative of many candidates for post-combustion CO₂ capture retrofit:

- Unit 5 and Unit 6 of Midwest Generation's Powerton Station are 825 MW (gross), cyclone-fired, once-through, subcritical units built in the early 1970s. Spray dry FGD, SCR, and pulse jet fabric filters are part of a planned emissions control retrofit, and would be required for use of MEA post-combustion CO₂ capture. An activated carbon injection system for mercury control has already been installed. Midwest Generation is also planning to add boiler economizer surface and re-blade the HP turbine. The plant uses a dedicated cooling lake with makeup from the Illinois River. Study results are summarized in EPRI report 1019680.²²²
- Intermountain Power Agency's Intermountain Generating Station, in Delta, Utah, has two 950 MW (gross) subcritical PC units that were built in the mid-1980s and uprated in 2004. Emissions controls include low-NO_x burners, wet FGD, and fabric filters. The baseloaded units fire a mix of Utah bituminous coal and Wyoming subbituminous coal. Study results are summarized in EPRI report 1019395.²²³
- Nova Scotia Power's Lingan Generation Station has four subcritical tangentially fired PC units, totaling 660 MW (gross), which were built from 1979 to 1984. They have ESPs for particulate control and have been retrofitted with low-NO_x burners and activated carbon injection for Hg. Addition of two wet FGD trains (each serving two boilers) is planned. The post-combustion CO₂ capture retrofit design basis also uses one train for each two boilers. The plant fires low-sulfur Colombian coal with fuel oil as a backup fuel. Study results are summarized in EPRI report 1019396.²²⁴
- Great River Energy's Coal Creek Station, in Underwood, North Dakota, has two 605 MW (gross) subcritical, tangentially fired PC units that were built in the mid-1980s. This baseloaded minemouth station is fired with North Dakota lignite, exports crossover steam to a nearby ethanol plant, and operates with no liquid discharge. Makeup water for wet cooling towers is pumped from the Missouri River. Each unit has a six-field ESP followed by a four-module wet FGD that now scrubs about 85% of the flue gas at a 90% SO₂ removal rate. In recent years, the plant added a coal drying (fuel "beneficiation") system known as DryFinTM to remove moisture from the lignite along with an appreciable amount of sulfur, mercury, and ash. Study results are summarized in EPRI report 1019397.²²⁵
- Unit 1 of First Energy's Bay Shore plant, located on the shore of Lake Erie near Oregon, Ohio, has a Foster Wheeler CFB boiler that was converted from a PC boiler. The CFB boiler supplies steam at 2015 psia (139 bar) and 1050°F (566°C) to the turbine inlet, plus export steam at 615 psia (42.4 bar) and 755°F (402°C) to a nearby oil refinery. SO₂, SO₃, and

²²² EPRI's *Pulverized Coal Post Combustion CO₂ Capture Retrofit Study Summary*. EPRI. Palo Alto, CA: 2010. 1019680.

²²³ *An Engineering and Economic Assessment of Post-Combustion CO₂ Capture Retrofit to Intermountain*. EPRI. Palo Alto, CA: 2011. 1019395.

²²⁴ *An Engineering and Economic Assessment of Post-Combustion CO₂ Capture Applied to Nova Scotia Power's Coal-Fired Lingan Station: Post Combustion CO₂ Capture Retrofit Report 3*. EPRI. Palo Alto, CA: 2011. 1019396.

²²⁵ *An Engineering and Economic Assessment of Post-Combustion CO₂ Capture Applied to Great River Energy's Coal-Fired Coal Creek Station: Post Combustion CO₂ Capture Retrofit Report 4*. EPRI. Palo Alto, CA: 2012. 1019397.

particulate emissions are controlled with limestone injection into the CFB boiler and a pulse jet fabric filter (baghouse), which reduces flue-gas sulfur by roughly 90%. Study results are summarized in EPRI report 1019398.²²⁶

For each plant, EPRI estimated the cost of adding a post-combustion CO₂ capture system adapted from EPRI's USC PC study. The capture system design is based on a 30% (by weight) solution of inhibited aqueous MEA, which has a heat of regeneration of 1380 Btu/lb (3.2 MJ/kg) of CO₂. Design features to reduce cost and improve performance include plate-and-frame heat exchangers, structured packing in the absorber, a supercritical CO₂ pump replacing the last stage of CO₂ product compression, heatless (molecular sieve) CO₂ drying, reboiler condensate flashing and re-injection, and waste heat recovery from hot reboiler condensate, stripper overhead, and first-stage CO₂ compression. The overall design employs a minimum number of trains to maximize economies of scale.

Findings from a comparison of results for the five plants include:

- All the plants were technically capable of retrofitting the post-combustion capture system capable of 90% CO₂ removal.
- If the existing plant is fully amortized and it can operate for another 30 years, adding post-combustion capture yields a lower COE than that for a new build USC PC with post-combustion capture.
- The greatest difference in capital between the plants was approximately \$2,000/kW, with much of the difference occurring because two of the plants needed to add FGD units; the resulting LCOE differed by about \$37/MWh and the cost of CO₂ avoided differed by about \$30/ton (\$33/tonne).
- Using the advanced solvents, currently under development, reduced the efficiency penalty by about 2.5 percentage points across all the plants studied. Improving efficiency can also lower capital and operating costs resulting in lower COE and avoided cost of CO₂ capture.

Performance results for the base plant and retrofit cases are shown in Table 3-24. Table 3-25 shows estimates of the capital cost and operating and maintenance costs. Alternative performance and cost analysis results are provided for several cases, assuming use of a future solvent technology with a regeneration energy requirement of 900 Btu/lb (2.1 MJ/kg) of CO₂.

²²⁶ *An Engineering and Economic Assessment of Post-Combustion CO₂ Capture Applied to FirstEnergy's Bay Shore Station Circulating Fluidized Bed Unit: Post Combustion CO₂ Capture Retrofit Report 5*. EPRI. Palo Alto, CA: 2011. 1019398.

Table 3-24
Performance Estimates for Post-Combustion CO₂ Capture Retrofits at Existing Coal-Fired Power Plants

	USC PC Bench-mark	Powerton Unit 5 (same as Unit 6)		Intermountain (Single Unit)		Lingan Station (4-Unit Totals)	Coal Creek Station	Bay Shore Station
EPRI report ID	101715	1019394, 1019680		1019395		1019396	1019397	1019398
Boiler Technology	USC PC	Cyclone-fired, Subcritical, Once-Through		Subcritical PC, Natural Circulation		Subcr. PC, Nat. Circ.	Subcr. PC, Nat. Circ., CHP****	Subcritical CFB, Nat. Circ., CHP****
Fuel	PRB	PRB		Utah Bit/PRB Mix		Low-S Colombian Steam Coal	ND Lignite (with DryFining)	Pet Coke
CO ₂ Capture Technology*	Optimized 30% MEA	Opt.30% MEA	Adv Solvent/ Process ²²⁷	Opt. 30% MEA	Adv Solvent/ Process	Opt.30% MEA	Opt.30% MEA	Opt. 30% MEA
Output of Original Unit, MWe net (gross)		765 (851**)	765 (851**)	896.8 (950)	896.8 (950)	617 (655)	1130 (1210)	129 (144)
Net Output after Retrofit, MWe		490 (693**) w/ BPST	550 (750**)	619.9 (798)	670 (848)	393 (526)	724 (995) w/ BPST	56 (102) w/ BPST
Change in Net MW, %		-36	-28	-31	-25	-36	-36	-57
Net Eff’y Orig Plant, % HHV		32.3	32.3	35.6	35.6	33.0	33.5	24.9
Net Eff’y. after Retrofit, % HHV		20.7	23.2	24.6	27.1	21	21.5	10.9
Eff. Change, % Points		-11.6	-9.1	-11.0	-8.5	-12.0	-12.0	-14.0
CO ₂ Captured, mt/day @ 90% eff.		16,540	16,540	17,083	17,083	14,305	24,913	3,866

²²⁷ D Dillon. *Post Combustion Capture Retrofit Study Update*. Presentation for EPRI P66-P165 Meeting, Hoover, Alabama, July 2011.

	USC PC Bench-mark	Powerton Unit 5 (same as Unit 6)		Intermountain (Single Unit)		Lingan Station (4-Unit Totals)	Coal Creek Station	Bay Shore Station
CO ₂ Emiss. Orig'l Plant, mt/MWh		1.000	1.000	0.882	0.882		1.021	1.388
CO ₂ Emiss. after Retrofit, mt/MWh		0.156	0.156	0.128	0.128		0.159	0.320
Incremental Water Import w/ PCC (mgd)		2				16 (seawater)	2.4	2.1

* Regeneration energy assumed to be 1380 Btu/lb-CO₂ for optimized 30% MEA process; 900 Btu/lb-CO₂ for future advanced solvent/process

** Assumes ST re-blade and other plant refurbishment prior to retrofit increases gross from 820 MWe to 851 MWe

*** Coal Creek exports a total of 160,000 lb/hr of steam. With 20 lb/hr from the feedwater system, the balance can be from one unit or taken as 70,000 lb/hr from the IP/LP crossover of each unit. Gross output by about 10 MWe (5 MWe per unit). Bay Shore exports about 37% of medium pressure steam flow.

Table 3-25
Cost Estimates for Post-Combustion CO₂ Capture Retrofits at Existing Coal-Fired Power Plants

	USC PC Benchmark	Powerton Unit 5 (same as Unit 6)	Intermountain (Single Unit)	Lingan Station (Totals for 4 Units)	Coal Creek Station (2 Unit Totals)	Bay Shore Station Unit 1
	1,695	(Assume paid off)	(Assume paid off)	(Assume paid off)	(Assume paid off)	(Assume paid off)
TPC for Plant Modifications, \$M		243 (incl. 15% contingency)	149 (incl. 10% contingency)	223 (incl. 15% contingency)	266	96
TPC for PCC Retrofit, \$M	459	496	440	490	770	135
TPC for Addition of FGD & SCR, \$M*		563				
TPC for plant with PCC Retrofit, \$M	2,154	1,302	5,589	713	1,036	230
TPC for New Plant \$/kWe	2,260	N/A	N/A	N/A	N/A	N/A
TPC for Plant with PCC Retrofit, \$/kWe	4,215	2,657	528	1,814		
Incremental O&M Costs, \$M/year						
Variable		56.2	79.0	30.0	72	9
Fixed		20.2	16.5	33.8	50	12
Total		76.4	95.5	63.7	122	21
EPRI Estimate of Dispatch Costs for Original Plant, \$/MWh		27.5**	26.9			
Cost of CO ₂ Avoided, \$/tonne (replacement power not incl.)	92.6	86.5 (109.1 with SCR and FGD)				

Costs in mid-2009 dollars

* EPRI estimate assuming ~\$750/kW

** Includes O&M for added FGD & SCR

Approaches to Minimize the Derate from CO₂ Capture and Compression

EPRI report 1023873 examines approaches to minimize the plant derate from CO₂ capture.²²⁸ The study is based on the application of an advanced amine solvent PCC process to the USC power plant described in EPRI report 1017515 and modified for 90% capture on about half of the stack's exhaust (notably, with a circulating dry scrubber instead of wet FGD and without a wet ESP). The unit is smaller in footprint because the gas processing volume is roughly half that required in the design described in EPRI report 1017515.

The following cases were examined:

- Case 1 – Base case that captures sufficient CO₂ to result in a plant emission rate of 1000 lb (454 kg) of CO₂ per MWh, gross output basis (i.e., EPA's originally proposed Section 111(b) NSPS) and based on a 30-year average of emissions
- Case 2 – Utilizes waste heat from the CO₂ capture and sorbent regeneration process to enhance steam cycle performance
- Case 3 – Adds a natural gas-fired low-pressure steam boiler to replace steam extraction for the CO₂ capture sorbent regeneration process
- Case 4A – Co-location of a General Electric 6FA gas turbine as a pre-engineered package, with a heat recovery steam generator (HRSG) and steam turbine-generator but with no integration with the coal plant's steam cycle
- Case 4B – Integration of the 6FA combined cycle to generate as much reheat steam as possible for the main steam cycle, with the remaining energy in the flue gas used to generate low-pressure steam for regeneration of the advanced amine sorbent

Table 3-26 summarizes performance results.

²²⁸ *Minimizing the Derate of Adding Post-Combustion Capture to Pulverized Coal Units*. EPRI, Palo Alto, CA: 2012. 1023864.

Table 3-26
Derate Compensation for CO₂ Capture Energy Penalty

Case	1 – Base	2– Low Temp Heat Recovery	3 – NG Boiler plus Low Temp Heat Recovery	4A – GE 6FA CC plus Low Temp Heat Recovery	4B – GE 6FA plus HRH steam plus Low Temp Heat Recovery
Coal ST MWe	785.7	793.2	858.7	795.4	836.9
Gas GT MWe	N/A	N/A	n/a	75.1	75.1
Gas ST MWe	N/A	N/A	n/a	41.3	N/A
Total Gross MWe	785.7	793.2	858.7	911.8	912.1
Auxiliary MWe	122.6	122.1	132.4	125.3	125.1
Total Net MWe	663.1	671.1	726.2	786.6	787.0
Net Heat Rate, kJ/kWh (Btu/kWh)	10,609 (10,055)	10,482 (9,935)	11,409 (10,814)	10,017 (9,494)	10,011 (9,489)
Net Efficiency, % HHV	34.0	34.4	31.6	36.0	36.0
% of Flue Gas to PCC	48.8	48.2	54.1	46.3	46.2
CO ₂ Captured, tpd	307.7	304.0	341.1	291.9	291.8
CO ₂ Emitted, tpd	392.9	396.6	429.3	455.9	456.1

Notes: Coal Q fired = constant = 6667 MBtu/hr; Specific CO₂ Emitted = constant = 1000 lb/MWh gross.

In Case 3, the natural gas boiler offsets some of the power loss associated with CO₂ capture, but at the cost of reduced overall thermal efficiency and increased COE. Its principal advantage is simplicity. However, it poses a greater economic risk exposure to natural gas price increases than the cases employing the 6FA gas turbine because the less efficient gas-fired boiler requires about 1.5 times as much natural gas as the 6FA gas turbine.

Cases 4A and 4B with the 6FA gas turbine appear to be the best at restoring the power loss attributable to CO₂ capture, doing so with improved overall plant efficiency and, at an assumed price of natural gas of \$4.25/MBtu (\$4.03/GJ), with an improvement in plant LCOE. The gas turbine cases also show significant reductions in the cost of CO₂ avoided. The standalone 6FA combined cycle case seems to be preferred because the gas turbine can be dispatched independently, whereas it cannot be in the more integrated case. The differences in thermal performance, capital cost, and COE between Cases 4A and 4B are relatively minor. Table 3-27 shows the COE results for the study.

Table 3-27
Capital Cost and Cost of Electricity for Cases to Offset a CO₂ Capture Derate

Cost, million \$/yr	No PCC	1 – Base	2– Low Temp Heat Recovery	3 – NG Boiler plus Low Temp Heat Recovery	4A – GE 6FA CC plus Low Temp Heat Recovery	4B – GE 6FA plus HRH steam plus Low Temp Heat Recovery
Coal	100.8	100.8	100.8	100.8	100.8	100.8
Natural Gas				35.3	35.3	35.3
Total Fuel	100.8	100.8	100.8	100.8	100.8	100.8
Fixed O&M	37.2	37.2	37.2	37.2	37.2	37.2
Variable O&M	19.8	19.8	19.8	19.8	19.8	19.8
CO ₂ T&S		19.6	19.6	19.6	19.6	19.6
Capital Related Charges	203.6	263.9	265.2	280.4	281.8	279.1
Total Annual Costs	361.4	468.6	470.2	527.9	513.5	509.9
COE, \$/MWh	68	101	100	104	93	92
Total Plant Cost (\$M)	1,680	2,180	2,190	2,320	2,330	2,310
\$/kW	2,210	3,290	3,270	3,190	2,960	2,930

June 2012 Cost Basis

Canadian Clean Power Coalition – Post-Combustion CO₂ Capture Retrofit with Molten Carbonate Fuel Cells

On behalf of the Canadian Clean Power Coalition (CCPC), Jacobs Engineering evaluated various post-combustion CO₂ capture options for coal-fired power plants. One study examined Fuel Cell Energy's SureSource Capture technology, formerly known as Combined Electric Power and Carbon Dioxide Separation (CEPACS), as a candidate for use at Nova Scotia Power's Lingan Generating Station to meet the Canadian government's carbon emission performance standard of 925 lb (420 kg) of CO₂ per MWh (net), excluding power for CO₂ compression.²²⁹

The Lingan plant currently has four units generating 165 MW each (gross basis). Units 1 and 2 are nearing retirement. The Jacobs study looked at using CEPACS to capture CO₂ from Units 3 and 4. The study assumed that a wet limestone FGD unit had already been installed on Units 3 and 4. Units 1 and 2 cooling water, switchyard, and transmission capacity is assumed to be available for the Unit 3 and 4 CEPACS retrofit. Excess heat from CEPACS provides additional boiler feedwater heating, and recovered process water is used in Units 3 and 4.

²²⁹ Butler, D. "Advanced Technology," presentation at CCPC "Keeping Coal in the Mix" seminar, Regina, Saskatchewan, October 22, 2014.

Fuel cells designed for CO₂ capture are also known as electrochemical membranes. The driving force for CO₂ separation is the electrochemical potential, not the pressure differential, across the membrane. The net results include simultaneous power production and CO₂ separation from the flue gas. Excess process water is recovered as a byproduct. The electrochemical membrane is completely selective toward CO₂, and all of the N₂ remains with the CO₂-depleted flue gas. Figure 3-9 shows a simplified flow diagram of the CEPACS process. SO₂ must be removed from the flue gas down to ppm levels to avoid deactivating the fuel cell. Natural gas is fed to the anode inlet. The anode exhaust gas consists of a concentrated CO₂ stream. This stream requires further treatment to condense water and recycle the unconverted fuel components back to the cathode. The end product is very pure CO₂ for compression to pipeline pressure.

The flue gas exiting the wet FGD is split, with half going to the electrochemical membranes and the other half going directly to the exhaust stack. The membrane captures about 83% of the CO₂ that enters with the flue gas, as well as the CO₂ formed from oxidizing the carbon in the natural gas.

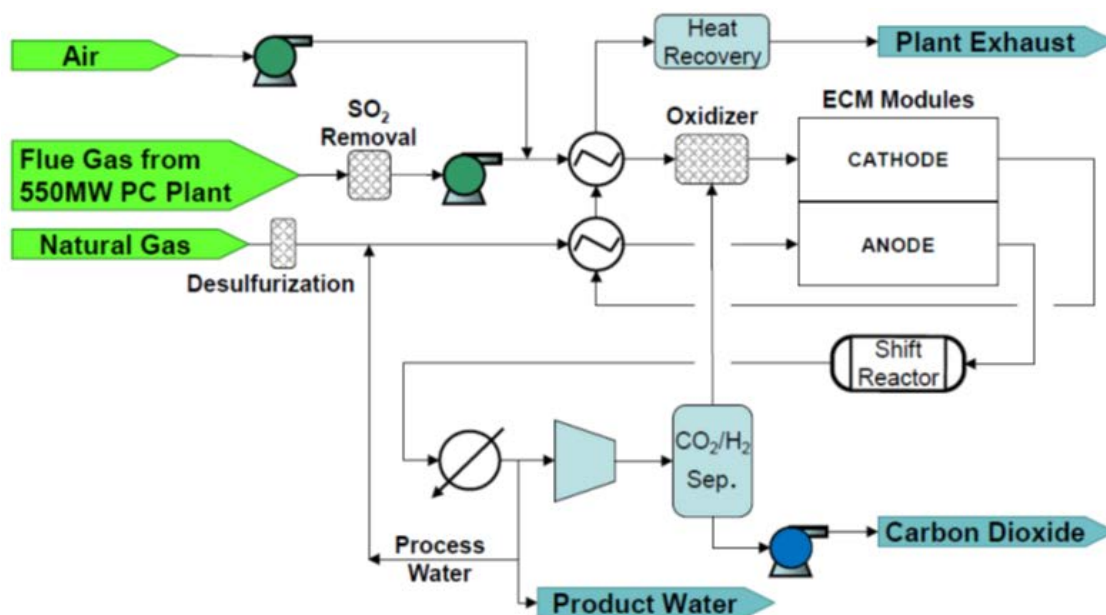


Figure 3-9
Simplified CEPACS Flow Diagram

Jacobs worked with Fuel Cell Energy to derive the cost and performance data for the fuel cells used in the study. Data for the Lingan plant were drawn from an EPRI study.²³⁰ Table 3-28 shows plant performance for Units 3 and 4 both with and without CEPACS.

²³⁰ *An Engineering and Economic Assessment of Post-Combustion CO₂ Capture Applied to Nova Scotia Power's Coal-Fired Lingan Station: Post Combustion CO₂ Capture Retrofit Report 3*. EPRI. Palo Alto, CA: 2011. 1019396.

Table 3-28
Overall Performance Summary for Lingan Retrofit with CEPACS

		Existing Power Plant		Retrofit with CEPACS	
		Generation	Aux Load	Generation	Aux Load
Units 3 and 4					
Gross Power	MW	327.5		327.5	
Auxiliary Loads	MW		17.0		17.0
Wet Flue Gas Desulfurization	MW		2.0		2.0
Additional power from BFW integration	MW			2.2	
Net Power Exported	MW	308.5		310.7	
CEPACS Summary					
Gross DC Power Generated	MW			170.0	
Auxiliary Loads	MW				27.4
Inverters	MW				6.8
Transformer Losses	MW				0.5
SW Cooling Water Pumps	MW				1.6
Net CEPACS Export	MW			133.7	
Total Net Power Generated	MW	308.5		444.4	
CO2 Intensity	kg/MWh	973.8		418.4	

Table 3-29 contains capital costs for the Lingan, Nova Scotia location and for a reference U.S. Gulf Coast location. Costs for the CEPACS unit include both the electrochemical membrane and the CO₂ purification and compression unit. The annual operating cost is estimated to be CAD\$26.9 million (about \$21 million using a June 2018 exchange rate), based on an ECM stack life of 10 years. This does not include the cost of 22 plant staff and operators for the CEPACS unit and supporting utilities.

Table 3-29
Total Plant Capital Cost for Nova Scotia and U.S. Gulf Coast Location

Item	Capital Cost	
	Nova Scotia Basis CAD (million)	USGC Basis USD (million)
CEPACS	371.1	283.3
Utilities & Offsites	67.3	50.9
Direct Field Costs	438.3	334.1
Total Indirect Field Costs	125.0	48.8
Total Field Costs	563.4	382.9
HO Costs - FEED & Detailed Engineering	46.7	43.7
Vendor Reps (Allow)	1.8	1.25
Sub-Total	611.8	427.9
Total Before Contingency	611.8	427.9
Contingency	122.4	85.6
Total Project Cost	734	513

The study concluded that molten carbonate fuel cells retrofitted to a coal-fired plant may be competitive with a new NGCC unit in some circumstances, but the technology needs to be demonstrated under various operating conditions and for longer durations.

4

OXY-COMBUSTION CO₂ CAPTURE FOR PC AND CFB PLANTS

Oxy-combustion plants separate and exclude most of the nitrogen in air prior to combustion, thereby burning fuel in concentrated oxygen instead of air. This produces a flue gas containing primarily CO₂ and water, allowing relatively simple CO₂ separation by condensing out the moisture. Due to the relative ease of capturing CO₂, oxy-combustion has the potential to be more cost-effective than post-combustion CO₂ capture, depending on the cost and energy penalty of oxygen production.

Coal oxy-combustion boilers have been successfully demonstrated at pilot scale in the United States, Europe, Australia, China, and elsewhere. Commercial-scale oxy-combustion demonstrations projects have been in development, primarily in China. “Novel” oxy-combustion cycles, such as NET Power’s Allam cycle, are being demonstrated at large pilot scale. Two high-profile oxy-combustion projects from the early 2010s were canceled in 2015–16: FutureGen 2.0 in the United States and White Rose in the United Kingdom. Although these projects did not proceed to construction and operation, their engineering design and permitting work has contributed to the body of information on the expected cost and performance of oxy-combustion technology.

Technology Overview

The arrangement of major components in a coal oxy-combustion power plant may closely resemble that of a conventional PC or CFB plant, as illustrated in Figure 4-1, or may be substantially different.²³¹ Retrofit and near-term new-build applications for boiler-type configurations are expected to fire coal with a mixture of oxygen and recycled flue gas, approximating the combustion temperatures and heat transfer characteristics of air-fired boilers. This reduces the need for a boiler redesign or new metallurgy. A new-build or repowering application may use this “synthetic air” approach or, alternatively, may use a boiler with modified metallurgy and gas paths to allow firing solely with high-purity (95–98%) oxygen (i.e., no flue gas recycle).

²³¹ J.C. Simpson, M. DeLallo (Worley Parsons Group), J. Phillips, and G. Booras (EPRI). *Economics of Carbon Dioxide Purity in Oxygen Fired Coal-Fired Power Plant*. Presentation to Ninth Annual Conference on Carbon Capture & Sequestration, May 10-13, 2010, Pittsburgh, PA.

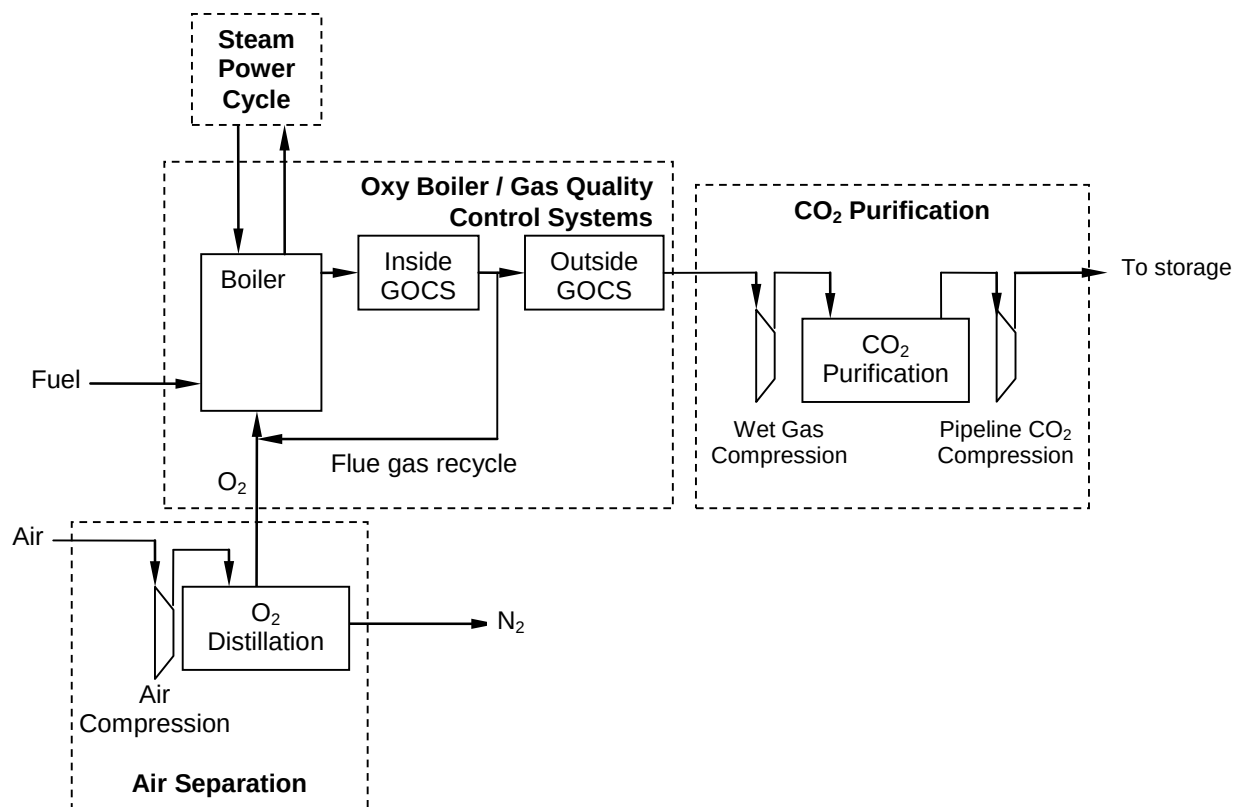


Figure 4-1
Process Flow Diagram for a Typical Oxy-Combustion System with CO₂ Purification

For most coal oxy-combustion applications, it is expected that the steam turbine-generator and most balance-of-plant systems will be identical or similar to air-fired units. Flue gas quality control systems (GQCS) for particulate, SO_x, and mercury may be nearly the same as the systems for air-fired boilers, or may use new approaches made possible by the different flue gas chemistry. For example, it may be possible to downsize or eliminate NO_x controls, as some oxy-combustion tests have shown NO_x levels lower than those achieved using SCR or SNCR in conventional air-fired boilers.²³² Criteria and hazardous pollutant control may also be integrated with CO₂ purification processes, as in Air Products' "sour" CO₂ compression technology.

High-purity oxygen will typically be supplied from an on-site (or nearby) air separation unit. CO₂ compression, drying, and purification may be integrated in a single, multi-stage process unit or configured in sequential process units. Some projects have considered use of a cryogenic CO₂ purification unit (CPU) to remove oxygen, nitrogen, and argon. An additional separation process (e.g., a membrane) may be used to capture part of the CO₂ that would be lost with the vent gas from the CPU. As with other CO₂ capture processes, the high-purity product CO₂ may be

²³² S. Gerdeman et al. *Developments in Integrated Pollutant Removal for Low-Emission Oxy-Fuel Combustion*. DOE Albany Research Center: 2005.

compressed to the final pressure required for pipeline transportation and/or geologic storage, or it may be liquefied after compression to an intermediate pressure and pumped to final pressure.

For an oxy-combustion boiler, it is particularly important to minimize air ingress. This entails careful attention to the design and construction of the boiler, gas quality control systems, and interconnecting ductwork. For a conventional air-fired boiler, rules of thumb suggest that air ingress may be 3% of total flue gas flow when the boiler is new, increasing to as much as 10% with boiler wear over time.²³³ To minimize corrosive and erosive constituents in the recycled flue gas stream, recirculation ducting will typically branch off downstream of the gas quality control systems. Other aspects of the design may be guided by the quantity and species of sulfur compounds and other corrosive and erosive constituents in the oxy-combustion flue gas.²³⁴

Fan locations and water condensing and collection systems are also important design variables. A single induced-draft fan and a single point for water condensation and collection may be installed upstream of the flue gas recycle duct tee. Alternatively, separate fans and separators may be installed on each branch. The design of the flue gas recycle system depends on the quantity and species of sulfur compounds and other corrosive constituents in the flue gas.

For an oxy-combustion power plant, critical determinants of economic performance and net generating efficiency are the costs and operating efficiencies of the air separation unit and the CO₂ purification and compression system(s). Industrial gas companies have therefore teamed with boiler manufacturers to develop oxy-combustion technologies along with technologies that reduce the costs and efficiency impacts of oxygen production and CO₂ purification.

Oxy-Combustion Project Updates and Results

Two small-scale oxy-combustion projects that have demonstrated full-chain CCS, including CO₂ transportation to a geologic storage site:

- The 30 MWe retrofit of Unit 4 of Callide A in Queensland, Australia, was large enough to generate data to support scale-up to a commercial oxy-combustion unit. A two-year demonstration ran from December 2012 to March 2015 and collected 10,000 hours of oxy-fuel operating data and 5500 hours of CO₂ capture plant data, with capture rates in excess of 85%.²³⁵ The project's capital cost was A\$140 million (about \$105 million using a June 2018 exchange rate). The operating budget was increased from A\$60 million to A\$100 million to extend the period of operation to December 2014. During the project's CO₂ capture phase, CO₂ transported by truck was used for four test injections at the CO₂CRC Otway geologic CO₂ storage demonstration project in Victoria.
- Total's project in the Lacq basin in southwest France provided CO₂ transport by pipeline to a geologic storage site. Total, Alstom, and Air Liquide retrofitted an existing gas-fired 30 MWt boiler at the Lacq Industrial Complex with four Air Liquide gas/oxy-combustion burners (8 MWt each), two Air Liquide CO₂-rich flue-gas dryers, flue gas recirculation, and a CO₂

²³³ S. Santos (IEA GHG R&D Programme). *Oxy-Pulverised Coal Combustion Technology for Power Generation with CO₂ Capture*. Presentation to Chemical Engineering Department, Newcastle University, March 11, 2010.

²³⁴ Detailed technology descriptions and schematics are provided in the "Process Selection" subsection of Section 1.2.3 of EPRI report 1021782.

²³⁵ <http://www.callideoxyfuel.com/informglossarytabid/89/how/what/who/inform/When/Projectmilestones.aspx>

compression system.²³⁶ Air Liquide also supplied a cryogenic air separation unit. Capture began in mid-2009, followed by three years of injection from 2010 to 2013. An existing natural gas pipeline transported CO₂ to a depleted natural gas field in Rousse (in the Pyrenees), a distance of 17 miles (27 km). An existing well was used for injection of more than 55,000 tons (50,000 tonnes) of CO₂. Post-injection monitoring continued to 2016.

Table 4-1 summarizes select coal oxy-combustion power projects from around the world.

Table 4-1
Oxy-Combustion Power Plant Demonstration Projects

Project/Location	Owner/Plant Name	Size, MW net	Vendors	Retrofit or New	Startup / Status
El Bierzo / Spain	Fundación Ciudad de la Energía (CIUDEN) / Compostilla	20 MWt PC; 30 MWt CFB	Foster Wheeler (Boiler), Air Liquide (CPU)	New	2011 / CFB on hold – project idle for much of 2017
Yingcheng, China	Huazhong University Science and Technology (HUST)	35 MWt	DEC, Hangzhou Kuaikai Hi-tech Co., Ltd., Sichuan Air Separation Group	Retrofit	2015 / Operating
Daqing / Heilongjiang Province / China	China Datang Corporation / Daqing	2 x 350	Alstom	New	Pre-FEED
Jupiter Oxygen / Xinjiang Province, China	Jupiter Oxygen Corp. & Guanghui New Energy / Guanghui	170	NETL (CPU)	Retrofit	Pre-FEED
SIEG CCUS Project / Taiyuan, Shanxi Province, China	Shanxi International Energy Group (SIEG) / Taiyuan	350	Air Products	New	Pre-FEED
Shenhua Guohau Power Plant / Shenmu, China	Shenhua Group / Guohua Power	200	Dongfang Electric Corporation (DEC), Hangzhou Kuaikai Hi-tech Co., Ltd., Sichuan Air Separation Group	New	Pre-FEED
NET Power / La Porte, Texas	NET Power	50 MWt	Toshiba (Combustor/Turbine)	New	2018 / Commissioning
FutureGen 2.0 / Illinois	FutureGen Alliance / Meredosia	99	B&W (Boiler), Air Liquide (ASU/CPU)	Retrofit	Project terminated after federal funding was suspended in February 2015.

²³⁶ Jean-Pierre Tranier et al. Air Liquide. “Oxycombustion for carbon capture on coal power plants: advantages, innovative solutions, and key projects,” 3rd IEAGHG Oxyfuel Combustion Conference, Ponferrada, Spain, 2013.

Project/Location	Owner/Plant Name	Size, MW net	Vendors	Retrofit or New	Startup / Status
White Rose CCS Project / England	Capture Power Ltd.	304	Alstom (Boiler), BOC-Linde (ASU/CPU)	New	Project terminated after application for development consent was denied.

Chinese Oxy-Combustion Projects

As shown in Table 4-1, China is the current locus for large-scale oxy-combustion projects, although most are still in the early stages of development. The Daqing (Heilongjiang province) project plans to capture 1.1 million tons (1.0 million tonnes) of CO₂ per year. The CO₂ would be transported by pipeline about 60 miles (100 km) for saline formation storage in the Songliao Basin or for EOR in the adjacent PetroChina Daqing oilfield. Alstom (now part of GE) signed an agreement with China Datang Corporation in November 2011 to conduct an oxy-combustion feasibility study for one of two new-build 350-MW cogeneration units at Daqing, using lignite from Inner Mongolia as a feedstock.²³⁷

The 350 MW SIEG oxy-combustion demonstration project, to be located at a new power plant in Taiyuan, Shanxi Province, intends to capture and purify CO₂ exhaust for EOR or sequestration. The DOE and China National Energy Administration have agreed to include this project in the U.S.-China Fossil Energy Protocol–Annex II: Clean Fuels, which is designed to promote scientific and technological cooperation between the countries. Air Products signed an agreement in 2010 to conduct a feasibility study and develop a reference plant design using its ASU and CPU technology. Babcock & Wilcox was selected to provide the oxy-combustion boiler.²³⁸ The plant would capture 2.2 million tons (2.0 million tonnes) of CO₂ per year at an expected purity of approximately 95%.

The Shenhua Guohua project consists of a new-build 200 MW oxy-combustion plant with a 44-mile (70 km) pipeline to transport 1.1 million tons (1.0 million tonnes) of CO₂ annually to the Erdos Basin. Also considered was a retrofit to a plant at Shenmu in Shanxi Province. An estimated 90% of the CO₂ would be stored in saline aquifers and 10% used for EOR. The new-build project is estimated at 2.21 billion RMB (about \$352 million), which is nearly double what a conventional air-fired unit operating with the same steam conditions without CCS would cost. Based on this and the assessment of the LCOE from the preliminary economic modeling, the break-even tariff price for electricity from the oxy-combustion power plant is 170% higher than a comparable air-fired power plant without CCS.²³⁹

²³⁷ <http://cornerstonemag.net/exploring-the-status-of-oxy-fuel-technology-globally-and-in-china/>

²³⁸ <http://uscec.wvu.edu/wp-content/uploads/2013/03/Sept-16-Final-AP.pdf>

²³⁹ *Combustion Technology Status: 2017 Update*. EPRI, Palo Alto, CA: 2017. 3002011209.

FutureGen 2.0

At the time of its cancelation, the FutureGen 2.0 oxy-combustion retrofit project at the Meredosia Energy Center in Illinois, with saline formation CO₂ storage, had cleared the permitting phase, including receipt of EPA UIC Class VI geologic sequestration permits.²⁴⁰

Major project features included:

- Repowered boiler/existing steam turbine: 167 MW (gross)
- Coal blend: 60% Illinois, 40% Powder River Basin
- CO₂ capture rate: >90%
- CO₂ capture volume: 1.2 million tons (1.1 million tonnes) per year
- 28-mile (45 km) CO₂ pipeline to storage site, with injection in the Mt. Simon sandstone formation

Project milestones achieved included:

- Power purchase agreement executed
- Final permits issued for air, water, pipeline, and CO₂ storage
- Subsurface rights acquired and CO₂ liability management addressed
- Mega-FEED completed (70–90% of final design, at a cost of \$90 million)
- Project labor agreements signed

Fixed price contracts had locked in engineering, procurement, and construction costs. The capital cost of the power plant was estimated to be \$1.256 billion based on a 2015 construction start. Table 4-2 lists a breakdown of the major capital cost categories. Excluded from the estimate are an over-the-fence ASU and \$423 million for the CO₂ pipeline and injection and storage facilities.²⁴¹

²⁴⁰ <http://www.sj-r.com/article/20150203/NEWS/150209841>

²⁴¹ Humphreys, Ken. “FutureGen 2.0.” Presentation at the CCS Cost Network 2016 Workshop, March 22, 2016. Cambridge, Massachusetts.

Table 4-2
Power Plant Capital Budget for FutureGen 2.0 (“As Spent” Basis)

	Total Cost/ \$ millions	Percent of Total Cost
Site purchase costs	\$29	2%
Design and early construction	\$90	7%
Boiler and GQCS	\$135	11%
Compression and purification unit	\$169	13%
Owners costs and working capital	\$146	12%
Owners management reserve	\$87	7%
Financing costs and debt service reserve	\$74	6%
Balance of plant	\$509	40%
Startup and commissioning	\$27	2%

As shown in Table 4-3, major operating cost drivers included oxygen, fuel, purchased power, ash disposal, consumables, and CO₂ transportation and storage. The total 20-year LCOE, including capital recovery, was estimated to be \$179/MWh. However, after accounting for energy and capacity sales to the Midcontinent Independent System Operator, the net cost to the ratepayers was expected to have been \$138/MWh.²⁴²

²⁴² Ibid.

Table 4-3
FutureGen 2.0 Major O&M Costs (Twenty-Year LCOE Basis)

Cost Category	2014\$/MWh
Oxygen	28.4
Coal	25.2
Purchased power, including ASU	18.4
Compression & purification	4.1
Fuel oil, raw materials, ash disposal, consumables	14.5
Carbon transport and storage	12.4
Materials & contract labor	6.5
Power block & compression & purification supervisory labor	7.4

FutureGen 2.0 successfully negotiated with a large number of landowners for the CO₂ pipeline rights-of-way and subsurface storage rights.

White Rose

The White Rose Carbon Capture and Storage project was a proposed new-build USC oxy-combustion unit of up to 448 MW (gross). Developed by Capture Power Limited, a consortium between Drax, Alstom, and BOC, the project was to be located at the Drax Power Station in North Yorkshire, United Kingdom. About 90% of the unit's CO₂ exhaust, approximately 2.2 million tons (2.0 million tonnes) per year, would have been stored beneath the North Sea, with pipeline transport via the proposed common-user Yorkshire and Humber CCS Cross Country Pipeline. National Grid Carbon Ltd., a subsidiary of National Grid, Ltd., was to have built the pipeline.

The White Rose project was a preferred bidder in the UK government's £1B CCS Competition. However, the UK government cancelled the competition in November 2015. In April 2016, the project's application for development consent was denied by the UK government due to insufficient funding.²⁴³

The capital cost for the White Rose project was estimated at £1.9 billion on a November 2015 cost basis (about \$2.5 billion using a June 2018 exchange rate). Table 4-4 lists the major cost components.²⁴⁴ The project scope included oversizing of infrastructure that was intended to serve multiple future projects. National Grid Carbon estimated that transport and storage costs would have decreased 60–80% for any future projects that could have piggybacked on the infrastructure put in place by White Rose.²⁴⁵ The decommissioning cost for the offshore facilities was estimated to be £64.5 million (about \$86 million using a June 2018 exchange rate).

²⁴³ <http://www.exchangemonitor.com/publication/ghg-daily-monitor/u-k-strikes-another-blow-white-rose-project/>

²⁴⁴ White Rose K.01 Full Chain FEED Summary Report.

²⁴⁵ Dixon, Patrick and Theo Mitchell, *Lessons Learned: Lessons and Evidence Derived from UK CCS Programmes, 2008-2015*. The Carbon Capture and Storage Association. London, UK. June 2016.

Table 4-4
Capital Cost Estimate for White Rose

Cost Element	Cost in millions*	Notes
Externally supplied utilities	£49 / \$65	Interconnections for coal, limestone, water, and power
Oxyfuel boiler, ASU, and gas processing unit (GPU)	£455 / \$600	
Generation equipment and balance of plant	£471 / \$620	Excludes costs for site raising, laydown areas and commissioning/ testing. Includes turbine, generators, environmental control equipment, transformers, switchgear, water systems (including raw, treatment, heating, cooling and waste), coal, limestone and ash handling systems, auxiliary systems, erection costs, project management costs and plant civil costs.
Onshore CO ₂ pipeline	£358 / \$470	Includes multi- junction, CO ₂ pumping station, the land, meters and monitors, and National Grid Carbon business costs
Offshore CO ₂ pipeline	£225/ \$300	Includes pipeline, landfall metering and monitoring and, National Grid Carbon business costs
Storage facilities	£344 / \$460	Includes the platform, the wells and any monitoring/ metering and National Grid Carbon business costs

* US\$ costs are approximate; converted at an exchange rate of 1.33 (June 2018 basis)

The boiler was designed for either air firing or oxygen firing with a recirculated CO₂-rich flue gas mix. The project design allowed for flexible operation in order to be able to respond to market conditions. Possible variations included:

- Load-level flexibility
 - A “flexibility concept” that mimics traditional “2-shifting day/night” operation. During this operating regime, for periods of up to 100 days per year, the CO₂ production can be reduced to 35% for approximately 8 hours on a daily basis. In this mode, the plant exports no power to the grid while still generating the power needed to operate the ASU and the GPU. This approach allows the plant to operate continuously, with CO₂ being provided to the transportation and storage system at a reduced rate.
 - A “normal ramping” range set by turndown limits of ASU and GPU while compliant with “Stable Export Limit.” The CO₂ output is expected to vary in the range between 100–75% during “normal ramping.”
 - Modulation of the CO₂ pumps at the pumping station to adjust to the CO₂ production rate and the process requirements of the pipeline.
- Adjustments to the injection wells
 - Using combination of injection wells would change the injection rates to accommodate the full range of CO₂ from the power plant.
 - The overall range of injection rates would vary as the reservoir pressure increases over the injection period.

- The wells’ maximum supply pressure of 2640 psig (182 barg) and minimum pressure of 1300 psig (90 barg) would prevent phase separation in the pipeline.

Annual operating expenses shown in Table 4-5 were estimated for the first full year of operation (November 2015 cost basis).

Table 4-5
Estimated Annual O& M Costs for White Rose

Cost Element	Cost in millions*	Notes
Fuel	£60 / \$80	International coal market price
Externally supplied utilities	£11 / \$15	Water, power import, costs of startups, chemical costs, and landfill costs
O&M for the power plant	£67 / \$89	Oxy power plant including ASU, GPU, and balance of plant
Transportation and storage	£47 / \$62	Full costs of onshore and offshore transport and storage.

* US\$ costs are approximate; converted at an exchange rate of 1.33 (June 2018 basis)

Technology Advancement Opportunities for Coal Oxy-Combustion

Technologies are being developed and tested at lab- or pilot-scale that should make significant improvements in oxy-combustion cost and performance in the next 5–20 years. In some cases, these technologies are directed toward improving a particular section of the oxy-combustion system, whereas in others the technologies represent an entirely different type of oxy-combustion system.

As shown in Table 4-6, alternative approaches to oxy-combustion, such as pressurized oxy-combustion and chemical looping, offer the promise of being more cost-effective than current oxy-combustion and post-combustion capture approaches, provided that developers reach their technical and funding goals.²⁴⁶

²⁴⁶ Based on Tables 1-2, 3-1, 3-2, and 3-3 of EPRI report *Oxy-Combustion Activities Worldwide: 2013 Update*. EPRI, Palo Alto, CA: 2013. 3002000763.

Table 4-6

Performance and Cost Comparisons for Pressurized Oxy-Combustion versus Atmospheric Oxy-Combustion and PC with Post-Combustion Capture

Parameter	PC without CCS	PC with MEA-based PCC	Atmospheric Oxy-Combustion w/ CPU	B&W/OSU Coal-Direct Chemical Looping	GTI (Aerojet Rocketdyne) Pressurized Oxy-CFB	WUSTL Pressurized Oxy-Combustion
Source	DOE NETL	DOE NETL	DOE NETL	B&W	DOE NETL	WUSTL
Heat Input, MW _t	1396	1935	1879	1559	1662	1512
Gross Power, MW	580.4	662.8	790.8	641.8	739	733
Aux Power, MW				93.5	189	178
Net Power, MW	550	550	550	548.3	550	555
Net Efficiency, %	39.3	28.4	29.3	41.2	33.1	36.7
CO ₂ Capture, %	0	90	90	97	98	90
Increase in LCOE	Baseline	81%	65%	33%	30%	
Increase in First-Year COE		81%	65%	28.8%		34%
First-Year COE, \$/MWh	58.9	106.5	96.9			
LCOE, \$/MWh	74.7	135.2	122.9			

Oxygen Production

Because oxygen supply is a major cost element for oxy-combustion (and IGCC) power plants, there is a substantial benefit to developing technologies that can supply oxygen at lower cost and energy requirements than cryogenic air separation units.^{247,248}

Membrane-Based Air Separation

With DOE and EPRI support, Air Products scaled up and tested an ion transport membrane (ITM) process based on selective diffusion of oxygen ions through a high-temperature perovskite ceramic membrane. Over the period of 2010–14, the scale of test units progressed from 1 ton-O₂/day stacks in a 5-ton-O₂/day unit to a 100 ton-O₂/day “intermediate scale test unit.” A design was also developed for a 2000 ton-O₂/day (1800 tonne-O₂/day) pre-commercial-scale facility,

²⁴⁷ EPRI report 3002000763, pp. 2-1 to 2-14.

²⁴⁸ The auxiliary power used in the ASU, and for CO₂ compression and purification will reduce net output of an oxy-combustion generating unit by up to 25% compared with an air-fired unit of the same capacity (and without CO₂ capture).

although funding to build it was not realized and development activity has ceased. An EPRI comparison of cryogenic ASU performance with the estimated performance of a two-stage ITM direct-fired oxygen supply at 1000°F (538°C) is shown in Table 4-7.²⁴⁹

Table 4-7
Comparison of ITM and Cryogenic ASU for an Oxy-Combustion Power System

Item	ASU	ITM
Steam Turbine Power	800.0	800.0
ITM Net Power, MW	0.0	370.3
Gross Power, MW	800.0	1170.3
Auxiliary Power, MW	246.9	131.6
Net Power, MW	553.1	1038.7
Thermal Input, MWt	1926.1	2858.5
Net Plant Efficiency, % HHV	28.7	36.3
Carbon Capture, %	73	72
Plant Cost, % change in \$	–	+24.9
Plant Cost, % change in \$/kW	–	-33.5
LCOE, % change in \$/MWh	–	-20.3

Inabensa was also developing an advanced ITM process, known as “AvantO2 II,” which uses perovskite ceramics for 100% selective separation of oxygen from air at high temperature and pressure. Inabensa modeling suggested a 7.5 percentage point improvement in net efficiency for oxy-combustion (versus a cryogenic air separation) when using AvantO2 II in a “4-end mode.” As with Air Products’ ITM process, efficiency was maximized by expanding the high-temperature nitrogen permeate through a power recovery turbine. Inabensa built a small test rig to determine the permeability, conductivity, and stability of the membranes.

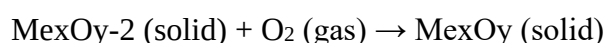
Praxair’s oxygen transport membrane (OTM) technology can be directly integrated with an oxy-combustion boiler in a manner that minimizes the need for air compression, potentially reducing parasitic power consumption by 70–80% relative to cryogenic air separation units. The OTM oxy-combustion system uses a chemical potential difference instead of pressure as the oxygen separation driving force, with a very low oxygen partial pressure on the combustion side of the membrane. Praxair’s techno-economic analysis on the full coal-based OTM power cycle estimated the capital cost for the system at about \$3,700/kW, with a thermal efficiency of about 38%. The resultant cost of CO₂ avoided cost was \$38/ton (\$42/tonne).²⁵⁰

²⁴⁹ *Plant-Wide Performance and Cost Analysis of ITM-Based Oxy-Combustion Generation Systems*, EPRI, Palo Alto, CA: 2013. 1022301.

²⁵⁰ M. Shah. “Praxair’s Oxygen Transport Membranes for Oxycombustion and Syngas Applications,” NETL Review, 2014.

Chemical Looping Air Separation

Chemical looping air separation uses a metal oxide oxygen carrier, typically cobalt, copper, or manganese, which alternatively captures oxygen from air and releases it into a concentrated stream. The technology can be implemented in a circulating bed or fixed bed configuration. In the fixed bed configuration, two beds alternatively serve as an “oxygen reactor” and as a “reduction reactor.” In the oxidation reactor, oxygen is removed from high-temperature air as it flows over the reduced oxide, according to the following reaction:



Once the solids in the oxygen reactor are “saturated” with oxygen, the flow is reversed and the bed becomes the reduction reactor. Steam (or flue gas) flows over the metal oxide in the reduction reactor to sweep oxygen produced by the reverse reaction. Steam is typically used as the sweep gas because separating it from oxygen is relatively easy.

The University of Newcastle in Australia has performed chemical looping air separation simulations and experimental tests at lab scales up to 5 kWt, and has evaluated about 20 different metal oxides for reactivity, selectivity, and sensitivity to impurities. Numerical studies indicate a reduction of 40–80% in energy consumption compared with cryogenic air separation. Planned next steps include building a test rig at 500 kWt scale.²⁵¹

Chemical Looping Combustion

Like chemical looping air separation, chemical looping combustion uses a reversible chemical reaction to separate oxygen from air. The oxygen carrier (generally a metal or limestone) is oxidized at high temperature in an “air reactor” and then transferred to a “fuel reactor.” The oxygen is released from the solid by the reverse (reduction) reaction that occurs as fuel is concurrently oxidized by the oxygen. The reduced solid carrier is collected from the products of combustion leaving the fuel reactor in a cyclone and returned to the air reactor.²⁵²

Because it eliminates the need for cryogenic air separation, chemical looping combustion has the potential to be more efficient than other power generation technologies that capture CO₂ from coal combustion. Energy losses from the reaction system are captured in the steam side of the plant, further reducing the energy penalty.

Chemical looping systems commonly employ a circulating bed or alternating fixed beds to maximize gas-solid contact in the reactors. With extensive lab-scale research conducted to identify the performance characteristics of a wide variety of candidate solid carriers, the leading candidates appear to be copper, iron, nickel, and limestone.²⁵³ Significant development efforts include Alstom’s limestone-based 3 MWt pilot and Babcock & Wilcox and Ohio State University’s iron oxide-based 1 MWt pilot.

²⁵¹ R. Stranger. “Integrated Chemical Looping Air Separation (ICLAS),” 3rd IEAGHG Oxyfuel Combustion Conference, 2013.

²⁵² EPRI report 3002000763. Op. cit. pp. 3-13 to 3-20.

²⁵³ A. Lungfelt. “Chemical Looping Combustion of Solid Fuels – Status of Development,” *Applied Energy*, 2013.

Pressurized Oxy-Combustion

Pressurized oxy-combustion further reduces the size of the boiler (which becomes a pressure vessel) as well as the size and power requirements of equipment for purification and compression of CO₂-rich flue gas. With combustors and flue gas flow paths typically operating at 145–435 psia (10–30 bar), volumetric flow rates are substantially reduced and flue gas dilution by air in-leakage is eliminated. Higher partial pressure allows water vapor in pressurized flue gas to be condensed at a temperature that allows for useful recovery of latent heat in the steam cycle. Net plant efficiency can also be increased by incremental reductions in power consumption for fans and other auxiliary equipment. Flue gas condensate can be recovered to reduce plant makeup water requirements and associated auxiliary loads.

Challenges associated with pressurized oxy-combustion units include:

- Material handling issues for introducing coal and bed material into pressurized systems and removing spent bed material or slag.
- Technology risk associated with unknown combustion science and integration of complex systems, particularly for gas-pressurized boiler/combustors, which need further development and testing.
- Environmental performance of pressurized oxy-combustion systems, including fate of fuel-bound sulfur, the amount of NO_x produced, and the amount of mercury and other air toxics, have not yet been comprehensively characterized with laboratory or field data.

Considerable theoretical and lab-scale research is ongoing in this area, and several technology developers have created pressurized coal oxy-combustion systems at small pilot scale.²⁵⁴ EPRI is part of a joint U.S. and Canadian project working to develop a 1 MWt oxy-fired pressurized fluidized-bed combustion pilot in Ottawa.

High-Temperature Oxy-Combustion

Findings from the Jupiter Oxygen test program (supported by DOE) suggest that high-temperature oxy-combustion technology is suitable for new-build or retrofit applications and can improve boiler efficiency while reducing CO₂ capture costs. Water recovery from the process may exceed feedwater requirements, and further efficiencies may be gained by heat integration with the air separation unit and NETL's integrated pollutant removal (IPRTM) compression/purification system. Parasitic power requirements are estimated to be reduced to 20% for the Jupiter Oxygen coal oxy-combustion technology with DOE's IPR system.

NETL has also conducted a systems analysis of a “direct power extraction” cycle combining magnetohydrodynamics (MHD) with high-temperature oxy-combustion, which would potentially allow power plants to be retrofit for improved efficiency and CO₂ capture. With high-power magnets for the MHD channel and an advanced USC steam cycle, overall plant efficiencies could approach 41–42% (HHV basis).²⁵⁵

²⁵⁴ EPRI report 3002000763. Op. cit. pp. 3-20 to 3-32.

²⁵⁵ https://www.netl.doe.gov/File%20Library/Events/2016/crosscutting-ree/Systems-Analysis_AUSC-and-DPE-Assessment.pdf

Combining Criteria Pollutant Removal with CO₂ Compression and Purification

R&D efforts in the early 2010s sought to reduce auxiliary power demand and the cost of coal oxy-combustion by integrating the removal of SO₂, NO_x, and Hg with the compression and purification process.²⁵⁶

- The sour compression process developed by Air Products aims to reduce the total cost and heat rate of a coal oxy-combustion unit by combining the capture of criteria and hazardous air pollutants with CO₂ compression and purification. After initial compression, water-based chemical processes convert SO₂ and SO₃ to H₂SO₄ (sulfuric acid) and convert NO and NO₂ to HNO₃ (nitric acid). The HNO₃ concentrations in the process are expected to remove Hg. The process also removes hydrochloric acid. Air Products tested the process using a slipstream from Doosan Babcock's 160 kW coal oxy-combustion test rig and subsequently commissioned a 1 MWt slipstream test unit in 2011 at Schwarze Pumpe, Germany. Air Products is also involved in a potential larger-scale oxy-combustion demonstration at Taiyuan (Shanxi Province) in China.
- NETL's Integrated Pollutant Removal system alternates spray heat exchanger/scrubber vessels with compression stages to remove water and criteria pollutants during the CO₂ compression and purification process. The process also recovers sensible and latent heat by routing the water from the spray vessel drains through heat exchangers to preheat boiler feedwater. Reagents may be added to the spray water to increase the amounts of SO_x, NO_x, and Hg that are captured. Testing on a coal oxy-combustion slipstream at Jupiter Oxygen's Hammond Boiler Test Facility suggests that 95–100%²⁵⁷ CO₂ capture is feasible if the storage formation can accept the levels of N₂, Ar, O₂, SO_x, and NO_x that remain after IPR treatment.²⁵⁸ IPR can use previously commercialized equipment at pilot and commercial scale.

Canadian Clean Power Coalition Coal Oxy-Combustion Retrofit Study

CCPC engaged a consortium of Japanese companies with experience in the Australian Callide A oxy-combustion project to conduct a Canadian oxy-combustion study using TransAlta's Sundance power plant in Alberta as a reference site.²⁵⁹

The study team examined the following cases:

- NGCC
- Sundance 2: base case 300 MW coal-fired unit before retrofit
- Oxy-Sun 2: Sundance Unit 2 retrofitted for oxy-combustion, with the sale of captured CO₂ for EOR and the sale of high-purity N₂ (from the ASU) as a byproduct.
- Oxy-Sun 2&1: Sundance Unit 2 retrofitted for oxy-combustion, as described in the Oxy-Sun 2 case, and Sundance Unit 1, unmodified, operated together such that the aggregate

²⁵⁶ V. White et al. *Purification of Oxyfuel-Derived CO₂*. Paper for GHGT-9. Energy Procedia I (2009) 399-406.

²⁵⁷ 100% capture requires an alternative power source during plant startup and shutdown and assumes no further processing to reach high CO₂ purity levels.

²⁵⁸ M. Schoenfield (Jupiter Oxygen Corporation) and T. Ochs (NETL). *JOC-NETL Project Update*, August 2, 2010. DOE Award Number: DE-FC26-06NT42811.

²⁵⁹ IHI Corporation, Electric Power Development Co., Ltd., Japan Coal Energy Center, and Mitsui & Co., Ltd.

emissions rate from the two units complies with Canada's emission performance standard of 925 lb (420 kg) of CO₂ per MWh, net basis excluding the auxiliary load for CO₂ compression.

The Oxy-Sun 2&1 case assesses the economic benefits of retrofitting oxy-combustion to Sundance Unit 2 and continuing to operate Sundance Unit 1 for five more years, between 2020 and 2025. This case assumes that a shared stack would qualify Units 1 and 2 for consideration as a single emission point source, which would allow Sundance Unit 1 to be operated without CCS, provided that together with Unit 2 the EPS is met.

Capital cost comparisons are shown in Table 4-8. The Sundance Unit 2 base plant is fully amortized, and the retrofit extends the life of the plant as an alternative to a boiler replacement. The following equipment was included in the retrofit:

- Expanded flue gas recirculation (recycle) system
- Dry FGD unit and auxiliary equipment
- Expanded boiler cold primary air/ flue gas recirculation system
- Air separation unit
- CO₂ processing (purification) unit
- Cooling water system
- Wastewater system
- N₂ liquefaction unit
- Electricity, instrumentation, and control system

Table 4-8
CCPC Oxy-Combustion Capital Cost Summary (CAD\$ million)

	NGCC	Oxy-Sun 2	Oxy-Sun 2&1
Base Plant	1,138		
Liquefaction Plant		36	36
ASU		247	247
CPU		112	112
Boiler & BOP		418	418
Contingency & Owners' Costs		203	203
Total in 2015	1,138	1,016	1,016
Total in 2025	1,406	1,287	1,287
Capital cost in 2015 (\$/kW)	2,130	6,392	3,656
Capital cost in 2025 (\$/kW)	2,630	8,095	4,630

* To obtain approximate costs in US\$, multiply the CAD\$ values shown by 0.77 (June 2018 exchange rate)

To keep the combined emissions of Unit 1 and 2 in compliance with the EPS, Sundance Unit 1 had to be run at partial load. As shown in Table 4-9, the first-year cost of power for the Oxy-Sun 2&1 case is lower than for the Oxy-Sun 2 case because of the additional lower cost power

provided by Sundance Unit 1. This plant, although derated, has a cost of power composed mostly of fuel and O&M because its capital cost has been largely amortized.

In the case of the oxy-combustion retrofit, an extremely high internal rate of return of 29% was obtained, compared with 5.7% for the new NGCC. This is because assumed revenue from the sale of CO₂ (2.1 Mtonne/yr) and N₂ (0.27 Mtonne/yr) supplements revenue from power sales. Thus, a first-year COE of \$101.80/MWh for the NGCC plant results in a negative net present value of \$226 million, whereas the net present value for the oxy-coal retrofit is a positive \$692 million. Figure 4-2,²⁶⁰ shows first-year COE costs including estimated revenue streams of CO₂ and N₂, as well as CO₂ credits.²⁶¹

Table 4-9
CCPC Oxy-Combustion Performance: Summary of Cases

	NGCC	Sundance 2	Oxy-Sun 2	Sundance 1	Oxy-Sun 2&1
Net Power (MW)	535	288	159	119	278
Derate (MW)			129	169	298
Derate, %			45	59	52
Heat Rate (GJ/MWh)	7.1	10.7	19.4	11.5	16.0
Capacity Factor, First Year, %	82	82	82	82	82
Design Life	20	20	20	20	20
Fuel Cost (CAD\$/GJ)	6.00	1.50	1.50	1.50	1.50
CO ₂ Produced (Mtonne/yr)	1.4	2.1	2.1	0.9	3.0
CO ₂ Captured (Mtonne/yr)			2.1		2.1
CO ₂ Capture, %			98		68
Fixed Operating Costs, 2015 (no fuel), \$CAD million	40.8	10.0	45.3	10.0	55.3
First Year COE (CAD\$/MWh)*	101.8		74.8		56.0
N ₂ transport costs not included in study. CO ₂ transport costs are included in CO ₂ capture costs of CAD\$42/tonne.					

For heat rates in Btu/kWh, multiply GJ/MWh values by 948. For emission rates in short tons rather than tonnes, multiply rates in tonnes by 1.102.

²⁶⁰ Dave Butler. Canadian Clean Power Coalition, “Results of Sundance 2 Oxy-Fuel Modelling,” June 17, 2015.

²⁶¹ *FY2014-2015 Final Report. Project Finding Research on CCUS Project Using Oxyfuel Technology in Canada*, June 2015. IHI Corporation, Electric Power Development Co., Ltd., Japan Coal Energy Center, and Mitsui & Co., Ltd.

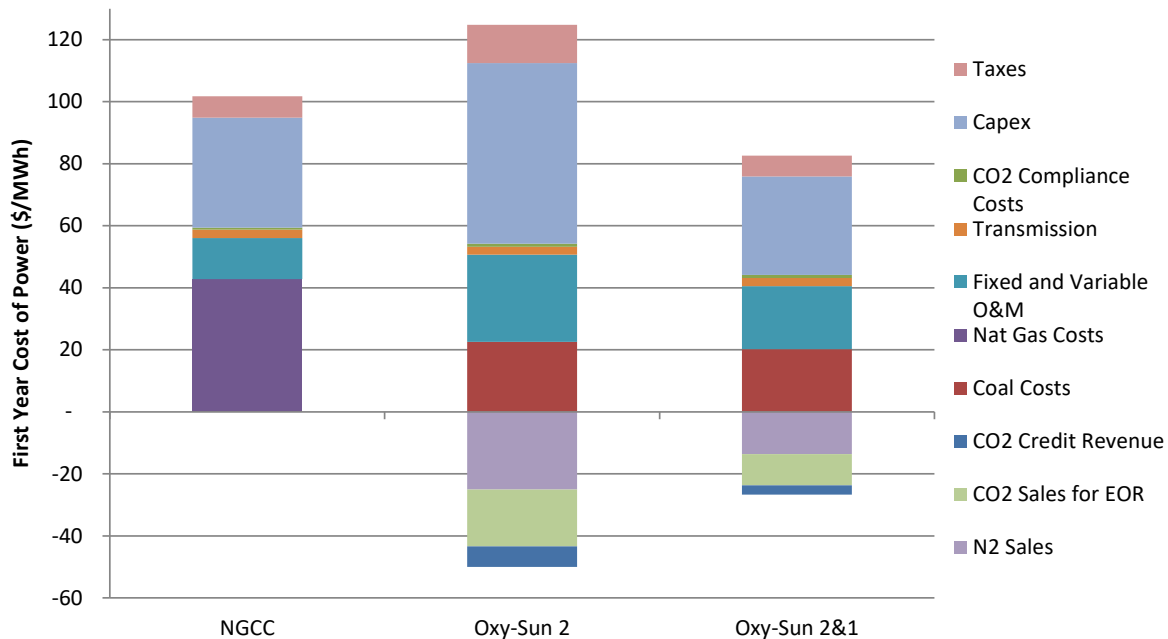


Figure 4-2
CCPC Oxy-Combustion First-Year Power Cost Components (CAD\$)

EPRI Engineering-Economic Evaluations of Oxy-Combustion

EPRI report 3002008148, developed with Amec Foster Wheeler, established the performance and economics for coal and natural gas oxy-combustion power systems.²⁶² The technologies examined in the study are listed in Table 4-10. Case 1 consists of the atmospheric pressure oxy-fired USC PC power plant used in EPRI's 2011 report 1021782, but updated to include the latest technical developments. The nominal 700 MW (net) unit fires Powder River Basin coal with steam conditions of 4205 psi/1110°F/1150°F (290 bar/600°C/620°C). The boiler design features two streams of flue gas recycle: (1) a primary stream with low water content, which is used for drying and transporting pulverized fuel through the coal mills to the burners, and (2) a secondary stream providing additional gas heat capacity to the burners to maintain temperatures within the furnace similar to those of air-fired boilers. The combined primary and secondary flue gas recycle rate is about 70% of the flue gas leaving the economizer. In this arrangement, secondary measures in the boiler for reducing SO_x and NO_x are not required, which yields significant capital savings.

The other four cases span promising oxy-fired natural gas turbine cycles. EPRI's standard reference location of Kenosha, Wisconsin, was used for all cases.

²⁶² *Oxy-Fired Coal and Natural Gas Power Plants – 2016 Detailed Feasibility Study*. EPRI, Palo Alto, CA: 2017. 3002008148.

Table 4-10
EPRI Oxy-Combustion Power Plant Cases

Case Number	Description	Plant capacity	CO ₂ capture
1	Oxy-combustion USC PC plant (PRB-fired)	Net power output of 700 MWe	90%
2	Semi-Closed Oxy-Combustion Combined Cycle (SCOC-CC)	Thermal input 1240 MWt (Equivalent to 2 F-class 60 Hz gas turbines)	90%
3	NET Power – Allam Cycle	Same thermal input as Case 2	90%
4	Modified S-Graz Cycle	Same thermal input as Case 2	90%
5	Clean Energy Systems (CES)	Same thermal input as Case 2	90%

Table 4-12 shows the 30-year, constant dollar LCOE, which is calculated using the “revenue requirements” method for an investor-owned utility, assuming an 85% capacity factor for all cases. An annual capital carrying charge factor of 12.1% is applied to the coal case, while a factor of 11.9% is applied to the natural gas cases.²⁶³ Calculations were performed with a delivered coal cost of \$1.85/MBtu (\$1.75/GJ) for Wyoming PRB and a delivered natural gas cost of \$4.00/MBtu (\$3.78/GJ). All cases assumed that captured CO₂ was compressed to 2200 psig (152 bar). A charge of \$9 per ton (\$10/tonne) of CO₂ was applied to account for the costs of pipeline transportation, saline formation injection, and monitoring.

The reference plants for calculating the “cost of CO₂ avoided” and “cost of CO₂ captured” are a PRB-fired USC PC plant without CCS²⁶⁴ for the coal case and an NGCC plant without CCS²⁶⁵ for the natural gas cases. The LCOE values for the reference plants are \$63.90/MWh for coal and \$48.40/MWh for natural gas at the same fuel prices and capacity factors assumed in the study. The cost of CO₂ captured excludes CO₂ transportation and storage costs.

The oxy-combustion USC PC plant design is assumed to use commercially proven equipment; accordingly, no process contingencies are included in the cost estimate. The natural gas “oxy-turbine” power plants include novel equipment that is either under development or at conceptual stage only, so for estimating purpose they would normally be considered as first-of-a-kind plants. However, because this investigated the potential capabilities of natural gas oxy-turbine power plants with respect to benchmark technologies for capturing CO₂, the oxy-turbine cycles are considered nth-of-a-kind for cost estimating purposes and the cost of novel equipment is

²⁶³ *Engineering-Economic Evaluations of Advanced Fossil Fuel Power Plants with Carbon Capture and Storage*. EPRI, Palo Alto, CA: 2015. 3002005909.

²⁶⁴ *Ultrasupercritical Pulverized Coal Power Plants with Partial Carbon Dioxide Capture: 2015 Detailed Feasibility Study*. EPRI, Palo Alto, CA: 2015. 3002005911.

²⁶⁵ *Program on Technology Innovation: Integrated Generation Technology Options 2012*. EPRI, Palo Alto, CA: 2013. 1026656.

evaluated as already suitable for large-scale commercial application. As a result, no process contingencies were added to the base plant cost for the oxy-combustion turbine technologies.

The estimate is based on a standard execution of the project and estimated costs are not based on a turnkey type of contract; therefore, all risk contingencies associated to a turnkey project are excluded. Only the project contingency is added to the Total Plant Cost. Consistent with the cost estimate classification and the level of detail of technical information available to develop the estimate, an average contingency of 15% was applied to all the plant systems.

Table 4-11
EPRI Levelized Cost of Electricity and Cost of CO₂ Avoided/Capture

Case	1	2	3	4	5
Power Technology	USC PC	SCOC CC	NET Power	Modified S-Graz	CES
Fuel	PRB Coal	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CO ₂ Capture Percent	90.1	90.4	90.1	90.2	90.2
Levelized Cost of Electricity, \$/MWh					
Capital	53.5	26.4	23.7	26.8	26.8
Fixed & Variable O&M	14.5	8.0	7.2	8.1	8.4
Fuel	20.3	32.1	28.2	31.9	31.4
CO ₂ Transport & Storage	9.5	3.9	3.4	3.8	3.8
Total LCOE, \$/MWh	97.8	70.4	62.5	70.6	70.4
Cost of CO ₂ Avoided, \$/tonne CO ₂ *	46	66	42	68	67
Cost of CO ₂ Captured, \$/tonne CO ₂ *	26	47	31	48	48

* Relative to USC PC without CCS for coal case and relative to NGCC without CCS for natural gas cases

Observations from the study include:

- Among the oxy-turbine cases, the regenerative NET Power cycle with 90% CO₂ capture has the highest efficiency and lowest capital cost, resulting in an LCOE of \$62.5/MWh, which is about 11% lower than the other three oxy-turbine cases. By comparison, an NGCC without CO₂ capture has an LCOE of about \$63.9/MWh.
- At \$42/tonne of CO₂, the cost of CO₂ avoided for the NET Power cycle is about 37% lower than the costs for the other three oxy-turbine cases, and it is nearly 9% lower than the cost of CO₂ avoided for the oxy-USC PC plant.

- As illustrated in Figure 4-3, the capital cost of the reference USC PC plant in Case 1 is nearly identical to the adjusted capital cost of the reference plant from the 2011 EPRI study. However, the capital cost of the oxy-USC PC plant is nearly 18% lower than the adjusted capital cost of the corresponding case from the 2011 EPRI report. This is due, in part, to eliminating the need for emissions control systems and reducing balance-of-plant costs.

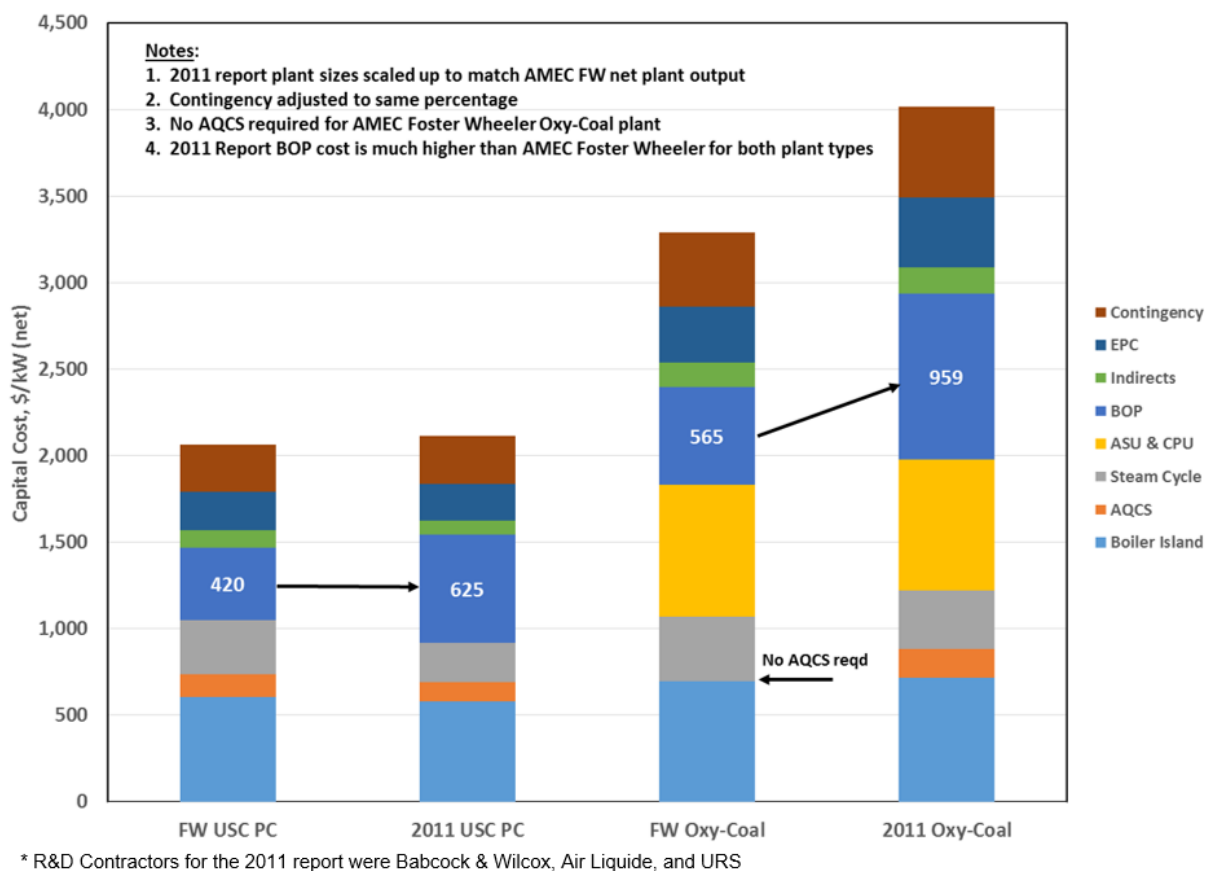


Figure 4-3
Comparison of Capital Cost Breakdowns for an Oxy-Fired USC PC (EPRI 2011 vs. 2017 Studies)

EPRI report 1021782 provides results of EPRI’s engineering-economic evaluation of coal oxy-combustion using data provided by Babcock & Wilcox and Air Liquide for technology similar to that proposed for FutureGen 2.0.²⁶⁶ The study examined air and oxy-fired configurations firing PRB coal in a nominal 700 MWe (gross) unit with 1100°F (593°C) steam conditions. The study included sensitivity cases for three different CO₂ purification scenarios. Table 4-12 summarizes results in the left-hand columns. Figure 4-4 illustrates sensitivity to CO₂ price for the different CO₂ purification scenarios. Costs are summarized in Table 4-13. Note that the base case oxy-combustion USC PC total plant cost is higher in this study than in the newer EPRI study in report 3002008148. However, the results of EPRI report 1021782 shown in Table 4-13 are still of

²⁶⁶ *Engineering and Economic Evaluation of Oxy-Fired 1100°F Ultra-Supercritical Pulverized Coal Power Plant with CO₂ Capture: Final Report*. EPRI, Palo Alto, CA: August 2011. 1021782.

interest in relative terms because the study contains a fairly broad set of sensitivity analyses, including the sensitivity of cost results to various financial assumptions.

EPRI report 1023870 provides interim results from a joint EPRI–Electricite de France study to develop and apply a nonproprietary model that approximates the design specifications and outputs of a Babcock & Wilcox/Air Liquide plant.^{267,268} In particular, the study’s Cases A and B approximate the Babcock & Wilcox/Air Liquide cases for 1100°F (593°C) USC-PC oxy-combustion, but with slightly lower CO₂ product purity. The values for A-USC steam conditions of 4500 psia/1260°F/1296°F (310 bar/682°C/702°C) were extrapolated from the study’s Case A 1100°F (593°C) ultra-supercritical design, while keeping the same fuel and oxidant flow rates. Refinements were then made in accordance with general rules of cycle design to obtain the Modified A-USC case values. The interim performance data for 1100°F (593°C) and the nominal 1300°F (700°C) oxy-combustion PC configurations are shown in the right-hand columns of Table 4-12.

²⁶⁷ *Engineering and Economic Evaluation of 1300°F (700°C) Series Oxy-PC Power Plant. Interim Report.* EPRI. Palo Alto, CA: December 2012. 1023870.

²⁶⁸ *Engineering and Economic Evaluation of Oxy-Fired 1100°F (593°C) Ultra-supercritical Pulverized Coal Power Plant with CO₂ Capture.* EPRI, Palo Alto, CA: 2011. 1021782.

Table 4-12

EPRI Performance Summary for Oxygen-Fired USC PC Power Plants with CO₂ Capture (PRB Coal)

Performance Parameter	Air-Fired USC PC (1100°F)	Oxy-USC PC Base Case ²⁶⁹ (1100°F)	Sens. Case 1	Sens. Case 2a	Sens. Case 2b	Sens. Case 3	Oxy-USC PC Base Case A (1100°F) ²⁷⁰	Oxy-USC PC Base Case B (1100°F)	A-USC Oxy-PC Case (1300°F)	Modified A-USC Oxy-PC (1300°F)
Case Definition										
CO ₂ Capture (% of total)	N/A	90%	90%	100%	90%	98%	90%	90%	90%	90%
Product Quality (vol%-CO ₂)	N/A	>99.99%	98.7%	84.4%	84.4%	>99.99%	>99.7%	>98.0%	>99.7%	>99.7%
Performance Results										
Unit Output, MWe-net (gross)	657.0 (697.8)	508.6 (701.7)	509.5 (702.1)	504.8 (706.1)	510.8 (705.1)	501.2 (700.8)	506.1 (701.9)	510.2 (701.9)	538.1 (733.2)	541.8 (737.3)
Net Efficiency, % HHV	39.0	31.5	31.53	31.23	31.6	31.01	31.3	31.6	33.3	33.5
Net Heat Rate, Btu/kWh HHV (kJ/kWh HHV)	8,743 (9,224)	10,842 (11,439)	10,823 (11,419)	10,925 (11,526)	10,797 (11,391)	11,003 (11,609)	10,893 (11,493)	10,806 (11,401)	10,246 (10,810)	10,176 (10,736)
Water Consumption, gpm (lpm)	5,073 (19,202)	6,432 (24,346)	6,388 (24,182)	6,325 (23,941)	6,282 (23,780)	6,504 (24,621)				
CO ₂ Removed, tonne/hour ²⁷¹		477.5	481.0	531.5	479.9	522.9	486	483		
CO ₂ Emitted, tonne/hour		54.0	50.4	0.0	51.6	8.52				
CO ₂ Emissions, tonne/MWh (net)	0.846	0.106	0.099	0.000	0.101	0.017				

²⁶⁹ EPRI report 1021782, op. cit.

²⁷⁰ EPRI report 1023870, op. cit.

²⁷¹ CO₂ emissions values are for baseload operation. Startup emissions would be comparable to the air-fired case.

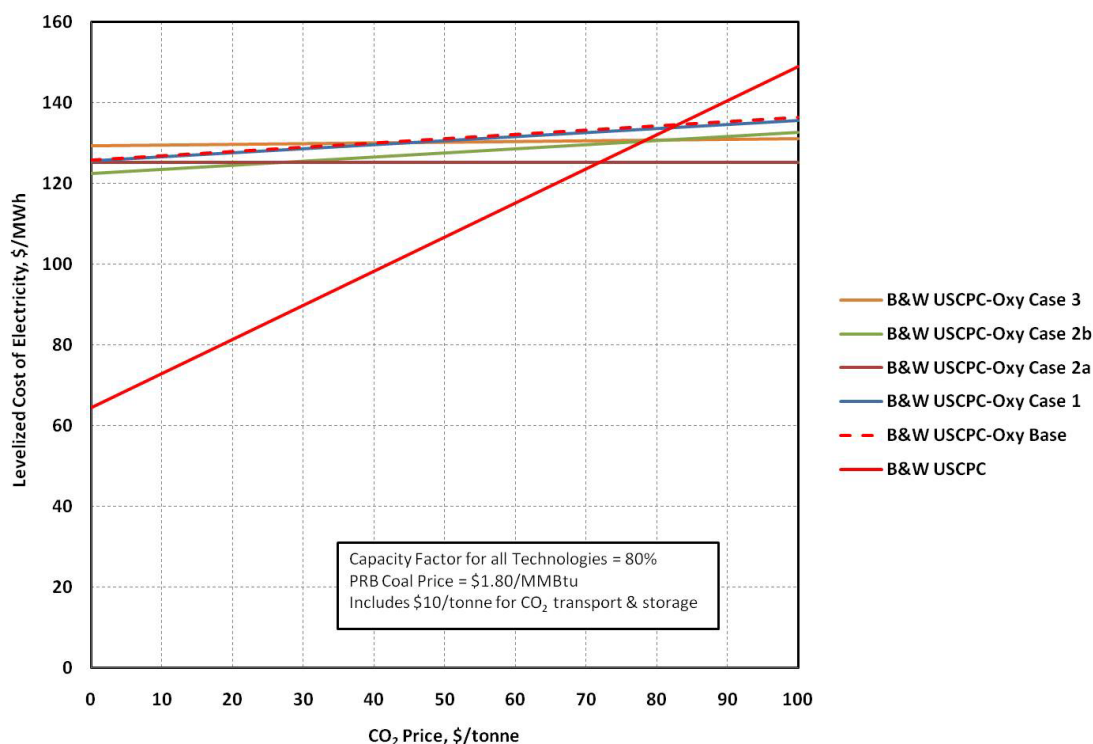


Figure 4-4
Levelized COE versus CO₂ Price for EPRI USC PC Oxy-Combustion Cases

Table 4-13
Cost Summary for an Oxygen-Fired 1100°F USC PC Power Plant with CO₂ Capture

Cost Parameter	Air-fired USC PC	B&W/AL Oxy-USC PC Base Case	Sens. Case 1	Sens. Case 2a	Sens. Case 2b	Sens. Case 3
Case Definition						
CO ₂ Capture (% of total)	NA	90%	90%	100%	90%	98%
Product Quality (vol%-CO ₂)	NA	>99.99%	98.7%	84.4%	84.4%	>99.99%
Cost Results						
TPC, \$/kW (net), \$/kW (gross)	2,297 2,163	4,638 3,362	4,630 3,360	4,539 3,245	4,472 3,239	4,745 3,393
LCOE, \$/MWh (net)	64.4	125.8	125.7	125.2	122.5	129.4
LCOE at \$50/tonne-CO ₂	106.7	131.1	130.6	125.2	127.5	130.2
LCOE at \$100/tonne-CO ₂	149.0	136.4	135.6	125.2	132.6	131.1
Cost of CO ₂ Avoided (\$/tonne)		83.0	82.0	71.9	77.9	78.3

Wyoming PRB Coal, \$1.80/MBtu (\$1.70/GJ) HHV; 80% Capacity Factor; EPRI TAG Class II Estimate (20% Project Contingency); Mature Technology; CO₂ Transportation, Storage, and Monitoring at \$10/tonne; nth of a kind cost basis.

The B&W/Air Liquide study also noted that the oxy-combustion PC plant had lower pollutant emissions than the air-fired PC plant, with the exception of carbon monoxide. Net efficiency is

reduced by about 7 percentage points by the added auxiliary load for the air separation unit and the CO₂ purification and compression unit. This is significantly less than the efficiency loss for amine-based post-combustion CO₂ capture. The oxy-fired USC PC plant had a net efficiency comparable to the average efficiency of currently operating U.S. coal plants without CO₂ capture.

EPRI report 1021782 suggests that CO₂ purity specification has less of an impact on oxy-combustion economics than did an earlier EPRI study with WorleyParsons,²⁷² which found the CO₂ purity specification to be among the most important factors in determining the economic feasibility of coal oxy-combustion.

EPRI believes that for transport in a common carrier pipeline, CO₂ purity requirements are fairly well established. A 97% purity specification is typically desired by EOR operators, as this allows for about 94% CO₂ purity at the point of separation from produced oil for compression and reinjection. Purity requirements for saline formation storage will depend partially on future regulatory decisions and partially on the physical and geochemical characteristics of the target formation. A suggested standard of 94% CO₂ purity could potentially be relaxed, depending on the circumstances of a given project.

Other issues also affect CO₂ purity specification for pipeline transportation. Increased transport distance may justify a higher purity specification, as impurities reduce the quantity of CO₂ per unit volume. Pipeline capacity decreases by about 10% as purity drops from 97% to 94%. The potential for hydrogen damage to the pipeline becomes a concern at H₂ concentrations above 1–2% (vol). H₂O and O₂ concentrations in high-pressure CO₂ typically must be kept in the low ppm range to avoid corrosion in carbon steel piping.

DOE Engineering-Economic Evaluations of Coal Oxy-Combustion

The challenges of developing coal oxy-combustion technology to commercial viability, along with potential solutions, were enumerated in an NETL study of advanced oxy-combustion technologies.²⁷³ When applied together, the identified technology improvements showed promise for meeting DOE's goal of 90% CO₂ capture with a COE increase of less than 35% relative to an equivalent plant without CO₂ capture (excluding the cost of CO₂ transport, storage, and monitoring).

The four major categories of technologies examined by NETL were advanced boiler design, advanced oxygen production, advanced flue gas treatment, and innovative CO₂ compression. The R&D areas with the largest potential benefits were oxygen supply, sulfur-tolerant materials, oxy-combustion boiler design, and advanced steam conditions.

Table 4-14 summarizes the cost results for two reference cases and seven improvements. The “Current OF [oxy-firing] Technology” case, although not yet implemented, is believed to be

²⁷² J.C. Simpson, M. DeLallo (Worley Parsons Group), J. Phillips, and G. Booras (EPRI). *Economics of Carbon Dioxide Purity in Oxygen Fired Coal-Fired Power Plant*. Presentation to Ninth Annual Conference on Carbon Capture & Sequestration, May 10-13, 2010, Pittsburgh, PA.

²⁷³ *Advancing Oxycombustion Technology for Bituminous Coal Power Plants: An R&D Guide, Final Report*. DOE/NETL-2010/1405. April 2012.

achievable with current technology.²⁷⁴ The remaining cases require substantial RD&D before they would be ready for full-scale demonstration.

Table 4-14
Summary of Results from DOE NETL Techno-Economic Study of Advanced Coal Oxy-Combustion Technologies

Study Case	First Year Cost of Electricity (\$/MWh)						Increase in COE, %
	Capital	Fixed O&M	Variable O&M	Fuel	TS&M	Total (less TS&M)	
Non-capture Reference, air-fired SC w/o CCS	31.68	7.97	5.03	14.22	0.00	58.90	–
Current OF Technology, O ₂ -fired SC w/ASU & CCS	53.72	11.81	6.47	19.08	5.83	91.07	54.6
Case 1, O ₂ -fired SC w/Boiler Adv. Membrane & CCS	52.35	11.53	5.99	17.32	5.60	87.19	48.0
Case 1A, O ₂ -fired SC w/NG Adv. Membrane & CCS	50.45	11.23	5.63	23.81	5.25	91.12	54.7
Case 3, O ₂ -fired USC w/ASU & CCS	54.15	11.81	6.10	17.25	5.58	89.31	51.6
Case 4, O ₂ -fired SC w/ASU & Co-sequestration	48.85	10.79	4.78	17.60	5.67	82.02	39.3
Case 5, O ₂ -fired SC w/ASU, West Recycle & CCS	53.66	11.80	6.47	19.11	5.91	91.03	54.5
Case 6, O ₂ -fired SC w/ASU & Shock Compression	52.59	11.60	6.34	18.81	5.87	89.34	51.7
Case 7, O ₂ -fired SC w/ASU Adv. Boiler & CCS	53.13	11.65	6.32	18.87	5.89	89.96	52.7
Cumulative Technology Case	48.52	10.66	4.30	14.68	5.28	78.15	32.7

In 2010, NETL published a study of oxy-combustion plants firing low-rank coal.²⁷⁵ Although this study focused on PC plants, it also examined two CFB cases. Findings included:

- The 20-year LCOE was estimated to be 58–78% higher for oxy-combustion cases than for equivalent air-fired cases without CO₂ capture.
- Total plant capital cost represented 69–75% of total LCOE for all cases.
- For the USC PC and SCPC cases, the total plant capital cost (\$/kW basis) was 58–67% higher for oxy-combustion than for air combustion. Removing first-of-a-kind premiums and other contingencies reduced this cost premium to 18–25%.

²⁷⁴ Ibid.

²⁷⁵ *Cost and Performance for Low-Rank Pulverized Coal Oxycombustion Energy Plants*. DOE/NETL-401/093010 Final Report. September 2010.

- For SC-CFB cases, the total plant capital cost (\$/kW basis) was 80–87% higher for oxy-combustion than for air combustion. Removing contingencies reduced this cost premium to 43–70%.

Implementing CO₂ capture using oxy-combustion reduced net plant efficiency by 7–9 percentage points (i.e., increased heat rate by about 21%). The impact for comparable CO₂ emissions reduction using amine scrubbing post-combustion capture was an 11 percentage point efficiency drop (about a 27% heat rate increase).

5

INTEGRATED GASIFICATION COMBINED CYCLE PLANTS

Interest in IGCC has been spurred by the opportunity to achieve the higher efficiencies of combined cycles, the very low air emissions of synthesis gas fueled gas turbines, and the price stability and supply reliability of coal and petroleum coke. Further, IGCC units use less water and require less acreage than PC or CFB units.

With respect to CO₂ capture, the energy consumption of the pre-combustion CO₂ capture and compression processes for IGCC is lower than for post-combustion capture methods because of the advantage of separating CO₂ at elevated pressure. As a result, economic evaluations by EPRI and others show that the incremental cost of adding CO₂ capture to IGCC units is less than the cost of adding CO₂ capture to other types of fossil power plants. IGCC technology with pre-combustion capture is also well suited to partial CO₂ capture, which was established as the “best system of emission reduction” in EPA’s 2015 publication of “Final Carbon Pollution Standards for New, Modified and Reconstructed Power Plants.”²⁷⁶

The chief concern for IGCC base plant technology is capital cost. EPRI and others have observed that the capital costs of recent U.S. IGCC and gasification-based polygeneration projects have been higher than expected, although the number of projects is small and most have had considerable first-of-a-kind and site-specific owner’s costs. EPRI has developed an R&D roadmap to reduce IGCC costs through equipment train economies of scale, more durable gasifier components, alternative oxygen production methods, improved heat exchangers and material conveyance equipment, advanced gas turbines, and improved CO₂ (and other acid gas) separation processes.²⁷⁷

Technology Overview

Current and emerging IGCC configurations reflect a variety of design approaches, feedstocks, and target markets. Figure 5-1 depicts a block flow diagram for a typical oxygen-fed IGCC unit and the modifications necessary to add a pre-combustion CO₂ capture process.²⁷⁸ For air-fed gasifiers, the air separation unit shown in Figure 5-1 would be replaced by a large air compressor to augment the air extracted from the gas turbine’s compressor to supply pressurized air to the gasifier.

²⁷⁶ 80 FR 64510.

²⁷⁷ 2012 Integrated Gasification Combined Cycle (IGCC) Research and Development Roadmap. EPRI, Palo Alto, CA: 2012. 1026868.

²⁷⁸ 2009 Integrated Gasification Combined Cycle Engineering Economic Evaluation: Desktop Reference Report, U.S. Units Version. EPRI, Palo Alto, CA: 2009. 1019367.

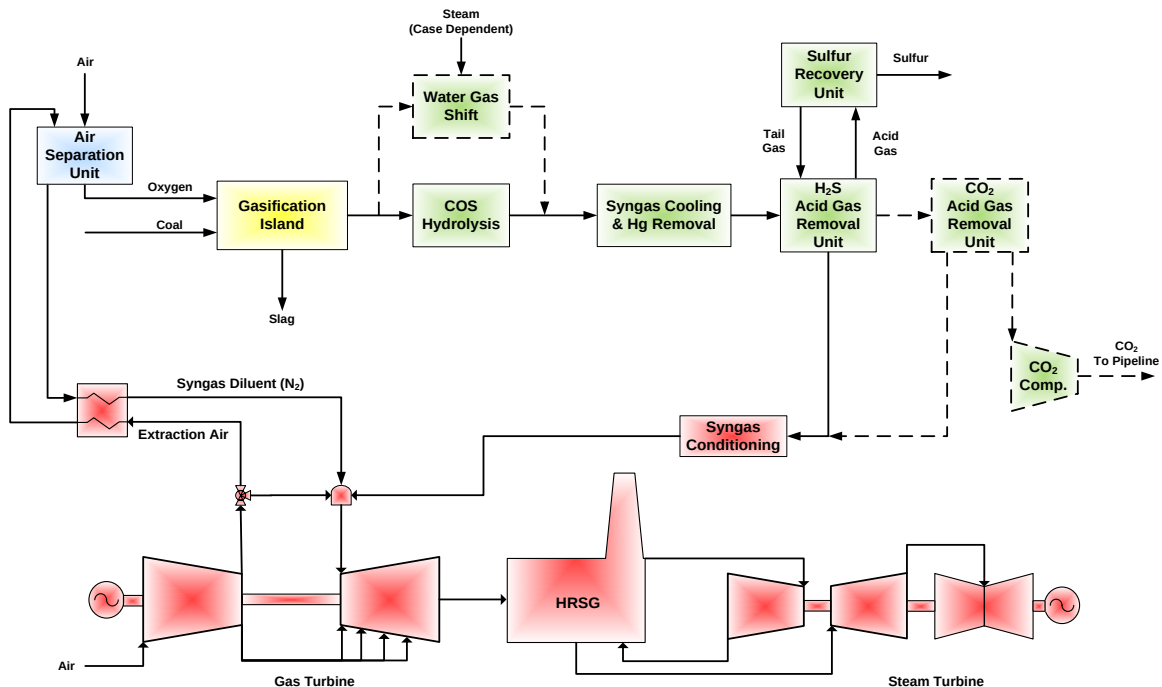


Figure 5-1
Process Flow Diagram of Generic IGCC Plant Showing Retrofit Modifications for CO₂ Capture

Coal is traditionally fed to a gasifier in the form of relatively dry solids or as a paste or slurry with water. Other fluids are being considered as slurry media, including liquid CO₂. Fuel and oxidant, either air or high-purity oxygen, are combined at elevated pressure and temperature in an entrained flow stream or in a fluidized-bed. The primary constituents of the resulting synthesis gas, or syngas, are carbon monoxide (CO) along with methane, hydrogen, CO₂, steam, and sometimes heavier hydrocarbons. Within and downstream of the gasifier, the raw syngas is cooled by radiant, convective, and/or quench methods. Additional filters, heat exchangers, and knockout drums are used to remove particulates, excess water, and heavier hydrocarbons. Undesired sulfur compounds, most notably hydrogen sulfide (H₂S) and smaller amounts of carbonyl sulfide (COS), are separated in an acid gas removal (AGR) process, typically employing physical or chemical absorption processes from the petrochemical industry. A catalyst is used to convert COS to H₂S upstream of the AGR absorption column to facilitate greater total sulfur removal. A sulfur recovery unit produces salable elemental sulfur or sulfuric acid. An activated carbon sorbent may be used to remove mercury and other trace metals. Once cleaned, the syngas is combusted in a gas turbine with an added diluent, typically nitrogen from the ASU in plants with oxygen-fed gasifiers, to limit flame temperature and NO_x formation. As in an NGCC plant, the hot exhaust exiting the gas turbine flows to a HRSG where it raises steam to drive a steam turbine.

Various IGCC designs use different degrees of thermal integration and “air integration” of the combined cycle power block with the other process units. Examples include (1) cooling syngas while recovering heat to produce steam or preheat boiler feedwater, and (2) extraction of compressed air from the gas turbine for feed to the air separation unit to reduce the ASU compressor’s power demand. Although greater integration usually increases plant efficiency, it can constrain plant operating flexibility (i.e., require longer startup time and/or slower ramp

rates). In the case of IGCC units with pre-combustion CO₂ capture, there may be little or no excess air available for extraction from the gas turbine's compressor.

CO₂ capture in an IGCC unit is normally accomplished by adding one or two stages of catalytic water-gas shift to convert CO and H₂O to H₂ and CO₂, followed by an AGR process to separate the CO₂ from the hydrogen-rich syngas. The amount of steam added to accomplish the desired extent of the water-gas shift reaction depends on the gasifier feed method (slurry or dry), syngas cooling method (quench or heat exchanger), coal moisture content, and catalyst effectiveness. Ongoing R&D aims to improve water-gas shift catalysts so that they require less steam, which would reduce extraction from the steam cycle and increase the steam turbine's power output.

Chemical AGR absorbents, such as methyldiethanolamine (MDEA) or other amines, react with the acid gases (i.e., CO₂, H₂S, COS) and require heat to reverse the reactions and release the captured gases. These AGR processes generally cost less than physical solvent processes, but use larger amounts of steam for solvent regeneration. Physical absorbents, such as the trade-name processes Selexol and Rectisol, dissolve acid gases preferentially with increasing pressure. The absorbed acid gases are released from the solvent when pressure is decreased and temperature is increased. Significantly less steam is required for solvent regeneration than with chemical solvents. The Rectisol process, which uses chilled methanol, generally has a higher capital cost than Selexol, but provides greater acid gas removal rates.

Both types of AGR solvents can accomplish >90% CO₂ removal, but the overall percentage of capture depends on the extent of the catalytic water-gas shift reaction. Space requirements for the water-shift reactor(s), AGR equipment, and CO₂ drying and compression equipment are similar for all solvent options at about 1.5 to 2 acres (0.6–0.8 hectare) for a utility-scale IGCC plant.

Generally, three levels of CO₂ capture are available for IGCC plants, based on the extent of catalytic water-gas shift used. “Full” (i.e., nominally 90%) capture employs two stages of water-gas shift, one at high temperature and one at low temperature. The resulting high rate of CO conversion produces a high hydrogen-content syngas that usually requires modified gas turbine combustors (relative to combustors for CO-based syngas or natural gas), even with nitrogen dilution.

“Partial” (i.e., nominally 50–80%) capture is more than sufficient to satisfy EPA's Section 111(b) NSPS of 1400 lb (635 kg) of CO₂ per MWh, gross basis, on an individual unit basis, and would normally also satisfy emissions performance standards in the range of 925 lb (420 kg) to 1100 lb (500 kg) of CO₂ per MWh used in select U.S. states and in Canada. Partial capture uses a single high-temperature stage of water-gas shift. The cost per ton of CO₂ avoided for this approach may be lower than for full capture, and the resulting hydrogen-rich syngas may still be compatible with commercial gas turbine combustors rated for CO-based syngas (as opposed to less-developed combustors for high-hydrogen syngas).

A low-performance, but low capital cost, partial capture approach known as “skimming” entails operation of the gasifier in a manner that promotes CO₂ formation without the use of catalytic water-gas shift but with CO₂ removal in a downstream Selexol (or other physical solvent) AGR process. This approach may be effective for compliance with EPA's Section 111(b) NSPS only

with a GE Energy gasifier (or comparable) firing bituminous coal and operating minimally in startup, shutdown, or upset conditions.²⁷⁹

When considering the effects of adding the water-gas shift for CO₂ capture, EPRI recommends looking at the inherent moisture content of the syngas from various gasifier/fuel combinations. The amount of moisture in syngas these combinations can vary markedly, which affects the amount of steam that must be extracted from the power cycle to provide the minimum moisture necessary for effective catalyst operation.

Market Activity

Rapid growth in the demand for chemical feedstocks, coupled with competitive prices for coal and petroleum coke relative to oil and natural gas in much of the world, has led to the development of many new gasification projects over the last decade. Table 5-1 shows the results of this market trend.²⁸⁰

Gasification development activity in Asia, led by China, far outstrips other regions. As shown in Figure 5-2,²⁸¹ the biggest global use for syngas is chemical synthesis, followed by gaseous and liquid fuels production, followed by power and industrial gases. Use of coal far outstrips other feedstocks. GE Energy and Shell have been the leading technology licensors.

Table 5-1
Summary of Worldwide Gasification Projects in 2017

Commercial	Projects	Gasifiers	GWt Syngas Capacity
Operating	379	938	173
Construction	131	348	108
Planned	146	734	116
Total	656	2020	398

²⁷⁹ *Integrated Gasification Combined Cycle Power Plants with Partial Carbon Dioxide Capture: 2015 Detailed Feasibility Study Update*. EPRI, Palo Alto, CA: 2015. 3002007021.

²⁸⁰ Higman, C. *GSTC Syngas Database 2017 Update*. Gasification & Syngas Technologies Conference, Colorado Springs, CO, October 17, 2017.

²⁸¹ Ibid.

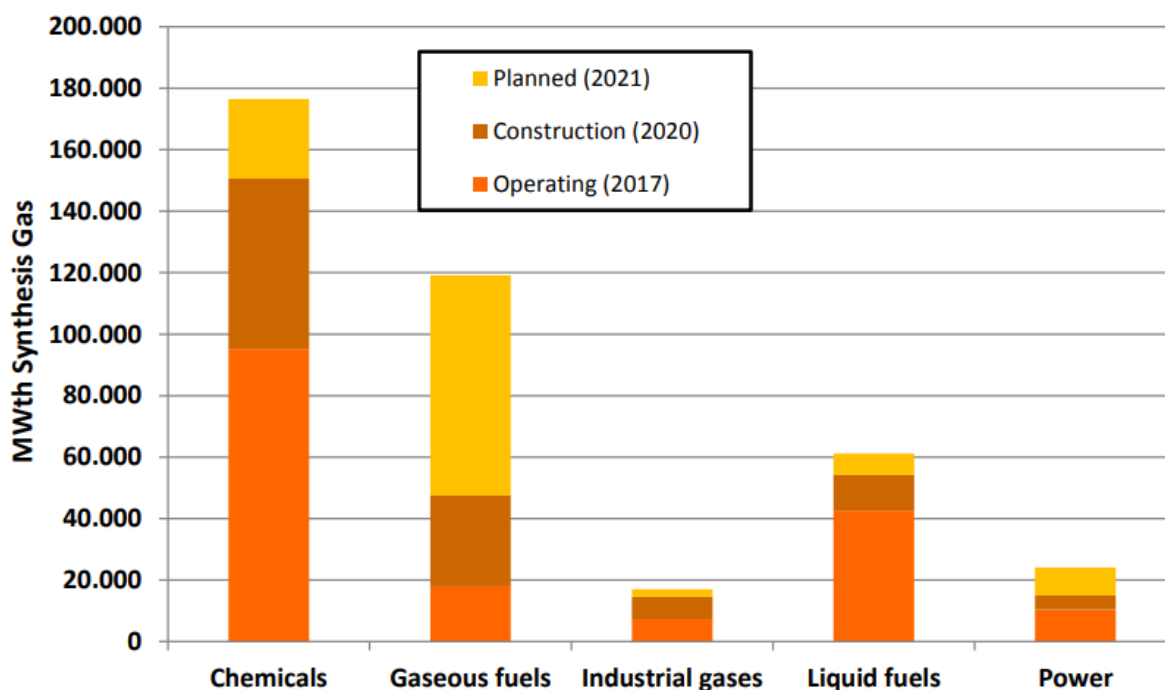


Figure 5-2
End-Use Application of Gasification Syngas

IGCC Project Updates and Results

Although few, a new generation of innovative coal-fed IGCC plants is entering service, as some earlier projects close. Table 5-2 summarizes a selection of IGCC projects around the world using coal and/or petroleum coke, without and with CO₂ capture.²⁸² Not shown are projects based on petroleum residuum as a feedstock.

In some power markets, IGCC plants have become uneconomical at the smaller “single train” scale, as reflected by the closure of three long-running IGCC demonstration projects: the 253 MW Nuon Willem-Alexander plant in Buggenum, Netherlands, in 2013, the 300 MW Elcogas plant in Puertollano, Spain, in 2015, and the 262 MW SG Solutions’ Wabash River plant in West Terre Haute, Indiana, in 2016.

Vattenfall/Nuon cited operating losses at Buggenum due to low wholesale power prices and O&M costs per MWh that were higher than those for large pulverized coal plants in a nearby German industrial corridor. The Shell dry-feed gasifier had accumulated nearly 96,000 hours of operation, including test runs with up to 70% biomass feed. The Elcogas plant, unable to compete with renewables in Spain, was scheduled to be dismantled.²⁸³ Low U.S. natural gas prices contributed to the decision to close the Wabash River plant. Wabash was purchased in

²⁸² *Coal Technologies with CO₂ Capture - Status, Risks, and Markets: 2013 Update*, EPRI, Palo Alto, CA: 2013. 3002000435.

²⁸³ <https://www.icis.com/resources/news/2016/06/29/10011686/spain-s-elcogas-igcc-power-plant-must-be-dismantled-despite-support/>

2016 by the Phibro Group with the intention of converting the gasification plant to ammonia fertilizer production. The gas turbine will be modified to fire natural gas and used for peaking duty.²⁸⁴

Table 5-2
Status of Select Coal-Based IGCC Projects Worldwide

Owner; Project, Location	Net MWe; feed	Power Block Technology / Configuration	Gasification Technology	Notes; CO ₂ Capture Provisions
Enel Fusina Project, Fusina, Italy	16	12 MWe GE10-1 GT modified for H ₂ firing; steam injection for NO _x control & power augmentation; condensing HRSG		Startup July 2010; first industrial-scale H ₂ -fired combined cycle; ~96–100% purity H ₂ supplied at 27 barg by 2.5 km pipeline. Surplus steam to 320 MW PC plant displaces 1.43 mt/h of coal (adds 4 MWe, net).
Elcogas S.A.; Puertollano, Spain	300; Puertollano coal & refinery waste	Siemens V94.3 GT	Prenflo entrained flow dry feed, oxygen blown gasifier, highly integrated (ASU air from GT; N ₂ to GT for dilution; HP and IP steam from syngas coolers)	Online December 1997. CO ₂ capture pilot startup Sept. 2010 with world's first CO ₂ capture from IGCC ²⁸⁵ (14 MWt / 2% slipstream; 90%+ CO ₂ capture with 2-stage WG shift, aMDEA; PSA H ₂ purification; 100 mt/d CO ₂ . Disconnected from the grid in January 2016 due to competition from renewables.
Mississippi Power (Southern Company), Kemper County IGCC, Mississippi	582; lignite	2x1 with SGT6-PAC 5000F GTs	2 x KBR / Southern TRIG air-blown gasifiers	Construction began 2010; CCPI-2 funding; planned 65% CO ₂ capture 3M tpy for EOR. Startup in 2017 followed by decision to run the plant on natural gas instead of syngas.
JSC, Sokolovská Uhelná, Vřesová / Czech Republic	398	GE 9E	Lurgi / Dry feed / Oxygen blown	1996. No CO ₂ capture.

²⁸⁴ *Gasification Technology Status: 2016 Update*. EPRI, Palo Alto, CA: 2016. 3002008398.

²⁸⁵ P. Casero, F. García-Peña, and P. Coca. Paper for GHGT-11. “Elcogas Pre-Combustion Carbon Capture Pilot. Real Experience of Commercial Technology.” *Energy Procedia* 37 (2013) 6374 – 6382.

Owner; Project, Location	Net MWe; feed	Power Block Technology / Configuration	Gasification Technology	Notes; CO₂ Capture Provisions
PSI Energy, Co., Wabash River / Indiana	262	1x1 with GE 7FA GT	CB&I E-Gas / Slurry feed / Oxygen blown	Startup in October 1995; scheduled for closure in 2016, followed by conversion to fertilizer production. No CO ₂ capture.
Tampa Electric Company, Polk Power Station, Florida	260; petcoke, coal	1x1 with GE 7FA GT	GE Energy quench gasifier with convective syngas cooler, slurry feed, oxygen blown. RTI warm gas cleanup demonstration	Polk Unit 1 IGCC demonstration Sept 1996 to 2001, then commercial. Warm gas cleanup and CCS demonstration online 2014 (50 MWe eq; \$169M ARRA funds) BASF aMDEA; 273k tpy to saline storage
Duke Energy, Edwardsport, Indiana	618; bituminous coal	2x1 with GE 7FB syngas GTs	GE Energy radiant quench gasifier, slurry feed, oxygen blown	Commercial operation June 2013. No CO ₂ capture.
GreenGen; Tianjin, China	250; China		CERI (TPRI); ST by Shanghai Electric Group; Siemens 2000E GT.	Startup for Stage I in 2012 (250 MWe IGCC), Stage II construction to add H ₂ production, fuel cell power block and 10% CCS slipstream. Stage III upgrade to a 400 MWe gasifier.
Joban Joint Power Co.; Joban Unit 10; Nakoso, Japan	230; China, PRB, Indonesia	MHI 701DA	MHI enriched air-blown; dry fed; fully integrated; CO ₂ to DGF?	IGCC startup 2007. CCS feas. study. Damaged in 2011 tsunami. Restarted later in 2011. In commercial dispatch since June 2013.
Nakoso IGCC Power GK; Nakoso, Japan	480	MHPS/MHI	MHPS/MHI	Startup 2020. No CO ₂ capture.
Hirono IGCC Power GK; Hirono, Japan	480	MHPS/MHI	MHPS/MHI	Startup 2021. No CO ₂ capture.

Owner; Project, Location	Net MWe; feed	Power Block Technology / Configuration	Gasification Technology	Notes; CO ₂ Capture Provisions
Osaki “CoolGen” – J-Power/Chugoku, Hiroshima, Japan	170 (1 st stage)		Eagle (O ₂ dry fed); physical solvent	Construction started March 2013. 1 st stage startup in 2017. 2 nd stage adds CO ₂ capture; planned startup in 2019. 3 rd stage adds gas purification and fuel cells to create IGFC, planned startup TBD
Korea Western Power Co., Ltd.; Taean IGCC Project, South Korea	305	GE 7FB syngas turbine/D11 steam turbine	Shell/Coal Gasification Process (O ₂ dry fed)	Commercial startup in August 2016. No CO ₂ capture.
POSCO E&C and Doosan; Namhae IGCC Project, South Korea	>300			Commercial operation planned for 2023. No CO ₂ capture.

Polk and Edwardsport

The longest running IGCC plant in the United States, Tampa Electric’s Polk County 260 MW (net) Unit 1, began commercial operation in 1996 and remains in service. The plant uses an entrained-flow, oxygen-blown gasifier that was developed by Texaco and later purchased by GE Energy.

In 2012, natural gas replaced distillate oil as the startup/backup fuel system, and modifications were made to allow for cofiring of syngas and natural gas (the cofiring gas turbine is dispatched as a separate unit). Polk had experienced fouling in its convective syngas coolers, which imposed a regime of about 45 days between cleanings. Testing has shown that reducing the syngas production rate by about 10% allows operation for over 100 days without fouling, whereas cofiring natural gas holds electric power production steady. Moreover, by reducing the downtime of the syngas system, annual power production from syngas fuel has increased.²⁸⁶

Its current feedstock is 85% petroleum coke and 15% bituminous coal. Unit availability over 15 years has averaged about 78%. Polk recently became the first power plant in the United States to combine the use of reclaimed water and reverse-osmosis technology with deep-well disposal of wastewater. The project creates environmental benefits by reducing overall groundwater

²⁸⁶ Mark Hornick, Tampa Electric Company. “Polk Power Key Lessons for IGCC,” Gasification Technologies Conference, Colorado Springs, CO. October 12-14, 2015.

withdrawals and by using excess wastewater that would otherwise be discharged into local bays.²⁸⁷

Duke Energy's Edwardsport plant, which entered commercial service in the United States in 2013, uses GE Energy's gasification technology. The 2 GT x 1 ST power block more than doubles the output of first-generation 1 GT x 1 ST units and is the first application of the syngas-rated GE 7FB gas turbine. For the period of January through July 2017, the plant ran predominantly on coal, achieving its highest gasifier availability rate and running hours and greatest MWh output for any seven-month period: the gasification system availability was 85.6%, the IGCC equivalent availability factor was 79.1%, and the capacity factor was 74.9%. For this period of approximately 5000 hours, gasifier #1 has operated 4377 hours and gasifier #2 has operated 4329 hours.²⁸⁸

Edwardsport does not capture CO₂. The project's capital requirement, which included relatively large owner's costs, was \$3.55 billion; its plant capital cost was estimated to be \$2.98 billion.

Kemper County

Mississippi Power's 582 MW Kemper County plant, a 2 gas turbine x 1 steam turbine configuration, would have been the first commercial application of the air-blown Transport Reactor Integrated Gasifier (TRIGTM) developed by KBR and Southern Company. The project began commercial operation in 2017, but on natural gas instead of syngas. Over the duration of the project, natural gas prices decreased from about \$10/MBtu (\$9.50/GJ) in the planning stage to about \$3/MBtu (\$2.85/GJ) in the commissioning stage, creating the economic incentive for operating only on natural gas. The project, which started construction in 2010 and would have captured CO₂ for EOR, saw cost escalation from \$1.8 billion to \$7.5 billion ("as spent" basis).

Kemper operated in demonstration mode for 224 days. It achieved an overall rate of 65% CO₂ capture on syngas, reducing emissions to approximately 550 lb (250 kg) of CO₂ per MWh (gross) and about 800 lb (363 kg) of CO₂ per MW (net), well below the EPA limit of 1400 lb (635 kg) of CO₂ per MWh (gross), and slightly better than the net CO₂ emissions rate of an NGCC plant without CCS.²⁸⁹

The TRIG gasifier had previously been demonstrated only at a much smaller scale in Alabama. Other new equipment developed by Southern Company includes the pressure-decoupled advanced coal feeder, the continuous coarse ash cooling and depressurization systems, and the continuous fine ash cooling and depressurization systems.

Two water-gas shift systems were operated, each with two stages. Performance was generally favorable, although synchronized operation of the fully integrated systems was not performed before suspension of operations.

²⁸⁷ <http://www.powermag.com/tampa-electric-co-s-polk-power-station-reclaimed-water-project/>

²⁸⁸ Gasification Users Association (GUA): *Technology Status—December 2017*. EPRI, Palo Alto, CA: 2017. 3002010370.

²⁸⁹ *Kemper IGCC Plant with CCS – Report from the Technical Review*. Georgia Tech – Energy Policy Innovation Center.

Kemper used the two largest Selexol CO₂ removal units in the world at time of commissioning, each capable of processing 700 tons (635 tonne) per hour of syngas, while capturing 235 tons (213 tonne) per hour of CO₂ and 10 tons (9 tonne) per hour of acid gas. The availability of both Selexol units was greater than 90% in 2017. Additionally, CO₂ and H₂S were produced within product quality specifications.

Table 5-3²⁹⁰ summarizes some of the issues encountered and lessons learned at Kemper, many of which were associated with scaling up new technologies.

Table 5-3
Major Technical Challenges and Lessons from Kemper County IGCC

Issue	Challenge / Impact on Plant	Description	Mitigation Action	Potential Future Risk?
General integration	Inconsistent raw coal quality / Reduced coal feeding capacity	Coal was frequently outside the specified range for moisture and particle size	Finer coal screens installed at mine; Redesign of dryer and addition of air cannons	Yes, but manageable; highly dependent on coal mine
First-of-a-kind scale-up of technology	Gasifier seal leg outlet spalling / Reduced availability	Refractory improperly installed in shop	Install replacement refractory in-place on site	Yes, but manageable; reduced risk by installing on site rather than in shop
	Syngas cooler superheater tube leaks / Reduced combined cycle power output and efficiency	Leaks developed in the tubes designed to transfer heat from the hot syngas from the gasifier to steam used to partially power the steam turbine	Shut down outer heat transfer to coil; other tubes had sufficient design margin to operate at full load	No; would increase tube thickness/design margin in future design
Other scale-up issues	Limited refrigeration capacity in the CO ₂ removal system / Limits gasifier operation at high load/capacity	Limited refrigeration limits the amount of CO ₂ that can be removed pre-combustion. This was caused by a hydraulic issue	New pumps would have resolved this issue	Yes, but manageable

Osaki CoolGen

In 2017, the 170 MW Osaki CoolGen Project, a joint venture between J-Power and Chugoku Electric Power, commenced its demonstration phase in Hiroshima, Japan. The CoolGen plant, shown in Figure 5-3, uses an oxygen-blown EAGLE gasifier. A net thermal efficiency of 40.8% (HHV) has been achieved and plant emissions are at or below target values.

Conversion to CO₂ capture is envisioned for 2019, with a planned operational period of three years. An engineering contract has been for the CO₂ capture slipstream system. Site work also begun to reclaim land for the capture equipment. Selexol Max has been chosen for the CO₂ capture system, and a Hitachi catalyst will be used in the water-gas shift reactors.

²⁹⁰ Ibid.

A third phase of the project looks to integrate advanced syngas purification technology and fuel cell stacks for even higher efficiency, the CoolGen project's ultimate goal.²⁹¹

The CoolGen project goal is a system that enables a future IGCC unit to achieve 40% thermal efficiency (HHV), excluding the auxiliary load for CO₂ compression, with 90% CO₂ capture.



Figure 5-3
Osaki CoolGen IGCC Project

Other Japanese IGCC Projects

Two IGCC projects employing 540 MW (gross), 480 MW (net) IGCC units are progressing in Japan's Fukushima Prefecture: one will be located at the Nakoso Power Station, site of the existing Joban Joint Power Company Unit 10 IGCC (250 MW using Mitsubishi Hitachi Power Systems' [MHPS] enriched air-blown two-stage entrained flow gasifier), and the other at the Tokyo Electric Power Company's Hirono Power Station. MHPS is leading the design of the gasification and combined-cycle power blocks, which will feature enriched air-blown gasification technology (akin to Joban Unit 10). CO₂ capture is not part of these projects.²⁹² Construction at Nakoso is under way, with the plant scheduled to come on line in September 2020. Construction at Hirono began in April 2018; the plant is scheduled to begin operation in September 2021.²⁹³

²⁹¹ https://www.energy-tech.com/article_a24682be-c329-11e7-9af9-f38702c45652.html

²⁹² <https://www.mhps.com/en/news/20140912.html>

²⁹³ <https://www.mhps.com/news/20180413.html>

South Korean IGCC Projects

Korea Western Power Company's IGCC in Taean County, which broke ground in November 2011, began commercial operation in August 2016.²⁹⁴ The 300 MW project uses the Shell gasification technology. Shell gasifier and syngas cooler were manufactured by Doosan Heavy Industries, which was also the EPC contractor for the gasification plant and syngas clean-up. The power block features GE's 7F syngas gas turbine. The design does not include CO₂ capture. The project cost has been reported as \$1.4 billion.²⁹⁵

A second South Korean IGCC plant is in the planning stage in Namhae County, South Gyeongsang Province. CO₂ capture is not included in the project.

GreenGen

Huaneng's 250 MW GreenGen IGCC in China, using Thermal Power Research Institute (TPRI) dry-feed, two-stage oxygen-blown technology, started up in 2012. A second phase involves the addition of a syngas slipstream with water-gas shift and pressure swing absorption separation. Some of the hydrogen product is to be used in fuel cell, gas turbine, and hydrogen storage testing. The CO₂ will be compressed and possibly sequestered in a geologic formation. A third phase of GreenGen envisions a 400 MW IGCC with full CO₂ capture.

Engineering-Economic Studies of IGCC

Engineering-economic studies of IGCC plants, without and with CO₂ capture, have been conducted by EIA, EPRI, NETL, the Canadian Clean Power Coalition, Elcogas, the UK government, and the Australian Energy Market Operator.

EIA Capital Cost Estimates for IGCC Plants

In 2017, EIA published updated U.S. cost and performance estimates for IGCC, with AGR but without water-gas shift for CO₂ capture (see Table 5-4), and also for other select types of power plants.²⁹⁶ Although the coal type isn't named, its heating value is 11,000 Btu/lb (26,000 kJ/kg) and sulfur content is 3.9% suggest an Illinois Basin bituminous, as EIA used in previous studies. Table 5-5 provides EIA's capital cost breakdown.

²⁹⁴ <http://www.businesskorea.co.kr/english/news/industry/15621-commercial-operation-igcc-korea-western-power-begins-commercial-operation-taeon>

²⁹⁵ *Integrated Gasification Combined Cycle Power Plants with Partial Carbon Dioxide Capture: 2015 Detailed Feasibility Study Update*. EPRI, Palo Alto, CA: 2015. 3002007021.

²⁹⁶ https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/eiatasks_10388_10687addendum.pdf

Table 5-4
IGCC Parameters from U.S. EIA Generating Cost Study (2017)

Parameter	
Power Block	2x1 F-Class
Gasifier Block	Two-stage, Slurry feed 2 Trains
Acid Gas Recovery Technology	COS cat, Selexol
Unit size, MWe (net)	618
Heat Rate (Btu/kWh, HHV)	8600
Capital Cost, \$/kW (net)	4,090 EPC 4,908 TPC
Fixed O&M (\$/kW-yr)	65.40
Variable O&M (\$/MWh net)	5.00
SO ₂ , lb/MBtu HHV	0.0095
NO _x , lb/MBtu HHV	0.013
CO ₂ , lb/MBtu HHV	206

TPC = “overnight cost” including owners costs less financing. Costs are in August 2016 U.S. dollars.
For approximate emission values in mg/Nm³, multiply values in lb/MBtu by 100.

Table 5-5
EIA IGCC Capital Cost Breakdown

Capital Cost Category	\$(000), August 2016\$
Civil Structural Material and Installation	124,918
Mechanical Equipment Supply and Installation	1,433,721
Electrical / I&C Supply and Installation	269,798
Project Indirects (incl. engineering, distributable costs, scaffolding, construction management, and startup)	428,356
EPC Cost before Contingency and Fee	2,256,793
Fee and Contingency	270,815
Total Project EPC	2,527,608
Owner Costs (excluding project finance)	505,522
Total Project Cost (excluding finance)	3,033,130
Total Project EPC Cost, \$/kW	4,090
Owner Costs 20% (excluding project finance), \$/kW	818
Total Project Cost (excluding project finance), \$/kW	4,908

EPRI IGCC with Partial CO₂ Capture Study

EPRI engaged Foster Wheeler Italiana to study IGCC plants with partial CO₂ capture.²⁹⁷ Six cases of greenfield plants located in EPRI's standard reference location of Kenosha, Wisconsin were evaluated:

- Case 1 – GE Energy Radiant Quench, Pittsburgh #8
- Case 2 – Siemens, PRB
- Case 3 – Siemens, Pittsburgh #8
- Case 4 – Shell Syngas Cooler, PRB
- Case 5 – Shell Syngas Cooler, Pittsburgh #8
- Case 6 – GE Energy Radiant Quench, Pittsburgh #8

Cases 1–5 include partial CO₂ capture, while Case 6 is a no-capture case. The study updates specific cases from the previous EPRI series of IGCC with CO₂ capture reports (1015690 [2009], 1019669 [2010], and 1022034 [2011]), taking into consideration the earlier proposed U.S. EPA Section 111(b) NSPS that would have required new coal-based power plants to include partial capture in order to limit CO₂ emissions to roughly NGCC equivalence (i.e., 1100 lb or 500 kg of CO₂ per MWh, gross basis, on an annual average).²⁹⁸

The plants are assumed to operate in baseload duty, but must also include emissions during normal startup and part-load operation. Gasifier capacity is set to fully load two advanced F-class gas turbines.

For all of the gasifiers other than the slurry-fed GE Energy gasifier, a single stage of catalytic water-gas shift was employed to achieve the NSPS emissions rate. For the GE Energy gasifier, it appeared that skimming alone, without catalytic water-gas shift, could achieve the NSPS emission rate due to the inherently higher CO₂ content of the GE Energy gasifier's syngas. However, a 98% capture rate of the naturally formed CO₂ would be required. This would mean measure in addition of the Selexol process, which achieves a 93% capture rate, reducing some of the savings from avoiding catalytic water-gas shift. The installation of such a polishing step and "amine guard" process unit downstream of the Selexol was recommended by its licensor, UOP, and factored into the costs of this case.

Table 5-6 shows the performance and cost results for the five cases (AACE Class 4 cost estimate at -15%, +30% level of accuracy). Costs are reported in 2Q 2014 U.S. dollars. Figure 5-4 shows the total plant cost breakdown for the six cases.

²⁹⁷ *Integrated Gasification Combined Cycle Power Plants with Partial Carbon Dioxide Capture: 2015 Detailed Feasibility Study Update*. EPRI, Palo Alto, CA: 2015. 3002007021.

²⁹⁸ Final standards published in August 2015 are 1400 lb (635 kg) of CO₂ per MWh, gross basis.

Table 5-6
Plant Performance and Cost Summary for IGCC with Partial CO₂ Capture

Case	1	2	3	4	5	6
Gasifier	GE	Siemens	Siemens	Shell	Shell	GE
Coal	Pitt #8	PRB	Pitt #8	PRB	Pitt #8	Pitt #8
Gas Turbine (MW)	464.0	464.0	464.0	464.0	464.0	464.0
Steam Turbine (MW)	291.3	237.2	225.6	260.7	257.8	302.2
Gross Power (MW)	755.3	701.2	689.6	724.7	721.8	766.2
Auxiliary Power (MW)	164.7	155.3	147.6	151.9	143.7	134.2
Net Power (MW)	590.6	545.9	542.0	572.8	578.1	631.9
Net Efficiency (HHV), %	35.8	35.5	36.7	36.8	38.7	38.1
Net Heat Rate, Btu/kWh	9534	9622	9301	9283	8814	8960
CO ₂ Capture, %	27.8	32.4	28.2	31.8	27.2	—
CO ₂ Emission, lb/MWh (gross)	1098	1071	1070	1059	1048	1498
CO ₂ Emission, lb/MWh (net)	1404	1376	1361	1340	1309	1821
TPC (\$M)*	\$2,635	\$2,391	\$2,436	\$2,560	\$2,593	\$2,519
Specific Cost TPC \$/kW (net)	\$4,461	\$4,380	\$4,494	\$4,469	\$4,486	\$3,998
TCR (\$M)**	\$3,590	\$3,253	\$3,319	\$3,482	\$3,532	\$3,433
Specific Cost TCR \$/kW (net)	\$6,078	\$5,959	\$6,123	\$6,078	\$6,110	\$5,448

* Direct materials, construction, other costs, EPC services, and contingency.

** TPC plus interest during construction, spare parts cost, working capital, startup costs, and owner's costs.

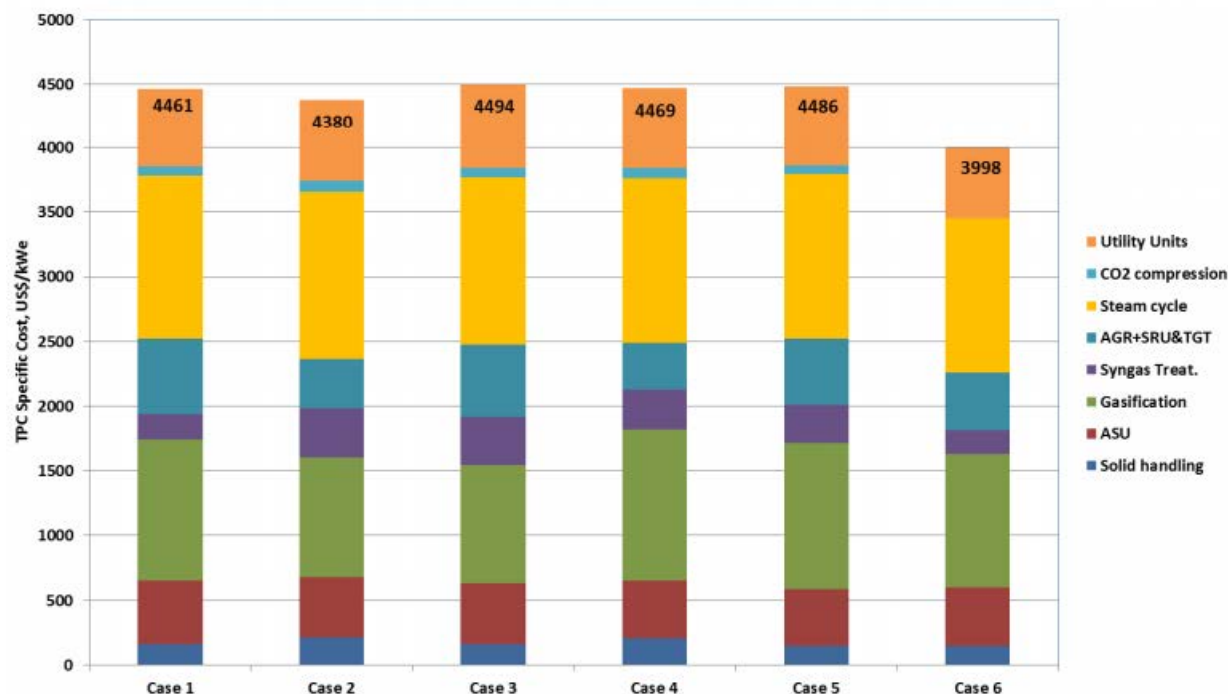


Figure 5-4
Total Plant Cost Breakdown for IGCC Partial CO₂ Capture Cases

- The study results deliver a less than 3% difference in capital costs between all capture cases on a \$/kW basis.
- Shell-based Cases 4 and 5 show the highest overall plant efficiencies, whereas the GE Energy and Siemens cases fall in a narrow range for the same coal type.
- The high CO₂ capture rates require that a catalytic CO oxidizer be included for all cases in order to meet the CO₂ purity specifications.
- The gross power in Cases 1, 4, and 5 (GE Energy and Shell) is higher than Case 2 and 3 (Siemens) due to steam generation in the syngas coolers.
- Case 1 (GE Energy) has highest auxiliary power consumption due to its slurry-feed technology, which leads to higher oxygen demand and a higher power requirement for the ASU.

Yearly direct labor costs were assumed to be the same for all five cases at \$13.3 million/year, which is nominally based on a cost of \$100,000/yr for 133 staff positions. Annual maintenance costs were estimated as a percentage of the installed capital costs. The plant is divided into major sections and the maintenance cost is determined by applying to each unit a percentage factor of its installed cost (i.e., TPC, excluding contingency). Table 5-7 provides an example of this breakdown for Case 1. Table 5-8 lists the O&M costs for all six cases.

Table 5-7
Example of Maintenance Cost Estimate Split for Major Units of an IGCC Plant (Case 1)

Unit	Maintenance %	TPC (\$M)	Maintenance (\$M/year)
Solids handling & storage	2.5	\$93	\$2.3
Gasification	2.5	\$643	\$16.1
ASU, AGR, SRU, CO ₂ compression	1.5	\$682	\$10.2
Syngas conditioning	1.5	\$115	\$1.7
Power Island	4.0	\$743	\$29.7
Balance of Plant	1.5	\$389	\$5.3
Total		\$2,634	\$65.5

Table 5-8
O&M Cost Estimates for New-Build IGCC Units with Partial CO₂ Capture

	Case 1 GE (Pitt #8)	Case 2 Siemens (PRB)	Case 3 Siemens (Pitt #8)	Case 4 Shell (PRB)	Case 5 Shell (Pitt #8)	Case 6 GE (Pitt #8) No Capture
Fixed costs, \$M/yr*	\$91	\$84	\$84	\$89	\$90	\$89
Variable operating costs per year, \$M/yr**	\$136	\$85	\$125	\$85	\$124	\$136
Total O&M costs, \$M/yr	\$227	\$169	\$209	\$174	\$214	\$225

* Includes: direct labor, admin/general overhead, and maintenance.

** Includes: feedstock, fluxant (limestone), makeup water, catalysts, chemicals (including solvents), and waste disposal.

An earlier series of EPRI reports published in 2009–2011 evaluated the cost and performance of IGCC configurations without and with CO₂ capture.

EPRI’s primary engineering-economic cases for U.S. IGCC plants were based on plant configurations incorporating two GE 7FB gas turbines, each with its own HRSG and a single steam turbine. “Paired case” evaluations highlighted the cost and performance differences for similar IGCC plants without and with CO₂ capture. These cases used EPRI’s standard reference site conditions (Kenosha, Wisconsin) and evaluated Siemens, Shell, and GE Energy gasifier configurations for Powder River Basin subbituminous and Pittsburgh #8 bituminous coals. Partial capture was examined for the GE Energy RQ gasifier firing Pittsburgh #8 coal.

Sensitivity cases were used to define the optimum design configuration of an IGCC plant in terms of output and efficiency, examining the following variations:²⁹⁹

- Gas turbine–air separation unit integration
- Syngas duct firing in IGCC without CO₂ capture
- Low steam turbine condensing pressure
- High gasification pressure (940 psig [66 bar] vs. 650 psig [46 bar])
- Syngas humidification upstream of the gas turbine
- Duct firing for maximum power production
- CO₂ liquefaction for high-purity CO₂ product specifications
- Air cooling systems for power production and CO₂ capture and compression
- Rectisol rather than Selexol AGR system
- MHI air-blown gasifier and MHI 501G gas turbine in lieu of GE Energy RQ gasifier and two GE 7FB gas turbine
- E-Gas gasifier firing Illinois #6 bituminous coal in lieu of GE Energy RQ gasifier firing Pittsburgh #8 bituminous coal

Although the focus of these reports was a comparison of the performance and economic impact of 90% CO₂ capture cases versus no capture cases, EPRI evaluated configurations for partial CO₂ capture using the GE Energy radiant quench gasification island design and varying degrees of catalytic water-gas shift and AGR retrofits to remove CO₂.

As shown in Figure 5-5, based on Pittsburgh #8 bituminous coal at \$2.00/MBtu (\$1.90/GJ), HHV, the efficiency penalty and COE increase as the percent of CO₂ capture is increased, whereas the cost of CO₂ avoided decreases with higher percent capture.

²⁹⁹ See Appendix A of EPRI report 1019367.

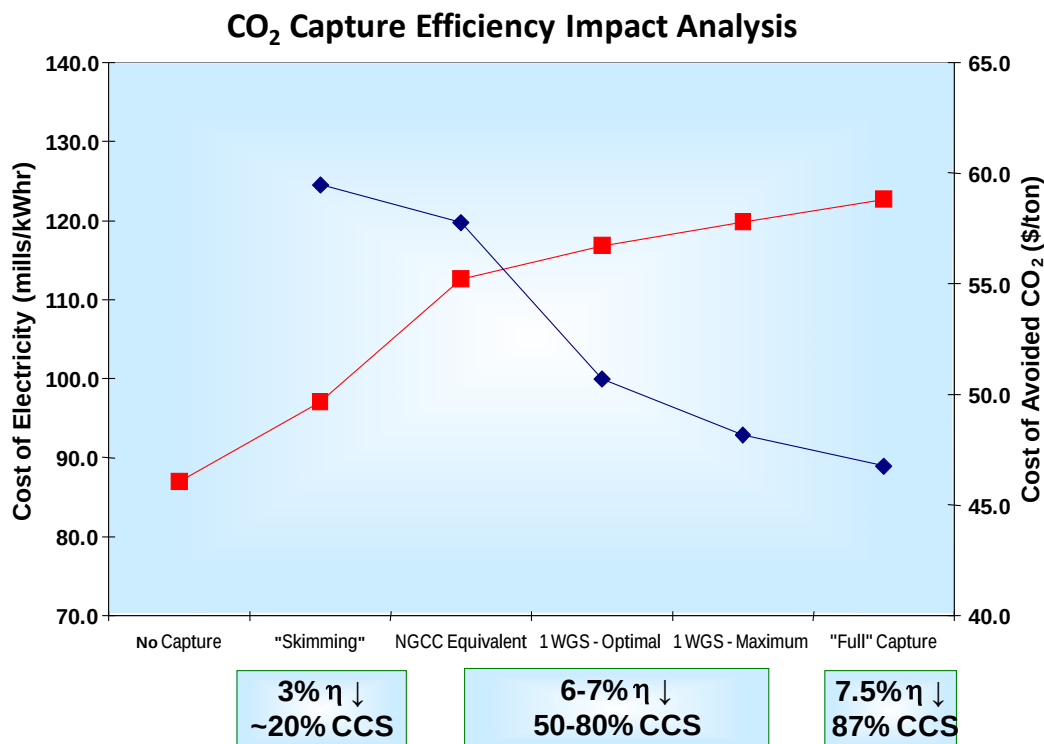


Figure 5-5
Comparison of COE and Cost of CO₂ Avoided for No Capture, Partial Capture, and Full Capture Cases for IGCC Plants with GE Energy RQ Gasifiers

EPRI also examined partial CO₂ capture retrofit options for the Duke Edwardsport two-train GE Energy IGCC plant, which uses Indiana #5 bituminous coal.³⁰⁰ The study found that retrofitting the Selexol AGR unit to capture CO₂ from unshifted syngas (i.e., skimming) in an “aggressive yet economically reasonable” manner would achieve a CO₂ capture rate of 29% at a cost in plant efficiency of about 1.4 percentage points (HHV). Employing a single stage of water-gas shift to make the plant nominally “NGCC equivalent” in terms of CO₂ emissions would yield a 59% CO₂ capture rate at a cost in plant efficiency of 4.0 percentage points relative to the base plant design. Adding two stages of water-gas shift (i.e., a “full capture” retrofit) would achieve 86% CO₂ capture at an efficiency cost of 6.2 percentage points.

EPRI report 1019669³⁰¹ evaluated IGCC plant configurations for a site in the Netherlands using an internationally traded eastern Australian bituminous coal. The study used Shell and Siemens gasifiers and 50 Hz F-Class gas turbines in a two-on-one configuration. This report also examined an MHI air-blown gasifier with a 50 Hz G-Class gas turbine in a one-on-one, single shaft configuration.

³⁰⁰ *Analysis of Carbon Dioxide Capture Retrofit Options: Duke Edwardsport Integrated-Gasification–Combined-Cycle Plant*. EPRI, Palo Alto, CA: September 2011. 1021656.

³⁰¹ *Integrated Gasification Combined Cycle (IGCC) Design Considerations for CO₂ Capture and Storage (CCS)—Phase 2: Engineering and Economic Evaluations of Case Studies for IGCC Power Plants with CCS (50-Hz Cases at European Location)*. EPRI, Palo Alto, CA: October 2010. 1019669.

EPRI Studies of IGCC Operating Flexibility

Worldwide, transmission system operators are facing the challenge of maintaining grid stability while accommodating a growing share of intermittent renewable power sources. Although little studied until recently, IGCC units appear to have considerable operational flexibility and can apply many of the fast-start and ramping enhancements being introduced for natural gas-firing turbines in NGCC units. EPRI report 3002003742 discusses operating characteristics of IGCC plants and the potential for applying new technologies to enhance IGCC operating flexibility.³⁰²

Renewables-driven flexibility requirements are comprised of two differing components: the need for enhanced ramping capabilities and the need to accommodate more starts and stops. Flexibility options examined by EPRI include rapid-response combined cycles, polygeneration with co-production of storable products, CCS system flexibility enhancements and synergies, and hybrid fossil/renewable systems that use solar thermal systems to supplement IGCC steam cycles or use IGCC and CCS system flexibility to accommodate solar and wind power variations. A current project modeled solvent flow dynamics in the AGR column during load increases (i.e., when syngas flow was increasing) and found that the necessary corresponding increase in solvent throughout the column occurred first in the upper section (often at the expense of the solvent inventory lower section) hampering performance unless the ramp rate were reduced. A proposed solution is to add a mid-column solvent feed stream to assure that the lower portion of the column is not solvent starved, enabling the AGR to maintain its performance during more rapid ramping.

New NGCC designs have increased ramp rates and cut NGCC startup times by a factor of four. Such combined cycles can also be used in IGCC units where natural gas is available for startup. Natural gas can also be used to temporarily bypass gasification or to supplement syngas to overcome ramping bottlenecks. This approach, which is in use at Duke Energy's Edwardsport IGCC plant in Indiana, enables ramping rates approaching those of NGCC units. At Edwardsport, it takes only another five minutes for syngas flow to reach the full load rate. Further, EPRI has identified design options that could match NGCC ramping performance from 50–100% load when natural gas cofiring is used.

An IGCC plant with CCS requires the ability to vent CO₂ in response to an instantaneous loss of CO₂ export capability. This capability can also be used to rapidly change net power output by reducing or increasing power consumption for CO₂ compression. Further flexibility can be provided by designing an IGCC plant for shutdown of catalytic water-gas shift and CO₂ capture, and switching of gas turbine fuel from hydrogen-rich syngas to unshifted syngas. Consistent with the time required to shut down CO₂ compression and vent CO₂ in response to a system reserve call, the resulting potential increase in power send-out qualifies as 10-minute (or spinning) reserves. Shutting down the water-gas shift and CO₂ capture systems and switching gas turbine fuel to unshifted syngas currently requires more than 10 minutes and qualifies as 1-hour reserves. Based on an initial analysis by EPRI, this ability to provide system services could provide lifetime value equivalent of about 15% of the plant's capital cost.

³⁰² *Design Options for Enhancing IGCC Flexible Operations Performance and Economics*. EPRI, Palo Alto, CA: 2014. 3002003742.

CO₂ Removal from Shifted Syngas Unit Using Membranes

EPRI report 3002001194 examines the performance of membranes for removing CO₂ from syngas.³⁰³ A base case was created by adjusting one of the IGCC cases from a previous EPRI study³⁰⁴ so that the CO₂ emissions matched EPA's 2012 proposed Section 111(b) NSPS of 1000 lb (454 kg) of CO₂ per MWh, gross basis.

Case 1 used a hydrogen removal membrane upstream of the AGR system and a CO₂ removal membrane downstream of the AGR system, a configuration proposed by membrane manufacturers. However, this configuration raised two concerns. Because the nitrogen/hydrogen stream flows directly to the gas turbine, the membrane must prevent any H₂S or COS from crossing the membrane to avoid an increase in SO_x emissions from the stack. A second concern was the proximity of the operating temperature of the membrane to the syngas dewpoint. In a process upset, water could condense in the membrane, reducing its efficiency. Because the condensed water would contain H₂S and CO₂, its acidic nature could potentially corrode the membrane.

Case 2 placed the hydrogen removal membrane downstream of the CO₂ removal membrane. Both membranes would be downstream of the AGR system so there should not be concern with having H₂S or COS pass through the membrane to the gas turbine. The gas entering the hydrogen membrane would have already passed through a dehydration system, so there should be virtually no water vapor.

The COE basis used in this study the same as the basis used in EPRI report 1015690 for Cases 8 and 9. The COE includes the fuel costs, variable and fixed operating costs, and annual carrying charge for capital amortization. The costs from EPRI report 1015690 were escalated from 2009 to 2012.

Table 5-9 shows the COE for all cases, based on the following assumptions:

- Annual capacity factor: 80%
- Coal cost: \$1.80/MBtu (\$1.70/GJ)
- Annual Capital Carrying Charge – 12.1% of Total Plant Cost
- Operator Cost – \$70,000 per year (plus 30% overhead). The base case with CO₂ capture has 121 operators. The membrane systems each have 119 operators.
- Administration/overhead cost – 30% of the operator cost.
- Maintenance labor and materials – 3.2% of the Total Plant Cost: 40% labor, 60% materials.
- Natural gas for the flare – 165 lb/hr (75 kg/hr) at a cost of \$5.00/MBtu (\$4.74/GJ)
- Raw water – \$0.13/ton (\$0.14/tonne). The makeup water was assumed to be proportional to the total heat rejected by the cooling tower.

³⁰³ *Engineering and Economic Analysis of CO₂ Removal from an Integrated-Gasification Combined-Cycle Unit Using Membranes*. EPRI, Palo Alto, CA: 2014. 3002001194.

³⁰⁴ *Integrated Gasification Combined Cycle (IGCC) Design Considerations for Carbon Dioxide (CO₂) Capture: Engineering and Economic Assessment of Integrated Combined Cycle Coal Plants for Near-Term Deployment*, EPRI, Palo Alto, CA: 2009. 1015690.

- Solvent – For the base case, the solvent cost was \$746,000/year. For the membrane cases, the solvent cost was \$503,000/year.
- Catalyst and Filters – It was assumed that the values in the previous report were proportional to the syngas flow through the water-gas shift reactors. For the base case, this was approximately \$2,280,000 per year. For Case 1, the cost was \$3,350,000/year, and for Case 2 it was \$3,030,000/year.
- Remaining miscellaneous chemicals –\$4,600,000/year for all cases
- Waste disposal –slag, fine ash, and mercury catalyst – \$3,700,000/year for all cases
- CO₂ transportation and storage – \$9/ton (\$10/tonne)
- A membrane replacement cost of \$1/ft² (\$10/m²) of membrane area per year was used.

Table 5-9
COE Comparison for EPRI IGCC with Membrane Capture Cases

	Base Plant with CO₂ Capture	Case 1	Case 2
Capital Cost, \$M/yr	367.4	364.2	366.3
Coal Costs, \$M/yr	94.1	94.1	94.1
Fixed Operating Costs, \$M/yr	112.0	111.0	111.5
Variable Operating Costs, \$M/yr	31.2	34.5	33.3
Total Operating Costs, \$M/yr	604.8	603.8	605.2
Cost of Electricity, \$/MWh	117	114	118

EPRI Case Study for Duke Edwardsport IGCC Project

In an attempt to understand the seemingly large differences in costs in EPRI engineering-economic evaluations and those reported for commercial projects in the United States, EPRI analyzed the public filings with the Indiana Utility Regulatory Commission for the Duke Edwardsport IGCC project. The Edwardsport IGCC project saw considerable cost escalation since its initial approval in November 2007, ultimately reaching a specific plant cost of \$4,660/kW. This value was significantly higher than EPRI's estimate at the time of \$2,612/kW for a comparable IGCC plant without CO₂ capture using the GE Energy radiant quench gasifier.³⁰⁵ By using the public files to compare the factors included in the two cost estimates, it appeared that the discrepancies emanated more from cost definitions rather than from the costs themselves. Edwardsport costs outside of GE/Bechtel's FEED study include land, transmission access, a rail spur, coal handling equipment, owners' costs, escalation, and interest.

Aside from coal handling equipment, which is typically included in EPRI's cost estimates, most of these costs outside of the GE/Bechtel FEED study costs were also not included in EPRI's total plant cost estimate. Rather, they are considered part of a total capital requirements estimate. To compare the estimates on a more even basis, two approaches were taken: (1) starting with the

³⁰⁵ EPRI report 1019669. Op. cit.

EPRI Phase 2 GE Radiant Quench IGCC estimate and adding the other components to arrive at a TCR, and (2) starting with the Edwardsport estimate and working backward to try to develop a TPC. When available, cost values from regulatory filing testimonies were used. When these were unknown, estimates were made based on internal EPRI resources, such as the Technology Assessment Guide (TAG). Figure 5-6 illustrates EPRI's analysis.

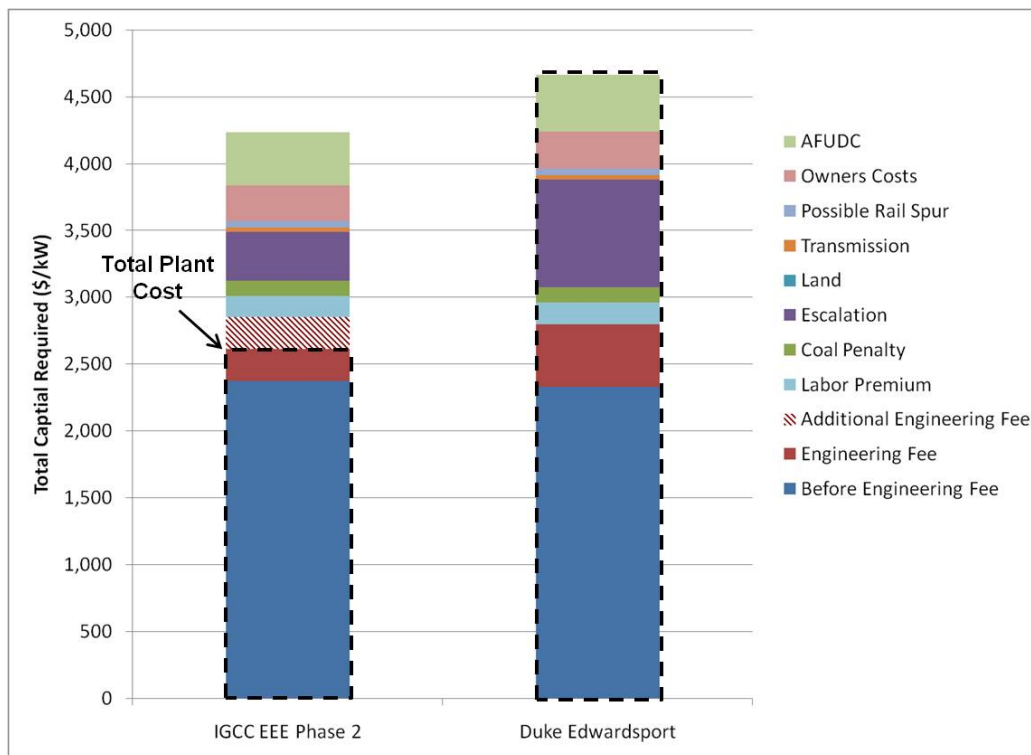


Figure 5-6
Comparison of Total Capital Required for Duke Edwardsport IGCC to EPRI EEE Case

In addition, EPRI's economic analyses generally assume an engineering fee of 10% for mature plant designs, whereas the Duke Edwardsport estimate likely included an engineering fee of about 18–20% due its first-of-a-kind nature. Further, the coal used in the EPRI GE Radiant Quench estimate is Pittsburgh #8 coal (13,260 Btu/lb and 2.1% sulfur), whereas the Duke Edwardsport plant uses Indiana #5 coal (11,268 Btu/lb and 3.7% sulfur). Previous studies that compared slurry fed gasifiers operating with Pittsburgh #8 and Illinois #6 (similar to the Edwardsport coal) have indicated that the capital cost of a plant operating with Illinois #6 is about 4% higher than the plant using Pittsburgh #8. Finally, as a result of being a first-of-a-kind project, there were learning experiences that likely led to increased costs beyond those factored into EPRI's studies (for example, changes in project scope; need for additional materials after initial purchasing).

A key conclusion from the EPRI analysis is that investigation of discrepancy in cost estimates should start with a tabulation of what is actually included in the estimates. Comparing an all-in total capital requirement cost with an overnight capital cost estimate that does not include site-specific costs, such as rail spurs or transmission interconnects, financing, or escalation can contribute to misunderstanding.

DOE NETL Baseline Studies

The National Energy Technology Laboratory has published a series of engineering-economic evaluations for U.S. IGCC plant configurations as part of its “Cost and Performance Baseline for Fossil Energy Plants” report series.

Volume 1b, issued in July 2015,³⁰⁶ updates the reference year cost basis for the IGCC designs and performance data developed for the November 2010 version of this report.³⁰⁷ Seven power plant configurations were analyzed, as shown in Table 5-10. Each is based on installation at a greenfield site. Capacity factors are assumed to equal an approximate availability of 80% for all configurations.

Table 5-10
DOE NETL IGCC Case Configuration Summary

Case	Steam Cycle, psig/°F/°F	Gasifier Technology	H ₂ S Separation	PM Control	CO ₂ Separation
B1A	1800/1050/1050	Shell	Sulfinol-M	Cyclone, candle filter, and water scrubber	N/A
B1B	1800/1000/1000	Shell	Selexol	Cyclone, candle filter, and water scrubber	Selexol 2 nd Stage
B4A	1800/1050/1050	CB&I E-Gas™	Refrigerated MDEA	Cyclone, candle filter, and water scrubber	N/A
B4B	1800/1000/1000	CB&I E-Gas™	Selexol	Cyclone, candle filter, and water scrubber	Selexol 2 nd Stage
B5A	1800/1050/1050	GEE Radiant	Selexol	Quench, water scrubber, and AGR adsorber	N/A
B5B	1800/1000/1000	GEE Radiant	Selexol	Quench, water scrubber, and AGR adsorber	Selexol 2 nd Stage
B5B-Q	1800/1000/1000	GEE Quench	Selexol	Quench, water scrubber, and AGR adsorber	Selexol 2 nd Stage

Note: Gas turbines for all configurations are two-train, state-of-the-art 2008 F-Class models.

The gas turbines used in each of the configurations are identical models with the output maximized. Although the output of the gas turbines is consistent between configurations, the cases have net outputs ranging from 494 MW (Case B5B-Q) to 629 MW (Case B1A). The differences in net output are the result of the significant auxiliary load in the CO₂ capture cases—primarily for CO₂ compression—and the need for extraction steam for CO₂ capture and the catalytic water-gas shift reaction, which reduces steam turbine-generator output.

Environmental emission requirements are based on the mercury and hydrochloric acid limits set by the March 2013 update to the Utility Mercury and Air Toxics Standards, and particulate

³⁰⁶ *Cost and Performance Baseline for Fossil Energy Plants Volume 1b: Bituminous Coal (IGCC) to Electricity, Revision 2b – Year Dollar Update*. DOE/NETL-2015/1727, July 31, 2015.

³⁰⁷ *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 2*. DOE/NETL-2010/1397, November 2010.

matter, SO₂, and NO_x limits set by the February 2013 update to the New Source Performance Standards. Mercury is controlled by dual sulfur-impregnated carbon beds. H₂S is separated with an AGR process and controlled using a Claus plant to limit SO₂ stack emissions. NO_x formation is minimized by low-NO_x burners and nitrogen dilution to reduce the combustion flame temperature. Particulate matter is controlled with a syngas scrubber, cyclone, and candle filter. Hydrochloric acid is removed primarily in the syngas scrubber, with the remainder removed with the low-temperature heat recovery condensate. The combined effluent is treated with calcium hydroxide.

The CO₂ capture cases are designed for 90% CO₂ removal, resulting in emission levels far below EPA's final Section 111(b) NSPS rate.

The baseline fuel cost is taken from the November 2012 version of the report, "Fuel Prices for Selected Feedstocks in NETL Studies," in the "Quality Guidelines for Energy System Studies" series. The first-year cost is \$2.94/MBtu (\$2.78/GJ) for Illinois No. 6 coal, HHV basis, delivered to the Midwest, in 2011 U.S. dollars.

The COE is assumed to escalate at a nominal annual rate equal to the general inflation rate (i.e., it remains constant or levelized in real terms over the operational period of the power plant). A cost for CO₂ transport and storage of \$10 per ton (\$11/tonne) is added to the COE, which is nominally based on a pipeline run of 62 miles (100 km) to an injection site for storage in a deep saline formation in the Midwest. Results for the IGCC cases are shown in Table 5-11.

Table 5-11
DOE NETL IGCC Performance and Economic Estimates (Bituminous Coal)

	Shell		CB&I E-Gas		GE Energy R+Q		
Case #	B1A	B1B	B4A	B4B	B5A	B5B	B5B-Q
CO ₂ Capture	No	Yes	No	Yes	No	Yes	Yes
Gross Power (MW)	737	673	738	704	748	734	684
Auxiliary Load Summary							
Balance of Plant	21	22	22	24	23	24	22
Air Separation Unit	84	103	86	111	98	115	115
Gas Cleanup/CO ₂ Capture	3	22	5	24	5	21	22
CO ₂ Compression	-	30	-	31	-	31	31
Total Aux. Power (MW)	108	177	113	190	126	191	190
Net Power (MW)	629	497	625	513	622	543	494
Heat Rate (Btu/kWh)	8100	10,927	8585	11,002	8758	10,459	11,505
Efficiency (HHV)	42.1	31.2	39.7	31.0	39.0	32.6	29.7
Energy Penalty*	-	11	-	9	-	6	9
Total Overnight Cost (2011 \$M)	2,107	2,442	1,830	2,252	1,888	2,279	2,086

	Shell		CB&I E-Gas		GE Energy R+Q		
Case #	B1A	B1B	B4A	B4B	B5A	B5B	B5B-Q
Cost of Electricity, \$/MWh (2011 USD basis)							
Capital	59.30	87.00	51.80	77.60	53.70	74.20	74.70
Fixed	14.70	20.50	13.50	19.10	13.70	18.20	18.00
Variable	9.30	13.00	9.20	12.80	9.40	12.20	12.20
Fuel	23.80	32.10	25.20	32.30	25.70	30.70	33.80
CO ₂ T&S	-	9.80	-	9.90	-	9.20	10.20
Total***	107.00	162.40	99.80	151.80	102.60	144.70	148.90
CO ₂ Capture, \$/tonne (2011 USD basis)							
Compared to SCPC or NGCC	-	77	-	65	-	61	59

* CO₂ capture energy penalty = percent point decrease in net power plant efficiency due to CO₂ capture

** Total overnight capital cost (includes total plant costs and all overnights costs including owner's fees)

*** 80% capacity factor

Similar to the EPRI studies, NETL used “paired case” evaluations for plants without and with CO₂ capture and compression. The environmental controls used for U.S. EPA criteria air pollutants and hazardous air pollutants are comparable to those in EPRI's studies.

DOE report NETL-2010/1399³⁰⁸ examined IGCC plant configurations fed with Powder River Basin subbituminous coal and North Dakota lignite at plants using gasifiers from Siemens, Shell, E-Gas (CB&I), and Southern Company/KBR TRIG, with F-Class gas turbines in a two-on-one configuration. Coal drying via the WTA process was assumed for the dry feed entrained gasifiers (i.e., Siemens and Shell). For the TRIG system, an indirectly heated fluidized bed was assumed. No coal drying was required for the E-Gas gasifiers.

Delivered fuel costs (in 2007 dollars) used in the analyses were \$0.89/MBtu (\$0.84/GJ) for PRB coal (HHV basis) and \$0.83/MBtu (\$0.79/GJ) for minemouth North Dakota lignite (HHV basis).

Canadian Clean Power Coalition

The Canadian Clean Power Coalition engaged Jacobs Engineering to evaluate four gasification technologies particularly suited for low-rank coal. The study sought to include designs not yet commercial, with the aim of identifying future “advanced IGCC” configurations.³⁰⁹ The selected gasification technologies were Siemens; Aerojet Rocketdyne (AR) compact gasifier (now owned by the Gas Technology Institute); China's Thermal Power Research Institute (TPRI) dry feed, upflow gasifier with water quench; and Synthetic Energy Systems (SES) U-Gas.

³⁰⁸ *Cost and Performance Baseline for Fossil Energy Plant—Volume 3a: Low Rank Coal to Electricity: IGCC Cases*. U.S. Department of Energy: May 2011. DOE/NETL-2010/1399.

³⁰⁹ *Advanced IGCC. A Phase III Final Report*. Canadian Clean Power Coalition. October 2013.

Table 5-12 summarizes results for the six IGCC-CCS cases and one supercritical PC reference case.³¹⁰ All cases are based on subbituminous coal. The IGCC cases assume use of “sour” water-gas shift and Selexol to capture nominally 90% of the CO₂:

- Reference case—SCPC without capture
- Siemens IGCC with CCS case from CCPC “Phase II” study
- Siemens 3 x SFG-500 gasifiers with water quench; 2 x GE 7FB gas turbines
- Siemens 2 x SFG-1200 gasifiers; 2 x GE 7FB gas turbines
- SES 3 x U-Gas gasifiers; 2 x GE 7FB gas turbines
- 2 x AR gasifiers; 2 x GE 7FB gas turbines
- 2 x TPRI gasifiers; 2 x GE 7FB gas turbines

³¹⁰ Ibid.

Table 5-12**Summary of CCPC Cost and Performance Estimates for Advanced IGCC Power Plants**

Gasifier	SCPC Reference	CCPC II Siemens*	Siemens 500	Siemens 1000	SES U-Gas	AR	TPRI
Coal Feed (Wet) (tonne/hr)	219	369	295	289	267	287	299
Net Plant Output (MW)	450	483	425.5	435	440	422	429
Plant Efficiency (%) (LHV)	41	33	30	30	33	29	28
Heat Rate (GJ/MWh) (LHV)	8.78	10.81	12.09	12.18	10.94	12.26	12.85
Plant Efficiency (%) (HHV)	39%	31%	28.1%	27.9%	31.1%	27.7%	26.5%
Heat Rate (GJ/MWh) (HHV)	9.3	11.45	12.81	12.90	11.59	12.99	13.61
Total Capital Req. (CAD\$ million)	2,001	4,315	5,100	4,907	3,709	4,052	4,815
Total Capital Req. (CAD\$/kW)	4,447	8,933	11,490	11,294	8,431	9,607	11,484
1st yr Cost of Power (CAD\$/MWh)	95	208	272	267	202	225	271
Capture Cost (CAD\$/tonne)		136	176	169	146	130	167
Avoidance Cost (CAD\$/tonne)		181	244	239	183	187	253
CO ₂ Capture Rate (%)		84%	93%	93%	78%	93%	91%
CO ₂ Intensity (tonne/MWh)	0.89	0.18	0.08	0.09	0.23	0.09	0.11

Notes: Cost estimates in Canadian dollars were made when its exchange rate with the U.S. dollar was near parity; in June 2018, the exchange rate was CAD\$/US\$ = 0.77). Original estimate basis is first quarter of 2010, except Case 2, which dates back to the third quarter of 2007. Costs are escalated to Q1 2015 (January 1, 2015 in-service date). Cost estimates assume revenue from sale of 50% of captured CO₂.

For costs per short ton, multiply \$/tonne values by 0.907. To obtain feed or emission rates in short tons rather than tonnes, multiply rates in tonnes by 1.102. For heat rates in Btu/kWh, multiply GJ/MWh values by 948.

“Total Capital Requirement” includes estimates for direct and indirect costs, owner’s costs, escalation and interest during construction and is meant to show the total capital cost expenditure at commissioning.

* Configuration from CCPC Phase II study using performance and cost model for this report with subbituminous coal rather than lignite.

CCPC work with Jacobs^{311,312} also examined IGCC configurations with partial capture to meet the Canadian emission performance standard of 925 lb (420 kg) of CO₂ per MWh, net basis excluding CO₂ compression power. These cases are based on Aerojet Rocketdyne and SES U-Gas gasifiers using subbituminous Alberta coal and the CB&I E-Gas Entrained-Slagging Transport Reactor (E-STR) gasifier fed with lignite available in southern Saskatchewan. Table 5-13 summarizes the estimated costs and performance of these partial capture cases. Costs were evaluated in Canadian dollars for construction in Edmonton, Alberta, and in U.S. dollars for construction on the Gulf Coast.

- Case 1: AR Partial Condensation Case
Two AR compact gasifiers feeding two GE 7F syngas gas turbines operating in combined cycle, with sour water-gas shift, LO-CAT AGR, and partial condensation with bypass for CO₂ removal.
- Case 2: AR PSA Case
AR with sour water-gas shift, LO-CAT AGR, and PSAs with bypass for CO₂ removal. It comprises two AR compact gasifiers feeding two GE 7F syngas gas turbines operating in combined cycle.
- Case 3: AR Membrane Case
Two AR compact gasifiers feeding two GE 7F syngas gas turbines operating in combined cycle with sour water-gas shift, LO-CAT AGR, and CO₂ absorbing membranes with bypass for CO₂ removal.
- Case 4: SES
Three U-Gas gasifiers feeding two GE 7F syngas gas turbines operating in combined cycle, with a split flow two stage shift followed by LO-CAT AGR and Selexol for CO₂ removal.
- Case 5-2: AR with Air Products' Ion Transport Membrane (ITM) Oxygen Production
Configured to Case 2 except that ITM O₂ production is used instead of a cryogenic ASU. The additional load of the ITM requires a third gasifier.
- Case 5-4: SES with ITM
Configured to Case 4 except that an ITM O₂ production is used instead of a cryogenic ASU.
- Case 6: E-Gas (CB&I) E-STR Lignite
Two E-STR gasifiers feeding two GE 7F syngas gas turbines operating in combined cycle with no water-gas shift and Selexol AGR for acid gas and CO₂ recovery.

³¹¹ *Advanced IGCC with Partial Carbon Capture*. Jacobs Presentation to GTC Conference. October 2013.

³¹² *Advanced IGCC with Partial Carbon Capture Study, Draft Report*. Jacobs for Canadian Clean Power Coalition. Revision A, November 2013.

Table 5-13**Summary of Costs and Plant Performance for CCPC Advanced IGCC Cases with Partial CO₂ Capture**

Case #	CCPC Phase 3 AR Ref. Case	1	2	3	5-2	CCPC Phase 3 SES Ref. Case	4	5-4	6
Gasifier	AR	AR	AR	AR	AR	SES U-Gas	SES U-Gas	SES U-Gas	CB&I E-STR
Oxygen Purity / Technology	95% / Cryo	95% / Cryo	95% / Cryo	95% / Cryo	99.5% / ITM	95% / Cryo	95% / Cryo	99.5% / ITM	95% / Cryo
CO ₂ Capture Technology	2-Stage Sour Shift; Selexol	Sour Shift; Partial Cond'n	Sour Shift; PSA	Sour Shift; Membrane	Sour Shift; PSA	2-Stage Sour Shift; Selexol	2-Stage Shift; Selexol	2-Stage Shift; Selexol	No Shift; Selexol
Coal Feed (Wet) (tonne/hr)	286.7	292.1	293.9	291.5	331.2	266.7	261.3	316.3	423.6
Net Plant Output (MW)	425.5	517.9	522.4	492.0	628.4	441.8	482.9	611.6	466.0
Plant Efficiency (%) (LHV)	29.61	35.37	35.42	33.68	37.86	33.05	36.88	38.57	34.64
Heat Rate (GJ/MWh) LHV	12.16	10.18	10.15	10.69	9.51	10.89	9.76	9.33	10.39
Plant Efficiency (%) (HHV)	27.95	33.39	33.47	31.79	35.73	31.19%	34.81	36.41	30.5
Heat Rate (GJ/MWh) HHV	12.88	10.78	10.76	11.32	10.08	11.54	10.34	8.89	11.80
Total Project Cost (CAD\$ million Edmonton, AB)	4,052	3,117	3,136	3,117	3,886	3,709	2,787	3,309	3,377
Total Project Cost (CAD\$/kW, Edmonton, AB)	9,607	6,019	6,003	6,335	6,184	8,431	5,771	5,411	7,247
Total Project Cost (US\$ million, U.S. Gulf Coast)		2,107	2,126	2,108	2,616		1,891	2,238	2,295
Total Project Cost (US\$/kW, U.S. Gulf Coast)		4,068	4,070	4,284	4,163		3,916	3,660	4,925
CO ₂ Capture (%) based on syngas	92.9%	59.2	56.8	61.0	54.3	78.7%	53.5	51.6	60.3
CO ₂ Intensity (kg/MWh)	80.0	418.0	417.9	418.9	416.3	212.0	417.2	416.7	416.4

Notes: Cost estimates in Canadian dollars were made when its exchange rate with the U.S. dollar was near parity; in June 2018, the exchange rate was CAD\$/US\$ = 0.77). Original estimate basis is first quarter of 2010, except Case 2, which dates back to the third quarter of 2007. Costs are escalated to Q1 2015 (January 1, 2015 in-service date). For costs per short ton, multiply \$/tonne values by 0.907. To obtain feed or emission rates in short tons rather than tonnes, multiply rates in tonnes by 1.102. For heat rates in Btu/kWh, multiply GJ/MWh values by 948.

ITM Oxygen Separation for IGCC with CCS

An EPRI industry collaborative supported the development of Air Products' ITM oxygen separation technology in the late 2000s and early 2010s. Results from techno-economic modeling of ITM application, compared with conventional cryogenic ASUs, on IGCC units with CCS (and two different gas turbine sizes) are shown in Table 5-14.³¹³

Table 5-14
Comparison of ITM and ASU for IGCC with CCS

	F-Class		H-Class	
Item	ASU	ITM	ASU	ITM
Gas Turbine Power, MW	464.0	464.0	618.3	618.3
Steam Turbine Power	300.8	325.0	384.8	408.1
ITM Net Power, MW	0.0	111.8	0.0	79.6
Gross Power, MW	764.8	900.8	1003.1	1106.0
Auxiliary Power, MW	205.7	129.8	262.4	156.5
Net Power, MW	559.1	771.1	740.7	949.5
Thermal Input, MWt	1827.2	2381.3	2321.5	2848.0
Net Plant Efficiency, % HHV	30.6	32.4	31.9	33.3
Carbon Capture, %	89	88	89	89
Plant Cost, % change	–	+21.0	–	+17.2
Plant Cost/kW, % change	–	-12.3	–	-8.5
LCOE, % change	–	-11.5	–	-9.3

Elcogas Pre-Combustion CO₂ Capture Study

A 2013 estimate of the cost and performance of a full-scale IGCC retrofit with CCS was developed by Elcogas based on the 14 MWt CO₂ capture pilot at Puertollano.³¹⁴ The evaluation examined “sweet” and “sour” catalytic water-gas shift and MDEA AGR to achieve 90% capture. Because CO₂ and H₂S capture are accomplished in a single step, the sour shift case had fewer efficiency and operating cost impacts (see Table 5-15).³¹⁵ However, this approach may be less appropriate for a retrofit, depending on the existing acid gas removal process(es).

³¹³ *Plant-Wide Performance and Cost Analysis of ITM-Based IGCC Generation Systems*, EPRI, Palo Alto, CA: 2013. 1022302.

³¹⁴ P. Casero, F. García-Peña, and P. Coca. “Elcogas Pre-Combustion Carbon Capture Pilot. Real Experience of Commercial Technology.” Paper for GHGT-11. *Energy Procedia* 37 (2013) 6374-6382.

³¹⁵ *Advanced IGCC with Partial Carbon Capture Study: Draft Report*. Jacobs for Canadian Clean Power Coalition. Rev A: November 2013.

Table 5-15
Estimated Cost and Performance Impacts for CCS Retrofit at Puertollano IGCC

Case #	IGCC without Capture	Sweet Shift	Sour Shift	Comparable PC-PCC
Plant Efficiency (%) (LHV)	42	33	35	
Retrofit Cost (million €)		349	349	
CO ₂ Capture (%) based on syngas		90	90	
Cost of CO ₂ Avoided (€/tonne)		26.35	26.00	103
CO ₂ Intensity (tonne/MWh)		0.789	0.744	

Cost estimates are based on 6500 hours/year at 92% load factor; 40 €/MWh electricity cost. Efficiency penalty is based on a 2005 study by the CARNOT European project. Compression cost and efficiency impacts are not included. Cost estimates in euros were made when its exchange rate with the U.S. dollar was about €/US\$ = 1.30; in June 2018, the exchange rate was about €/US\$ = 1.18. For costs of CO₂ avoided in \$/ton, multiply €/tonne values by 1.05. For CO₂ emission rates in short tons per MWh rather than tonnes, multiply rates in tonnes by 1.102.

UK Government Electricity Generation Costs

The United Kingdom’s Department for Business, Energy & Industrial Strategy (formerly Department of Energy & Climate Change) provided routine updates of estimated electricity generation costs using a “Levelised Electricity Cost Model” first published in 2010.³¹⁶ Case 2 of the 2013 update, which analyzed costs for projects starting in 2019, included comparisons of LCOE elements and total LCOE for fossil technologies with and without CCS (along with renewable and nuclear technologies).³¹⁷ A companion publication provided detailed explanation of how model inputs were updated for the 2013 publication.³¹⁸ Inputs for the Levelised Electricity Cost Model were based on industry survey data rather than technology-specific engineering estimates.

Table 5-16 summarizes results for first-of-a-kind IGCC cases from the 2013 update (with low, medium, and high values, where applicable); the table also includes sensitivity results for five new-build IGCC-CCS scenarios.

³¹⁶ *UK Electricity Generation Costs Update*, Report by Mott MacDonald for DECC.

³¹⁷ *Electricity Generation Costs 2013*, UK Department of Energy & Climate Change. July 2013.

³¹⁸ *Electricity Generation Cost Model – 2013, Update of Non-Renewable Technologies*, Parsons Brinkerhoff for UK Department of Energy & Climate Change. April 2013.

Table 5-16
IGCC Cases from UK Levelised Electricity Cost Model Studies

Technology	IGCC with CCS	IGCC with partial CCS (300 MW eq.)	IGCC with CCS retrofit
Power Block	2x1		
Gasifier Block	Generic (single gasifier)		
Unit size, MWe net	L-704 M-743 H-796	L-774 M-821 H-884	L-686 M-724 H-776
Net Thermal Efficiency (% LHV)	L-35.4 M-37.5 H-40.4	L-35.4 M-37.5 H-40.4	L-29.9 M-31.6 H-33.8
Total levelized costs (US\$/MWh)*	214.4	233.6	179.2
Pre-development	1.6	1.6	1.6
Capital	84.8	78.4	43.2
Fixed O&M	30.4	25.36	30.4
Variable O&M	0.0	0.0	0.0
Fuel	57.6	51.2	60.8
Carbon tax	11.2	67.2	16
CCS	27.2	9.6	28.8
Percentage of CO ₂ emissions captured	L-85 M-90 H-95	L-35.8 M-36.2 H-36.3	L-84.3 M-87.2 H-88.6
Total levelized costs (US\$/MWh) from sensitivity cases*			
Central	214.4		
High capex	275.2		
High capex, high fuel	292.8		
Low capex	166.4		
Low capex, low fuel	153.6		

* Values from *Electricity Generation Costs 2013*, DECC; Converted on a £1.0 = \$1.60 basis. Levelized Cost Estimates for FOAK Technologies – Projects Starting in 2019 – 10% discount rate. Cost model inputs are stated as Low, Medium, and High values.³¹⁹

IGCC Cases from Australian Energy Market Operator Study

The Australian Energy Market Operator and WorleyParsons compared the construction and operating costs for a broad range of fossil and renewable generating technologies in 2012.³²⁰ In

³¹⁹ *Electricity Generation Cost Model – 2013, Update of Non-Renewable Technologies*, Parsons Brinkerhoff for UK DECC. April 2013.

³²⁰ *Cost of Construction New Generation Technology*, WorleyParsons for the Australian Energy Market Operator, 101010-00676, July 2012.

addition to developing cost estimates, their report examined potential costs under five economic scenarios for projects initiated in each year from 2012 to 2032.

Table 5-17 summarizes results for IGCC cases based on Latrobe Valley brown coal (lignite) and Hunter Valley bituminous coal. Both cases assume the following IGCC configuration:

- Shell oxygen-blown, dry feed gasifier with convective syngas coolers
- GE 9FA GT in 2x1 configuration with single-pressure HRSG
- CO₂ removal with amine process

The estimates include plant and equipment costs, typical electrical and site preparation costs, fuel, and cooling costs inside the nominal project fence. Factors such as electrical connection, fuel pipelines, and delivery handling systems were excluded.

Table 5-17
IGCC Cases from AEMO Study

Technology	IGCC with CCS	
Power Block	50 Hz 2x1 F-Class (GE 9FA); Single Pressure HRSG	
Gasifier Block	2xShell dry-feed gasifier; O ₂ -blown, convective syngas coolers	
Acid Gas Recovery Technology	Water-gas shift; amine absorption	
Feed	Aus. Brown Coal, Latrobe Valley (50-70% moisture)	Aus. Bit. Coal. Hunter Valley
Unit size MWe Gross (Net) ["typical new entrant size"]	936 (552)	821 (557)
Auxiliary Load	384 MW / 41%	263 MW / 32%
Thermal Efficiency (net – HHV)	25.50%	28.90%
Thermal eff. learning rate (% improvement per annum);	0.30	0.30
First year avail for construct (assumed)	2023	2023
Cap Costs A\$/kW net	8,616	7,330
Fixed O&M (A\$/kW-year)	123.40	98.70
Variable O&M (A\$/MWh net) 2012	10	8
Percentage of CO ₂ emissions captured	90	90
Emissions rate, kg-CO ₂ e/MWh (net)	151	127
Cost confidence level*	±40%	±40% (Estimated)
Economic Life	>30 years; 50 years anticipated	>30 years; 50 years anticipated
Min. output level for stable operation	50%	50%

* Based on source data accuracy to provide a % band or ranking for each technology.

Cost estimates in Australian dollars were made when its exchange rate with the U.S. dollar was near parity; in June 2018, the exchange rate was A\$/US\$ = 0.76).

Technology Advancement Opportunities for IGCC Technologies

The “demonstration turned commercial” plants from the 1990s still running today have served as test beds for technology refinements to improve reliability, operating flexibility, efficiency, and/or environmental performance. For example, RTI successfully completed a test program for a 50 MWe pilot plant on an approximately 20% syngas slipstream at the TECO Polk IGCC plant in Florida. The performance met or exceeded expectations. RTI claims that it sees no restrictions in the system that would impact cycling capability, and has stated that the technology is now available for commercial deployment.

The major thrust in R&D for IGCC is to reduce capital costs and to reduce the energy penalty for capture. Specifically, improving the efficiency and reducing the auxiliary power consumption of the gasification unit, CO₂ capture equipment, power block, and air separation unit are important for reducing operating costs. Economies of scale through larger gasifiers, gas turbines, and other components should also help reduce capital costs. EPRI, the Coal Utilization Research Council, the Canadian Clean Power Coalition, and others have developed RD&D roadmaps to systematically advance IGCC technology and reduce the COE of future IGCC units.

EPRI’s 2012 IGCC R&D Roadmap³²¹ focuses on IGCC base-plant cost reduction and efficiency improvement as well as CO₂ capture and compression technology improvements and their integration with the base plant. Table 5-18 highlights key technology advancement opportunities in the Roadmap.

³²¹ 2012 *Integrated Gasification Combined Cycle (IGCC) Research and Development Roadmap*. EPRI, Palo Alto, CA. 2012. 1023867.

Table 5-18
IGCC with Capture—Potential Efficiency Improvements from R&D

IGCC R&D Improvements	Change in Net Efficiency (%HHV)	Change in Total Plant Cost	Change in Cost of Electricity (% of \$/MWh)
Coal Beneficiation	+0.6%	-2%	-0.3%
Ion Transport Membrane (ITM)	+1.6%	-18%	-14%
High Temperature Desulfurization (HTDP)	+0.9%	-5%	-4%
HTDP + Hydrogen Transport Membrane (HTM)	+2.7%	-15%	-13%
Sour Pressure Swing Adsorption (PSA)	+0.5%	-3%	-3%
CO ₂ Liquefaction & Pumping	+0.1%	-2%	-1%
Advanced Gas Turbine #1 (2600°F/1430°C)	+2.4%	-15%	-14%
Advanced Gas Turbine #2 (2700°F/1480°C)	+4.2%	-21%	-20%
Advanced GT + Supercritical ST	+4.7%	-25%	-24%
Advanced Gas Turbine #3 (2900°F/1590°C)	+5.5%	-22%	-21%

6

NATURAL GAS POWER PLANTS

The expectation of ample natural gas supplies at modest prices in North America over the next two to three decades is a major factor behind the selection of natural-gas-firing units for new fossil power capacity. In the United States, EIA forecasts that almost all of the new fossil power units added over the period from 2015 to 2040 will be gas-fired. Globally, the growth in liquefied natural gas transportation infrastructure and natural gas production from unconventional resources are working to reduce natural gas price differences among continents and subcontinents. Accordingly, gas turbine and reciprocating internal combustion engine (RICE) based power plants are commonly being selected for capacity additions worldwide.

Excepting three relatively brief periods, the monthly average spot price at the Henry Hub in Louisiana—a representative wholesale spot market—has stayed below \$3.00/MBtu (\$2.84/GJ) from January 2015 through June 2018.³²² This supports the relatively high rates of dispatch currently seen by NGCC plant operators. A similar market situation exists in Canada. In both countries, older coal-fired power plants are being retired in response to increasing maintenance costs, new environmental regulations, and a change in duty cycle brought on by the addition of intermittent renewable power sources to the grid. Lower first costs and faster permitting for natural gas generating units are also driving their selection for new capacity.

Market Activity

EIA expects about 21 GW to natural gas capacity to come online in 2018. About half of this consists of combined-cycle units to be added to the PJM Regional Transmission Organization, which spans parts of several Mid-Atlantic and Midwestern states. In the PJM region, Pennsylvania plans to add 5.2 GW; Maryland 1.9 GW, and Virginia 1.9 GW.³²³

Gas turbine manufacturers continue to offer improved heavy-frame and aeroderivative gas turbines and combined cycle units, although 2017 and early 2018 have proven to be a challenging business period for several manufacturers' broader power divisions.

Notable gas turbine developments in 2017 include Siemens' news that it would work with Duke Energy in North Carolina to validate the technologies making up its HL-class designs, which promise combined cycle efficiencies of more than 63% (LHV).³²⁴ Siemens will offer three HL-class machines in various sizes, with the HL version of its STG5-8000H providing almost 7% more output.

Siemens and other manufacturers have also announced use of “additive manufacturing” techniques for intricate high-temperature parts and passages, ceramic and matrix thermal barrier

³²² <https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm>

³²³

EIA. “Natural Gas and renewables make up most of the 2018 electric capacity additions.” *Today in Energy*, May 7, 2018.

³²⁴ <https://www.siemens.com/press/en/pressrelease/?press=en/pressrelease/2017/power-gas/pr2017080379pgen.htm>

coatings including some with laser-cut grooves to accommodate thermal expansion, outer coatings intended to erode away during the first few hundred hours of operation, and other innovations to enable higher firing temperatures, air cooling, and improved seals.

MHPS announced that its JAC model, introduced in late 2016 for both 50 Hz and 60 Hz markets, had been technically selected for myriad projects on three continents.³²⁵ Rated at 575 MW in a combined cycle configuration, the JAC uses extracted compressor air and an external heat exchanger, instead of steam, to cool the combustion liner.

Other manufacturers, except perhaps GE, are now also offering air-cooled versions of their H-Class machines. Several manufacturers claim their combined cycle units with H-class or J-class turbines have LHV efficiencies exceeding 63% or even 64%, although such figures are usually on a gross basis at the generator terminals.

Ansaldo Energia's H-class GT36 passed its first validation phase at a test power plant in Switzerland.³²⁶ Among the GT36's unique features is the PSM FlameSheet™ combustor, offering flame stability in low NO_x operation. It will be available in both 50 Hz and 60 Hz models. The first two 50 Hz units are scheduled to be installed near Shanghai, China. Ansaldo is 40% owned by Shanghai Electric and a 2017 agreement sets out an investment sharing plan for market introduction in Asia.

GE announced a new version of its 50 Hz H-class machine, the 9HA.02. Several units have been installed in Pakistan and elsewhere. GE introduced a new aeroderivative gas turbine, the LM9000, rated at nominally 65 MW.³²⁷ GE also introduced a new version of the LMS100, designated PA+/PB, which is rated at 117 MW (net) in both 50 Hz and 60 Hz configurations.

All manufacturers are optimizing three-dimensional airfoil designs in both the compressor and power turbine sections using advanced computer design and manufacturing tools. Some models are using inlet air compressor interstage cooling and reheat combustion and/or power stage recuperation to increase output and efficiency. Fast ramping is made possible, in part, by looser clearances and changes in blade/nozzle materials and coatings. Turndown capability is being enhanced as well. New combustor designs for F-Class models allow minimum loads down to 20% for simple cycle operation and down to 14% in combined cycle mode while still meeting emissions guarantees.

Heat recovery steam generator advances are allowing use of higher steam conditions to boost efficiency and recover more heat from the gas turbine exhaust. In some advanced models, efficiency is further enhanced by recovering energy via steam cooling of the power turbine nozzles and blades.

Models with improved inlet air cooling schemes and variable vanes allow mass flow to be tuned to optimize efficiency across a broader load range, especially at high ambient temperatures. For

³²⁵ <http://www.power-eng.com/articles/2017/12/mitsubishi-hitachi-power-systems-revolutionary-jac-gas-turbine-technically-selected-for-26-projects.html>

³²⁶ <http://www.powerengineeringint.com/articles/2017/05/new-ansaldo-energia-gas-turbine-passes-rigorous-testing.html>

³²⁷ <https://www.ge.com/reports/ge-oil-gas-just-turned-worlds-largest-jet-engine-65-megawatt-power-plant/>

example, Siemens has developed advanced compressor coatings to accommodate a high level of wet compression (increasing mass flow).³²⁸

Upgrades to existing gas turbine gas models are being introduced to minimize start time, maximize operating flexibility, and maintain thermal efficiency and emissions control at part-load operation. Such approaches include:

- HRSG bypass dampers/stacks that allow extended operation in simple cycle mode
- Once-through HRSG, which shortens the start to full-load time to as little as 30 minutes
- Depending on design priorities, HRSG designers may use one-, two-, or three-pressure steam cycles to balance ramp rate, efficiency, and cost considerations

The various natural gas generating technologies differ with respect to the logistics and cost for CO₂ capture. With the availability of steam from the steam cycle portion of the power production process, NGCC plants are most amenable to post-combustion CO₂ capture and can generally apply the same regenerable solvent processes being developed for coal plants. However, because of the differences in flue gas CO₂, O₂, and H₂O contents between natural gas and coal, there is interest in potential CO₂ capture process optimizations specific to NGCC units. In contrast, simple cycle gas turbines and RICE are usually selected for fast start, fast ramp, renewables balancing or peaking applications. Such frequent on-off and variable output operation as well as the lack of an easily extractable source of heat makes post-combustion CO₂ capture challenging. Pre-combustion fuel reforming to create a hydrogen-rich fuel gas is an established technology, albeit expensive, and firing hydrogen-rich gas in gas turbines may require burner, airfoil, and other internal modifications. Natural gas oxy-combustion power cycles offer inherent CO₂ capture capability and their cost competitiveness for CO₂ capture is embedded in their overall process economics.

Mergers and acquisitions activity continued, with Doosan acquiring the U.S. gas turbine services firm ACT Independent Turbo Service.

Installations of multiple reciprocating internal combustion engines are providing capacity additions in the 100–250 MW range, often to balance higher levels of renewables on the grid. In the continental United States, natural gas spark-ignited engines are favored to meet strict emissions requirements and allow turndown to as low as 10% load per engine or just a few percent of the overall rated plant capacity. Engine power plants also offer relatively high efficiency (including at part load), fast start capability, short construction lead time, and low water use.

With hot jacket water and lube oil in the block, state-of-the-art 10 or 20 MW engines can go from standstill to 100% load in less than 5 minutes, and from 100% load to stop in 1 minute.³²⁹ Smaller engines can achieve full load in 2 minutes. Traditionally used in <5 MW per engine size for backup power and combined heat and power applications, fleets of larger gas engines are now being selected for deployment in utility bulk power and peaking/grid services projects throughout North America. Liquid and dual fuel engine plants are being selected for similar

³²⁸ <http://www.energy.siemens.com/br/en/services/fossil-power-generation/modernization-upgrades/wet-compression.htm>

³²⁹ <http://www.turbomachinerymag.com/blog/>

applications in isolated areas of the transmission grid, island states and nations, and in global regions where oil-based fuels and infrastructure predominate.

A world record for the largest internal combustion engine power plant was achieved in late 2014 with the startup of IPP3, a 573 MW plant in Jordan.³³⁰ IPP3's 38 Wärtsilä multi-fuel 18V50DF engines can run on heavy fuel oil, light fuel oil, or natural gas. In addition to fast start and ramping times, the option to dispatch a select number of these RICE units further increases the flexibility to meet load requirements. IPP4, a 250 MW plant in Jordan, is similarly configured. Following the deployment of RICE units, most of Jordan's gas turbine power plants were relieved of load balancing duties and can operate in steady-state baseload mode. This has resulted in overall efficiency gains, with fuel savings and reduced CO₂ emissions.³³¹

GHG emission or "new source" performance standards and other regulations for new units in various countries are allowing NGCC plants without CO₂ capture to compete against coal-fired units that must include at least partial CO₂ capture. Analysts have debated whether such regulations are encouraging earlier CO₂ capture investment for coal plants or deferring CO₂ capture investment for both coal and NGCC plants without government support or niche market drivers. Regardless, provisions in the authorizing legislation of the various emission performance standards typically call for a review of the standards on a periodic basis. If future standards were significantly lowered, CCS would also be required for new NGCC plants. In EPRI's view, a consensus remains that in the long term, achieving societal targets for GHG emissions reductions will require use of CCS on both coal and NGCC units.

CO₂ Capture for NGCC Units

The lower CO₂ emissions from uncontrolled NGCC units, relative to coal units, results from the lower carbon-to-hydrogen ratio in natural gas and from NGCC's higher thermal efficiency. Nonetheless, NGCC units still produce significant CO₂ emissions. Continued advances in gas turbine and HRSG technology should yield further efficiency gains and CO₂ emissions reductions, but these will be modest compared with the reductions possible from CO₂ capture technologies.

Pre-combustion, oxy-combustion, and post-combustion CO₂ capture approaches have all been proposed for NGCC units, but current development efforts are focused on pressurized oxy-combustion processes for novel natural gas power cycles and post-combustion capture processes for conventional combined cycles. Many post-combustion capture process developers are also pursuing CO₂ capture applications in coal-fired power plants and gas-fired industrial processes. With relatively modest process variations in the CO₂ capture systems for these applications, pilot-scale, demonstration-scale, and early commercial experience in any of these applications advances the state of technology readiness for NGCC applications. One facet of CO₂ capture system design of special interest for gas-fired applications is exhaust gas recycle (EGR) to concentrate CO₂ in the flue gas entering the CO₂ absorber, selective membrane, or other separation device. Researchers have estimated an efficiency benefit of 0.5 percentage point for an NGCC plant with a solvent type CO₂ capture system operating at full load using EGR

³³⁰ <http://www.utilities-me.com/article-3509-wartsila-inaugurates-worlds-largest-engine-plant/>

³³¹ <http://www.out-law.com/en/articles/2015/april/jordan-launches-worlds-largest-internal-combustion-power-plant/>

compared with no EGR. This benefit diminishes as load is reduced down to 50% load, where EGR provides no advantage.³³²

Commercial experience with CO₂ capture on NGCC units is limited. A slipstream unit at the Bellingham Energy Center in Massachusetts operated from 1991 until 2005, recovering 365 tons (330 tonnes) per day of food-grade CO₂ using the Fluor Econamine FG process (i.e., a 30% by weight monoethanolamine aqueous solution).³³³ The application at Bellingham served as a proving ground for advances that led to the higher-efficiency Econamine FG “Plus” solvent now offered by Fluor. Small-scale CO₂ capture has also been applied to industrial facilities firing natural gas.

The Technology Centre Mongstad at a Statoil refinery in Norway installed a CO₂ capture test platform designed to allow well-controlled testing of multiple capture technologies simultaneously at a scale up to 110,000 tons (100,000 tonnes) of CO₂ per year.

CO₂ capture economic metrics differ in their apparent competitiveness for NGCC and coal power plants. For example, because amine solvent processes for NGCC don’t require as extensive of flue gas pretreatment as for coal, and because the CO₂ stripper and compressors for NGCC can be smaller and don’t use as much energy as those for coal, the incremental levelized cost for adding capture to an NGCC plant (on a per MWh basis) is lower than that for a coal plant. In contrast, the levelized cost of CO₂ avoided (on a per ton basis) is higher for NGCC than for coal because of the lower inlet CO₂ concentration in NGCC flue gas.

With current relatively low natural gas prices in North America, the levelized cost of an NGCC plant (on a per MWh basis), either without or with CO₂ capture, will generally be lower than the cost for a comparable coal plant. However, a chief economic risk for any power plant equipped with CO₂ capture is low capacity factor, given the high capital cost of capture equipment. If a jump in the cost of natural gas or a supply curtailment, as has happened during extreme cold weather events, were to cause an NGCC-CCS unit to dispatch at a lower capacity factor, amortizing the CO₂ capture equipment over fewer operating hours could cause the cost per MWh to exceed that of a coal plant with CO₂ capture remaining at a higher capacity factor.

NGCC-CCS Project Updates

Oil and Gas Climate Initiative

The Oil and Gas Climate Initiative (OGCI) is a consortium of 10 oil and gas companies that have pledged to share knowledge and work together to reduce CO₂ and methane emissions. OGCI members have also pooled resources to create a \$1 billion investment fund, known as OGCI Climate Investments, to support the development, scale-up, and deployment low GHG emissions technology.

³³² <https://www.sciencedirect.com/science/article/pii/S1743967117304154>

³³³ S. Reddy, D. Johnson, and J. Gilmartin. “Fluor’s Econamine FG PlusSM Technology for CO₂ Capture at Coal-Fired Power Plants.” Presented at Power Plant Air Pollutant Control “Mega” Symposium, Baltimore, MD, August 25-28, 2008.

In October 2017, the OGCI announced its first three projects to be funded by OGCI Climate Investments, one of which is a design study for full-scale CO₂ capture at an NGCC power plant, with the objective of achieving a “commercially viable concept and basic engineering design that can receive government support and attract private sector investors.”³³⁴

Peterhead CCS Project

Although it has been nearly three years since the UK government cancelled the £1 billion CCS Commercialisation Competition, which led to the termination of the Shell Peterhead demonstration project in Scotland, the FEED study and other documents published by the project remain available to developers of new projects.³³⁵

The Peterhead project would have used Shell’s Cansolv post-combustion CO₂ capture process on the full flue gas stream of one of the three Siemens V94.3A gas turbine/HRSG trains at SSE Generation Limited’s Peterhead NGCC plant in Aberdeenshire, Scotland. At a nominal CO₂ removal rate of 90%, 1.1 million tons (1.0 million tonnes) of CO₂ would have been captured per year, compressed to a pipeline pressure of 1740 psig (120 barg), and piped about 60 miles (100 km) offshore for storage beneath the North Sea in the depleted Goldeneye natural gas reservoir. The storage site has an estimated CO₂ storage capacity of at least 22 million tons (20 million tonnes).

Planned modifications to the power plant consisted of rerouting the flue gas from the GT13 gas turbine to a new CO₂ capture process unit. An SCR system would have been fit to the existing HRSG13 for NO_x removal. A new steam turbine-generator, ST20, with an output of approximately 135 MW, would have been installed to operate in combined cycle with GT13. For capture operations, LP steam was to be diverted from the turbine and supplied to the new carbon capture, compression, and conditioning (CCCC) plant. New auxiliary boilers would have been installed within the power station to provide IP steam to the entire site. Figure 6-1 shows a schematic of the configuration.³³⁶

³³⁴ <https://www.total.com/en/media/news/press-releases/OGCI-announces-three-investments-in-low-emissions-technologies-and-launches-third-annual-report>

³³⁵ <http://www.theguardian.com/environment/2015/nov/25/uk-cancels-pioneering-1bn-carbon-capture-and-storage-competition>

³³⁶ Peterhead CCS Project. Doc. No.: PCCS-00-PT-AA-7704-00001, *Basis of Design for CCS Chain*. Revision K06.

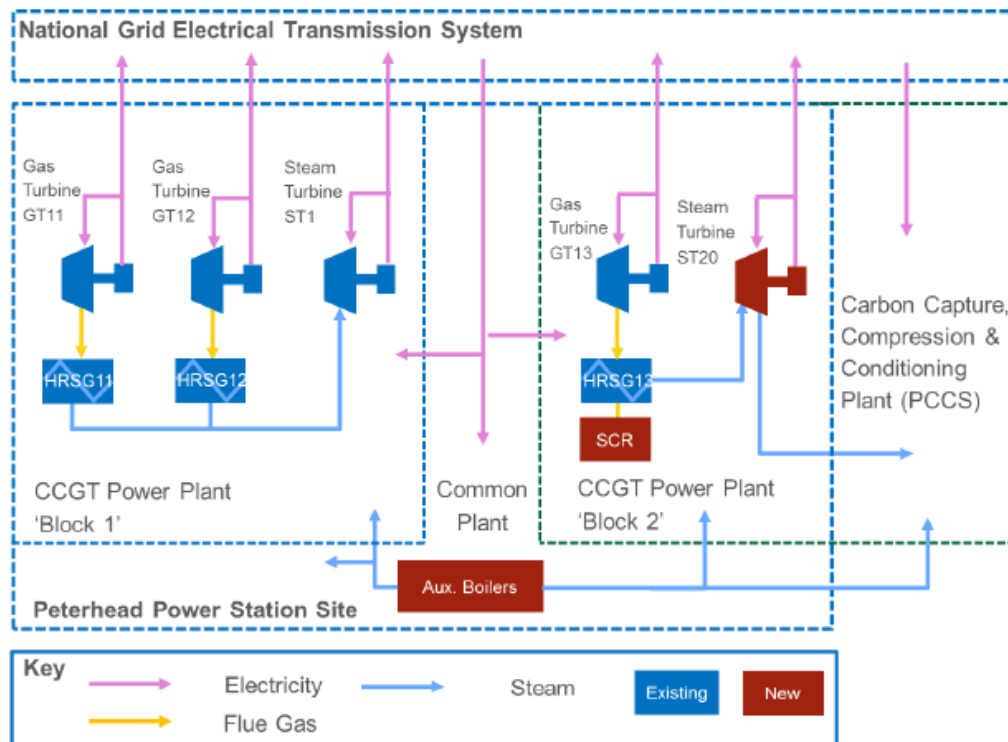


Figure 6-1
Peterhead Power Block Configuration with Additions for CO₂ Capture

Minimal modifications to the existing Goldeneye Platform were anticipated for CO₂ injection. The platform is served by five wells, which would have been converted to CO₂ injection wells. Initial analysis of the exiting Goldeneye pipeline, which had ceased transporting natural gas in 2010, indicated that it was in good condition and should be suitable for carrying dense-phase CO₂. A new pipeline segment would have been added to connect the existing pipeline to onshore facilities. During normal operations, remote control of the platform from onshore was planned.

The capital cost estimate for the Peterhead CCS project was £999.7 million based on cost information from December 2015 (about \$1.3 billion using a June 2018 exchange rate). The estimate includes inflation and escalation to the most likely date of expenditure (i.e., the known cost in 2015 was escalated and inflated, at 2% per annum, to line up with an anticipated execution schedule).

Table 6-1³³⁷ shows a capital cost breakdown by major cost categories. Shell notes that some cost and schedule information had not been finalized in EPC bids, although the final information was not expected to differ much.

The estimate covered the anticipated costs prior to entering operations (i.e., EPC and commissioning costs). Almost two-thirds of the costs were associated with the onshore scope, including the required power plant modifications and new-build CCCC process unit. The offshore components included transportation, platform, wells, and subsurface works. The relative

³³⁷ Peterhead CCS Project. Doc. no.: PCCS-00-MM-FA-3101-00001, *Cost Estimate Report*. Revision K03.

cost split was approximately 64% onshore, 22% offshore, and 14% other costs. Within the onshore estimate, the costs were split approximately into 26% for the power plant and 74% for the CCCC plant.

Table 6-1
Capital Cost for Peterhead CCS Project

Cost Element	Base Estimate £ (000)	Base Estimate \$ (000)*
Venture (SPV) Implementation	10,620	14,000
Owner's Costs	108,990	143,000
Onshore	639,460	838,000
Landfall, Pipeline, Subsea	72,580	95,000
Goldeneye Platform Modifications	60,690	80,000
Wells and Subsurface	88,470	116,000
Commissioning (full CCS chain)	18,500	24,000
FOREX (anticipated foreign exchange related costs)	440	580
Total	999,750	1,310,000

Notes:

SPV = special purpose vehicle

Onshore covers Peterhead Power Station modification scope of work including the new steam generator and associated balance of plant, and the CCCC plant scope of work.

* U.S. costs are rounded. US\$ costs converted at a rate of 1.31 (June 2018 exchange rate).

A breakdown of operating costs over the 25-year life of project (between 2016 and 2041) is shown in Table 6-2.³³⁸ This does not include decommissioning. The cost basis is 2015; costs do not include market escalation or inflation.

³³⁸ Ibid.

Table 6-2
25-Year OPEX Cost Estimate and Breakdown for the Peterhead CCS Project

Cost Element	Sub-Element	Cost**
	Base Plant	£367 / \$480 (million)
	Fuel Gas	£2.4 / \$3.1 (billion)
	Carbon Cost	£197 / \$260 (million)
Power plant OPEX total		£3.0 / \$3.9 (billion)
	Pre-startup	£17 / \$22 (million)
	CCCC* plant power import	£235 / \$310 (million)
	CCCC plant operations	£388 / \$510 (million)
	Transport	£90 / \$120 (million)
	Storage	£1.8 / \$2.4 (million)
	Monitoring (during & post-operation)	£37 / \$48 (million)
Carbon capture, transport, and storage total		£0.769 / \$1 (billion)
Total		£3.7 / \$4.8 (billion)

* Carbon capture, compression, and conditioning

** All costs rounded. US\$ costs converted at a rate of 1.31 (June 2018 exchange rate).

Oxy-Combustion Technology and Novel Cycles for Power and CO₂ Capture

A “conventional” oxy-combustion approach for NGCC would introduce high-purity oxygen at the combustor, where it would mix with the natural gas fuel and recycled exhaust gas, consisting chiefly of CO₂, water vapor, some oxygen, inert gases from the oxygen supply, and traces of nitrogen and other constituents. The compatibility of this heavier-than-air working fluid and its aerodynamic and thermodynamic properties would need to be confirmed or accommodated throughout the gas turbine, which could potentially involve redesign of turbine components. Combustor and catalyst system design to minimize CO formation and emissions, respectively, would also be important. As a result, most technology development efforts for natural gas oxy-combustion units involve new power cycles or configurations aimed at about 250 MWe scale and markets where CO₂ sales are on par in importance with power sales. Some of the more developed processes include:

- NET Power’s Allam cycle, which is in commissioning at 50 MWt-scale in La Porte, Texas. The project achieved its first firing of the combustor in May 2018. The Allam cycle is a direct-fired, semi-closed version of a closed loop Brayton power cycle using CO₂ as the working fluid. A distinctive feature of this power cycle is CO₂ production at high pressure, eliminating the need for a compressor to achieve CO₂ pipeline pressures. CB&I and Exelon Corporation are partners in the project.³³⁹ The plant design is a scaled-down version of an envisioned 250 MWe commercial plant, with the objective of the demonstration plant being to gain operability and performance insights to validate and refine

³³⁹ <https://netpower.com/news-posts/net-power-breaks-ground-on-demonstration-plant-for-worlds-first-emissions-free-low-cost-fossil-fuel-power-technology/>

the commercial plant design. Although NET Power has not published detailed cost studies of its turnkey power plant, it claims that a “first generation” dual-train unit (i.e., a plant with a nominal capacity comparable to a 2x1 NGCC plant) should have a capital cost somewhat higher than a current 2 x 1 NGCC plant. NET Power claims its “second generation” dual-train units should have a capital cost somewhat lower than a current 2 x 1 NGCC plant. NET Power believes its fixed O&M costs should be slightly lower than those for a current NGCC plant and its variable O&M costs should be about the same as a current NGCC plant.³⁴⁰

The 50 MWt turbine built by Toshiba uses nickel-based materials with internal nozzle and blade CO₂ cooling passages and thermal barrier coatings to allow operation at NET Power’s high cycle temperatures. Toshiba use a welded rotor design to minimize the need for nickel-based forgings.³⁴¹

- Clean Energy Systems’ “rocket engine derived” pressurized oxy-combustion cycle is, in essence, a two-stage oxy-fuel gas turbine power process wherein the high combustion temperatures are moderated by injecting water/steam. In the first stage, hot, liquid water is injected into the combustor to moderate the oxy-fuel flame temperature. The products of combustion issuing from the first stage combustor are largely water vapor with about 10% CO₂ when firing natural gas. This high-temperature, high-pressure mixture is partially expanded in a conventional steam turbine and then used to moderate the temperature of an oxy-fired natural gas flame in a reheat combustor. This reheat combustion raises the working fluid temperature to levels typical of gas turbines. The working fluid is still largely steam albeit with slightly higher levels of CO₂ from the reheat combustor. This moderate-pressure, high-temperature gas is then turboexpanded to a moderate pressure and cooled to pre-heat injection water before being expanded further in a low-pressure steam turbine. Water is condensed the exhaust for reuse, leaving high-purity CO₂ for commercial sale and/or geologic storage. Clean Energy Systems offers variants on this flow scheme for niche markets in remote and developing market regions, but these variants are lower in efficiency.
- The Korean Institute of Machinery and Metals, in partnership Southern Electric Power Company, Hyundai Engineering, Sung-Il Turbine, Inc., and several universities, has developed a 100 kWe concept that uses a pressurized oxy-combustor to burn fuel with oxygen combined with steam that has been recirculated. The steam/gas mixture serves as the working fluid to drive a gas turbine; water is condensed from the exhaust and pumped through a HRSG that uses waste heat to create steam for the oxy-combustor.
- The Linde Group has conducted development work on an oxy-combustion system using CO₂ as a base working fluid which is then thermodynamically “tuned” by adding light gases (e.g., helium and/or neon to reduce molecular weight, density, and heat capacity) to enable use in existing gas turbines without aerodynamic modifications (as might be necessary for CO₂-rich working fluids with a heavier molecular weight).
- SINTEF Energy Research Center and Siemens have worked to develop a system targeted for 125 MW scale that burns both oxygen and air in an NGCC combustor to create a CO₂-based working fluid on the gas turbine side. A HRSG would remove heat for use in a standard steam cycle. A back-end system would use a scrubber/condenser to remove water and trace

³⁴⁰ EPRI personal correspondence with B. Brown, February 2014.

³⁴¹ Brown, Bill (NET Power LLC) and Hideo Nomoto (Toshiba Corp.) “The NET Power Process.” EPRI Advanced Generation Program. Savannah, GA. February 19, 2013.

contaminants followed by the bleed removal of a portion of CO₂ for compression and export for utilization or geologic storage. The majority of the CO₂ is recycled back to the power cycle.

- Chemical looping combustion concepts adaptable to gas turbine combustors have been developed at “lab bench” scale.

EPRI NGCC Post-Combustion CO₂ Capture Retrofit Study

In 2015, EPRI conducted an engineering-economic evaluation of a post-combustion CO₂ capture retrofit to the Cartagena NGCC plant in Spain.³⁴² The 1247 MW (net) facility had been operating since 2005. It consisted of three units, each featuring an Alstom GT26B2 gas turbine and an Alstom steam turbine in a single-shaft arrangement. It had no pre-investment for adding CO₂ capture.

Aker Solutions designed the PCC process unit based on its ACCTM CO₂ capture technology. The study focused on the performance penalties, cost, and layout requirements for the following cases:

- Base Capture Case: Capturing 90% of the CO₂ from only one of the three units at Cartagena.
- Flexible Capture Case: Capturing 90% of the CO₂ from any one of the three units at Cartagena.
- Full Capture Case: Capturing 90% of the CO₂ from all of the three units at Cartagena.

For the Flexible Capture Case, the PCC gas intake system must be modified to collect flue gas from any of the three power units. LP/IP turbine steam extraction and condensate return must be added to each unit. Apart from these changes, the CO₂ capture and compression train remains the same as the Base Capture Case.

For the Full Capture Case, three CO₂ capture and compression trains, each with a capacity of that for the Base Capture Case, work together to capture 90% of the total plant CO₂ emissions at full load. By using inlet dampers, the common flue gas duct can be open or shut to flue gas from a given unit. It is therefore possible to operate all power units without CO₂ capture. Table 6-3 shows key components for all three capture cases. For the Base Capture and Flexible Capture Cases, sufficient plot space existed within the plant boundary. However, for the Full Capture Case, additional land outside the plant boundary was required.

³⁴² *Flexible Operation of Current and Next-Generation Fossil Plants With and Without Carbon Capture*. EPRI, Palo Alto, CA: 2016, EPRI Report 3002006388.

Table 6-3
Comparison of PCC Process Unit Components for Cartagena Plant Retrofit

Base Capture Case	Flexible Capture Case	Full Capture Case
1 flue gas fan	1 flue gas fan	3 flue gas fans
Single duct with tie-in to one unit	Single duct with tie-in to 3 units	3 ducts, each with a tie-in to a separate unit
1 absorber train	1 absorber train	3 absorber trains
1 desorber train	1 desorber train	3 desorber trains
4 solvent reboilers	4 solvent reboilers	12 solvent reboilers
1 compression train	1 compression train	3 compression trains

In EPRI's previous generic NGCC-CCS study with Aker Solutions, there had been concern about rapid changes in pressure upstream of the stack during startup, shutdown, or a trip of the PCC process unit. As a consequence, the design included an open stack to which the flue gas could be redirected immediately if the CO₂ capture process unit went off-line. With an open stack, it was assumed that during a no-flow situation, the temperature of the gas volume idled in the stack would decrease and become denser. This could result in condensation of moisture in the flue gas, which could potentially be corrosive to the stack wall. To avoid this possibility, a small flow (on the order of 2–5%) of untreated flue gas was routed to the stack even during PCC unit operation. This approach was deemed necessary, however, by operators of the Cartagena plant.

In the design for Cartagena, flue gas would be extracted from the duct between the HRSG and the stack. A damper would allow service and inspection of PCC unit's flue gas path while operating the power plant with the PCC unit off-line.

The HP section of the Alstom steam turbine at Cartagena had a separate casing and the IP and LP sections were in a common opposed-flow casing. Because there was no IP/LP crossover providing access to steam for PCC solvent regeneration, a turbine modification would be required to accomplish steam extraction. This modification would entail drilling holes in the casing in order to extract the required steam quantity. Alstom confirmed that such modifications could be made in its workshop in Switzerland. Alstom also recommended replacing the inner casing, LP rotor, and blading. However, the cost would be considerably lower if the LP rotor could be retained. Alstom could not confirm this approach without further study. The LP steam extraction would also require new piping, valves, and modification to the distributed control system.

LCOE results from the Cartagena retrofit study include:

- For the base design where only one specific gas turbine train is retrofit for CO₂ capture, the estimated increase in LCOE from adding capture was €48/MWh (about \$56/MWh using a June 2018 exchange rate). This represented an 84% increase over the assumed LCOE for a single Cartagena gas turbine unit without CO₂ capture.
- For the flexible capture design, in which ducting allows any of the three Cartagena gas turbine units to supply flue gas to the CO₂ capture system, the estimated increase in LCOE from adding flexible CO₂ capture capability was €50/MWh (about \$58/MWh using a June

2018 exchange rate). This represented an 88% increase over the assumed LCOE for a single Cartagena gas turbine unit without CO₂ capture. Thus, providing the flexibility to allow any one of three gas turbine units to provide flue gas to the CO₂ capture system at a given time caused a 4 percentage point increase to the incremental LCOE.

- For the full capture case in which all three of the gas turbine units are retrofit for CO₂ capture, the estimated increase in LCOE from adding capture was €38/MWh (about \$48/MWh using a June 2018 exchange rate). This represented a 65% increase over the assumed LCOE for operating all three Cartagena units without CO₂ capture.

Capital cost results from the study include:

- The capital cost for adding full CO₂ capture to all three gas turbine trains is estimated to be about \$1 billion.
- The capital cost for adding CO₂ capture to one gas turbine train is estimated to be about \$480–510 million. The higher end of this cost range is for the design allowing plant operators to any of the three gas turbine units as the source for flue gas feeding the CO₂ capture process unit whereas the lower end of the cost range is for the design in which the CO₂ capture process unit is ducted to only one specific gas turbine train.

Key findings from an economic review of the study include:

- Retrofitting three units together results in significant capital savings (i.e., the cost is considerably less than three times the cost of retrofitting a single unit). In particular, unit savings accrue in the absorption and reclaimer systems, as well as in bulk materials and freight, construction, engineering management, commissioning, insurance, and contractors' fees.
- If multiple units are retrofitted together, the incremental LCOE for CO₂ capture is significantly less than the incremental LCOE for a single unit adding CO₂ capture (i.e., the aforementioned economies of scale are realized).
- To achieve a cost of CO₂ avoided below \$90/ton (\$99/tonne) with the Aker Solutions ACC™ technology at Cartagena, the Full Capture Case would need to be implemented, the operating capacity factor would need to be at 80% or above, and the price of natural gas would need to be less than \$6/MBtu (\$5.70/GJ).

As noted, EPRI's 2012 report developed with Aker Solutions examined an NGCC plant with advanced amine post-combustion CO₂ capture based on Aker Clean Carbon technology in retrofit and new-build scenarios.³⁴³ The study methodology and the baseline site conditions were for EPRI's standard reference location of Kenosha, Wisconsin. The Aker Clean Carbon process can achieve 90% CO₂ capture using a solvent specifically designed for natural gas applications with a heat of regeneration of 1300 Btu/lb (3 MJ/kg). Norsk Energi provided the steam cycle analysis, optimization, and costing for the overall assessment of the capture process and process integration with the NGCC steam cycle.

³⁴³ *An Engineering and Economic Evaluation of Post-Combustion CO₂ Capture for Natural Gas-Fired Combined Cycle Power Plants*. EPRI, Palo Alto, CA: 1024892. March 2012.

EPRI report 1024892 presents key technical insights, performance impacts, emission data, and capital cost information for four cases:

- 556 MW (net) NGCC base plant reference case (2 x 1 60 Hz F-Class)
- Retrofit case applying post-combustion CO₂ capture to the base plant with no pre-investment for CO₂ capture
- New-build NGCC plant designed with post-combustion CO₂ capture
- New-build NGCC plant designed with exhaust gas recycle and post-combustion CO₂ capture

All designs allow the NGCC plant to operate with or without the PCC system (i.e., it can be turned off for maximum peak power output). The retrofit capture plant design and the new-build design without EGR each incorporate two absorber trains, one stripper train with four reboilers, and two compression trains. The design with EGR increases flue gas CO₂ concentration from 3.9% to 7.3% (vol) and only requires one absorber train. Steam for solvent regeneration is obtained from the IP/LP crossover in the existing steam turbine train. Performance and cost results are summarized in Table 6-4.³⁴⁴ A key finding of this study is that EGR at a 45% recycle rate reduces the total capital and operating costs (assuming an nth-of-a-kind design) and increases the output of a new-build NGCC plant with CCS.

Specifically, in the design with EGR, plenums installed after the HRSG split the exhaust gas flow into two streams: one recycling flue gas to the gas turbine compressor's inlet air filters and one directed to the CO₂ absorber. Both streams are cooled by their own direct-contact cooler. Cooling of the recycle stream is necessary to avoid a loss of power output from the gas turbine due to increased average inlet air temperature. Cooling of the stream entering the CO₂ absorber is necessary to attain the design performance of the capture solvent. Flow rates between the streams are controlled by the plenum arrangement, louvers/dampers, and fans. Figure 6-2 shows a block diagram of the EGR gas flows in the EPRI NGCC-CCS study and the resulting molar composition of the flue gas entering the CO₂ absorber. Modification of the burner or other combustion hardware may be required to prevent flame instability or possible blow out.

³⁴⁴ EPRI report 1024892, op. cit.

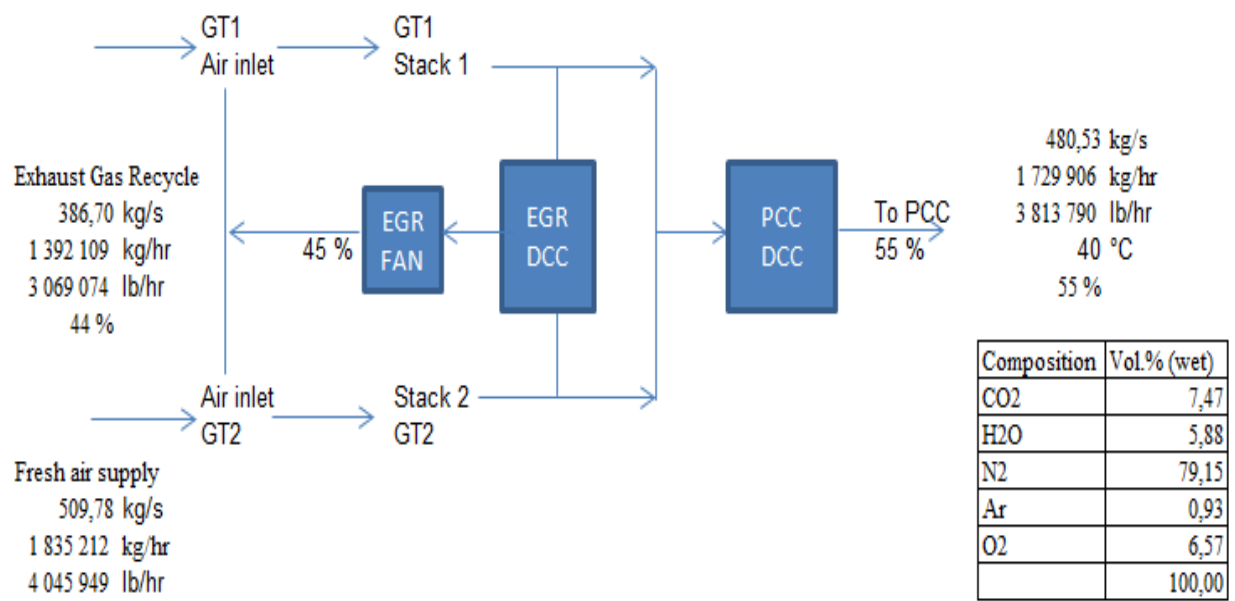


Figure 6-2
Block Diagram of NGCC Exhaust Gas Recycle for CO₂ Concentration

Table 6-4
EPRI Cost and Performance Estimates for NGCC Configurations without and with Post-Combustion CO₂ Capture

Technology (4Q2011 Cost Basis)	2 x 1 NGCC with GE 7FA.05			
	Base Plant (no capture)	Retrofit (90% capture)	New-Build (90% capture)	New-Build EGR (90% capture)
Capacity Factor, %	60	60	60	60
GT Output, MWe	368.8	368.8	368.8	368.8
ST Output, MWe	197.3	163.5	163.5	163.5
Gross Output, MWe	566	532.3	532.3	532.3
Auxiliary Power Load, MWe	9.5	45.1	45.1	38.6
Net Output, MWe	556.5	487.2	487.2	493.7
Net Heat Rate – Average Annual Btu/kWh (kJ/kWh) HHV	6625 (6990)	7560 (7975)	7560 (7975)	7470 (7880)
Net Efficiency, % HHV	51.5	45.1	45.1	45.7
Efficiency Loss, % pts HHV	--	6.4	6.4	5.8
TPC, \$M (no contingency)	434	846	817	783
TPC, \$/kW (no contingency)	780	1,736	1,676	1,586
Capital, \$/MWh	17.60	39.30	37.90	35.90
Variable O&M, \$/MWh	1.20	4.20	4.20	4.00
Fixed O&M, \$/MWh	3.78	7.20	6.76	6.48
Fuel, \$/MWh	42.00	48.00	48.00	47.30
CO ₂ T&S, \$/MWh		3.80	3.80	3.75
30 year LCOE, \$/MWh with CO ₂ T&S	64.60	102.50	100.60	97.50
30-year LCOE, \$/MWh with CO ₂ T&S, and 20% contingency on PCC equipment cost		106	104	101
CO ₂ emissions lb/MWh (net) (kg/MWh-net)	814 (369)	93.0 (42.2)	93.0 (42.2)	93.0 (42.2)
Cost of CO ₂ Avoided, \$/ton (\$/tonne)		105 (116)	99.8 (111)	91 (101)

The EPRI NGCC-CCS study evaluated costs on a 2011 U.S. dollar basis, with estimates at a ±30% accuracy from pre-FEED studies. LCOE is calculated using the “revenue requirements” method for an investor-owned utility, assuming a 60% capacity factor. An annual capital carrying charge factor of 11.9% is applied. Calculations were performed with a delivered natural gas cost of \$7.00/MBtu (\$6.60/kJ). All cases assumed that captured CO₂ was compressed

to 2200 psig (153 bar). A value of \$9 per ton (\$10/tonne) of CO₂ was applied to account for pipeline transportation, saline formation injection, and monitoring costs.

Table 6-5 compares the results from EPRI studies of applying CCS to NGCC and coal power plants.³⁴⁵ The coal cases are for plants firing PRB subbituminous. An annual capital carrying charge factor of 12.1% is used for the PC cases, and 12.5% is used for the IGCC cases. A capacity factor of 80% is used for all PC, oxy-combustion, and IGCC cases, with and without CO₂ capture. Other design basis information includes:

- Air- and oxy-fired PC steam conditions are based on a nominal 1100°F (600°C) USC steam generator
- The PC plant's post-combustion CO₂ capture system is based on MHI KM-CDR technology, fully integrated with a new-build plant, using KS-1 solvent with a heat of regeneration of 1200 Btu/lb (2.8 MJ/kg)
- The IGCC plant uses Siemens gasifier technology

Table 6-5
Results from EPRI Studies of NGCC and Coal Power Plants Without and With CO₂ Capture

Type	Capture	Efficiency, % HHV	Plot Space, hectares	LCOE, \$/MWh*	CO ₂ Avoided, \$/ton*	Water, gpm/MW
NGCC Post-Combustion	No Capture	51	1.6	58-70	--	5
	Capture	45	3.2	89-112	82-118	7
PC Post-Combustion	No Capture	38.5	36.4	54-70	--	9
	Capture	28.7	40.0	128-170	82-126	17
IGCC Pre-Combustion	No Capture	38.2	33.6	70-99	--	5
	Capture	29.8	34.2	100-140	38-57	7
Oxy-Combustion	Capture	31.5	39.6	99-138	50-97	13

* Costs do not include contingency. For costs of CO₂ avoided in \$/tonne, multiply the \$/ton values by 1.102. For plot areas in acres, multiply values in hectares by 2.47. For water consumption in liters/min, multiply gpm values by 3.79.

Comparing the studies yields the following observations:

- NGCC units with post-combustion CO₂ capture have a higher thermal efficiency than USC PC or IGCC plants without capture, and a much higher efficiency than USC PC, IGCC, or boiler-type oxy-combustion plants with CO₂ capture.
- NGCC units with CO₂ capture may have a lower capital cost than coal plant without CCS.

³⁴⁵ D. Dillon. *Assessment of NGCC with CCS: Comparison to Other Low CO₂ Power Options*. Presentation to CoalFleet Technical Meeting, Mobile, Alabama: December 2012.

- At the fuel prices used in these studies, NGCC with CO₂ capture has an LCOE advantage over coal plants with CO₂ capture. The magnitude of the advantage depends on the fuel price differential between coal and natural gas. Representative wholesale U.S. natural gas prices in 2015–18 were considerably lower than the values used in the Aker Clean Carbon study. Conversely, the “polar vortex” over the eastern United States in January 2014 and January 2018 showed that price volatility risk still remains in short-term market prices.
- Although the LCOE for an NGCC plant with CO₂ capture may be lower than that for a PC, IGCC, or coal oxy-combustion plant with CO₂ capture, NGCC with CO₂ capture has a higher cost than IGCC or coal oxy-combustion using the metric of dollars per ton of CO₂ avoided.
- The variable O&M cost (dispatch order basis) for NGCC and coal plants with CO₂ capture are higher than those for comparable plants without CO₂ capture at the currently modest prices for CO₂ emission allowances. Without regulatory intervention to assure preferential dispatch of plants with CO₂ capture, the resulting lower capacity factors would increase their LCOE (i.e., fewer MWh over which to amortize capital costs).
- A post-combustion CO₂ capture plant for an NGCC unit has a smaller incremental plot space requirement than that for a PC plant and about the same plot space requirement as for an IGCC plant with pre-combustion CO₂ capture.

DOE NETL Studies of NGCC Plants with Post-Combustion CO₂ Capture

In 2018, NETL is reportedly updating its fossil power “baseline” studies, which include cases for NGCC without and with CCS. In 2017, NETL released preliminary results for a forthcoming update of the report, *Cost and Performance of Retrofitting NGCC Units for Carbon Capture*. Assumptions included:

- Steam conditions: 2400 psig/1050°F/1050°F (165 barg/565°C/565°C)
- Gas turbine: 2 x GE 7FA
- Gas turbine inlet temperature: 2479°F (1360°C)
- CO₂ capture process: Shell Cansolv
- CO₂ capture rate: 90%
- CO₂ fate: offsite saline storage
- CO₂ pipeline transport distance: 62 miles (100 km)

Figure 6-3 shows the impact of natural gas prices on COE. The study results included:

- Retrofit Capital Cost: \$647,300,000
- Heat Rate (pre-retrofit): 6629 Btu/kWh (6994 kJ/kWh)
- Heat Rate (post-retrofit): 7466 Btu/kWh (7877 kJ/kWh)
- CO₂ Capture Rate: 445,000 lb/hr (202,000 kg/hr)
- Energy Penalty: ~0.19 kWh/lb-CO₂ captured (~0.42 kWh/kg-CO₂ captured)
- Incremental O&M: \$6.15/MWh

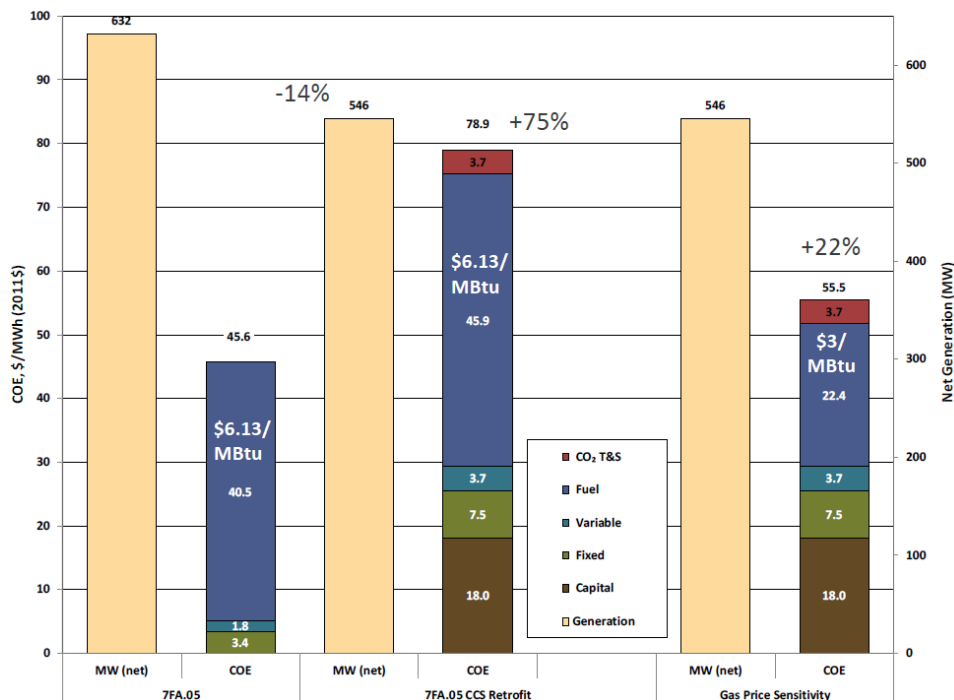


Figure 6-3
NETL NGCC Retrofit Study Results

In 2012, NETL published a “well to wires” life-cycle analysis for electricity production using natural gas power plants.³⁴⁶ In addition, NETL recently re-analyzed the performance and cost of NGCC configurations, without and with post-combustion CO₂ capture, at the standard conditions that NETL uses in its fossil power “baseline” report series.³⁴⁷ DOE’s 2012 “Natural Gas Technology Assessment” provides supplemental analyses at the minemouth site conditions used in NETL’s low-rank (western) coals baseline study.³⁴⁸ The Natural Gas Technology Assessment also reviews expectations for U.S. natural gas supplies. Results from these studies are summarized in Table 6-6. An analysis of cost uncertainty factors from NETL’s Natural Gas Technology Assessment report is shown in Table 6-7.³⁴⁹

³⁴⁶ *Role of Alternative Energy Sources: Natural Gas Technology Assessment*. DOE/NETL-2012/1539. June 2012.

³⁴⁷ *Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3*. DOE/NETL-2015/1723, July 2015.

³⁴⁸ *Cost and Performance Baseline for Fossil Energy Plants, Volume 3c: Natural Gas Combined Cycle at Elevation*. DOE/NETL-2010/1396. March 2011.

³⁴⁹ From *Role of Alternative Energy Sources: Natural Gas Technology Assessment*. DOE/NETL-2012/1539. June 2012.

Table 6-6
NETL Estimates of Cost and Performance of NGCC Plant Configurations and Locations

NETL Study	Bituminous Baseline		Low-Rank Coal Baseline (NGCC at Elevation)			
Technology/Fuel	2 x 7F (2013), no CCS	2 x 7F (2013), CCS	2 x 7FB, no CCS	2 x 7FB, no CCS	2 x 7FB, CCS	2 x 7FB, CCS
Location Elevation, ft (m)	Midwest 600 (180)	Midwest 600 (180)	Montana 3400 (1040)	N. Dakota 1900 (580)	Montana 3400 (1040)	N. Dakota 1900 (580)
Capacity Factor (CF) %	85	85	85	85	85	85
GT Output, MWe	422	422	335.3	385.6	335.3	358.6
ST Output, MWe	219	179	186.8	198.4	134.7	143.0
Gross Power Output	641	601	522.1	557.0	470.0	501.6
Aux. Power Load, MWe	11	42	9.7	10.0	34.9	37.0
Net Output, MWe	630	559	512.4	547.0	435.1	464.6
Net Heat Rate – Ave. Annual, Btu/kWh (kJ/kWh) HHV	6,629 (6,994)	7,466 (7,877)	6,757 (7,130)	6,743 (7,144)	7,959 (8,397)	7,938 (8,375)
Net Efficiency, % HHV	51.5	45.7	50.5	50.6	42.9	43.0
Eff Reduction, % pts HHV	--	5.8	--	--	7.6	7.6
CO ₂ emissions, lb/MWh (net) (kg/MWh-net)	786 (357)	89 (40)	799 (363)	797 (362)	94 (43)	94 (43)
Fuel Cost, \$/Btu (\$/GJ) HHV	6.13 (5.81)	6.13 (5.81)	7.13 (6.76)	7.13 (6.76)	7.13 (6.76)	7.13 (6.76)
TPC, \$/kW (2007 dollars)	685 (2011 \$)	1,481 (2011 \$)	666	637	1,315	1,267
Total Overnight Cost \$/kW for Power Plant (incl PCC if used)	838 (2011 \$)	1,804 (2011 \$)	817	782	1,607	1,548

NETL Study	Bituminous Baseline		Low-Rank Coal Baseline (NGCC at Elevation)			
Technology/Fuel	2 x 7F (2013), no CCS	2 x 7F (2013), no CCS	2 x 7FB, no CCS	2 x 7F (2013),	2 x 7FB, no CCS	2 x 7FB, CCS
First Year COE, \$/MWh, with CO ₂ TS&M	57.6	87.3	64.4	63.6	92.9	91.4
Capital \$/MWh	11.8	26.9	11.5	11.0	24.0	23.1
O&M \$/MWh	5.1	10.6	4.8	4.5	8.8	8.5
Fuel \$/MWh	40.7	45.9	48.2	48.1	56.7	56.6
CO ₂ TS&M \$/MWh	-	4.0	-	-	3.4	3.3
LCOE, \$/MWh, incl CO ₂ TS&M	57.6	87.3	81.7	80.6	117.8	115.8
Total Overnight Cost \$/kW	718	1497	for Power Plant inside fence line			
Total Overnight Cost \$/kW	802	1,913	incl Trunkline; Switchyard; CO ₂ Pipeline & Injection			
“Life-Cycle” COE, \$/MWh	53.36	81.37	incl Trunkline, Switchyard, CO ₂ TS&M, and 7% Electric Transmission Loss			

Table 6-7
NETL Assessment of Uncertainty in Cost Parameters for Natural Gas Power Plants

Parameter	Units	Low	Expected Value	High	% Uncertainty
NGCC					
Natural Gas Price	\$/MBtu (2007 USD)	2.50	5.00	7.50	±50
Capital	\$/kW (2007 USD)	561	802	1,043	±30
Total Tax Rate	%	28.0	38.0	48.0	±10
Capacity Factor	%	80.0	85.0	90.0	±5
Variable O&M	\$/MWh (2007 USD)	0.92	1.32	1.72	±30
NGCC-CCS					
Natural Gas Price	\$/MBtu (2007 USD)	2.50	5.00	7.50	±50
Capital	\$/kW (2007 USD)	1,339	1,913	2,486	±30
Total Tax Rate	%	28.0	38.0	48.0	±10
Capacity Factor	%	80.0	85.0	90.0	±5
Variable O&M	\$/MWh (2007 USD)	1.88	2.68	3.48	±30

NETL's analyses are based on post-combustion CO₂ capture using the Fluor Econamine FG Plus process. Its 30% (by weight) MEA solvent with proprietary additives has a sorbent regeneration energy of 1180 Btu/lb-CO₂ (2760 kJ/kg-CO₂). CO₂ is transported off-site for injection into a saline formation. The DOE studies use a mid-2007 or 2011 U.S. dollar cost basis, as noted.

The DOE NGCC analyses assume a configuration of two advanced F-class gas turbines and one steam turbine. Emissions controls consist of dry-low NO_x combustors and SCR. The HRSG employs a multi-pressure drum-type design with steam conditions of 2400 psia/1050°F/1050°F (165 bar/566°C/566°C).

Table 6-8 summarizes the gas turbine air intake and steam turbine exhaust parameters and cooling systems, which are also important for understanding the difference in performance and cost data between DOE's bituminous cases and the NGCC cases at higher elevation.

Table 6-8
Gas Turbine Air Intake and Steam Turbine Exhaust Parameters for NETL NGCC-CCS Studies

NETL Study	Bituminous Baseline		Low-Rank Coal Baseline (NGCC at High Elevation)			
Technology	2 x 7F (2103)	2 x 7F (2013), CCS	2 x 7FB	2 x 7FB, CCS	2 x 7FB	2 x 7FB, CCS
Location	Midwest		Montana		North Dakota	
Elevation, m (ft)	600 (180)		1040 (3400)		580 (1900)	
Ambient Temp, °F (°C)	59 (15)		42 (6)		40 (4)	
GT Compressor Inlet Pressure, psia (bara)	14.7 (1.0)		13.0 (0.9)		13.8 (0.95)	
ST Condensing Pressure	2 in Hga (50.8 mm Hga)		0.7 psia		0.7 psia	
ST Condensing Temp, °F (°C)	101 (38)		90 (32)		90 (32)	
Condenser & Cooling Technology	Wet Surface Condenser with Wet Mechanical Draft Tower, 60°F (16°C) Cooling Water		Parallel Air-Cooled Condenser and Wet Condenser with Wet Mech Draft CT, 48°F (9°C) Cooling Water		Parallel Air-Cooled Condenser and Wet Condenser with Wet Mech Draft CT, 47°F (8°C) Cooling Water	

IEAGHG Study of CO₂ Capture at Natural Gas Combined Cycle Plants

In 2012, IEAGHG assessed the performance and cost of several post-combustion and pre-combustion CO₂ capture approaches for NGCC power plants at a northern European location.³⁵⁰ The study examined the following six cases using IEAGHG's "Criteria for Technical and Economic Assessment of Plants with Low CO₂ Emissions:"

Scenario 1: Reference plant without CO₂ capture

Scenario 3: Plant with post-combustion CO₂ capture using a nonproprietary solvent absorption process with a 35% MEA solution

Scenario 3b: Plant with post-combustion CO₂ capture using a proprietary advanced amine solvent absorption process

Scenario 4: Plant with a 35% MEA post-combustion CO₂ capture system and exhaust gas recycle

Scenario 5: An integrated, natural-gas-reforming combined cycle plant with pre-combustion CO₂ capture that uses air-blown partial oxidation of natural gas, followed by water-gas shift, to create a hydrogen-rich syngas from which CO₂ is removed with a Selexol process prior to firing in a gas turbine

³⁵⁰ Report 2012/8. IEAGHG: July 2012.

Scenario 6: Plant with separate reforming and pre-combustion CO₂ capture that uses underground buffer storage of hydrogen-rich gas that is fired in a separate combined cycle plant

Ambient conditions at the northeast Netherlands coastal site selected for the study are:

- Average Dry Bulb Temperature: 48°F (9°C)
- Maximum Temperature: 86°F (30°C)
- Minimum Temperature: 50°F (10°C)
- Average Humidity: 80%

All of the cases in the study assumed a typical 50 Hz NGCC configuration using two F-Class gas turbines each exhausting to a separate triple-pressure, single reheat HRSG that supplies steam to a common steam turbine. The study's steam conditions of 2450 psig/1112°F/1112°F (170 bara/600°C/600°C) are not currently used commercially in this application, but are expected to be proven and commercially available by 2020. The steam turbine exhausts to a wet surface condenser with 58°F (14°C) cooling water supplied from a wet, mechanical draft cooling tower.

After examining turbine models available from Siemens, GE, MHPS, and Ansaldo (formerly Alstom), the study team selected the GE 9FB gas turbine offered in Europe because of its commercial maturity and active development program for syngas firing.

Table 6-9 (in U.S. dollars and unit conventions) and Table 6-10 (in euros and European unit conventions) summarize the results of the IEAGHG study. Key observations and conclusions include the following:

- As in the EPRI study, IEAGHG found that adding EGR can reduce capital and operating costs and increase the net output of a new-build NGCC plant with post-combustion CO₂ capture. However, unlike the EPRI study, IEAGHG did not include costs for modifying the gas turbine to accommodate EGR, as the turbine manufacturers are still researching the necessary changes. Also, the apparent benefit for implementing EGR on a generic MEA process is not as great as the benefit gained from selecting an advanced solvent process in lieu of MEA.
- The cost and performance penalties for syngas production via natural gas reforming, or via partial oxidation and catalytic water-gas shift, appear to offset any benefit from the higher operating pressure of pre-combustion CO₂ capture process. These cases also had higher water consumption.
- A sensitivity evaluation of fuel cost did not change the relative life-cycle cost rankings for the NGCC technologies.
- A sensitivity evaluation of the CO₂ penalty did not change the ranking of the CO₂ capture cases. The breakeven point for the no-capture case versus Scenarios 3B, 4, 3, 5, and 6 were at CO₂ penalty costs of €64.50/tonne, €75.50/tonne, €89.75/tonne, €155.75/tonne, and €271.75/tonne, respectively. The values of these breakeven CO₂ penalties on a \$/ton basis are proportionally the same and about 5% higher (using a June 2018 exchange rate).

Table 6-9
IEAGHG Estimates of Cost and Performance for NGCC Configurations without and with CO₂ Capture (U.S. Customary Units)

Technology	Scenario 1 2 x 9FB	Scenario 3 2 x 9FB, PCC 35% MEA	Scenario 3b 2 x 9FB, PCC Proprietary Amine	Scenario 4 2 x 9FB PCC 35% MEA, EGR	Scenario 5 2 x 9FB, Integrated Reforming, Pre-combustion Capture	Scenario 6 2 x 9FB, Reforming with Storage Buffer, Pre-combustion Capture
Capacity Factor (CF), %	93	90	90	90	85	85
First Year CF, %	90	60	60	60	60	60
GT Output, MWe	590.5	590.3	590	575.3	587.7	640.1
ST Output, MWe	343.5	269.8	284.2	275.3	397.7	323.3+49.8
Gross Power Output, MWe	934	860	874	851	985	1014
NGCC Aux Power Load, MWe	23.7	19.4	20.2	19.4	26.0	38.2
CO ₂ Capture/Compression Aux. Power Load, MWe		51.4	50.1	45.7	109.5	238.1
Net Output, MWe	910	789	804	786	850	737
Net Heat Rate – Btu/kWh HHV	6,415	7,399	7,266	7,359	8,927	10,275
Net Efficiency, % HHV	53.2	46.1	47.0	46.4	38.2	33.2
Eff Reduction, % pts HHV	--	7.1	6.2	6.8	15.0	20.0
CO ₂ capture rate (tonne/hr)	--	288	289	284	336	335
CO ₂ emitted, lb/MWh-net	768	90	88	90	197	229
CO ₂ stored, lb/MWh-net	--	805	792	798	871	1001
Total Capital Requirement, \$M (TPC + Owners Costs)	843	1,613	1,366	1,472*	1,992	2,620
TCR, \$/kW	925	2,044	1,699	1,875	2,344	3,555
TPC, \$/kW	849	1,868	1,553	1,713	2,127	3,228

Technology	Scenario 1 2 x 9FB	Scenario 3 2 x 9FB, PCC 35% MEA	Scenario 3b 2 x 9FB, PCC Proprietary Amine	Scenario 4 2 x 9FB PCC 35% MEA, EGR	Scenario 5 2 x 9FB, Integrated Reforming, Pre-combustion Capture	Scenario 6 2 x 9FB, Reforming with Storage Buffer, Pre-combustion Capture
Levelized COE, \$/MWh	71.9	102.1	94.3	98.8	122.3	157.3
Capital	13.7	31.7	26.4	29.1	38.4	58.0
Fuel at \$8.38/MBtu HHV	48.9	56.4	55.5	56.1	68.1	78.4
CO ₂ Emissions Penalty at \$12.00/ton	4.7	0.5	0.5	0.5	1.2	1.3
CO ₂ TS&M at \$6.00/ton	0.0	2.4	2.4	2.4	2.7	3.1
O&M	2.7	7.9	6.4	7.5	8.4	12.8
General Overhead	1.9	3.1	3.1	3.1	3.5	3.7

Note: Costs are converted from Euros as constant (real) prices as of January 2011, based on an exchange rate of 0.75 Euro = 1 USD; 8% baseline discount rate.

* The Scenario 4 estimate does not include the unknown cost for gas turbine modifications to accommodate EGR.

Table 6-10
IEAGHG Estimates of Cost and Performance for NGCC Configurations without and with CO₂ Capture (European Units)

Technology	Scenario 1 2 x 9FB	Scenario 3 2 x 9FB, PCC 35% MEA	Scenario 3b 2 x 9FB, PCC Proprietary Amine	Scenario 4 2 x 9FB PCC 35%MEA, EGR	Scenario 5 2 x 9FB, Integrated Reforming, Pre- combustion Capture	Scenario 6 2 x 9FB, Reforming with Storage Buffer, Pre-combustion Capture
Capacity Factor (CF), %	93	90	90	90	85	85
First Year CF, %	90	60	60	60	60	60
GT Output, MWe	590.5	590.3	590	575.3	587.7	640.1
ST Output, MWe	343.5	269.8	284.2	275.3	397.7	323.3+49.8
Gross Power Output, MWe	934	860	874	851	985	1014
NGCC Aux Power Load, MWe	23.7	19.4	20.2	19.4	26.0	38.2
CO ₂ Capture and Comp. Aux. Power Load, MWe		51.4	50.1	45.7	109.5	238.1
Net Output, MWe	910	789	804	786	850	737
Net Heat Rate – kJ/kWh LHV	6,115	7,053	6,926	7,015	8,510	9,795
Net Efficiency, % LHV	58.9	51.0	52.0	51.3	42.3	36.8
Eff Reduction, % pts LHV	—	7.8	6.9	7.6	16.6	22.1
CO ₂ Capture Rate (tonne/hr)	—	288	289	284	336	335
CO ₂ emitted, kg/MWh-net	348	41	40	41	89	104
CO ₂ stored, kg/MWh-net	—	365	359	362	395	454
Total Capital Requirement, million €	632	1,210	1,025	1,104*	1,494	1,965
TCR, €/kW	694	1,533	1,274	1,406	1,758	2,666
TPC, €/kW	637	1,401	1,165	1,285	1,595	2,421

Technology	Scenario 1 2 x 9FB	Scenario 3 2 x 9FB, PCC 35% MEA	Scenario 3b 2 x 9FB, PCC Proprietary Amine	Scenario 4 2 x 9FB PCC 35%MEA, EGR	Scenario 5 2 x 9FB, Integrated Reforming, Pre- combustion Capture	Scenario 6 2 x 9FB, Reforming with Storage Buffer, Pre-combustion Capture
Capital	10.3	23.8	19.8	21.8	28.8	43.5
Fuel at €6/GJ LHV	36.7	42.3	41.6	42.1	51.1	58.8
CO ₂ Emissions Penalty at €10/tonne	3.5	0.4	0.4	0.4	0.9	1
CO ₂ TS&M at €5/tonne		1.8	1.8	1.8	2	2.3
O&M	2	5.9	4.8	5.6	6.3	9.6
General Overhead	1.4	2.3	2.3	2.3	2.6	2.8

Note: Costs are stated in Euros as constant (real) prices as of January 2011. 8% baseline discount rate

* The Scenario 4 estimate does not include the unknown cost for gas turbine modifications to accommodate EGR.

7

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A

EPRI'S DESIGN AND ECONOMIC BASES

To facilitate comparison among its engineering-economic evaluations, EPRI's uses a standard reference location, which is in Kenosha, Wisconsin. The site has following characteristics:

- Clear and level site with no access issues; however, 100 foot (30 m) pile foundations are required
- Raw water is available from Lake Michigan
- Coal is delivered by rail
- The inactive coal storage pile is sized for 90 days storage, and the active storage pile is sized for 7 days of full-load operation
- Limestone is delivered by truck for FGD systems less than 200 MW and by rail for larger systems. The limestone consists of 94.1% CaCO_3 , 3.3% MgCO_3 , 0.6% SiO_2 , and 2.0% H_2O .
- On-site emergency coal ash storage is sized for 90 days. Final disposal is off-site.

Annual average ambient air conditions—used for material balances, thermal efficiencies, and equipment sizing—are as follows:

- Dry bulb temperature 60°F (15°C)
- Atmospheric pressure 14.4 psia (0.99 bar)
- Maximum dry bulb temperature 95°F (35°C)
- Maximum wet bulb temperature 75°F (24°C)

Fuel and Consumables Prices

In the analyses, the cost of coal delivered to a Kenosha, Wisconsin, plant site is \$2.65/MBtu (\$2.50/GJ), HHV basis, for Illinois #6 bituminous, \$1.85/MBtu (\$1.75/GJ) for Wyoming PRB subbituminous coal, and \$3.00/MBtu (\$2.85/GJ) for Pittsburgh #8 bituminous coal.

For natural gas, EPRI evaluations use three long-term contract prices: \$5, \$7, and \$10/MBtu (\$4.70, \$6.60, and \$9.50/GJ).

Occasionally, EPRI evaluates lignite-fired plants, and assumes they are minemouth generating units in Texas or North Dakota. Table A-1 lists the characteristics of coals used in EPRI's analyses. Although not shown in the table, the properties for North Dakota lignite are similar to those for Texas lignite for moisture, ash, and sulfur content.

Table A-1
Characteristics of Coal Used in EPRI Engineering-Economic Evaluations

	Pittsburgh #8	Illinois #6	Wyoming PRB	Texas Lignite
Proximate Analysis (Wt %, as received)				
Moisture	5.2	13.0	30.24	33.03
Ash	7.1	11.0	5.32	15.92
Fixed Carbon	51.0	41.0	33.05	23.89
Volatile Matter	36.7	35.0	31.39	27.17
Ultimate Analysis				
Moisture	5.2	12.2	30.24	33.03
Carbon	73.8	61.0	48.18	35.04
Hydrogen	4.9	4.25	3.31	2.68
Nitrogen	1.4	1.25	0.70	0.77
Chlorine	0.07	0.07	0.01	0.09
Sulfur	2.13	3.28	0.37	1.16
Oxygen	5.4	6.95	11.87	11.31
Ash	7.1	11.0	5.32	15.92
Ash Mineral Analysis				
SiO ₂	46.45	50.66	31.38	45.16
Al ₂ O ₃	24.04	19.00	15.12	21.91
TiO ₂	1.19	0.83	1.11	1.63
Fe ₂ O ₃	18.63	20.30	5.36	6.97
CaO	4.10	2.42	23.56	16.42
MgO	0.58	0.89	4.68	3.26
Na ₂ O	0.97	0.67	1.48	0.78
K ₂ O	1.36	2.54	0.31	0.80
P ₂ O ₅	0.21	0.17	0.86	0.81
SO ₃	2.08	1.90	14.67	1.26
Undetermined	0.39	0.62	1.47	1.00
Ash Fusion Temperature (in Reducing Atmosphere)				
Softening (H=W) °C (°F)	1216 (2220)	1143 (2090)	1188 (2171)	1243 (2270)
Heating Value (as received)				
HHV MJ/kg (Btu/lb)	30.84 (13,260)	25.54 (10,982)	19.40 (8340)	14.00 (6018)
LHV MJ/kg (Btu/lb)	29.76 (12,797)	24.61 (10,584)	17.94 (7712)	12.60 (5417)

Environmental Design Criteria

Plant designs in EPRI engineering-economic studies employ emission controls for SO₂ and NO_x commensurate with federal New Source Performance Standards. Although regulations for mercury and other hazardous air pollutants are still somewhat uncertain, EPRI's reference plants include state-of-the-art mercury controls.

In anticipation of future tighter standards, EPRI's PC plants firing bituminous coal and lignite are designed with wet FGD for 98% and 96% sulfur removal, respectively, whereas the PC plants for PRB subbituminous coal are designed with spray dry absorption (semi-dry) FGD for 96% sulfur removal. The PC units have low-NO_x burners and selective catalytic reduction (SCR)

to reduce NO_x emissions to 0.07 lb/MBtu (~70 mg/Nm³). For bituminous coal and lignite, no extra mercury control measures are included because mercury is assumed to be largely captured in the FGD unit. For PRB subbituminous coal, carbon injection and a baghouse are added for mercury control.

Additional assumptions for the PC plant designs include:

- Coal analysis for mercury (Hg) and chlorine (Cl): Pittsburgh #8, Hg = 17 lb per trillion Btu (21 µg/Nm³), Cl = 1000 ppmw; PRB, Hg = 6 lb per trillion Btu (7.4 µg/Nm³), Cl = 100 ppmw
- Total Air to Boiler = 120% (20% excess air)
- Overfire Air to Boiler = 20–30%
- Combustion NO_x Emission (Downstream of Economizer):
 - Pittsburgh #8 = 0.30 lb/MBtu (370 mg/Nm³)
 - PRB = 0.30 lb/MBtu (220 mg/Nm³)

AFBC plants include a combination of in-bed and post-combustion dry FGD to yield 95% SO₂ removal for PRB coal and 98% removal for Texas lignite. Selective noncatalytic reduction for NO_x control is included in all CFB cases. Because CFB units are usually designed with a baghouse, no additional mercury capture steps are included.

IGCC plants are designed for >99% sulfur removal and with SCR in the HRSG section so that SO₂ emissions in the gas turbine exhaust are less than 2 ppmv (wet) and NO_x emissions are less than 3.5 ppmv (dry) at 15% oxygen in the gas turbine flue gas. A bed of pre-sulfided activated carbon is used to remove >90% of the mercury from the synthesis gas prior to sulfur removal. EPRI's more recent IGCC evaluations include the further specifications, per EPRI CoalFleet UDBS Environmental Design 2, in which total PM is limited to 37 lb/hr (17 kg/hr) per gas turbine and ammonia slip is limited to 5.0 ppmvd. CO is limited to 25 ppmvd.

All wastewater discharged following treatment must comply with U.S. EPA Effluent Guidelines and Standards.

For non-hazardous dry solid waste disposal, plant equipment and facilities are designed so that AFBC ash (containing spent sorbent), FGD solids, and sludge produced from water treatment are disposed of offsite in accordance with the non-hazardous waste disposal guidelines of the Resource Conservation and Recovery Act (RCRA). Appropriate temporary onsite storage facilities are specified in accordance with the guidelines.

The only byproduct considered as hazardous dry solid waste is spent carbon from mercury removal processes. Provision is made for its disposal in accordance with this classification.

For noise, in plant noise levels must not exceed 65 dBA during the day and 55 dBA at night.

Plant Book Life and Levelization Factor

EPRI assumes a 30-year book life for plant costs, and a 30-year levelization factor (carrying charge) is used as a multiplier applied to the TPC to yield a capital charge in \$/MWh. The factor takes into account owner's costs, allowance for funds used during construction (AFUDC), depreciation, and return on investment. For coal plants, EPRI assumes a 4-year construction

period based on recent experience and delivery times for major equipment. The appropriate levelization factor for any individual study will depend on the specifics of financing, return on investment requirement, payback period, etc.

The bases for EPRI's AFUDC factors are shown in Table A-2. AFUDC can add about 15% to the TPC. Modest owner's and startup costs can add an additional 5–7%, yielding a TCR about 20–23% greater than the TPC. Recent North American experience has shown that higher costs are also being encountered in the permitting, project definition, and project development phases.

Table A-2
TAG Financial Parameters

		<u>Current Dollars</u>		<u>Constant Dollars</u>	
	% of Total	Cost (%)	Return (%)	Cost (%)	Return (%)
Debt	60.0	4.0	2.4	2.0	1.2
Preferred Stock	0.0	0.0	0.0	-2.0	0.0
Common Stock	40.0	9.0	3.6	6.9	2.7
Total Annual Return			6.0		3.9
Inflation Rate (%)	2.0				
Income Tax Rate (%)	39.3				
Discount Rate	39.3				
After Tax			5.1		3.5
Before Tax			6.0		3.9

Finance charges may be higher for newer technologies such as IGCC or oxy-combustion, which do not have the extent of industry operating history as PC and CFB plants. Recent studies in which EPRI has participated have shown a range of an additional 20–40% of TPC when different organizations have evaluated the total capital requirement. This can make a large difference in the evaluated COE. However, in this report a TCR/TPC factor of 1.21 has been used for PC plants and 1.24 for IGCC plants. Note that “other” owner's costs can add another 10–15% to TPC. The “other” owner's costs can include items such as utility interconnections, site development, permitting, owner's engineer, etc.

U.S. Regional Labor Cost Indices

U.S. general construction labor rates by major region are shown in Table A-3. These construction labor rates represent average “all in” wages. These rates are calculated by dividing the total labor cost for a coal power project by the total craft labor hours expended. The all-in rates are based on:

- Subcontracted wage rates
- Union labor rates for cities throughout the United States
- Fringe benefits (vacation days, holidays, paid leave, health insurance, other employee benefits)

- Legalities (FICA, state and federal unemployment insurance, and worker's compensation)
- Subcontractor indirects (temporary facilities, overhead and supervision, construction equipment and small tools, and profit)

Exclusions include:

- Productivity differences between locations
- General Contractor's costs (including General Contractor's liability insurance)
- Home office costs
- Permanent plant costs

In some cases, labor costs among metropolitan areas and rural areas within a region can vary widely (by up to 100% in the West and Northeast). EPRI has compiled labor rates for 121 cities and 38 rural areas in the various U.S. regions. Metropolitan area labor rates have generally been used in EPRI's engineering-economic studies.

Table A-3
Construction Craft Labor and Productivity Factors, 2016 Factors

Region	Construction Craft Labor Wage Rate	Productivity	Composite
East/West Central (E/WC)	0.883	0.960	0.848
Northeast (NE)	1.000	1.000	1.000
South Central (SC)	0.647	0.960	0.621
Southeast (SE)	0.664	0.951	0.631
West (W)	0.891	0.995	0.887

The effect of productivity on relative total labor costs is shown in Table A-4.

Table A-4
Relative Labor Rates and Productivity, 2016 factors

Location	Pennsylvania	Wisconsin	Georgia	Texas	Wyoming
Relative Labor Rate	1.09	1	0.73	0.61	0.64
Relative Productivity	1.02	1	0.97	0.98	1.00
Relative Total Labor Cost	1.12	1	0.71	0.60	0.64

The regional costs for power plant reagents, water, other consumables, and coal ash disposal is shown in Table A-5.

Table A-5
Cost Data for Consumable Items by Region (in September 2016 dollars)

Consumables and Variable Cost Items ¹	Units	North-east	South-east	E/W Central	South Central	West
H₂O and Chemicals						
Raw Water[1]	\$/1000 gal	\$1.50	\$1.03	\$1.72	\$1.54	\$3.28
Ammonia (aqueous 29.4 wt%) [2]	\$/short ton	\$176	\$170	\$176	\$171	\$176
Sorbent (Delivered)						
Lime [3]	\$/ton	\$140	\$150	\$140	\$150	\$150
Limestone [4]	\$/ton	\$42	\$48	\$36	\$46	\$39
Dry Disposal						
Fly Ash [5]	\$/ton	\$43	\$13	\$14	\$4	\$2
Other						
Urea [6]	\$/ton	\$412	\$364	\$412	\$364	\$364
Activated Carbon [7]	\$/ton	\$1,320	\$1,320	\$1,320	\$1,320	\$1,320

Notes, Assumptions, and References

[1] Survey of water and sewer utilities for industrial service and raw and untreated water costs

[2] Cost developed based on dilution of anhydrous ammonia according to airgasspecialtyproducts.com/wp-content/uploads/2016/02/Appendix_D_-_Delivery_and_Storage_Information.pdf. Regional anhydrous ammonia costs based on import ammonia and published fertilizer costs.

[3] Assumed to be available in all regions, price based on USGS data, <http://minerals.usgs.gov/minerals/pubs/commodity/lime/mcs-2016-lime.pdf>, includes transportation by truck to site

[4] Assumed to be available in all regions, price based on pulverized agricultural grade material, includes transportation by truck to site

[5] Weight average sale price from plants reporting on 2014 EIA 923 forms

[6] Regional costs from Argus FMB Fertilizer report Issue 14-28 July 2014, transportation to site by truck included.

[7] From operating plant surveys, extrapolated to all regions with price set at average received from operating facilities in West Regions

Transportation cost assumptions

1. Transportation costs to the site are included.
2. Consumable prices from Alibaba include transportation by shipping container to San Francisco. Transportation cost to site by truck based on central location in regions
3. For large volume commodities transported across regions, rail is considered where indicated
4. Transportation costs developed through worldfreightrates.com.

B

LIST OF ACRONYMS AND ABBREVIATIONS

Acronym	Meaning	Acronym	Meaning
ACI	activated carbon injection	DCS	distributed digital control system
AEO	Annual Energy Outlook	DGF	depleted gas field
AEP	American Electric Power	DOE	U. S. Department of Energy
AFBC	atmospheric fluidized bed combustion	DOE NETL (or NETL)	U.S. Department of Energy's National Energy Technology Laboratory
AFUDC	allowance for funds used during construction	ECBM	enhanced coal bed methane
AGR	acid gas removal/recovery	EIA	U.S. Energy Information Administration
ASTM	American Society for Testing and Materials	EGR	exhaust gas recycle
ASU	air separation unit	EOR	enhanced oil recovery
B&W	Babcock & Wilcox	EPA	U.S. Environmental Protection Agency
BAU	Business as usual	EPAct 2005	Energy Policy Act of 2005
BFW	boiler feedwater	EPRI	Electric Power Research Institute
BOP	balance of plant	ESP	electrostatic precipitator
CAIR	Clean Air Interstate Rule	FBC	fluidized-bed combustion/combustor
CAMR	Clean Air Mercury Rule	FGD	flue gas desulfurization
CC	combined cycle	FW	Foster Wheeler
CCS	carbon or CO ₂ capture and storage	GDP	Gross Domestic Product
CCT	Clean Coal Technology	GHG	greenhouse gas
CFB	circulating fluidized bed combustion	GI	Gasification Island
CLAS	Chemical looping air separation	H ₂ S	hydrogen sulfide
CLC	Chemical looping combustion	Hg	mercury
CO	carbon monoxide	HHV	higher heating value
CO ₂	carbon dioxide	HP	high pressure
COE	cost of electricity	HRSG	heat recovery steam generator
COS	carbonyl sulfide	IEA	International Energy Agency
CURC	Coal Utilization Research Council	IEAGHG	International Energy Agency's Greenhouse Gas Programme

Acronym	Meaning	Acronym	Meaning
IGCC	integrated gasification combined cycle	PC	pulverized coal
IP	intermediate pressure	PCC	post-combustion capture of CO ₂
IPP	independent power producer	PCFB	pressurized circulating fluidized bed
ITM	ion transport membrane	PFBC	pressurized fluidized-bed combustion
LCOE	levelized cost of electricity	PM	particulate matter
LHV	lower heating value	RCRA	Resource Conservation and Recovery Act
LP	low pressure	RD&D	research, development, and demonstration
MDEA	methyldiethanolamine	SCPC	supercritical pulverized coal
MEA	monoethanolamine	SCR	selective catalytic reaction
NGCC	natural gas combined cycle	SNCR	selective non-catalytic reduction
N ₂ O	nitrous oxide	SO ₂	sulfur dioxide
NO _x	nitrogen oxides	SO _x	sulfur oxides
NZE	near-zero emissions	TAG	Technical Assessment Guide
NSPS	New Source Performance Standards	TCR	Total Capital Requirement
NSR	New Source Review	TPC	Total Plant Cost
NGCC	natural gas combined cycle	tpd	tons per day
O&M	operation and maintenance	UIC	Underground Injection Control
PAC	powdered activated carbon	USC	ultra-supercritical
PA FD fan	primary-air forced-draft fan	ZLD	zero liquid discharge wastewater treatment

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