COAL POWER

Smart Policies in Support of

CLEANER STRONGER ENERGY

COAL POWER
Smart Policies in Support of Cleaner, Stronger Energy

July 2020

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July 24, 2020

The Honorable Dan Brouillette
U.S. Secretary of Energy
U.S. Department of Energy
1000 Independence Ave., SW
Washington, DC 20585

Dear Mr. Secretary:

On behalf of the members of the National Coal Council (NCC), we are pleased to submit to you the report "COAL POWER: Smart Policies in Support of Cleaner, Stronger Energy." The report's primary focus is on assessing Federal and state policies and initiatives that would support the accelerated deployment of advanced technologies for coal-based power generation. In the report:

- We provide an overview of the current status of advanced coal technologies – including carbon capture, utilization and storage (CCUS), high efficiency-low emissions (HELE) and transformational technologies – with applications for both the existing coal fleet and new coal power plants.
- We detail Federal regulatory and legislative initiatives that would advance each of these technologies. Included are policies and initiatives to advance U.S. Department of Energy research and development programs, minimize costs and risks associated with technology deployment, reduce regulatory burdens and reform energy markets.
- We identify policies and initiatives in support of coal technology deployment that could be undertaken by state policymakers, state energy regulators and tribal entities, highlighting as well the value of regional and intra-state collaboration among state governments, universities, industry and non-profit organizations.
- We cite energy infrastructure initiatives that are critical for the deployment of CCUS, HELE and transformational technologies, including power generation/transmission, CO_2 pipelines and storage sites, and pilot and demonstration projects.

As you are aware, a growing number of states and utilities have established mid-century carbon reduction goals. Meeting these goals with affordable, reliable energy will require deployment of low-carbon technologies. Three critical objectives will need to be met over the next 20 years if we are to achieve these objectives:

- By 2030, retrofit a critical mass of existing coal power plants with carbon capture and efficiency enhancing technologies, more fully demonstrating the viability and maturity of these technologies and their availability through competitive bid from multiple vendors.

- By 2035, establish a growing network of CO_2 storage sites and pipelines approximately five time larger than what exists today.
- By 2040, a variety of new coal plant technologies will need to be commercially available, cost competitive and have a near-zero emissions profile.

These objectives are achievable if the U.S. is willing to pursue an aggressive agenda that acknowledges the urgency of the need and the economic-environmental implications of not meeting these goals, both in the U.S. and globally. Existing energy policies are insufficient to incentivize deployment of advanced coal generation technologies at scale and in a timely manner.

As detailed in NCC's COAL POWER report, there is an abundance of policy options and initiatives available that could support Department of Energy and private sector efforts to accelerate deployment of advanced coal generation technologies. An integrated suite of policy tools and incentives will allow the U.S. to lead the technology development required to enable use of coal with improved efficiency and a lower emissions profile.

As you have stated, coal is essential to this nation. The U.S. coal fleet plays an indispensable role in providing reliable and resilient electric power. Fuel-secure coal generation is a critical component of the U.S. power grid, which is strengthened through a diversity of electricity sources. The U.S. must maintain a readiness, both in technology and human resources, to utilize the most abundant resources under this nation's control to supply critical energy needs. A strong coal future will power not only our electric generation needs, but a renaissance in U.S. advanced manufacturing industries that are dependent on reliable, affordable energy.

Thank you for the opportunity to prepare this report. The Council stands ready to address any questions you may have regarding its findings and recommendations.

Sincerely,

Danny L. Gray

Danny Gray, National Coal Council Chair 2019-2020

Randall W. Atkins

Randall Atkins, National Coal Council Vice Chair 2019-2020

Janet Gellici

Janet Gellici, National Coal Council CEO

The Secretary of Energy
Washington, DC 20585

July 3, 2019

Mr. Danny Gray
Chairman
National Coal Council, Inc.
1101 Pennsylvania Avenue, NW, Suite 300
Washington, DC 20004

Dear Chairman Gray:

I am writing today to request the National Coal Council (NCC) develop a white paper assessing smart policies in support of advanced coal-fired power-generation technologies.

The white paper should focus on an industry perspective on the future of advanced coal technologies in the power sector, including carbon capture, utilization, and storage (CCUS); advanced energy systems to enhance energy efficiency and flexibility; high efficiency-low emissions technologies; small modular coal power plant technologies; and transformational technologies, such as supercritical CO_2 cycles and pressurized oxy-combustion.

The report would address how various regulatory and legislative policies could be employed to enhance and accelerate the deployment of these technologies. The prospective policies would include, but are not limited to:

- For CCUS: 45Q Federal Tax Incentive, USE IT Act, Master Limited Partnerships, Private Activity Bonds
- EPA's New Source Review Regulation
- Public Utility Regulatory Policies Act
- EPA Regulations on Coal Combustion Residuals and Effluent Limitation Guidelines
- Wholesale Electricity Markets
- State Initiatives and State Public Utility Commission Regulatory Oversight
- The newly-authorized U.S. International Development Finance Corporation
- Energy Infrastructure

Key questions to be addressed include:

- What regulatory and legislative initiatives could be advanced to help accelerate the deployment of coal-fired power-generation technologies?
- What coal-fired power-generation technologies would benefit from regulatory and legislative reforms?
- What energy infrastructure initiatives would support the deployment of advanced coal-fired power-generation technologies?

The white paper should be managed under the auspices of the Executive Advisory Board within the NCC. I ask that the white paper be completed by March 31, 2020.

Upon receiving this request and establishing your internal working groups, please advise me of your schedule for completing the white paper. The Department looks forward to working with you in this effort.

Sincerely,

Rick Perry

Rick Perry

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Executive Summary

" … we can't get rid of coal. It is essential to this nation."[i]
Dan Brouillette, U.S. Secretary of Energy

Energy Secretary Brouillette's words underscore the imperative the United States must address in order to ensure the continued availability of coal-based power generation. The nation's coal fleet plays an essential and indispensable role in providing reliable and resilient electric power. Fuel-secure coal generation is a critical component of the U.S. power grid, which is strengthened through a diversity of electricity sources.

Since 2010, however, more than 40% of the nation's coal fleet has retired or announced plans to do so. Today, coal provides about 24% of U.S. electricity. Further reductions in coal generation availability jeopardize grid reliability as well as the economic and price-stabilizing values of resource diversity.

The critical attributes of the coal fleet and its supply chain have been demonstrated in extreme weather events and acknowledged during the recent pandemic. The vast coal resources of the U.S. provide a reliable, resilient, flexible and affordable energy source, enhancing our nation's national, economic and energy security. The U.S. must maintain a readiness, both in technology and human resources, to utilize the most abundant resources under this nation's control to supply critical energy needs. A strong coal future will power not only our electric generation needs, but a renaissance in U.S. advanced manufacturing industries reliant on reliable, affordable energy.

***

The world was a different place in the fall of 2019 when the National Coal Council (NCC) launched a report in response to the Secretary of Energy's request for an assessment of smart policies in support of advanced coal generation technologies.

Prior to the global pandemic, U.S. policymakers were wrestling with how best to balance national, economic, energy and environmental security objectives. This balancing act has defied consensus on a defined pathway toward achieving these objectives, at times resulting in policies that are resource-biased, insufficient, counter-productive and/or unattainable.

Today, the unprecedented economic challenges we face as a result of the COVID-19 pandemic, elevate the urgency of initiating recovery efforts to restore the economic health of our nation's citizens and businesses. The pandemic's consequences have impressed upon us the urgent need to re-evaluate the reliability and resilience of critical sectors of our nation's economy, including our energy system and supply chain. This evaluation must include an assessment of the value of all our domestic energy resources, detailing the benefits and challenges each possess and acknowledging the merits of a diversified portfolio.

A growing number of states and utilities have established low-carbon or carbon reduction requirements and goals to be met by mid-century if not earlier. These goals are often being achieved through shuttering of existing coal power plants and through initiatives that effectively eliminate the option to deploy new coal generation, both of which have increased power prices, threatened electricity grid reliability and curtailed deployment of advanced generation technologies with beneficial environmental profiles.

Meeting environmental goals with affordable, reliable energy will require deployment of low- or decarbonized power systems. While other nations have made strides in deploying cost-effective low-carbon technologies, U.S. efforts have been hindered on many fronts.

- High capital costs and stringent regulations have disincentivized efficiency upgrades at existing plants and plans for new, efficient coal generation.
- Financial and insurance institutions have imposed policies restricting funding and services for coal projects.
- Competitive challenges from low-cost natural gas and natural gas-based generating facilities.
- Shareholder and investor Environmental, Societal and Governance (ESG) initiatives that enhance the perception of coal as an unwelcome fuel source.
- Lack of long-term policy certainty and consistency.
- Historically insufficient U.S. Department of Energy (DOE) research and development (R&D) funding for fossil energy technologies commensurate with the value of the associated greenhouse gas (GHG) reduction potential.
- Insufficient government support for large-scale pilot and demonstration projects to verify technology performance and reduce investment risks.
- Lack of energy infrastructure in support of advanced coal generation technologies, new sources of electricity and distribution networks.
- Insufficient public engagement of key stakeholders in the deployment of advanced coal generation technology projects.

Existing energy policies are insufficient to incentivize deployment of advanced coal generation technologies at scale and in time to achieve U.S. and global energy, economic and environmental objectives. There is an urgent need to undertake initiatives that will:

- Lower the cost of carbon capture, utilization and storage (CCUS) and advanced coal generation technologies through learning by doing at large-scale demonstration and commercial projects.
- Eliminate deployment bottlenecks created by lack of carbon dioxide (CO_2) pipelines and storage sites.
- Foster commercialization of next generation near-zero emission coal power plants that can compete on cost and environmental performance with low-carbon energy resources.

As detailed in this report, there is an abundance of policy options available that could enhance efforts to achieve these objectives, accelerating the deployment of advanced coal generation technologies. An integrated suite of policy tools and incentives – Federal, state, regional and tribal – are needed to ensure technology deployment on a cost-effective and timely basis. More than 25 such policies and initiatives have been identified herein that would provide a pathway toward cleaner, stronger energy, including:

- **Enhanced Support for U.S. Department of Energy Research and Development.** Most notably, support for technology projects that extend beyond basic research and the pursuit of niche market applications for small-scale modular coal power units.

- **Support for Federal Legislative and Regulatory Policies.** Most notably, support for policies that minimize investor cost and risk, reduce regulatory burdens and reform energy markets.

- **Support for State, Regional and Tribal Policies.** Most notably, support for policies that expand eligibility for and incentivize deployment of low-carbon energy technologies in compliance with state emissions reduction goals, and that recognize the value of coordinated state-regional-tribal initiatives.

- **Support for Energy Infrastructure Projects that Enable Deployment of Advanced Coal Generation Technologies.** Most notably, support for policies and initiatives facilitating deployment of demonstration and commercial-scale energy projects, characterization of geologic storage and CO_2 pipeline capacity.

Time is of the essence. In order to meet mid-century state and utility industry carbon reduction targets, three critical objectives will need to be met over the next 20 years. These objectives are achievable if we are willing to pursue an aggressive agenda that acknowledges the urgency of the need and the economic-environmental implications of not meeting these goals, both in the U.S. and globally.

- By 2030, retrofit a critical mass of existing coal power plants with carbon capture and efficiency enhancing technologies, more fully demonstrating the viability and maturity of these technologies and their availability through competitive bid from multiple vendors.
- By 2035, establish a growing network of CO_2 storage sites and pipelines approximately five times larger than what exists today. The network will need to expand over time to meet 2050 needs of the power and industrial sectors.
- By 2040, a variety of new coal plant technologies will need to be commercially available, cost competitive and have a near-zero emissions profile to meet power sector commitments to reduce/eliminate their CO_2 emissions by 2050.

The following initiatives are most urgently needed to achieve these objectives:[1]

Retrofit Existing Coal Fleet with Advanced Technology by 2030:

- Enhance Utilization of 45Q Tax Credits: 1) extend the “under construction” deadline to at least 2030; 2) extend the credit period from 12 years to 20 years; 3) expedite Class VI permits issued by EPA to states; 4) extend 48A tax credits to existing power plants; 5) pass Master Limited Partnership (MLP) and Private Activity Bond (PAB) legislation to complement 45Q; and 6) secure 100% relief from Base Erosion and Anti-Abuse Tax (BEAT) for CCUS technology through the duration of the 45Q tax credit.

- Government must take an active role in risk-sharing with and incentivizing private sector investors to support the deployment of advanced generation technologies. This could be accomplished through reforms to the DOE Loan Guarantee Program that would lower fees and lift restrictions for projects receiving Federal grants. Consideration might also be given to establishing an independent Federal development corporation or authority chartered to accelerate the deployment of clean energy technologies developed in the U.S.

[1] See Chapter 6 for a comprehensive list of NCC recommendations on smart policies in support of advanced coal generation technologies.

Deploy Infrastructure Supporting Advanced Technology by 2035:

- Include CCUS infrastructure – storage sites and pipelines – in post-pandemic economic revitalization initiatives.

- Support research, development and characterization of geologic storage at the level of $400 million per year for 10 years as recommended by the National Petroleum Council (NPC).

- Support passage of the USE IT Act (Utilizing Significant Emissions with Innovative Technology Act) to streamline permitting of storage projects and pipelines and the INVEST CO_2 Act (Investing in Energy Systems for the Transport of CO_2), providing low-interest Federal loans to finance extra CO_2 pipeline capacity.

Deploy Commercially Available, Cost Competitive, Near-zero Emissions Advanced Technology by 2040:

- Enhance Federal funding support for Front End Engineering Design (FEED) studies to reduce technology performance and cost risks.

- Make Federal funding available for demonstration and commercial-scale projects and make it available at enhanced levels ($300 million per year over 10 years as recommended in the 2018 CURC-EPRI Roadmap[ii]).

The U.S. Energy Information Administration (EIA) recently reported that global electricity consumption continues to increase faster than the world population, "… leading to an increase in the average amount of electricity consumed per person … [with] Nearly all of the increase [is] attributable to growing electricity consumption in developing countries outside the Organization for Economic Cooperation and Development (OECD)."[iii] Much of this growth in electricity will be fueled by coal and other carbon-based fuels.

The U.S. can lead the technology development required to enable use of coal with improved efficiency and lower emissions profiles. Investment in CCUS and advanced coal generation technology must increase to keep the U.S. relevant in this race for technology superiority, for the benefit of the U.S. and the world.

Chapter 1. Background

KEY FINDINGS

- **Advanced coal technologies for power generation are capable of delivering significant benefits for the United States in furtherance of national security, energy, economic and environmental policy objectives.**

- **U.S. energy policy fails to adequately incentivize advanced coal technology deployment, hindering investments in low-carbon energy.**

- **Financial and insurance institutions' policies restricting funding and services for coal projects are inhibiting the deployment of advanced generation technologies.**

- **The significant loss of coal-based generation capacity and lack of new thermal generation has and will continue to increase power prices and threaten electricity grid reliability.**

Coal is Necessary to Meet U.S. Energy Policy Objectives

Ongoing measures in the United States by policy makers and industry to accelerate advanced coal technology[2] deployment must be consistent with and further national, regional and state energy policy objectives in order to maximize the chances of their ultimate commercial success.[3] Based upon a mix of law, regulation and consumer preferences, the U.S. has been pursuing three energy policy objectives: (1) security of energy supply; (2) energy cost containment; and (3) environment and climate protection. These objectives, as reflected in Figure 1-1, are interrelated and may be sorted into three broad categories: (1) reliability and resilience; (2) affordability; and (3) environmental performance. Advanced coal technology has a unique role to play in supporting all three of these policy objectives.

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[2] Advanced coal technologies include, but are not limited to: (1) high-efficiency low-emission (HELE); (2) carbon capture utilization and storage (CCUS); (3) various transformational technologies including oxy-combustion, supercritical CO_2 and chemical looping; and (4) modularization (see Mills, S. "Modularization for Clean Coal", IEA CCC/299 Nov. 2019 available at https://www.iea-coal.org/modularisation-for-clean-coal.) Chapter 2 of this report provides an overview of these technologies.

[3] The National Coal Council has emphasized this point in several recent studies. *See, e.g.*, "Power Reset: Optimizing the Existing Coal Fleet to Ensure a Reliable and Resilient Grid" (Oct. 2018) (available at https://www.nationalcoalcouncil.org/studies/2018/NCC-Power-Reset-2018.pdf); "Leveling the Playing Field: Policy Parity for Carbon Capture and Storage Technologies" (Nov. 2015) (available at https://www.nationalcoalcouncil.org/studies/2015/Leveling-the-Playing-Field-for-Low-Carbon-Coal-Fall-2015.pdf). In the context of policies to advance modern coal generation technologies, this report reemphasizes and updates these prior NCC recommendations, many of which remain unfulfilled, in light of the continuing enactment of ever-more-stringent low-carbon emission requirements.

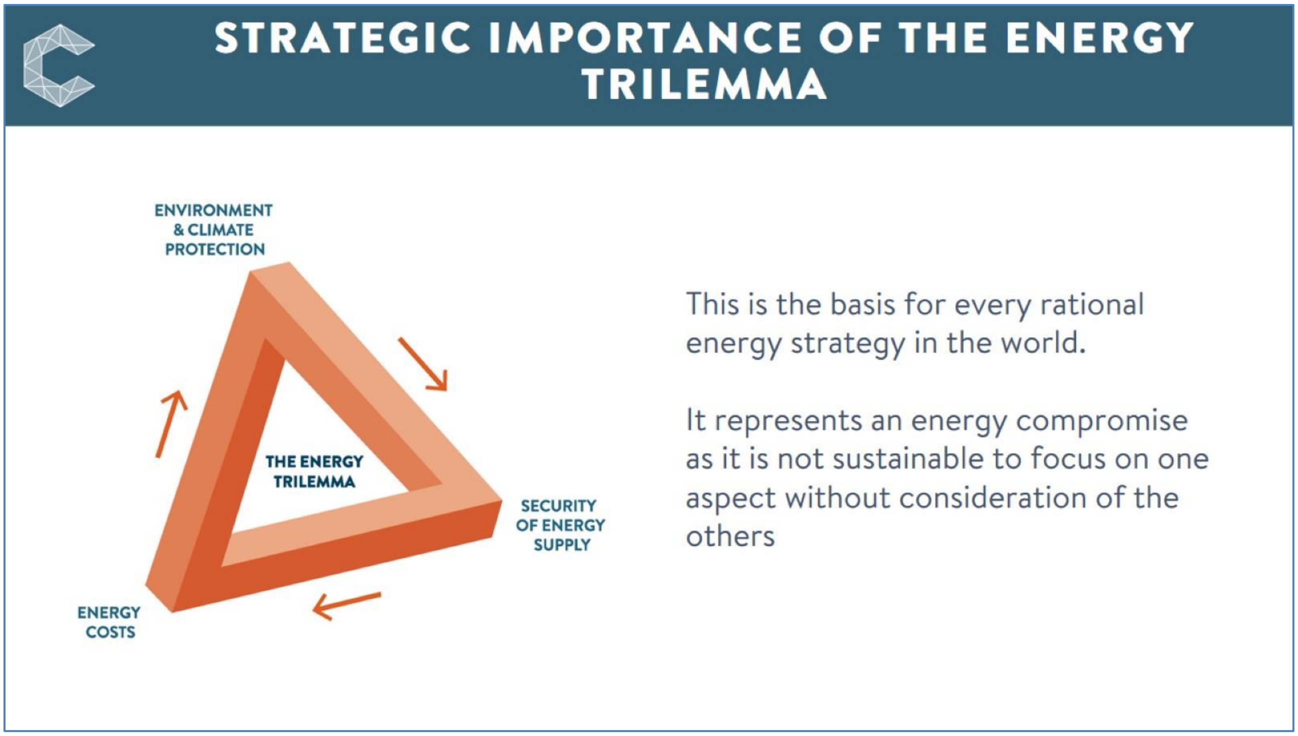

Figure 1-1: Interrelationship of Energy Policies
Source: International Energy Agency[iv]

Reliability and Resilience

The U.S. power system benefits from an electric grid that is not only reliable, but resilient. A reliable electric system minimizes the likelihood of disruptive electricity outages, while a resilient system is designed with the understanding that outages will occur, is prepared to deal with them, is able to restore service quickly and draws lessons from the experience to improve performance in the future. Reliability and resilience are both critical to maintaining the nation's power grid.

Power plants are expected to, and must, produce electricity reliably in accordance with the performance characteristics of the generation technology being utilized, and the manner in which they are owned and regulated. For example, Section 215 of the Federal Power Act (FPA) requires the Electric Reliability Organization (ERO) to develop mandatory, enforceable reliability standards that are subject to review and approval by the Federal Energy Regulatory Commission (FERC).[4] The North American Electric Reliability Corporation (NERC) is the ERO for the U.S.

[4] Section 215(a)(3) of the FPA defines "reliability standard" as a "requirement, approved by [FERC], to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities … and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system …." 16 U.S.C. § 824o(a)(3) (emphasis added). FERC-approved reliability standards become mandatory and enforceable in the U.S. on a date established in the specific order(s) approving the standards.

NERC reliability standards effectively apply to all participants in the U.S. electricity market – i.e., investor-owned utilities, independent power producers, municipals and cooperatives – and through the entire lifecycle of electricity generation, from modeling to resource and demand balancing.[v] NERC, in turn, has delegated its authority to monitor and enforce compliance to several regional entities. State public utility/service commissions regulate utilities to insure they provide safe, adequate and reliable service at just and reasonable rates pursuant to state law and regulation.[vi]

In recognition of reliability concerns related to, among other issues, the accelerating pace of retirement of coal power plants, in 2018 FERC initiated a new proceeding to "specifically evaluate the resilience of the bulk power system in the regions operated by regional transmission organizations (RTO) and independent system operators (ISO)."[vii] The proceeding remains open.

Coal provides dispatchable and reliable power. Dispatchable, "always on" power is critical to the grid, and to integration of intermittent sources. The concept of "reliability" generally encompasses the related and important concepts of "adequacy" and "security."[viii]

A typical definition of "adequacy" under state law in this context is "the ability of the electricity system to supply the aggregate electrical demand and energy requirements of the customers from various electric generation suppliers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."[ix] Under current policy, "adequacy" is reflected in various mechanisms, including but not limited to: (1) "capacity" markets administered by regional transmission organizations (RTO) or independent system operators (ISO); and (2) "planning reserve margins" as administered by the Electric Reliability Council of Texas (ERCOT).

Texas provides a case study in the perils of replacing baseload coal generation with wind.[x] Appendix D presents an "adequacy" case study on the value of coal and the cost of early retirements of coal power plants.

Similarly, a representative definition of "security" is the "ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements."[xi] With abundant domestic supplies and the ability to stockpile needed quantities onsite, coal provides fuel security that few other sources can match.

Affordability

Coal-based power plants participate in competitive energy markets where economic attributes such as fuel costs, operations and maintenance costs, and capital expenditure requirements determine dispatch order, shareholder returns and/or related critical factors. Many of those plants are also subject to regulation by state utility regulators that are intended to ensure that power companies deliver reliable power at the lowest cost to ratepayers.

The existing coal fleet continues to provide the U.S. with low-cost power. Applying levelized cost of electricity (LCOE) metrics, a recent report analyzed publicly available data to estimate the average LCOE from existing generation resources, such as coal power plants, as compared to the LCOE from new generation resources that might replace them.[xii] The report reached two conclusions:[5]

- First … that, on average, continuing to operate existing natural gas, coal, nuclear and hydroelectric resources is far less costly than building and operating new plants to replace them. Existing coal-fired power plants, for example, can generate electricity at an average LCOE of $41 per megawatt-hour… whereas we project the LCOE of a new CC [combined cycle] gas plant to be $50/MWh.
- Second … [w]ind and solar resources increase the LCOE of dispatchable resources they cannot replace by reducing their utilization rates without reducing their fixed costs, resulting in a levelized fixed cost increase. Our calculations estimate that the “imposed cost” of wind generation is about $24 per MWh (of wind generation) when we model the cost against new [combined cycle] gas generation it might displace, and the imposed cost of solar generation is about $21 per MWh (of solar generation) when we model the CC and combustion turbine (CT) gas generation it might displace. The average LCOEs from existing coal ($41), CC gas ($36), nuclear ($33) and hydro ($38) are less than half the cost of new wind resources ($90) or new PV [photovoltaic] solar resources ($88.7) with imposed costs included.[xiii]

Maintaining a diversified, dispatchable energy portfolio allows the U.S. to maintain low electricity rates which, in turn, enhance the nation’s competitiveness in international markets. Countries that predominantly rely upon fossil fuels for electricity enjoy lower power costs. Conversely, those countries with the highest residential and commercial electricity prices are typically imposing costs on consumers such as taxes to subsidize renewable energy and advance energy policies designed to eliminate baseload generation.

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[5] LCOE is one among a number of tools available for assessing the economic viability of various power generation fuel resources. As measured by LCOE, the economic viability of fuel resources may vary on a plant-by-plant and/or unit-by-unit basis.

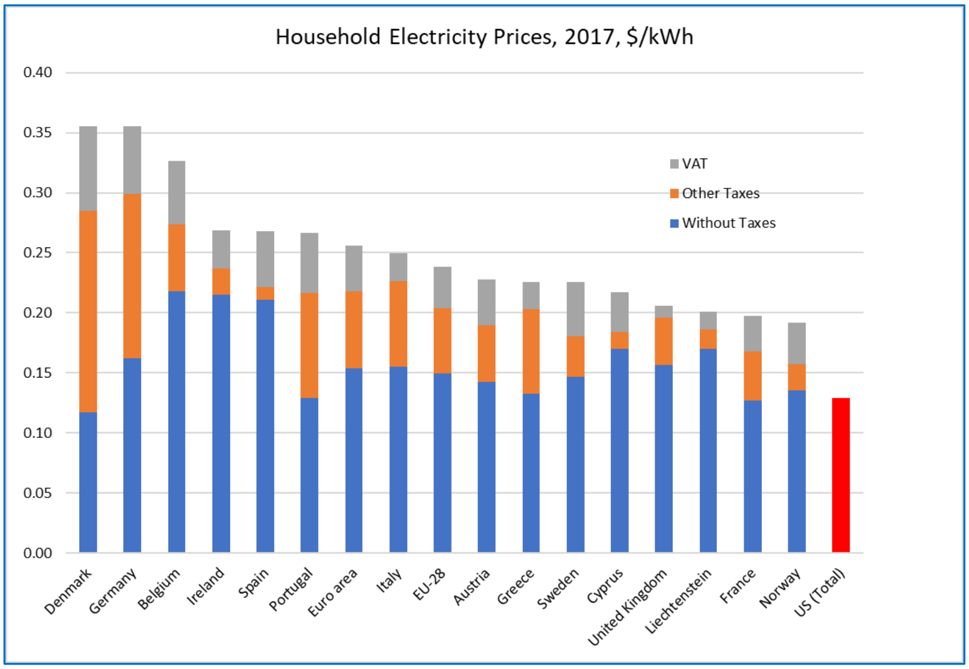

Figure 1-2: Residential Electricity Rates
Source: National Coal Council, *Power Reset*

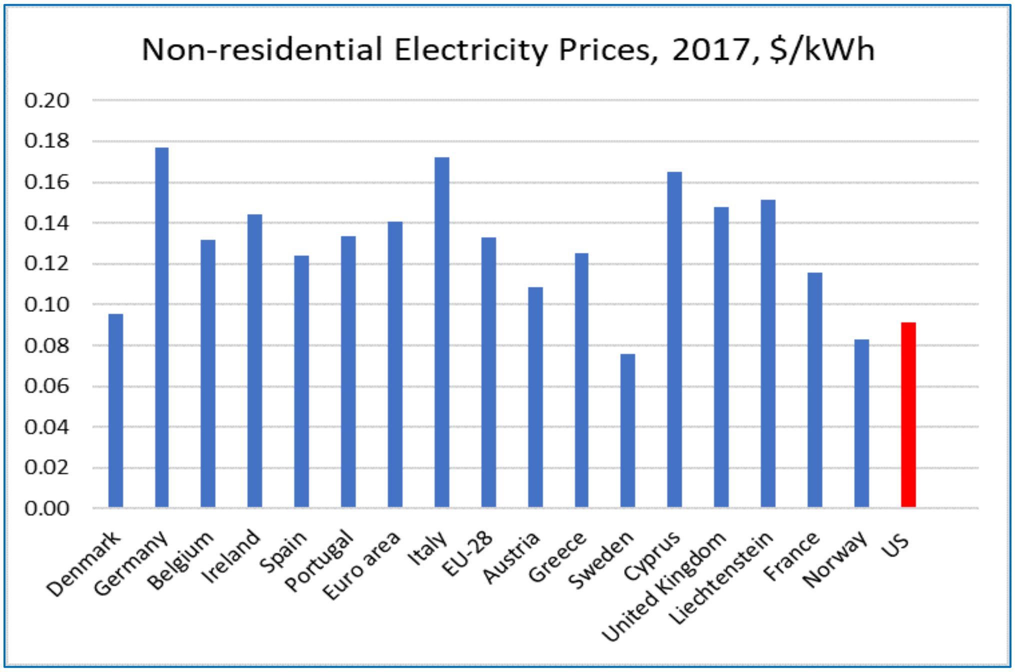

Figure 1-3: Non-residential Electricity Rates
Source: National Coal Council, *Power Reset*

Environmental Performance

All energy systems in the U.S. are subject to a mix of stringent federal, state and local environmental performance requirements that limit impacts to air, water and land, as well as exposures to humans and wildlife. To date, improvements in coal-based energy systems have ensured that they are capable of continuing to meet all applicable environmental requirements pertaining to: (1) atmospheric emissions of criteria and hazardous air pollutants; (2) water utilization and discharge; (3) management of solid and hazardous wastes; and (4) related matters.

In recent years, international, Federal and state environmental policies, coupled with commitments by power companies, have targeted reductions in emissions of greenhouse gases (GHG) including carbon dioxide (CO_2), which is produced when fossil fuels are combusted, and methane, a more potent GHG which may take the form of fugitive emissions during the production and transportation of fossil fuels.

Internationally, the Paris Agreement is expected to take effect in 2021. Nearly every developed and developing country is a party to the Agreement. Although in late 2019 the U.S. started the one-year withdrawal process, the Paris Agreement is anticipated to continue to influence U.S. utilities, states and investors, thereby pressuring U.S. coal in domestic and export energy markets even if the nation, in fact, withdraws and never becomes a party to the Agreement again.

If implemented in accordance with its objectives, the Paris Agreement would require the effective decarbonization of all energy systems by mid-century.[6] A 2018 report by the Intergovernmental Panel on Climate Change (IPCC) concluded that even more stringent international policies to reduce GHGs may have to be implemented as early as 2030, with Carbon Dioxide Removal technologies (CDRs[7]) such as Bioenergy with Carbon Capture & Storage (BECCS) perhaps needed to be deployed thereafter to maximize the odds that mid-century carbon reduction goals can be achieved.[xiv] Indeed, in order to achieve the Paris Agreement's ultimate aspiration of limiting the temperature increase to 1.5°C above pre-industrial levels with no or limited overshoot, the IPCC concluded that CDRs would be required, with amounts and relative contributions of the same varying across modeled pathways.[xv] In electricity generation in particular, shares of nuclear energy and fossil fuels with CCS are modeled to increase in most 1.5C pathways with no or limited overshoot.[xvi] IPCC pathways reflecting CCS, including BECCS, are shown in Figure 1-4.

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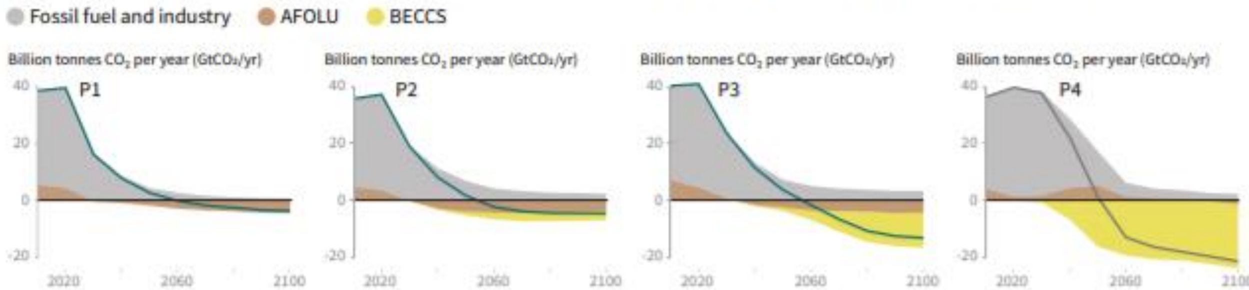
[6] The GHG management objective of the Paris Agreement is "[h]olding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels …." Paris Agreement, art. 2, para. 1(a) (available at https://unfccc.int/files/essential_background/convention/application/pdf/english_paris_agreement.pdf).

[7] CDRs are sometimes referred to as net or negative emission technologies (NETs).

Breakdown of contributions to global net CO_2 emissions in four illustrative model pathways



P1: A scenario in which social, business and technological innovations result in lower energy demand up to 2050 while living standards rise, especially in the global South. A downsized energy system enables rapid decarbonization of energy supply. Afforestation is the only CDR option considered; neither fossil fuels with CCS nor BECCS are used.

P2: A scenario with a broad focus on sustainability including energy intensity, human development, economic convergence and international cooperation, as well as shifts towards sustainable and healthy consumption patterns, low-carbon technology innovation, and well-managed land systems with limited societal acceptability for BECCS.

P3: A middle-of-the-road scenario in which societal as well as technological development follows historical patterns. Emissions reductions are mainly achieved by changing the way in which energy and products are produced, and to a lesser degree by reductions in demand.

P4: A resource- and energy-intensive scenario in which economic growth and globalization lead to widespread adoption of greenhouse-gas-intensive lifestyles, including high demand for transportation fuels and livestock products. Emissions reductions are mainly achieved through technological means, making strong use of CDR through the deployment of BECCS.

Global indicators	P1	P2	P3	P4	**Interquartile range**
Pathway classification	No or limited overshoot	No or limited overshoot	No or limited overshoot	Higher overshoot	No or limited overshoot
CO_2 emission change in 2030 (% rel to 2010)	-58	-47	-41	4	(-58,-40)
└ in 2050 (% rel to 2010)	-93	-95	-91	-97	(-107,-94)
Kyoto-GHG emissions in 2030 (% rel to 2010)*	-50	-49	-35	-2	(-51,-39)
└ in 2050 (% rel to 2010)	-82	-89	-78	-80	(-93,-81)
*Final energy demand** in 2030 (% rel to 2010)*	-15	-5	17	39	(-12,7)
└ in 2050 (% rel to 2010)	-32	2	21	44	(-11,22)
Renewable share in electricity in 2030 (%)	60	58	48	25	(47,65)
└ in 2050 (%)	77	81	63	70	(69,86)
Primary energy from coal in 2030 (% rel to 2010)	-78	-61	-75	-59	(-78, -59)
└ in 2050 (% rel to 2010)	-97	-77	-73	-97	(-95, -74)
from oil in 2030 (% rel to 2010)	-37	-13	-3	86	(-34,3)
└ in 2050 (% rel to 2010)	-87	-50	-81	-32	(-78,-31)
from gas in 2030 (% rel to 2010)	-25	-20	33	37	(-26,21)
└ in 2050 (% rel to 2010)	-74	-53	21	-48	(-56,6)
from nuclear in 2030 (% rel to 2010)	59	83	98	106	(44,102)
└ in 2050 (% rel to 2010)	150	98	501	468	(91,190)
from biomass in 2030 (% rel to 2010)	-11	0	36	-1	(29,80)
└ in 2050 (% rel to 2010)	-16	49	121	418	(123,261)
from non-biomass renewables in 2030 (% rel to 2010)	430	470	315	110	(245,436)
└ in 2050 (% rel to 2010)	833	1327	878	1137	(576,1299)
Cumulative CCS until 2100 ($GtCO_2$)	0	348	687	1218	(550,1017)
└ of which BECCS ($GtCO_2$)	0	151	414	1191	(364,662)
Land area of bioenergy crops in 2050 (million km^2)	0.2	0.9	2.8	7.2	(1.5,3.2)
Agricultural CH_4 emissions in 2030 (% rel to 2010)	-24	-48	1	14	(-30,-11)
in 2050 (% rel to 2010)	-33	-69	-23	2	(-47,-24)
Agricultural N_2O emissions in 2030 (% rel to 2010)	5	-26	15	3	(-21,3)
in 2050 (% rel to 2010)	6	-26	0	39	(-26,1)

NOTE: Indicators have been selected to show global trends identified by the Chapter 2 assessment. National and sectoral characteristics can differ substantially from the global trends shown above.

** Kyoto-gas emissions are based on IPCC Second Assessment Report GWP-100*
*** Changes in energy demand are associated with improvements in energy efficiency and behaviour change*

Figure 1-4. Characteristics of Four Illustrative Model Pathways to Global Warming of 1.5°C
Source: Intergovernmental Panel on Climate Change[xvii]

With perhaps one or two exceptions, commercial-scale BECCS projects are not in operation anywhere in the world. The existing coal fleet, retrofitted with BECCS, provides a potential way to remove CO_2 from the atmosphere while making use of coal plants.

In the U.S., the Environmental Protection Agency (EPA) has been regulating anthropogenic GHG emissions for the past decade, following the 2007 decision of the U.S. Supreme Court in *Massachusetts v. EPA*, which held that GHGs were "air pollutants" under the Federal Clean Air Act.[xviii] GHG emissions from both stationary (including fossil power plants) and mobile sources remain regulated under Federal law, although specific regulations remain in flux and subject to litigation.

A growing number of states, meanwhile, have established mid-century or earlier carbon neutral, zero carbon and/or net negative GHG emission requirements or goals. Although these requirements will be implemented in the decades ahead, it is generally understood that low- or decarbonized baseload power systems will be required for technical and/or economic reasons; stated another way, "while renewable supply resources are an important and growing part of the portfolio, 100% renewable power is not feasible today in the United States."[xix]

A 2018 study concluded that the costs of achieving zero-carbon goals are much higher where firm – i.e., baseload – resources are not allowed and only wind, solar and storage are permitted.[xx] As summarized in Figure 1-5, the study examined the role of firm energy in a northeast and southern electric system and found a dramatic cost difference between 100% zero-carbon electric systems (i.e., those that rely upon wind, solar and decarbonized fossil) and those that rely solely on wind and solar.

A growing number of investor-owned utilities, as well as rural cooperatives and municipal utilities, have made GHG reduction commitments.[xxi] Incentivized with effective low-carbon and related policy instruments, advanced coal technology can help power companies meet their GHG commitments and obligations under international, Federal and state requirements in the decades to come while continuing to deliver reliable, low-cost power. (See Appendix A for a list of utility decarbonization pledges.)

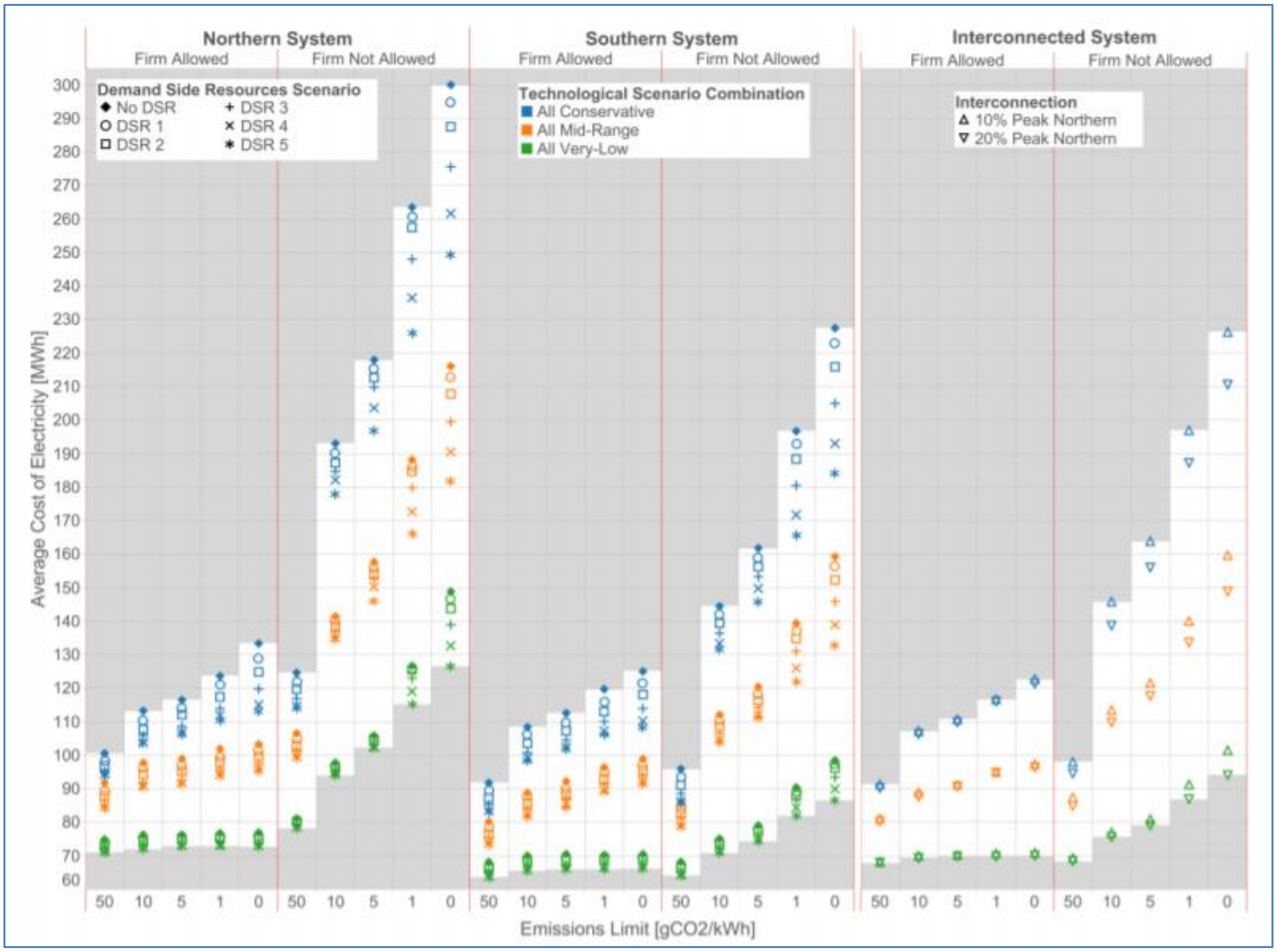


Figure 1-5: Costs of Achieving Zero-Carbon Grids Are Much Higher Where Firm Resources Are Not Allowed
Source: Nestor A. Sepulveda[xxii]

U.S. Energy Policy Fails to Adequately Incentivize Advanced Coal Technology, Hindering Needed Low-Carbon and Related Investments

The deployment of advanced coal generation technologies, both here in the U.S. and internationally, holds tremendous promise in further reducing GHG emissions, as reflected in Figure 1-6.

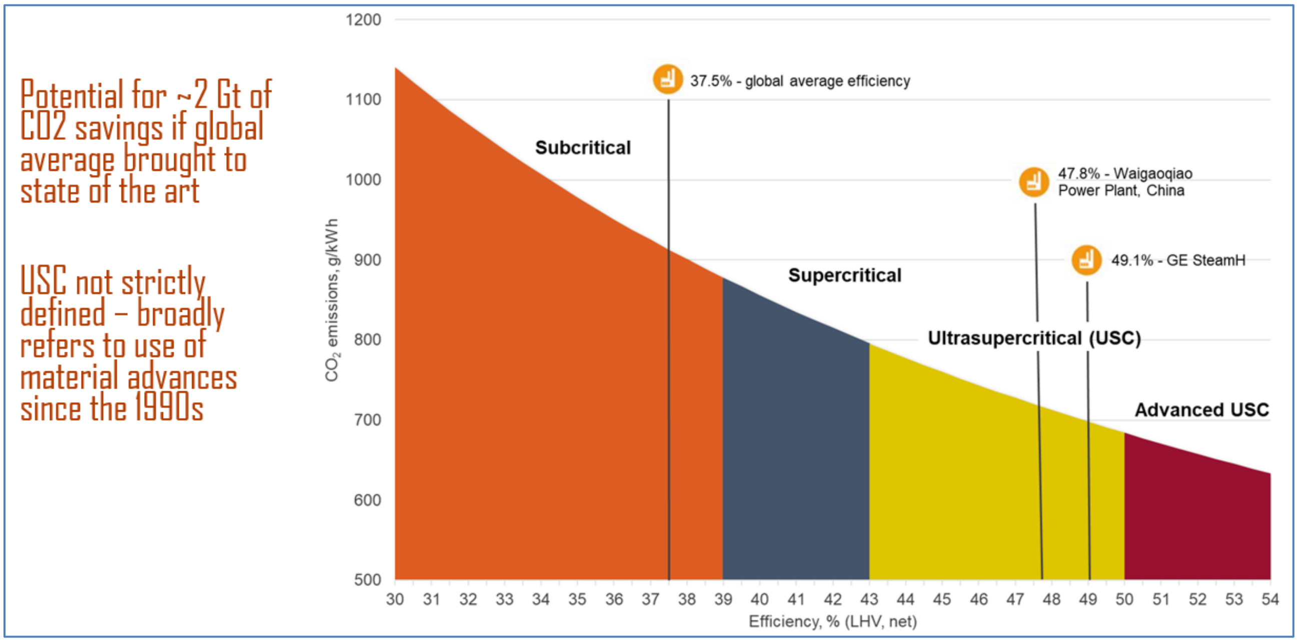


Figure 1-6: HELE Efficiency and CO_2 Emissions
Source: International Energy Agency[xxiii]

Unfortunately, the U.S. lags behind most of the rest of the world in deploying advanced coal generation technologies, as reflected in Figure 1-7.

REGION	IN OPERATION
	2018
Asia	224203
Europe	19208
Middle East	0
Eurasia	300
North America	665

Figure 1-7: Ultra-Supercritical Coal Capacity Worldwide (MW)
Source: International Energy Agency[xxiv]

There are several reasons why advanced coal technologies are not taking root in the U.S. One of the primary reasons is the absence of needed Federal policies and financial support to align low-carbon incentives with those given to renewables. According to the Joint Congressional Committee on Taxation, wind and solar power will have received $36.5 billion in Federal tax credits between 2016 and 2020; state subsidies in the form of renewable portfolio standards and related incentives add to that total. Preferential subsidies have negatively impacted the commercialization of coal generation technologies.

The NCC summarized the disparity between low-carbon and renewable technology Federal incentives in its “Leveling the Playing Field” report[xxv] which concluded:

> The EIA … shows the single largest recipient category of Federal energy subsidies is, by far, renewables. Confining the discussion to electricity subsidies, where renewables and coal compete (i.e., screening out subsidies for vehicle fuels), in 2013 renewables received more than 12 times the subsidies as received for coal - $13.227 billion for renewables, and just $1.085 billion for coal. EIA reported that renewables received 72% of total subsidies while coal received just 6%. Conversely, support for renewables (i.e., solar, wind, biomass, geothermal and hydro) has increased from 14.9% in 2007 vs. 72% in 2013. Support for wind alone increased from 10.7% (2007) to 37% (2013; support for solar alone increased from 0.2% (2007) to 27% (2013). Coal’s share of support has declined significantly from 12.7% in 2007 to 6% in 2013.

Another reason is a deterioration of the ability of Federal policymakers to adequately assess technologies and stay abreast of technological issues associated with the many energy transformations underway. The absence of an Office of Technology Assessment, which was shuttered in1995, impacts policymakers’ ability to make informed decisions.[xxvi]

The NCC has previously noted that Federal policy has “severely tilted the energy playing field” with the result being, for example, that existing “incentives for CCS are simply too small to bridge the gap between the cost and risk of promising, but immature, CCS technologies vis-à-vis other low-carbon technologies.”[xxvii] This report builds upon those prior efforts by updating needed CCS-related policies, assessing a broader suite of advanced coal technologies and energy infrastructure needs, and considering Federal and state policy initiatives.

Finally, it should be noted that financial and insurance institutions are also inhibiting the deployment of advanced generation technologies with policies designed to restrict funding and services for coal-based projects. Financial institutions have announced ‘coal exclusion’ policies that limit how they do business or if they will do business at all with companies that use coal.[xxviii] These policies are, in turn, contributing to insurance firms’ efforts to deny or restrict insurance coverage for coal producers and consumers.[xxix] An inability to secure affordable financing and insurance will curtail deployment of environmentally beneficial technologies.

The Role of Advanced Coal Technologies In Post-Pandemic Recovery

The COVID-19 pandemic has prompted a re-assessment of the reliability and resilience of critical sectors in our nation's economy, including U.S. energy systems. The COVID experience has reinforced the value of diversity of supply chains in these critical sectors and the need to shore up our domestic-based resources.

The economic downturn triggered by the pandemic presages the need for an economic stimulus initiative of epic proportions. The deployment of advanced coal generation and low-carbon technologies, along with associated infrastructure and advanced manufacturing facilities fueled by reliable, affordable electricity, can aid in our national economic recovery. These projects will drive economic growth and employment, creating and sustaining jobs, advancing clean energy industries and infrastructure, and making effective use of existing energy assets.

Innovative clean energy technologies must be included as critical components of our nation's future economic engine, based on high-value industries that support our energy and environmental objectives. The opportunity exists now to build on our previous leadership in basic energy research and development, and move forward with the deployment of demonstration and large-scale advanced technology projects.

The U.S. Department of Energy's existing loan authority for advance fossil energy and tribal energy projects could be expanded from the current $10.5 billion to support commercialization and deployment of existing technologies, as well as to jumpstart new projects and energy infrastructure with promising employment and economic growth potential. Modest reforms to DOE's loan program as detailed in this report could unleash authorized funds that have remained unexpended.

Additional Federal and state regulatory and legislative initiatives detailed herein could incentivize private sector engagement, reducing costs, risks and adversity in the interest of advancing our economic recovery.

Winston Churchill has been credited with saying, “Never let a good crisis go to waste.” The COVID crisis provides an opportunity for the U.S. to reinforce the reliability and resilience of our nation's energy systems. The opportunity to accelerate the deployment of the advanced coal generation technologies and energy infrastructure highlighted in this report should not be wasted.

Chapter 2. Coal Generation Technologies in Support of National Energy Objectives

KEY FINDINGS

- **Efficiency improvements are critical for reducing CO_2 emissions at coal generation power plants. Prioritizing retrofit applications of efficiency-enhancing and carbon capture, utilization and storage technologies would benefit near-term reductions of CO_2.**

- **There is significantly limited deployment of advanced, highly efficient coal generation technologies in the United States today. Stringent regulations and low-cost natural gas have hindered the development and installation of these low-carbon technologies.**

- **The U.S. lags behind other nations in the cost-effective deployment of high efficiency, low emissions technologies. U.S. HELE technology deployment is hindered by higher capital costs and regulatory burdens.**

- **The U.S. Department of Energy has recently secured modest increases in research and development funding for fossil energy technologies. However, in order to realize a low-carbon future derived from reliable generation sources, a greater investment in these technologies is needed along with enhanced support for demonstration and large-scale pilot projects. Efforts must be undertaken to ensure that demonstration projects are managed by personnel experienced in the management of large-scale projects.**

Executive Overview of Coal Generation Technologies

As the electricity sector in the United States evolves, technological innovation will be crucial to meeting the goals of ensuring energy security and affordability, while minimizing environmental impacts. Most of the generation capacity installed in the U.S. today consists of conventional steam boilers (subcritical) and higher-efficiency supercritical steam boilers. Supercritical steam boilers achieve higher efficiencies than conventional boilers by operating the steam cycle at higher pressure. Ultra-supercritical (USC) steam boilers and gasification systems represent advanced, highly efficient technologies that are commercially available.
There has, however, been very limited deployment of these technologies in the U.S. today. Figure 2-1 shows the currently installed generation capacity of the existing coal

fleet (2018 data) by technology type.[8] Limited installation of advanced technologies is primarily due to a recent lack of interest in installing new coal capacity because of stringent regulations and low-cost natural gas. Fortunately, considerable technology exists, and more is under development, that can be retrofitted to the existing fleet of coal power plants to improve efficiency and comply with future environmental regulations. Additionally, novel advanced power generation systems are under development that will have high efficiency, low emissions, and the ability to ramp up and down quickly to meet current electric grid demands.

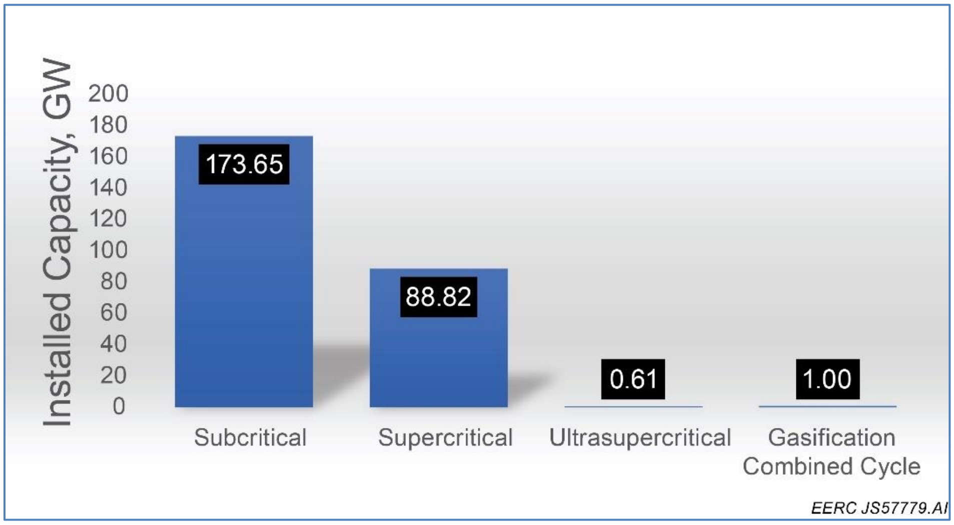


Figure 2-1: Installed generation capacity in the United States
Source: U.S. Energy Information Administration 2018
Note: Includes electric utility generation as well as heat and power for industrial users.

Given the rapidly evolving U.S. grid, a variety of technologies and approaches will likely be required. One of many programs under development by the U.S. Department of Energy (DOE) is Coal FIRST[9]. This program aims to provide a new coal-derived electricity "product" that would have minimal environmental footprint, reduce up-front costs, and be more responsive and flexible. The Coal FIRST parameters are as follows:

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[8] EIA does not include the Longview Power Plant in the ultra-supercritical category. Longview describes the plant as advanced supercritical with a 43%-50% lower heating value (LHV) efficiency range. Its performance is similar to the Turk Power Plant, the ultra-supercritical plant included in the census.
[9] The U.S. Department of Energy Office of Fossil Energy's Coal FIRST program is a research and development initiative to advance first-of-a-kind coal generation technologies to provide secure, stable, and reliable power. https://www.energy.gov/sites/prod/files/2019/10/f67/Coal%20FIRST%20-%20Transformative%20R%26D%20Program_0.pdf

- Flexible: Quick to adjust to the changing needs of the grid.
- Innovative: Cleaner, more agile and more efficient through cutting-edge technology.
- Resilient: Able to recover rapidly from severe weather and other events.
- Small: Compact relative to today's conventional utility-scale coal plants.
- Transformative: Fundamentally redesigned to change how coal technologies are manufactured.

While the Coal FIRST program is in its infancy and is focused on new power plants, many of the essential traits can be incorporated into the existing fleet and are found in advanced technologies under development.

Table 2-1 summarizes advanced energy technologies and indicates their ability to meet national energy objectives. Advanced coal technologies that are currently deployed include USC steam cycles, integrated gasification combined cycle (IGCC) systems and selective post-combustion CCUS[10] technologies. Advanced coal technologies that are in various stages of development include advanced ultra-supercritical (AUSC) steam cycles; supercritical CO_2 cycles (sCO_2); additional post-combustion carbon capture, utilization, and storage (CCUS); oxygen-fired combustion (oxy-combustion); pressurized oxy-combustion; pressurized fluid bed combustion (PFBC); and chemical looping.

[10] Deployment of commercial-scale CCUS post-combustion technologies has been limited; numerous post-combustion CCUS technologies are still under development. Nothing included in this NCC report should be construed to support a conclusion of "adequately demonstrated" for Clean Air Act (CAA) purposes.

Technology	Retrofit	New Plants	Flexible	Innovative	Resilient	Small	Trans-formational
Currently Deployed Technology							
USC	X	X	X	X	X	X	X
IGCC	X	X	X	X	X	X	X
Post-combustion CCUS	X	X	X	X	X	X	X
Technologies Under Development							
AUSC	X	X	X	X	X	X	X
sCO_2	X	X	X	X	X	X	X
Post-combustion CCUS	X	X	X	X	X	X	X
Oxy-Combustion	X	X	X	X	X	X	X
Pressurized Oxy-Combustion	X	X	X	X	X	X	X
PFBC	X	X	X	X	X	X	X
Chemical Looping	X	X	X	X	X	X	X

Table 2-1: Matrix of Technologies as Related to Coal FIRST Energy Objectives Red indicates not likely applicable, yellow indicates potentially applicable, green indicates highly applicable.

Source: Applicability rankings developed by Josh Stanislowski, EERC/University of North Dakota and Holly Krutka, SER/University of Wyoming

The following sections describe the existing coal fleet and then highlight select state-of-the-art technologies first from a retrofit perspective and then for new construction. Utilities have expressed a strong desire to have technology options available that enable continued operation of the existing fleet and those that represent the next generation of coal-based technologies.

Existing Coal Fleet

State of the Existing Fleet

The National Coal Council (NCC) provided an update on the state of the existing coal power generation fleet in its October 2018 “Power Reset” report.[xxx] At that time, NCC reported that the U.S. Energy Information Administration’s (EIA) 2018 Annual Energy Outlook projected U.S. coal-based electric generating capacity to decrease by approximately 65 gigawatts (GW) between 2017 and 2030, then remain relatively stable at about 190 GW through 2050.[xxxi] A year later in its Annual Energy Outlook (AEO 2019), EIA projected a decrease of 86 GW of coal capacity between 2018 and 2035 before leveling off at 155 GW by 2050.[xxxii] In January 2020, in its AEO 2020, EIA projected coal generation capacity would decrease 109 GW between 2019 and 2025, leveling off near 127 GW by 2050.[xxxiii]

In its Power Reset report, NCC noted that numerous private sector forecasts anticipate even greater declines in coal generation than those projected by EIA.[xxxiv] The broad consensus, as represented by the projections from EIA's Annual Energy Outlook in Figure 2-2 and NCC's assessment in Figure 2-3, is that coal's role as a fuel source for electricity generation is expected to continue to dwindle significantly because of a confluence of factors, including economics, unit age, unit size, impacts of load cycling, staffing, existing and future regulations, and societal pressures.

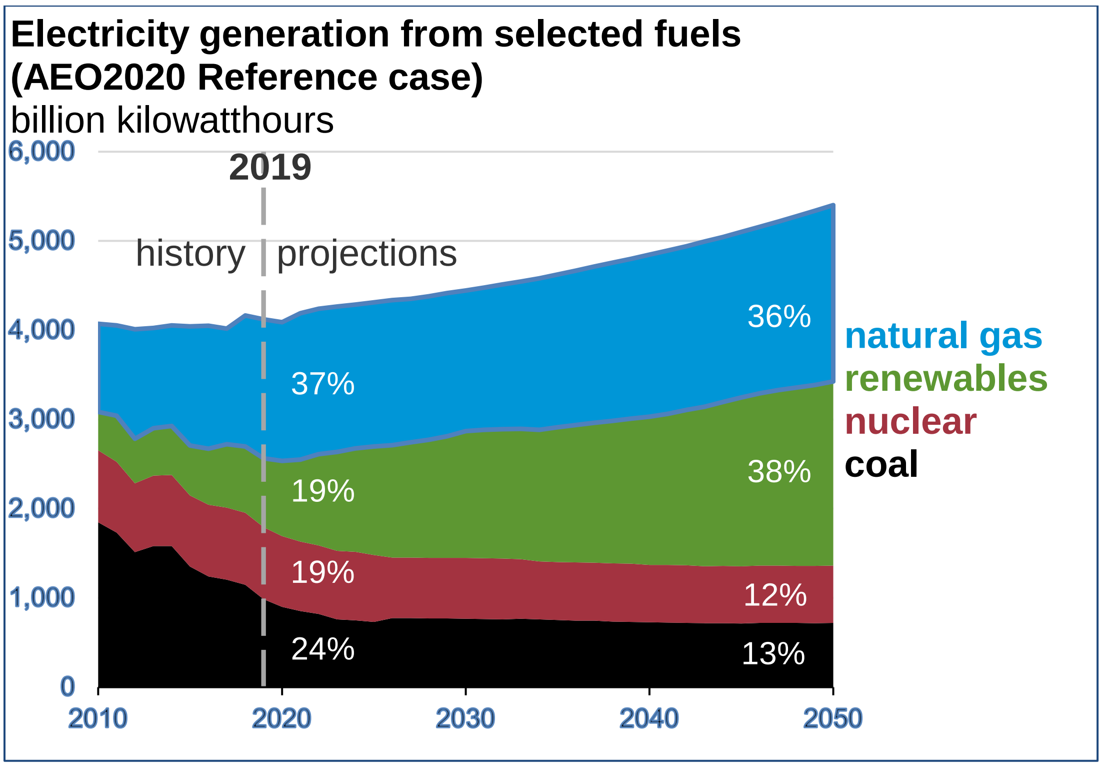

Figure 2-2: Electricity generation from selected fuels
Source: U.S. Energy Information Administration, AEO 2020

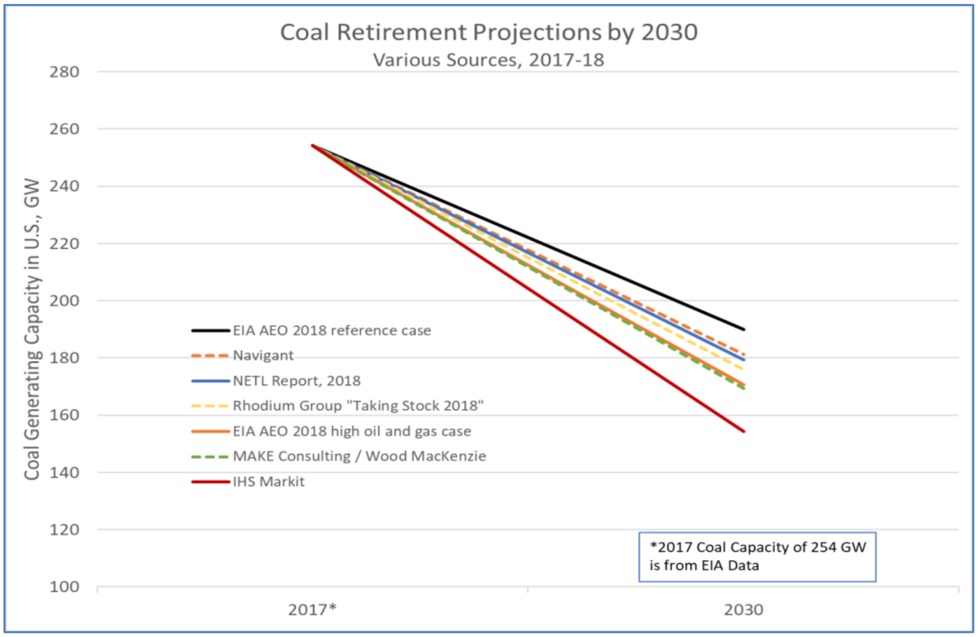

Figure 2-3: Coal generation retirements projected through 2030[xxxv]
Source: National Coal Council, Power Reset Report

In June 2019, America's Power noted that since 2010, 644 coal generating units in 43 states totaling nearly 125,700 megawatts (MW) of electric generating capacity had retired or announced plans to retire. At that time, retirements were approaching 40% of the coal fleet once operational in 2010.[11] Through the end of 2018, approximately 82,200 MW of coal generating capacity had retired. In 2019 and 2020, an additional 16,600 MW was expected to retire, bringing total retirements to 98,800 MW by the end of 2020.[xxxvi]

In its assessment, Energy Ventures Analysis (EVA) projects a continued increase in coal plant retirements over the next four years. Nearly 32 GW of coal generation is expected to retire between 2020 and 2023 (Figure 2-4).

It is important to note that nationwide figures for coal-based power mask a significant amount of variation in the generation mix at the state and regional levels. Those states and regions more heavily dependent on coal-based generation will incur more significant impacts as a result of coal plant retirements. The independent system operator (ISO)/regional transmission organization (RTO)[12] regions in the U.S. with the most retirements from 2010 to 2020 are PJM (36,200 MW), MISO (14,800 MW), ERCOT (5800 MW), and SPP (5000 MW).

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[11] According to EIA, the U.S. coal fleet in 2010 comprised 1396 electric generating units located at 580 power plants for a total electric generating capacity of approximately 317,000 MW.
[12] There are seven ISOs/RTOs in the U.S.: California ISO (CAISO), Texas ISO (ERCOT), Midcontinent ISO (MISO), ISO New England (ISONE), New York ISO (NYISO), PJM Interconnection (PJM) and Southwest Power Pool (SPP).

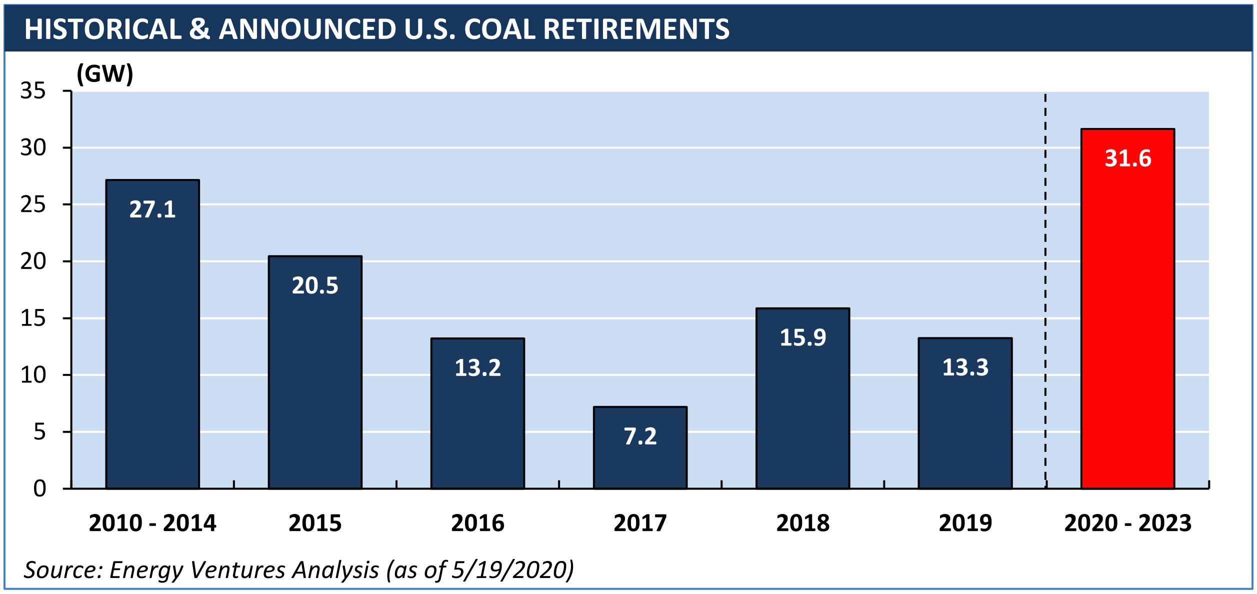

Figure 2-4: Annual coal plant retirements 2010–2023 (GW)
Source: Energy Ventures Analysis

Overview of Retrofitting and Repowering

Generally speaking, electric power utilities have only made investments in coal-based power plants when updates were needed to comply with environmental regulations. The low cost of natural gas and preferential tax credits for other energy sources have made it exceedingly difficult for coal power plants to compete in today's market. The measures adopted include plant retrofits/upgrades and repowering, either done to increase plant reliability and output or efficiency while reducing plant emissions (including CO_2) and maintenance costs.

Definition of Retrofitting and Repowering. Retrofitting/upgrades include making changes to the existing coal fleet via adoption of newer technologies/features with modest cost and a reasonable cost/benefit ratio. Retrofits/upgrades are very site specific, depending on plant age and dispatchability needs. Examples of retrofits/upgrades include:

- Upgrading the plant control system – including real time performance models and the use of AI (artificial intelligence) features.
- Upgrading emissions control equipment.
- Upgrading steam path (turbine blading).
- Replacing boiler components/systems.
- Adding variable-speed drives for fans/pumps or variable pitch axial flow fans.
- Balance-of-plant upgrades.
- Upgrading to mitigate plant-cycling impacts and improve operational flexibility.

Repowering includes modifying all or a part of an older coal-fired power plant with new components (or fuel) to significantly increase plant output and/or efficiency, thereby significantly decreasing plant emissions (including CO_2) and water consumption. This often entails a major investment, with a plant outage extending from 15 to 30 months. Examples of repowering include the following:

- Full site repowering
- Gas repowering
- Hybrid repowering (e.g., adding a solar thermal system)
- AUSC repowering

AUSC repowering would have higher efficiency (approaching 45% to 47% on a higher heating value [HHV] basis) than any existing coal power plant. This can lead to 25%–30% reduction in CO_2 emissions. The first such plant would likely be relatively expensive.

A recent DOE National Energy Technology Laboratory (NETL) repowering study[xxxvii] assumed that a power plant boiler, turbine and other steam cycle components could be replaced while continuing to use the existing air pollution control equipment and electricity-generating and transmission infrastructure. NETL found that repowering would cost about half that of building a new coal-based power plant at a greenfield (i.e., new-build) site and that there were no technical limitations to repowering. However, there are likely regulatory hurdles, such as triggering New Source Review (NSR). If triggered, NSR would require that the plant be treated as new with respect to environmental regulations including New Source Performance Standards (NSPS). Regulatory uncertainties, especially in regard to NSR, have limited the ability of plant owners to aggressively pursue energy efficiency improvement opportunities.[13]

[13] As noted in the policy section of this chapter, NSR reform had been proposed as part of the EPA's Affordable Clean Energy plan but was not included in the final rule.

New Source Review Constraints

The inhibiting impacts of NSR regulations on coal power plant efficiency improvements were first addressed by NCC in its 2001 report, “Increasing Electricity Availability from Coal-Fired Generation in the Near-Term.”[xxxviii] The report identified approximately 40,000 MW of increased electrical production capability that could potentially be produced from then-existing coal power plants. The increased electricity supply would be possible through the installation of standard improvements and deployment of clean coal technologies, with the dual benefit of enhanced efficiency and reduced emissions. As noted in the report, the opportunity to realize these benefits was being diminished by a change in how EPA had begun interpreting NSR requirements since 1998.

NCC recommended that DOE initiate and lead a dialogue with EPA with the goal of returning to the traditional pre-1998 interpretation of NSR. This recommendation has been reiterated in every NCC report related to coal generation technology deployment since May 2001.[14] More recently, in its May 2014 report to the Secretary of Energy on the value of our nation’s existing coal fleet, NCC highlighted the challenges for power plant owners considering making investments in efficiency improvements,[xxxix] noting that EPA’s revised interpretation of NSR could lead to a “major modification” designation, subjecting the existing plant to NSR permitting requirements, that would entail additional expenditures and delays that would prove too onerous for the plant owner to pursue. The curtailed interest by power plant operators in pursuing efficiency improvements was also noted to have “all but eliminated RD&D (research, development, and deployment) that would more than marginally innovate the fleet,” thus negating the opportunity to reduce coal plant emissions. The May 2014 report highlighted EPA’s own acknowledgment of the conundrum posed by the more recent enforcement of NSR.

In its most recent report for the Secretary of Energy on coal generation technologies (Power Reset, 2018), NCC noted that NSR requirements add burdens and barriers to improving efficiencies that could make coal plants more competitive.[xl] In that report, NCC supports regulatory initiatives at EPA and legislative proposals in Congress to eliminate regulatory uncertainty and reduce litigation risks for utilities seeking to implement energy efficiency measures at their coal plants.

[14] NCC has consistently included recommendations regarding NSR in its reports (National Coal Council, 2003, 2004, 2006, 2007, 2008, 2011, 2014, 2015a, 2015b, 2018).

Retrofit Efficiency Upgrades and High Efficiency, Low Emission (HELE) Technologies

New technologies, such as high efficiency-low emissions (HELE) technologies, offer opportunities for dramatically improved efficiency and lower CO_2 emissions versus subcritical coal plants. For a coal plant to qualify as HELE, it needs to be in the category of a supercritical technology, as shown in Figure 2-5. For existing coal plants, the degree to which efficiency improvements can be realized is largely a function of the level of capital expenditures made either to refurbish or in some cases upgrade existing plant systems. Without such substantial capital investment, improvements on the order of 1% to 2% can often be realized by tighter operational control of the plants and use of performance optimization tools/processes and plant tuning. These types of improvements generally would not move an existing plant into the HELE category. Substantially higher improvements, on the order of 4% to 6% in efficiency gains, can generally be achieved if business-justified (acceptable cost/benefit ratios) capital investment is made.

HELE Power Plant Definition

Category	Efficiency Rate	CO_2 Intensity	Coal Consumption	Steam Temperature
Advanced ultra-supercritical	More than 45%	670-740 g CO_2/ kWh	290-320 g/kWh	700ºC+
Ultra-supercritical	Up to 45%	740-800 g CO_2/ kWh	320-340 g/kWh	600ºC+
Supercritical	Up to 42%	800-880 g CO_2/ kWh	340-380 g/kWh	Approx. 550ºC-600ºC
Subcritical	Up to 38%	≥880 g CO_2/ kWh	≥380 g/kWh	<550ºC

HELE Plants

Figure 2-5: HELE Power Plant Definition[15]
Source: National Mining Association/Wood Mackenzie, 2019

[15]Higher Efficiency = Lower Heating Value; Coal Consumption = the type and quality of coal will affect overall efficiency and operation costs.

In its 2018 “Power Reset” report, the NCC identified numerous plant efficiency improvements and their associated cost/benefit value (Figure 2-6).

Project Name	Capital Cost	B/C Ratio	B/C Ratio Rank
Circulating Water Pump Refurbishment	Low	High	1
Sootblowing Steam Source	Low	High	2
Coal Mill Inerting Source	Low	High	3
Add Condensate Polishing	Medium	High	4
HP/ IP/ LPTurbine Upgrade	High	High	5
Coal Mills Replacement	High	High	6
Boiler Feed Pump Refurbishment	Low	Moderate	7
Helper Cooling Tower Replacement & Pumps	Medium	Moderate	8
Replace Flame Scanners	Low	Moderate	9
VFD's for Forced Draft Fans	Medium	Low	11
Air Heater Overhaul	Medium	Low	10
Replace Air Preheat Coils	Low	Low	12
VFD's for Induced Draft Fans	Medium	Low	13
Alternate Air Heater Overhaul	Medium	Low	14
Alternate Air Preheat Coils Modification	Medium	Low	15

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Figure 2-6: Coal Power Plant Efficiency Audit Results
Source: National Coal Council, 2018

More recently, EPA’s Affordable Clean Energy Rule (ACE) created a list of “candidate technologies” to achieve power plant efficiency or heat rate improvements (HRI) that could be achieved inside-the-fence at power plants. The EPA-approved technologies include intelligent sootblowers, boiler feed pump upgrades, air heater and duct leakage control, variable frequency drives, blade path upgrade, economizer redesign/replacement, and improved operations and maintenance (O&M) practices. The respective HRI potentials shown below are based on an EPA-commissioned 2009 Sargent & Lundy[xli] study.

HRI Measure	< 200 MW Min	< 200 MW Max	200 - 500 MW Min	200 - 500 MW Max	>500 MW Min	>500 MW Max
Neural Network/Intelligent	0.5	1.4	0.3	1.0	0.3	0.9
Sootblowers						
Boiler Feed Pumps	0.2	0.5	0.2	0.5	0.2	0.5
Air Heater & Duct Leakage Control	0.1	0.4	0.1	0.4	0.1	0.4
Variable Frequency Drives	0.2	0.9	0.2	1.0	0.2	1.0
Blade Path Upgrade (Steam Turbine)	0.9	2.7	1.0	2.9	1.0	2.9
Redesign/Replace Economizer	0.5	0.9	0.5	1.0	0.5	1.0
Improved O&M Practices	Can range from 0 to > 2.0% depending on the unit's historical O&M practices					

Figure 2-7: Range of HRI Potential from EPA-Approved Technologies Cited in ACE Rule (% of heat rate improvement)
Source: Sargent & Lundy

Although not required, EPA allows states to consider natural gas co-firing on a case-by-case basis as an appropriate and approvable technology to reduce CO_2 emissions. ACE does allow plant owners to average CO_2 emission rates of multiple ACE-affected units located at the same site or consider biomass co-firing as an appropriate HRI. States are required to create emission rates for plants that have already taken advantage of all HRIs listed above at business-as-usual levels.

Carbon Capture Retrofits

CCUS from existing fossil fuel power plants and industrial processes is being pursued by many governmental, commercial and research entities in the U.S. and abroad to address global climate change concerns. CCUS largely leaves the existing plant intact and adds technology to the back end of the system to effectively separate the CO_2 from the other flue gas constituents.

CO_2 is produced in combination with other gases during power generation and industrial processes. The CCUS process involves the capture, transport and utilization and/or storage of CO_2. CO_2 capture involves the separation of the CO_2 from the other gases. This separation can be accomplished using many different technologies, the most common of which is amine absorption. Once the CO_2 is separated, it is typically compressed or refrigerated so that it behaves like a liquid, making it ready for transport and storage. The captured CO_2 is transported from the capture location to a different location where it can be used or stored. This transport is typically accomplished using pipelines operating at a pressure that enables the CO_2 to remain compressed into a dense liquid phase. This compressed CO_2 can also be transported by rail, truck, ship and barge. The captured CO_2 is stored, used in enhanced oil recovery (EOR), or used in the production of other products, such as building materials and carbon fiber.

Combined Heat and Power (CHP)

CHP, also known as cogeneration, has been in use in the U.S. for more than 100 years. CHP is the simultaneous generation of useful heat and power from a single fuel or energy source at or close to the point of use. CHP captures energy that would normally be lost in power generation and uses it to provide heating and cooling, or process energy, making CHP systems much more efficient. A highly efficient CHP plant offers one template for keeping coal generation viable.

According to DOE, CHP currently accounts for about 8% of total U.S. power generation.[xlii] Although not significantly lower than the global average of about 10%, the Energy Information Administration (EIA) says CHP has the potential to command a 15% to 20% share of total electricity generation in the U.S. by 2030. Despite a national goal of adding 40 GW of CHP capacity by 2020, very little progress toward that goal has been achieved.

One example of relatively new CHP capacity is the Spiritwood Station located in North Dakota adjacent to the Cargill malt facility and the Dakota Spirit AgEnergy biorefinery. Spiritwood Station, which came on line in 2014, is owned and operated by Great River Energy (GRE) and replicates the success the company has experienced at its Coal Creek Station (CCS), which supplies steam to the Blue Flint Ethanol biorefinery for process energy and is used to dry distillers' grains.[16]

According to EIA, average efficiency for U.S. coal power plants is under 33%, but Spiritwood, with its key industrial partners operating at full capacity, achieves about 60% efficiency. By design, it could reach 66% efficiency depending upon steam use. The plant's electrical capacity is 99 MW and it burns about 610,000 tons of North Dakota lignite annually.

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[16] In May 2020, GRE announced that it will be retiring CCS in 2022 and will be looking to refuel Spiritwood. The State of North Dakota, however, is working closely with industry to keep both of these facilities operational.

Cycling and Flexibility Technologies

Over the last decade or so, the U.S. electric power sector has been challenged. Load growth has effectively disappeared as a result of lower industrial demand, energy efficiency improvements, demand side management and behind the meter generation. Lower generation eliminated the organic growth in power generation which adversely affected utility earnings. The shale gas revolution significantly increased the supply of gas ahead of increased demand. With no other readily available markets for the gas, gas pricing was discounted sufficiently to move excess supply into the power market by displacing coal generation. Finally, costs for renewable resources declined, due to Federal tax credits such the production tax credit (PTC) and investment tax credit (ITC) benefitting wind and solar, respectively. With no growth in demand and higher generation from natural gas and renewables, coal generation was squeezed.

As a result of these changes, coal units, which are optimally operated as baseload generation have been operated at lower capacity factors and are cycled more frequently. Increased cycling operations of coal plants, including more frequent startups and shutdowns, as well as faster changes in unit output, have a considerable impact on the reliability and cost of the plant. More frequent cycling increases wear-and-tear of plant equipment and can lead to shorter equipment lifespan due to thermal fatigue, thermal expansion, increased corrosion and increased cost of start-up fuel. Without proper maintenance of the plant during these operations, unexpected plant outages become more frequent.

A recent report by Energy Ventures Analysis (EVA) for the National Association of Regulatory Utility Commissioners[xliii] (NARUC) noted that despite the increase in plant operating costs due to cycling, there exist numerous options for plant operators to minimize the financial impact and optimize the plant's operation. One option for mitigating the effects of flexible operation is for plants to implement system modifications that recover plant efficiency lost to continuous cycling operation. Examples include sliding pressure operation, variable-speed drives for the primary cycle and auxiliary equipment, and boiler draft control schemes and operating philosophy.

Other options include establishing and following cycle chemistry guidelines for flexible operations, accurate damage estimation, flexible operation studies and plant operator coaching. Additionally, areas to minimize coal plant cycling costs, outside the control of coal plant operators, include the increased deployment of energy storage and demand-side management resources and curtailing wind and solar generation during times of high generation or low demand.

Most of the cycling cost mitigation strategies require significant capital investment. However, recent market developments have undercut the profitability of existing coal power plants and reduced the amount of working capital plant owners are able or willing to spend on the maintenance necessary to ensure plant reliability.

Energy Storage

As more intermittent renewable energy (IRE) in the form of wind and solar are added to the power grid, it puts pressure on the ability of the existing dispatchable resources like coal power plants to provide firm capacity to balance their intermittent nature, causing such plants to cycle up and down in load and even shut down temporarily. While existing coal power plants have some capability to deliver flexible output to keep the grid stable in the face of unexpected reductions in wind and solar output, they were not designed for these modes of operation. Hence, this push towards flexible operation comes at an economic cost to the coal power plant due to the thermal cyclic damage of pressure parts and generating power during low grid price periods. Additionally, the efficiency of the plants is also compromised when operating in this responsive duty, increasing fuel costs and emission intensities. Moreover, this will lead to coal power plants operating at low overall capacity factors (CF), further deteriorating their economics. These issues will only get worse as the intensity of the demand changes become more pronounced as more IRE comes online.

One such element that has the potential to alleviate some of the problems associated with plant cycling and maintaining energy and grid stability is the concept of energy storage (ES) systems. These systems utilize excess or waste energy and store it until needed, at which time the energy is released from the system and converted into electricity. ES systems also have the potential to increase the efficiency of generation systems by preventing or reducing the cycling of large power plants and can decrease overall environmental impacts by improving the efficiency of energy generation. Likewise, the viability of IREs increases with ES technologies by enhancing grid stability and minimizing their impact to baseload generation assets. ES technologies appear in various forms, utilizing the storage of different types of energy, and can include the storage of mechanical, chemical, electrochemical, magnetic, cryogenic and thermal energy. Generally speaking, ES technologies are not widely used today and most technologies are at a low Technology Readiness Level (TRL).

New Coal-Based Generation

High Efficiency, Low Emission (HELE) Technologies

HELE technologies exist today that can reduce coal power plant emissions by more than 20%. A 1-percentage-point improvement in efficiency of a standard coal plant results in a 2%–3% reduction in CO_2 emissions.[xliv]

Plant thermal efficiency depends on several variables, most notably steam temperature and pressure. The maximum steam conditions are constrained by the available materials of construction that can operate satisfactorily at these conditions. The focus over more than 50 years has been to develop advanced material alloys having higher strength, improved weldability and resistance to corrosion/erosion.

The first generation of coal power plants operated at subcritical steam conditions, followed by next-generation supercritical (SC) steam conditions, and then USC steam conditions. Materials research over the last 20 years has supported the development of AUSC steam conditions. Table 2-2 lists a representative demarcation by steam conditions. Efficiency improvements from the progression from subcritical to AUSC are presented in Figure 2-8.

Coal Technology	Steam Turbine inlet Temperature and Pressure
Subcritical	≤1050°F and <3205 psi, usually 2400 psi
SC	1050°–1100°F and 3205–3600 psi
USC	1100°–1150°F and 3205–3600 psi
AUSC	1300°–1400°F and 3600–5000 psi

Table 2-2. Definition of Demarcation of Steam Cycle Conditions
Source: EERC/University of North Dakota

Advanced Ultra-Supercritical. Europe, the U.S., Japan, China and India are each developing their own version of AUSC plants. As shown in Figure 2-9, the U.S. formalized its AUSC materials program in 2001. Primarily funded by DOE along with the State of Ohio, the 15-year program successfully developed and tested materials to allow AUSC coal power plants to operate at steam temperatures up to 1400°F (760°C). At this temperature, efficiencies up to 47% (HHV basis) and 50% (lower heating value [LHV] basis) can be attained.[xlv] These AUSC projects achieved technology readiness levels (TRLs) of 4–5.[17]

[17] These materials have not yet received ASME certification and are not yet ready for commercial deployment.

HELE Technologies and Efficiency Improvements

More efficient ↑	Efficiency Rate+	CO_2 Intensity	Coal Consumption	Steam Temperature
Advanced Ultra-Supercritical	45–50%	670-740g CO_2/kWh	230-320g/kWh	700°C+
Ultra-Supercritical	Up to 45%	740-800g CO_2/kWh	320-340g/kWh	600°C+
Supercritical	Up to 42%	800-880g CO_2/kWh	340-380g/kWh	Approx. 550°C-600°C
Subcritical	Up to 38%	≥880g CO_2/kWh	>380g/kWh	≤550°C

+ Lower heating value

Source: Adapted from IEA, *Technology roadmap: High-efficiency, low-emissions coal-fired power generation*, 2012

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Figure 2-8: Efficiency improvements from HELE technologies
Source: EERC Adapted from IEA Technology Roadmap

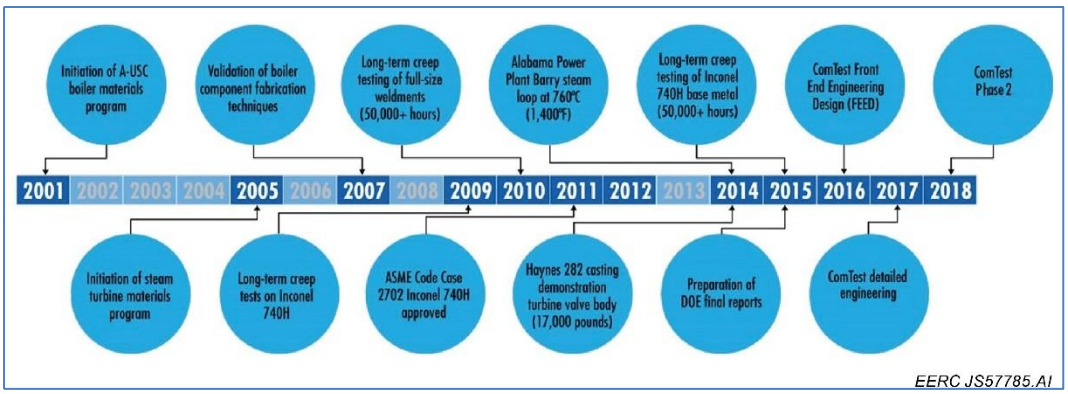

Figure 2-9: History of the U.S. AUSC Materials Program
Source: Hack et al., 2019

Building on this program, a U.S.-based consortium has been working on project AUSC ComTest to allow the construction of a commercial-scale AUSC demonstration power plant. The ComTest project will validate that components made from the advanced alloys can be designed and fabricated to perform under AUSC conditions. This validation will accelerate the development of a U.S.-based supply chain for key AUSC components and decrease the uncertainty for cost estimates of future commercial-scale AUSC power plants. The project is intended to bring AUSC technology to the commercial-scale demonstration level of readiness (TRL 7) by 2022.

The capabilities validated by this project would support both greenfield and retrofit applications of AUSC technology. Additionally, the higher-strength nickel-based alloys may facilitate enhanced flexible operation of new or existing power plants (e.g., by allowing the design and manufacture of thinner, reduced-cost components). Adoption of these technologies commercially will require the advanced materials to be economically competitive with current state-of-the-art technology. Crosscutting benefits from the project may apply to other high-temperature power generation options such as sCO_2 cycles, concentrated solar thermal and nuclear power generation.[xlvi]

Indirect-Fired sCO_2. Supercritical CO_2 as a working fluid holds promise for diverse energy resources and power cycles including coal, coal–biomass, natural gas and solar thermal. Higher heat-transfer coefficient, density and behavior as liquid (incompressibility) in circulation systems gives sCO_2 intrinsic benefits over steam as a working fluid. These benefits include:

- Higher cycle efficiencies due to the unique thermodynamic properties of sCO_2.
- Reduced emissions (gaseous, liquid, solid) resulting from lower fuel usage, with and without CO_2 capture.
- Reduced water usage, including water-free capability in dry-cooling applications.
- Compact turbomachinery, resulting in lower capital cost, reduced plant size/footprint and more rapid response to load transients.
- Greater ability to maintain high efficiencies at smaller scales; potential for improved flexibility and load-following capability.

sCO_2 cycles can offer a 2–4-percentage-point plant efficiency improvement over equivalent steam cycles in coal and coal–biomass-fired plants.

The crosscutting capability of sCO_2 with natural gas, coal, next-generation nuclear, concentrated solar thermal and industrial waste heat sources will be demonstrated under an $80 million contract from DOE’s Supercritical Transformational Electric Power (STEP) Program. GTI and partners Southwest Research Institute (SwRI) and GE Global Research are designing, building and demonstrating a grid-connected 10-megawatt electrical (MWe) sCO_2 pilot plant that will integrate and prove compact, modular technologies, including coal-based systems. Ideally, the qualifying and derisking of materials, components and power cycles will facilitate support and adoption of by the power industry.[xlvii]

Direct-Fired sCO_2 – Allam-Fetvedt Cycle. The Allam–Fetvedt Cycle, shown in Figure 2-10, is a new method of carbon capture from power generation that was invented by 8 Rivers Capital in 2008. The cycle is a zero-emissions fossil fuel technology which uses oxy-combustion and a sCO_2 turbine to achieve efficiency and cost comparable to a combined cycle or pulverized coal plant, but with full carbon capture.

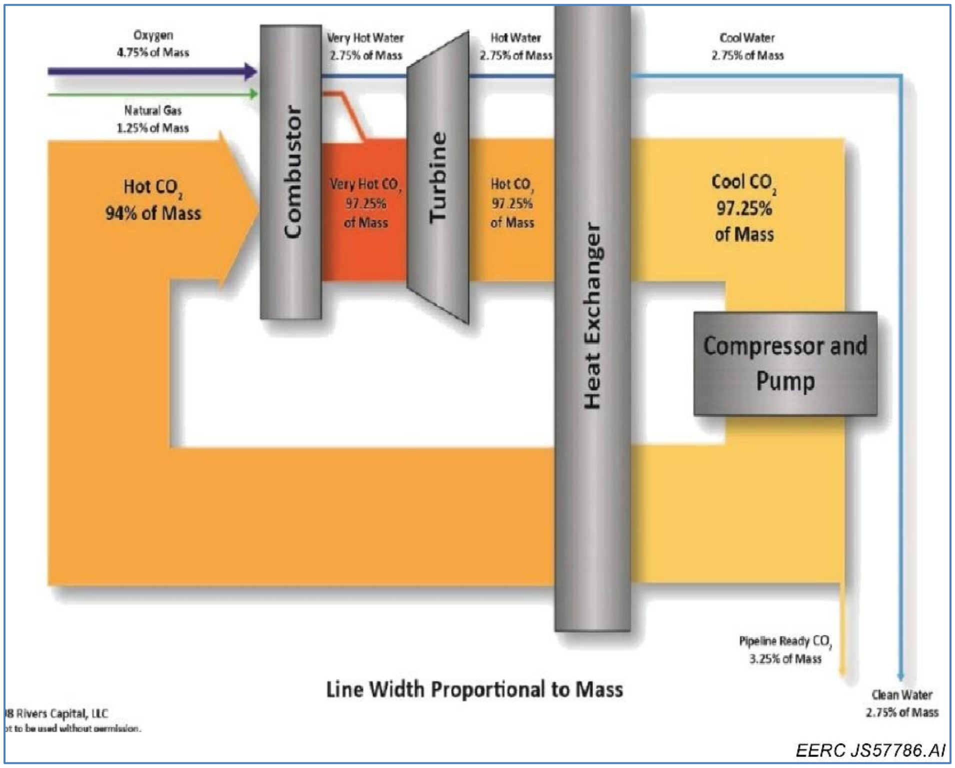

Figure 2-10: Allam–Fetvedt Cycle
Source: 8 Rivers Capital, LLC

Natural gas or coal-derived syngas is burned in pure oxygen, rather than air, creating a high-purity stream of CO_2 as the exhaust. The CO_2 stream drives the turbine instead of steam or conventional gas turbine exhaust. CO_2 capture is inherent to the system, unlike conventional power generation technologies that require CO_2 capture equipment. By using sCO_2 as a working fluid, the Allam–Fetvedt cycle can reach approximately the same efficiency as a conventional natural gas power plant while achieving over 97% carbon capture. Because the cycle utilizes oxy-combustion, NO_x, SO_x, mercury and particulate emissions are virtually eliminated when firing coal. As with other carbon capture processes, the high-purity CO_2 can be used for enhanced oil recovery (EOR), cement production and other forms of carbon utilization, as well as for underground sequestration or storage.

The coal-based version of the cycle is being commercialized by 8 Rivers and was recently awarded a grant for pre-front-end engineering and design (FEED) by DOE as one of the CoalFIRST technologies. NET Power, LLC (an 8 Rivers portfolio company) built a first-of-a-kind 50-MWth Allam–Fetvedt plant in La Porte, Texas, that is proving the technology on a natural gas fuel.

Integrated Gasification Combined Cycle. IGCC systems offer the potential to achieve high efficiencies while capturing carbon. In gasification, coal is partially oxidized at elevated pressure, which creates a CO_2 product that is less energy intensive to capture as compared to combustion technologies. Cycle efficiencies of over 40% are possible with gasification systems that include carbon capture technology. Technologies are commercially available today, but deployment has been limited because of high capital costs and the low cost of natural gas.

Worldwide HELE Deployment and CAPEX Costs. As detailed in a recent National Mining Association (NMA) report prepared by Wood Mackenzie, advanced coal technologies are being cost-effectively deployed in other nations, including Japan, Germany and China[xlviii] (Figure 2-11). These nations lead the world in coal plant efficiency while the U.S., with just 28% of its coal fleet considered as highly efficient, lags behind a global average HELE penetration of 43%. Improving the average efficiency rate of coal power plants from 33% to 40% could cut U.S. CO_2 emissions by up to 21%. Achieving these gains would likely require new plant builds.

Incentives are needed in the U.S. to reduce the capital expense of deploying HELE technologies. The NMA/Wood Mackenzie report notes that when compared to plants in China, U.S. HELE plants have 72% higher levelized costs and capital costs that are seven times higher. The report concludes that U.S. HELE deployment will require policy support in numerous areas, including:

- Regulatory – streamline regulatory requirements; provide investment tax credits/ production tax credits for coal or eliminate them for other generation technologies.
- Financing – support for financial institutions that finance HELE projects; provide insurance for HELE projects; lift restrictions on global lending for coal power plants.
- Technology – encourage U.S. engineering, procurement, and construction cost (EPC) firms to participate in HELE development overseas; support cogeneration technologies to increase power plant efficiency.

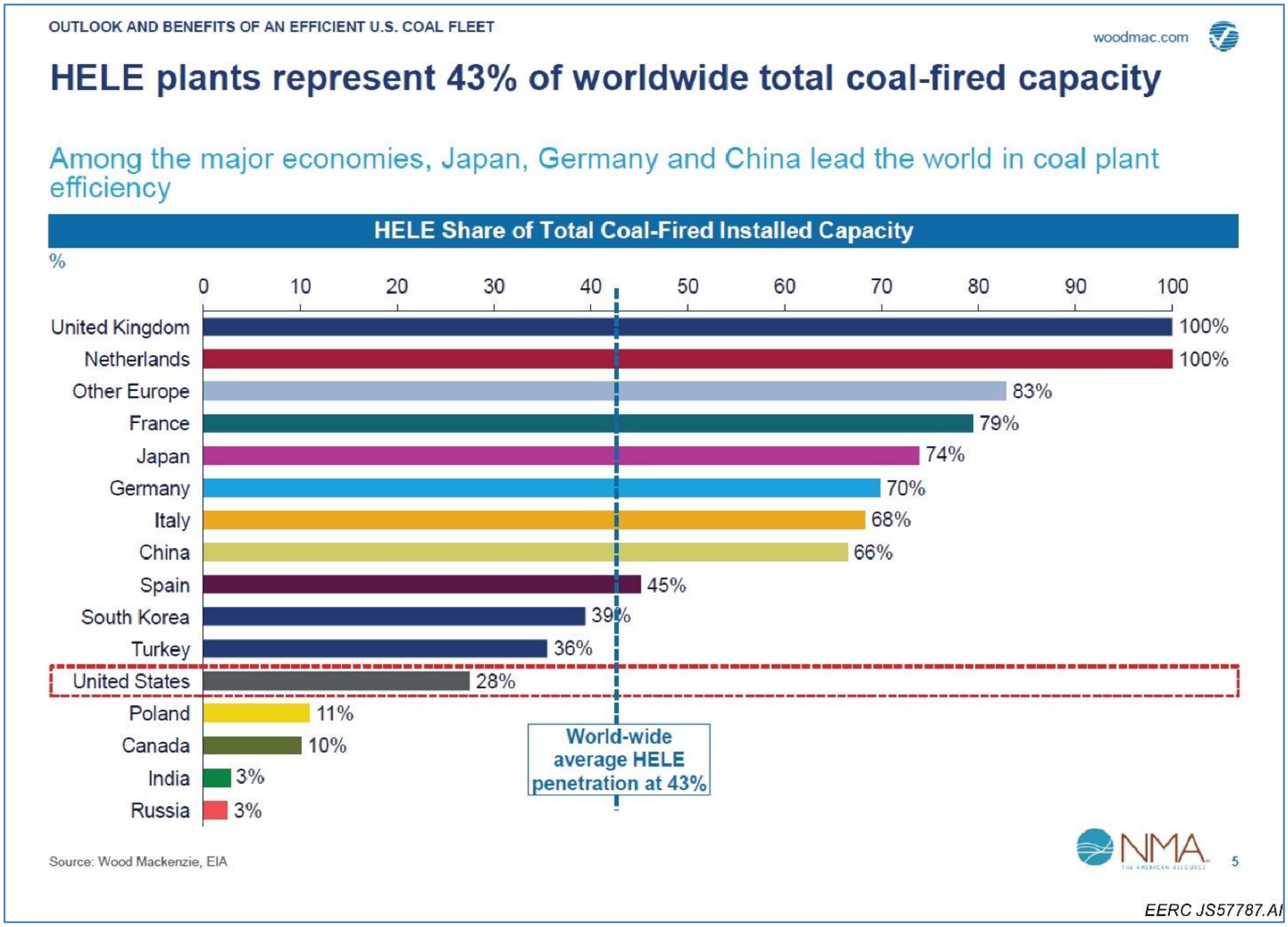

Figure 2-11: HELE installed capacity worldwide and in the U.S.
Source: National Mining Association/Wood Mackenzie, 2019

Oxy-Combustion

Overview. Oxy-combustion (oxygen-fired combustion) is a form of low-carbon power generation that facilitates CO_2 capture from fossil fuels or biomass by separating nitrogen from combustion air and burning the fuel in oxygen with flue gas recycle (FGR) acting as a diluent. The resultant flue gas consists primarily of CO_2 and water vapor, allowing relatively simple CO_2 purification largely by cooling the flue gas to condense out the moisture and removing small amounts of diluting N_2, O_2 and argon, and any remaining combustion byproducts.

Most oxy-combustion systems are designed for coal power plants, primarily because their relatively high CO_2 emissions make them more likely candidates for regulated CO_2 emissions reductions in the nearer term. First-generation oxy-combustion processes utilize an atmospheric-pressure cycle mimicking air-combustion cycles using much of the same equipment. On the gas side, the primary differences are found in the provision of oxidant to the boiler through a cryogenic air separation unit (ASU) and the CO_2 purification process, while the power island is nearly identical.

Successful coal plant demonstrations of atmospheric-pressure combustion at pilot or large pilot scale were performed in Australia, China, Europe and the U.S. with the Callide Oxyfuel Project in Australia being the largest complete atmospheric-pressure oxy-combustion demonstration at 30 MWe net. There are TRL6 level oxy-combustion based carbon capture technologies ready for full scale demonstration at existing coal power plants. These oxy-combustion technologies are well suited for a retrofit application for existing coal generation facilities. Oxy-combustion carbon technology is scalable from 50 MW to 600 MW, whereas post-combustion carbon capture may be less cost effective on smaller units (less than ~300 MW). Having both oxy-combustion and post-combustion available for deployment on the existing coal fleet can help to address the downward spiral of future coal plant shutdowns.

More recently, variants on oxy-combustion have been developed to attempt to potentially create systems with more significant improvements in efficiency and cost reductions. These more novel systems include:

- Chemical Looping: Oxy-combustion process in which oxygen separation is done using an oxygen carrier, eliminating need for an energy-intensive cryogenic ASU.
- Direct-Fired, Supercritical CO_2 Power Cycles: Also known as “Allam Cycles,” these high-pressure (HP) cycles perform oxy-combustion in-situ in the system, yielding a working fluid of CO_2 and water that drives a turbine and allows CO_2 separation at pressure. (See Allam Cycle detail on page 46).
- High-Temperature Oxy-Combustion: A form of atmospheric oxy-combustion that employs high flame temperature through a modified burner designed to improve heat transfer. (See Jupiter Oxygen’s detail on its Dave Johnston CCUS-EOR project on page 118.)
- Pressurized Oxy-Combustion: Oxy-combustion processes performed at higher pressure yielding smaller components and allowing the latent heat recovery of water at useful temperatures designed to improve efficiency.

Atmospheric-Pressure Oxy-Combustion. The most basic form of oxy-combustion technology, which has only been designed for solid fuels, uses an atmospheric pressure, slightly positive draft operation of the steam generator setting with oxygen injection produced by an ASU, instead of air, and recycling the treated flue gas back to the burners and furnace gas inlet plenums. FGR moderates the furnace temperatures to the same level as air firing and provides similar gas velocities across the convection tube banks, thereby providing the same order of heat absorption as an air-fired steam generator.[xlix] FGR must also be set to temper the flame temperature to prevent high upset heat fluxes and, for pulverized coal (PC) applications, wet slagging and “wet bottom” operation of the furnace enclosure. The furnace exit gas temperature is an important boiler design parameter and based on the fuel ash content, must be limited to prevent excessive bridging and plugging of the convection pass tubes.[l] Oxy-circulating fluidized bed boilers are possible, but the bed temperature must be maintained to limit agglomeration.

An example atmospheric-pressure oxy-combustion process flow diagram, one developed by Babcock & Wilcox Company (B&W) and proposed for the FutureGen 2.0 project, which went through full front-end engineering design (FEED) work, is shown in Figure 2-12.[li] Oxygen is introduced at three locations in the diagram. Mixing and heating some oxygen at the recycle gas heater is important for the heat balance and efficiency. Oxygen is introduced to the pulverizer primary gas after the recycle gas heater because the higher-pressure primary gas would leak oxygen into the flue gas presenting problems for the CPU. Burner oxygen injection is used to quickly respond to the measured O_2 and control requirement.

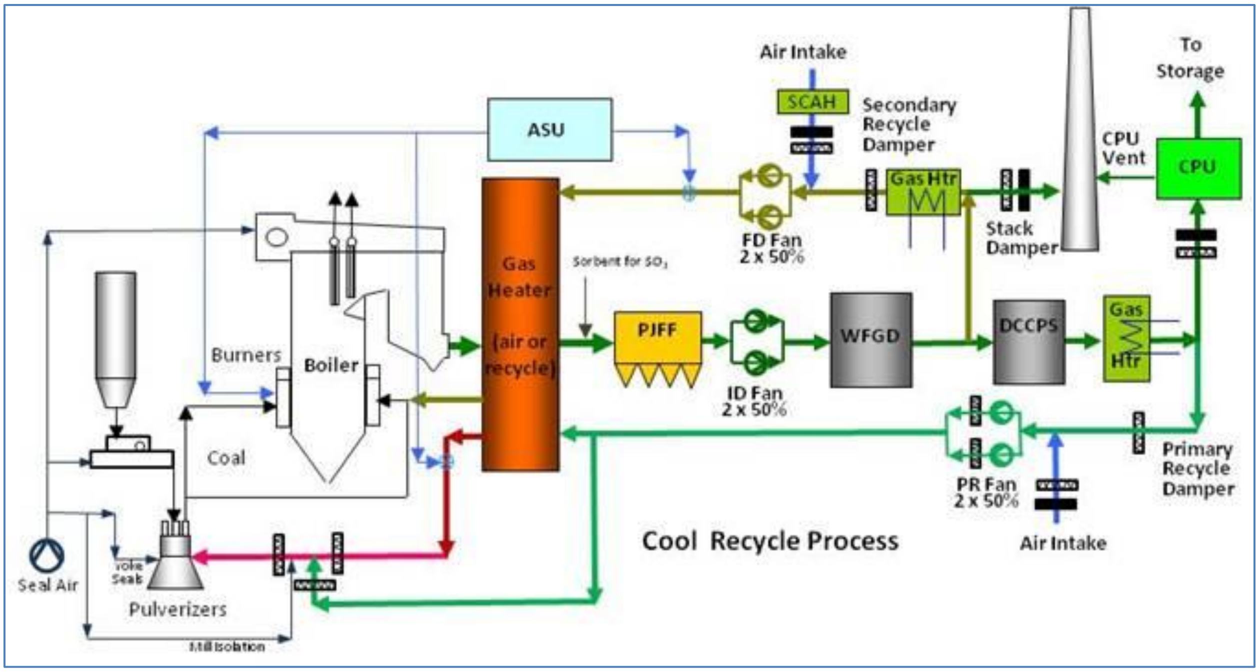

Figure 2-12: B&W's Proposed FutureGen 2.0 Oxy-Combustion Process Flow Diagram
Source: Used with permission from Babcock & Wilcox Company

One example of atmospheric-pressure oxy-combustion is Jupiter Oxygen Corporation's (JOC) proposed use of its proprietary technology's untempered oxygen burners to produce higher burner flame temperatures with high-purity oxygen (95–100%) and lower FGR rates in the furnace of a PC-fired oxy-combustion process.[lii,liii] The goal is to provide higher furnace radiation heat flux with a more uniform absorption pattern to the furnace wall enclosure to improve overall efficiency.

JOC's oxy-combustion process and burner testing was completed to the level of 15 MWth at JOC's facility in Hammond, Indiana between 2008 to 2012, resulting in a TRL 6 status (TRL levels range from 1-9).[liv] Also, significant computational fluid dynamic (CFD) modeling was used to investigate the process benefits of reduced FGR and the impact on material issues. JOC is currently conducting an oxygen burner development program involving full-scale testing and providing engineering modeling studies for components and overall system, which were used to create a commercial-scale design for retrofitting to an existing boiler. The balance of the oxy-combustion steam generator system components and other balance-of-plant equipment required for the commercial plant would be supplied by existing vendor and aftermarket suppliers.

Staged Pressurized Oxy-Combustion (SPOC). Staged, pressurized oxy-combustion (SPOC) technology was conceived at Washington University in St. Louis and is being developed in collaboration with the Electric Power Research Institute (EPRI), Doosan Babcock Ltd. and Air Liquide.[18] This process has shown promise as a near-zero emissions source of coal-based power with high efficiency and flexibility. The efficiency of the SPOC process is almost 3.5%–7.5% points higher than first-generation, 550-MWe atmospheric pressure carbon capture and storage (CCS) processes. SPOC uses coal or biomass (or some combination) as feedstock. The small, modular design provides high flexibility and low capital cost. Flexibility of the SPOC system is driven by the ability to bypass individual combustion/boiler stages, for example, where there are seasonal variations in demand.

This system also allows for additional load-following capability through energy storage, in which pressurized, liquid oxygen that is provided by the ASU can be stored in times of low demand and utilized in lieu of the ASU in times of peak demand. Storage also significantly reduces parasitic load and, since there is less cycling, results in less wear and tear on the plant.

Flameless Pressurized Oxy-Combustion (FPO). Flameless pressurized oxy coal combustion (FPO) is a reduced-emissions technology that was developed to recover energy from high-to-low-rank coals, petcoke, other brown fuels, biomass and wastes.[lv] In the FPO process, nitrogen is separated from air and the combustion takes place with oxygen at elevated pressure (up to 20 atm). Pressurized recirculated flue gas is used to maintain combustion temperatures at acceptable levels. The resultant flue gas is primarily CO_2 and water, which allows for a relatively simple and inexpensive CO_2 capture, compression and liquefaction (CCL) process. In comparison, air combustion systems require a complex and costly post-combustion CO_2 capture (PCC) process.

FPO is proven on the 100-kW bench scale and the 5-MWth pilot scale and is estimated to have a relatively low LCOE. The ability of FPO to accept fuels containing high levels of moisture makes the FPO technology of particular interest for Powder River Basin (PRB), other subbituminous coals and lignite. Firing high-water-content, low-ranking coals such as PRB or lignite with FPO produces a lower Levelized Cost of Electricity (LCOE) than when firing high-rank coals, which is not the case for conventional pulverized coal technology. The lower LCOE is due to a larger recovered heat of vaporization of water in the flue gas because of elevated pressure, the possibility of flue gas heat recovery in a turboexpander due to the low particulate concentration, and the lower-cost per Btu of low-rank coals.

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[18] This initiative is funded, in part, by the U.S.-China Clean Energy Research Center. China has shown interest in the technology; no U.S. company has expressed interest in funding expansion of this technology which is ready for scale-up.

Chemical Looping. Chemical looping combustion (CLC) is an advanced combustion process that uses oxides of metals (e.g., iron oxides, copper oxides or manganese oxides) to act as an oxygen carrier for transporting oxygen between two separate reactor vessels (Figure 2-13).

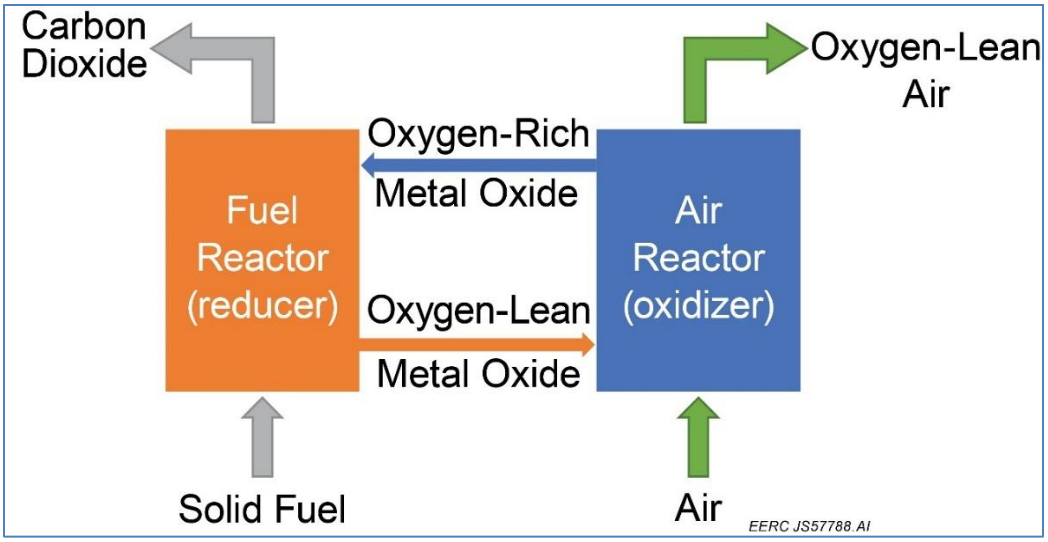

Figure 2-13: Simplified schematic for CLC process
Source: EERC

The circulating metal oxide ensures the fuel is converted in a "nitrogen-free" environment, producing a near-pure CO_2 stream. The heat generated in the air reactor is used to produce steam which can be used for electricity generation or heating. The entire process operates at temperatures of about 1000°C.

Key benefits of the CLC technology include the following:

- CO_2 capture-ready, with costs estimated to be 50% lower than installing a capture system on existing facilities[lvi]
- Higher thermal efficiency, with estimates of up to 46%[lvii]
- Substantial reduction in oxides of nitrogen compared to traditional combustion systems

Currently, significant research is ongoing to advance CLC to commercialization with over 19 pilot plants reported worldwide. Research is currently focused on developing more active oxygen carriers, improving fuel conversion, facilitating adoption of existing commercial equipment or developing novel equipment.

Negative Emissions Technologies

Negative emissions technologies (NETs) remove CO_2 directly from the atmosphere and sequester the carbon, rather than avoid emissions. The principal NETs are a) biological processes to increase carbon stored in soils and biomass, b) biomass energy production with carbon capture and storage (bioenergy carbon capture and storage [BECCS]), c) direct removal of CO_2 from the air by chemical means for geologic sequestration, and d) enhanced geologic processes reacting CO_2 with mineral matter. The costs and ultimate capacities of these methods are uncertain, and each faces legal, ethical and environmental obstacles that may limit its use more than engineering and economic constraints.

Table 2-3 summarizes the results from numerous assessments of the potentials and costs of NETs.[lviii] Estimates for costs and capture/storage potential vary by orders of magnitude. For comparison, current world CO_2 emissions are about 36 Gt/y. BECCS shows the narrowest range of cost estimates and greatest potential and could be implemented through biomass cofiring at existing coal power plants that have been retrofitted with CCUS or new facilities built for that purpose. NETs require considerably more research and analysis to identify the most promising candidates and advance their technological implementation.

Negative Emissions Technology	**Potential Flux, $GtCO_2$/y**		**Cost, $/tCO_2$**
	2050	**2100**	
Afforestation	1–6	1–12	1–100
Biochar	1–5	1–35	0–300
BECCS	2–11	11–70	45–250
Direct Air Capture	0–11	4–37	10–1000
Enhanced Weathering	0–5	2	20–1000
Soil Carbon Sequestration	2	605	0–100

Table 2-3: CO_2 Capture/Storage Potential and Costs for Negative Emissions Technologies Source, Minx, Lamb, et. Al., 2018

Chapter 3. Federal Regulatory and Legislative Initiatives to Accelerate Deployment of Coal Power Generation Technologies

KEY FINDINGS

- **Advanced coal-based generation technologies face three main challenges to deployment. The first is cost and the associated financial risk. Second is regulatory risks. Third is shareholder and investor risk.**

- **With respect to cost and financial risk, advanced coal-based generation technologies face competitive challenges related to low-cost natural gas and natural gas-based generating facilities that generally have lower capital and operating costs than those fueled with coal during periods when gas prices are low. Advanced coal-based generation technologies also have a limited deployment track record, which increases financial risk.**

- **With respect to regulatory risks, the combustion of coal produces more carbon dioxide (CO_2) emissions per unit of energy than other fossil fuels, which increases challenges under international, Federal and state carbon reduction programs. These risks can be addressed through implementation of technologies such as carbon capture utilization and storage (CCUS) and high efficiency-low emissions (HELE) advances. CCUS technologies face separate challenges related to costs and regulatory acceptance.**

- **With respect to shareholder and investor risk, coal's greenhouse gas (GHG) emissions profile has become a focus of shareholders and investor attention under Environmental, Societal and Governance (ESG) initiatives. Despite its long service to society, improved environmental performance over the decades and the essential role it continues to play as an abundant, reliable source of electricity, coal risks being perceived as an unwelcome fuel source.**

- **Public engagement of key stakeholders will enhance prospects for the successful development and deployment of advanced coal generation technology projects by building support for and thus reducing risks associated with these projects.**

Summary Matrix of Technologies-Policies

Table 3-1 summaries how various technologies could be advanced by specific policies and initiatives.

Technology / Policy	CCUS	HELE	USC/AUSC	Allam Cycle	Oxy-Combustion	Other Transformational	Small Modular	Energy Infrastructure	Other	Coal Conversion & Utilization	Exports Coal & Coal Technology
Initiatives to Advance R&D											
Coal FIRST	x	x	x	x	x	x	x				x
EFFECT Act	x	x	x	x	x	x	x			x	x
Fossil Energy R&D	x		x	x	x	x	x				
Technology Transitions Act	x	x	x	x	x	x	x				
Initiatives to Minimize Cost & Risk											
45Q	x										
Master Limited Partnerships	x								x		
Private Activity Bonds	x										
BEAT Tax Relief	x										
48A	x	x	x								
Technology Neutral Tax Credit	x	x	x	x	x	x	x				
USDA RUS Leg.	x									x	
Contracts for Differences	x	x	x	x	x	x					
LPO Reforms	x	x	x	x	x	x					
Development Finance Corp	x	x	x	x	x	x	x	x	x		x
Initiatives to Bolster Emissions Abatement											
Clean Energy Standard	x	x	x	x	x	x	x				
Affordable Clean Energy	x				x						
Initiatives to Address Regulatory Risk & Burden											
USE IT Act	x							x			
NSR/Gain Act	x	x									
Coal Combustion Residuals								x	x	x	x
Effluent Limitation Guidelines									x		
Initiatives to Reform Energy Markets											
PURPA	x	x	x	x	x	x					
Capacity Market Reforms	x	x	x	x	x	x					
Initiatives in Support of Energy Infrastructure											
LIFT America Act								x			
INVEST CO_2 Act								x			
FAST Act								x			

Table 3-1: Summary Technologies-Policies Matrix

Background

Advanced coal-based generation technologies face three main challenges.

First is cost, and the associated financial risk. The United States is fortunate to have an abundance of low-cost fossil fuels. Coal has long been the dominant low-cost fuel for electric generation. However, in recent years the cost of natural gas has been persistently low, making it a formidable competitive choice for generating electricity. Natural gas combined cycle generation is widely deployed and therefore has little technology risk. New natural gas units generally are replications or refinements of widely deployed designs, and therefore the technology risk is low. In contrast, advanced coal-based generation technologies – as the word "advanced" suggests – have a limited deployment track record, at least at scale. Natural gas generation facilities have relatively low non-fuel operating costs, require a small labor force to operate and have lower heat rates (higher efficiencies), whereas coal facilities typically have higher non-fuel operating costs, require a larger labor force and have higher heat rates (lower efficiencies). However, natural gas fuel costs have traditionally been volatile and high, where coal fuel costs have been relatively stable. A return to higher natural gas costs with higher volatility would reduce its current competitive advantage over coal.

Second is regulatory risk. Coal combustion generates more carbon dioxide (CO_2) emissions per unit of energy than other energy sources, which creates challenges under regulatory programs designed to reduce atmospheric emissions of GHG. Internationally, the Paris Agreement is expected to take effect in 2021, following a year-long delay caused by the coronavirus. In the wake of the 2007 decision by the U.S. Supreme Court in *Massachusetts v. EPA* and an Endangerment Finding by the EPA Administrator, the EPA sought to regulate CO_2 emissions from major stationary sources through the Clean Power Plan (CPP). The CPP was never implemented and, in 2019, was replaced by the Affordable Clean Energy (ACE) Rule. The CPP incorporated a broader definition of Best System of Emission Reduction (BSER) that the current Administration concluded was inconsistent with the Clean Air Act. ACE confined the BSER definition to the plant itself, focusing on heat rate improvements that could be adopted by generators. Meanwhile, an increasing number of states are themselves, individually or in regional alliances, imposing a carbon or clean energy regime.

Advanced coal-based generation technologies can meet current and future GHG-related regulatory challenges through implementation of technologies such as carbon capture utilization and storage (CCUS). In pioneering applications with support from the U.S. Department of Energy (DOE), CCUS technologies have been effective in reducing CO_2 emissions in excess of 90% – achieving resultant emissions levels far below any other CO_2-emitting fuel sources without CCUS. CCUS-equipped coal power plants – through a process known as bioenergy with CCS (BECCS) – also may remove CO_2 from the atmosphere, and thus qualify as Negative Emission Technologies (NET).

Decarbonized fossil fuels also generally qualify as “clean energy” under a variety of regulatory programs. Nevertheless, there is a growing risk that state and Federal policies do not provide a sufficient pathway for fossil-based generation, even with technology to dramatically reduce GHG emissions, to maintain future operations in the interest of addressing climate change. This is so, in part, due to the limited value electricity markets place on the essential grid-supporting attributes that coal provides, particularly reliability and fuel security.

Third is shareholder and investor risk. Independent of regulation, a company’s GHG emissions profile has become an issue on which shareholders and investors judge fossil using and producing corporations through metrics such as Environmental, Societal and Governance (ESG). ESG refers to the sustainability and societal impact of businesses; evaluation of relevant ESG criteria are intended to help investors and others assess an entity’s future financial performance. The ESG measurements attribute little value to the reliability, affordability and fuel security coal power plants provide, even with plants that could be retrofit with carbon capture.

Shareholder and investor risk is, in part, an issue of public perception. Despite its long service to society, improved environmental performance over the decades and the essential role it continues to play as an abundant, reliable source of electricity, coal is perceived by some as an unwelcome fuel source.

* * *

It is important broadly, visibly and promptly to demonstrate coal as a clean energy option by deploying new advanced coal facilities, or else society may risk losing the opportunity to do so. Thus, the recommendations to overcome the above challenges take on urgent importance. It is critical that DOE play a role in addressing this issue because U.S. technological leadership for coal is a critical path component for addressing environmental concerns around the world.

Despite these key challenges, coal-based generation possesses a critical attribute of significant value to the grid that few other energy resources can match: the resilience that comes from having fuel on site. Some areas of the country have struggled to assure sufficient electricity generation, particularly during periods of high demand paired with low output from intermittent renewable energy (IRE) resources or coincident high demand on natural gas. Coal has proven to be not just important, but irreplaceable during these periods. These factors may take on added importance in post-pandemic society in the years and decades ahead as policymakers and citizens re-evaluate the reliability of all manner of systems, from health care to transportation to energy.

The generation mix across the grid has changed very substantially over the past decade, relying more heavily on IRE resources and generation dependent upon just-in-time fuel supply. The reliability and resilience of such a system rests on the availability of rapidly dwindling "always on" fuel secure generation, which can no longer be taken for granted. Policy updates are needed to assure sufficient fuel-secure resources to maintain reliability, particularly for high-risk, low frequency events, such as the polar vortex in 2014 and the bomb cycle in 2018. Concerns stemming from COVID-19 accentuate the importance of diversity.

Thus, it is recommended that DOE:

- Implement a communications strategy for low-emissions coal technologies, to include partnerships with aligned organizations.
- Continue to advance a broad research and deployment agenda on low-emissions coal technologies.
- Focus on states and industry segments that recognize coal's favorable attributes.
- Value the resilience benefits of coal, deriving from its ability to produce on-demand energy and being a fuel that can be stored on-site.

Initiatives to Advance Research & Development

DOE's research and development (R&D) programs would benefit from more flexible and expansive authorization, and among other things, increased focus on bridging the so-called "valley of death" that promising early-stage technologies must cross to make it to commercialization. Federal R&D support must be made available for demonstration and commercial-scale initiatives for CCUS and advanced coal generation technologies. Restricting Federal R&D funding only to basic research, will hinder the deployment of these technologies.

To enhance the opportunity for success of these demonstration and commercial-scale efforts, DOE should ensure that staff experienced in managing large-scale projects are in place to oversee their management.

DOE has noted that carbon capture costs must be reduced to around \$30/tCO_2 for CCUS to be commercially viable. According to the International Energy Agency's Clean Coal Centre (IEA-CCC), current carbon capture costs of coal power plants with post-combustion CO_2 capture using amine-based solvents range from \$105/tCO_2 at Boundary Dam to \$65/tCO_2 at Petra Nova.[lix]

The deployment of additional CCUS projects will aid in significantly reducing the cost of CO_2 removal. The International CCS Knowledge Centre conducted a Shand Power Station CCS Feasibility Study indicating the potential in the 2024-2028 timeframe to achieve a $45/t$CO_2$ cost, 57% lower than the previously designed Boundary Dam facility. Further cost reductions for subsequent CCUS facilities through 'learning by doing' will be achieved where a learning rate of 8-13% could reduce the cost for post-combustion CO_2 removal by a further 50-75% by 2060.[lx]

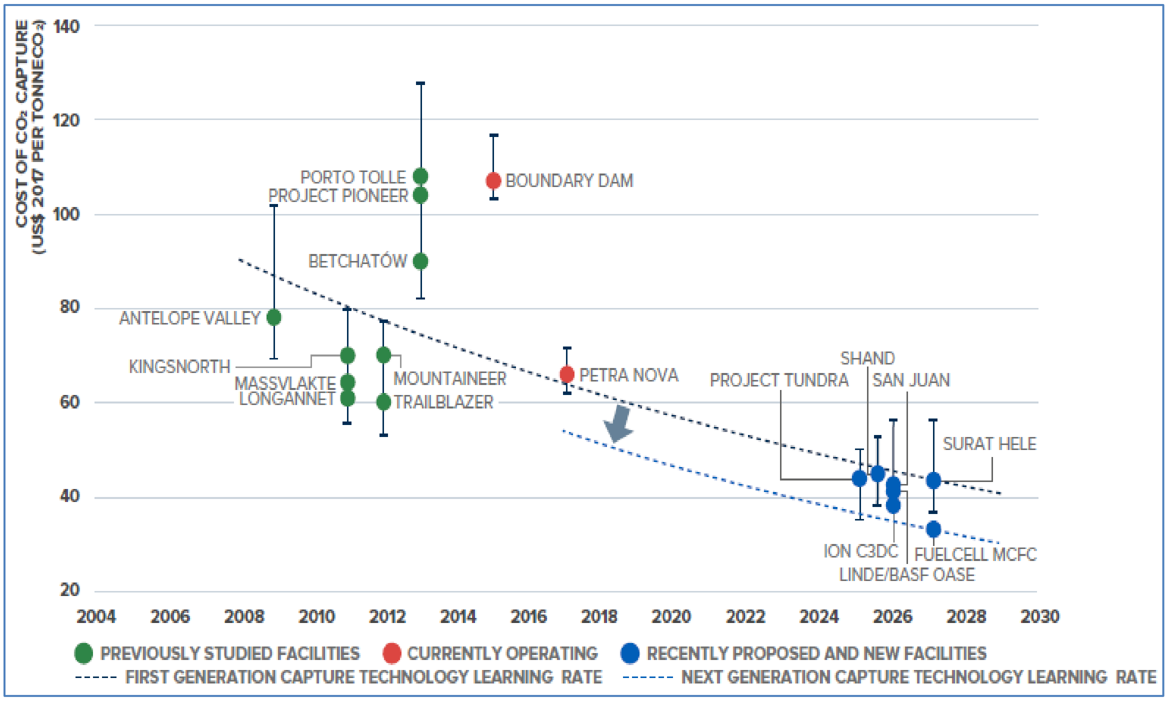

Figure 3-1: Cost of CO_2 Capture
Coal Power Plant with Post-combustion Capture
Source: Global CCS Institute

The following policy initiatives will enhance R&D efforts and commercialization of advanced coal generation technologies.

The EFFECT Act

The Enhancing Fossil Fuel Energy Carbon Technology Act of 2019 (EFFECT Act)[lxi] would expand DOE's fossil energy R&D objectives and establish new R&D programs for CCUS, amending the program authorized under Sections 961, 962 and 963 in Subtitle F of Title IX of the Energy Policy Act of 2005. It also would add a new section at the end of the subtitle to create a carbon utilization program to identify and assess novel uses for carbon.

Amendments in the bill to the fossil energy research and development program would make it an explicit goal of the program to increase the export of U.S. emissions control technology. That authorization is broad enough to encompass CCUS, high efficiency-low emissions (HELE), advanced ultra supercritical (AUSC), oxy-combustion, and new combustion cycle technologies. The bill also would authorize research and development of carbon removal and utilization technologies, and technologies for conversion, use and storage of CO_2.

The EFFECT Act provides explicit direction for DOE to establish programs for demonstration projects, large-scale pilots, front-end engineering and design (FEED), and research and development. The goals of the program include ensuring reliable, low-cost power from new and existing fossil power plants; achieving high conversion efficiencies; addressing CO_2 emissions; developing small-scale and modular technologies; supporting dispatchable operations; and accelerating transformational energy conversion technologies.

Fossil Energy Research and Development Act

Similar to the EFFECT Act, the Fossil Energy Research and Development Act[lxii] amends DOE's R&D programs in Sections 961, 961, and 963 of the Energy Policy Act of 2005. It adds a new program to fund advanced energy systems to reduce emissions from fossil fuel power generation by at least 50%. Amendments in the bill to the fossil energy R&D program would make it an explicit goal of the program to lower greenhouse gas (GHG) emissions and develop carbon removal and utilization technologies. It would increase funding authorization levels from the program dramatically.

The Act would transform the current coal and related technologies program into a carbon capture technologies program. Under the new program, DOE would conduct a research, development, deployment and commercialization program for development and use of carbon capture technologies, other emissions reductions and carbon separation. The program would focus on large-scale pilot projects of less than 100 MW, large-scale demonstration projects and FEED studies, as well as fund at least three carbon capture test centers.

Furthermore, the bill would establish a new advanced energy systems program within DOE, for research, development, demonstration and commercial application of, among other technologies, supercritical and ultra-supercritical CO_2 cycles, including directly and indirectly fired cycles; advanced combustion systems, including oxy-combustion and chemical looping; gasification technologies; thermal cycling technologies; and small modular coal with carbon capture.

Technology Transitions Act

The Technology Transitions Act[lxiii] would revise Section 1001 of the Energy Policy Act of 2005 to establish an Office of Technology Transitions within DOE, setting as its mission the expansion of the commercial impact of DOE research, and the commercialization of GHG reducing technologies and technologies supporting other DOE missions. This would assist in focusing DOE research programs on bridging the so-called “valley of death” for emerging technologies. Program goals would include reducing GHG emissions, ensuring economic competitiveness, enhancing domestic energy and national security, enhancing domestic jobs and serving other departmental missions.

The bill would add a new section of law requiring DOE to review its current applied R&D programs for emission-reducing technologies to determine whether there are written program goals, identify overlap and duplication, and develop recommendations for restructuring or consolidating the programs. Such reforms would help DOE focus its research toward technologies that have a strong likelihood of success and fit an overall DOE mission.

In addition to these legislative initiatives, DOE’s R&D program would benefit from support for the following:

Coal FIRST

DOE’s Coal FIRST initiative will facilitate the deployment of advanced coal generation technologies that can support the critical need for:

- Reliable, on-demand, dispatchable power available to backstop intermittent energy resources.
- Resilient, fuel secure power able to weather low frequency, high impact events.
- Cost-effective, efficient and environmentally advantageous technologies that enable the continued use of abundant, affordable coal resources in the U.S. and internationally.

Small-scale Modular Coal Power Plants

The Coal FIRST initiative also supports advancing technologies for the development and deployment of small-scale modular coal power plants. NCC encourages R&D efforts be undertaken in pursuit of niche market applications for small-scale modular applications in order to advance the concept of modularization, substantiate the economic and environmental benefits of the concept, and validate the applicable technology performance of small-scale modularity.

Potential niche markets applications which could initially be pursued include:

- Small capacity combustion and gasification units for co-fueling coal and biomass/waste.
- Replacement of more costly diesel-fueled plants.
- On-site coal mining operations for coal drying and other localized applications.
- Remote, off-grid locations, including those with limited access to or potential for use of other energy resources, i.e., natural gas or renewables.
- Captive power plants at industrial facilities, including coal-to-products advanced manufacturing facilities, i.e., for production of carbon fibers, graphene, etc.

Ultimately, these efforts could facilitate deployment of a number of small-scale modular units linked together to achieve economies of scale supporting the power production, environmental controls and transportation logistics associated with coal generation.

International Collaboration in Support of Advanced Technologies

Support for collaborative R&D with international partners will help accelerate the development and deployment of advanced coal generation technologies.

The efforts of the U.S.-China Clean Energy Research Center (U.S.-China CERC)[lxiv] are just one example of the potential of these partnerships to advance commercialization of critical technologies. Among the U.S.-China CERC's achievements are advancements in Staged Pressurized Oxy-Combustion (SPOC); collaboration on large-scale demonstration projects of CO_2 capture, utilization and sub-surface storage; demonstration of the use of microalgae for the cost-effective conversion of CO_2 into value-added products; and commercial-scale demonstration of low-cost gasification technologies for coal-to-chemical and coal-to-liquid applications.

Recent initiatives restricting financing for coal power plants in international markets may potentially hinder international collaboration efforts to advance environmentally beneficial technologies. An extensive discussion of these restrictive initiatives by Multilateral Development Banks (MDBs), the U.S. Export-Import Bank, the World Bank, and European and Asian financial institutions was addressed in NCC's report on "Advancing U.S. Coal Exports."[lxv]

The United Nations Economic Commission for Europe (UNECE) has an active initiative underway to facilitate funding energy projects by international institutions, such as the MDBs and World Bank, as well as European and Asian financial institutions. The initiative supports all types of energy projects, including fossil energy. DOE would benefit from increased participation with UNECE.

Opportunities remain to enhance collaboration with entities such as the African Development Bank which continues to support all sources of energy as part of its efforts to achieve universal access to electricity. Additionally, continued support is warranted for the Japan-U.S. Strategic Energy Partnership (JUSEP) which aims to ensure energy security and universal access to affordable and reliable energy in order to eradicate poverty, including through the deployment of HELE coal technologies.

Initiatives to Minimize Cost and Risk

Various risk factors contribute to the cost associated with deploying emerging technologies. In a recent presentation, the International Energy Agency (IEA) Clean Coal Centre quantified the risk premium associated with CCUS and its impact on the availability of debt and equity financing.[lxvi] When combined, the standard low risk project debt financing rate of 4% and the risk premium of 11% associated with CCUS brings the debt rate of CCUS projects to 14-15%. Cross-chain risk, policy/revenue risk and storage liability rank as the top-most risks, indicating where development and prioritization of policies should be focused.

Perceived risk	Risk rating	Debt rate risk premium
Cross-chain	25	2.7%
Policy and revenue	20	2.2%
Storage liability	10	1.1%
Leakage	10	1.1%
Stranded asset	10	1.1%
Political risk	6	0.7%
Project financing	4	0.4%
Market design and regulation	3	0.3%
Social acceptance	3	0.3%
Operating and performance	3	0.3%
Legal system	3	0.3%
Construction	2	0.2%
Administrative risk	2	0.2%
CCUS risk premium		10.9%

Figure 3-2: Perceived Risk of CCUS Projects

Source: International Energy Agency, Clean Coal Centre

Federal financial support for fossil energy in recent years has significantly lagged that for conservation/efficiency and non-fossil energy as noted in a recent analysis conducted by the U.S. Energy Information Administration (EIA) and summarized in Table 3-2.

Federal Financial Interventions & Subsidies in Low-Carbon Energy
FY 2010, FY 2013 and FY 2016 (in millions of 2016 dollars)
https://www.eia.gov/analysis/requests/subsidy/pdf/subsidy.pdf

FY 2010	conservation & efficiency	non-fossil energy (renewables & nuclear)	fossil energy (coal, oil & gas)	total
direct expenditures	$3,881	$5,804	$82	$9,767
r&d expenditures	$1,366	$1,020	$325	$2,711
tax expenditures	$4,684	$9,913	$477	$15,074
loan guarantees	$1,139	$588	$0	$1,727
total	**$11,070**	**$17,325**	**$884**	**$29,279**
percent of total	**37.8%**	**59.2%**	**3.0%**	**100.0%**

FY 2013	conservation & efficiency	non-fossil energy (renewables & nuclear)	fossil energy (coal, oil & gas)	total
direct expenditures	$984	$8,753	$405	$10,142
r&d expenditures	$1,593	$1,063	$264	$2,920
tax expenditures	$2,955	$6,838	$575	$10,368
loan guarantees	$0	$0	$0	$0
total	**$5,532**	**$16,654**	**$1,244**	**$23,430**
percent of total	**23.6%**	**71.1%**	**5.3%**	**100.0%**

FY 2016	conservation & efficiency	non-fossil energy (renewables & nuclear)	fossil energy (coal, oil & gas)	total
direct expenditures	$271	$949	$64	$1,284
r&d expenditures	$435	$621	$389	$1,445
tax expenditures	$3,313	$5,476	$770	$9,559
loan guarantees	$0	$0	$0	$0
total	**$4,019**	**$7,046**	**$1,223**	**$12,288**
percent of total	**32.7%**	**57.3%**	**10.0%**	**100.0%**

AVERAGE	**conservation & efficiency**	**non-fossil energy** (renewables & nuclear)	**fossil energy** (coal, oil & gas)	**total**
direct expenditures	**$1,712**	**$5,169**	**$184**	**$7,064**
r&d expenditures	**$1,131**	**$901**	**$326**	**$2,359**
tax expenditures	**$3,651**	**$7,409**	**$607**	**$11,667**
loan guarantees	**$380**	**$196**	**$0**	**$576**
total	**$6,874**	**$13,675**	**$1,117**	**$21,666**
percent of total	**31.7%**	**63.1%**	**5.2%**	**100.0%**

Table 3-2: Federal Financial Support of Low-Carbon Energy
Source: Energy Information Administration, April 2018
Compiled by The EnergyBlue Project

Various regulatory, legislative and tax initiatives would provide financial support, minimizing risk and incentivizing the development and commercialization of advanced coal generation technologies.

Section 45Q Tax Credit Enhancements

In its report on the impact of 45Q Federal tax credits[lxvii], the Clean Air Task Force (CATF) noted that 45Q has the potential to support deployment of CCUS in the U.S. at levels that can remove approximately 49 million tonnes of CO_2 emissions on a yearly basis by 2030 from the power sector alone. CATF's analysis also indicated that "… the infrastructure build out necessary to support the levels our modeling predicts can be achieved by 2030."

Congress greatly enhanced the Section 45Q tax credit in the Bipartisan Budget Act of 2018. The 2018 amendments significantly increased the credit; made its term more certain (and therefore made it more attractive for investment) by establishing that the credit would apply for 12 years, rather than for an unknown period determined by how many credits were claimed by all taxpayers; expanded the credit to include utilization of carbon oxides in making products, and not just for geologic storage; and made it easier to transfer the credit, providing more flexibility to devise business arrangements to make use of it.

Since the tax credit was amended, many developers have been waiting to announce CCUS projects, in significant part because the Department of Treasury and the Internal Revenue Service have yet to finalize regulations and guidance to interpret many of the new statutory terms included in the 2018 amendments to the law. Project developers and investors need to understand the rules and risks with respect to the types of allowable corporate structures for ownership of CCUS equipment; what work will constitute commencement of construction; under what circumstances the tax credit may be subject to recapture, and for how long; what rules apply under various circumstances to assure that sequestering carbon oxides constitutes "secure geological storage" under the statute; and how the lifecycle analysis will apply (and thus how much of the tax credit will be received) when a party is "utilizing" carbon oxide, e.g. through chemical conversion into a material.

The Section 45Q credit could benefit from additional enhancements. Stakeholders have proposed several changes to revise the credit, which would encourage deployment of CCUS:

- **Extend the "under construction" deadline from January 1, 2024 to at least January 1, 2030.** The lack of timely finalization of regulations and guidance from Treasury and the IRS means project developers and investors have less time to decide whether to pursue a project. What was a six-year decision window is now less than a four-year window. For electric utilities in particular, this is a too-short period. In many parts of the country, approval must be received from a state utility commission, in addition to the time it takes to assess the subsurface geology, find project partners, select equipment vendors, conduct public outreach and arrange financing. It also may be necessary to secure rights to the subsurface.
- **Extend the credit period from 12 years to 20 years.** Extending the credit period from 12 years to 20 years better aligns the credit with the cost and life of a project and will make the credit more attractive to investors.
- **Clarify what constitutes "Secure Geological Storage."** The Treasury Department should clarify what measures are required to demonstrate secure geologic storage of CO_2 through Enhanced Oil Recovery (CO_2-EOR). In addition to reporting through a monitoring, reporting and verification plan approved by the EPA under Subpart RR of the Greenhouse Gas Reporting rule, Treasury has proposed a rule allowing use of ISO 27916 to demonstrate secure storage. This would be a good additional means of demonstrating secure geological storage.

Further Incentivizing 45Q

In previous reports[lxviii] for the Secretary of Energy, the National Coal Council (NCC) has endorsed support for Master Limited Partnerships (MLPs) and Private Activity Bonds (PABs) as a means to further incentivize carbon capture, in conjunction with the 45Q tax credit and enable more carbon capture projects to become commercially feasible.

- **Master Limited Partnerships.** Section 7704 of the Internal Revenue Code provides that business structures receiving at least 90% of their income from "qualifying income" can be treated as Master Limited Partnerships (MLPs) for tax purposes. The MLP structure combines the tax benefits of a partnership with a corporation's ability to raise capital in public markets. Allowing carbon capture projects to be MLPs would reduce the cost of equity and provide access to capital on more favorable terms. Neither renewable nor low-carbon fossil technologies, such as CCUS, currently qualify for this treatment. In previous reports, NCC has recommended that should renewable sources be made eligible for MLP treatment, parity requires that CCUS also qualify.

- **Private Activity Bonds.** A variety of activities can be funded by tax-preferred and tax-exempt bonds. Renewable energy projects funded by local governments and electric cooperatives, for example, may issue Clean Renewable Energy Bonds under Section 54 of the Internal Revenue Code to finance clean energy projects, including those also covered by Section 45 tax credits. Extending Private Activity Bond status to CCUS projects would allow developers of carbon capture projects access to tax-exempt debt, thus lowering their capital costs.
- **Base Erosion and Anti-Abuse Tax.** Potential tax equity partners in CCUS projects may be subject to the Base Erosion and Anti-Abuse Tax (BEAT) which was revised in the 2017 tax reform legislation lowering the threshold that triggers application of the tax to multinational corporations. 45Q tax credits cannot be applied to offset BEAT obligations; the wind and solar industries have secured an 80% exemption from BEAT based on the potential adverse impact it might have on the ability of the industry to attract multinational equity partners. As a less mature technology than wind/solar, CCUS would benefit from a 100% exemption from BEAT obligations, removing a barrier to attracting international equity partners in the deployment of CCUS projects. The opportunity to secure BEAT relief should be extended through the duration in which the 45Q tax credit is available.

Section 48A Tax Credit Reform

Section 48A provides a 30% investment tax credit for advanced coal-based generation technology projects. The tax credit was first enacted in 2005 to support coal-based technology that would dramatically reduce SO_2, NOx, particulate matter and mercury emissions. Eligible technologies need to meet both emissions reduction and efficiency improvement requirements (except for IGCC).

Congress later amended section 48A to allow projects that capture at least 65% of CO_2 emissions to be eligible for the tax credit. However, Congress failed to reconcile the heat rate threshold requirements with the carbon capture requirement. In other words, a project would have to capture at least 65% of the CO_2 emissions from a power facility, while also increasing the efficiency of the facility.

Given the parasitic load[19] and steam requirements of carbon capture technology currently available, it is not possible to install post-combustion carbon capture and achieve an increase in unit efficiency. As a result, while the section 48A tax credit could be an important incentive for carbon capture investment and deployment, Congress must provide a technical correction to reconcile the conflicting requirements within the current statute.

[19] Post-combustion carbon capture typically requires 25-30 percent of the electrical output of a unit to operate the system.

Bipartisan legislation – the Carbon Capture Modernization Act[lxix] – is currently pending in both the House and Senate that seeks to enact these needed changes.

Master Limited Partnerships for Repowered and Small-Scale Modular Projects
In addition to using MLPs to complement 45Q projects, there are potential benefits associated with MLPs used in the capital structure of repowered and new coal power generation.[20]

- The refinancing of a coal generator, especially in an independent power producer scenario, could be expedited if MLP status were available to the repowered generator. This could constitute a regulatory incentive for the efficiency and emissions improvement that would come from repowering of an installation. This regulatory incentive would produce maximum impact if it was more broadly available to a "capture ready" installation rather than limited to those involving a complete CCUS package.

- This type of regulatory incentive would likely advance repowering projects, where older plants would retain selected infrastructure involving solids handling and grid connections and replace existing steam generation and turbo-generator equipment with advanced technologies involving higher pressure and temperature steam conditions, including those in the ultra-supercritical category.

- The availability of MLP incorporation for repowered coal generation capacity would help restore a level playing field, which has been tilted toward renewables due to incentives such as renewable energy tax credits. This would be especially useful for post-PURPA (Public Utility Regulatory Policies Act – see page 84) power projects, frequently operating at PURPA capacity limits (100 MW small power producer, 250 MW cogenerators), whose PURPA power contracts have expired and are facing subsidized competition in deregulated power markets. Capacity in this size range would also be an optimum fit for a new generation of small-scale modular technologies which are envisioned as well for outputs in this range.

[20] While there are tax advantages to MLPs, the requirement to pay multiple state taxes where the MLP does business in multiple states would be a disincentive. A single MLP for each installation within a state would mitigate this issue.

Technology-Neutral Tax Credit

Advanced coal generation technologies could benefit from a technology-neutral tax credit to encourage technological innovation, improve energy conversion efficiency, reduce emissions and encourage U.S. clean energy technological leadership.

Legislation for these purposes has been introduced[lxx] to provide up to a 30% investment tax credit (ITC) for a "qualified emerging energy property," or a production tax credit (PTC) of up to 60% of the cost of electricity from a "qualified production facility" for a 10-year period from the date the facility was placed in service.

A "qualified production facility" eligible for the PTC would include innovative facilities utilizing a variety of different clean generation types, including generation – irrespective of fuel source – with at least 60% carbon capture, new nuclear reactor designs, advanced renewable energy and other technologies to produce electricity with an emission rate of less than 150g CO_2-e per kWh with a 75% capacity factor. The credit would decline as the emerging technology gains market share. Facilities would be eligible for the credit in accordance with the following schedule:

Percent Domestic Electricity Production in the Prior Year	Credit Amount
<1%	60%
1-2%	45%
2-3%	30%
>3%	0%

A "qualified emerging energy property" eligible for the ITC would include facilities that qualify for the 60% PTC above, or facilities that can capture at least 60% of the facility's maximum hourly carbon oxide emission rate, and at least 100,000 metric tons annually. First-of-a-kind (FOAK) facilities, as certified by the Secretary of Energy, would be eligible for a 40% credit rather than 30% credit.

Even under a technology-neutral credit, coal-based technologies face one significant challenge in comparison with some competitors – namely, that the facilities are likely to be larger and therefore more capital-intensive. A technology-neutral credit as set forth above would help all advanced coal technologies identified in the Secretary's request. However, they would require integration of carbon capture with the project.

Rural Utilities Service Programs

The Rural Utilities Service ("RUS") under the U.S. Department of Agriculture administers programs to maintain, expand, upgrade and modernize America's rural electric infrastructure. The Rural Electrification Act of 1936 authorizes loans, loan guarantees and, in limited cases, direct grants for construction and improvement of electric generation facilities serving rural areas.

Legislation[lxxi] introduced in the last Congress would authorize the RUS under its existing programs to provide a loan or loan guarantee to CCUS facilities. While this applies only to facilities employing commercially demonstrated technologies, it nevertheless could help foster advanced coal technologies by extending the learning around CCUS in the power sector, given that to-date there still are a limited number of commercial-scale demonstrations. The legislation also would extend the RUS's grant authority for rural areas with high cost electricity to projects including CCUS.

Because rural areas rely more heavily on coal-based generation than other parts of the country, this legislation could have a more significant impact for CCUS than might be assumed.

In addition to the above-noted regulatory, legislative and tax initiatives, the following approaches and programs could help reduce the costs and risks associated with the deployment of advanced coal generation technologies:

Contracts for Differences (CfDs)

In its "Policy Parity" report[lxxii] for the Secretary of Energy, the NCC recommended that the U.S. Department of Energy (DOE) institute a "contracts for differences" (CfD) structure in which a limited number of CCUS projects would bid for financial support making use of a combination of proposed incentives. The value of a CfD approach resides in its ability to tailor a bundle of options to the unique needs of individual projects and contractors.

A CfD structure could, for example, provide a power plant contract recipient with a grant to reduce capital costs, along with a loan guarantee to reduce borrowing cost and a tax credit to reduce the cost of electricity over time. Another recipient might, instead, prefer to make use of a variable price support for electricity or a variable price support for CO_2 sold from its facility.

To achieve maximum effectiveness, the CfD approach should be deployed to advance large-scale pilots and commercial demonstrations supporting a diverse set of technologies in a variety of circumstances and locations. The combination of options available for prospective recipients must be of sufficient value to incentivize their pursuit.

Department of Energy Loan Guarantees

Over its short history, DOE's Loan Program Office (LPO) has successfully steered tens of billions of private sector dollars into advanced energy technologies.[lxxiii] The program could bring an additional $100 billion off the sidelines with existing authorities *and* without new appropriations, according to a study by a research group founded by former Energy Secretary Ernie Moniz.[lxxiv] Despite its success in mobilizing capital into new technologies, the 2005 program has not disbursed funds to any advanced fossil energy projects to date. Of the $8.5 billion authorized within LPO for clean fossil and carbon capture projects, $6.5 billion remains available. One conditional $2 billion loan was extended to Lake Charles Methanol, a Louisiana carbon capture project in 2016.

With the recent changes to the federal carbon capture tax credit (section 45Q) and complementary state policies, significant commercial interest in carbon capture projects is materializing. For example, private companies are working with DOE to engineer how to install carbon capture at five coal power plants across the country. Further, the Department's Coal FIRST and Transformational Coal R&D programs designed to jumpstart investment by the mid-2020s make reconsiderations of the loan program office especially timely. The Department could leverage its remaining authorities for carbon capture and clean fossil projects to accelerate additional investment.

A number of structural reforms to the loan program should be considered:

- **Allow LPO recipients to leverage DOE grants.** Several DOE Office of Fossil Energy (FE) reauthorization bills introduced in Congress allocate significant resources for public-private demonstration projects. Under current rules, projects receiving direct FE support are ineligible for LPO support. The policy should be broadened to allow FE and other applied office award recipients to leverage LPO loans, such that their combined value does not exceed public-private cost thresholds[lxxv].

- **Ensure LPO technology parity**. LPO's activities traditionally supported renewable energy and energy storage projects, in part, because Congress provided a "credit subsidy appropriation," preferential treatment for renewable energy projects within the loan program. With the credit subsidy appropriation, renewable energy and energy efficiency projects could be exempted from paying certain loan program fees.[lxxvi] Conversely, carbon capture projects were always required to pay "credit subsidy costs" designed to cover a project's commercial risk. Any future credit subsidy appropriations should apply uniformly across all LPO-eligible technologies.

- **Address Barriers to Program Use**. In 2016, the State CO_2-EOR Deployment Work Group highlighted a number of barriers to use of DOE's Loan Guarantee Program in its report "Putting the Puzzle Together: State & Federal Drivers for Growing America's Carbon Capture & CO_2-EOR Industry."[lxxvii] The report notes that "Current federal loan guarantees are costly to apply for, limited in terms of the number of projects financeable, burdened by a cumbersome four-year, multi-stage process as required by law, generally triggered a federal environmental impact statement, and require major upfront payments by the project to the U.S. Treasury." These issues need to be addressed as part of any LPO reforms.

Stakeholder Engagement

Broad stakeholder engagement is needed to build support for and reduce risks associated with deploying CCUS and advanced coal technologies. The engagement process must take into consideration Environmental, Societal and Governance (ESG) metrics; employ effective and transparent means of communication with critical stakeholders; provide educational opportunities; and align with local objectives and government policies.

The recent National Petroleum Council CCUS report[lxxviii] noted that deployment of CCUS would remain limited without public commitment and support.

> At present, awareness of CCUS among the general public is low, primarily because a limited cross section of stakeholders has direct interaction with CCUS projects. As a result, the role that CCUS can play in effectively addressing key issues, such as climate change, energy security, and economic growth, is not well understood by the public. Additionally, knowledge and opinions about CCUS vary widely among those who do have a working knowledge of CCUS. This working knowledge is often directly associated with coal and, to a lesser degree, oil and natural gas. Gaining public confidence in, and support for, CCUS will require significantly improving its understanding of CCUS and multiple demonstration projects to illustrate that CCUS is safe and its operations are environmentally sound.

Stakeholder engagement can be a significant enabler of CCUS deployment; it can impede deployment if not done well. Coalitions, independent organizations and NGOs will need to work closely with industry, policymakers, labor organizations and NGOs to educate and inform the public and support policies that will enable wide-scale deployment of CCUS.

The technical complexity of CCUS poses a unique challenge in communicating a project's process, benefits and challenges. Employing terminology more accessible to the public will advance understanding and discourse among critical stakeholders.

NCC supports the recommendations of the NPC report to enhance stakeholder engagement, including 1) conducting meaningful engagement, 2) clarifying messaging, 3) demonstrating society benefits and 4) funding engagement research and education opportunities.

U.S. International Development Finance Corporation Implementation

On January 2, 2020, the U.S. International Development Finance Corporation (DFC) officially began operations. Created by the Better Utilization of Investments Leading to Development (BUILD) Act of 2018, DFC consolidates and modernizes the development finance functions of two federal entities: the Overseas Private Investment Corporation (OPIC) and the U.S. Agency for International Development's Development Credit Authority (DCA).

The mission of DFC is to mobilize private investment for projects in emerging markets that support development, advance American foreign policy and improve lives. In addition to absorbing the functions and capabilities of OPIC and DCA, the new agency is authorized to address development needs through expanded financial tools such as equity investments, technical assistance and feasibility studies. The agency is also authorized to invest up to $60 billion (more than double OPIC's prior limit) and thus is poised to have a significantly expanded impact on the economic development of low- and middle-income countries.

These characteristics make DFC well-suited for financing energy projects in developing countries. The direct and powerful relationship between energy access, economic development and human progress is universally recognized. According to the IEA, 1.2 billion people gained access to the electricity grid between 2000 and 2017.[lxxix] Coal-based power was responsible for 45% of this electrification, providing affordable energy to 540 million people, often through multilateral development banks and other government-backed financing institutions such as DFC.

As IEA Executive Director Faith Birol has stated, coal “remains the backbone of electricity generation and has been the fuel underpinning the rapid industrialization of emerging economies, helping to raise living standards and lift hundreds of millions of people out of energy poverty.”[lxxx] Nonetheless, numerous restrictions instituted over the last decade have limited financial support for coal and other fossil fuel-related projects in developing countries.

For example, in 2009, a legal settlement with non-governmental organizations committed OPIC to a 50% reduction in GHG emissions associated with its development portfolio between 2008 and 2023. This agreement was then codified by Congress later that year, and has been further incorporated into OPIC’s Environmental and Social Policy Statement operating guidance that has accompanied the transition to DFC.[lxxxi] As a practical matter, these conditions severely if not entirely restrict DFC from supporting coal-related development projects.[21]

The NCC’s 2018 report, Advancing U.S. Coal Exports, examined the implications of these restrictions, concluding that in addition to restricting energy access and development opportunities, they may fail to achieve stated environmental objectives:[lxxxii] These circumstances not only place the U.S. at a disadvantage by limiting the potential for U.S. coals and plant technologies to supply international markets, but in many cases, they also result in inferior environmental controls. For example, between 2008 and 2016, China, Japan, and Korea combined to supply over 55 gigawatts of less efficient subcritical boiler technology to developing countries.

According to the World Coal Association (WCA),[lxxxiii] a typical one-gigawatt subcritical power plant in Southeast Asia emits 1.2 million tonnes of additional CO_2 annually compared to a supercritical plant of equal size. By this metric, if the subcritical plants supplied by China, Japan and Korea had instead used high efficiency, low emissions (HELE) supercritical and ultra-supercritical boiler technology, annual CO_2 emissions from those plants would be nearly 66 million tonnes lower – an amount nearly equivalent to the total annual coal-related emissions in countries such as Thailand and Brazil.

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[21] International Development Association (“IDA”) countries as defined by the World Bank are exempt from these restrictions.

These statistics illustrate that, to the extent that U.S.-driven prohibitions on international coal plant financing have led to the deployment of inferior coal plant technologies in developing countries, CO_2 emissions may have increased as a result – precisely the opposite effect intended by their supporters.

Therefore, reversing these policies and restoring U.S. and multilateral development bank (MDB) support for construction of new coal power plants, not only holds promise to better enable institutions such as DFC to achieve its core development mission, but they also present an opportunity to ensure that state-of-the-art environmentally favorable technologies such as the Advanced Ultra-Supercritical power plants can be a part of these development efforts. Accordingly, NCC recommends that DFC work to update and reform its Environmental and Social Policy Statement to end the practice of discriminating against energy sources when considering investment opportunities.

Initiatives to Bolster Emissions Abatement

In addition to the R&D and risk-minimizing initiatives noted above, the following could enhance efforts to achieve CO_2 and criteria emissions reductions.

Clean Energy R&D and Clean Energy Standard

Legislation has been discussed, but not yet introduced, to provide a substantial increase in R&D funding for clean energy technologies, including for coal; provide a regulatory pause for a period of 10 years to allow these technologies to commercialize; and thereafter to institute a national clean energy portfolio standard that gradually would increase the amount of clean energy that each utility would have to provide to its customers. Without details, it is not possible to assess fully the merits of the approach. However, providing a regulatory pause could encourage energy technology innovation.

Mandating performance standards for technology that is not yet mature enough to meet those standards has not encouraged deployment of advanced coal technology, at least during recent years when low-cost competing technologies have been available. The approach of funding and encouraging clean technology with a ‘stretch mandate’ has been successful, as evidenced by state Renewable Portfolio Standards (RPS), in conjunction with the PTC and ITC, in advancing the deployment of intermittent renewable energy. A similar model could be applied to advanced coal technology, if carefully crafted to ensure there is sufficient incentive to deploy technology without causing significant cost impacts to consumers.

Two climate bills currently pending in the U.S. House of Representatives, by and large recognize CCUS-equipped coal plants as qualifying as clean energy technology: H.R. 2597 Clean Energy Standard Act (2019) and H.R. 330 Climate Solutions Act (2019).

Affordable Clean Energy Rule (ACE)
On June 19, 2019, EPA finalized the Affordable Clean Energy Rule (ACE) as a replacement for the Clean Power Plan (CPP). ACE, unlike CCP, focused on power plant efficiency or heat rate improvements (HRI) that could be achieved inside-the-fence at a power plant.[22] States have three years after the final ACE rule is published in the Federal Register to submit their State Implementation Plans (SIPs) for EPA review. EPA will then have up to 18 months to review the SIP submittal and either approve or disapprove it. Should a state fail to submit an adequate SIP, EPA has two years after the SIP submittal deadline to impose a Federal Implementation Plan (FIP). If the state subsequently submits an approvable SIP, the SIP can replace the FIP. Most compliance dates for affected electric generating units (EGUs) will likely fall into the mid-2020s timeframe.

Initiatives to Address Regulatory Risk and Burden

Regulatory uncertainties, risks and burdens have a significant effect on business decisions, most notably contributing to recent decisions to retire coal power plants and/or reduce investments in plant maintenance and technology upgrades. These decisions, in turn, have led to increases in the price of electricity as detailed in a recent report by DOE's National Energy Technology Laboratory (NETL) presenting four scenarios assessing the impact of coal retirements.[lxxxiv]

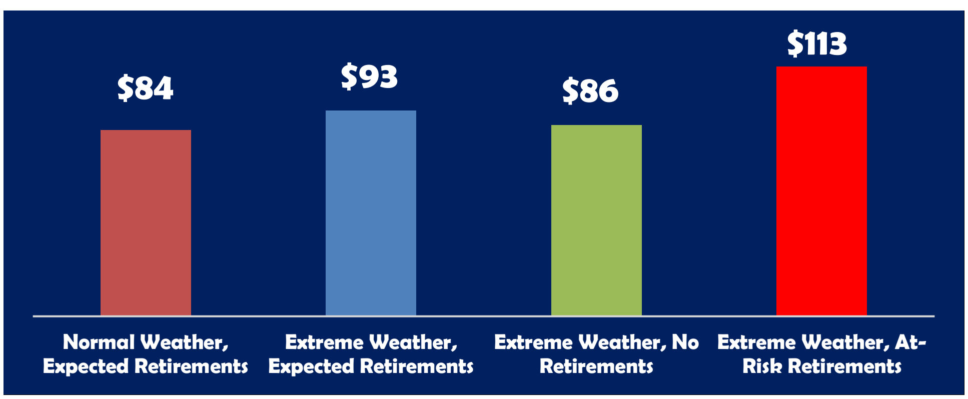


Figure 3-3: Cost of Electricity ($billions)
Source: America's Power
Based on National Energy Technology Laboratory Report Data

[22] The CPP assumed that the Best System of Emission Reduction (BSER) was not limited to a specific plant but to the entire interconnected grid.

The NETL scenarios for future winter season (2020-2024) electricity costs in ISO-New England, PJM, NYISO and MISO included:

- Normal – average power demand and announced coal retirements (10.7 GW in the four market areas assessed)
- Expected – extreme winter power demand and announced coal retirements
- No Retirements – extreme winter power demand and no future coal retirements
- At Risk – extreme winter power demand and retirement of announced plus at-risk coal units (34.3 GW)

As noted in Figure 3-3, NETL found that the expected cost of electricity would increase by almost 11% ($9 billion) due to higher electricity demand during extreme winter weather. If weather conditions are extreme and coal plant retirements accelerate, electricity costs would increase by 35% ($29 billion). On the other hand, if neither announced or at-risk coal plants were to retire, demand during extreme weather would only increase electricity costs by 2.5% ($2 billion).

Initiatives to ease regulatory burdens could reduce the time and expense associated with regulatory compliance, enhancing opportunities for deployment of advanced coal technologies and potentially reducing the number of coal plant retirements.

USE IT Act

The bipartisan Utilizing Significant Emissions with Innovative Technologies (USE IT) Act would support carbon utilization and direct air capture (DAC) research. The bill would also support Federal, state and non-governmental collaboration in the construction and development of CCUS facilities and CO_2 pipelines.

The USE It Act, which has been passed out of the Senate Environment and Public Works Committee, would narrowly amend the Clean Air Act (CAA) to direct the Environmental Protection Agency (EPA) to use its existing authority to support carbon utilization and DAC research and clarify that CCUS projects and CO_2 pipelines are eligible for the permitting review process established by the FAST Act. It would also direct the White House Council on Environmental Quality (CEQ) to establish guidance to assist project developers and operators of CCUS facilities and CO_2 pipelines and establish task forces to secure input from affected stakeholders for updating and improving guidance over time.

New Source Review (NSR)-Growing American Innovation Now (GAIN) Act
Congress has undertaken steps to modify the existing New Source Review (NSR) program, including the introduction of the Growing American Innovation Now (GAIN) Act. The GAIN Act reforms the NSR program under the Clean Air Act to provide greater regulatory certainty about when facility upgrades require an NSR permit.

By amending the definition of "modification" and "construction" under the existing program, the bill would clarify when NSR permits are required and enable facilities to more readily carry out pollution control projects, energy efficiency projects, and equipment reliability and safety improvements. It would also provide the EPA Administrator with authority under certain, clearly defined circumstances to require NSR permitting after determination of an adverse effect to human health or the environment.

The EPA has also taken steps to modernize and streamline the NSR program. To date, the Agency has issued final guidance revising its policy on exclusions from ambient air quality regulations and its interpretation of "adjacent" for NSR purposes. It also issued a decision not to reconsider the 2007 "Reasonable Possibility in Recordkeeping Rule." The rule clarified record-keeping obligations when a major stationary source of emissions undergoes a modification that does not trigger the Agency's "major" NSR requirements. If a company predicts its emissions will not trigger major NSR requirements, it is only subject to emissions record-keeping and reporting requirements if there is a "reasonable possibility" that the predicted emissions from the modification will equal or exceed 50% of the CAA's significant threshold levels for any pollutant.

An Environmental Group's Perspective on NSR
by the Clean Air Task Force

The Clean Air Act requires an existing source to undergo New Source Review whenever it makes a "modification," which includes any physical or operational change that "increases the *amount* of any air pollutant emitted."[23] The Courts have held that the Clean Air Act "unambiguously defines 'increases' in terms of actual emissions,"[24] have upheld EPA's interpretation limiting the applicability of the program to "major modifications" with threshold amounts defined in regulation,[25] and have determined that increased greenhouse gas emissions alone do not trigger applicability.[26] Therefore, if a coal plant improves its efficiency – increases electric output per unit of coal – that does not trigger NSR. It is only when that project leads to the plant operating more often and emitting more conventional air pollution – in amounts above the statutory and regulatory triggers – that the program applies to a modification.[27]

Thus, the Clean Air Act and case law do not allow efficiency projects, or pollution control projects to escape NSR when they lead to an increase in actual annual emissions by significant amounts. If a power plant increases its emissions in this way it must install modern and health-protecting pollution controls as the law requires. As intended by Congress, the NSR program provides a pathway toward modernization for coal-fired power plants. The proposed legislative revisions to NSR would erect a roadblock on that path.

[23] 42 USC § 7411(a)(4) (emphasis added); *see also id*. at § 7479(2)(C) (adopting same definition of "modification" into the prevention of significant deterioration program); and *id*. at § 7501(4) (same for nonattainment new source review program).
[24] *New York v. EPA*, 413 F.3d 3, 39-40 (D.C. Cir. 2005).
[25] *Alabama Power Co. v. Costle*, 636 F.2d 323, 360-61, 400 (D.C. Cir. 1979).
[26] *Util. Air Regulatory Grp. v. EPA*, 573 U.S. 302, 315 (2014).
[27] *New York*, 413 F.3d at 40.

Coal Combustion Residuals

As noted in the accompanying sidebar, using Coal Combustion Residuals (CCRs) in various industrial applications provides an opportunity to reduce GHG emissions. Regulatory programs associated with CCRs (aka Coal Combustion Products - CCPs) should quantify the environmental emissions reductions realized by CCR/CCP utilization and reduce the regulatory constraints associated with this resource recovery activity. The Resource Conservation and Recovery Act (RCRA) clearly states in the goals and objectives set out by Congress that the U.S. should promote the resource recovery and energy savings associated with beneficial use of byproducts that would otherwise be destined for landfills. CCR/CCP utilization is one of the best industry examples that meet the original goals and objectives of RCRA. In addition, use of fly ash CCRs/CCPs to substitute for imported cement meets another goal of RCRA in that it helps reduce the balance of trade since much of the offset cement used is subtracted from imported cement which is often the most expensive cement utilized in U.S. construction and infrastructure.

EPA should reinstate its partnership program with industry to advance the substitution of recovered CCRs/CCPs for raw materials. The former EPA program known as C2P2 proved helpful in meeting RCRA's stated goals and objectives before it was eliminated. A new program with similar objectives should be implemented.

Federal and state agencies should strengthen the purchasing commitments or mandates for recovered CCR/CCP co-products and construction materials which incorporate recovered CCR/CCP materials. Current purchasing requirements do not appear to be having success in improving CCR/CCP substitution. Currently approximately 10%-12% of the cement used in U.S. concrete manufacture is substituted with fly ash. Industry has proven that a replacement rate of 20%-35% within each unit of concrete is achievable while maintaining the same quality as concrete without recovered fly ash. Thus, the economic savings and improved emissions easily could be tripled with more focus on purchasing programs and technical specifications which prioritize use of recovered CCR/CCP materials.

Federal research efforts should renew their focus on the technical improvements in construction materials, such as advanced concrete materials, that are critical to U.S. infrastructure. Continued focus on advanced technology construction materials will help drive the implementation of lower emission construction materials. As an example, new high-ratio CCR/CCP-based cements are proving successful in the field with 50% plus CCR/CCP content. Raising the ratio of CCR/CCPs used in advanced cements is achievable with focused research. Each advancement in cement technology reduces the CO_2 emissions of cement manufacturing and improves the U.S. balance of trade. Leading in the construction materials industry also supports export of technology associated with coal-related products and co-products.

Effluent Limitation Guidelines

Effluent Limitation Guidelines (ELGs) are national regulatory standards for wastewater discharged to surface waters and municipal sewage treatment plants. EPA issues ELGs for categories of existing and new sources under Title III of the Clean Water Act. EPA's ELGs for Steam Electric Power Generating units were last promulgated in 2015 and incorporated into National Pollutant Discharge Elimination Systems (NPDES) permits.

EPA has proposed revisions to the 2015 rule for flue gas desulfurization (FGD) wastewater and for bottom ash transport water. The Agency estimates the proposed rule would result in compliance cost savings of more than $175 million pre-tax annually while reducing pollutants discharged into the nation's waters by approximately 100 million pounds per year compared with existing regulations. Savings would result from less costly FGD wastewater technologies to comply with selenium limits, less costly bottom ash transport water technologies to comply with system water recycling requirements, a two-year extension of compliance timeframes for FGD wastewater and additional subcategories for FGD wastewater and bottom ash transport water. The public comment period on the proposed rule closed in January 2020; EPA projects the proposed rule will be finalized by August 2020.

The Value of Coal Combustion Residuals/Coal Combustion Products

Coal contains mineral components which have many beneficial uses in industrial applications. When coal is prepared and combusted for energy production, the resultant coal combustion residuals (CCRs) become a valuable commodity for industrial applications. CCR minerals (aka coal ash) include heavy particles that fall to the bottom of the boiler (bottom ash) and smaller particles (fly ash) which exit the boiler with the combustion exhaust air and are captured by pollution control devices. Based on the physical nature of the ash particles, each component of the non-combustible mineral has unique uses within the industrial value chain.

In addition to coal ash mineral residuals, the combustion electricity generation process also liberates coal sulfur gases which exit with the exhaust gas stream and are removed by flue gas desulfurization (FGD) control processes also located downstream of the boiler. These sulfur emissions are scrubbed from the exhaust gases by passing through a limestone slurry. The limestone and captured sulfur represent a third CCR which can be utilized in various applications. At power plants that use wet FGD processes, the plant can modify the process to produce a useful calcium sulfate gypsum product that meets or exceeds the characteristics of natural gypsum deposits.

EPA regulates CCRs under the Resource Conservation and Recovery Act (RCRA), classifying CCRs that are beneficially used as Coal Combustion Products (CCP). Under the current rules (October 2015), EPA also regulates disposal of CCRs, exempting CCPs that are beneficially used in subsequent applications which preserve natural resources and meet certain other qualifying criteria. CCPs have been successfully utilized as a valuable part of the construction materials industry for many decades and the benefits of CCP utilization are reflected in monetary savings to utilities, ratepayers and taxpayers throughout the U.S. economy.

While using CCPs saves money for these stakeholders, the use of CCPs also provides major environmental benefits in the form of reductions in disposal landfills, reduced mining of other mineral resources and reduced emissions that would have been released as part of the mining and manufacture of products for which the CCPs are substituting. The most prominent example of this 'win-win-win' scenario is found when fly ash is used to replace cement in the concrete manufacturing process. Fly ash can typically replace a substantial portion of cement in concrete manufacturing which reduces the need for mining of raw materials and manufacture of cement.

Additionally, the use of fly ash as a substitute for cement improves the quality and life cycle of concrete while reducing the cost of concrete to projects such as taxpayer funded highways and bridges, as well as residential housing construction. At the same time, the CO_2 emissions associated with cement manufacturing are offset by fly ash use at a rate of approximately one ton of CO_2 emission reduction for each ton of fly ash used in concrete. In recent decades, the volume of fly used to replace cement has ranged from 10 to 18 million tons per year; CO_2 emissions have thus been reduced at a rate of 10-18 million tons per year, an amount equivalent to the recently announced worldwide CO_2 emissions from Microsoft.

Similar benefits are realized through the use of CCPs in all other applications as well. Calcium sulfate recovered from power plant co-products are used to manufacture approximately 50% of the wallboard manufactured within the U.S. Bottom ash is often used to manufacture lightweight masonry blocks which reduce back injuries in masons and extend their careers leading to productivity gains and better quality of life for employees who serve in the construction industry. Again, in this area, the CCPs substitute for materials that otherwise would have required natural resource mining and processing to manufacture other lightweight aggregates. The continued expansion of CCP use generates economic value for utilities, ratepayers and taxpayers while saving on other raw material extraction and manufacturing.

For additional information on CCRs/CCPs
American Coal Ash Association https://www.acaa-usa.org/

Initiatives to Reform Energy Markets

In its "Power Reset" report,[lxxxv] the NCC noted that the existing U.S. coal fleet offers unique benefits in support of the nation's need for reliable and resilient electric power. The Council recommended steps be undertaken to assess the value of the coal fleet, identifying attributes associated with reliability and resilience, equitably compensating the fleet for these services. Firm, dispatchable power must remain a sustained part of the nation's fuel mix. The following market reforms would support these efforts.

Public Utility Regulatory Policies Act (PURPA) Reform

Modernization of the Public Utility Regulatory Policies Act of 1978 is needed to more realistically reflect today's 21st century electricity landscape, as opposed to that of the 1970s in which PURPA was initially promulgated.

Legislation has been introduced[lxxxvi] to revise Section 210 of PURPA to modify provisions that advantage renewables over utility-owned generation, a large portion of which historically has been coal. Under Section 210, utilities are required to purchase power from qualifying cogeneration facilities and small power production facilities of less than 80 MW at "the cost to the electric utility of the electric energy which, but for the purchase from such co-generator or small power producer, such utility would generate or purchase from another source,"[lxxxvii] otherwise known as "avoided cost."

In recent years concern has grown that some large projects were circumventing PURPA rules to qualify as small power production facilities and become eligible for PURPA's "mandatory purchase" obligation. The Federal Energy Regulatory Commission (FERC) established a standard that multiple generation units would be "considered to be located at the same site as the facility for which qualification is sought if they are located within one mile of the facility for which qualification is sought."[lxxxviii] This is known as the "one mile rule." FERC can waive this requirement for good cause. There has been controversy over whether wind projects in particular have separated generation units into separate clusters more than a mile apart to avoid aggregating the power output capacity to above 80 MW.

The legislation in Congress would change the one mile rule to a rebuttable presumption. FERC could determine that generation units more than a mile apart are part of the same facility taking into consideration whether the units are under common ownership and control, whether they are considered to be a single project for regulatory purposes, and whether they have a common land lease and financing. Furthermore, the local utility would not be under an obligation to purchase output from a small power production facility if the state utility regulator or a non-regulated utility finds that there is no need to purchase the power in order for the utility to meet its obligation to serve customers, or that the facility can compete under an integrated resource planning process that provides for competitive procurement.

Removing undue preferences for other sources will help advanced coal-based technologies to compete.

Wholesale Electricity Market Reforms
Currently, services provided by the U.S. coal generation fleet are not appropriately valued for both the reliability and resilience attributes they provide for the nation's power system. Congress should consider legislation to value fuel security and resilience. Doing so would encourage new generation with those attributes, including advanced coal generation technologies. DOE should continue to develop evaluative tools to assess and report on threats and vulnerabilities regarding fuel security, and make available its expertise to Congress.

The Federal Energy Regulatory Commission (FERC) has authority under existing law to address reliability, an element of which is maintaining a sufficiently resilient power generation fleet, which in turn rests on fuel security. Section 215 of the Federal Power Act provides the Commission with the authority to order the North American Electric Reliability Corporation (NERC), the FERC-designated national electric reliability organization, to submit a proposed or modified electric reliability standard if FERC considers it to be appropriate to maintain electric reliability.

In January of 2018, in considering a proposal by DOE to order regional transmission organizations to provide for sufficient fuel security, FERC noted that the country has: seen a variety of economic, environmental and policy drivers that are changing the way electricity is procured and used. These changes may impact the resilience of the bulk power system. As the nation navigates these changes, the Commission's markets, transmission planning rules, and reliability standards should evolve as needed to address the bulk power system's continued need for reliability and resilience.[lxxxix]

As a result, FERC opened a docket to take commentary on how to address the issue.[xc] However, it has not taken any action pursuant to that docket.

Then Commissioner (now Chairman) Neil Chatterjee noted in his concurrence in the January 2018 order that:

> Neither current RTO/ISO tariffs nor the NERC Reliability Standards require RTOs/ISOs to assess these fuel supply risks or other significant resilience risks and mitigate their potentially significant impact on the bulk-power system. This suggests that existing RTO/ISO tariffs may be unjust and unreasonable insofar as they may not adequately compensate resources for their contributions to bulk power system resilience.

> Consequently, I believe it would have been prudent, in addition to establishing the proceeding in Docket No. AD18-7-000, for the Commission to issue an order to show cause pursuant to section 206 of the Federal Power Act directing each RTO/ISO to either (1) submit tariff revisions to provide interim compensation for existing generation resources that may provide necessary resilience attributes and are at risk of retirement before the conclusion of the proceeding established today or (2) show cause why it should not be required to do so.[xci]

Placing a higher value on fuel-secure generation would encourage construction of new advanced coal-based generation technologies, which are fuel secure. (See sidebar item on Wholesale Electricity Market Impacts on Reliability and Resilience of the U.S. Power Grid.)

Wholesale Electricity Markets
Impacts on Reliability & Resilience of the U.S. Power Grid

Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) have a major effect on the nation's coal fleet because some 150,000 megawatts (MWs) of coal-based generation – almost two-thirds of the fleet – are located in ISO/RTO footprints. Almost all of this coal-based capacity is located in four regions: MISO's footprint includes 57,000 MW; PJM 51,000 MW; SPP 26,000 MW; and ERCOT 15,000 MW. As a consequence, ISO/RTO market policies affect the competitiveness and economic viability of the coal fleet.

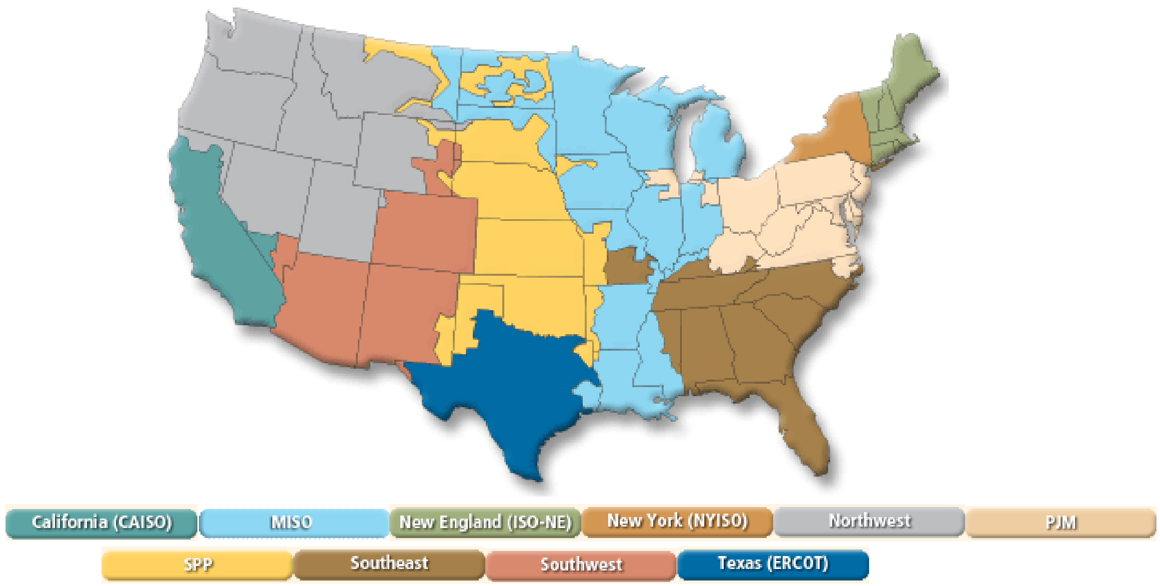


Figure 3-4: U.S. ISOs and RTOs[xcii]
Source: FERC

For a number of reasons, including market policies, 67,000 MW of coal-based generating capacity in ISO/RTO regions have retired between 2010 and 2019. An additional 21,000 MW in these regions have already announced plans to retire. The regions with the most retirements and planned retirements are PJM (37,500 MW); MISO (32,800 MW); ERCOT (6,200 MW); and SPP (5,800 MW).

Generally, ISO/RTOs provide compensation to electricity generators for energy, capacity and essential reliability services. The existing coal fleet is competing with natural gas in many of these markets. In addition, various out-of-market subsidies and mandates can put dispatchable sources, such as coal, at a competitive disadvantage. For example, wind and solar will have received $36.5 billion in tax credits alone over the five-year period 2016–2020, according to the Joint Committee on Taxation.[xciii,28]

[28] For a more expansive Analysis of Federal Expenditures for Energy Development, 1950-2016, see http://misi-net.com/publications/EnergyIncentives-0517.pdf.

Wind and solar benefit from a Federal PTC and ITC, respectively. In the case of wind, the PTC allows wind energy sources to bid into markets at a zero or negative cost that suppresses prices for other electricity resources and increases the need for load following and ramping from coal units. Without the PTC, coal units might be dispatched more frequently, potentially reducing the amount of retirements.

The economic value of the PTC for renewable energy projects “remains one of the core motivators for wind power deployment,” according to DOE’s Office of Energy Efficiency & Renewable Energy.[xciv] The EIA projects that absent the economic incentive of the PTC, new wind generating facilities will come online at a much lower level.[xcv]

In addition to tax benefits such as the PTC, 29 states have renewable portfolio standards requiring that specific percentages of electricity sales come from renewables. These percentages range from 10% in Wisconsin to 100% in Hawaii, Maine and the District of Columbia.

There are other out-of-market subsidies that disadvantage the coal fleet. For example, within PJM's 13-state footprint, 4 states – Northern Illinois, Pennsylvania, New Jersey and Ohio – have adopted or considered zero-emissions credit policies to subsidize existing nuclear plants. Subsidies allow renewable and nuclear generators to enter capacity auctions at prices below their operating costs, pushing down overall market prices and sometimes leading to power plant retirements.

The Value of Fuel Security & Resilience

There have been increasingly serious discussions in energy policy circles about resilience because of the continuing retirement of large amounts of coal and nuclear generation, both of which provide fuel security and essential reliability services. While coal-based generation receives the same compensation as other generators for electric reliability services, coal-based units are not compensated for the increased operating costs associated with being dispatched to provide load following and ramping services.

Fuel security is important to resilience because it enables the grid to absorb and recover quickly from man-made or natural disturbances that could have potentially disastrous consequences. Markets compensate reliability attributes, but not resilience attributes, such as fuel security. Further, markets do not incent investments in fuel-secure infrastructure.

The coal fleet maintains a large coal stockpile at each power plant. In 2019, the average coal-based power plant had an on-site coal supply ranging from 62 days to 105 days of coal burn.[xcvi] Coal stockpiles provide resilience against high impact, low frequency disruptions because on-site fuel supplies minimize the potential for fuel supply disruptions. By contrast, at least 40% of the nation’s electricity resources are not fuel secure.

The U.S. Department of Energy has highlighted concerns about coal and nuclear retirements in its “Staff Report to the Secretary on Electricity Markets and Reliability” and in a proposed “Grid Reliability and Resilience Pricing Rule” to compensate electricity sources that maintain a 90-day supply of fuel on site and provide essential reliability services.[xcvii]

FERC terminated the proposed rule and initiated a new proceeding to define resilience and to evaluate the resilience of the bulk power system in wholesale electricity markets.[xcviii] FERC has proposed to define resilience as “the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.” It is unclear what steps FERC might take as a result of this proceeding, and the timing of any such steps is unknown. In the meantime, coal retirements continue.

Both PJM and ISO-NE have studied fuel security because of the importance of fuel security to resilience. Fuel security enables the grid to absorb and recover quickly from manmade or natural disturbances that could have disastrous consequences. However, the attribute of fuel security is not valued in wholesale markets at the present time.

ISO-NE. ISO-NE defines fuel security as “… the ability of the system’s supply portfolio, given its fuel supply dependencies, to continue serving electricity demand through credible disturbance events … that could lead to disruptions in fuel delivery systems … which could impact the availability of generation over extended periods of time.” ISO-NE has an ongoing analysis of fuel security which it considers to be the region’s most significant resilience challenge. ISO-NE is concerned that power plants in New England might not be able to obtain fuel, particularly in winter, because of coal, oil and nuclear retirements, constrained fuel infrastructure, and difficulty in permitting and operating dual-fuel generating capability.[xcix] So far, the ISO has concluded the region is vulnerable to the season-long outage of any of several major energy facilities and enacted a revision to its tariff to compensate fuel secure generation during periods of high winter demand.[c]

PJM. According to PJM, "Fuel security focuses on the vulnerability of fuel supply and delivery to generators and the risks inherent in increased dependence on a single fuel-delivery system.” PJM has initiated a three-phase effort to analyze and value fuel security.[ci] The PJM analysis has evaluated numerous combinations of coal and nuclear retirements, as well as disruptions to fuel delivery systems. Although the effort has identified risks to the system that could arise from the retirement of coal and nuclear generators and disruptions to the natural gas infrastructure, PJM has decided against enacting market rules to compensate generators for fuel secure attributes for the time being.

Considerations on Funding and Appropriations

Federal support for demonstration and commercial-scale projects for CCUS and advanced coal generation technologies is critical to the development, cost reduction and deployment of these technologies. Efforts should also be undertaken to ensure that these projects are managed by personnel experienced in the management of large-scale projects.

In testimony before the House Subcommittee on Environment and Climate Change in July 2019[cii], Shannon Angielski, Executive Director of the Carbon Utilization Research Council (CURC) noted that Congress is funding DOE's carbon capture program at about $200 million per year. The CURC-EPRI Advanced Fossil Energy Technology Roadmap[ciii] recommends nearly doubling that amount for research, development and testing of large-scale pilot projects, with an additional $300 million/year over 10 years in funding for commercial demonstration projects. Angielski also noted that:

> In addition to these DOE programs, in FY 2017, Congress appropriated $50 million to DOE to undertake a new, transformational carbon capture pilot program, and has since appropriated an additional $60 million for the program (for a total of $110 million). In FY 2019, Congress appropriated an additional $30 million to undertake Front End Engineering and Design (FEED) studies, which may prove to be a more cost-effective way for DOE to advance technologies within the R&D pipeline.

Investments in CCUS and advanced generation technologies support U.S. economic, energy and environmental goals. Continued support of DOE's programs in the form of Congressional appropriations will create jobs, ensure affordable energy for residents and businesses, and provide global markets for technology innovations.

CURC and ClearPath Foundation published an analysis of the macroeconomic benefits to the U.S. of new, lower-cost fossil energy technologies with CCUS.[civ] Under an aggressive RD&D scenario that achieves the CURC-EPRI cost targets, the macroeconomic impacts of CO_2 captured from the power sector for enhanced oil recovery was shown to:

- Contribute up to 925 million barrels of annual domestic oil production
- Increase coal production for power by as much as 40% between 2020 and 2040
- Add 270,000 to 780,000 jobs relating to increased oil production
- Result in a $70 to $190 billion increase in annual GDP by 2040

PROJECT FINANCING OPTIONS
FEDERAL DEVELOPMENT CORPORATION/AUTHORITY

To accelerate the deployment of advanced energy technologies, government must take an active role in incentivizing private sector investments. A couple of recently proposed initiatives would establish an independent Federal development corporation or authority chartered to accelerate deployment of clean energy technologies through financing mechanisms to support early mover CCUS projects. While NCC did not secure universal support for these types of initiatives, DOE may wish to convene a workshop or industry task group to vet these concepts.

Federal Development Corporation Option

This option proposes that the Federal government charter and fund a Federal corporation that develops first mover CCS projects. By structuring the work in a stand-alone corporation as opposed to an arm of a government agency, the corporation can maximize the chances of retaining personnel with experience in managing large construction projects.

This corporation, with Federal funding, would develop 25 CCS projects for electricity generators on the basis of a build-own-transfer business model. This model minimizes performance and cost risks to participating companies since they would not take possession of the unit unless it met cost and performance criteria. The projects would include gas, coal or biomass. At least 3 to 6 CCS applications per vendor would be completed by the corporation.

For those power suppliers who prefer to build their own projects, the corporation would negotiate financial terms to allow those projects to advance using the corporation's financing with the goal of minimizing risks to the developer.

The corporation would also secure needed storage site and pipelines either through contract or through its own development actions to secure long-term storage for the initial CCS projects. At the end of 2035, the corporation would cease to exist, with all assets transferred to the federal treasury.

Congress would initially fund the corporation with $15 billion. In year 7, Congress would provide an additional $15 billion. By staggering these investments, the corporation would have every incentive to spend money effectively to ensure securing the second tranche of funding.

Clean Energy Development Administration

In the midst of the last recession, in 2009, bipartisan legislation was introduced in the House and Senate to establish a new Federal entity, the Clean Energy Development Administration (CEDA). The idea was that an independent, business-driven Federal financing agency with access to a diverse set of tools could better leverage private investment to accelerate the deployment of clean energy technologies developed in the U.S.

It was proposed that CEDA would focus its resources in two areas:

- Direct support in the form of loans, loan guarantees, letters of credit, insurance products and other credit enhancements or debt instruments to project employing innovative clean energy technologies that help achieve broader energy and climate goals.
- Indirect support for projects through securitization or other means of credit enhancement.

According to the Bipartisan Policy Center, CEDA, if adopted today, would help create a more streamlined connection from the earlier-stage Federal energy innovation being supported by the Advanced Research Projects Agency – Energy (ARPA-E) to commercial deployment. CEDA could leverage significant private capital in support of clean energy technology innovation, commercialization and deployment.

U.S. Funding of International Technology. While international collaboration in support of deployment of advanced technologies is valuable, consideration should be given to the economic beneficiaries of U.S.-funded investments. Technologies being supported through U.S. funds may be benefitting foreign-based developers for technologies neither designed nor manufactured in the U.S. Domestic turbine manufacturers are, today, concentrating their efforts on natural gas combined cycle plants, while major boiler manufacturers are now based overseas.

Technology funding may be awarded to companies with U.S. offices, but whose parent companies are not U.S.-based. The U.S. risks losing domestically based power sector R&D competence, technical expertise and manufacturing capability. Initiatives to incentivize private sector engagement in deploying advanced generation technologies should take into consideration support for U.S. owned companies that can help rebuild capacity in these areas. Support for U.S.-based companies could facilitate a transfer of expertise from experienced senior designers/engineers to younger staff, enabling a succession of personnel skilled in the development and deployment of sustainable technologies.

DOE's recent $81 million Funding Opportunity Announcement (FOA)[cv] for R&D projects in support of the Office of Fossil Energy's Coal FIRST initiative, notes that FEED work supported by this award must provide:

- At least 50% of the planned fuel input (by HHV) be coal mined in the U.S.
- At least 50% of the planned plant equipment (on a dollar basis) be fabricated in the U.S.
- At least 75% of the planned labor in design and construction be U.S. based.

More of these types of requirements associated with Federal funding opportunities would support U.S. economic, energy and environmental objectives.

Department of Energy Funding Priorities

The U.S. Department of Energy's (DOE) coal research and development budget priorities include:

- Implementing the Coal FIRST initiative. R&D on first-of-a-kind small-scale modular coal plants of the future which are highly efficient and flexible, with near-zero emissions.
- Improving the performance, reliability and efficiency of the existing coal fleet.
- Reducing the cost and risk of carbon capture for commercial deployment.
- Creating new market opportunities for coal.

A significant number of funding opportunity awards (FOA) for fossil energy-related projects have been granted in 2019 in support of these priorities (see Appendix B).

CCS and Power Systems, $ in thousands	FY 2019 Enacted	FY 2020 House	FY 2020 Senate	Future Plants	Existing Plants	Cost of Capture	New Markets
Carbon Capture	100,671	125,000	113,000	✓	✓	✓	
Carbon Storage	98,096	102,000	103,000			✓	✓
Advanced Energy Systems	129,683	107,000	139,000	✓	✓	✓	✓
Crosscutting Research	56,350	65,255	64,3000	✓	✓		
Rare Earth Elements	18,000	23,000	25,000				✓
STEP sCO_2	22,430	24,000	14,000	✓	✓		
Transformational Coal Pilots	25,000	20,000	17,000	✓	✓	✓	
NETL Coal R&D	36,000	38,000	42,000	✓	✓	✓	✓
TOTAL CCS and Power Systems	**486,230**	**504,255**	**517,300**				

Table 2-2. DOE Funding for Advanced Fossil Energy Technology Research (FY2019 enacted versus FY2020 proposed)
Source: National Energy Technology Laboratory, U.S. Department of Energy

DOE's Office of Fossil Energy and National Energy Technology Laboratory (NETL) have secured modest increases in research funding for fossil energy for FY2020 over FY2019 as shown in Table 2-2. These increases are positive and can help foster innovation in technologies that produce dispatchable low-carbon power. However, in order to realize a low-carbon future derived from reliable generation sources, more investment in these technologies is needed.

Meeting the Dual Challenge
A Roadmap to At-Scale Deployment of Carbon Capture, Use and Storage

In December 2019, the National Petroleum Council (NPC) published a report addressing the Secretary of Energy's request for advice on actions needed to deploy CCUS technologies at scale in the U.S. The Secretary requested that the National Coal Council (NCC) support NPC's efforts on this report; NCC provided background from its expansive body of work on this topic and NCC members participated in NPC report committees.

Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage, recognizes that the world faces a dual challenge to provide affordable, reliable energy while reducing GHG emissions and addressing the risks of climate change. The report builds the case for CCUS and details three phases of specific, actionable recommendations needed to achieve deployment at scale, a level defined by the study as ~500 million tonnes per annum (Mtpa) or 20% of U.S. stationary source emissions. The report concludes that at-scale deployment requires strong collaboration between industry and government; improved policies, financial incentives, and regulations; broad-based innovation and technology development; and increased understanding and confidence in CCUS – to create a roadmap for achieving at-scale deployment over the next 25 years.

The U.S. leads the world in CCUS deployment today with approximately 80% of the world's CO_2 capture capacity, but this represents less than 1% of the U.S. CO_2 emissions from stationary sources. Increasing deployment can deliver benefits and favorably position the U.S. to participate in new market opportunities as the world transitions to a lower carbon energy system. As part of the study, the costs associated with the capture, transport, and storage of CO_2 emissions from the largest 80% of U.S. stationary sources were assessed and presented as a CCUS cost curve, where the costs to capture, transport and store one tonne of CO_2 is plotted against the volume of abatement it could provide. The calculated cost per tonne gives an indication of the minimum financial value needed to incentivize CCUS supply chain development. Using the resulting economics as a basis, the report presented a set of recommendations in four areas – financial incentives, regulatory frameworks, technology and capability, and stakeholder engagement

Activation phase: Clarifying existing federal tax policy and more efficient geologic storage permitting regulations could double existing CCUS capacity (from 25 to 60 Mtpa) within the next 5 to 7 years. This phase can be achieved without Congressional action. Other actions, described below, need to start in this timeframe as well.

Expansion phase: Congress will need to extend and increase existing financial incentives to a level of about $90/tonne and, working with Federal and state agencies, further develop a durable legal and regulatory framework to incentivize and enable an additional 75-85 Mtpa of CCUS capacity within 15 years.

At-scale deployment phase: Substantial Congressional policy action, including economic support of about $110/tonne, backed by industry investment and public support, will be required to achieve an additional 350-400 Mtpa of capacity in the next 25 years. Policy options to achieve this level of support should be thoroughly evaluated during the expansion phase to determine an economically efficient option.

R&D: A commitment to CCUS must include a commitment to critical R&D. Substantially increased government and private research, development, and demonstration (RD&D) will be needed to improve performance, reduce costs, and advance alternatives beyond currently deployed technologies. To achieve this, Congress will need to increase RD&D funding for CCUS technologies to $15 billion over the next 10 years, with a significant amount directed to less mature and emerging technologies that offer the greatest potential for a step change in performance and cost reduction, including direct air capture and negative emission technologies.

Reference: National Petroleum Council (2019). *Executive* Summary. Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage in the United States. NPC. Washington DC.

Chapter 4. State-Regional-Tribal Initiatives to Accelerate Deployment of Coal Power Generation Technologies

KEY FINDINGS

- **States can take a unique leadership role in accelerating the deployment of advanced coal generation technologies by providing regulatory certainty, supporting infrastructure planning, streamlining permitting in cooperation with the Federal government and providing technology and infrastructure financing incentives.**

- **Intra-state and regional collaboration among states, universities, industry and NGOs can contribute to advancing and accelerating the deployment of coal technologies.**

- **State public utility regulators have a role to play and tools at their disposal for bolstering the reliability and resilience of the power grid, for encouraging adoption of carbon capture, utilization and storage (CCUS) technologies and for extending the life of existing coal power plants while curtailing CO_2 emissions.**

- **Tribal entities are being economically impacted by energy resource and generation decisions and must play an active role in establishing and implementing energy policies that support coal utilization.**

Managing Generation Resources at State, Regional and Tribal Levels

Federal legislative and regulatory initiatives detailed in Chapter 3 of this report are critical to accelerate deployment of advanced coal generation technologies. Integration of these Federal initiatives with state policies enhances the chances of successfully deploying technologies in support of national environmental, economic and energy security objectives. Regional initiatives in which states, universities, industry and NGOs combine their efforts to advance goals that extend beyond state borders are proving to be effective in maximizing resources and leveraging opportunities made available through Federal policies. Tribal initiatives further contribute to these efforts.

State governments influence energy resource-related decisions through tax optimization, regulatory policies and financial incentives. State energy regulators and public utility commissioners, tasked with ensuring that safe, reliable and affordable electric power is available to state residents and businesses, are increasingly pressured to balance emissions goals, customer demands and a slate of challenging policy objectives. The recent wave of coal power plant closures and changes in the nation's electricity generation mix are creating additional challenges for state energy regulators, especially in those states with a high reliance on intermittent renewable energy (IRE) and those which have experienced significant coal plant retirements.

The recent report prepared by Energy Ventures Analysis for the National Association of Regulatory Utility Commissioners[cvi] (NARUC) examined challenges faced by coal plants now operating as load-following or cycling resources. The report details options for addressing these challenges for both operators and regulators. Between 2008 and 2018, all but one state (Alaska) experienced a drop in coal generation.

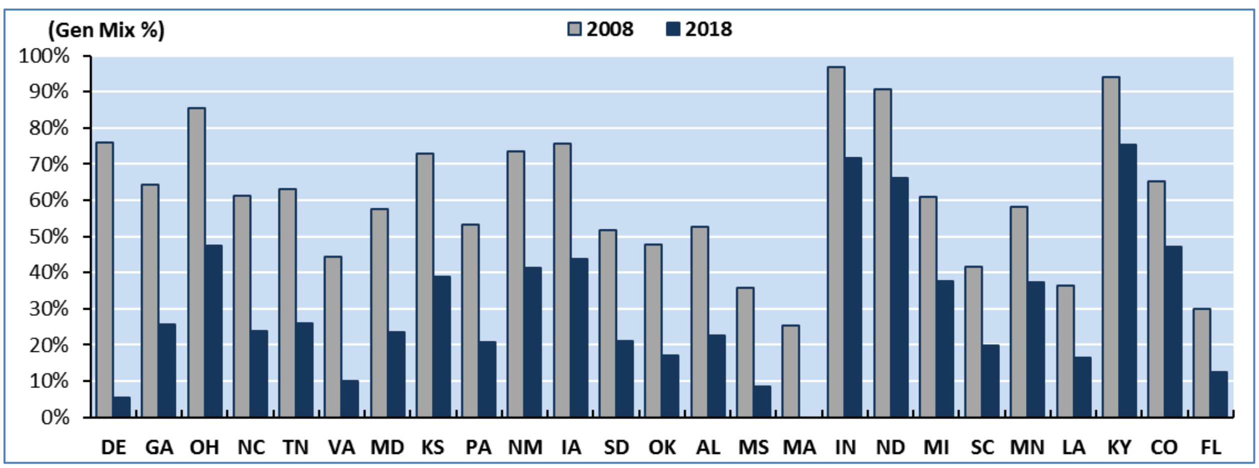


Figure 4-1: Top 25 Declines in Coal Generation Share by State – 2008 vs. 2018
Source: NARUC/Energy Ventures Analysis

In those states in which IRE has been added to the power system, utilities and ISOs have had to balance considerable amounts of variable generation with dispatchable, on-demand power from coal and natural gas. Dispatchable generation has become increasingly important to balance variability associated with IRE. As an increasing number of coal power plants are retired and more IRE plants are deployed, balancing load will become more challenging, impacting state energy regulators' ability to ensure reliable electric power.

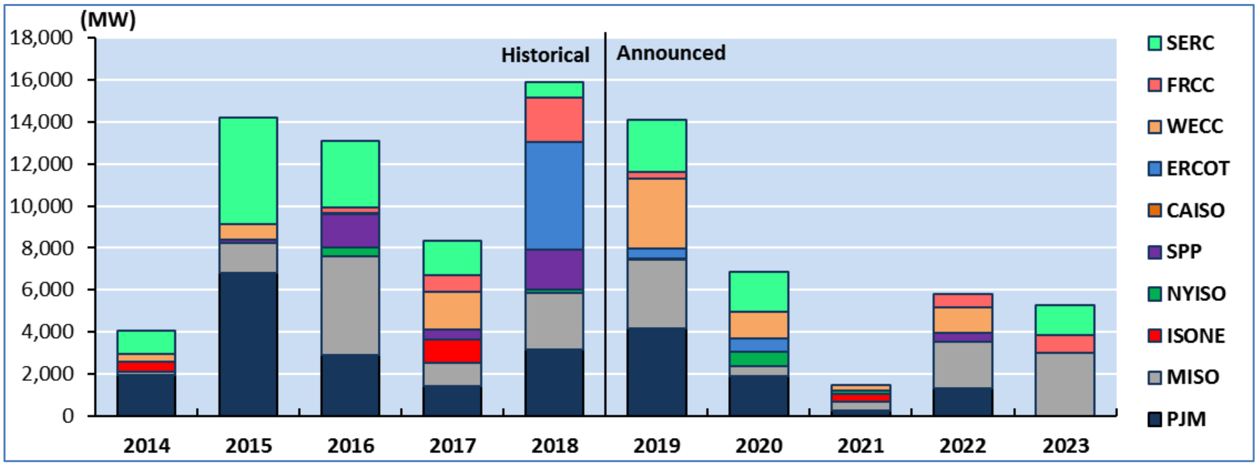


Figure 4-2: Historical/Projected Coal Retirements by Power Market 2008 to 2018
Source: NARUC/Energy Ventures Analysis

The NARUC report details various mitigation strategies to counteract increased maintenance and capital costs associated with increased coal plant cycling, most of which require significant additional capital investments by coal plant owners. The revenue stream of these plant owners has, however, declined as a result of increased generation from IRE and low natural gas prices, eroding the economic viability of coal-based generation across the nation. So, while they provide essential reliability and flexibility services, the existing coal fleet is at risk.

State energy regulatory bodies and market participants recognize the need to retain generating capacity at levels above peak demand to compensate for unexpected losses in IRE and other power generation disruptions. Those regions with power markets, such as PJM, are providing capacity payments to generating resources to ensure capacity is available when needed. However, as noted in the NARUC report, the two markets with the highest share of IRE – SPP and ERCOT – do not currently have capacity markets but acknowledge the need to develop compensation mechanisms to address capacity uncertainties. PJM and MISO are also developing new market mechanisms to compensate coal plants for their reliability and flexibility.

Current market and regulatory mechanisms are not sufficient to compensate coal plant operators for costs associated with enhancing the efficiency and flexibility of the existing fleet. State energy regulators must initiate and continue efforts that support the reliability and resilience values provided by dispatchable coal generation. This includes advancing policies, market instruments and incentives for sustaining the existing coal fleet and promoting the deployment of coal generation technologies. This chapter highlights various initiatives being employed at the state and regional levels and by the nation's tribal entities.

State Initiatives

State Public Utility Commission
Support for Advanced Coal Technology Deployment

In November 2018, NARUC released a report detailing measures state policymakers and regulators could undertake to encourage adoption of CCUS technologies to extend the life of existing coal power plants while curtailing CO_2 emissions.[cvii] The report cites a number of options that can be employed by public utility commissioners to create regulatory certainty and shorten payback periods for utility investments in CCUS, including:

- Renewable Portfolio/Clean Energy Standards
- Low-carbon Credits
- Cost Recovery for CCUS
- Siting
- Planning

While the measures noted in the report are specific to CCUS deployment, many could be adopted to enhance deployment of other advanced coal generation technologies.

Renewable Portfolio/Clean Energy Standards. Renewable Portfolio Standards (RPS) have been adopted in a majority of states, successfully mandating the deployment of renewable power generation. RPSs are generally set by state legislatures and implemented by commissions which are responsible for ensuring utility compliance with those RPSs. Coal generation with CCUS is typically not included in the definition of RPS compliance options, although a few states have adopted a broader "clean energy standard" (CES) that includes coal with CCUS – Pennsylvania, Ohio, Michigan and West Virginia.

Broadening RPS or CES eligibility to include coal generation with CCUS or low-carbon fuels would require legislative approval, with commissions having a "role in setting and reviewing cost-benefit analyses and/or approving investment decisions by utilities across RPS-eligible technologies," according the NARUC report.

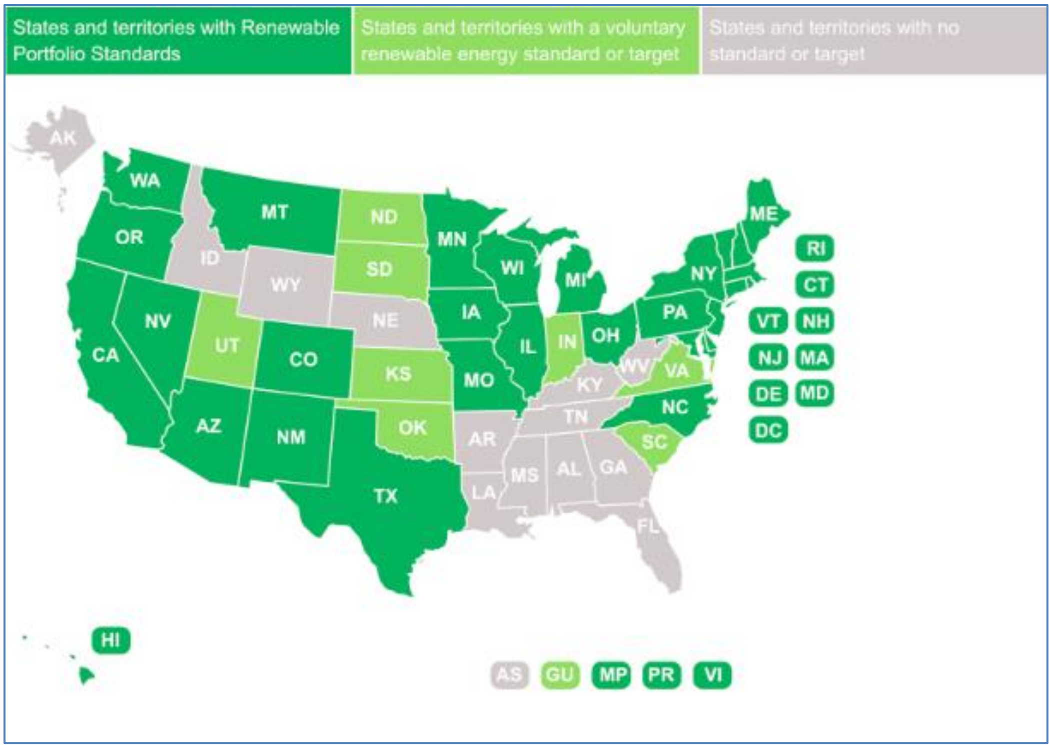


Figure 4-3 Renewable Portfolio Standards or Voluntary Targets
Source: National Conference of State Legislatures[cviii]

Low-carbon Credits. Commissions could implement low-carbon credit programs to include CCUS, similar to initiatives in Illinois and New York that incentivize nuclear power in an effort to retain the nuclear generation option.

Cost Recovery for CCUS. Commissions in vertically integrated states decide what costs can be passed on to ratepayers as "prudent" investments in electricity generation, transmission and distribution. Including CCUS retrofit costs as a prudent investment would create a favorable environment for utilities, enabling them to recover retrofit costs through rate bases and ensuring a measure of regulatory certainty.

For retrofits or new power plants, commissions could also approve rate recovery on construction work in progress, thus enabling stakeholders to begin recovering investments before projects are operational. The NARUC report notes that "selected states have also allowed periodic adjustment mechanisms to recover environmental compliance costs, rather than requiring utilities to go through a general rate case." These mechanisms could allow CCUS projects to provide gradual payback to developers or shareholders.

Siting. State commissions typically have no authority over siting of source facility, pipeline and sequestration sites for CCUS projects. There are, however, actions state energy regulators and commissions can take to improve the siting process, including encouraging carbon capture development by pre-approving project siting and environmental criteria, and working with stakeholders to streamline pipeline permitting.

Planning. Commissions could issue guidance requiring consideration of carbon capture in integrated resource plans (IRPs) along with other forms of generation.

State Legislative and Regulatory Support for Advanced Coal Technology Deployment

Regulatory certainty is critical to support investments in development and deployment of advanced coal generation technologies. Recommendations from NARUC's November 2018 report, which identify numerous state legislative and regulatory options to encourage deployment of CCUS, suggest a model approach to support regulatory certainty in advocating for a "cradle to grave" regulatory framework. The CCUS-specific approach recommends a comprehensive framework addressing regulatory requirements for CO_2 source facilities, transport and sequestration. Among the potential CCUS support mechanisms:

- Enable CCUS projects to participate in state Private Activity Bond markets (see Chapter 3, page 68). PABs enable states to finance CCUS infrastructure at no cost or risk to the state itself.

- Secure state authority from EPA to permit Class VI Underground Injection Control (UIC) wells to replace Federal enforcement (see Chapter 5, page 126). North Dakota is currently the only state that has received EPA approval to enforce its own Class VI program. Wyoming is currently in the public comment period for primacy approval.

- Clarify long-term liability issues associated with CO_2 storage sites. Five states have passed legislation transferring liability for CO_2 storage sites to the state – Illinois[29], Louisiana, Montana, North Dakota and Texas.

- Codify definitions of subsurface ownership of CO_2 and pore space injection sites. Three states have laws in place – Montana, North Dakota and Wyoming.

[29] Illinois' legislation was a one-time effort specifically associated with the FutureGen project. No CO_2 storage since then has been considered for transferability to the state.

State engagement is vital in all phases of the energy technology deployment process. Among the incentives that can be offered by states:

- Front End Engineering & Design (FEED): Grants
- Permitting: Liability/Ownership Clarification, Clear Regulatory Framework, Time-Certain Permitting
- Financing: Grants, Loans, Franchise Tax Credits, Sales Tax Reduction on Equipment, Rate Recovery
- Construction: Eminent Domain for Pipelines/Infrastructure, Sales Tax Exemptions, Property Tax Abatement
- Operation: Franchise Tax Credits, Severance Tax Exemptions or Reductions, Gross Receipts and Income Tax Exemptions, Property Tax Exemptions

Among the Initiatives being advanced by states in support of deployment of advanced coal generation technologies (see Appendix C for examples of state-specific initiatives):

Clean Energy Standards. A number of states are establishing CESs, either in addition to or as extensions of Renewable Portfolio Standards. Unlike RPSs that mandate use of intermittent renewable energy sources, CESs prioritize performance and outcomes as opposed to a particular energy technology, broadening the opportunity beyond just IRE to include low-carbon options such as coal generation with CCUS.

R&D Support. States are leveraging Federal funding opportunities for coal technology research and development with state-supported initiatives recognizing the economic and environmental benefits coal generation provides for its residents and businesses.

Expediting Coal Projects. In addition to providing favorable tax incentives, states are supporting the deployment of coal technologies and projects by streamlining permitting and providing opportunities for advanced environmental compliances reviews.

Tax Treatment for Coal Projects. States are establishing favorable tax incentives to support deployment of clean energy technologies, including reduced sales/property taxes, exemptions and modifications, and extending other tax incentives to aid in the purchase and R&D of these technologies.

Coal Plant Retirements – A Measured Approach. In recent testimony before the Ohio Senate Energy and Public Utilities Committee, America's Power President and CEO Michelle Bloodworth noted that since 2010, more than 133,000 MW of coal generation has retired or announced plans to retire.[cix] This represents about 40% of the coal fleet that was operating in 2010. The extent of these coal plant retirements has implications for grid reliability/resilience and consumer electricity rates, prompting states to establish procedures to evaluate these impacts prior to proceeding with coal plant closures.

State-Specific Initiatives in Support of Advanced Coal Technologies

States are employing various legislative and regulatory tools to support coal and the deployment of advanced coal technologies. The following table provides a summary of the areas in which select states are supporting such initiatives. Appendix C provides details on state-specific legislation and regulations.

	GA	IN	IA	KY	MT	ND	OH	OK	VA	SC	WV	WY
Financial Support	x			x	x							
Reliability & Resilience		x		x	x		x				x	x
R&D Support						x	x					
Regulatory Certainty			x			x						
Permitting & Environment	x		x						x	x		x
Tax Incentives				x	x	x		x			x	x

Table 4-1. State Initiatives in Support of Coal/Coal Technologies

Intra-State Collaboration

The success of initiatives in support of advanced coal technology deployment can be greatly enhanced by collaborative efforts among entities within a state. This potential is best illustrated by the endeavors undertaken by state government, university, industry and trade/non-profit organizations in various states. In North Dakota, for instance, the North Dakota Industrial Commission, Energy & Environmental Research Center (University of North Dakota) and Minnkota Power have worked closely with the DOE and made significant progress toward implementation of Project Tundra, a retrofit of Minnkota's Milton R. Young Power Station. If completed, the retrofit will serve as the world's largest post-combustion capture and storage project.

Regional Collaboration

Regional collaboration between states can also contribute to advancing and accelerating the deployment of coal technologies. The State Carbon Capture Work Group is one such example of a regional initiative designed to enhance deployment of CCUS technology and infrastructure. Formed in 2015 by then Governor Mead (R-WY) and Governor Bullock (D-MT), the Group now includes the states of Arkansas, Colorado, Illinois, Indiana, Kansas, Louisiana, Michigan, Mississippi, Montana, Oklahoma, Pennsylvania, Ohio, Utah and Wyoming.

The Group is currently overseeing midwestern and western regional carbon capture deployment initiatives, including the modeling of candidate capture and storage projects and pipeline infrastructure. State policy teams are being formed to develop tailored policy recommendations to complement the Federal 45Q tax credit. Industry, universities, consulting firms, national labs and Federal agencies (DOE, EPA) are engaged in identifying potential early mover capture projects by state and modeling regional CO_2 transport infrastructure to maximize CCUS. Economic impact and jobs analyses are also planned.

This initiative is driving awareness among state officials, industry, labor and NGO stakeholders of the opportunity presented by the 45Q tax credit; helping to advance state CO_2 transport infrastructure planning and policy development; and redefining the CO_2 challenge as an opportunity to enhance domestic energy and industry production and high-wage jobs.

Tribal Considerations

Changes in the generation mix are impacting the nation’s tribes. Jonathan Nez, President of the Navajo Nation recently noted that “As the state's [Arizona and New Mexico] utilities begin to pivot their energy portfolios away from coal, the Navajo Nation is faced with significant economic repercussions.”[cx] Nez notes that salaries at the Navajo Generating Station and Four Corners plants were "typically in excess of $100,000/year, and including retirement and health benefits brings the average closer to $150,000/year. These jobs are irreplaceable on the Navajo Nation and this loss will have a significant impact on community members."

This situation underscores the importance of taking into consideration regulatory issues associated with tribal energy resources, including those associated with tribal sovereign immunity, and energy development and self-determination. These issues influence the decision-making ability of the tribes to advance the development and deployment of coal and related resources.

Sovereign Immunity. The Navajo Transitional Energy Company (NTEC) is being required, as part of its mining permit transfer/application process in both Montana and Wyoming, to provide waivers of sovereign immunity to the states. The key concerns for NTEC, as a wholly-owned tribal entity, are the extent of the waivers (limited vs. complete) that the states will require. This also relates to far broader sovereignty issues for all tribes to the extent to which states may insist on waivers from tribes whenever they seek to conduct business off reservations.

NTEC recognizes it is dealing with state regulatory agencies that are confronting this issue for the first time. As a consequence, NTEC has focused on explaining the extent to which state and Federal regulatory agencies retain enforcement and oversight authority (even in the absence of a waiver) whenever a tribal entity operates outside of a reservation. Nevertheless, NTEC considers it extremely important to advocate for the position that complete waivers are entirely inappropriate simply in return for being able to conduct business in a given state. Ultimately, this would be a significant "end-run" by the states which would seriously undermine very hard-fought rights currently held by the tribes. Finally, with respect to NTEC itself, the Company is not authorized to provide anything other than a limited waiver of its sovereign immunity regardless.

Energy Resource Agreements and Self Determination. In 2005, Congress passed a law authorizing tribes, at their discretion, to apply for and enter into Tribal Energy Resource Agreements (TERAs) with the Secretary of the Interior. The 2005 law is entitled "Indian Trial Energy Development and Self Determination Act of 2005" (Title XXVI, Section 2604 of the Energy Policy Act - Pub.L.109-58).

Secretarial approval of a TERA will allow the tribe or tribes seeking a TERA to enter into energy-related leases, business agreements and rights-of-ways on tribal lands without Secretarial review and approval. The Bureau of Indian Affairs (BIA) finalized regulations to allow tribes to perform under this new authority in Indian Energy Development in 2008 (25CFR, part 224).

In addition to the Indian Minerals Development Act, TERAs allow tribes another option to access development on Indian lands. TERAs fall in line with the national energy policy to provide development for tribes with both energy renewables and fossil/mineral development.

Congress passed amendments to authorize provisions in the TERAs (Indian Tribal Energy Development and Self-Determination Act Amendments of 2017). The Amendments updated the procedures and conditions for the Secretary's approval of TERAs. Tribes are authorized to enter into energy business leases, leases and business agreements. A Tribal Energy Development Organization (TEDO) does not need Secretarial approval for energy-related leases, business agreements and rights-of-ways between the tribe and a certified TEDO when issued from the tribe to the TEDO.

The Tribal Energy Resource Agreements and the current Secretarial Order by Interior Secretary Bernhardt will allow tribes to have better access to the self-determination provisions under the Indian Tribal Energy Development and Self-Determination Act. Secretary Bernhardt will accomplish this by directing the Office of the Solicitor to provide guidance on inherent Federal functions to promote tribal self-determination and utilization of Indian energy resources. The BIA, Bureau of Land Management (BLM) and Office of Natural Resources Revenue (ONNR) are currently developing a Memorandum of Agreement to meet Secretary Bernhardt's directives. This allows tribes to get creative in establishing their TERAs.

The Department of Energy could help support access to funding to execute development on Indian lands, providing guidance on how the Guaranteed Loan Program of $2 billion can be used to assist tribes who are looking to perform a TERA on their own lands. Tribal Guaranteed Loan Programs should be amended to allow for Tribal Energy Development Organizations so it can work together with the new TERA amendments.

Colorado's Comanche Generating Station

Project Background

Xcel's plans to shutter Comanche Generating Station Units 1 & 2 earlier than initially announced (2022 & 2025) were approved by the PSC of Colorado. The coal units are to be replaced with 2,000 MW of natural gas, wind, solar and storage. Xcel projects the cost to be $2.5 billion.

Low-cost, High Capacity, Clean Electricity

The Comanche Power Station has a production cost of $23.30 MWh; lower than any of the natural gas baseload plants in the state. Due to its low cost, the plant operates at a high capacity/utilization rate – Unit 1 – 69%, Unit 2 – 82%

This low cost did not come at the expense of the environment. Comanche Power Station has spent $190 million to add Dry Scrubbers, Fabric Filters, Low-NOx burners, and Activated Carbon Injection controls.

Prime Candidate for CCUS

Diminishing Supply of CO_2: Oxy Petroleum, owners of the Sheep Mountain field and pipeline, has reported a diminishing supply of natural CO_2. The company has expressed interest in anthropogenic sources in the Colorado Plateau.

Close proximity to CO_2 wellhead: Comanche Generating Station is located only 37 miles from the Sheep Mountain CO_2 Wellhead. A pipeline from the well carries CO_2 508 miles from southern Colorado to the Permian basin in west Texas.

Pipeline Capacity Low: At its peak in 1988, Oxy was transporting 35 Bscf/y of CO_2 from the Sheep Mountain field through its pipeline. In 2018, the amount declined to 7.7 Bscf/y. While the Oxy pipeline also carries natural CO_2 from the Bravo Dome and anthropogenic CO_2 from the La Veta gas processing plant, there is significant capacity for CO_2 from the Comanche Station.

DOE Sponsored Study

In June 2019, Leonardo Technologies, Inc. (LTI) and Management Information Services, Inc. (MISI) released a study of the economic feasibility of a CCUS retrofit project for the Comanche Station. The study, commissioned by the U.S. Department of Energy, provided a detailed analysis of physical, social, and economic issues applicable to the installation and operation of a carbon capture facility on all three units of the power plant.

Physical Capabilities

Close to CO_2 pipeline: A short, 37 mile, feeder pipeline over favorable terrain provides no obstacle for delivering the CO_2 from the power plant to the Sheep Mountain Pipeline (SMPL) wellhead

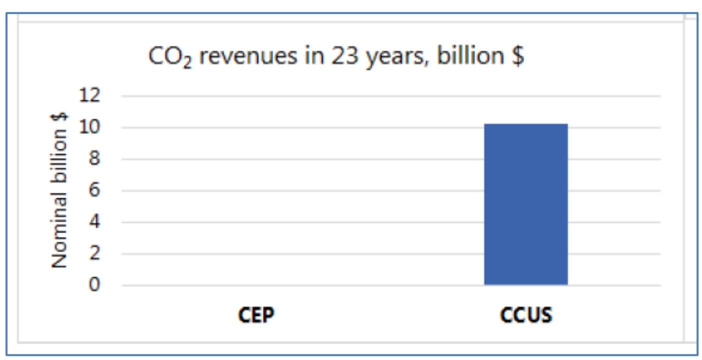
Pipeline capacity: At a 90% CO_2 capture rate, Units 1, 2, & 3 could provide 9MMT/y of CO_2 to the SMPL, which is well within the capacity needs of the SMPL of 11MMT/y.

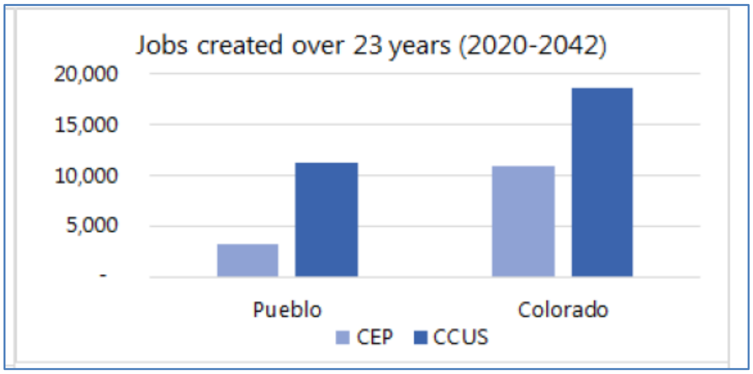
Market: CO_2 consumption in the Permian Basin exceeded 1 billion tons in 2018. Although the deliveries of CO_2 continue to rise, the need demand for the commodity is increasing at an even greater rate.

Economic Advantages

Capital Costs: Xcel estimated the cost of the Colorado Energy Plan (CEP) at $2.55 billion; the DOE study pegs the cost of CCUS retrofit at $2.86 billion.

Revenue: Combining the market price of CO_2 and the 45Q credit (assuming 12 years of tax credit and 85% monetization of the credit), the average sales price over the duration of the CCUS project is estimated to be $36/tonne. Given this price over the duration of the CCUS project (2023-2042), Xcel would reap $10.21 billion in additional revenue.





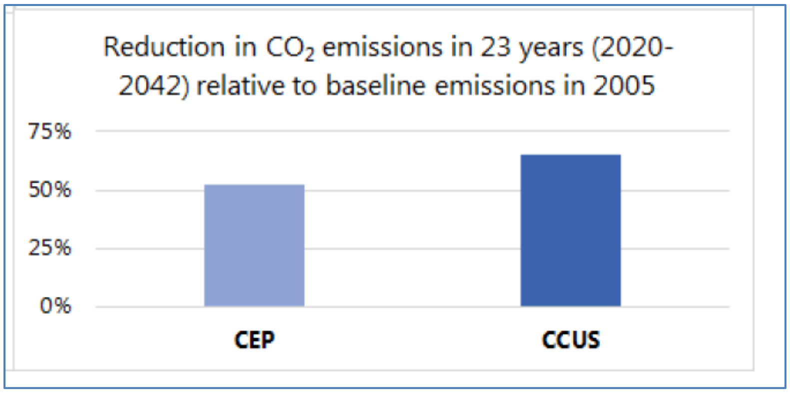
Jobs, Wages Taxes & Education

The construction and operation of the Comanche CCUS project would create 18,600 jobs, whereas Xcel's CEP estimates an additional 13,300 jobs. These jobs would increase salaries and earnings by $900 million and increase income tax revenues by $40 million.

The Comanche CCUS project would increase real estate tax revenue for Pueblo, Colorado by $800 million, and transform the public school district from one of the poorest to one of the wealthiest.

Environmental Benefits

CO_2 Emissions: Over the estimated life of the project (2020-2042), emissions of CO_2 would be reduced by 460 MMT (65% reduction below 2005 emissions). The reductions under Xcel's CEP plan (closing units, replacing with 2,000 MW renewable energy) would lower CO_2 by 369 MMT (52% below 2005 emissions).



DOE Summary

The analysis demonstrates the CCUS retrofit option:

- Delivers lower-cost power for Xcel customers,
- Takes advantage of 45Q tax incentives,
- Accelerates the transformation to a low-carbon economy,
- Generates significant economic development in Pueblo and Colorado,
- Provides significant CO_2 reductions, and
- Continues progress Colorado has made on cleaner air and on reducing its carbon footprint.

Opportunities for Comanche

Xcel has slated Unit 1 to close in 2022 and Unit 2 in 2025. From a logistical standpoint, it is too late to initiate a CCUS effort on Unit 1. However, there is still time to physically implement CCUS on Unit 2.

The original bids for wind, solar, and battery storage was vastly underbid. In November 2019, Xcel filed amendments to its CEP which included the new higher bids for wind and solar generation. Public comments are due by July 13, 2020 (Colorado PUC docket 19A-0530E "Public Service 2016 ERP amendment"). The PSC will vote on the amended "Colorado Energy Plan" later in the summer of 2020.

Currently, Xcel has no plans to close Unit 3 early. However, a group of state legislators recently petitioned the PSC, requesting the agency study the feasibility of closing Unit 3. This unit is the largest of the three units (700 MW). Given the economic benefits defined in the LTI study ($5 Billion in CO_2 profits from Unit 3), Xcel should seriously consider carbon capture at Unit 3.

Colorado CO_2 Resource Study – Phase II

http://lti-global.com/download/colorado-co2-resource-study-phase-ii/

Wyoming's Dry Fork Station

Project Background

Basin Electric Power Cooperative, headquartered in Bismarck, North Dakota, has partnered with Membrane Technology Research (MTR) Inc. to explore the feasibility of post-combustion carbon capture utilizing MTR's membrane technology at Dry Fork Station. The proposed project would capture 70% of the CO_2 from all or a portion of the flue gas from the 385 megawatt (MW) coal-based unit at Dry Fork Station.

Low-cost, High Efficiency, High Capacity

Located near Gillette, Wyoming, Dry Fork Station was placed into commercial operation in 2011, making it one of the newest coal-based facilities in the country. The adjacent Dry Fork Mine delivers some of the lowest-cost subbituminous coal in the Powder River Basin via a conveyor system approximately one mile in length. Dry Fork Station also utilizes the largest air-cooled condenser installed in North America, an option that was pursued to conserve water resources. Dry Fork Station's high efficiency and low-cost fuel has resulted in baseload operation since being placed into service.

Prime Candidate for CCUS

Dry Fork Station is also the host site for the Wyoming Integrated Test Center (ITC), a facility that delivers flue gas provided by Dry Fork Station to testing bays for researchers to explore new and innovate solutions to remove CO_2 and develop it into a marketable commodity.

While the attributes of the plant itself make it a prime candidate for CCUS development, Basin Electric has also been a partner with the University of Wyoming in the U.S. Department of Energy's CarbonSAFE program. The project was recently awarded $15.2 million in DOE funds to begin work under Phase III of the initiative, which seeks to develop integrated carbon capture and storage complexes that are constructed and permitted for operation between 2025 and 2030. CarbonSAFE Wyoming is characterizing reservoirs for 50 million tons of CO_2 in secure geologic storage. In addition, Dry Fork Station is located approximately 10 miles from the Greencore Pipeline which currently carries CO_2 for enhanced oil recovery projects, and has capacity for additional CO_2.

Project Development

MTR is currently utilizing DOE funding to complete a commercial-scale front-end engineering and design (FEED) study. Upon completion in 2021, the FEED study could prove the feasibility of beginning construction activities of commercial scale post-combustion carbon capture at Dry Fork Station sometime in 2022, with anticipated capital expense of approximately $800 million. The membrane-based capture system is expected to offer compact size, low water usage, and no disruption to the Dry Fork Station steam cycle relative to other CO_2 capture technology. Project advancement assumes technological feasibility, as well as ability to secure capital and return on investment through the life of the project.

Environmental and Social Benefits

- Expected CO_2 reduction of approximately 2 million tons annually – equivalent to offsetting the CO_2 emissions from the energy use of every household in Wyoming.
- Ensure continued operation of Dry Fork Station and its associated benefits in a carbon constrained future.

New Mexico's San Juan Generating Station

Project Background

In 2017, Public Service Company of New Mexico (PNM) closed Units 2 & 3 of the San Juan Generating Station (SJGS). PNM further announced that it intended to close Units 1 & 4 in 2022; these units had a combined generating capacity of 847 MW of electricity and consumed 3.2 mmt of coal in 2018.

The SJGS is owned by five entities (PNM 56%, Tucson Electric 20%, City of Farmington 5%, City of Los Alamos 4%, UAMPS 4%). Even though the power plant's majority owner is PNM, the New Exit Agreement signed by the former and current SJGS owners states that Farmington has opted to purchase SJGS. The City of Farmington signed a 2019 agreement to sell 95% of SJGS to Enchant Energy Corporation (Enchant), which mainly includes the operating assets of units 1 and 4.

Low-cost, High Capacity, Clean Electricity

Electricity Market: The average publicly reported fuel cost plus non-fuel fixed and variable operations and maintenance cost of electrical power from SJGS over the past five years (2014-2018) was $34.81/MWh ($03.5/KWh). The production cost of the 8 coal-fueled power plants located in the 4 contiguous states (AZ, CO, NM, UT) ranged from $26.93 – $49.91 MWh over the past four years. SJGS's electricity price of $34.81/MWh falls in the mid-range. The location of SJGS is ideal for the continued growth of electricity demand in the southwest; with transmission hubs to AZ, CA, CO, NV, and UT the market is prime for baseload power.

High Capacity Utilization: Units 1 & 4 ran at a total plant average net capacity factor of 67.48% for the 5-year average (2014-2018). This capacity factor speaks to the continued need for electricity from this facility. The capacity factor is higher than those of all other power plants in the State. After the installation of carbon capture and the plant improvements/deferred maintenance made to SJGS, the power plant is expected to run above 85% net capacity factor in order to serve the carbon capture facility.

Extensive Environmental Controls: Both units have advanced environmental controls (wet scrubbers, baghouse fabric filters, select non-catalytic reduction, and activated carbon injection). The plant achieves EPA-approved removal rates of 90-95% for sulfur dioxide (0.06 lb SO_2/MMBtu), 99% for particulate matter, and 98.9% for mercury, and a nitrogen oxides (NO_X) emission rate of 0.26 lb/MMBtu.

Prime Candidate for CCUS

Proximity and Capacity of CO_2 Pipeline: The SJGS is ideally located just 21 miles from the Cortez CO_2 pipeline. The pipeline is part owned and operated by Kinder Morgan and runs 502 miles from southwestern Colorado through northwestern New Mexico to the Permian Basin in west Texas. This major pipeline is 30 inches in diameter, the largest in the U.S. The Cortez pipeline currently transports 27 mmt/y of CO_2. The pipeline has the capacity to carry 1.5 Bscf/d of CO_2 and is currently transporting 1.3 Bscf/d, with additional capacity expected to become available for accommodating new sources in the next few years due to changes in the supply mix.

Production and Market for CO_2

Based on an 85% net capacity factor for SJGS and 90% capture rate, SJGS CCUS would deliver 6.0 MMT/y of CO_2 to the Cortez pipeline. CO_2 consumption in the Permian Basin exceeded 1 billion tons in 2018. Although deliveries of CO_2 continue to rise, the demand for the commodity is increasing at an even greater rate.

Sargent & Lundy CO_2 Capture Pre-Feasibility Study of SJGS

https://sargentlundy.com/in-the-news/co2-capture-pre-feasibility-study/

SJGS - CCUS study (Sargent and Lundy)

Enchant Energy, in a public-private partnership with the City of Farmington, commissioned a study by Sargent and Lundy to research the feasibility of a carbon capture, utilization and storage (CCUS) project at the SJGS. The report looked at the practical, social, environmental and economic benefits of CCUS on the SJGS facility. Following the initial report, the U.S. DOE has commissioned and partly funded Sargent & Lundy to produce a FEED study on the project. The study under the DOE cooperative funding agreement was commissioned in September 2019 and the findings are scheduled to be published in summer 2021. The overall value of Farmington-Enchant's cooperative funding agreement is $3.4 million. In addition, Enchant was recently part of an award under the DOE CarbonSAFE program totaling $22 million.

Economics

Enchant Energy expects to invest $1.3 billion for the carbon capture system installation. An additional $40 million will be spent on the feeder pipeline (21 miles). This cost of carbon capture is estimated to be $39-43 metric tons, 35% lower than previous CCUS projects. SJGS is expected to generate $2.5 billion in 45Q tax credits over 12 years. The 45Q benefits are almost twice the cost of CCUS construction and operation. The carbon capture technology will consume 209 MW of the 847 MW of generation at the SJGS. This leaves 638 MW for sale into the 6-state market.

Social Benefits

Direct jobs of 458 and indirect jobs of 1,000 (additional jobs while under construction).
Additional $8 million in local taxes annually.
The project will not increase the cost of electricity from the current price at SJGS.

Environmental Benefits

The project will decrease CO_2 emissions in New Mexico by 6 million metric tonnes of CO_2.

Opportunities for SJGS

The opportunities for the SJGS are exciting. Enchant Energy expects to complete the agreement with Mitsubishi to provide post-combustion amine-based carbon capture in the near future. Retrofit of the CCUS project is scheduled to begin in 2021 and be completed in 2023.
1,458 jobs and $8 million in tax revenue for the community
6 million tons of CO_2 permanently stored for the environment
Low-cost energy for the ratepayers
With secured access to the market (Permian basin) through the Cortez pipeline and 45Q tax credits, the projected income of $2.5 billion over the next 12 years is almost double the cost of the project ($1.3 billion).

Conclusion

It is obvious that the success of the Petra Nova CCUS retrofit project in Texas has caused investors, oil companies, utilities, and environmental groups to rethink CCUS/EOR. The Sargent & Lundy SJGS and the DOE Comanche Station studies are prime examples of how coal-based power should be viewed in the future. To build upon this success, the U.S. DOE should:

- Explore opportunities to partner with the Native American tribes in the western U.S.
- Develop a matrix and map of the physical location and logistics of coal-based plants and potential EOR opportunities.
- Increase matching grants and funding to private industry to help with the initial characterization and economic assessment of potential CCUS projects.

North Dakota's Milton R. Young Station – Project Tundra

Project Background

Minnkota Power Cooperative (Minnkota) has been developing Project Tundra over the last five years. The objective of Project Tundra is to retrofit Unit 2 at the Milton R. Young Station (MRYS) with carbon capture technology to capture at least 90% of the unit's CO_2 emissions. The project was originally conceived with enhanced oil recovery (EOR) as the storage/sale target for the captured CO_2. However, with the expanded 45Q tax credit program and the North Dakota oil and gas industry being not quite ready for widespread EOR operations, Project Tundra has pivoted to a geologic storage project. MRYS Unit 2 is rated at 455 MW and is fired by North Dakota lignite coal. In total, Project Tundra will capture about 4 million tonnes/annum of CO_2 and permanently store the CO_2 in multiple geologic formations more than a mile beneath the plant and adjacent lignite mine.

Low-cost, High Capacity, Clean Energy

Both units at MRYS provide low-cost and reliable energy to Minnkota's members. The plant's costs are also competitive in the MISO market, resulting in both a high historical (2017-2019) availability and net capacity factor:

- Unit 1: Average 3-year availability of 88%; Average 3-year net capacity factor of 78.5%
- Unit 2: Average 3-year availability of 90.2%; Average 3-year net capacity factor of 81.8%

In addition to being economically competitive, MRYS has added >$400 million in air pollution control equipment since 2010 to address emissions of SO_2, NOx, particulate and mercury. MRYS is 100% compliant with all EPA standards.

Prime Candidate for CCUS

Unique Geology: MRYS is situated in an area that is both ideally suited for EOR opportunities and for geologic storage opportunities. The conventional oil resources in western North Dakota, about 100 miles from MRYS, are technically ready to accept CO_2, but the EOR market has yet to take off. Use of CO_2-EOR for the Bakken shale is also being researched. The near-term opportunity for Project Tundra is the multiple deep geologic formations that appear ideal for permanent and large-scale CO_2 storage. Through several years of DOE, state and industry funded efforts, the University of North Dakota's Energy & Environmental Research Center (EERC) has characterized the storage opportunities in North Dakota, including the area surrounding MRYS. Recently, Minnkota has taken over the lead role on the site characterization, including a full 3D seismic survey and drilling of a stratigraphic test well. To date, the storage potential appears highly favorable.

State Support: North Dakota's political leaders, industry and state regulatory agencies have worked hard over the last several years to put into place policies and regulatory structures that will incentivize CCUS projects. One particularly important factor is that North Dakota is the only state with primacy over the Underground Injection Control (UIC) Class VI program, which regulates injection and geologic storage of CO_2 for non-EOR operations.

Project Tundra Development

Project Tundra was originally conceived in 2015 as a potential replication of the Petra Nova project in Texas. There has been a tremendous amount of R&D work accomplished over these five years, which has also leveraged previous research on EOR and CO_2 storage through the EERC's DOE-sponsored Plains CO_2 Reduction Partnership (PCOR) that was initiated in 2003.

Through early 2019, the development was mainly aimed on the research side to prove the technical and economic feasibility of capturing CO_2 at commercial scale from North Dakota lignite flue gas (which is significantly different than other coals), and to characterize the CO_2 storage potential of the geologic formations beneath and surrounding MRYS. Both of these efforts were led by the EERC, in partnership with Minnkota and other sponsors.

Beginning in 2019, Minnkota shifted gears into more of a project development mode, and is now in the advanced engineering and design phase. A DOE-sponsored FEED study was recently kicked off with carbon capture technology provider Fluor Corporation. Simultaneously, Minnkota is leading additional efforts on site characterization for the CO_2 storage facility and is partnering with EERC on the third phase of EERC's CarbonSAFE initiative, which was recently awarded a ~$17 million grant from DOE. CarbonSAFE will involve additional CO_2 storage site characterization as well as all of the data analysis and simulation work that is required as part of the storage facility permitting process. Minnkota anticipates submission of the various permits and approvals beginning in 2020, with all permits approved by early 2022.

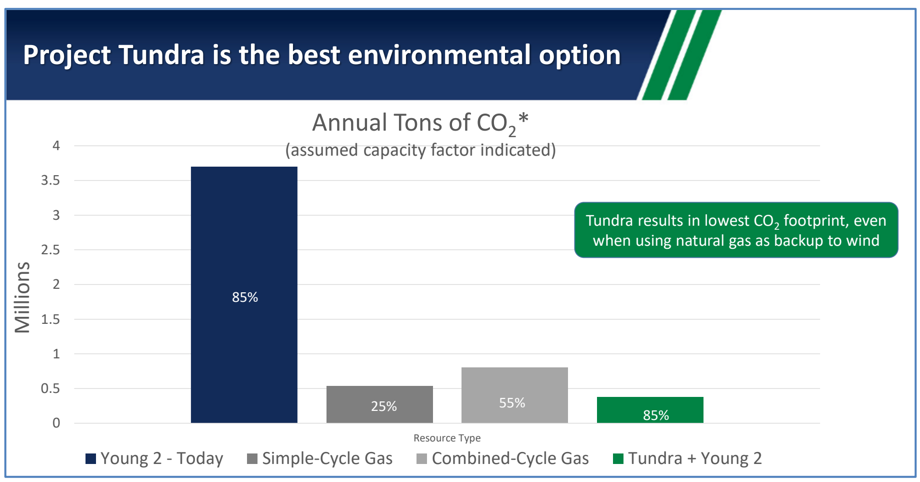
Minnkota and its team is working on project financing in parallel to the technical and engineering work and has a target of final investment decision and initiation of construction following receipt of all permits.

Project Economics

The total cost of Project Tundra is expected to be ~$1.1 billion for the capital required to construct the carbon capture facility and build out the CO_2 storage facility. Based on financial modeling to date and pre-FEED data for the carbon capture system, Minnkota anticipates that the 45Q tax credit, at $50/tonne of CO_2 stored, will be enough to pay for all of the capital costs and ongoing operating costs, while also providing an adequate return for all project investors. The ongoing FEED study with Fluor and additional work with Minnkota's financial advisor will fine tune the project economics and financing structure.

Environmental Benefits

Project Tundra will capture about 4 million tonnes of CO_2 annually, which is equivalent to permanently removing about 800,000 vehicles from the road or about equal to the total number of vehicles registered in the state of North Dakota. Capturing >90% of the CO_2 from Unit 2 is a better environmental option than switching to natural gas.



Social Benefits

Project Tundra will strengthen the future of MRYS and the adjacent lignite coal mine, which together employee about 360 people. Construction and ongoing operation will add a large number of additional temporary and permanent jobs, and add significant new tax revenue to the state and surrounding area.

Conclusions

Minnkota and its partners are highly motivated to make Project Tundra a commercial reality. The State of North Dakota is the prime location for FOAK CCUS projects. A tremendous amount of effort and investment of resources from multiple parties has placed Project Tundra in a position to be one of the first coal plants to utilize the 45Q tax credit. If all goes as planned, Minnkota expects a final investment decision in early 2022, with construction to initiate the same year and commercial operation to be achieved in 2025.

Project Tundra - https://www.projecttundrand.com/
Plains CO_2 Reduction Partnership - https://undeerc.org/PCOR/Default.aspx

Prairie State Energy Campus

Project Background

The Prairie State Energy Campus is a stand-alone, technologically advanced energy campus located in southern Illinois, which includes a 1,632 MW coal-based generating plant, adjacent coal mine and on-site coal combustion residuals monofill. The first 816 MW unit began commercial operations in June 2012, and the second 816 MW unit promptly followed in November 2012.

The overall project goal is to complete a FEED study for the installation of a carbon capture system for Unit 2, based on the Advanced KM CDR Process™ CO_2 capture technology from Mitsubishi Heavy Industries (MHI). Flue gas from Unit 2 will be treated, along with the natural gas flue gas generated by the capture facility. The project will utilize the state-of-the-art KS-21 solution.

This capture technology employs greater thermal stability, oxidative stability and reduced process volatility than previous designs. Coupled with ever advancing technology and lessons learned, MHI predicts reducing both projected capital costs (up to 30%) and project risks during construction.

Unique Design, High Efficiency, High Capacity

Prairie State's position in the energy industry is unique. The campus is solely owned by nine not-for-profit public power entities, providing baseload power to more than 2.5 million families and businesses across eight states. With two supercritical pulverized coal boilers and a mine mouth design, the campus was conceived with efficiency and the environment in mind. As one of the newest supercritical power plants in the country, Prairie State generates electricity more efficiently than traditional, sub-critical coal plants. In fact, Prairie State ranks among the top five of all U.S. coal plants for heat rate efficiency.

In 2019, Prairie State achieved the highest Equivalent Availability Factor (85.8%) and Net Capacity Factor (84.1%) in plant history. The plant has over $1 billion in environmental controls, making Prairie State one of the top ten cleanest plants in the nation. Prairie State has lower production costs and a lower heat rate than other coal-based power plants in the region.

DOE Sponsored Study

In September 2019, Prairie State was selected as the site of a $15 million Department of Energy (DOE) project to design a transformational carbon capture system. Prairie State is investing $3.75 million in cost-share for the project to produce a shovel-ready FEED study on one of the 816 MW coal-based power units.

Prairie State has partnered with the University of Illinois' Sustainable Technology Center, Mitsubishi Heavy Industries, Kiewit Corporation and Sargent & Lundy for this study. The purpose of the FEED study is to complete preliminary engineering and design work to support developing a detailed cost estimate for the cost of retrofitting CO_2 capture at Prairie State. Project partners will perform multiple feasibility and design studies based on project-specific details in preparation for developing engineering deliverables.

Expanding the Possibilities for CCUS

As one of the newest, most efficient coal-based power plants in the country, Prairie State provides a unique opportunity for advancing CCUS technology on a commercial scale. Available space at the energy campus, proximity to the Kaskaskia river, low-cost mine mouth design and high capacity factor all make Prairie State an ideal candidate. This FEED study is examining the economic potential for the largest carbon capture retrofit in the world.

Fossil fuels accounted for 62.7% of all U.S. electricity generation in 2019, according to the Energy Information Administration. Technology that reduces carbon emissions while maintaining low cost is vital to our nation. As a result, the successful completion of this and subsequent project phases will demonstrate the technical feasibility of carbon capture and provide a blueprint for power facilities globally.

Jobs & Economic Impact

Prairie State's current impact on the southern Illinois region is equal to more than $785 million annually, and the campus employs more than 650 full-time employees. In addition to maintaining the current economic impact of the campus, the construction and operation of this carbon capture facility is estimated to create 2,000 direct-hire employees and 500 indirect-hire jobs during construction.

Environmental Benefits

When completed, the Prairie State carbon capture project could remove as much as 95% CO_2 from one of the 816 MW units. This equates to the removal of 19,573 tons of CO_2 daily.

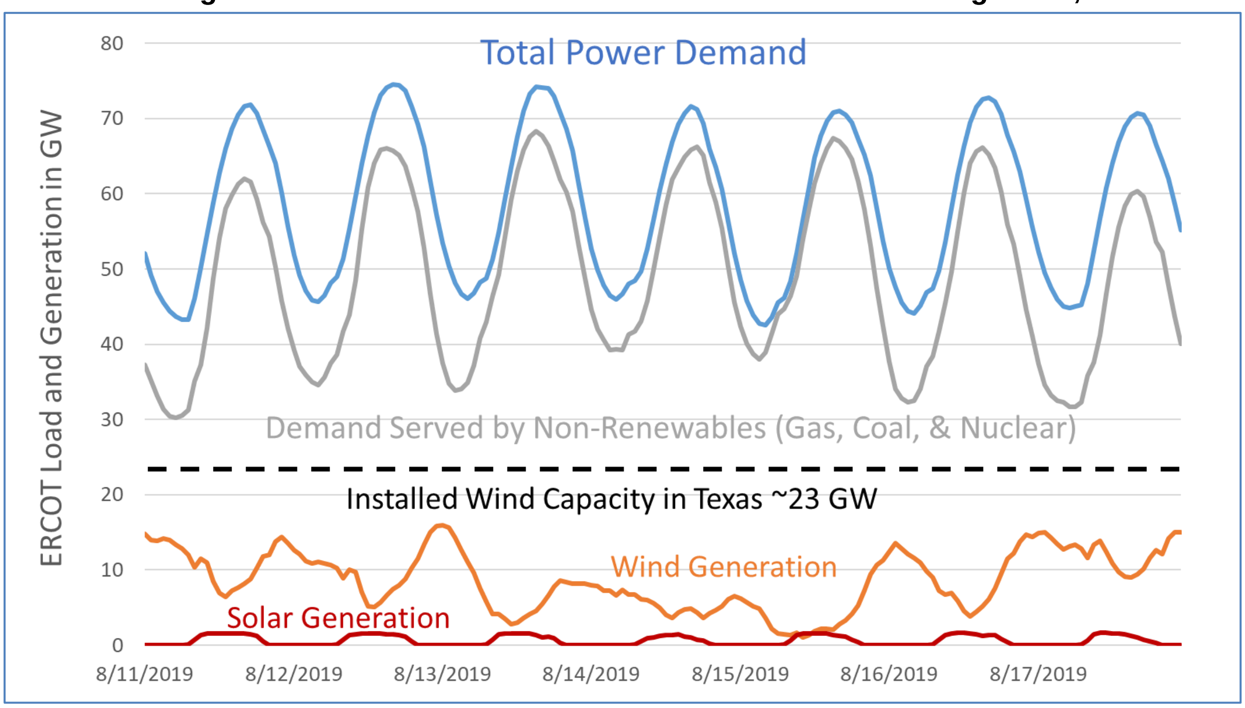
The Value of Coal and the Cost of Early Retirements in Texas

This sidebar is an abbreviated version of a more expansive case study featured in Appendix D.

Although Texas remains atop the rankings of both coal-based capacity and generation, it has lost several coal plants over the past two years due to a combination of many factors, including regulatory costs and the erosive economics of the ERCOT deregulated wholesale market resulting from subsidized renewables and sustained low natural gas prices. These factors have undermined continued investment in major capital projects necessary to sustain older coal plants.

This significant loss of coal-based capacity, combined with a lack of new thermal generation, has resulted in razor thin reserve margins during critical times over the past two years. The Texas ERCOT market tells a cautionary tale about what less coal capacity and more subsidized wind power can do to a previously well-performing electric market. This thinning reserve margin in Texas has significantly increased the ERCOT market's volatility during extreme cold events, not just during the heat of the summer. In March 2019, demand peaked in ERCOT due to cold weather and wind's underperformance relative to forecast. This escalated power prices 700%, which is a significant event but pales in comparison to scarcity events during the summers of 2018 and 2019.

Figure A: ERCOT Load vs. Generation for the Week of August 11, 2019



Source: *ERCOT*.

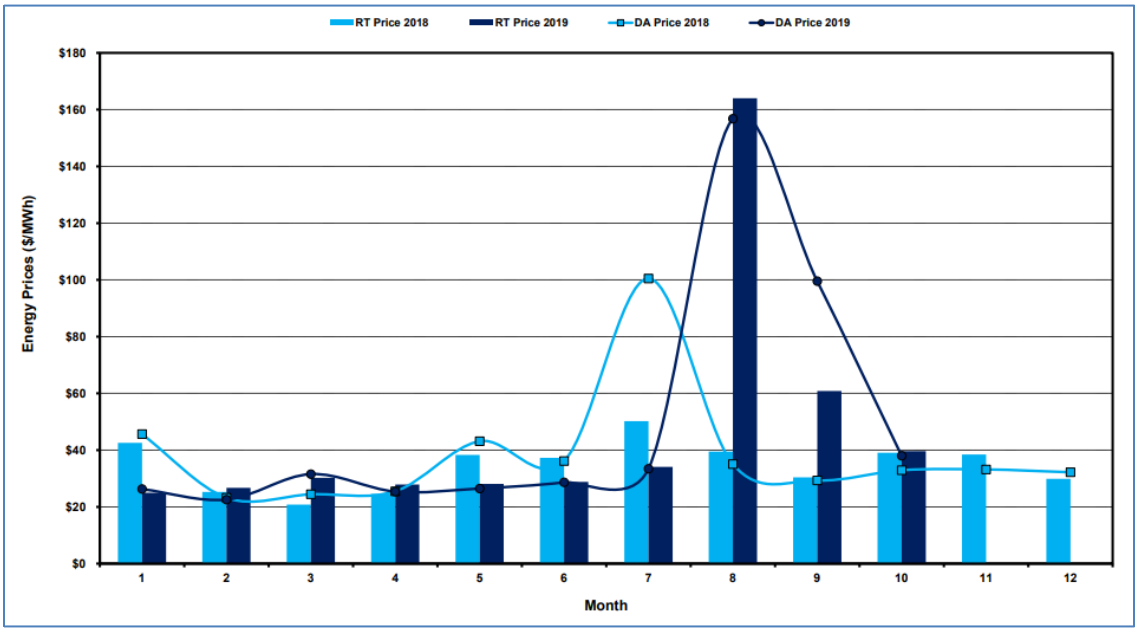
As seen in Figure A, the week of August 11, 2019 is a case study in the kind of price volatility and reliability risk created by coal retirements, suppressed new thermal builds due to renewable subsidy market distortions, and expanded exposure to highly variable (and unpredictable) wind energy.

On Monday, August 12, a new record peak demand was set, and real time prices reached $6500/MWh while averaging over $1000/MWh for the afternoon hours. But it was not record peak demand that drove the most extreme conditions the ERCOT market faced that week – it was the underperformance of wind relative to forecast.

On Tuesday, August 13, ERCOT declared emergency conditions and real time prices reached $9000/MWh for six periods and averaged $2500/MWh for the afternoon. On Thursday, August 15, real time prices reached $9000/MWh for seven periods and averaged $2900/MWh for the afternoon.

As striking as all of the above-referenced data are to the informed market observer, perhaps the most concerning fact about the ERCOT market is that power prices are now on the rise in Texas despite sustained low natural gas prices. As seen in Figure D, ERCOT year-over-year prices jumped over 40% during a timeframe when natural gas prices fell over 15%. This trend shows just how valuable the existing thermal fleet is to the affordability and reliability of the Texas grid.

Figure D: ERCOT system-wide average prices for 2018 and 2019



Source: *Potomac Economics*

The Cautionary Tale of Texas Municipal Utilities Moving to Renewables

While Texas is just beginning to see these problems arise with a low level of renewable generation – currently about 20% of total electricity generation – the problems of a high-renewable grid have become fully apparent in the small city of Georgetown, just north of the state capitol in Austin. In 2012, Georgetown, along with several other Central Texas municipalities, had the opportunity to break their contracts with the Lower Colorado River Authority and seek out other parties for their power contracts. Georgetown was forecasting that wholesale prices would rise from the $40/MWh range at the time to $60/MWh or more, and they decided to lock-in long-term solar and wind contracts at prices that were near their market forecasts.

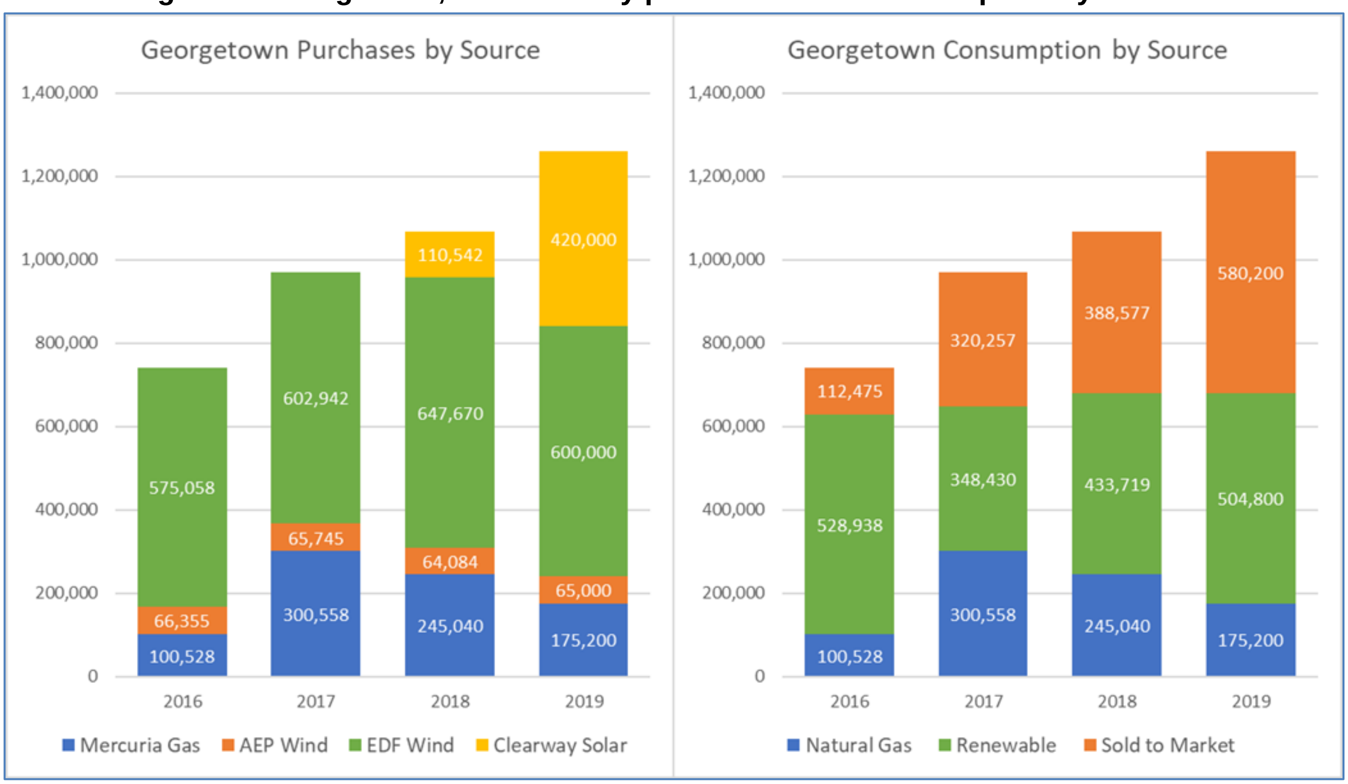
City officials claimed at the time that their decision to go “100% renewable” was purely economic because they wanted to secure stable prices in a rising price environment (The Guardian). The national press and the environmental community hailed this decision as a sign that 100% renewable really was doable, especially since it was coming from a city that was politically conservative. But this decision turned out to be far from economically sound, and Georgetown’s utility has begun to lose more and more money as its renewable contracts come into effect. It raised electricity rates three times in 2019 (Austin American Statesman), and its customers now pay up to 50% more for their electricity than similar communities in Central Texas. So, what went wrong?

Right as Georgetown started finalizing its contracts in 2014, wholesale prices began to plummet due to falling natural gas prices and an explosion of subsidized wind energy in the ERCOT market. Georgetown's 100% renewable plan depends on its ability to sell excess wind energy during periods of low demand, primarily at night in Texas, and it is now selling most of that excess energy at a loss.

Georgetown compounded this problem by buying significantly more wind and solar than it needed, contracting for almost double their current annual demand in wind and solar (see Figure E). Despite this excess of wind and solar under contract, the city is still having to pay a premium for a natural gas contract to meet peak demand, which often coincides with times, such as late summer afternoons, when wind and solar resources are low.

While Georgetown thought they were bringing price certainty with their fixed contracts, they were actually incurring significant price risk by moving away from dispatchable generation and relying on the market, still primarily powered by dispatchable generators, to both absorb their excess energy and meet their peak demand. Although the city made their problem much worse by moving all-in immediately and making a bad bet on wholesale prices, their situation is illustrating in the real-world what energy researchers have long known is the fundamental problem with wind and solar: you have too much of it when you don't need it and not enough of it when you do need it. No matter how much the technologies for capturing these resources improve, the fundamental physical problem will remain.

Figure E: Georgetown, TX electricity production and consumption by source



Source: *Georgetown Utility Systems*

Wyoming's Dave Johnston CCUS-EOR Project

Project Background

In September 2018, PacifiCorp issued a Request for Expressions of Interest for a Carbon Capture Utilization and Storage project in conjunction with enhanced oil recovery for its Dave Johnston facility in Glenrock, Wyoming. Jupiter Oxygen responded and, subsequently, was selected to provide a comprehensive engineering study to retrofit Unit 1 and/or Unit 2 (99 and 106 MW, respectively) with its proprietary high flame temperature oxy-combustion and carbon capture technology.

The Feasibility Study was completed in May 2019. The ensuing FEED study was initiated in February 2020 and is scheduled to be completed in May 2021.

The Dave Johnston plant is a four-unit coal-based power plant with a net maximum capacity of 755 MW with PacifiCorp as sole owner and operator. The depreciable life for ratemaking purposes for the four units is 2027. The plant site occupies 2,500 acres, with an additional 14,700 acres owned adjacent to the plant. There are multiple oil fields located within 10 miles of the plant interested in the long-term off-take of CO_2 for CO_2-EOR.

PacifiCorp's latest Integrated Resource Plan has the Dave Johnston facility shuttered in 2027 and capacity replaced with renewables and gas-fired generation, unless CCUS proves to be more advantageous to the parties concerned.

Physical Capabilities and Prime Candidate for CCUS

Unit size: Unit 1 and 2 are the ideal size (~100 MW) for the FOAK oxy-combustion based carbon capture facility. Post-combustion carbon capture technology is not cost effective for these smaller size units.

Emissions: Unit 1 and 2 are grandfathered and equipped with electrostatic precipitators and activated carbon injection (ACI). Retrofitting these units with Jupiter's technology will significantly reduce the emissions to near-zero levels.

Close proximity to CO_2-EOR field: The plant is located less than 10 miles from the oil field and will be served with a dedicated CO_2 pipeline under favorable terrain with minimal obstacles. At a 95% CO_2 capture rate, each of these 100 MW units produce approximately 750,000 MT/y of CO_2 at an 85% capacity factor.

Market: There are numerous CO_2-EOR opportunities near the power plant. Denbury's Greencore CO_2 pipeline is less than 30 miles away and could be a viable option for future CO_2 market opportunities.

Future projects: The site is well suited for retrofitting the entire Dave Johnston facility (755 MW) with oxy-combustion based carbon capture technology to serve the ever-growing CO_2-EOR market while significantly reducing the emissions and carbon footprint.

DOE Sponsored Study

DOE is undertaking a study for the Dave Johnston power plant and other PacifiCorp coal-based facilities in Wyoming. The study will be similar to the DOE study for Excel Energy's Comanche Station of June 2019. This study will provide a detailed analysis of physical, social and economic issues applicable to the installation and operation of a carbon capture facility versus shuttering the facility and replacing with renewables and gas-fired generation.

Economic Advantages

The estimated equipment cost is $160 million, not including the flue gas desulfurization unit (for cost comparisons to other CCUS technologies as FGD typically exists at coal-based facilities). The project is expected to generate $315 million in 45Q tax credits over 12 years resulting in the cost of CO_2 to be $25 – 30/MT. The project will not increase the cost of electricity PacifiCorp charges its customers.

Social Benefits

The project will allow PacifiCorp to retain jobs at the plant that would be lost if the plant closes. Further, the project will result in a net job increase from construction and operations. Wyoming will see an increase in state revenues from CO_2-EOR operations, coal consumption and taxes that will provide for further economic development in the region.

Environmental Benefits

At present, Unit 1 and 2 do not have emissions control equipment due to its grandfathered status. The project will take the unit(s) from being one of the dirtiest to the cleanest and most environmentally friendly in the entire U.S. coal fleet as 95%+ of the CO_2 emissions along with NOx and SOx are captured.

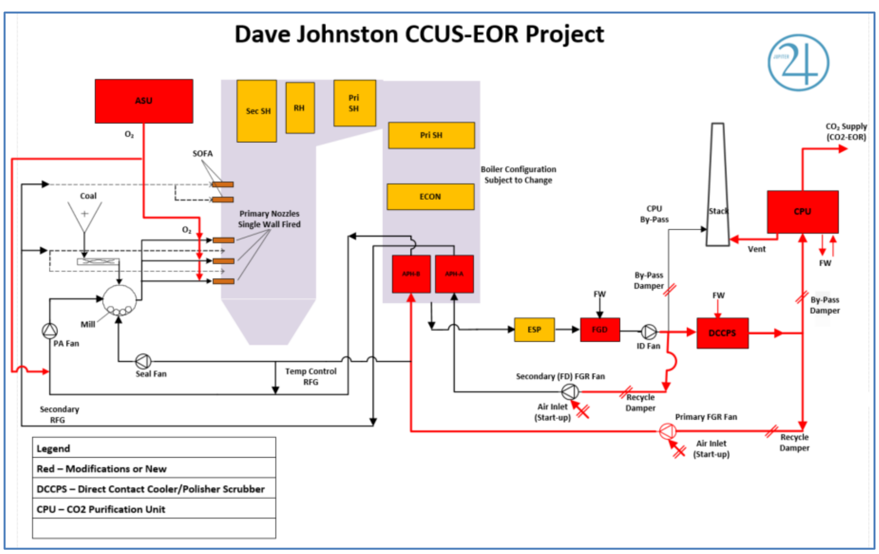
Opportunities for PacifiCorp and Dave Johnston

The project will allow PacifiCorp to keep the plant operational well beyond its planned shutdown date of 2027 and will benefit as these units are among the lower cost of electrical generation for its fleet. The project will result in near zero emissions while pioneering new carbon capture technology. The larger opportunities for PacifiCorp and key stakeholders include a broader application and deployment of this technology, leading to the reduction of the number of coal-based facility shutdowns in the future while preserving its fuel diversity mix with a significantly lower carbon footprint.

Conclusion

A CCUS project is PacifiCorp's only viable option for extending the life of the plant beyond its planned shutdown date of 2027. The project aligns with the state of Wyoming's key initiative to advance the deployment of CCUS-EOR technologies to help thwart the shutdown of coal-based facilities while significantly reducing the carbon footprint. Sustained coal-based generation will continue to provide good grid stability and reliability and will help to re-energize the coal industry, enhance oil production, grow state revenues and promote further economic development.

Jupiter Oxygen's High Flame Temperature Oxy-Combustion and Carbon Capture Technology



Chapter 5. Energy Infrastructure Initiatives that Would Support the Deployment of Advanced Coal Power Generation Technologies

KEY FINDINGS

- **Maintenance of existing energy infrastructure and development of new infrastructure as new sources of electricity and distribution networks are developed is critical to ensuring the technical and environmental viability of the nation's energy grid.**

- **Policy and financial certainty are an important consideration for the development of CCUS infrastructure.**

- **Research, Development and Demonstration (RD&D) projects are needed to prove the economics of full-scale CCUS systems for widespread deployment to be feasible.**

Introduction

Coal power generation will continue to be an important part of the country's energy portfolio for decades to come. Ensuring the proper maintenance and development of infrastructure as new sources of electricity and distribution networks are developed is an important part of maintaining the technical and environmental viability of coal power. Solutions to address these issues must include the following:

- Effective use and maintenance of existing and new infrastructure for power generation and transmission,
- Development of infrastructure needed to implement Carbon Capture, Utilization, and Storage (CCUS) and other coal utilization initiatives,
- Policies and investments needed to advance these infrastructure needs, and
- Effective research projects to demonstrate the viability, profitably and attractiveness of advanced coal power generation projects.

This chapter provides an overview of the salient topics related to each of these points in order to identify the current state of power generation and transmission infrastructure, coal utilization implementation and the gaps that must be filled for full and effective infrastructure development and utilization opportunities.

Power Generation and Transmission Infrastructure

This section addresses upstream infrastructure needs for advanced coal generation and transmission. Topics covered in this section include recommendations for new and retrofitted coal power generation, technology needs for electricity transmission that can handle the intermittent nature of renewable fuels and changes in power pricing markets needed to spur innovation.

Power Generation

Traditional power plants remain the most reliable and consistent forms of electric energy available today.

The existing coal fleet and retired coal power plants can be repurposed for advanced coal power generation or CO_2 utilization. When siting new advanced coal power facilities, the advantage of repurposed locations is that they are uniquely positioned at locations that can take advantage of the current configuration of the grid. Many retired coal power plants are also located near existing coal mining operations. In addition, repurposing existing coal power plants can take advantage of brownfields, where coal power generation has already taken place, as opposed to greenfields. Most of the current sites have transmission interconnections that are suitable for repurposed operations, plenty of land associated with the existing site, and infrastructure, buildings and equipment in serviceable condition for the repurposed design (Figure 5-1).

New plant locations also have advantages. Newly constructed plants can be sited in ideal locations, constructed with CO_2 utilization in mind, and sized appropriately for shifting power needs. However, greenfield siting does typically increase cost by 10s to 100s of millions of dollars for permitting, site development and infrastructure improvements.

The Carbon Utilization Research Council-Electric Power Research Institute (CURC-EPRI) Roadmap[cxi] identified trends that drive innovative technologies that would affect advanced coal power generation technologies. The authors state that declining growth of power generation is at risk of being outstripped by electricity demand. While renewables can come online to meet some of this demand, their intermittent nature means that fossil fuels will remain an important part of the electricity grid until power storage technologies improve. At the same time, the authors identify the need for generation sources with low or no CO_2 emissions that will be required to meet state and Federal goals and requirements. Finally, the advanced age of the existing fleet of power generation sources highlight the need for new, transformational energy technologies.

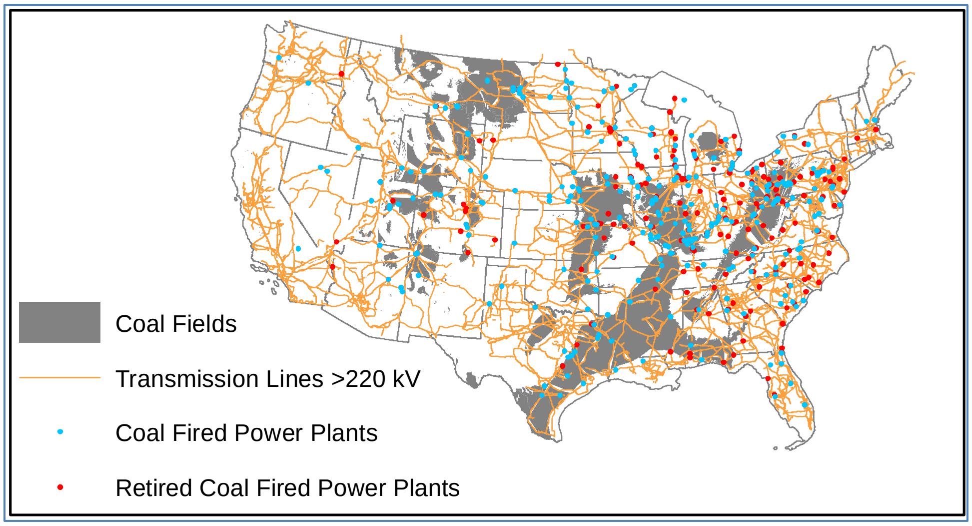


Figure 5-1: U.S. Coal Fields, Transmission Lines and Coal Power Plants Sources: EIA (2020), USGS (2018), HIFLD (2020)

The CURC-EPRI Roadmap supported transformational advanced energy systems technologies, including Pressurized Oxy-Combustion (P-Oxy), Chemical Looping Combustion (CLC), Direct-Fired Supercritical CO_2 (sCO_2) Cycles, indirect-fired sCO_2 cycles, gasification, compact hydrogen generator and cross-cutting technologies, including Advanced Ultra-Supercritical Materials (AUSC), turbines, CO_2 capture and CO_2 storage. The authors recommend four policy positions to promote these technologies, including public-private partnerships for a full research, development and demonstration (RD&D) cycle, streamlined and effective rules and regulations, aggressive commitment to carbon capture and power systems program, and a clear interpretation of 45Q by the Internal Revenue Service. Existing infrastructure is particularly helpful for the implementation of these technologies because many of them could be implemented with modifications to the existing boilers and associated equipment and could even use existing turbines with modifications. This makes the cost of transition to these technologies more manageable.

The Roadmap benefits that could be realized by supporting the technologies include reducing water use, reducing air pollutants (including CO_2), providing affordable electricity production while maintaining a diverse energy portfolio, significant GDP growth through increased oil production and reduce electricity costs, and improved energy security. In addition, the Roadmap recommended a level of investment from the Federal government of $760 million a year, an increase of about 75% compared to the current funding of $430 million.

Power Transmission and Grid

The existing power transmission system and grid will need to be repurposed to deal with renewable power sources (e.g., solar and wind) mixed with traditional power plants.

With the increasing use of renewable power sources, the electrical grid will need to be able to handle intermittent generation and still ensure reliable operations.

Deployment of advanced coal systems must be supported by Federal and state policy mechanisms for efficient and cost-effective scale-up. The experience with renewable energy development provides a relevant case study and examples of the types of policies that may work for advanced coal systems. Development of renewable energy has been enabled by several mechanisms, including tax credits and power purchasing agreements. Infrastructure will need to be reworked for the transmission of energy from renewable sources. This has largely not been factored into the cost of renewables and will be a factor in the cost of renewables going forward. In addition, uncertainty in the capacity that will be developed for some renewable sources and where this will be located leads to uncertainties for investors and the potential for poor cost-recovery due to an oversupply of energy.

Using existing infrastructure can speed up the rollout of transmission infrastructure, but this will be difficult for renewables sited in places where the requisite infrastructure does not exist. Upgrades are needed for new distributed power sources and smaller conventional plants on the same grid as intermittent renewables. Renewables will also require battery storage to translate off-peak generation to peak demand.

Despite the reliability and dependability of coal power plants and the cost savings of baseload energy versus renewables (particularly with its additional infrastructure needs), coal power plant owners are often criticized for the environmental performance of their facilities. The implementation of clean coal technologies could mitigate this; however, no mechanism exists for passing the costs of clean coal technology through to markets.

The U.S. has significantly less fabrication and manufacturing capacity for boiler tube products needed for advanced coal development because much of this work has been driven to offshore production. This trend is due to the slowing U.S. market for new generation, as well as to low-cost labor markets dominating sourcing strategies. A shortage of qualified suppliers for demonstration projects, particularly those involving the use of the new high alloy materials for which there is little fabrication/welding experience, has resulted from these developments. The U.S. DOE supported advanced coal demonstration projects represent an opportunity to re-develop these capabilities and capacities here in the U.S.

Environmental Infrastructure

Environmental infrastructure refers to the infrastructure necessary to use coal to develop advanced products (coal-to-products) or to implement CCUS. Ultimately, environmental infrastructure helps make coal power a low-carbon power source and coal the source of useful products with environmental benefits.

CCUS Infrastructure

CO_2 Capture. Capture systems refer to the way CO_2 is removed from the flue gas. Capture system options include pre-combustion, post-combustion and oxyfuel capture methods. Pre-combustion capture methods for coal sources involve creating a syngas from which CO_2 can be captured using a solvent. The syngas is then burned as the power source. Post-combustion methods for coal sources involve direct capture from the flue gas using solvents, sorbents or membranes after the coal is burned as a heat source. This is the likely technology that will be used on coal power plants that are retrofitted for CO_2 capture.[cxii] Oxyfuel combustion involves burning coal in an environment of pure oxygen as opposed to air. After scrubbing the flue gas of NOx, SOx, particulates, and other National Ambient Air Quality Standard (NAAQS) pollutants, the resulting gas is almost pure CO_2 that can be compressed and transported easily.

Developing technologies to economically capture CO_2 from coal power plants can be an effective way to make a significant contribution to reducing greenhouse gas (GHG) emissions. Because most emissions from coal usage are from energy generation, the most effective way to make a meaningful contribution to climate change mitigation and remain a viable energy source is to develop CO_2 capture systems for power generating units. Newly designed coal power plants, which will complete with (and also be part of the infrastructure alongside) natural gas and renewable power sources, must be smaller, modular and CO_2 capture ready.

Developing technologies to capture CO_2 from industrial sources is also important for the long-term viability for coal beyond power generation. There is often no alternative in many industrial processes that is free of GHG emissions. Thus, CCUS is essential to achieve deep cuts in GHG emissions.

Enabling capture system infrastructure can be done with a two-pronged approach: reducing the cost of capture and promoting policies that reduce the financial and non-technical risks associated with CCUS. Of all the components of an integrated CCUS system, the most work needs to be done to drive down the cost of CO_2 capture. CO_2 capture requires the most investment of any component of a CCUS project and, therefore, requires project certainty to facilitate potential investors interest.

Promoting policies that allow CCUS projects access to inexpensive capital while providing investor certainty will help promote the adoption of carbon capture. In addition, the installation of CO_2 capture systems hinges on the ability to use or store the captured CO_2. Thus, policies and RD&D initiatives that promote storage certainty (see below) will also drive the development of capture technologies.

CO_2 Transport. Large-scale transport of CO_2 is normally done using pipelines for onshore projects and pipelines and/or barges for offshore projects. The scale of CO_2 pipelines must increase from its current level to facilitate widescale implementation of CCUS. Around 5,000 miles of CO_2 pipelines are currently operating in the U.S. Most of the pipelines are transporting CO_2 for CO_2-EOR through Colorado and New Mexico and into the Permian Basin in west Texas, across Wyoming, and in Mississippi, Louisiana, and eastern Texas.[cxiii] In order to expand CCUS in the U.S., CO_2 must be transported on a larger scale.

Planning for pipelines needs to consider appropriate source-sink linkages. The likely scale and extent of CO_2 transport systems for CCUS implementation across the U.S. was investigated by the State CO_2-EOR Working Group.[cxiv] Oilfields in the U.S. are poised to implement CO_2-EOR, and infrastructure for transporting CO_2 is needed for widespread CCUS operations. The State CO_2-EOR Working Group generated a network of five potential priority trunk-lines to transport CO_2 from industrial sources in the Appalachian Basin, Illinois Basin, Great Plains and Upper Midwest to existing pipelines in the Gulf Coast, West Texas, Wyoming and North Dakota. These pipelines will serve to expand CO_2-EOR to operations in depleted oilfields in these areas. The report notes that this would triple the U.S. CO_2-EOR industry to 375 million barrels per year, reduce CO_2 emissions from stationary sources by 4% and enhance economic and jobs benefits resulting from construction efforts.

To maximize the impact of CCUS on CO_2 utilization and emissions reduction, the transport systems must also be positioned to take advantage of saline targets, which often have a higher potential storage capacity than oilfields. Saline formations co-located with oilfields provide opportunities for CO_2 to be utilized for CO_2-EOR while excess CO_2 is disposed of in saline formations, a process referred to as stacked storage. Stacked storage opportunities exist in the areas identified by the State CO_2-EOR Working Group as well as the Central Appalachian Basin, Great Plains and parts of the Rocky Mountain Region.[cxv]

Other considerations beyond source-sink matching must also be addressed. For instance, injection and storage certainty are important for minimizing stranded (unutilized or under-utilized) pipeline assets.[cxvi] In addition, certainty of tax credits and some revenue sources can be achieved through Federal and state policy. Certainty with tax credits and storage incentives can support the development of CCUS projects despite the uncertainty of volatile oil prices. This certainty of revenue sources could help to clarify pipeline needs and avoid delays in infrastructure investments.

The permitting process for siting pipelines must be streamlined. The Pipeline and Hazardous Materials Safety Administration (PHMSA) is the Federal authority for pipeline operations; however, there currently is no Federal authority for siting CO_2 pipelines. Instead, permits for pipeline siting must be obtained from state and local authorities, making obtaining approval for an interstate pipeline more difficult. In addition, pipelines that cross public lands or use Federal funding must undergo a National Environmental Policy Act (NEPA) assessment.

Advancing a “hubs and clusters” approach for CO_2 infrastructure development would provide an opportunity for aggregation of emissions from numerous industrial and power generation sources, as detailed in the Global CCS Institute’s (GCCSI) 2016 report on “Understanding Industrial CCS Hubs and Clusters.”[cxvii] GCCSI notes that “A CCS hub and cluster network brings together multiple CO_2 emitters and/or multiple storage locations using shared transportation infrastructure … [and that] [T]he hub and cluster approach reduces costs and risks for many potential CCS projects …”

CO_2 Storage. Issues associated with implementing CO_2 storage include determining the likely scale of assets and the strategy to implement CCUS. This includes determining whether to employ storage hubs or distributed systems, how to achieve a balance between CO_2-EOR and saline storage, and how to manage regional storage resources.

The renewed interest in CCUS due to the passage of 45Q tax credits means the U.S. Environmental Protection Agency (EPA) will be receiving Class VI permits at a larger scale than before. For the effective and efficient implementation of CCUS programs, these permit applications must be processed in a reasonable timeframe. At present, six Class VI permits have been issued, all in Illinois. Two of these are in use; four were issued for the FutureGen 2.0 project which did not utilize the permits. Although carbon storage has been demonstrated throughout the U.S., the permitting timeframe has been and is likely to remain a rate-limiting step in the development of commercial projects. Approaches to expedite the processing of these permits should be considered, including additional staff at the EPA to process the permit applications or third-party reviews by independent Professional Engineers (PE) and Professional Geologists (PG).

While CO_2 capture is the most expensive component of a CCUS project, CO_2 storage requires a high level of certainty for reservoir storage capacity, seal effectiveness and operational safety. Developing storage certainty by proving CO_2 storage sites through government-funded characterization efforts further facilitates the implementation of CCUS. The National Coal Council supports the National Petroleum Council's[cxviii] recommendation of $400 million a year for 10 years for R&D of geologic storage. Research efforts should focus on certifying storage sites that have the potential to support commercial-scale CCUS projects as well as mitigating risks of storage, such as basement rock characterization and fault characterization.

Technological gaps must also be addressed for the effective implementation of CCUS. This includes R&D required to support infrastructure development, resource development determination, siting of infrastructure, modeling and monitoring, and decision support systems/machine learning.

Storage operators must also address real or perceived long-term risk and liability. Currently, the default post-injection monitoring period, referred to a Post-Injection Site Care (PISC) for Class VI UIC projects is 50 years. During this time, the owner/operator is liable for project activities and must maintain a financial responsibility instrument capable of addressing potential project issues. Mechanisms for risk mitigation include certified storage sites that indicate a shorter PISC timeframe or shifting liability to states after a specified period. In addition, pore space and surface access issues must be clarified to effectively implement CCUS, including establishing who owns pore space and the possibility of pore space unitization to make storage projects more feasible.

Regional Carbon Sequestration Partnerships and CarbonSAFE

DOE's Office of Fossil Energy began funding research into CCUS on a regional basis in 2003 with the development of the Regional Carbon Sequestration Partnership (RCSP) program. Seven RCSPs were funded around the country, designed to include a diversity of organizations, including government, academic, non-profit and private sector organizations with expertise in geology, hydrology, engineering, outreach and education, and other disciplines. The underlying objective is to understand the suitability of regionally varying geologic resources to safely and effectively isolate CO_2 underground and to also consider CO_2 sources and transportation options. Field testing included injection for EOR, injection into unminable coal seams and injection into saline reservoirs without potential recovery of any hydrocarbon resources.

Since its inception, the RCSP program has secured participation from 27 states and the Canadian provinces of Alberta, Saskatchewan and Manitoba to demonstrate the entire CO_2 storage process – pre-injection characterization, injection process monitoring and post-injection monitoring – at large volumes. In January 2018, DOE announced that RCSP and its Major Demonstration Projects program had together injected more than 16 million tonnes of CO_2.

The RCSP program was a highly successful DOE program that, in 2018, Congress directed undergo continuation through a competitive bid process. In 2019, DOE selected four new regional initiatives to continue the objectives of the RCSP program for developing and accelerating regional deployment of CCUS (Figure 5-2).

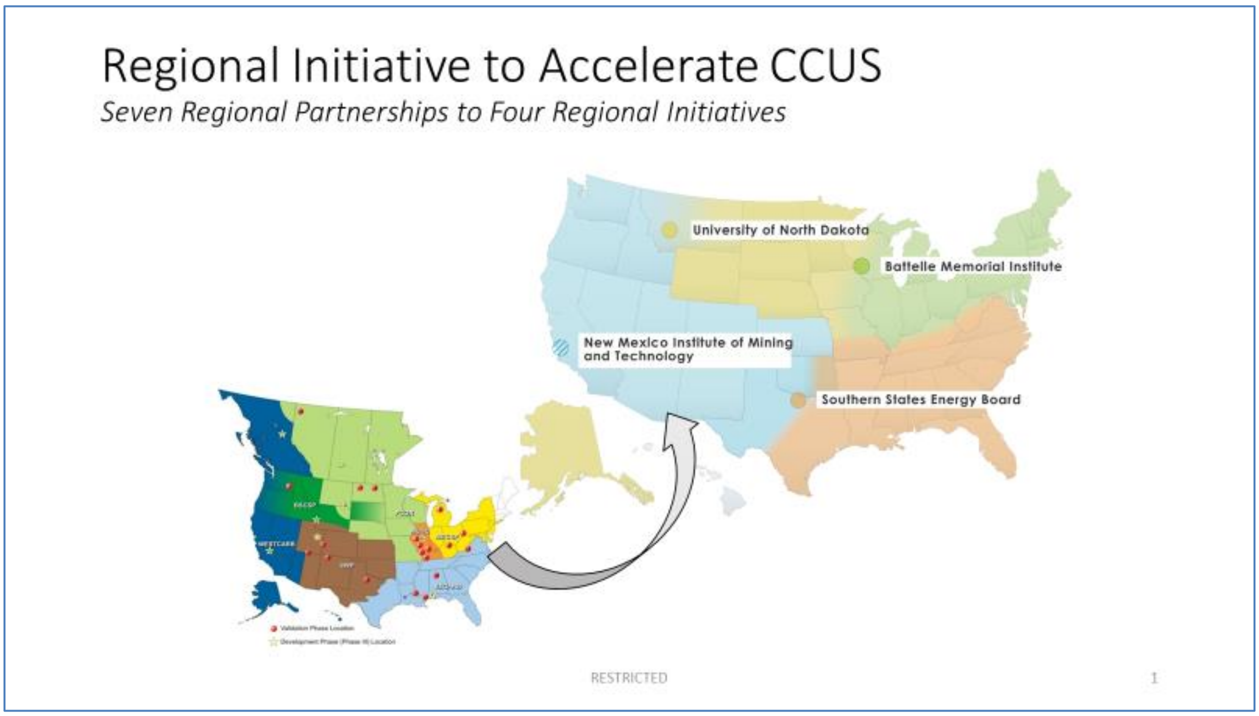


Figure 5-2: CCUS Regional Partnerships/Regional Initiatives
Source: Battelle

The newly selected Regional Initiatives are in place to further regional characterization and infrastructure development throughout the U.S. and are largely based in the previous successful RCSPs. The RCSP program and new Regional Initiatives are necessary and important infrastructure networks that demonstrate carbon storage potential and serve as the building blocks for the next and current phase of DOE CCUS commercial storage efforts – the CarbonSAFE program (Figure 5-3). The Regional Initiatives and the CarbonSAFE program are being executed in parallel to fulfill both the regional and local-scale project objectives.

Figure 5-3: DOE's CarbonSAFE Program
Source: National Energy Technology Laboratory

Carbon Storage Assurance Facility Enterprise (CarbonSAFE) projects focus on development of geologic storage sites for the storage of 50+ million tonnes of CO_2 within a 30-year time frame from power and industrial sources. Feasibility projects are now in place through the 2020-2021 timeframe in which all aspects of secure carbon storage will be addressed. The objective is to develop projects much closer to commercial scale that not only address the technical challenges of injectivity, adequate storage volume and assured containment, but also are focused on non-technical issues, including the application for and obtainment of Class VI permits, long-term liability issues, post-injection site care and business arrangements necessary to obtain and transport CO_2. Six CarbonSAFE Storage Complex Feasibility projects are currently underway in Illinois, the Wabash Valley (Illinois-Indiana), Nebraska-Kansas, Wyoming, Mississippi, and North Dakota.

In April 2020, DOE selected five projects to receive $85 million to complete detailed site characterization and CO_2 capture assessment, as well as obtaining National Environmental Policy Act approvals and Underground Injection Control Class VI permits to begin construction. These projects are located in the Illinois Storage Corridor, San Juan Basin in New Mexico, Kemper County in Mississippi, North Dakota and Wyoming. Subject to availability of funding, the CarbonSAFE initiative will culminate with the selection of project(s) that will focus on developing risk and mitigation plans, obtaining UIC Class VI permits to inject and completion of the injection and monitoring wells.

An important aspect of CarbonSAFE is further work with the EPA Underground Injection Control (UIC) Class VI injection permitting process. Class VI permits must be obtained for the planned CO_2 injection in saline reservoirs. Among the six projects only one, the project in North Dakota, will be carried out under a regulatory regime where the state has assumed primacy for the Class VI permitting process.

The primacy by individual states for Class VI injection permits brings important decisions closer to the regulators and the data necessary to make informed permitting decisions. Two other states, Louisiana and Wyoming, have applied for Class VI primacy. Texas has not applied, but a recent (November 29, 2019) opinion piece in the *Houston Chronicle*[cxix] suggested that it would be appropriate for the state to do so. It was suggested that given Texas' experience with all aspects of oil and gas development, it would make sense for the state to have the primary authority of making sure that CCUS occurs in a safe and environmentally responsible way. It was also suggested that bringing the regulatory framework closer to state implementation would allow for greater innovation and better environmental protection.

Another Texas-based analysis pointed to five areas in which clarity is needed for CCUS to move forward.[cxx] The analysis: (1) supported Texas seeking Class VI primacy; (2) considered the lack of clarity on CO_2 as a waste or a commodity and the implications for pipeline development; (3) noted the need for liability caps and clarification of long-term liability for storage operators; (4) reviewed the benefits of compulsory unitization of storage reservoirs to facilitate development of a storage project across multiple landowners; and (5) reviewed the lack of clarity on pore space ownership where the mineral estate and the surface estate are separate. The latter is of particular importance in oil and natural gas producing regions where depleted reservoirs offer potential storage capacity and where mineral rights and surface ownership are frequently severed. The authors conclude: "… given Texas' enormous capacities and relative economic advantages over other states as a carbon capture and sequestration hub, national attention will inevitably turn to it for a glimpse of our collective future road to carbon management in energy."

While the analysis focused on Texas, these same issues have national implications and clearly indicate that states can take well-defined leadership roles to facilitate CCS within their jurisdictions. Addressing regulatory and legal issues through state action, including primacy in permitting, in combination with the DOE-supported research outcomes of the RCSP program and now the CarbonSAFE program, would allow carbon-based fuels to continue to support economic activity *and* address concerns with related CO_2 emissions.

Other Co-Benefits

Additional co-benefits from environmental infrastructure could also be realized, including the following:

- Because CO_2 capture requires the removal of contaminants in the flue gas to improve the efficiency of the capture process, NAAQS criteria pollutants (NOx, SOx, particulates, etc.) are also removed when implementing CO_2 capture.
- Aggressive RD&D in CCUS could lead to increased coal production, 100 to 923 MMbbls of annual domestic oil production ($70 to $190 billion increase to annual GDP and 270,000 to 780,000 new jobs), and decrease of electricity costs by 1.1% to 2.0% by 2040, adding $30 to $55 billion to GDP and 210,000 to 390,000 new jobs.

Coal-to-Products

Advanced coal generation technology infrastructure can enable the deployment of a U.S. manufacturing renaissance the utilizes CO_2 and carbon for coal-derived, value-added products that provide environmental, economic and energy security benefits. The availability of reliable, affordable and environmentally compliant power generation will contribute greatly to the successful deployment of advanced manufacturing coal-to-carbon products industries. Synergistically, a vibrant coal-to-carbon products market can play a role in supporting the need for baseload coal generation, providing an incentive to continue to use and enhance the efficiency of the existing coal fleet, the deployment of new advanced generation and the retention and development of infrastructure assets.

In May 2019, the National Coal Council (NCC) released a report assessing opportunities to enhance the use of U.S. coal beyond conventional markets for power generation and steelmaking. The report – "Coal in a New Carbon Age: Powering a Wave of Innovation in Advanced Products & Manufacturing"[cxxi] – includes a qualitative analysis of opportunities for products such as coal to liquids (fuels and chemicals), coal to solid carbon products (carbon fiber, graphite/graphene, electrodes, building and construction products, carbon foam), rare earth elements (REE) and life science/medical/agricultural applications.

The NCC report provides strategic and tactical recommendations for DOE to pursue to accelerate the development and manufacturing of U.S. coal-derived products. In support of these recommendations, NCC identified the need for and benefits of the following infrastructure-related opportunities:

- Analyzing the condition and suitability of existing infrastructure assets. Reliable, efficient and affordable infrastructure is essential to grow sustainable coal-to-carbon solid products, chemicals, fuels and REE economic sectors. Infrastructure repairs, upgrades and improvements will likely be required for successful U.S. competitiveness and job creation in the global economy.
- Using shuttered and producing mines, coal power plants and coal communities as economic revitalization zones for new coal to fuels and products production and manufacturing centers. Brownfield coal mines, power plants and communities with existing infrastructure assets offer low startup costs to establish coal to chemicals, fuels, REEs and carbon products.

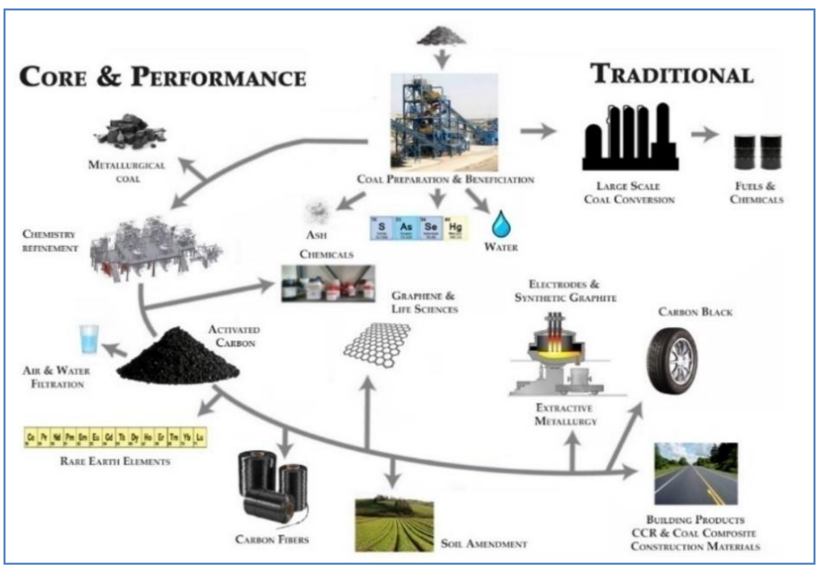


Figure 5-4: Coal-to-Products Markets
Source: National Coal Council

Infrastructure Enablers

This section addresses the key enabling factors and actions that are needed to support infrastructure buildout. Three infrastructure enablers identified are policy, collaboration with the oil and gas industry, and demonstration projects (public-private partnerships).

Policy

This section addresses policy elements that support advanced coal and CO_2 utilization infrastructure development and provides recommendations to fill policy and research gaps to advance these technologies. Several proposed and existing Federal and state policies are focused on the development of this infrastructure.

- Leading Infrastructure for Tomorrow's America (LIFT America) Act focuses money on developing the communications, drinking water, clean energy, brownfield development and healthcare infrastructure. While three quarters of the money that would be appropriated by the act is focused on the installation of telecommunications broadband networks in underserved communities, the bill could provide about $16 billion over five years for energy infrastructure.[cxxii]

- The Investing in Energy Systems for Transport of CO_2 Act (H.R. 4905 – INVEST CO_2 Act)[cxxiii] is the first-ever legislation to help finance the development of regional infrastructure to transport CO_2 captured from industrial facilities and power plants to where it can be geologically stored or put to beneficial use.

- The Utilizing Significant Emissions with Innovative Technologies (USE IT) Act would help to accelerate the deployment of CCUS by streamlining the permitting process of storage projects and CO_2 pipelines by making the issues applicable to the Fixing America Surface Transportation (FAST) Act.[cxxiv] The Carbon Capture Coalition recommends focusing on improving the monetization of the 45Q tax credits for CO_2 utilization projects.[cxxv]

- In addition to the FAST Act, additional policies could be implemented to support pipeline projects. The U.S. EPA recently revised the regulations to implement the Clean Water Act to restrict the public comment period to a "reasonable length," as determined by Federal regulators, not to exceed one year from initial application. State policies to support CO_2 pipeline development are also available, including streamlining the pipeline siting and permitting protocols at all jurisdictional levels, allowing eminent domain for CO_2 pipelines, and incentives such as tax abatements or royalty abatements.

Specific incentives and policies addressed earlier in this report can help to make aspects of environmental infrastructure a reality. CCUS as a technology has received more attention recently as the result of the recent enhancement of the 45Q tax incentives. These incentives provide investors with an impetus to provide capital to CCUS projects.[cxxvi] These investors are important because their tax liability will help to take full advantage of the 45Q tax credits, particularly for companies with a lower tax liability, while simultaneously funding infrastructure projects.

Access to inexpensive capital and other financial considerations is also an important aspect to supporting new and uncertain technologies. Allowing CCUS projects to access America Energy Bonds, the interest of which could be paid with the 45Q tax credits, could allow an additional source of capital for project implementation.[cxxvii] Additional financial mechanisms available through other Federal agencies, such as loans and grants from the U.S. Department of Commerce and U.S. Department of Agriculture, should also be considered.

In addition to 45Q tax credits, two additional policy tools that can be expanded to support the implementation of CCUS have been proposed by Congress. First, legislation to amend the 48A tax credits (the Qualifying Advanced Coal Project Credit) was introduced in early 2019, extending the tax credits to existing plants by allowing retrofit carbon capture systems to be eligible for the tax credit. (See Chapter 3 for further details.) Second, the USE IT Act (described above) would streamline the permitting of storage projects and CO_2 pipelines.

Areas with sources with low capture costs, characterized sinks and/or existing infrastructure will be important early movers for CCUS. For instance, commercial CO_2 capture is already economically feasible at ethanol plants, gasification plants and other sources with high concentrations of CO_2. Disposal of CO_2 from these sources in a suitable on-site storage area or connecting them to a nearby sink will help advance CCUS implementation early on. Cost reductions will then be realized through experiential learning as lessons learned from early movers will help avoid pitfalls and mistakes.[cxxviii] This prospect will be helped by 45Q, which can help defray the costs of first-of-its-kind (FOAK) technology implementation and incentivize early adoption of CCUS.

Public Engagement

Public engagement on infrastructure development is an important part of successfully citing and constructing infrastructure projects. As noted earlier, pipelines have a prominent footprint that can attract negative attention at both the local and the national level. Public engagement at both levels will be necessary to facilitate successful pipeline construction. It is important that all stakeholders be engaged in these efforts. Public engagement is shown to be more effective if the messengers are trusted by the target constituencies.[cxxix] Coal life-cycle analysis should be undertaken as part of the public engagement/education process; opening the door to stabilizing jobs will help gain the support of labor.

Collaboration with the Oil and Gas Industry

The oil and gas industry must be engaged for the effective roll-out of CCUS technologies. With a wealth of experience conducting geologic assessments, drilling wells, operating pipelines, engaging in lease negotiations and working within complex regulatory frameworks, the oil and gas industry will help bridge the knowledge gap and significantly shorten the learning curve. In addition, CO_2-EOR is an important part of enabling the development of the infrastructure needed to advance CCUS deployment.

Demonstration Projects

Pilot and Demonstrations as Energy Infrastructure

A number of R&D projects have shown the potential for commercial-scale CCUS implementation in the U.S. Capture-specific studies are also being conducted through efforts that are funded by the Federal government or through private initiatives such as those being completed by ExxonMobil Energy Factor (joint agreement with FuelCell Energy Inc.) to demonstrate CO_2 capture at Southern Company's Plant Barry using molten carbonate fuel cells (MCFCs). Contrary to traditional amine scrubbing, the process generates power rather than consumes it. This increases the plant output while maintaining efficiency. In addition, numerous pilot-scale demonstrations of amine scrubbing technology are also currently in development.

As detailed earlier in this chapter, the DOE Carbon Storage Assurance Facility Enterprise (CarbonSAFE) project seeks to promote the development of commercial-scale CCS projects. The program is being developed through a phased process that addresses all aspects of an integrated saline storage project, including geologic characterization, CO_2 capture and transport, Class VI permit development, risk assessment and public outreach. Currently in the Site Feasibility Phase (Phase II), the program is expected to begin the Site Characterization and Permitting Phase (Phase III) with projects selected in April 2020 and culminate in the construction of the project(s) selected for implementation (Phase IV).

CCUS Opportunity Zones are also an effective way to rollout CO_2 utilization and storage projects nationwide. This work would identify specific areas where carbon storage is feasible from a technical (i.e., verified storage capacity and safety) and non-technical (e.g., public acceptance, regulatory certainty, and economic feasibility) standpoint.

Studies showing the potential for advanced coal power generation technologies are also important for the continued use of coal power plants. The DOE Transformational Coal Pilots Program ($50 million in funding) is currently in the second of three phases. During Phase III, at least one coal transformation power technology will be constructed. These projects are critical in allowing the projects to move forward with government assistance to ease the financial burden of demonstrating the capabilities of the technology at a pilot scale.

The DOE's Coal Flexible, Innovative, Resilient, Small, Transformative (Coal FIRST) program seeks to support transformative technologies for coal power generation. The new plants will be smaller (50-350 MW nameplate capacity) compared to current power plants, making them easier to construct and site in strategic areas to increase grid efficiency.[cxxx] In addition, environmental benefits will be realized from the plants. They will require a reduced water consumption compared to traditional plants, are expected to be 40% more efficient than traditional power plants and will allow for the capture of CO_2 to increase the overall environmental benefits.

Key Lessons Learned from Demonstration Projects

Several projects have been implemented to demonstrate the potential for CCUS. Figure 5-5 provides an overview of large CCUS demonstration projects and their incentive profiles.[cxxxi] These demonstrations projects have had different characteristics, including operating under specific policies, taking advantage of the availability of grants, and realizing additional revenue through sources such as tax credits or CO_2-EOR. Other projects have been developed in response to a regulatory requirement or through a government provision. Vertical integration opportunities have also lessened the complexity of a few projects. However, in addition to CO_2-EOR, one of the most common features of each demonstration project that has been implemented is low costs of capture and/or transport and storage. This emphasizes the need for additional funding to bring down the costs of carbon capture, transport and storage to accelerate the implementation of CCUS.

Policies & project characteristics	Carbon tax	Tax credit or emissions credit	Grant support	Provision by government or SOE	Regulatory requirement	Enhanced oil recovery	Low cost capture	Low cost transport and storage	Vertical integration
US									
Terrell						○	●	●	
Enid Fertiliser						○	●	●	
Shute Creek					●	○	●	●	
Century Plant		●				○	●		
Air Products SMR		●	○			○			
Coffeyville		●				○	●		
Lost Cabin		●				○	●		
Illinois Industrial		●	○				●	●	●
Petra Nova		●	○			○			
Great Plains						○	●		
Canada									
Boundary Dam			○	●	●	○		●	
Quest		●	○						●
ACTL Agrium			○			○	●		
ACTL Sturgeon			○			○	●		
Brazil									
Petrobras Santos				●		○	●	●	●
Norway						○			
Sleipner	●			●			●	●	●
Snøhvit	●			●	●		●		●
UAE									
Abu Dhabi CCS				●		○		●	
Saudi Arabia									
Uthmaniyah				●		○	●	●	●
China									
CNPC Jilin				●		○	●	●	●
Sinopec Qilu*				●		○	●	●	
Yanchang*				●		○	●		
Australia									
Gorgon			○		●		●	●	●

Figure 5-5: CCUS Demonstration Projects
Source: Global CCS Institute

Chapter 6. Recommendations

Guiding Principles for Policy Action

- The vast coal resources of the United States provide a reliable, resilient, versatile, flexible and affordable energy source, enhancing our nation's national, economic and energy security. The U.S. must maintain a readiness, both in technology and human resources, to utilize the most abundant resources under this nation's control to supply critical energy needs should alternative energy sources be unavailable at reliable and affordable levels.
- Advanced coal generation technologies, including carbon capture utilization and storage (CCUS) and high efficiency-low emissions (HELE) technologies, have a significant role to play in meeting global environmental objectives. Enhancing energy efficiency through the deployment of advanced coal generation technologies should be acknowledged as a critical environmental strategic objective. Deployment of coal resources for electric generation in the future requires methods to reduce plant costs and CO_2 emissions to a level that closes the gap between coal and other energy resources.
- While achieving environmental goals, advanced coal generation technologies also provide economic benefits, such as job creation/preservation and extended utilization of valuable existing energy infrastructure assets. The nation's post-pandemic economic revitalization efforts can be supported with deployment of generation technology demonstration projects, advanced coal-to-products manufacturing facilities and CCUS infrastructure.
- Current policies are insufficient to ensure deployment of advanced coal generation technologies at scale and in time to achieve U.S. and global environmental objectives. An integrated suite of policy tools and incentives are needed to ensure technology deployment. Global energy demand growth will continue to be served by coal and other carbon-based fuels. The U.S. can lead the technology development required to enable use of coal with improved efficiency and lower emissions profiles. Investment in deployment of CCUS and other advanced coal generation technologies must increase to keep the U.S. relevant in this race for technology superiority.
- Integration of Federal, regional, state and tribal policies and initiatives will enhance the timely and cost-effective deployment of advanced technologies and infrastructure.
- Government must take an active role in risk-sharing with and incentivizing private sector investors to support the deployment of advanced coal generation technologies.

Policy Recommendations

The National Coal Council (NCC) recognizes that many U.S. states and power generators have established low carbon or carbon reduction targets by mid-century, if not earlier. In order to meet these targets, three critical objectives will need to be met over the next 20 years. These objectives are achievable if we are willing to pursue an aggressive agenda that acknowledges the urgency of the need, and the economic-environmental implications of not meeting these goals, both in the U.S. and globally.

- By 2030, retrofit a critical mass of existing coal power plants with carbon capture and efficiency enhancing technologies, more fully demonstrating the viability and maturity of these technologies and their availability through competitive bid from multiple vendors.
- By 2035, establish a growing network of carbon dioxide (CO_2) storage sites and pipelines approximately five times larger than what exists today. The network will need to expand over time to meet 2050 needs of the power and industrial sectors.
- By 2040, a variety of new coal plant technologies will need to be commercially available, cost competitive and have a near-zero emissions profile to meet power sector commitments to reduce/eliminate their CO_2 emissions by 2050.

NCC offers the following recommendations in pursuit of solutions to meet these objectives. Policy recommendations can help accelerate the deployment of carbon capture, utilization and storage (CCUS) and other advanced coal generation technologies at the Federal, state, regional and tribal levels of government. These efforts must be supported by industry, through public-private partnerships – with the U.S. Department of Energy (DOE) along with other Federal agencies – and a willingness to contribute its expertise and financial resources.

Economic Revitalization Post-Pandemic

The deployment of advanced coal generation technology demonstration and commercial-scale plants, advanced coal-to-product manufacturing facilities and CCUS infrastructure projects (e.g., CO_2 pipelines) can support U.S. economic stimulus efforts in the post-pandemic environment. These projects can drive economic growth and employment, creating and sustaining jobs, advancing clean energy industries and infrastructure, and making effective use of existing energy assets.

Economic stimulus projects can be supported through funds authorized but as yet unreleased from DOE’s Loan Guarantee Program, through reversal of financial and insurance institutions’ ‘coal exclusion’ policies, and through support for regulatory and legislative policies at the Federal, state, regional and tribal levels as follows.

U.S. Department of Energy Recommendations

In general, NCC recommends the U.S. Department of Energy:

- Implement a communications strategy for low-emissions coal technologies, to include partnerships with aligned organizations
- Continue to advance a broad research and deployment agenda on low-emissions coal technologies
- Focus on states and industry segments that recognize coal's favorable attributes
- Value the resilience benefits of coal, deriving from its ability to produce on-demand energy and being a fuel that can be stored on-site

Support for Research & Development

Continued and enhanced support for research and development (R&D) is critical to advancing the next generation of coal technologies. NCC supports:

- Continued R&D efforts detailed in the Department's Coal FIRST initiative and Transformational Coal Pilots Program.
- R&D to accelerate deployment of (thermal) energy storage to accommodate increased demand on coal plants to cycle operations while backstopping intermittent renewable energy (IRE).
- Enabling carbon capture to facilitate deployment of CCUS technologies. R&D efforts must continue to reduce the cost of carbon capture and promote policies that reduce the financial and non-technology risks associated with CCUS.

Support for Technology Projects

- Federal support for advanced coal generation technologies should not be restricted to basic research only. Demonstration projects are critical to expedite deployment of these technologies. Federal funding should be made available for demonstration and commercial-scale initiatives to support projects that bridge the gap between FOAK and NOAK initiatives. NCC supports recommendations in the 2018 CURC-EPRI Roadmap for public-private funding for these projects.

  Finally, to enhance the opportunity for success of these efforts, DOE should ensure that staff experienced in managing large-scale projects are in place to oversee the management of demonstration projects.

- Efforts should be undertaken to assess opportunities to repurpose retired coal power plants for deployment of new advanced coal power generation, CO_2 utilization and coal-to-products advanced manufacturing. These endeavors must take into consideration the benefits associated with the existing grid configuration, transmission interconnections, fuel transportation capacity and building/land infrastructure.

- DOE should enhance Federal funding support for FEED (Front End Engineering Design) studies to aid in reducing technology performance and cost risks.

- DOE should reform the DOE Loan Guarantee Program to lower fees and lift restrictions for projects receiving Federal grants.
- DOE should employ contracts-for-differences (CfDs) initiatives to advance large-scale pilots and commercial demonstrations supporting a diverse set of technologies in a variety of circumstances and locations.
- DOE funding awards should take into consideration support for U.S. owned companies with the aim of building domestically based capacity in power sector R&D competency, technical expertise and manufacturing capability.
- Consideration might be given to establishing an independent Federal development corporation or authority chartered to accelerate the deployment of clean energy technologies developed in the U.S.

Small-scale Modular Coal Power Plants

- NCC encourages the pursuit of niche market applications for small-scale modular coal power plants with the aim of advancing the concept, substantiating the economic and environment benefits, and validating applicable technology performance of small-scale modularity. Niche market applications would potentially include:
    - Small capacity combustion and gasification units for co-fueling coal and biomass/waste.
    - Replacement of more costly diesel-fueled plants.
    - On-site coal mining operations for mining equipment, coal preparation plants, coal drying and other localized applications.
    - Remote, off-grid locations, including those with limited access to or potential for use of other energy resources, i.e., natural gas or renewables.
    - Captive power plants at industrial facilities, including coal-to-products advanced manufacturing facilities (i.e., for production of carbon fibers, graphene, etc.).
- Export market potential exists for small-scale modular coal units in developing countries. U.S. pursuit of technology R&D for small modular coal units should include an assessment of both the technology export potential and the opportunity to enhance exports of U.S. coal to supportive markets in Asia and Africa.

Federal Policy Recommendations
Summary Matrix of Technologies-Policies

Technology Policy	CCUS	HELE	USC/AUSC	Allam Cycle	Oxy-	Other Transformation	Small Modular	Energy Infrastructure	Other	Coal Conversion & Utilization	Coal Exports & Technology
Initiatives to Advance R&D											
Coal FIRST	x	x	x	x	x	x	x				x
EFFECT Act	x	x	x	x	x	x	x			x	x
Fossil Energy R&D	x		x	x	x	x	x				
Technology Transitions Act	x	x	x	x	x	x	x				
Initiatives to Minimize Cost & Risk											
45Q	x										
Master Limited Partnerships	x								x		
Private Activity Bonds	x										
BEAT Tax Relief	x										
48A	x	x	x								
Technology Neutral Tax Credit	x	x	x	x	x	x	x				
USDA RUS Leg.	x									x	
Contracts for Differences	x	x	x	x	x	x					
LPO Reforms	x	x	x	x	x	x					
Development Finance Corp	x	x	x	x	x	x	x	x	x		x
Initiatives to Bolster Emissions Abatement											
Clean Energy Standard	x	x	x	x	x	x	x				
Affordable Clean Energy	x				x						
Initiatives to Address Regulatory Risk & Burden											
USE IT Act	x							x			
NSR/Gain Act	x	x									
Coal Combustion Residuals								x	x	x	x
Effluent Limitation Guidelines									x		
Initiatives to Reform Energy Markets											
PURPA	x	x	x	x	x	x					
Capacity Market Reforms	x	x	x	x	x	x					
Initiatives in Support of Energy Infrastructure											
LIFT America Act								x			
INVEST CO_2 Act								x			
FAST Act								x			

NCC encourages support for Federal legislative and regulatory initiatives as summarized in the table above and detailed below.

Initiatives to Advance Research & Development

- EFFECT Act (Enhancing Fossil Fuel Energy Carbon Technology) – updates and strengthens DOE Fossil Energy's CCUS RDD&D programs.
- Fossil Energy Research and Development Act – funds a new program for advanced fossil energy systems with the goal of reducing power generation emissions by 50%.
- Technology Transitions Act – establish a DOE Office of Technology Transitions to enhance commercialization of energy technologies.
- Enhance DOE participation in the United Nations Economic Commission for Europe to facilitate funding of international fossil energy projects.

Initiatives to Minimize Cost & Risk

- 45Q Tax Credits
  - Ensure effective implementation of 45Q by the U.S. Treasury. Extend the "under construction" deadline from January 1, 2024 to at least January 1, 2030 and extend the credit period from 12 years to 20 years. Allow CCUS projects to access American Energy Bonds to provide an additional source of capital for project implementation.
  - 45Q Class VI permits issued by EPA to states should be expedited.
  - Enact a broader portfolio of federal CCUS polices to complement 45Q:
    - ✓ 48A – extend 48A tax credits to existing power plants, allowing retrofits of carbon capture systems to be eligible for the tax credit. Carbon Capture Modernization Act.
    - ✓ Master Limited Partnerships – Financing Our Energy Future Act – makes CCUS projects eligible for MLPs. Analyze potential advantage of using a single MLP for each installation in support of the capital structure of coal generation projects.
    - ✓ Private Activity Bonds – Carbon Capture Improvement Act – authorizes use of tax-exempt PABs in financing CCUS projects.
    - ✓ Secure 100% relief from BEAT (Base Erosion and Anti-Abuse Tax) for CCUS technology development/deployment, like the 80% tax exemption afforded to the wind and solar industries. Extend BEAT relief through the duration of the 45Q tax credit availability.
  - Encourage the Treasury Department to clarify what measures are required to demonstrate "secure geologic storage" of CO_2 through enhanced oil recovery; allow use of ISO 27916 to demonstrate secure storage through third party certification or state regulatory agencies – such as state oil and gas regulatory authorities.

Initiatives to Minimize Cost & Risk (continued)

- Technology Neutral Tax Credits – Investment Tax Credits (ITC) and Production Tax Credits (PTC) would encourage technological innovation for a range of advanced coal technologies integrated with carbon capture.
- The U.S. Department of Agriculture's Rural Utilities Service (RUS) programs should be expanded to enable loans and loan guarantees to CCUS and coal-to-products facilities in rural U.S. communities.
- In furtherance of enhancing integration of advanced coal generation technologies in international markets, NCC recommends that the International Development Finance Corporation (DFC) work to update and reform its Environmental and Social Policy Statement to end the practice of discriminating against energy sources when considering investment opportunities.

Initiatives to Bolster Emissions Abatement

- Clean Energy Standards – several legislative initiatives introduced in the U.S. House of Representatives would qualify coal plants equipped with CCUS as clean energy technology.
- Affordable Clean Energy (ACE) Rule – remove permitting barriers to efficiency improvement projects and enable states to tailor CO_2 performance standards unique to their resident electric generating units.

Initiatives to Address Regulatory Risk & Burden

- Utilizing Significant Emissions with Innovative Technologies (USE IT Act) – streamline the permitting process for CO_2 storage and pipelines projects among Federal, state, tribal and non-government parties, making them eligible for review under the FAST Act.
- Growing American Innovation Now (GAIN) Act – reform the New Source Review program under the Clean Air Act providing greater regulatory certainty for facility upgrades and efficiency improvements.
- Coal Combustion Residuals (CCRs) – In compliance with RCRA goals, regulatory programs should quantify environmental emissions and cement import reductions realized through CCR utilization; EPA should reinstate its C2P2 industry partnership program to increase the beneficial use of CCRs; Federal and state agencies should strengthen purchasing commitments for CCR materials; Federal research efforts should be renewed to advance technical improvements in construction materials.
- Effluent Limitation Guidelines – Support EPA revisions to the 2015 rule for FGD and bottom ash transport water, including extension of the compliance deadline.

Initiatives to Reform Energy Markets

- PURPA Reform – The Public Utility Regulatory Policies Act (PURPA) imposes burdens on U.S. utilities to purchase electricity that is not needed, for contract terms that are beyond what generators can secure in the market, and for contract prices far in excess of market costs. These financial liabilities are documented on utility financial statements and evaluated by ratings agencies, effectively adding more debt and increasing utility risks and cost of capital. This, in turn, potentially impacts a utility's willingness and ability to expend capital for technology adoption/deployment.

- Wholesale Markets – In support of Congressional and FERC initiatives to value fuel security and resilience attributes of the nation's energy resources, DOE should continue to develop evaluative tools to assess and report on threats and vulnerabilities regarding fuel security and resilience.

NCC further encourages the Department of Energy to work to reinstitute a Congressional Office of Technology Assessment to provide Congress with new and effective means for securing competent, unbiased information concerning the physical, biological, economic, social and political effects of technological applications.

Tribal Recommendations

The nation's tribes own significant energy resources and are actively engaged in development and management of those resources. Among the most critical tribal issues that need to be addressed in relation to coal and deployment of advanced coal technologies:

- Requests by states for full waivers of sovereign immunity undermine tribal rights and should be curtailed.
- DOE guidance is needed on how the Loan Guarantee Program might be used to assist tribes looking to undertake a Tribal Energy Resource Agreement (TERA).
- Loan Guarantee Programs should be amended to allow Tribal Energy Development Organizations to interact with TERA amendments.

State/Regional Policy Recommendations

- Support continuation and expansion of the Regional Carbon Sequestration Partnerships through the four Regional Initiatives to further commercialize CCUS.
- Support enhanced participation of states in the State Carbon Capture Work Group initiative and the Regional Carbon Capture Deployment Initiative.
- Federal and state energy policies that are intended to incentivize investments in low-carbon energy technologies must include support for advanced coal generation technologies. Expand eligibility for low-carbon generation technologies, including CCUS/HELE, under state electricity portfolio standards.
- Employ market mechanisms to compensate coal power plants for “resiliency” attributes, including unit flexibility, dispatchability, resource availability, on-site fuel supply and other resilient parameters. This is especially crucial in those NERC regions with high concentrations of IRE, such as ERCOT and SPP.
- Offer a selective/temporary waiver or reduction in severance tax rates for CCUS projects and oil produced using capture CO_2.
- Encourage state governments and public utility commissions to:
  - Implement low-carbon credit programs to include CCUS, requiring utilities to purchase capacity and/or energy from fossil units with CCUS.
  - Allow periodic adjustment mechanisms for CCUS projects to recover environmental compliance costs on a timely basis, rather than requiring utilities to go through a general rate case.
  - Pre-approve project siting and environmental criteria.
  - Grant certificates of public convenience and necessity.
  - Allow pre-approvals for emissions controls at specific plants, thereby reducing uncertainty that an investment will be recovered through rate base treatment.
  - Issue guidance requiring consideration of carbon capture in Integrated Resource Plans (IRPs).
  - Pursue a comprehensive regulatory framework for CCUS similar to that of the Resource Conservation & Recovery Act’s (RCRA) “cradle to grave” framework for generation, transportation, treatment, storage and disposal of hazardous waste.
  - Enable CCUS projects to participate in state Private Activity Bond markets.
  - Secure from EPA, on an expedited basis, state authority to permit Class VI Underground Injection Control (UIC) wells, reducing regulatory barriers to carbon storage.
  - Pursue state assumption of liability for CO_2 storage sites following a certain amount of time.

Energy Infrastructure Recommendations

NCC encourages support for the following policies and programs to advance deployment of energy infrastructure, including CCUS pipelines and commercial-scale power plant technology projects.

Policies.

- INVEST CO_2 Act – Investing in Energy Systems for the Transport of CO_2 – would provide low-interest Federal loans to finance extra pipeline capacity and key regional hubs. Would provide for state and local government support for CO_2 pipelines as "pollution control devices" – enabling tax abatement. The scale of CO_2 pipelines must increase to facilitate widespread implementation of CCUS.
- Leading Infrastructure for Tomorrow's America (LIFT America Act – H.R. 2741) – supports modernization of energy infrastructure ($16 billion over 5 years).
- The Utilizing Significant Emissions with Innovative Technologies (USE IT) Act would help to accelerate the deployment of CCUS by streamlining the permitting process of storage projects and CO_2 pipelines by making the issues applicable to the Fixing America Surface Transportation (FAST ACT) Act. Under the FAST Act, the Federal Permitting Improvement Steering Council (FPISC) would be responsible for leading ongoing government-wide efforts to modernize the Federal permitting and review process for major infrastructure projects.
- Incorporate CO_2 pipeline infrastructure into national infrastructure policy initiatives, notably those associated with post-pandemic economic recovery.

Programs.

- Advance a "hubs and clusters" approach for CCUS infrastructure development, providing an opportunity for aggregation of emissions from numerous industrial and power generation sources.
- Continue support for the Regional Carbon Sequestration Partnerships under the newly launched Regional Initiative to support the continued buildout of value-added regional solutions to carbon management.
- CarbonSAFE – continue public-private support to facilitate deployment of geologic storage sites for CO_2, advance efforts to secure state primacy for permitting of injection sites, and address other regulatory and legal issues associated with CO_2 storage.
- Demonstrate secure geologic storage through CO_2-EOR, exploring the potential applicability of ISO 27916 (International Organization of Standardization).
- The U.S. government should undertake characterization of CO_2 storage sites. NCC supports the National Petroleum Council (NPC) recommendation of $400 million per year for 10 years for research and development of geologic storage.
- Engage the support and expertise of the oil and gas industry in support of CCUS deployment related to CO_2 transport and utilization for EOR.

Appendices

Appendix A
Utility Decarbonization Commitments

Timeline of Utility Deep Decarbonization Pledges

Month/Year	Utility	Pledge
Jan/2016	AVANGRID	Carbon neutral by 2035
Apr/2016	MidAmerican	100% renewable energy by 2020
Sep/2017	Ameren Missouri	80% reduction in GHG emissions (from 2005 levels) by 2050
Feb/2018	AEP Portland General Electric	80% reduction in GHG emissions (from 2000 levels) by 2050 80% reduction in CO2 (from 2010 levels) by 2050
Jun/2018	National Grid	80% reduction in GHG emissions (from 1990 levels) by 2050
Aug/2018	Alliant Energy WEC Energy Group	80% reduction in GHG emissions (from 2005 levels) by 2050 80% reduction in GHG emissions (from 2005 levels) by 2050
Sep/2018	FirstEnergy	90% reduction in CO2 emissions (from 2005 levels) by 2045
Oct/2018	Sacramento Municipal Utility District (SMUD)	90% reduction in CO2 emissions by 2050
Nov/2018	NiSource	90% reduction in CO2 emissions by 2028
Dec/2018	Xcel Energy	Zero carbon by 2050
Mar/2019	Idaho Power Co.	Zero carbon by 2045
Apr/2019	Avista Green Mountain Power PNM Resources	100% clean energy by 2045 100% renewable energy by 2030 Zero carbon by 2040
May/2019	Madison Gas & Electric	Carbon neutral by 2050
Jul/2019	Public Service Enterprise Group (PSEG)	80% reduction in CO2 (from 2005 levels) by 2046
Aug/2019	Duke Energy	Net zero carbon emissions by 2050
Sep/2019	DTE Energy	Net zero carbon emissions by 2050
Jan/2020	Arizona Public Service Company	100% Carbon-Free Electricity by 2050
Feb/2020	Consumers Energy Dominion	Net Zero Carbon Emissions by 2040 Net Zero Emissions by 2050
Jun/2020	Southern Company	Net Zero Emissions by 2050

Source: Clean Air Task Force

Appendix B
U.S. Department of Energy, Office of Fossil Energy
Funding Opportunities 2020 & 2019

FOAs – Awards – 2020

DE-FOA-0002186 – $15 million for *Novel Concepts of the Utilization of Carbon Dioxide from Utility and Industrial Sources* (January 17, 2020)
DE-FOA-0002057 - $64 million for *Critical Components for Coal FIRST Power Plants of the Future* (February 7, 2020)
DE-FOA-0001816 - $9 million for *Advanced Components for 65% Combined Cycle Efficiency, sCO_2 Power Cycles and Advanced Modular Heat Engines* (January 29, 2020)
DE-FOA-0002188 - $22 million for *Novel Research and Development for the Direct Capture of Carbon Dioxide from the Atmosphere* (March 30, 2020)
FE-DOE-0002187 - $46 million for *Carbon Capture Research and Development (R&D): Engineering Scale Testing from Coal- and Natural Gas-Based Flue Gas and Initial Engineering Design for Industrial Sources* (April 13, 2020)
DE-FOA-0002151 - $85 million for *Carbon Storage Assurance Facility Enterprise (CarbonSAFE): Site Characterization and CO_2 Capture Assessment* (April 24, 2020)
DE-FOA-0002332 - $6 million for *Energy Storage for Fossil Power Generation* (May 11, 2020)
DE-FOA-002180 - $81 million for *Design Development and System Integration Design Studies for Coal FIRST Concepts* (May 18, 2020)
DE-FOA-0002300 - $30 million for *Small-Scale Solid Oxide Fuel Cell Systems and Hybrid Energy Systems* (May 29, 2020)

FOAs – Awards – 2019

- DE-FOA-0001988 – $44 million for *Advanced Technologies for Enhanced Oil Recovery* (January 10, 2019)
- DE-FOA-0001990 – $44 million for *Advanced Technologies for Recovery of Unconventional Oil and Gas Resource*s (January 10, 2019)
- DE-FOA-0001991 – $4.8 million for *University Training and Research for Fossil Energy Applications* (January 7, 2019)
- DE-FOA-0001993 – $6 million for *University-Based Turbine Systems Research* (January 15, 2019)
- DE-FOA-0001992 – $9.5 million for *Maximizing the Coal Value Chain* (January 15, 2019)
- $38 million for *Improving Efficiency, Reliability, and Flexibility of Existing Coal-Based Power Plants* (January 23, 2019)
- $30 million for *Front-End Engineering Design Studies for Carbon Capture Systems on Coal and Natural Gas Power Plants*
- DE-FOA-0001996 – $22 million for *Advancing Steam Turbine Performance for Coal Boilers* (April 10, 2019)
- DE-FOA-0001931 – $1.95 million for *Coal-Based Power Plants of the Future* (April 12, 2019)
- DE-FOA-0001998 – $4.8 million for *Transformational Sensing Systems for Monitoring the Deep Subsurface* (April 10, 2019)

- DE-FOA-0002001– $14.5 million for *Crosscutting Research for Coal-Fueled Power Plants* (April 10, 2019)
- DE-FOA-0002002 – $26 million for *Advanced Materials for High-Efficiency, Flexible and Reliable Coal-Fueled Power Plants* (April 10, 2019)
- DE-FOA-0002003 – $20 million for *Process Scale-Up and Optimization/Efficiency Improvements for Rare Earth Elements (REE) and Critical Materials (CM) Recovery from Coal-Based Resources* (April 10, 2019)
- DE-FOA-0002005 – $15 million for *Advanced Subsea Systems Technologies to Improve Efficiency and Capabilities for Enhanced Oil Recovery (EOR) in Offshore Wells* (April 16, 2019)
- DE-FOA-0002006 – $24 million for *Advanced Natural Gas Infrastructure Technology Development* (April 16, 2019)
- DE-FOA-0002004 – $5 million for *Low Cost, Efficient Treatment Technologies for Produced Water* (May 13, 2019)
- DE-FOA-0001990 – $44.5 million for *Advanced Technologies for Recovery of Unconventional Oil & Gas Resources* (June 26, 2019)
- DE-FOA-0001996 – $22 million for *Advancing Steam Turbine Performance for Coal Boilers (April 10, 2019)*
- DE-FOA-0001931 – $1.95 million for *Coal-Based Power Plants of the Future (April 12, 2019)*
- DE-FOA-0001998 – $4.8 million for *Transformational Sensing Systems for Monitoring the Deep Subsurface (April 10, 2019)*

- DE-FOA-0002001– $14.5 million for *Crosscutting Research for Coal-Fueled Power Plants (April 10, 2019)*
- DE-FOA-0002002 – $26 million for *Advanced Materials for High-Efficiency, Flexible and Reliable Coal-Fueled Power Plants (April 10, 2019)*
- DE-FOA-0002003 – $20 million for *Process Scale-Up and Optimization/Efficiency Improvements for Rare Earth Elements (REE) and Critical Materials (CM) Recovery from Coal-Based Resources (April 10, 2019)*
- DE-FOA-0002005 – $15 million for A*dvanced Subsea Systems Technologies to Improve Efficiency and Capabilities for Enhanced Oil Recovery (EOR) in Offshore Wells (April 16, 2019)*
- DE-FOA-0002006 – $24 million for *Advanced Natural Gas Infrastructure Technology Development (April 16, 2019)*
- DE-FOA-0002004 – $5 million for *Low Cost, Efficient Treatment Technologies for Produced Water (May 13, 2019)*
- DE-FOA-0001990 – $44.5 million for *Advanced Technologies for Recovery of Unconventional Oil & Gas Resources (June 26, 2019)*

- DE-FOA-0001999 – $35 million for *Carbon Storage Assurance Facility Enterprise (CarbonSAFE): Site Characterization and CO_2 Capture Assessment* (September 13, 2019)
- U.S. Department of Energy Announces $4M for Projects to Collaborate Internationally and Accelerate CCUS Technologies (November 1, 2019)

FOAs – Selections – 2019

- DE-FOA-0001792 – $24 million for *Novel and Enabling Carbon Capture Transformational Technologies (February 28, 2019)*
- DE-FOA-0001829 – $2 million for *Developing Technologies for Advancement of Associated Geological Storage for Basinal Geo-Laboratories (March 29, 2019)*
- DE-FOE-0001830 – $2.9 million for *Transformational Pre-Combustion Carbon Capture Technologies (March 29, 2019)*
- DE-FOA-0001991 – $4 million for *University Training and Research for Fossil Energy Applications (May 22, 2019)*
- DE-FOA-0001989 – $39 million for *Improving Efficiency, Reliability, and Flexibility of Existing Coal-Based Power Plants (June 10, 2019)*
- DE-FOA-0001993 – $5.4 million for *University Turbine Systems Research (UTSR)* (June 20, 2019)
- DE-FOA-0001788 – $14.7 million for *Fossil Fuel Large-Scale Pilots* (July 9, 2019)
- HPC4Mtls projects –$600 thousand for *High Performance Computing for Materials (HPC4Mtls) Program* (July 10, 2019)
- DE-FOA-0001988 – $39.9 million for *Advanced Technologies for Enhanced Oil Recovery* (July 18, 2019)
- DE-FOA-0002058 – $55.4 million for *Front-End Engineering Design (FEED) Studies for Carbon Capture Systems on Coal and Natural Gas Power Plants* (September 13, 2019)
- DE-FOA-0002000 – $20 million for *Regional Initiative to Accelerate CCUS Deployment* (September 13, 2019)
- DE-FOA-0002005 – $9 million for *Advanced Subsea System Technologies to Improve Efficiency and Capabilities for Enhanced Oil Recovery (EOR) in Offshore Wells* (September 17, 2019)
- DE-FOA-0001992 – $10 million for *Maximizing the Coal Value Chain* (September 20, 2019)
- DE-FOA-0001996 – $11.9 million for *Advancing Steam Turbines for Coal Boilers* (September 20, 2019)
- DE-FOA-0002001 – $9.3 million for *Crosscutting Research for Coal-Fueled Power Plants* (September 20, 2019)
- DE-FOA-0002002 – $5 million for *Advanced Materials for High-Efficiency, Flexible and Reliable Coal-Fueled Power Plants* (September 20, 2019)
- DE-FOA-0002003 – $15 million for *Process Scale-Up and Optimization/Efficiency Improvements for Rare Earth Elements (REE) and Critical Materials (CM) Recovery from United States Coal-Based Resources* (September 20, 2019)
- DE-FOA-0001998 – $5.3 million for *Transformational Sensing Systems for Monitoring the Deep Subsurface* (September 20, 2019)
- DE-FOA-0002004 – $4.6 million for *Low-Cost, Efficient Treatment Technologies for Produced Water* (September 26, 2019)
- DE-FOA-0002057 – $7 million for *Coal-Based Power Plants of the Future* (October 11, 2019)
- Office of Fossil Energy Announces $8 Million for Projects under DOE's 2019 Grid Modernization Lab Call (November 6, 2019)

Appendix C
Select State-by-State Legislative & Regulatory Initiatives in Support of Coal and Advanced Coal Technology

Information for this appendix was submitted by the Indiana Coal Council, Kentucky Coal Association, Energy Policy Network, Lignite Energy Council, Energy & Environmental Research Center at the University of North Dakota, West Virginia Coal Association, School of Energy Resources at the University of Wyoming and the Southern States Energy Board.

SSEB compiles an annual review of passed and pending coal legislation in select states which can be accessed at https://www.sseb.org/wp-content/uploads/2020/05/Coal_Legislation_2020.pdf.

Following are representative examples of initiatives undertaken by states in support of coal and advanced coal technology deployment.

Georgia

Financial Support. Passed legislation in 2020 eliminating the coal ash surcharge imposed by host local governments regarding municipal solid waste disposal facilities operated by private enterprise.

Permitting & Environmental Compliance. Introduced legislation in 2020 detailing conditions for the issuance of a permit for solid waste or special waste handling for a coal combustion unit or landfill.

Indiana

Reliability & Resilience. In the spring of 2020, Indiana lawmakers approved a bill (House Bill 1414) mandating that a coal power plant be closed only upon the approval of state regulators and not solely by a decision of the utility. The legislation:

> Provides that a public utility that owns and operates a reliable capacity electric generation resource shall operate and maintain the unit using good utility practices and in a manner reasonably intended to support the availability of the unit for dispatch and for providing reliable service to customers of the public utility. Prohibits a public utility from terminating a power agreement with a legacy generation resource in which the public utility has an ownership interest unless the public utility provides the utility regulatory commission (IURC) with at least three years advance notice of the termination. Provides that the IURC shall determine the reasonable costs incurred by the public utility under the power agreement and allow the public utility to recover those costs in a fuel adjustment charge proceeding. Provides that a public utility may not retire, sell, or transfer a reliable capacity resource with a capacity of at least 80 megawatts before May 1, 2021, unless: (1) the public utility first provides written notice to the IURC of the public utility's intent to do so; and (2) the IURC conducts a public hearing to receive information concerning the reasonableness of the planned retirement, sale, or transfer. Provides that if a public utility seeking to retire, sell, or transfer a reliable capacity resource by May 1, 2021 who cites a federal mandate as basis, the utility regulatory commission may consider as part of the commission’s analysis and conclusions, if the cited federal mandate is in force, has not expired or been revoked, and is not merely anticipated to be enacted.

Iowa

Permitting & Environmental Compliance. In 2018, Iowa passed SF 2311: Modifying Provisions Relating to Public Utilities. This bill establishes that a rate-regulated public utility that owns one or more electric power generating facilities fueled by coal and located in this state may, in its sole discretion, file for advanced review of projects for managing regulated emissions from its facilities in a cost-effective manner.

The Department of Natural Resources must determine whether the project meets applicable state or Federal environmental requirements for regulated emissions, including requirements related to air, water, or solid waste. If the plan project does not meet these requirements, the department must recommend amendments that outline actions necessary to bring the plan or update project into compliance with current environmental requirements.

Kentucky

Tax/Financial Incentives

Passed tax refund legislation for coal exports under the state revenue bill, providing a refund of state severance tax for coal that is transported directly to a market outside of North America.

SB 263, Returning Funds to Coal Companies. In 2017, the legislature passed HB 377, which transferred the liabilities, assets and management of the Coal Workers Pneumoconiosis fund to a third party administration. The law provided that the funds shall be returned to the employers who paid in on a pro-rata share, but didn't provide a mechanism or process for this refund. SB 263 creates a process to return $18 Million in excess funds to coal operators or the Self-Insured Guaranty Fund to help pay benefits for miners employed by a self-insured coal company.

Workers Compensation Reform HB2: Passed workers compensation reform to reduce costs for coal companies in the future, especially regarding claims associated with complicated black lung diagnosis. The bill requires all diagnosis be done by pulmonologists instead of radiologists.

Reliability & Resilience

House Resolution 144: A resolution urging the Public Service Commission to consider all costs related to the importation of coal for electricity generation.

Public Service Commission amendment to 807 KAR 5:056 Requires the PSC, when evaluating the reasonableness of a utility's fuel purchase decision, to deduct from the purchase price of the coal the amount of Kentucky severance tax assessed on the coal to be purchased.

Montana

Tax Incentives.

In 2016, Montana passed HB 421: Severance Tax Coal Washing Credit. This legislation revises the coal severance tax coal washing credit to extend the termination date of the credit by eight years from July 1, 2017 to July 1, 2025.

SB 328 (2019): Allows for counties to abate up to 50% of the coal gross proceeds tax received from a new or expanding surface coal mine.

HB 403 (2019): Removed the sunset date on the reduced tax rate of 2.5% on coal gross proceeds from new and existing underground coal mines.

Financial Support. In 2017, HB 585: Coal-Fired Generating Unit Loans, was signed into law. This allows the Board of Investments to make loans to an owner of a coal-fired generating unit in Montana from the state's permanent Coal Tax Trust Fund for the operation and maintenance of a coal-fired generating unit. According to the bill, the total amount of loans made annually may not exceed $10 million. In determining the size of a loan, the board must consider the direct and indirect tax implications to the state if a coal generating unit is retired prematurely, the current and projected ability of an owner to operate and maintain a coal generating unit, and any other matters that the board considers necessary. The bill also provides loan criteria and limitations such as requiring the owner to provide the Board of Investments and the Governor of Montana with a minimum of 90 days' notice prior to filing for bankruptcy, reorganization, or other insolvency proceeding or prior to a merger, sale, or transfer, by operation of law or otherwise.

In 2019, Montana passed HB 476: Coal-Fired Generation Loan Amendments which revises Board of Investments (BOI) loan statutes for coal-fired generation and associated transmission by allowing the BOI to increase the amount of the Permanent Coal Tax Trust Fund loans made to a public utility from $10 million up to $50 million annually. The bill allows the loans to be used for coal, coal improvements, additional coal interests, and transmission.

Reliability & Resilience. Again in 2017, both bodies of the state legislature passed a resolution, SJ5: Interim Study Regarding Coal Phase. This resolution requests an interim study to investigate threats to the mining and burning of coal in Montana and the consequences of significant reductions in coal mining and usage.

North Dakota

Regulatory Certainty.

North Dakota Policy on Geologic Storage (NDCC Section 38-22-01) states that it is in the public interest to promote the geologic storage of carbon dioxide. Doing so will benefit the state and the global environment by reducing greenhouse gas emissions. Doing so will help ensure the viability of the state's coal and power industries, to the economic benefit of North Dakota and its citizens. Further, geologic storage of carbon dioxide, a potentially valuable commodity, may allow for its ready availability if needed for commercial, industrial, or other uses, including enhanced recovery of oil, gas, and other minerals. Geologic storage, however, to be practical and effective requires cooperative use of surface and subsurface property interests and the collaboration of property owners. Obtaining consent from all owners may not be feasible, requiring procedures that promote, in a manner fair to all interests, cooperative management, thereby ensuring the maximum use of natural resources.

Release of Long-Term Liability (NDCC Section 38-22-17) - At least ten years after carbon dioxide injections end title to the stored CO_2 transfers to the state. Monitoring and managing the storage facility is the state's responsibility to be overseen by the commission until such time as the federal government assumes responsibility for the long-term monitoring and management of storage facilities.

State UIC Class VI Primacy – April 24, 2018 - On June 21, 2013 the official North Dakota Class VI primacy application was submitted to the EPA and North Dakota received approval on April 24, 2018.

Tax Incentives (NDCC 57-39.2, 57-40.2, 57-51.1, and 57-60).

CO_2 Capture (NDCC 57-39.2, 57-40.2, and 57-60)

- Coal conversion tax: tax reduction with CO_2 capture (up to 50%). (NDCC 57-60)
- Coal conversion facilities privilege tax credit for CO_2 capture.
- No sales tax on capture-related infrastructure. (NDCC 57-39.2-04.14)
- Sales and use tax exemption for CO_2 equipment to compress, gather, collect, store, transport, or inject CO_2.
- CO_2 capture equipment on a coal (or other) facility is considered personal property, exempt from property tax.
- Carbon dioxide capture system exemption from ad valorem and coal conversion facilities privilege tax.
- Sales and use tax exemption for environmental upgrade materials used in power plants and processing plants.
- No sales tax on CO_2 sold for EOR. (NDCC 57-39.2-04 Exemptions)

Sales and use tax exemption for CO_2 used for EOR.
EOR (NDCC 57-39.2, 57-40.2, and 57-51.1)

- Extraction tax: 0% for 20 years for tertiary incremental recovery.
- Oil extraction tax exemptions for incremental production from a secondary or tertiary recovery project.
- Note: Production tax still applies.
- CO_2 separation/recycle/compression infrastructure: No sales tax on CO_2 EOR infrastructure.

- CO_2 equipment at a wellsite is considered personal property, exempt from property tax.

CO_2 Pipeline (NDCC 57-39.2 and 57-40.2)

- No sales tax on construction of pipeline.
- Property tax exemption for pipeline property and associated transportation and storage equipment used for EOR.
- Property tax-exempt for 10 years (equipment).

R&D Support.

North Dakota Industrial Commission Lignite Research Program (NDCC 54-17.5)
The North Dakota Lignite Research, Development and Marketing Program was established in 1987 and receives funding from several sources including the coal severance tax, coal conversion tax and the North Dakota Strategic Investment and Improvements Fund. The Program includes R&D related to "new" technology options for clean and efficient use of lignite. The program is a state-industry partnership and maintains synergy with the Renewable Energy and Oil & Gas Research Programs as the state works toward optimum use of regional resources for clean, efficient, low-cost reliable power while reducing the carbon footprint.

Leveraged Funds for Research and Development – State, Federal, and Industry
North Dakota continues to strategically leverage state dollars with industry investments as well as funding from the U.S. Department of Energy for research, development and demonstration projects. North Dakota has invested more than $75 million in lignite research since 1987. Combined with industry and federal funding North Dakota has leveraged over $700 million in research, development and demonstration focused on clean, efficient lignite generated energy.

Ohio

Reliability & Resiliency. At 47%, coal still provides the largest portion of the state's net electric generation, followed in turn by natural gas (34%), nuclear (15%), renewables (3%, with wind the largest segment) and other (3%). In 2019, with the passage into law of *Ohio's House Bill 6* (signed by the Governor in July) their respective "share" of the energy pie likely will remain stable for now.

HB 6 was a very contentious bill, as its primary purpose was to require all Ohio ratepayers to subsidize First Energy's two nuclear power plants, Davis Besse near Toledo and Perry near Cleveland. First Energy stated it would promptly close the plants if they did not receive the subsidy. Thus, a surcharge on all Ohio ratepayers was devised. To help finance some of this by relieving other costs on the utilities, the General Assembly also eliminated the state's 12.5% Renewable Portfolio Standard (RPS). HB 6 also eliminates energy efficiency and demand-reduction programs. Overall, HB 6 was touted as saving jobs and ratepayer costs.

To appeal to a broader audience of legislators, the Bill was expanded to include two coal power plants owned by Ohio Valley Electric Corporation (a consortium of AEP Ohio – largest owner, Buckeye Power, DP&L, Duke Energy Ohio, LG&E and Kentucky Energy (PPL), First Energy, Vectron South, and Peninsula Generating Cooperative).

These two plants, Clifty Creek near Madison, IN (1303 MW) and Kyger Creek near Cheshire, OH (1086 MW) were labeled as “Legacy Generation Resources.” Subsequently, the Ohio Public Utilities Commission replaced the riders on these two OVEC plants for “prudently incurred costs” with new riders that commenced January 1, 2020 and will continue through December 31, 2030. The coal plant subsidy statewide generally works out to $1.50/month for residential ratepayers.

More specifics on HB 6 can be found at Ohio’s Legislative Services Commission site: https://www.legislature.ohio.gov/download?key=13060&format=pdf. A copy of the Ohio Public Utilities Commission’s Opinion and Order setting the new rates can be found here: www.PUCO.ohio.gov then click on the link to Docketing Information Services and search for cases 19-2121-EL-ATA, 19-2123-EL-ATA, 19-2133-EL-ATA and 19-2135-EL-ATA.

R&D Support. Ohio continues its coal research and development program through its Ohio Coal Development Office (OCDO), created in 1984, and now housed in the Ohio Development Services Agency. OCDO states, “Moving forward, the [OCDO] will focus its resources on demonstration and pilot projects that have potential for commercialization and adoption by the market.” Its most recent report on the status of the Ohio coal industry and OCDO’s coal R&D program can be found here: https://development.ohio.gov/files/bs/2018%20Coal%20report.pdf

In its latest Request for Proposals, found here - https://procure.ohio.gov/PDF/132019153830DEVOCA1901%20RFP.pdf – some OCDO activities/priorities were expanded to include:

- Improved technologies/processes that enable the more efficient conversion of Ohio coal to a chemical feedstock, liquid, commercial product/material (such as rare earth elements), or gas;
- Analysis of the potential impact on the Ohio coal industry of: 1) the increased electrification of the ground transportation sector and identification of opportunities to advance Ohio coal so that the state can optimize environmental and economic benefits, or 2) the integration of thermal or energy storage to ease intermittency inefficiencies and equipment damage that results from operating Ohio coal-fired electric generation units more flexibly and rapidly adjusting to cycling load demands;
- Technologies/processes consuming Ohio coal that allow electric generating units to operate more flexibly and rapidly adjust to cycling load demands that maximizes output efficiencies, and minimizes criteria air emissions.

The 2019 RFP resulted in the following projects being announced:

- $249,999 grant to the University of Cincinnati for their project: “Sequestration of Regulated Selenium, Arsenic and Heavy Metals from FGD Wastewater Using Zero-Valent Iron Adsorbents.”
- $190,000 grant to Battelle for their project: “A Novel Process for Converting Coal to High-Value Polyurethane Products.”
- $500,000 grant to The Ohio State University for their project: “Novel Transformational Membranes and Process for CO_2 Capture from Flue Gas.”
- $150,000 grant to The Ohio State University for their project: “Transformational Membranes for Pre-combustion Carbon Capture.”

Oklahoma

Tax Incentives.

In 2016, Oklahoma passed SB 1614: Coal Purchase and Production Tax Credit. This tax credit modifies the existing coal tax credits to be in the amount of $2.85 per ton for each ton of Oklahoma-mined coal purchased. In addition, for the period of July 1, 2006, through December 31, 2006, and except where prohibited, for tax years beginning on or after January 1, 2007, and ending on or before December 31, 2021, it permits a credit in the amount of $2.15 per ton for each ton of Oklahoma-mined coal purchased.

In 2018, Oklahoma enacted HB 1034: Income Tax Credit Modifications. This measure establishes an annual cap equal to $5 million for coal tax credits effective tax year 2018. The measure directs the Oklahoma Tax Commission to use a percentage adjustment formula to determine a percentage by which the credits authorized are to be reduced to satisfy the $5 million annual cap. In the event that the total tax credits authorized exceed the annual cap, the commission will permit any excess, but must factor the excess into the percentage adjustment formula for subsequent years.

South Carolina

South Carolina passed legislation which will increase the resource conversation and recovery and subsequent beneficial use of coal combustion products. Signed into law in 2019, HB 3483 requires that coal combustion residuals from an electric utility, an electric cooperative, a governmental entity, a corporation or an individual producing electricity must be placed in a Class 3 solid waste, management landfill unless the coal combustion residuals that are located contiguous with the electric generating unit are intended to be beneficially reused, placed in beneficial use or placed in an appropriate landfill owned or operated by the entity that produced the residual.

Texas

Please see Appendix D for an update on the value of coal and the cost of early retirements in Texas.

Virginia

Permitting & Environmental Compliance. SB876 replaces the voluntary renewable energy portfolio standard program with a mandatory clean energy standard program that sets requirements for all investor-owned electric utilities and cooperative electric utilities. The CES program requires 30% of the total electric energy sold by each utility in 2030 to be clean energy, which is defined as electricity generated without emitting carbon dioxide or generated by a natural gas-fired facility with 80% carbon capture or a coal-fired facility with 90% carbon capture. The CES goals increase incrementally in future years until 2050 and thereafter, by which time 100% of the electric energy sold is required to be clean energy.

West Virginia

Reliability & Resilience. The State of West Virginia is considering executive and legislative action that assigns the highest priority to preserving coal mining and coal-fired electricity in order to secure the electric grid and uninterrupted delivery of industrial and household electricity. This policy action is designed to stabilize the state's economy going forward by maintaining the current level of coal jobs which are the highest paying industrial jobs in the state and will reflect West Virginia's commitment to provide leadership under Homeland Security and National Defense policies.

Consideration is also focused on the creation of the position of State Energy Secretary within the Governor's Office to advise the Governor generally on matters related to energy and coordination of the state's energy plan and to create and administer a comprehensive strategy and public relations program for communicating the advantages of a strong, affordable coal and energy industry.

Tax Incentives.

HB 3142 (2019): Thermal and Steam Coal Severance Tax Reduction. Reduces the severance tax on thermal or steam coal to from 5% to 3% over a period of 3 years. It also eliminates restrictions on counties and municipalities expending and reporting the expenditure of the county and municipality portion of the severance tax.

HB 3144 (2019): North Central Appalachian Coal Severance Tax Rebate Act. Establishes the North Central Appalachian Coal Tax Rebate allowing for capital investment in new machinery and equipment directly used in severing coal for sale, profit, or commercial use and coal preparation and processing facilities placed in service or use on or after the effective date of this article. The bill establishes the rebate amount at 35% of the cost of new machinery and equipment. According to the bill, the rebate amount is limited to 80% of the state portion of the severance taxes attributable to the additional coal produced as a result of the new machinery and equipment. Further, the bill provides regulations to protect the existing severance tax base attributable to the production of coal.

HB 207 (2019): Exempts a merchant power plant from the business and occupation tax on the generation units located in the State of West Virginia that are owned or leased by the taxpayer and used to generate electricity. A merchant power plant is defined as an electricity generating plant that is not subject to regulation of its rates by the West Virginia Public Service Commission, that sells electricity it generates only on the wholesale market, does not sell electricity pursuant to one or more long-term sales contracts, and does not sell electricity to retail customers.

SB 207 (2020): Reduces the Business and Occupation Tax liability for coal-fired electric power generation units of up to $15.0 million in Fiscal Year 2022 and by as much as $16.3 million each year thereafter. The provisions of the bill allow coal-fired electric generators to reduce their taxable generation capacity tax base to 45% beginning July 1, 2021 in exchange for an agreement to keep those facilities open until at least July 1, 2025.

Wyoming

Reliability & Resilience.

SB 159 (2019): Establishing New Opportunities for Coal-fired Generation. Establishes that the rates charged by an electric utility must not include any recovery of costs associated with new electric generation facilities built to replace the electricity generated from retired coal-fired electric generating facilities unless the Public Service Commission determines that the electric utility made a good faith effort to sell the facility prior to its retirement. The bill outlines the process for the sale of an otherwise retiring coal-fired electric generating facility, and it exempts a person purchasing an otherwise retiring coal fired electric generation facility from regulation as a public utility. Finally, the bill requires a public utility to purchase electricity generated from a purchased retiring coal-fired electric generation facility if it is offered at a specified rate determined by the commission.

HB 4 (2020): Establishes the Wyoming Coal Marketing Program to be administered by the governor. The purpose of the program is to protect and expand Wyoming's coal markets and coal facilities and to address impacts cities, towns and counties have experienced or will experience due to changes in the coal market.

SB 21 (2020): The bill allows the purchaser of a coal-fired facility to sell electricity generated by the facility to the utility selling the facility in order to pass on the generated electricity with specifically permitted markups to customers meeting certain criteria. The bill also requires any utility seeking to retire a facility to first make a good faith effort to sell the facility for continued use as a coal-fired electric generation facility.

Tax Incentives. HB 231 (2020): Creates a severance tax exemption for surface col transported to markets outside of North America.

Permitting & Environmental Compliance. HB 0200 (2020): Reliable and Dispatchable Low-Carbon Energy. Mandates that the Wyoming Public Service Commission "establish by rule energy portfolio standards that will maximize the use of dispatchable and reliable low-carbon electricity." Low-carbon is defined as "electricity that is generated using carbon capture, utilization and storage technology that produces carbon emissions not greater than 620 pounds of carbon dioxide per megawatt hour of generated electricity averaged over 1 calendar year." Dispatchable is defined as "a source of electricity that is available for use on demand and that can be dispatched upon request of a power grid operator or that can have its power output adjusted, according to market needs." The ultimate standards are to take effect no later than July 1, 2030. These standards apply to power companies regulated by the PSC and do not apply to cooperatives.

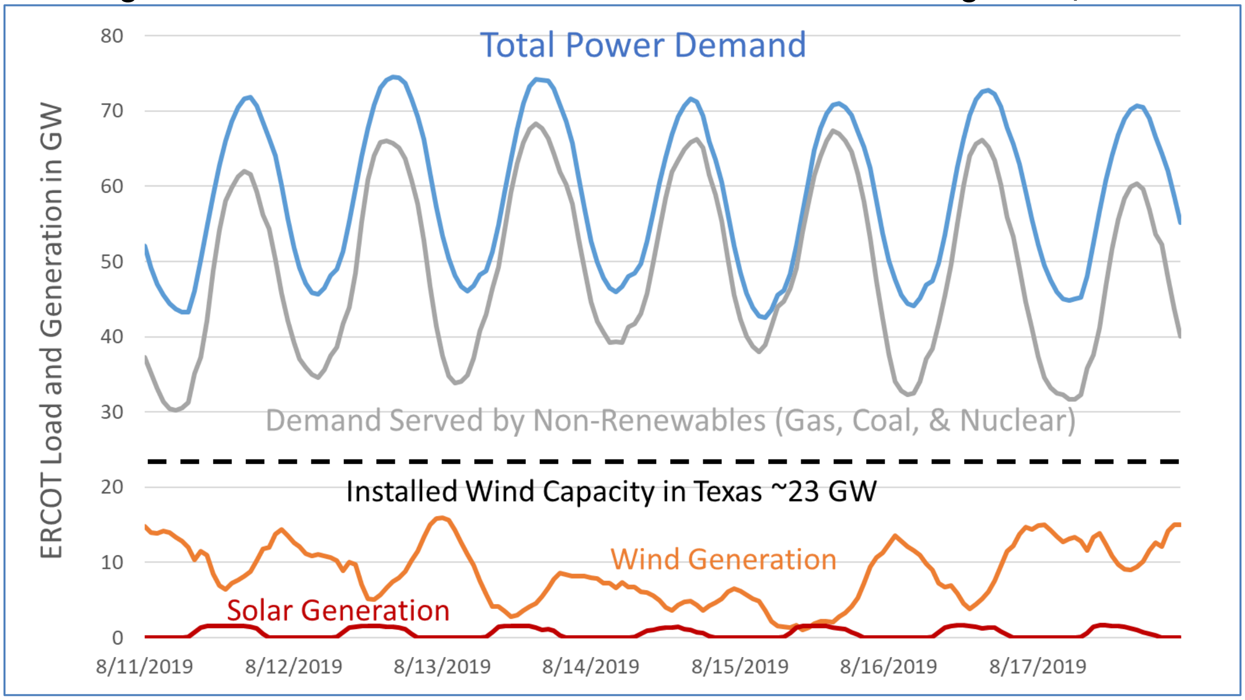
Appendix D
The Value of Coal and the Cost of Early Retirements in Texas

Although Texas remains atop the rankings of both coal-based capacity and generation, it has lost several coal plants over the past two years due to a combination of many factors, including regulatory costs and the erosive economics of the ERCOT deregulated wholesale market resulting from subsidized renewables and sustained low natural gas prices. As reported by the NCC in its report entitled “Leveling the Playing Field: Policy Parity for Carbon Capture and Storage Technologies” (November 2015)[cxxxii], deregulated wholesale electric markets like ERCOT have become severely distorted by the production tax credit for wind, which often results in a phenomenon called “negative pricing.”

Because the combined effect of these market distortions with sustained low natural gas prices has undermined continued investment in major capital projects necessary to sustain older coal plants, several of the oldest Texas plants were retired in 2018 and 2019. The retirements came primarily from the Vistra/Luminant fleet, with over 4,000 MWs of retired capacity, followed by the City of San Antonio’s Deely plant (932 MW), AEP’s Oklaunion plant (670 MW), and Texas Municipal Power Agency’s Gibbons Creek plant (470 MW).

This significant loss of coal-based capacity, combined with a lack of new thermal generation, has resulted in razor thin reserve margins during critical times over the past two years. The Texas ERCOT market tells a cautionary tale about what less coal capacity and more subsidized wind power can do to a previously well-performing electric market. This thinning reserve margin in Texas has significantly increased the ERCOT market’s volatility during extreme cold events, not just during the heat of the summer. In March 2019, demand peaked in ERCOT due to cold weather and wind’s underperformance relative to forecast. This escalated power prices 700%, which is a significant event but pales in comparison to scarcity events during the summers of 2018 and 2019.

Figure A: ERCOT Load vs. Generation for the Week of August 11, 2019



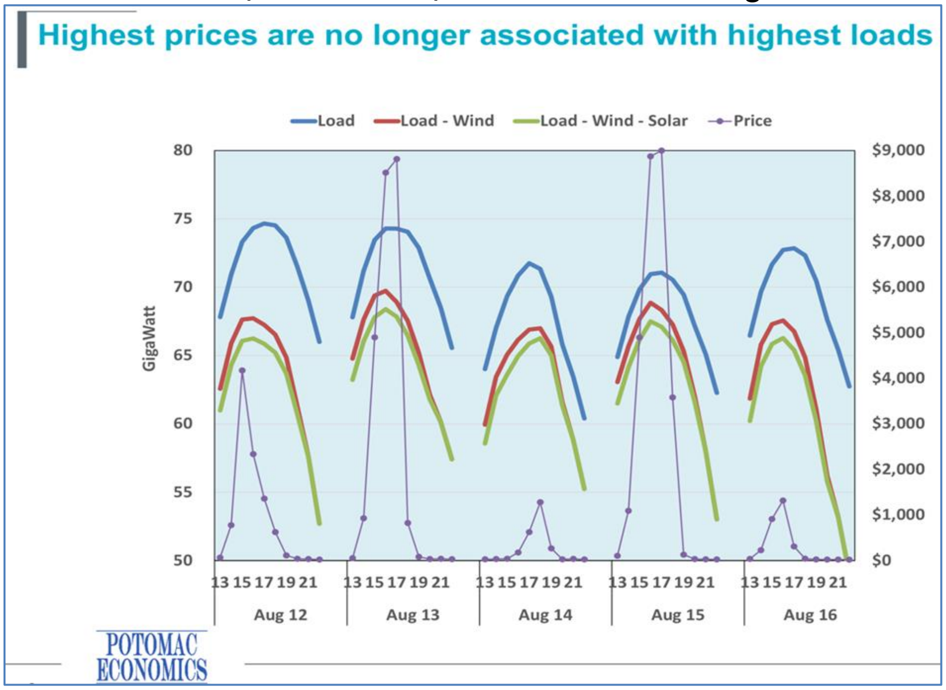
Source: *ERCOT*.

Just this year, in August of 2019, perhaps the most dramatic lesson was learned about growing risk of coal retirements and expanded wind penetration. As seen in Figure A, the week of August 11, 2019 is a case study in the kind of price volatility and reliability risk created by coal retirements, suppressed new thermal builds due to renewable subsidy market distortions, and expanded exposure to highly variable (and too often unpredictable) wind energy.

On Monday, August 12, a new record peak demand was set, and real time prices reached $6500/MWh while averaging over $1000/MWh for the afternoon hours. But it was not record peak demand that drove the most extreme conditions the ERCOT market faced that week – it was the underperformance of wind relative to forecast.

On Tuesday, August 13, ERCOT declared emergency conditions (referred to as “EEA-1”) and real time prices reached $9000/MWh for six periods and averaged $2500/MWh for the afternoon. On Thursday, August 15, real time prices reached $9000/MWh for seven periods and averaged $2900/MWh for the afternoon. Those two days did not involve record peak demand. Rather, as documented by the Texas Independent Market Monitor (IMM) in its Annual Report, it was the drop-off of wind beyond what was forecasted that sent prices skyrocketing (see Figure B).

Figure B: ERCOT Load, Generation, and Prices from August 12 to August 16



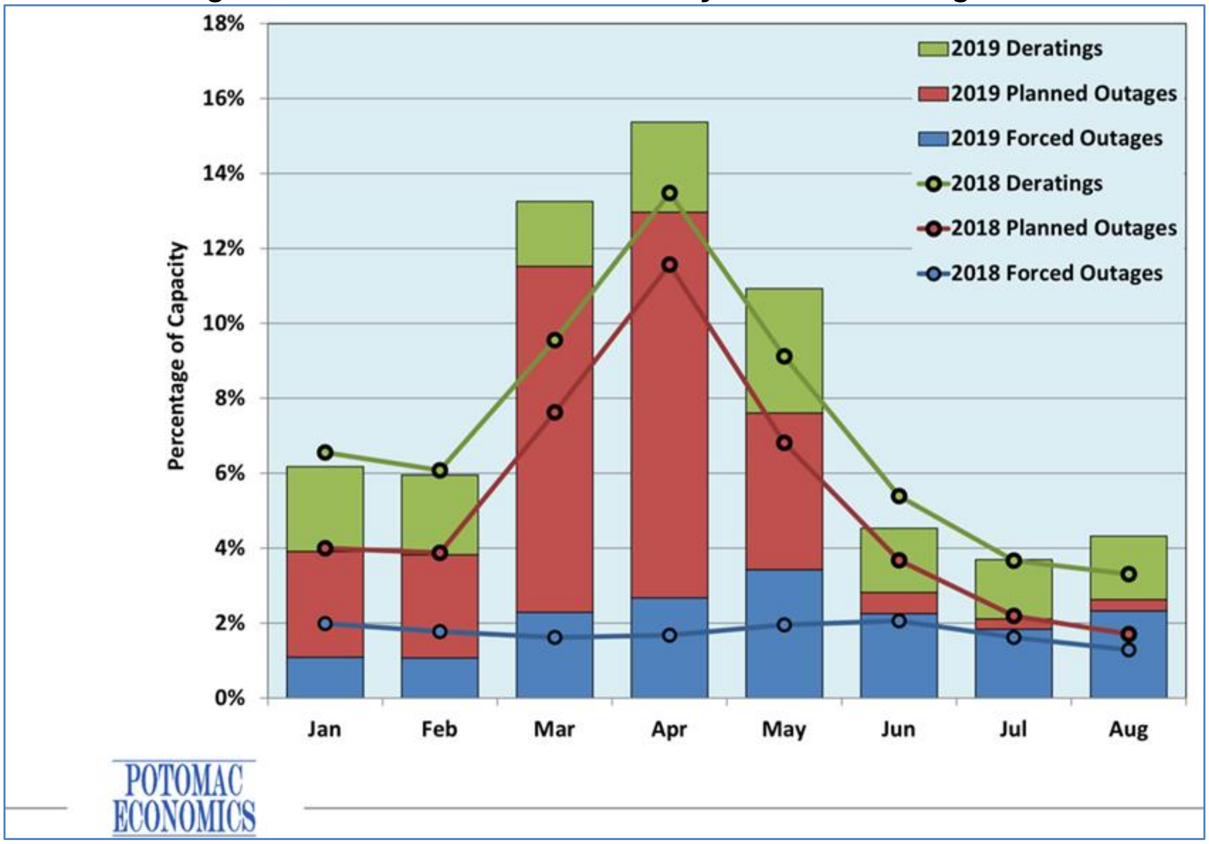
Source: *Potomac Economics*

ERCOT is compounding the perception problem by the way it calculates and reports its reserve margins. It uses the average contribution of wind and solar during peak demand periods over the course of the entire summer, rather than using the lowest observed output. The Capacity, Demand, and Reserve Report (ERCOT 2019a) bases its forecasts on 63% capacity for coastal wind, 29% for panhandle wind, and 16% for other wind, and 76% for solar during summer peaks. But the reality is that wind was operating at only 12% capacity and solar at 59% during the peak hour on August 15 (ERCOT 2019b). If we apply these observed capacity factors to ERCOT's 2024 projections, the forecasted reserve margin drops from 12.9% to just 4.9%.

And those numbers are true only if the projected capacity gets built. Over the past few years, ERCOT has consistently forecasted increasing reserves only to have to revise those numbers down. It forecasted in 2016 (ERCOT 2016) that the reserve margin would be 19.6% in 2019. Instead, the margin was 8.6% entering this summer, (ERCOT 2019c) with reserves dropping below 2% during the emergency situations. The current predictions should be met with clear-eyed skepticism, as recent experience suggests that Texas cannot count on renewable generation for reliable electricity and that their erosion of the Texas electricity market may force more retirements of dispatchable generation.

Another important lesson learned from the ERCOT market over the past two summers is just how valuable and reliable the thermal fleet is in the midst of highly variable renewable generation. As documented by the IMM in Figure C, extremely high reliability in the coal, gas, and nuclear fleets in Texas was a saving grace in the summers of 2018 and 2019 as forced outage rates dropped to just below and above 2% in 2018 and 2019, respectively.

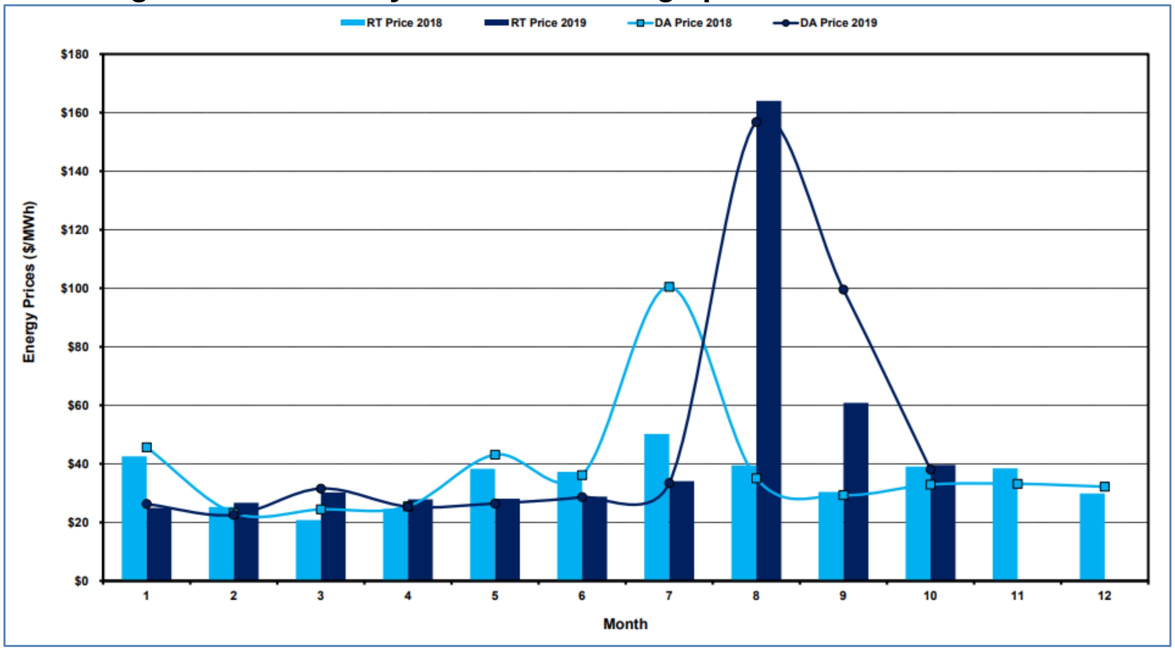
Figure C: 2018 and 2019 ERCOT system-wide outage rates



Source: ***Potomac Economics***

As striking as all of the above-referenced data are to the informed market observer, perhaps the most concerning fact about the ERCOT market is that power prices are now on the rise in Texas despite sustained low natural gas prices. As pointed out by IMM in Figure D, ERCOT year-over-year prices jumped over 40% during a timeframe when natural gas prices fell over 15%. This trend shows just how valuable the existing thermal fleet is to the affordability and reliability of the Texas grid, and the rest of the country should heed the warning of this cautionary tale.

Figure D: ERCOT system-wide average prices for 2018 and 2019



Source: *[Potomac Economics]()*

The Cautionary Tale of Texas Municipal Utilities Moving to Renewables

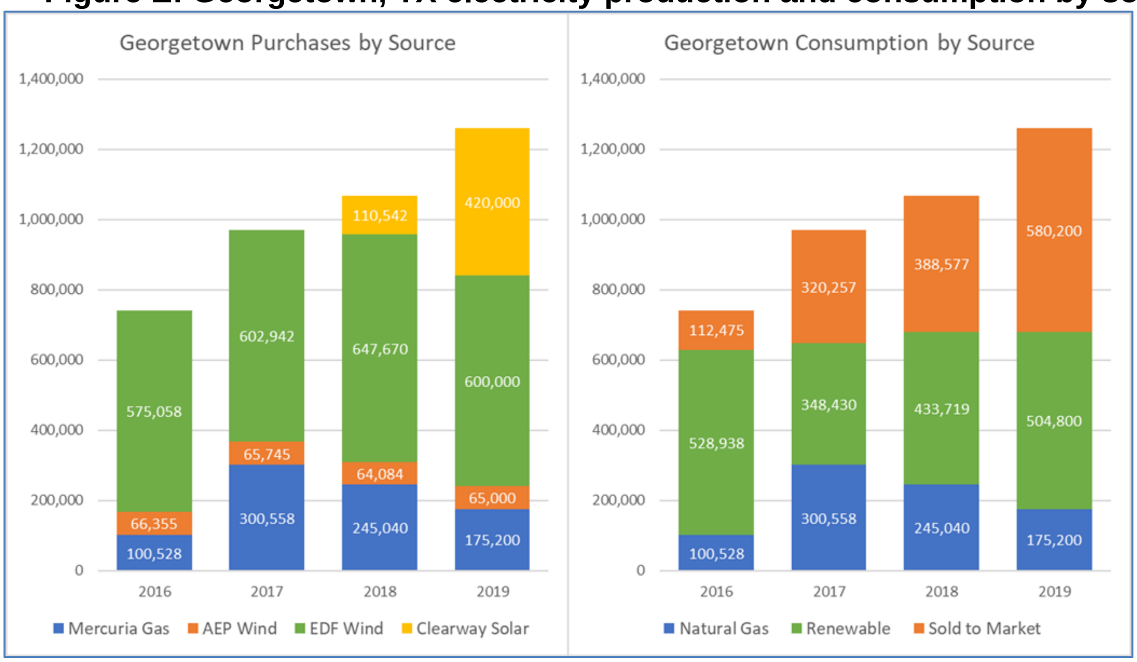
While Texas is just beginning to see these problems arise with a low level of renewable generation – currently about 20% of total electricity generation – the problems of a high-renewable grid have become fully apparent in the small city of Georgetown, just north of the state capitol in Austin. In 2012, Georgetown, along with several other Central Texas municipalities, had the opportunity to break their contracts with the Lower Colorado River Authority and seek out other parties for their power contracts. Georgetown was forecasting that wholesale prices would rise from the $40/MWh range at the time to $60/MWh or more, and they decided to lock-in long-term solar and wind contracts at prices that were near their market forecasts.

City officials claimed at the time that their decision to go “100% renewable” was purely economic because they wanted to secure stable prices in a rising price environment (The Guardian). The national press and the environmental community hailed this decision as a sign that 100% renewable really was doable, especially since it was coming from a city that was politically conservative. But this decision turned out to be far from economically sound, and Georgetown’s utility has begun to lose more and more money as its renewable contracts come into effect. It has raised electricity rates three times in 2019 (Austin American Statesman), and its customers now pay up to 50% more for their electricity than similar communities in Central Texas. So, what went wrong? Right as Georgetown started finalizing its contracts in 2014, wholesale prices began to plummet due to falling natural gas prices and an explosion of subsidized wind energy in the ERCOT market. Georgetown’s 100% renewable plan depends on its ability to sell excess wind energy during periods of low demand, primarily at night in Texas, and it is now selling most of that excess energy at a loss.

Georgetown compounded this problem by buying significantly more wind and solar than it needed, contracting for almost double their current annual demand in wind and solar (see Figure E). Despite this excess of wind and solar under contract, the city is still having to pay a premium for a natural gas contract to meet peak demand, which often coincides with times, such as late summer afternoons, when wind and solar resources are low.

While Georgetown thought they were bringing price certainty with their fixed contracts, they were actually incurring significant price risk by moving away from dispatchable generation and relying on the market, still primarily powered by dispatchable generators, to both absorb their excess energy and meet their peak demand. Although the city made their problem much worse by moving all-in immediately and making a bad bet on wholesale prices, their situation is illustrating in the real-world what energy researchers have long known is the fundamental problem with wind and solar: you have too much of it when you don't need it and not enough of it when you do need it. No matter how much the technologies for capturing these resources improve, that fundamental physical problem will remain.

Figure E: Georgetown, TX electricity production and consumption by source



Source: *Georgetown Utility Systems*

Wind and Solar Will Never Eliminate the Need for Dispatchable Generation

Another argument being made by renewables advocates is that the falling costs (Lazard) of installing wind and solar generation mean that utilities should not be investing in thermal power plants because those assets will be "stranded" as they are unable to compete with the low prices that wind and solar can bid into the electricity markets. However, Texas again shows that, absent an extraordinary amount of almost free energy storage to handle the intermittent output of renewables, reliable generation from fossil fuels will continue to be necessary as more wind and solar are added to the grid.

Research conducted by *Life:Powered*, an energy policy initiative of the Texas Public Policy Foundation, (Bennett) illuminates the problems facing the Texas electric grid if it were to reach high renewable penetrations. As shown in Figure F, if Texas were to derive 50% of its annual electricity from wind and solar by 2030, it would still require almost as much dispatchable generation capacity to meet peak demand as it does now with 20%. Even with renewables meeting 80% of Texas's annual electricity demand in 2030 – and more than twice its peak demand in installed wind and solar capacity – Texas would still require enough dispatchable generation to meet well over half of its peak demand. Eliminating dispatchable generation entirely would require enough energy storage to power the entire state for more than a day, which is nearly 100 times the amount of energy storage installed worldwide in 2018 (IEA).

Figure F: 2030 capacity requirements of 50 percent, 80 percent, and 100 percent wind and solar generation for ERCOT compared to 2030 base case and 2018 generation mix

	2018	Current Policies	50 Percent Renewables	80 Percent Renewables	100 Percent Renewables
Wind Capacity (MW)	22,066	37,596	49,877	102,928	107,737
Solar Capacity (MW)	1,861	11,019	25,372	86,091	91,597
Battery Capacity (MW)	87	527	10,626	23,260	533,833
Nuclear Capacity (MW)	4,960	4,960	4,960	4,960	-
Gas Capacity (MW)	45,449	51,997	54,700	42,000	-
Coal Capacity (MW)	14,225	14,225	-	-	-

Source: *Life:Powered*

Because of the increasing amount of backup generation, energy storage, transmission lines, and other system costs needed to support wind and solar, the costs of integrating wind and solar into the grid rises exponentially from 50% to 100% renewable. Figure G shows how the generation and transmission costs double when moving from 50% to 80%, primarily due to the buildout and wind and solar generation and transmission required, and double again from 80% to 100% due to energy storage requirements. And these figures are for Texas, which is blessed with enough wind and solar resources to have an optimal roughly 50/50 wind and solar mix. Recent research from the MIT Energy Initiative (Sepulveda et al.) shows that this exponential rise in system costs would be even more true for the grids at higher latitudes with fewer solar resources.

Figure G: 2020-2030 average annual cost of 50 percent, 80 percent, and 100 percent scenarios for ERCOT compared to 2030 base case and 2018 (values not adjusted for inflation)

	2018	Current Policies	50 Percent Renewables	80 Percent Renewables	100 Percent Renewables
Annual Cost ($ Billion)	13	19	33	61	120
Annual Cost ($/MWh)	36	44	73	138	270

Source: *Life:Powered*

Falling costs to install wind, solar, and batteries can mitigate some of this extreme system cost, but technology alone cannot solve the physical problems inherent in the massive scale of our energy system. As leading energy researcher Vaclav Smil often points out (Smil), a massive restructuring of our economy and society would be required in order to rely entirely upon intermittent and diffuse wind and solar energy. In order to continue the growth in prosperity that we have seen over the past 200 years, we will continue to need energy dense and reliable fuels.

The Difference Between Low and High Penetrations of Renewables

Despite the clear physical limitations of wind and solar energy and the risks of policies that mandate their use, renewables advocates are still trumpeting the falling costs of building wind turbines and solar panels (Lazard) as evidence that we need to keep building more and striving for high-renewable grids. And they are convincing many policymakers, notably in New Mexico (SB 489) and California (SB 100), to pass zero-carbon mandates under the assumption that improvements in energy storage and demand response technologies will enable further renewable penetration in the future.

What is being lost in this conversation is the difference between using wind and solar for marginal generation and relying on it for a majority of generation, as Georgetown is doing. Policymakers and the public need to understand the physical reasons why wind and solar generators cannot supplant the need for firm generation, no matter how cheap they are to build and install.

The example of San Antonio and their recent debate over their recently adopted Climate Action and Adaptation Plan (City of San Antonio) is an example of how these realities are lost in the relevant policy discussions. The plan dictates that the city should become carbon neutral by 2050 to fulfill the goals of the Paris Agreement. While the plan does not require the city to go 100% renewable, the primary backers of the plan, such as the Sierra Club, are advocating for nothing but renewables (Sierra Club).

To bolster their argument, the Sierra Club hired Synapse Energy Economics to do a study (Synapse Energy Economics) of what would happen if San Antonio shut down its coal plant in 2025 and replaced it with a mix of wind, solar, and energy storage. These studies claim economic advantages of using wind and solar for marginal energy production but are used to advocate for policies that mandate deep renewable penetration glosses over a whole set of physical realities, outlined in this report, that are missed when considering only the cost to install wind turbines and solar panels.

Figure H: 2050 annual cost (in 2018 dollars) of 80 percent and 100 percent scenarios for CPS Energy compared to 2050 base case and 2018 actual cost

	2018	2050 Base Case	80 Percent Renewables	100 Percent Renewables
Annual cost ($ billion)	1.02	1.38	2.96	4.00
Annual cost ($/MWh)	42.65	40.64	87.41	118.06
Cost per ton of CO_2 emissions reduction	-	-	115.14	190.59

Source: *Life:Powered*

Another study from Life:Powered shows just how problematic this transition could be for San Antonio (Bennett and Griffey). Just like for Texas, San Antonio would face a cost increase of up to three times if they attempted to get a majority of their electricity from wind and solar. Even for a small city, the cost of the extra capacity, transmission, and energy storage needed to account for the intermittency problem is extreme.

But before the city even reaches high renewable penetrations, it will have to deal with the price risk of moving from firm generation that the city owns to variable generation that is owned by other entities. If CPS Energy, the municipal utility, cannot cover its demand during peak hours, it will have to rely on power purchases from the broader ERCOT market. A similar situation caused a price spike for Austin Energy this past August that will be passed on to its customers (Jankowski). These price risks were not captured in the Sierra Club study, which did not attempt to create a probabilistic forecast of future outcomes but instead used a set of fixed price forecasts.

CPS Energy is currently in a strong market position because it owns most of the assets it is relying on for its electricity and can still cover its peak demand with dispatchable generation. If it maintains this position as the rest of the Texas market encounters more reliability problems and variable prices due to renewables, it could see significant gains. Despite this clear reality, the utility is currently shifting most of its capital expenditures to acquiring wind and solar contracts, slowly moving in the direction of Georgetown in order to meet the mandates of its climate action plan.

Unless knowledgeable electricity market participants make their case to policymakers for market reforms that value the reliability and require renewable generators to pay for reliability, the market will continue to erode until serious reliability problems become manifest. We need to be making this case now, or else the American public will be left with an eroding grid that becomes less reliable and more expensive every year.

Appendix E
Report Acronyms

ºC – Degree Centigrade
ºF – Degree Fahrenheit
% – Percent

ACE – Affordable Clean Energy Rule
AEO – Annual Energy Outlook
AI – Artificial Intelligence
ARPA-E – Advanced Research Projects Agency - Energy
ASU – Air separation unit
AUSC – Advanced Ultra-supercritical

B&W – Babcock & Wilcox
BEAT – Base Erosion and Anti-abuse Tax
BECCS – Bioenergy with Carbon Capture & Storage
BIA – Bureau of Indian Affairs
BLM – Bureau of Land Management
BSER – Best System of Emission Reduction
BUILD Act – Better Utilization of Investments Leading to Development Act

CAA – Clean Air Act
CAISO – California ISO
CarbonSAFE – Carbon Storage Assurance Facility Enterprise
CATF – Clean Air Task Force
CC – Combined cycle
CCL – Capture compression & liquefaction
CCP – Coal combustion products
CCR – Coal combustion residuals
CCS – Carbon capture & storage
CCUS – Carbon capture, utilization and storage
CDR – Carbon dioxide removal
CEQ – White House Council on Environmental Quality
CES – Clean Energy Standard
CF – Capacity factor
CfD – Contracts for Differences
CFD – Computational fluid dynamic
CHP – Combined heat & power
CLC – Chemical looping combustion
CM – Critical materials
CO_2 – Carbon dioxide
CPP – Clean Power Plan
CT – Combustion turbine
CURC – Carbon Utilization Research Council

DAC – Direct air capture
DCA – Development Credit Authority
DFC – U.S. International Development Finance Corporation
DOE – Department of Energy

EERC – Energy & Environmental Research Center (University of North Dakota)
EFFECT Act – Enhanced Fossil Fuel Energy Carbon Technology Act
EGU – Electric generating unit
EIA – Energy Information Administration

ELG – Effluent Limitation Guidelines
EOR – Enhanced oil recovery
EPA – Environmental Protection Agency
EPC – Engineering, procurement & construction
EPRI – Electric Power Research Institute
ERO – Electric reliability organization
ERCOT – Electric Reliability Council of Texas
ES – Energy storage
ESG – Environmental, Societal & Governance
EVA – Energy Ventures Analysis

FAST Act – Fixing America Surface Transportation Act
FE – Office of Fossil Energy
FEED – Front-end engineering and design
FERC – Federal Energy Regulatory Commission
FGD – Flue gas desulfurization
FGR – Flue gas recycle
FIP – Federal Implementation Plan
FOA – Funding opportunity announcement
FOAK – First of a kind
FPA – Federal Power Act
FPO – Flameless pressurized oxy-combustion

GAIN Act – Growing American Innovation Now Act
GDP – Gross domestic product
GHG – Greenhouse gases
GRE – Great River Energy
GW – Gigawatt

HELE – High efficiency, low emissions
HHV – High heating value
HP – High pressure
HRI – Heat rate improvement

IEA – International Energy Agency
IEA-CCC – IEA Clean Coal Centre
IGCC – Integrated gasification combined cycle
INVEST CO_2 Act – Investing in Energy Systems for Transport of CO_2
IPCC – Intergovernmental Panel on Climate Change
IRE – Intermittent renewable energy
IRP – Integrated Resource Plan
ISO – Independent System Operator
ISONE – ISO New England
ITC – Investment Tax Credit
ITC – Integrated Test Center

JOC – Jupiter Oxygen Corporation
JUSEP – Japan-U.S. Strategic Energy Partnership

LCA – Life cycle analysis
LCOE – Levelized Cost of Electricity
LHV – Low heating value
LIFT Act – Leading Infrastructure for Tomorrow's America Act
LPO – Loan Program Office
LTI – Leonardo Technologies, Inc.

MATS – Mercury air toxics standards
MCFC – Molten carbonate fuel cell
MDB – Multilateral Development Bank
MHI – Mitsubishi Heavy Industries
MISI – Management Information Services, Inc.
MISO – Midcontinent ISO
MLP – Master Limited Partnership
MRYS – Milton R. Young Station
MTPA – Million tons per annum
MTR – Membrane Technology Research
MW – Megawatt
MWe – Megawatt electrical
MWh – Megawatt hour

NAAQS – National Ambient Air Quality Standards
NARUC – National Association of Regulatory Utility Commissioners
NCC – National Coal Council
NEPA – National Environmental Policy Act
NERC – North American Electric Reliability Corporation
NET – Negative emissions technologies
NETL – National Energy Technology Laboratory
NMA – National Mining Association
NOAK – Nth of a kind
NOx – Nitrogen Oxide
NPC – National Petroleum Council
NPDES – National Pollutant Discharge Elimination Systems
NSPS – New Source Performance Standards
NSR – New Source Review
NTEC – Navajo Transitional Energy Corporation
NYISO – New York ISO

O&M – Operations & Maintenance
OECD – Organization for Economic Cooperation and Development
OPIC – Overseas Private Investment Corporation
Oxy-combustion – Oxygen combustion

PAB – Private Activity Bonds
PC – Pulverized coal
PCC – Post-combustion capture
PCOR – Plains CO_2 Reduction Partnership
PE – Professional engineer
PFBC – Pressurized fluid bed combustion
PG – Professional geologist
PHMSA – Pipeline Hazardous Materials Safety Administration
PISC – Post-injection site care
PJM – PJM Interconnection
PNM – Public Service Company of New Mexico
PRB – Powder River Basin
PTC – Production tax credit
PURPA – Public Utility Regulatory Policy Act

RCSP – Regional Carbon Sequestration Partnership
R&D – Research and development
RD&D – Research, development and deployment
RCRA – Resource Conservation and Recovery Act
REE – Rare earth elements

RPS – Renewable Portfolio Standard
RTO – Regional Transmission Organization
RUS – USDA Rural Utilities Service

SC - Supercritical
sCO_2 – Supercritical CO_2
SIP – State Implementation Plan
SJGS – San Juan Generating Station
SOx – Sulfur oxides
SPOC – Staged pressurized oxy-combustion
SPP – Southwest Power Pool
STEP – Supercritical Transformative Electric Power
SwRI – Southwest Research Institute

TEDO – Tribal Energy Development Organization
TERA – Tribal Energy Resource Agreements
TRL – Technology Readiness Level

UIC – Underground injection control
UNECE – United Nations Economic Commission for Europe
U.S. – United States
USC – Ultra-supercritical
USDA – United States Department of Agriculture
USE IT Act – Utilizing Significant Emissions with Innovation Technology

WCA – World Coal Association

Appendix F
Membership Roster

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CFO/COO
Babcock Power Services Inc.

Rodney Andrews, Director
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University of Kentucky

Shannon Angielski
Executive Director
Van Ness Feldman LLP
Carbon Utilization Research Council

Duane Ankney, Senator
State of Montana

Randall Atkins
Chairman & Chief Executive
Ramaco Carbon

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Richard Bajura, Director Emeritus
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Dominion Energy, Inc.

Appendix G

NCC Overview – 1984|2020

In the fall of 1984, Secretary of Energy Don Hodel announced the establishment of the National Coal Council (NCC). In creating the NCC, Secretary Hodel noted that "The Reagan Administration believes the time has come to give coal – our most abundant fossil fuel – the same voice within the federal government that has existed for petroleum for nearly four decades."

The Council was tasked to assist government and industry in determining ways to improve cooperation in areas of coal research, production, transportation, marketing and use. On that day in 1984, the Secretary named 23 individuals to serve on the Council, noting that these initial appointments indicate that "the Department intends to have a diverse spectrum of the highest caliber of individuals who are committed to improving the role coal can play in both our Nation's and the world's energy future."

Throughout its over 35-year history, the NCC has maintained its focus on providing guidance to the U.S. Secretary of Energy on various aspects of the coal industry. NCC has retained its original charge to represent a diversity of perspectives through its varied membership and continues to welcome members with extensive experience and expertise related to coal.

The NCC serves as an advisory group to the Secretary of Energy chartered under the Federal Advisory Committee Act (FACA). The NCC is incorporated as a 501c6 non-profit organization in the State of Virginia. Serving as an umbrella organization, NCC, Inc. manages the business aspects of running the Council.

The Council's activities include providing the Secretary with advice on:

- Federal policies that directly or indirectly affect the production, marketing and use of coal;
- Plans, priorities and strategies to address more effectively the technological, regulatory and social impact of issues relating to coal production and use;
- The appropriate balance between various elements of Federal coal-related programs;
- Scientific and engineering aspects of coal technologies, including coal conversion, utilization or environmental control concepts; and
- The progress of coal research and development.

The principal activity of the NCC is to prepare reports for the Secretary of Energy. Over the past 35 years, the NCC has prepared nearly 40 report for the Secretary. All NCC reports are publicly available on the NCC website.

Appendix H
Supplemental Comments
Efficient and Economical Carbon Capture from Integrated Coal Refinery/IGCC Power Generation

A. CONCEPT SUMMARY - COAL IS TOO VALUABLE TO BURN!

Coal is a hydrocarbon feedstock, which can be "refined" to produce valuable coproducts, including complex aromatic chemicals and feedstocks (BTX), green diesel, ammonia and methanol. One such coproduct – char - is a pollutant-free pure carbon which allows Carbon Capture & Storage (" CCS") systems to be used in eliminating the carbon footprint in electricity generation (IGCC). In addition, all of the inorganics, including rare earths report to the char, which when combusted in the gasifier yields an easily handled, prilled material.

A Short Residence Time, flash hydropyrolysis Coal Refining Process, like petroleum refining, produces a slate of coproducts from coal (*see* flowchart below). This coal refining process removes substantially all the pollutants from the feed coal, as well as "coal moisture" to produce, as one of the coproducts, a moisture-free, substantially pollutant-free, pure carbon product, CHAR. The coal inorganics (ash), which reports to the char, is modified by the process, thus reducing fly ash production upon oxidation of the char.

The advantage of this process over conventional CCS from standard Rankine cycle coal-fired units is the concentration of the CO_2 from combusting pure carbon with oxygen in the gasifier with steam to make methane which drives the "combined cycle" turbine.

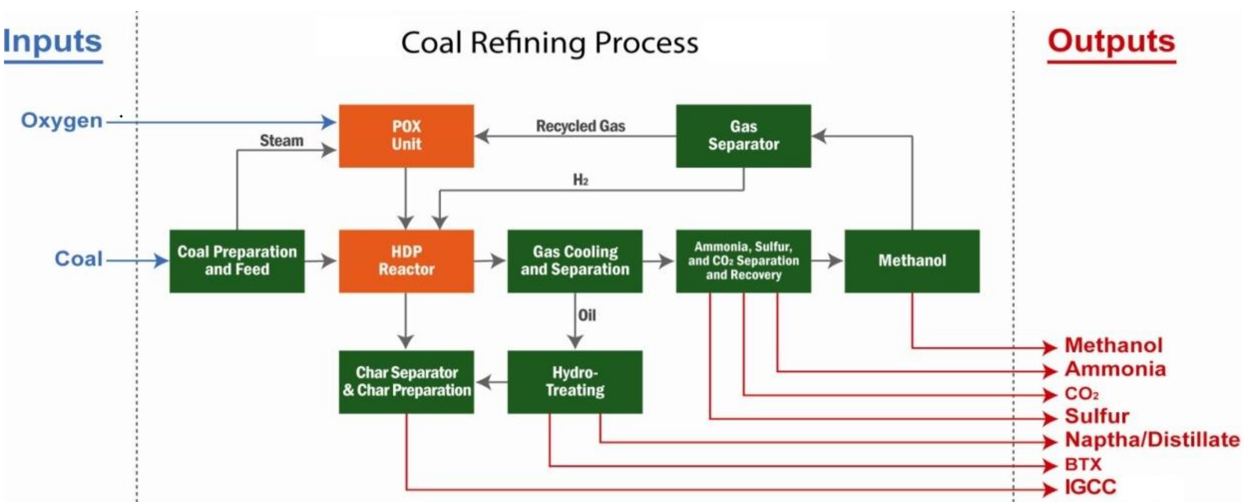

Figure 1. Coal Refinery

The char obtained from Coal Refining has a number of attributes which make it an ideal fuel for gasification in an IGCC electrification unit with CCS, as an integral part of the coal refinery. These IGCC/CCS generation facilities, in addition to having substantially no carbon (emission) footprint, have phenomenal load-following capabilities.

Specifically, char, obtained from the Coal Refining Process is a dry (Substantially no water), free-flowing (power grind), stable material with substantially all of the inherent coal pollutants (S, N, Hg, Cl, and the like) being removed. It is an ideal fuel for an oxygen-blown gasifier/IGCC electrification system. The char product, which requires no further crushing and/or grinding, upon combustion, produces none of the downstream pollutants associated with using raw coal, negating the need for expensive downstream removal, e.g., acid gas removal while producing no fly ash. Thus, the primary coal polluting elements are turned into valuable coproducts during the Coal Refining Process adding favorably to the economics of this process.

In addition, the oxygen blown gasifiers, using char, produce almost "pure" CO_2 and little CO. The CO can be removed efficiently and inexpensively using off-the-shelf absorber-generator removal systems. Because the process gas is primarily CH_4 and CO_2 with little CO, CO_2 removal is relatively inexpensive and very efficient using conventional means in contrast to CCS of standard boiler combustion gases.

Thus, integrating CCS technology with a Coal Refining Process would automatically reduce capital and operating costs of conventional CCS technologies and provide load-following capabilities. Pollutants that generally pose limitations on CO_2 separation technologies are removed upstream, further allowing efficient use of conventional CCS technologies.

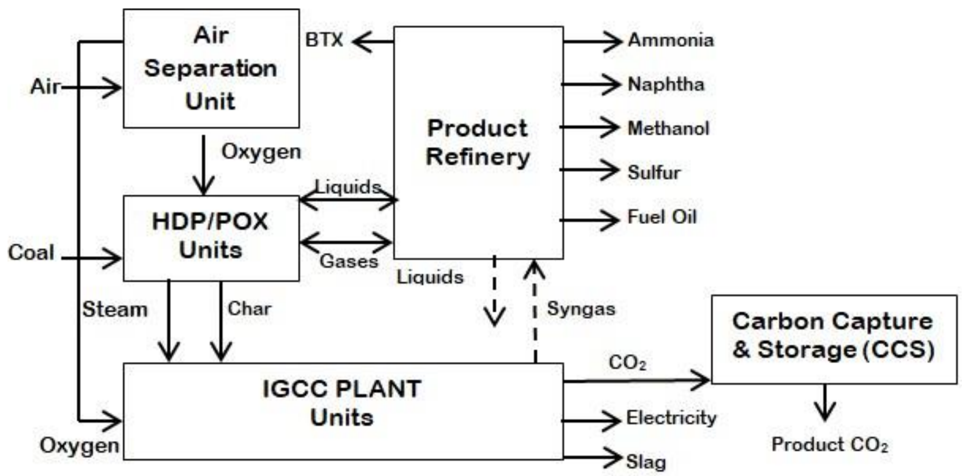

Figure 2. Coal Refinery/Integrated Gasification Combined Cycle Plant with CCS

B. LOAD FOLLOWING (COAL "FIRST")

DOE's Coal FIRST (Flexible, Innovative, Resilient, Small, Transformative) program to provide secure, stable, and reliable power capable of flexible operation to meet the needs of the grid, use innovative and cutting-edge components that improve efficiency and reduce emissions; provide resilient power to Americans; are small compared to today's conventional utility-scale coal power plants; and transform how coal power plant technologies are designed and manufactured.

In order to integrate these transformative power plants into the grid they must demonstrate capability for load following. The coal refinery/ IGCC system (set forth above) employs a combined cycle power plant having a Rankine cycle generator component and a gas turbine generator component wherein the gas turbine can be operated to follow load requirements, including integration with wind and solar units. The gas turbine, when idled, allows syngas to be recycled through the product refinery (see above) thus turning the syngas into valuable coproducts. These units can efficiently be built and operated at the 300 MW level in compliance with the Coal FIRST criteria.

C. INNOVATION AND IMPACT

A Coal Refining Process as above described allows upstream separation of N, S, Cl, Hg, and other undesirable emissions products typically found in the syngas stream in a conventional coal-fired boiler or in a conventional coal-fired IGCC gasifier (pre-combustion removal is very efficient). This results in a relatively clean syngas stream with concentrations of CO_2 that are more easily and economically separated and removed from the stream by more conventional and efficient removal methods. The relatively pure separated CO_2 stream can be used for industrial purposes without further post-treatment.

Table 1. Cost Analysis and Comparison

Attribute	**SOA Value[1]**	**Coal Refinery Integrated Plant**	**Description / Justification**
Power generator type	IGCC	Oxy-combustion char gasification	Oxygen blown char gasifier will generate clean process gas with little CO and high partial pressure of CO_2 for cost-effective CCS
CCS plant technology	46 $/ton	<36 $/ton	Dry feed, removed pollutants, and increased CO_2 concentration (PP) results in estimated 25%-45% reduction in <u>cost</u> of conventional CO_2 capture and
Capital cost (TACS)	$8,810 $/kW (IGCC)	7,084 $/kW (Oxy-comb.)	CCS equipment adds about 11% to IGCC capital costs. Using char generated by CharFuel® process will reduce capital costs by >25%
Fixed O&M cost	223.62 $/Kw	<15O .0$/kWh	Reduction in cost of CCS plant results in lower O&M costs
Variable O&M cost	17.28 $/kWh	<10.00 $/kWh	Reduction in cost of CCS plant results in lower Var. O&M costs
Power generator heat rate	10,497/BTU/kWh (w CCS)	<8,840 BTU/kWh (w CCS)	Saving upstream (preparation) and downstream (no pollutant removal i.e. acid gas; system simplicity and greater $CO_{2,}$ separation efficiency.)
Capture rate	<80%	>90%	Char/oxygen IGCC/CCS will meet or exceed CO_2 capture rate of coal/oxygen IGCC/CCS

[1] 14 (NETL) – "COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY".

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One comment/clarification for the report is related to suggested improvements on page 34: The reference to addition of VFD to fans/ pumps and variable pitch axial flow fans. I believe the intent is the use of VFD on centrifugal fans OR the use of Variable Pitch Axial Flow (VPAF) fans. Specifically, VFD are not being suggested to be added to VPAF Fans. This doesn't make too much sense as VPAFs are constant speed devices that wouldn't benefit from the VFD application. I think this intent is in place but the wording isn't clear.

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CLEAN AIR TASK FORCE

July 23, 2020

The Honorable Dan Brouillette
Secretary of Energy
1000 Independence Ave., SW
Washington, DC 20585

Dear Mr. Secretary:

I appreciate the privilege of serving on the National Coal Council and contributing to the most recent report, *Coal Power, Smart Policies in Support of Cleaner, Stronger Energy*. I'm especially pleased with many thoughtful recommendations on carbon capture and expanding the infrastructure needed to decarbonize America by mid-century. I'm also grateful to my fellow council members for allowing me to write a specific dissenting view on NSR contained in the report.

The strength of the National Coal Council is in the diversity of views, its willingness to find common ground, and where necessary, allow members to respectfully "agree to disagree" on approaches or recommendations to finalize a report that represents the judgments of most, but certainly not all of those involved.

As you might imagine, as an environmental organization, the Clean Air Task Force takes positions in legal proceedings, advocacy, and communication that are not in general agreement and often contrary to many of the recommendations in this report. My report participation should not be viewed as assent to these contrary positions, either by my employer or me. Please note the language that appears near the beginning of the report, "The findings and recommendations from this report reflect a consensus of the NCC membership, but do not necessarily represent the views of each NCC member individually or of their respective organizations."

I'm grateful that the National Coal Council clarifies that the views of each member and the member's organization are not necessarily reflected in each of its reports. This language allows me to fully participate without having to provide lengthy dissents on specific recommendations to clarify my views or those of my employer.

Sincerely,

John Thompson
Technology and Markets Director

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