Testimony

Hearing of the Subcommittee on Energy and Environment, Committee on Science and Technology

U.S. House of Representatives

Jeffrey N. Phillips
Program Manager, Advanced Coal Generation
The Electric Power Research Institute

April 15, 2008

Thank you, Chairman Lampson, Ranking Member Inglis, and Members of the Subcommittee. I am Jeffrey Phillips, Program Manager, Advanced Coal Generation for the Electric Power Research Institute (EPRI). EPRI conducts research and development on technology, operations and the environment for the global electric power industry. As an independent, non-profit Institute, EPRI brings together its members, scientists and engineers, along with experts from academia, industry and other centers of research to:

- collaborate in solving challenges in electricity generation, delivery and use;
- provide technological, policy and economic analyses to drive long-range research and development planning; and
- support multi-discipline research in emerging technologies and issues.

EPRI's members represent more than 90 percent of the electricity generated in the United States, and international participation extends to 40 countries. EPRI has major offices and laboratories in Palo Alto, California; Charlotte, North Carolina; Knoxville, Tennessee, and Lenox, Massachusetts.

EPRI appreciates the opportunity to provide testimony to the Subcommittee for the hearing entitled, "The Department of Energy's FutureGen Program".

The Role of the FutureGen program in a comprehensive federal research and development effort to develop and deploy carbon capture and sequestration technologies.

The FutureGen Industrial Alliance and the Department of Energy (DOE) were intending to build a first-of-its-kind, near-zero emissions coal-fed integrated gasification combined cycle (IGCC) power plant integrated with CO_2 capture and storage (CCS) The project aimed at storing CO_2 in a representative geologic formation at a rate of at least one million metric tons per year, beginning in 2013.

A general description of IGCC plants and the role of IGCC with CCS as part of a strategy to develop and deploy a full portfolio of advanced coal with CCS technologies were included in testimony recently provided by John Novak of EPRI before the Senate Science, Technology and Innovation Subcommittee of the Committee on Commerce, Science, and Transportation. A copy of that testimony is included in Appendix A to this testimony for your reference.

EPRI stresses that no single advanced coal generating technology (or any generating technology) has clear-cut economic advantages across the range of U.S. applications. The best strategy for meeting future electricity needs in an economic and environmentally sustainable way lies in developing multiple technologies from which power producers (and their regulators) can choose the one best suited to local conditions and preferences. EPRI strongly recommends that policies reflect a portfolio approach that enables commercial incorporation of CCS into multiple advanced coal power technologies.

Through the development and deployment of advanced coal plants with integrated CO_2 capture and storage (CCS) technologies, coal power can become part of the solution to satisfying both our energy needs and our global climate change concerns. However, a sustained RD&D program at heightened levels of investment and the resolution of legal and regulatory unknowns for long-term geologic CO_2 storage will be required to achieve the promise of advanced coal with CCS technologies. The members of EPRI's *CoalFleet for Tomorrow®* program—a research collaborative comprising more than 60 organizations representing U.S. utilities, international power generators, equipment suppliers, government research organizations, coal and oil companies, and a railroad—see crucial roles for both industry and governments worldwide in aggressively pursuing collaborative RD&D over the next 20+ years to create a full portfolio of commercially self-sustaining, competitive advanced coal power generation and CCS technologies. Elements of the CoalFleet RD&D program were included in testimony recently provided by John Novak of EPRI before the Senate Science, Technology and Innovation Subcommittee of the Committee on Commerce, Science, and Transportation, included in Appendix A.

The key to proving CCS capability is the demonstration of CCS at large-scale (on the order of 100,000 to 1 million tons CO_2/year) for IGCC, for pulverized coal (PC) and for oxy-combustion, with storage in a variety of geologies. We must start immediately if we are to meet the CoalFleet goals of demonstrating a full portfolio of advanced coal with CCS technologies by 2025.

EPRI's assessment of the proposed restructured FutureGen program and the program's potential to complement other federal research and development efforts on carbon capture and sequestration technologies including the Clean Coal Power Initiative (CCPI) and the Carbon Sequestration Partnership Program (CSPP).

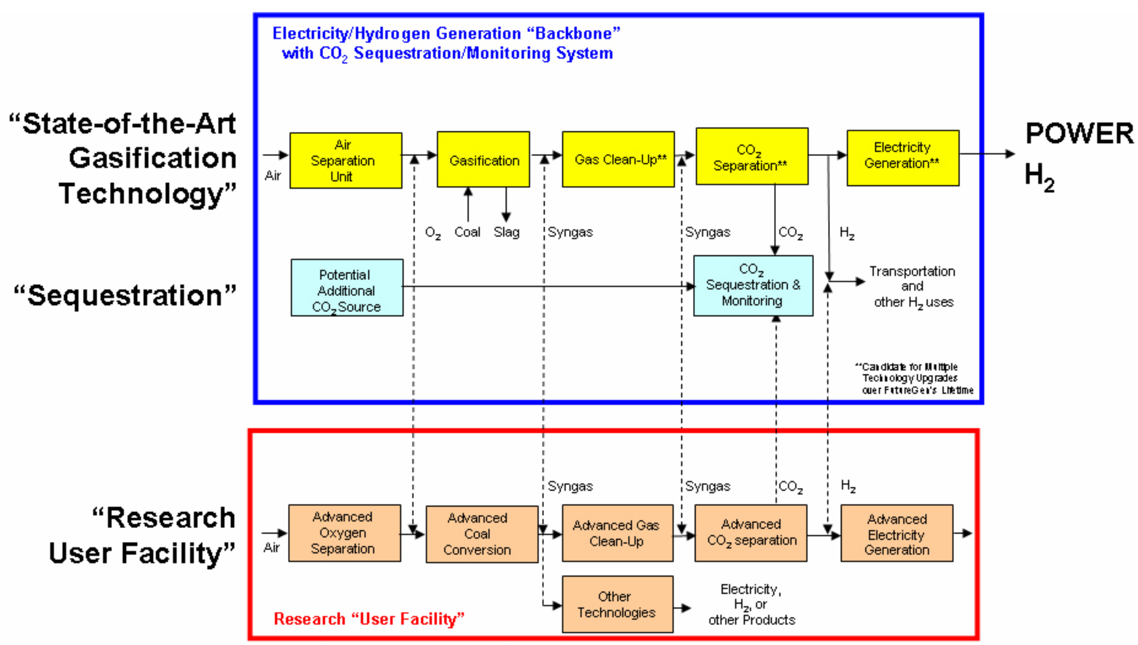
In January of this year, DOE announced a restructured approach to the FutureGen project. Previously, the FutureGen Industrial Alliance and DOE were intending to build a first-of-its-kind, near-zero emissions coal-fed IGCC power plant integrated with CCS.

The commencement of full-scale operations was targeted for 2013. The project aimed at storing CO_2 in a representative geologic formation at a rate of at least one million metric tons per year. DOE had committed to spend $1.1 billion in support of the project while the FutureGen Industrial Alliance had agreed to contribute $400 million.

Under its revised approach, DOE will offer to pay the additional cost of capturing CO_2 at multiple IGCC plants. Each plant would capture and store at least 1 million tons of CO_2 per year. DOE's goal is to have the plants in operation between 2015 and 2016.

The original FutureGen concept was meant to serve as a "living laboratory" for testing advanced technologies that offered the promise of clean environmental performance at a reduced cost and increased reliability. The original FutureGen concept, as shown in Figure 1 was to have the flexibility to conduct full-scale and slipstream tests of such scalable advanced technologies as:

- Membrane processes to replace cryogenic separation for oxygen production
- An advanced transport reactor sidestream with 30% of the capacity of the main gasifier
- Advanced membrane and solvent processes for H_2 and CO_2 separation
- A raw gas shift reactor that reduces the upstream clean-up requirements
- Ultra-low-NO_X combustors that can be used with high-hydrogen synthesis gas
- A fuel cell hybrid combined cycle pilot
- Smart dynamic plant controls including a CO_2 management system



Source: FutureGen Industrial Alliance

Figure 1 – FutureGen technology platforms

While the revised DOE FutureGen concept will meet the original goal of having a CCS test of at least 1 million tons of CO_2 per year (albeit two to three years later than the original target according to DOE), the other original goal of also hosting the development of several advanced technologies for decreasing plant costs appears to have been dropped.

EPRI has responded to DOE's Request for Information (RFI) on the revised FutureGen concept. We asked for clarification on what aspects of the costs of including CO_2 capture and storage (CCS) would be covered, and we gave our estimate of what the total costs would be for including CCS on one train of a two-train 600 MW IGCC. We also highlighted the other major RD&D activities that are needed for improving the efficiency and cost of IGCC technologies with CO_2 capture (see Figure 2). In addition, we asked whether non-IGCC coal power plants that capture at least 1 million tons of CO_2 per year could qualify for funding under the revised FutureGen concept. For example, would the incremental CCS costs of a project such as our proposed UltraGen advanced SCPC plant with post-combustion capture and geological storage of CO_2 be eligible for DOE support under the restructured FutureGen concept. I have included this response, which was submitted by our Vice President for Environment and Generation, Bryan Hannegan, as Appendix B to this testimony for your reference.

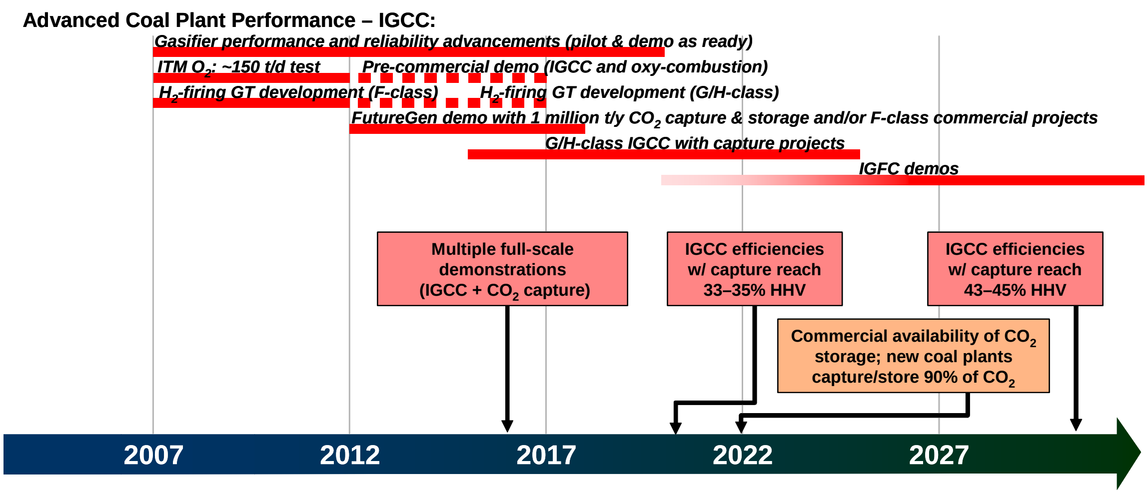


Figure 2 – Timing of advanced IGCC and CO_2 capture integration RD&D activities and milestones

I would like to elaborate on the cost of adding CO_2 capture to IGCC. EPRI's CoalFleet for Tomorrow® program has been tracking the costs of various types of coal-based power plants, and we have seen a remarkable increase in these costs over the past two years. Figure 3 provides an overview of various indices that could be used to track the inflation of construction projects. It can be seen that while the GDP Deflator index, which reflects inflation in the entire US economy, rose less than 15% between 2000 and 2006, all of the construction cost indices rose at least 20% and in several cases reached 30% over that same period. Even more striking is the rapid increase seen in the Handy-Whitman Electricity Utility Construction Index and the IHS-CERA Downstream Construction Index (DCCI) since 2006. My colleagues believe the DCCI is most representative of IGCC and CO_2 capture cost trends because IGCC and CO_2 capture equipment is similar to equipment used in the "downstream" oil and gas industry (i.e., refining and petrochemicals).

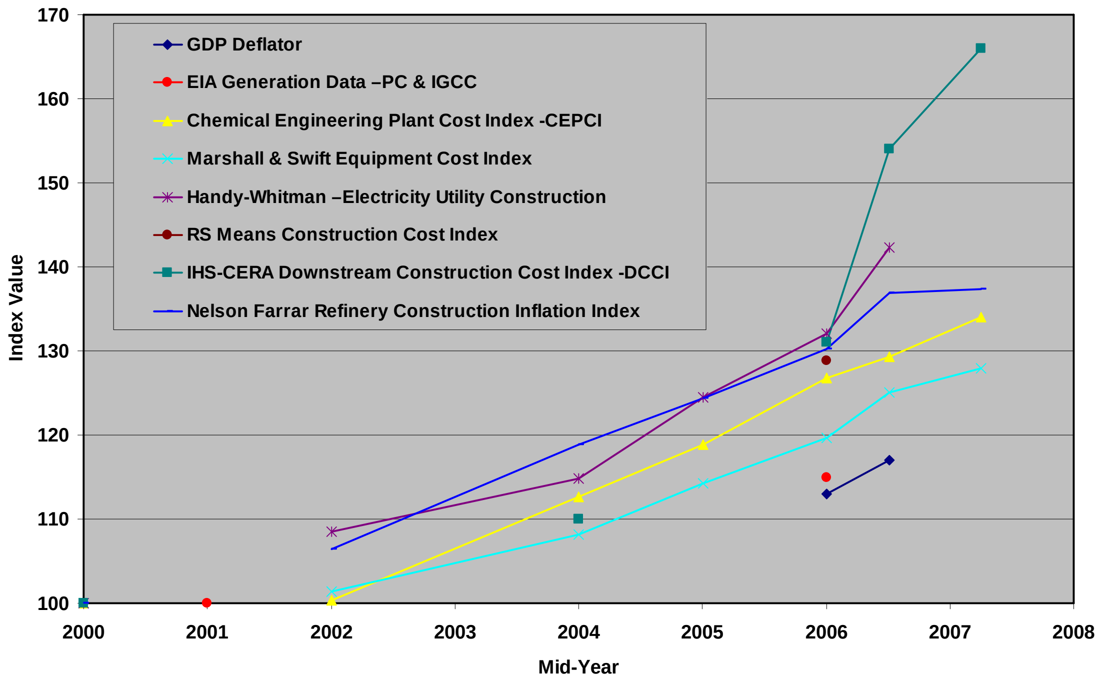


Figure 3 – Inflation indices for construction projects – all indices are set to 100 in the year 2000.

It is clear that the cost for coal power projects (and really all types of infrastructure construction projects) is increasing more rapidly than general inflation. In our response to the FutureGen RFI, Dr. Hannegan has provided EPRI's current estimate for the cost of adding CO_2 capture to one train of a two-train IGCC which has a combined power output capacity of 630 MW (before capture is added). Such a system would be capable of capturing up to 1.6 million tons of CO_2 per year. The details can be found in the appendix to my testimony, but the results are summarized in Table 1.

Table 1 – Estimated Costs of Adding CO_2 Capture to an IGCC (one 315 MW train)

Cost of CO_2 Capture Equipment	$80-100 million
Cost of CO_2 pipeline and storage wells	$100 million
Cost of maintenance on added equipment	$6.3 million/yr
Cost of lost power production	$18.2 million/yr
Total cost for a 10 year demonstration	$425-445 million

Using the upper end of the estimate in Table 1, DOE's proposed total budget of $1.3 billion would be slightly less than what would be required for 3 such projects (approximately $1.335 billion). However, DOE's proposed budget is on an "as spent" basis where inflation is included. EPRI's estimate is based on 2007 dollars and does not reflect potential future escalation. If costs between 2008 and 2015 increase at the same rate as they have between 2000 and 2007, one could expect as much as a 66% increase in costs. That would escalate EPRI's per project total to approximately $706 – 739 million,, and the DOE total budget of $1.3 billion would not be sufficient to support even two projects unless the demonstration time period was decreased.

Potential to Complement the Clean Coal Power Initiative (CCPI) and the Carbon Sequestration Partnership Program (CSPP).

As noted earlier, EPRI believes a comprehensive CCS RD&D program must encourage the commercialization of multiple technologies beyond just IGCC with CCS. The CCPI program could serve as a complement to the FutureGen program by subsidizing the demonstration costs of non-IGCC projects. However, the funding level of the CCPI has been inadequate to support a robust demonstration program. The Administration's budget request for FY 2009 is $85 million. EPRI's estimate of the incremental cost for one 200 MW scale post combustion CCS demonstration is $340 million and this total does not include the cost of a CO_2 pipeline or the injection wells (see page 18 of Appendix A).

In addition, there are opportunities for decreasing the cost of IGCC plants outside of the CO_2 capture technology equipment which would benefit from a demonstration program. Since the restructured FutureGen program does not appear to support such demonstrations, they would have to compete with the non-IGCC projects for the sparse CCPI dollars.

Since the restructured FutureGen program delays the implementation of a large-scale (>1 million tons of CO_2 /yr) CCS project integrated with an IGCC, it is more important than ever that the CSPP implement multiple large-scale CCS projects in a variety of geologic formations by the 2012 timeframe when the original FutureGen was scheduled to start. While the CSPP sequestration projects will not be able to use CO_2 captured from coal plants1, such tests will help us address the legal issues (permitting and liability) of CO_2 sequestration while also increasing our experience with predicting and monitoring the location of underground CO_2 plumes and building public confidence in the concept of deep geologic storage.

To be effective in proving the concept, the large-scale sequestration projects in the CSPP should inject on the order of 100,000 to 1 million tons or more of CO_2 for at least 3 years. Monitoring of the underground location of the CO_2 to verify computer simulations will take another 3 to 5 years after injection has stopped. Consequently, in order to have large-scale sequestration proven in multiple US geologies by 2020, it is necessary to have the injections begin by 2012.

[1] It would not be cost-effective for a power plant to build CO_2 capture equipment and then sell the CO_2 for a CSPP test for only 2-3 years – the per ton cost of the CO_2 would be higher than other options. In addition, it would be difficult to construct such a large system by 2012 unless design and permitting activities such as those already conducted by the FutureGen Industrial Alliance had already taken place by today.

Appendix A

Testimony

Hearing of the Science, Technology and Innovation Subcommittee of the Committee on Commerce, Science, and Transportation

United States Senate

John Novak
Executive Director, Federal and Industry Activities
Environment and Generation
The Electric Power Research Institute

April 9, 2008

Introduction

Thank you, Mr. Chairman, Ranking Member Ensign, and Members of the Subcommittee. I am John Novak, Executive Director of Federal and Industry Activities for the Environment and Generation Sectors of the Electric Power Research Institute (EPRI). EPRI conducts research and development on technology, operations and the environment for the global electric power industry. As an independent, non-profit Institute, EPRI brings together its members, scientists and engineers, along with experts from academia, industry and other centers of research to:

- collaborate in solving challenges in electricity generation, delivery and use;
- provide technological, policy and economic analyses to drive long-range research and development planning; and
- support multi-discipline research in emerging technologies and issues.

EPRI's members represent more than 90 percent of the electricity generated in the United States, and international participation extends to 40 countries. EPRI has major offices and laboratories in Palo Alto, California; Charlotte, North Carolina; Knoxville, Tennessee, and Lenox, Massachusetts.

EPRI appreciates the opportunity to provide testimony to the Subcommittee on the topic of integrated gasification combined cycle (IGCC) technologies and the need for large scale IGCC demonstration projects that feature CO_2 capture and sequestration.

Integrated Gasification Combined Cycle (IGCC)

In integrated gasification combined cycle plants, coal or petroleum coke is partially oxidized with oxygen to CO and hydrogen, the impurities cleansed in an acid gas removal process and the clean gas (called “syngas”) burned in a combined cycle to produce electricity. The energy use in the cycle is integrated between the gasification section and the power block, hence the name.

There are only six IGCC plants in the world operating on coal. These operating units also use petroleum coke or blends due to its lower price. One, the Vresova IGCC based in the Czech Republic (Lurgi-type gasifier) is 350 MW. The others are each about 250 MW. The two in the United States are Wabash (Conoco Phillips gasifier) and Polk (GE gasifier) in Indiana and Florida. Two additional IGCCs in Europe are Buggenum Netherlands and Puertollano Spain (both variations on the Shell gasifier). A new IGCC started operation this year at Nakoso, Japan (MHI gasifier). Chemical plants around the world have accumulated a 100-year experience base operating coal-based gasification units and related gas cleanup processes. The most advanced of these units are similar to the front end of a modern IGCC facility. Similarly, several decades of experience firing natural gas and petroleum distillate have established a high level of maturity for the basic combined cycle generating technology.

IGCC technology is still relatively new and needs more commercial installations. Based on the limited data available, today’s IGCC plants are available 5-7% fewer hours per year than conventional pulverized coal (PC) plants. While it is likely that IGCC will “catch up” with PC, the initial learning curve on all IGCCs to date has been slow. Better designs, models, incorporation of lessons learned would all help. Ongoing RD&D continues to provide significant advances in the base technologies, as well as in the suite of technologies used to integrate them into an IGCC generating facility.

The emissions of air pollutants and greenhouse gases from an IGCC are less than a conventional pulverized coal plant (though latest designs make this difference smaller). The IGCC design uses less water than a conventional coal plant since a great deal of power comes from the gas turbine. The pre-cleaning of primary pollutants prior to combustion in the gas turbine allows possible later capture of CO_2 from a concentrated high-pressure gas requiring relatively low energy use.

IGCC plants (like PC plants) do not capture CO_2 without substantial plant modifications, energy losses, and investments in additional process equipment. No one is currently capturing CO_2 at full scale from IGCC plants that generate electricity from coal. CO_2 separation processes suitable for IGCC plants are used commercially in the oil and gas and chemical industries at a scale close to that ultimately needed, but their application requires the addition of more processing equipment to an IGCC plant and the deployment of gas turbines that can burn nearly pure hydrogen.

The electricity cost premium for including CO_2 capture in IGCC plants, along with drying, compression, transportation, and storage, is about 40–50%. Although this is a lower cost increase in percentage terms than that for conventional PC plants, IGCC plants initially cost more than PC plants. Thus, the bottom-line cost to consumers for power from IGCC plants with capture using today's technology is likely to be comparable to that for PC plants with capture (the actual relative competitiveness depends on coal moisture content and other factors as described below). However, the magnitude of these impacts could likely be reduced substantially through aggressive investments in R&D.

The CO_2 capture cost premiums listed above vary in real-world applications, depending on available coals and their physical-chemical properties, desired plant size, the CO_2 capture process and its degree of integration with other plant processes, plant elevation, the value of plant co-products, and other factors. Nonetheless, IGCC with CO_2 capture generally shows an economic advantage in studies based on low-moisture bituminous coals. For coals with high moisture and low heating value, such as subbituminous and lignite coals, an EPRI study shows PC with CO_2 capture being competitive with or having an advantage over IGCC.[2] EPRI stresses that no single advanced coal generating technology (or any generating technology) has clear-cut economic advantages across the range of U.S. applications. The best strategy for meeting future electricity needs in an economic and environmentally sustainable way lies in developing multiple technologies from which power producers (and their regulators) can choose the one best suited to local conditions and preferences. EPRI strongly recommends that policies reflect a portfolio approach that enables commercial incorporation of CCS into multiple advanced coal power technologies.

The key to proving CCS capability is the demonstration of CCS at large-scale (on the order of 1 million tons CO_2/year) for both pre- and post-combustion capture with storage in a variety of geologies. Large combined capture and storage demonstrations should be encouraged in different regions and with different coals and technologies.

Advanced Coal Generation with CO_2 Capture and Storage

Through the development and deployment of advanced coal plants with integrated CO_2 capture and storage (CCS) technologies, coal power can become part of the solution to satisfying both our energy needs and our global climate change concerns. However, a sustained RD&D program at heightened levels of investment and the resolution of legal and regulatory unknowns for long-term geologic CO_2 storage will be required to achieve the promise of advanced coal with CCS technologies. The members of EPRI's *CoalFleet for Tomorrow*® program—a research collaborative comprising more than 60 organizations representing U.S. utilities, international power generators, equipment suppliers, government research organizations, coal and oil companies, and a railroad—see crucial roles for both industry and governments worldwide in aggressively pursuing collaborative RD&D over the next 20+ years to create a full portfolio of commercially self-sustaining, competitive advanced coal power generation and CCS technologies.

[2] Feasibility Study for an Integrated Gasification Combined Cycle Facility at a Texas Site, EPRI report 1014510, October 2006.

Key Points:

- Advanced coal power plant technologies with integrated CO_2 capture and storage (CCS) will be crucial to lowering U.S. electric power sector CO_2 emissions. They will also be crucial to substantially lowering global CO_2 emissions.
- The availability of advanced coal power and integrated CCS and other technologies could dramatically reduce the projected increases in the cost of wholesale electricity under a carbon cap.
- It is important to avoid choosing between coal technology options. We should foster a full portfolio of technologies.
- While there are well-proven methods for capturing CO_2 resulting from coal gasification, no IGCC plant captures CO_2. IGCC technology is still relatively new and in need of more commercial installations.
- PC technology is already well proven commercially in the power industry, although potential for significant improvement exists; the need is for demonstration of post combustion capture at a commercial and affordable scale.
- There will inevitably be additional costs associated with CCS. EPRI's latest estimates suggest that the levelized cost of electricity (COE) from new coal plants (IGCC or supercritical PC) designed for capture, compression, transportation and storage of the CO_2 will be 40-80% higher than the COE of a conventional supercritical PC (SCPC) plant.
- EPRI's technical assessment work indicates that the preferred technology and the additional cost of electricity for CCS will depend on the coal type, location and the technology employed. Without CCS, SCPC has an advantage over IGCC. However, the additional CCS cost is generally lower with IGCC than for SCPC.
- Some studies show an advantage for IGCC with CCS with bituminous coal. With lignite coal, SCPC with CCS is generally preferred. With sub-bituminous coal, SCPC with CCS and IGCC with CCS appear to show similar costs.
- Our initial work with post-combustion CO_2 capture technologies suggests we can potentially reduce the current estimated 30% energy penalty associated with CCS to about 15% over the longer-term. Improvements in IGCC plants offer a comparable potential for reducing the cost and energy penalty as well.
- The key to proving CCS capability is the demonstration of CCS at large-scale (i.e., on the order of 1 million tons CO_2/year) for both pre- and post-combustion capture and oxy-combustion with storage in a variety of geologies. Large combined capture and storage demonstrations should be encouraged in different regions and with different coals and technologies.
- EPRI's *CoalFleet for Tomorrow®* program has identified the RD&D pathways to demonstrate, by 2025, a full portfolio of economically attractive, commercial-scale advanced coal power and integrated CCS technologies suitable for use with the broad range of U.S. coal types. EPRI is currently developing collaborations to develop and demonstrate a series of IGCC and post combustion capture processes to improve the cost and energy use of integrated gasification plus capture and post combustion technologies. Some technologies will be ready for some fuels sooner, but the

economic benefits of competition are not achieved until the full portfolio is developed.

- The identified RD&D is estimated to cost $8 billion between now and 2017 and $17 billion cumulatively by 2025, and we need to begin immediately to ensure that these climate change solution technologies will be fully tested at scale by 2025.
- Major non-technical barriers associated with CO_2 storage need to be addressed before CCS can become a commercial reality, including resolution of regulatory and long-term liability uncertainties.

The Role of Advanced Coal Generation with CO_2 Capture and Storage in a Carbon-Constrained Future

Coal currently provides over half of the electricity used in the United States, and most forecasts of future energy use in the United States show that coal will continue to have a dominant share in our electric power generation for the foreseeable future. Coal is a stably priced, affordable, domestic fuel that can be used in an environmentally responsible manner. Through development of advanced pollution control technologies and sensible regulatory programs, emissions of criteria air pollutants from new coal-fired power plants have been reduced by more than 90% over the past three decades. And by displacing otherwise needed imports of natural gas or fuel oil, coal helps address America's energy security and reduces our trade deficit with respect to energy.

EPRI's "Electricity Technology in a Carbon-Constrained Future" study suggests that it is technically feasible to reduce U.S. electric sector CO_2 emissions by 25–30% relative to current emissions by 2030 while meeting the increased demand for electricity. The study showed that the largest single contributor to emissions reduction would come from the integration of CCS technologies with advanced coal-based power plants coming on-line after 2020.

Economic analyses of scenarios to achieve the study's emission reduction goals show that in 2050, a U.S. electricity generation mix based on a full portfolio of technologies, including advanced coal technologies with integrated CCS and advanced light water nuclear reactors, results in wholesale electricity prices at less than half of the wholesale electricity price for a generation mix without advanced coal/CCS and nuclear power. In the case with advanced coal/CCS and nuclear power, the cost to the U.S. economy of a CO_2 emissions reduction policy is $1 trillion less than in the case without advanced coal/CCS and nuclear power, with a much stronger manufacturing sector. Both of these analyses are documented in the 2007 EPRI Summer Seminar Discussion paper, "The Power to Reduce CO_2 Emissions–the Full Portfolio," available at

http://epri-reports.org/DiscussionPaper2007.pdf.

Accelerating RD&D on Advanced Coal Technologies with CO_2 Capture and Storage—Investment and Time Requirements

The portfolio aspect of advanced coal with integrated CCS technologies must be emphasized because no single advanced coal technology (or any generating technology) has clear-cut economic advantages across the range of U.S. applications. The best strategy for meeting future electricity needs while addressing climate change concerns and minimizing economic disruption lies in developing a *full portfolio* of technologies from which power producers (and their regulators) can choose the option best suited to local conditions and preferences and provide power at the lowest cost to the customer. Toward this end, four major technology efforts related to CO_2 emissions reduction from coal-based power systems must be undertaken:

1. Increased efficiency and reliability of IGCC power plants
2. Increased thermodynamic efficiency of PC power plants
3. Improved technologies for capture of CO_2 from coal combustion- and gasification-based power plants
4. Reliable, acceptable technologies for long-term storage of captured CO_2

Identification of mechanisms to share RD&D financial and technical risks and to address legal and regulatory uncertainties must take place as well.

In short, a comprehensive recognition of all the factors needed to hasten deployment of competitive, commercial advanced coal and integrated CO_2 capture and storage technologies—and implementation of realistic, pragmatic plans to overcome barriers—is the key to meeting the challenge to supply affordable, environmentally responsible energy in a carbon-constrained world.

A typical path to develop a technology to commercial maturity consists of moving from the conceptual stage to laboratory testing, to small pilot-scale tests, to larger-scale tests, to multiple full-scale demonstrations, and finally to deployment in full-scale commercial operations. For capital-intensive technologies such as advanced coal power systems, each stage can take years or even a decade to complete, and each sequential stage entails increasing levels of investment. As depicted in Figure 1, several key advanced coal power and CCS technologies are now in (or approaching) an "adolescent" stage of development. This is a time of particular vulnerability in the technology development cycle, as it is common for the expected costs of full-scale application to be higher than earlier estimates when less was known about scale-up and application challenges. Public agency and private funders can become disillusioned with a technology development effort at this point, but as long as fundamental technology performance results continue to meet expectations, and a path to cost reduction is clear, perseverance by project sponsors in maintaining momentum is crucial.

Unexpectedly high costs at the mid-stage of technology development have historically come down following market introduction, experience gained from "learning-by-doing," realization of economies of scale in design and production as order volumes rise, and removal of contingencies covering uncertainties and first-of-a-kind costs. An

International Energy Agency study led by Carnegie Mellon University (CMU) observed this pattern of cost-reduction-over-time for power plant environmental controls, and CMU predicts a similar reduction in the cost of power plant CO_2 capture technologies as the cumulative installed capacity grows.[3] EPRI concurs with their expectations of experience-based cost reductions and believes that RD&D on specifically identified technology refinements can lead to greater cost reductions sooner in the deployment phase.

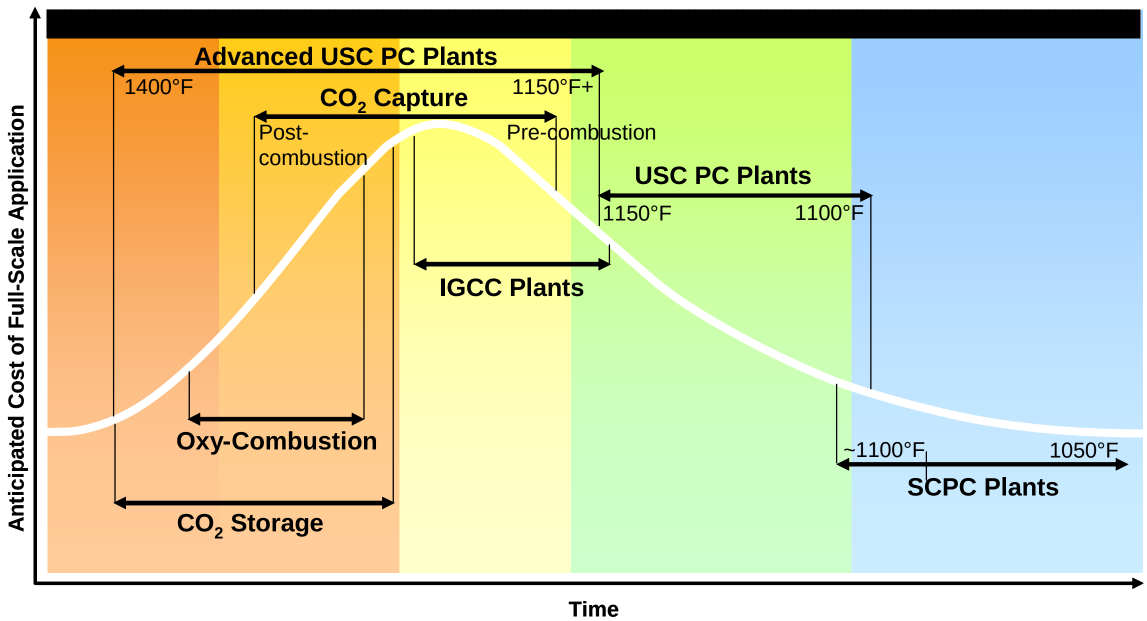


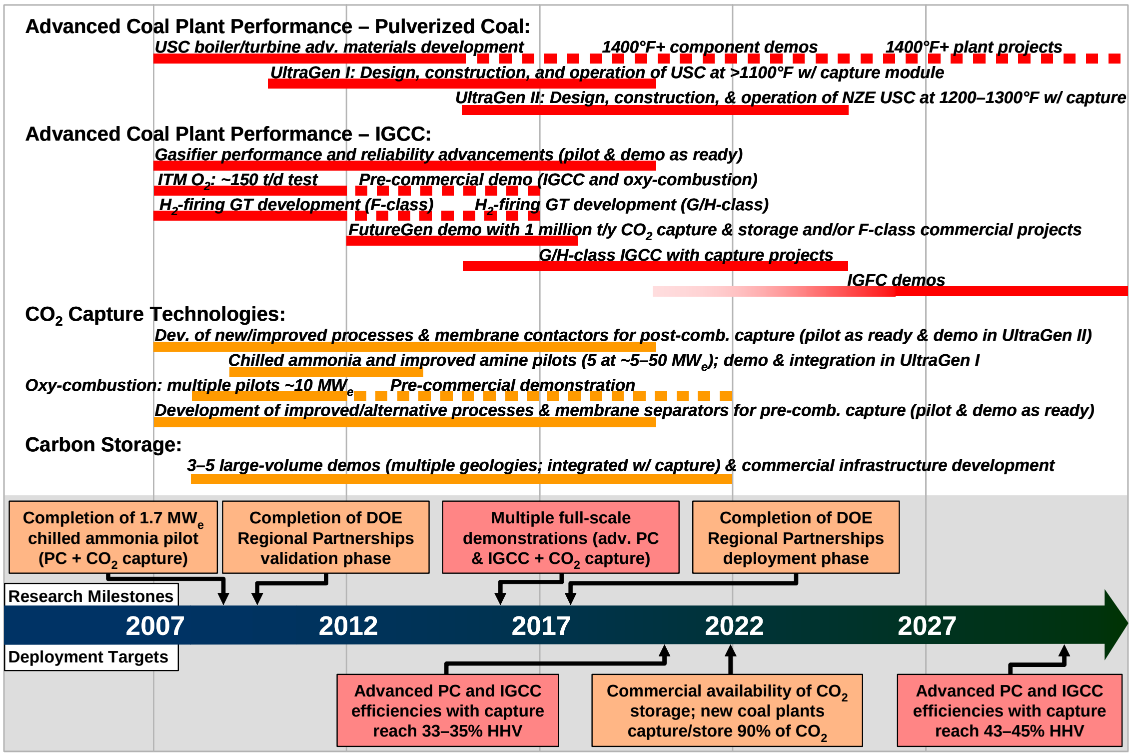
Figure 1 – Model of the development status of major advanced coal and CO_2 capture and storage technologies (temperatures shown for pulverized coal technologies are turbine inlet steam temperatures)

Of the coal-based power generating and carbon sequestration technologies shown in Figure 1, only SCPC technology has reached commercial maturity. It is crucial that other technologies in the portfolio—namely ultra-supercritical (USC) PC, IGCC, CO_2 capture (pre-combustion, post-combustion, and oxy-combustion), and CO_2 storage—be given sufficient support to reach the stage of declining constant dollar costs *before* society's requirements for greenhouse gas reductions compel their application in large numbers.

Figure 2 depicts the major activities in each of the four technology areas that must take place to achieve a robust set of integral advanced coal/CCS solutions. Please note that UltraGen III is not included in Figure 2 but the schedule for "Design, construction & operation of NZE USC PC at up to 1400°F w/capture" is expected to commence around 2020. Important, but not shown in the figure, are the interactions between RD&D activities. For example, the ion transport membrane (ITM) oxygen supply technology shown under IGCC may also be able to be applied to oxy-combustion PC units. Further,

[3] IEA Greenhouse Gas R&D Programme (IEA GHG), "Estimating Future Trends in the Cost of CO_2 Capture Technologies," 2006/5, January 2006.

while the individual goals related to efficiency, CO_2 capture, and CO_2 storage present major challenges, significant challenges also arise from complex interactions that occur when CO_2 capture processes are integrated with gasification- and combustion-based power plant processes.



Source: The Power to Reduce CO_2 Emissions – the Full Portfolio," http://epri-reports.org/DiscussionPaper2007.pdf

Figure 2 – Timing of advanced coal power system and CO_2 capture and storage RD&D activities and milestones

Reducing CO_2 Emissions Through Improved Coal Power Plant Efficiency—A Key Companion to CCS that Lowers Cost and Energy Requirements

Improved thermodynamic efficiency reduces CO_2 emissions by reducing the amount of fuel required to generate a given amount of electricity. A two-percentage point gain in efficiency provides a reduction in fuel consumption of roughly 5% and a similar reduction in flue gas and CO_2 output. Because the size and cost of CO_2 capture equipment is determined by the volume of flue gas to be treated, higher power block efficiency reduces the capital and energy requirements for CCS. Depending on the technology used, improved efficiency can also provide similar reductions in criteria air pollutants, hazardous air pollutants, and water consumption.

A typical baseloaded 500 MW (net) coal plant emits about 3 million metric tons of CO_2 per year. Individual plant emissions vary considerably given differences in plant steam cycle, coal type, capacity factor, and operating regimes. For a given fuel, however, a new supercritical PC unit built today might produce 5–10% less CO_2 per megawatt-hour (MWh) than the existing fleet average for that coal type.

With an aggressive RD&D program on efficiency improvement, new USC PC plants could reduce CO_2 emissions per MWh by up to 25% relative to the existing fleet average. Significant efficiency gains are also possible for IGCC plants by employing advanced gas turbines and through more energy-efficient oxygen plants and synthesis (fuel) gas cleanup technologies.

EPRI and the Coal Utilization Research Council (CURC), in consultation with DOE, have identified a challenging but achievable set of milestones for improvements in the efficiency, cost, and emissions of PC and coal-based IGCC plants. The EPRI-CURC Roadmap projects an overall improvement in the thermal efficiency of state-of-the art generating technology from 38–41% in 2010 to 44–49% by 2025 (on a higher heating value [HHV] basis; see Table 1). As Table 1 indicates, power-block efficiency gains (i.e., without capture systems) will be offset by the energy required for CO_2 capture, but as noted, they are important in reducing the overall cost of CCS. Coupled with opportunities for major improvements in the energy efficiency of CO_2 capture processes per se, aggressive pursuit of the EPRI-CURC RD&D program offers the prospect of coal power plants *with* CO_2 capture in 2025 that have net efficiencies meeting or exceeding current-day power plants without CO_2 capture.

It is also important to note that the numeric ranges in Table 1 are not simply a reflection of uncertainty, but rather they underscore an important point about differences among U.S. coals. The natural variations in moisture and ash content and combustion characteristics between coals have a significant impact on attainable efficiency. An advanced coal plant firing Wyoming and Montana’s Powder River Basin (PRB) coal, for example, would likely have an HHV efficiency two percentage points lower than the efficiency of a comparable plant firing Appalachian bituminous coals. Equally advanced plants firing lignite would likely have efficiencies two percentage points lower than their counterparts firing PRB. Any government incentive program with an efficiency-based qualification criterion should recognize these inherent differences in the attainable efficiencies for plants using different ranks of coal.

Table 1 – Efficiency Milestones in EPRI-CURC Roadmap

	2010	2015	2020	2025
PC & IGCC Systems *(Without CO_2 Capture)*	38–41% HHV	39–43% HHV	42–46% HHV	44–49% HHV
PC & IGCC Systems *(With CO_2 Capture*)*	31–32% HHV	31–35% HHV	33–39% HHV	39–46% HHV

**Efficiency values reflect impact of 90% CO_2 capture, but not compression or transportation.*

New Plant Efficiency Improvements–IGCC

Although IGCC is not yet a mature technology for coal-fired power plants, chemical plants around the world have accumulated a 100-year experience base operating coal-based gasification units and related gas cleanup processes. The most advanced of these units are similar to the front end of a modern IGCC facility. Similarly, several decades of experience firing natural gas and petroleum distillate have established a high level of maturity for the basic combined cycle generating technology. Nonetheless, ongoing RD&D continues to provide significant advances in the base technologies, as well as in the suite of technologies used to integrate them into an IGCC generating facility.

Efficiency gains in currently proposed IGCC plants will come from the use of new “FB-class” gas turbines, which will provide an overall plant efficiency gain of about 0.6 percentage point (relative to IGCC units with FA-class models, such as Tampa Electric’s Polk Power Station). This corresponds to a decrease in the rate of CO_2 emissions per MWh of about 1.5%. Alternatively, this means 1.5% less fuel is required per MWh of output, and thus the required size of pre-combustion water-gas shift and CO_2 separation equipment would be slightly smaller.

Figure 3 depicts the anticipated timeframe for further developments identified by EPRI’s *CoalFleet for Tomorrow®* program that promise a succession of significant improvements in IGCC unit efficiency. Key technology advances under development include:

- larger capacity gasifiers (often via higher operating pressures that boost throughput without a commensurate increase in vessel size)
- integration of new gasifiers with larger, more efficient G- and H-class gas turbines
- use of ion transport membrane or other more energy-efficient technologies in oxygen plants
- warm synthesis gas cleanup and membrane separation processes for CO_2 capture that reduce energy losses in these areas

- recycle of liquefied CO_2 to replace water in gasifier feed slurry (reducing heat loss to water evaporation)
- hybrid combined cycles using fuel cells to achieve generating efficiencies exceeding those of conventional combined cycle technology

Improvements in gasifier reliability and in control systems also contribute to improved annual average efficiency by minimizing the number and duration of startups and shutdowns.

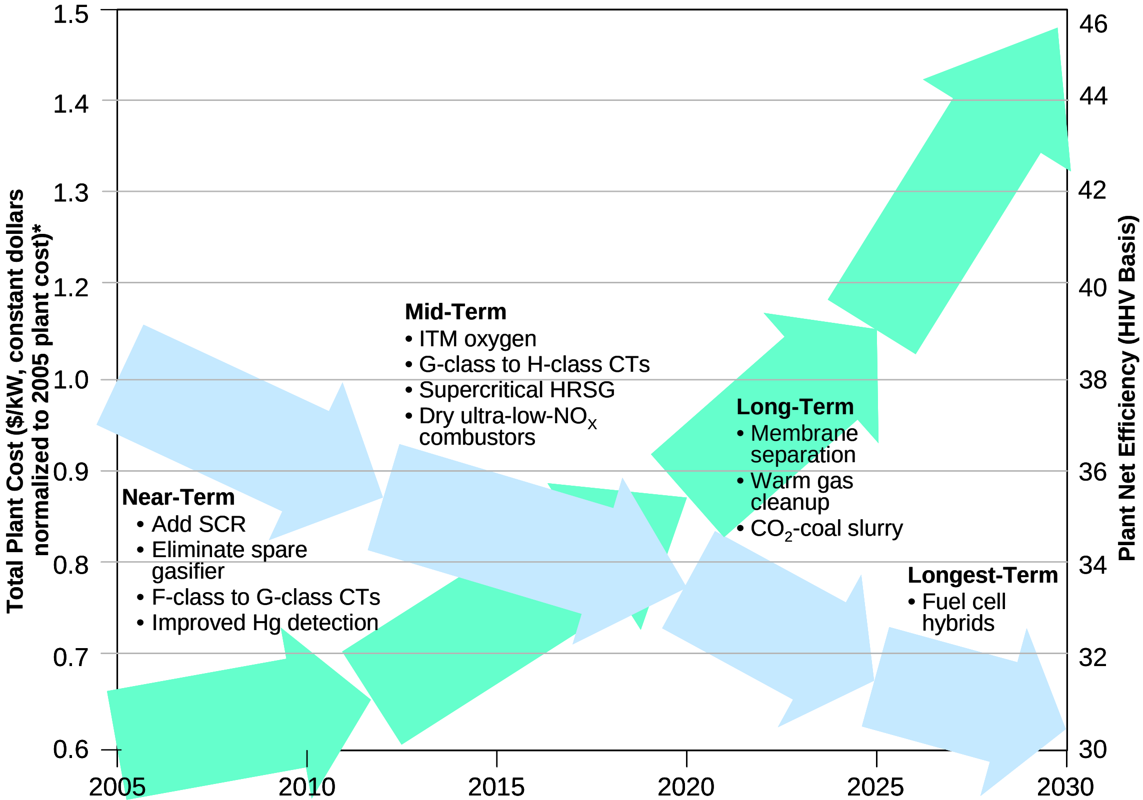


Figure 3 – RD&D path for capital cost reduction (falling arrows) and efficiency improvement (rising arrows) for IGCC power plants with 90% CO_2 capture

* *For a slurry-fed gasifier designed for 90% unit availability and 90% pre-combustion CO_2 capture using Pittsburgh #8 bituminous coal; cost normalization using Chemical Engineering Plant Cost Index or equivalent. A similar trend is observed in analyses of dry-fed gasifiers using Power River Basin subbituminous coal, although the absolute values vary somewhat from those shown.*

Counteracting Gas Turbine Output Loss at High Elevations. IGCC plants designed for application in high-elevation locations must account for the natural reduction in gas turbine power output that occurs where the air is thin. This phenomenon is rooted in the fundamental volumetric flow limitation of a gas turbine, and can reduce power output by up to 15% at an elevation of 5000 feet (relative to a comparable plant at sea level). EPRI is exploring measures to counteract this power loss, including inlet air chilling (a technique used at natural gas power plants to mitigate the power loss that comes from thinning of the air on a hot day) and use of supplemental burners between the gas turbine and steam turbine to boost the plant's steam turbine section generating capacity.

Larger, Higher Firing Temperature Gas Turbines. For plants coming on-line around 2015, the larger size G-class gas turbines, which operate at higher firing temperatures (relative to F-class machines) can improve efficiency by 1 to 2 percentage points while also decreasing capital cost per kW capacity. The H-class gas turbines coming on-line in the same timeframe, which also feature higher firing temperatures as well as steam-based internal cooling of hot turbine components, will provide a further increase in efficiency and capacity.

Ion Transport Membrane–Based Oxygen Plants. Most gasifiers used in IGCC plants require a large quantity of high-pressure, high purity oxygen, which is typically generated on site with an expensive and energy-intensive cryogenic process. The ITM process allows the oxygen in high-temperature air to pass through a membrane while preventing passage of non-oxygen atoms. According to developers, an ITM-based oxygen plant consumes 35–60% less power and costs 35% less than a cryogenic plant. DOE has been supporting development of this technology. EPRI is performing a due diligence assessment of this technology in advance of potential participation in technology scale-up efforts and is planning to solicit an industry consortium to support development .

Supercritical Heat Recovery Steam Generators. In IGCC plants, hot exhaust gas exiting the gas turbine is ducted into a heat exchanger known as a heat recovery steam generator (HRSG) to transfer energy into water-filled tubes producing steam to drive a steam turbine. This combination of a gas turbine and steam turbine power cycles produces electricity more efficiently than either a gas turbine or steam turbine alone. As with conventional steam power plants, the efficiency of the steam cycle in a combined cycle plant increases when turbine inlet steam temperature and pressure are increased. The higher exhaust temperatures of G- and H-class gas turbines offer the potential for adoption of more-efficient supercritical steam cycles. Materials for use in a supercritical HRSG are generally established, and thus should not pose a barrier to technology implementation once G- and H-class gas turbines become the standard for IGCC designs.

Synthesis Gas Cleaning at Higher Temperatures. The acid gas recovery (AGR) processes currently used to remove sulfur compounds from synthesis gas require that the gas and solvent be cooled to about 100ºF, thereby causing a loss in efficiency. Further costs and efficiency loss are inherent in the process equipment and auxiliary steam required to recover the sulfur compounds from the solvent and convert them to useable products. Several DOE-sponsored RD&D efforts aim to reduce the energy losses and costs imposed by this recovery process. These technologies (described below) could be ready—with adequate RD&D support—by 2020:

- The Selective Catalytic Oxidation of Hydrogen Sulfide process eliminates the Claus and Tail Gas Treating units, along with the traditional solvent-based AGR contactor, regenerator, and heat exchangers, by directly converting hydrogen sulfide (H_2S) to elemental sulfur. The process allows for a higher operating temperature of approximately 300ºF, which eliminates part of the low-temperature gas cooling train. The anticipated benefit is a net capital cost reduction of about $60/kW along with an efficiency gain of about 0.8 percentage point.
- The RTI/Eastman High-Temperature Desulfurization System uses a regenerable dry zinc oxide sorbent in a dual loop transport reactor system to convert H_2S and COS to

H_2O, CO_2, and SO_2. Tests at Eastman Chemical Company have shown sulfur species removal rates above 99.9%, with 10 ppm output versus 8000+ ppm input sulfur, using operating temperatures of 800–1000ºF. This process is also being tested for its ability to provide a high-pressure CO_2 by-product. The anticipated benefit for IGCC, compared with using a standard oil-industry process for sulfur removal, is a net capital cost reduction of \$60–90 per kW, a thermal efficiency gain of 2–4% for the gasification process, and a slight reduction in operating cost. Tests are also under way for a multi-contaminant removal processes that can be integrated with the transport desulfurization system at temperatures above 480°F.

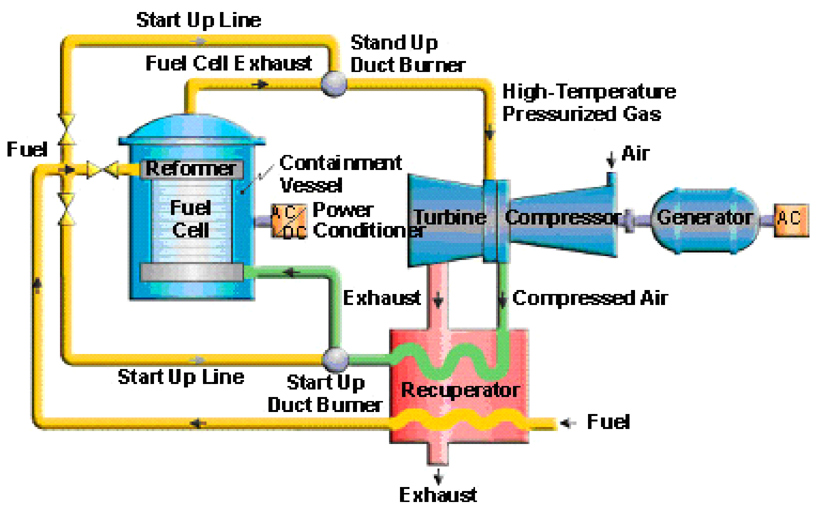
Liquid CO_2-Coal Slurrying for Gasification of Low-Rank Coals. Future IGCC plants with CCS may recycle some of the recovered liquid CO_2 to replace water as the slurrying medium for the coal feed. This is expected to increase gasification efficiency for all coals, but particularly for subbituminous coal and lignite, which have naturally high moisture contents. The liquid CO_2 has a lower heat of vaporization than water and is able to carry more coal per unit mass of fluid. The liquid CO_2-coal slurry will flash almost immediately upon entering the gasifier, providing good dispersion of the coal particles and potentially yielding the higher performance of a dry-fed gasifier with the simplicity of a slurry-fed system.

Traditionally, slurry-fed gasification technologies have a cost advantage over conventional dry-fed fuel handling systems, but they suffer a large performance penalty when used with coals containing a large fraction of water and ash. EPRI identified CO_2 coal slurrying as an innovative fuel preparation concept 20 years ago, when IGCC technology was in its infancy. At that time, however, the cost of producing liquid CO_2 was too high to justify the improved thermodynamic performance. Requirements for CCS change that, as it will substantially reduce the incremental cost of producing a liquid CO_2 stream.

To date, CO_2-coal slurrying has only been demonstrated at pilot scale and has yet to be assessed in feeding coal to a gasifier, so the estimated performance benefits remain to be confirmed. It will first be necessary, however, to update previous studies to quantify the potential benefit of liquid CO_2 slurries with IGCC plants designed for CO_2 capture. If the predicted benefit is economically advantageous, a significant amount of scale-up and demonstration work would be required to qualify this technology for commercial use.

Fuel Cells and IGCC. No matter how far gasification and turbine technologies advance, IGCC power plant efficiency will never progress beyond the inherent thermodynamic limits of the gas turbine and steam turbine power cycles (along with lower limits imposed by available materials technology). Several IGCC–fuel cell hybrid power plant concepts (IGFC) aim to provide a path to coal-based power generation with net efficiencies that exceed those of conventional combined cycle generation.

Along with its high thermal efficiency, the fuel cell hybrid cycle reduces the energy consumption for CO_2 capture. The anode section of the fuel cell produces a stream that is highly concentrated in CO_2. After removal of water, this stream can be compressed for sequestration. The concentrated CO_2 stream is produced without having to include a water-gas shift reactor in the process (see Figure 4). This further improves the thermal efficiency and decreases capital cost. IGFC power systems are a long-term solution, however, and are unlikely to see full-scale demonstration until about 2030.



Source: U.S. Department of Energy; http://www.netl.doe.gov/technologies/coalpower/fuelcells/hybrids.html

Figure 4 – Schematic of fuel cell-turbine hybrid

The Changing Role of FutureGen. In January of this year, DOE announced a restructured approach to the FutureGen project. Previously, the FutureGen Industrial Alliance and DOE were intending to build a first-of-its-kind, near-zero emissions coal-fed IGCC power plant integrated with CCS. The commencement of full-scale operations was targeted for 2013. The project aimed at storing CO_2 in a representative geologic formation at a rate of at least one million metric tons per year. DOE had committed to spend $1.1 billion in support of the project while the FutureGen Industrial Alliance had agreed to contribute $400 million.

Under its revised approach, DOE will offer to pay the additional cost of capturing CO_2 at multiple IGCC plants. Each plant would capture and store at least 1 million tons of CO_2 per year. DOE's goal is to have the plants in operation between 2015 and 2016.

The original FutureGen concept was meant to serve as a "living laboratory" for testing advanced technologies that offered the promise of clean environmental performance at a reduced cost and increased reliability. The original FutureGen concept, as shown in Figure 5 was to have the flexibility to conduct full-scale and slipstream tests of such scalable advanced technologies as:

- Membrane processes to replace cryogenic separation for oxygen production
- An advanced transport reactor sidestream with 30% of the capacity of the main gasifier
- Advanced membrane and solvent processes for H_2 and CO_2 separation
- A raw gas shift reactor that reduces the upstream clean-up requirements
- Ultra-low-NO_X combustors that can be used with high-hydrogen synthesis gas

- A fuel cell hybrid combined cycle pilot
- Smart dynamic plant controls including a CO_2 management system

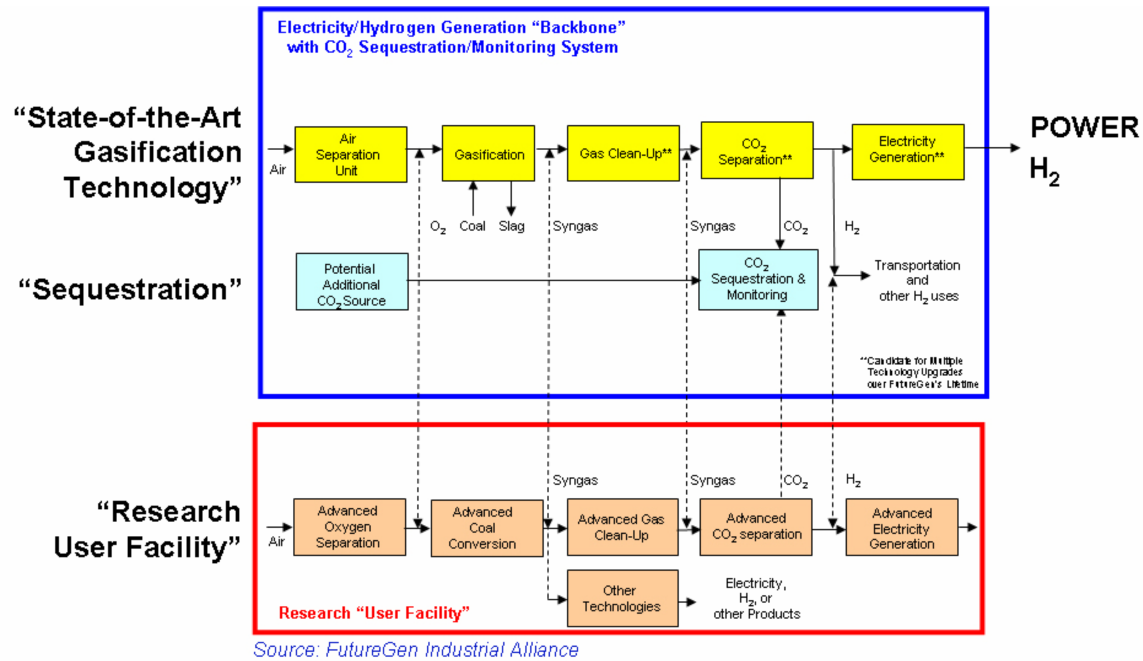


Figure 5 – FutureGen technology platforms

While the revised DOE FutureGen concept will meet the original goal of having a CCS test of at least 1 million tons of CO_2 per year (albeit two to three years later than the original target), the other original goal of also hosting the development of several advanced technologies for decreasing plant costs appears to have been dropped.

EPRI has responded to DOE's RFI on the revised FutureGen concept. We asked for clarification on what aspects of the costs of including CO_2 capture and storage (CCS) would be covered, and we gave our estimate of what the total costs would be for including CCS on one train of a two-train 600 MW IGCC. We also highlighted the other major RD&D activities that are needed for improving the efficiency and cost of IGCC technologies with CO_2 capture (see Figure 6). In addition, we asked whether non-IGCC coal power plants which capture at least 1 million tons of CO_2 per year could qualify for funding under the revised FutureGen concept. For example, would the incremental CCS costs of a project such as our proposed UltraGen advanced SCPC plant with post-combustion capture and geological storage of CO_2 be eligible for DOE support under the restructured FutureGen concept.

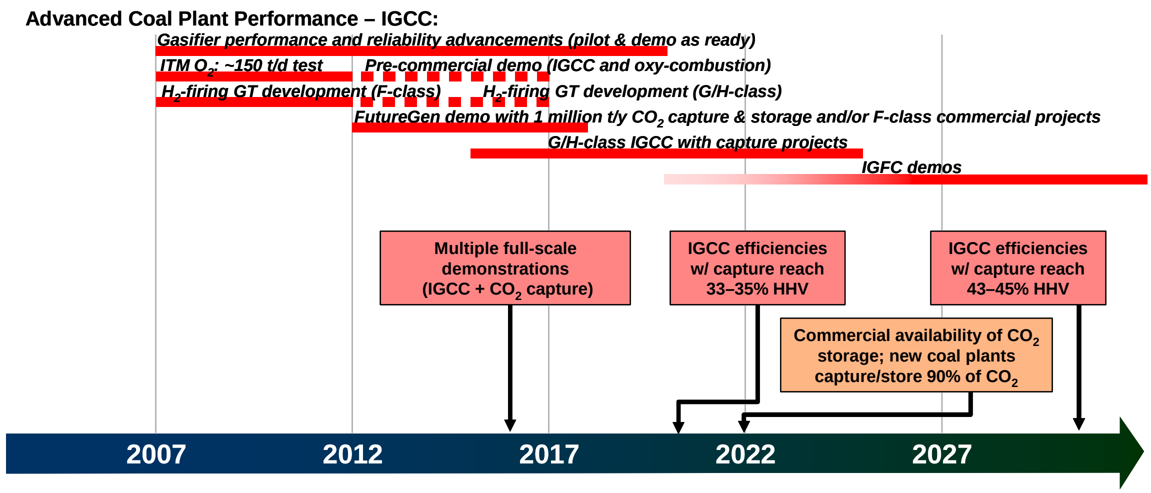


Figure 6 – Timing of advanced IGCC and CO_2 capture integration RD&D activities and milestones

New Plant Efficiency Improvements – Advanced Pulverized Coal

Pulverized-coal power plants have long been a primary source of reliable and affordable power in the United States and around the world. The advanced level of maturity of the technology, along with basic thermodynamic principles, suggests that significant efficiency gains can most readily be realized by increasing the operating temperatures and pressures of the steam cycle. Such increases, in turn, can be achieved only if there is adequate development of suitable materials and new boiler and steam turbine designs that allow use of higher steam temperatures and pressures.

Current state-of-the-art plants use supercritical main steam conditions (i.e., temperature and pressure above the “critical point” where the liquid and vapor phases of water are indistinguishable). SCPC plants typically have main steam conditions up to 1100°F. The term “ultra-supercritical” is used to describe plants with main steam temperatures in excess of 1100°F and potentially as high as 1400°F.

Achieving higher steam temperatures and higher efficiency will require the development of new corrosion-resistant, high-temperature nickel alloys for use in the boiler and steam turbine. In the United States, these challenges are being address by the Ultra-Supercritical Materials Consortium, a DOE R&D program involving Energy Industries of Ohio, EPRI, the Ohio Coal Development Office, and numerous equipment suppliers. EPRI provides technical management for the consortium. Results are applicable to all ranks of coal. As noted, higher power block efficiencies translate to lower costs for post-combustion CO_2 capture equipment.

It is expected that a USC PC plant operating at about 1300°F will be built during the next seven to ten years, following the demonstration and commercial availability of advanced materials from these programs. This plant would achieve an efficiency (before installation of CO_2 capture equipment) of about 45% (HHV) on bituminous coal, compared with 39% for a current state-of-the-art plant, and would reduce CO_2 production per net MWh by about 15%.

Ultimately, nickel-base alloys are expected to enable stream temperatures in the neighborhood of 1400°F and pre-capture generating efficiencies up to 47% HHV with bituminous coal. This approximately 10 percentage point improvement over the efficiency of a new subcritical pulverized-coal plant would equate to a decrease of about 25% in CO_2 and other emissions per MWh. The resulting saving in the cost of subsequently installed CO_2 capture equipment is substantial.

Figure 7 illustrates a timeline developed by EPRI's *CoalFleet for Tomorrow®* program to establish efficiency improvement and cost reduction goals for USC PC plants with CO_2 capture.

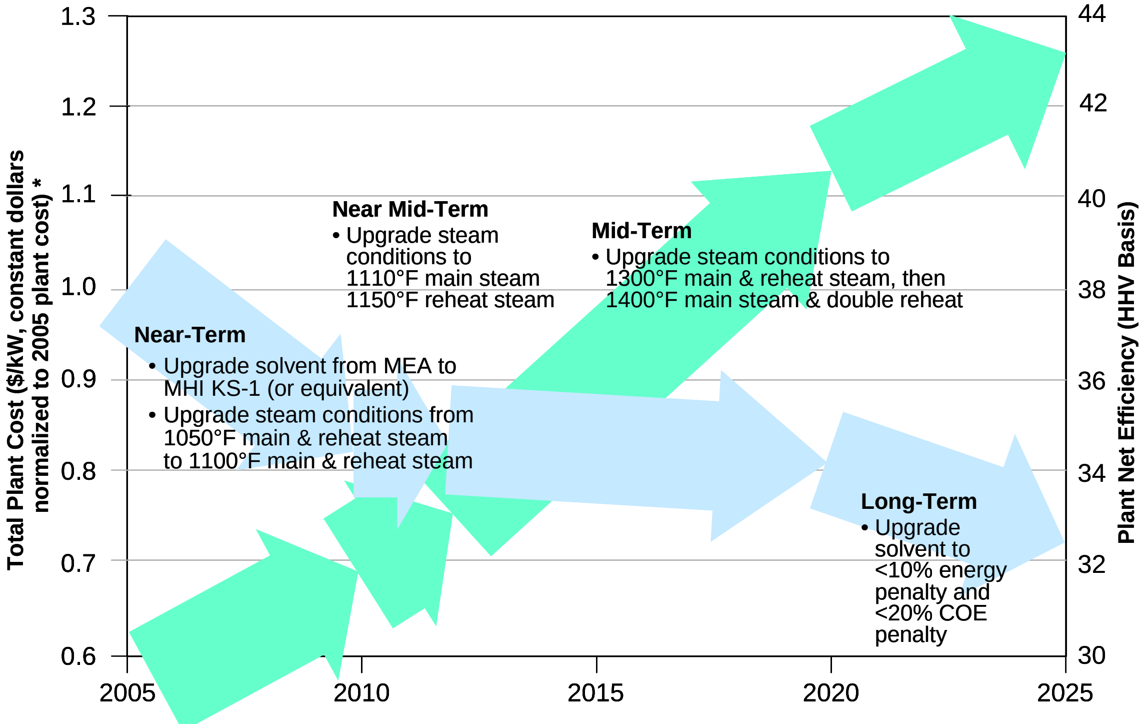


Figure 7 – RD&D path for capital cost reduction (falling arrows) and efficiency improvement (rising arrows) for PC power plants with 90% CO_2 capture

** For a unit designed for 90% unit availability and 90% post-combustion CO_2 capture firing a Pittsburgh #8 bituminous coal; cost normalization using Chemical Engineering Plant Cost Index or equivalent. A similar trend is observed in analyses of PC units with CCS using other U.S. coals, although the efficiency values are up to two percentage points lower for units firing subbituminous coal such as Powder River Basin and up to four percentage points lower for units firing lignite.*

UltraGen Ultrasupercritical (USC) Pulverized Coal (PC) Commercial Projects. EPRI and industry representatives have proposed a program to support commercial projects that demonstrate advanced PC and CCS technologies. The vision entails construction of two (or more) commercially operated USC PC power plants that combine state-of-the-art pollution controls, ultra-supercritical steam power cycles, and innovative CO_2 capture technologies.

The UltraGen I plant will use the best of today's proven ferritic steels in high-temperature boiler and steam turbine components, while UltraGen II will be the first plant in the United States to feature nickel-based alloys and is designed for steam temperatures up to

1300F. UltraGen III will be designed for steam temperatures up to 1400F using materials currently under development by the DOE boiler and steam turbine materials program.

UltraGen I will demonstrate CO_2 capture modules that separate about 1 million tons CO_2/yr using the best-established technology. This system will be about 6 times the size of the largest CO_2 capture system operating on a coal-fired boiler today, and will be integrated into the thermal cycle of the boiler to minimize parasitic loads and capacity loss. UltraGen II will at least double the size of the UltraGen I CO_2 capture system, and may demonstrate a new class of chemical solvent if one of the emerging low-regeneration-energy processes has reached a sufficient stage of development. UltraGen III is expected to capture up to 90 percent of the CO_2, 3.5 times more than for UltraGen I All three plants will demonstrate ultra-low emissions, and dry and compress the captured CO_2 to demonstrate long-term geologic storage and/or use in enhanced oil or gas recovery operations. Figure 8 depicts the proposed key features of UltraGen I, II, and III

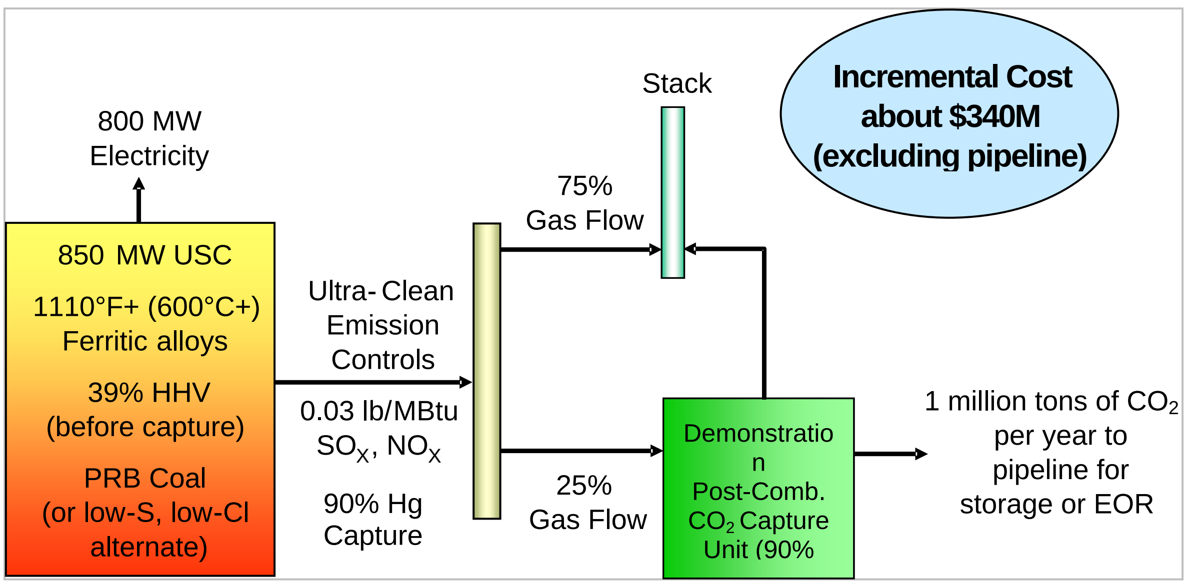
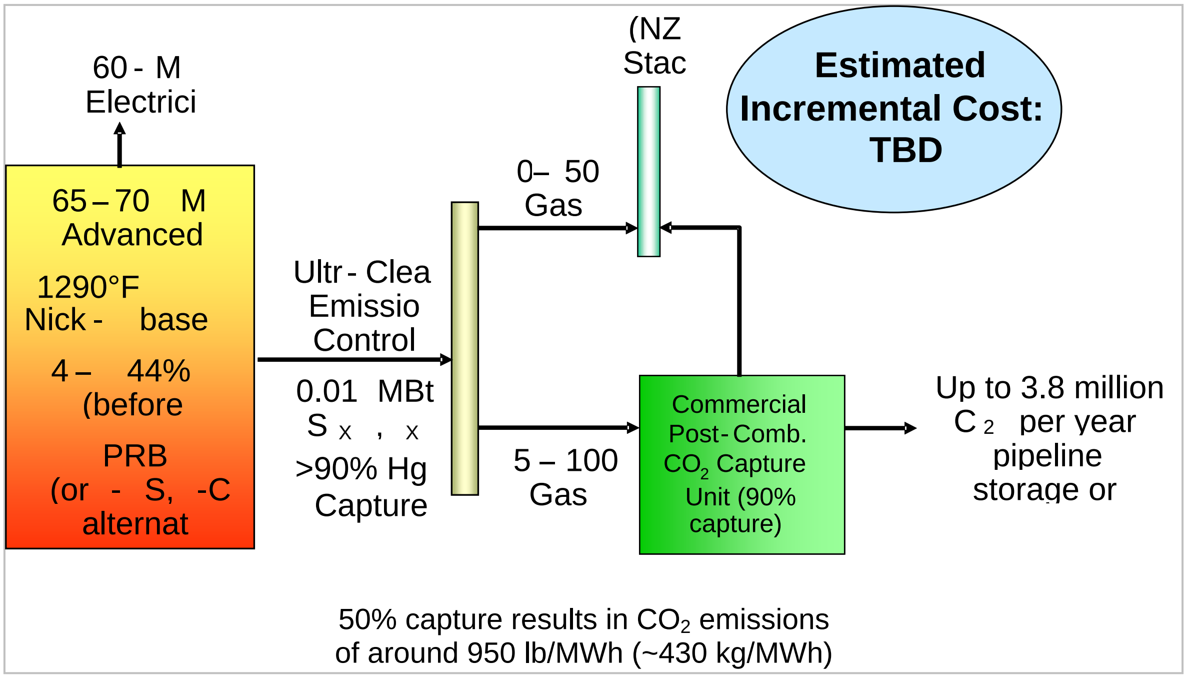


Figure 8 – Key parameters for UltraGen I, assuming a subbituminous feed coal such as Powder River Basin



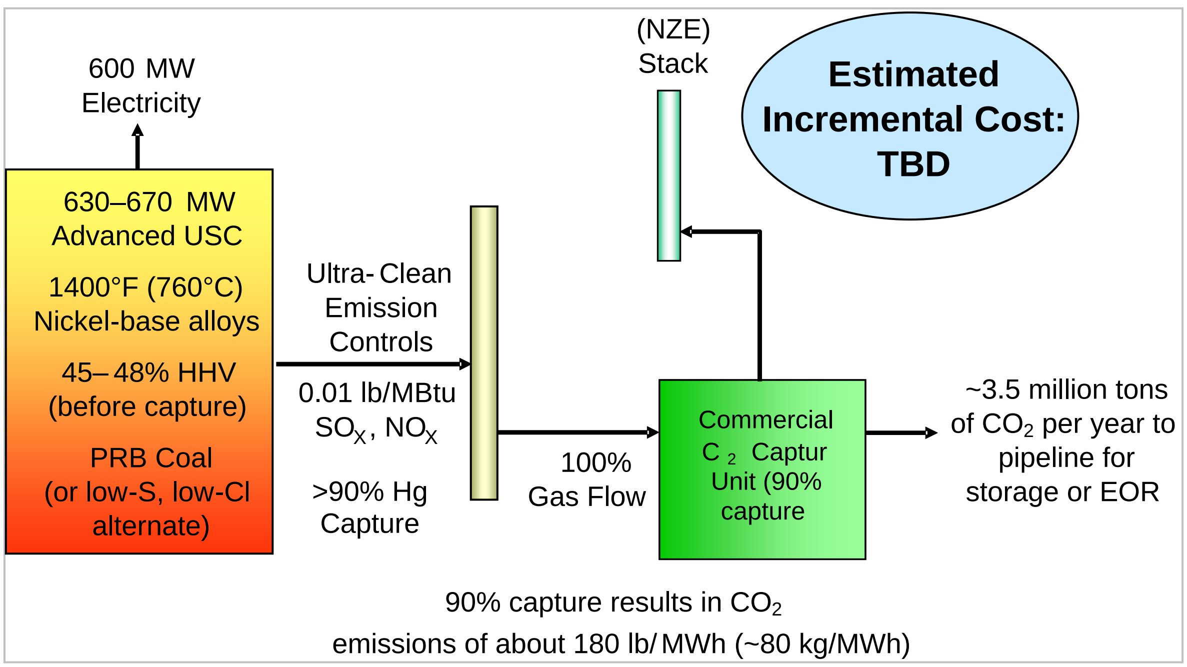


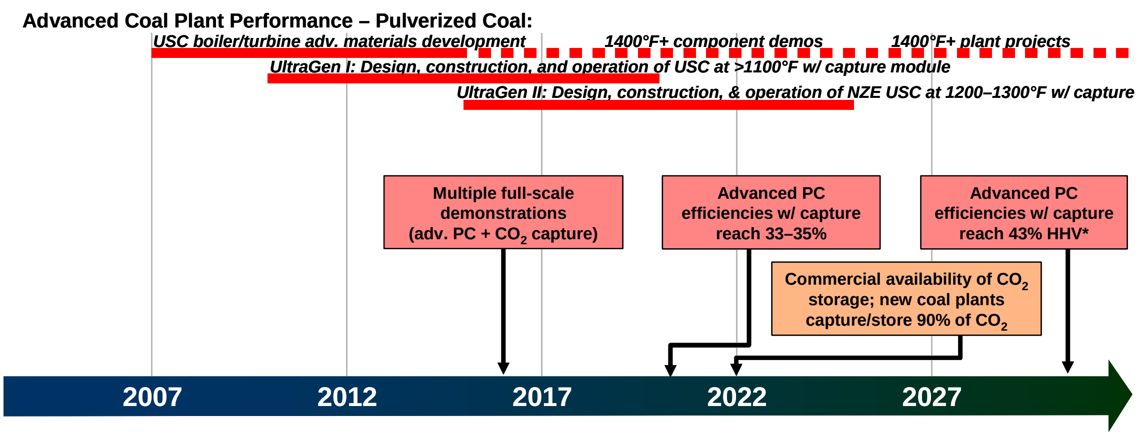
Figure 8 – Key parameters for UltraGen II (upper schematic) and UltraGen III (lower schematic), assuming a subbituminous feed coal such as Powder River Basin

To provide a platform for testing and developing emerging PC and CCS technologies, the UltraGen program will allow for technology trials at existing sites as well as at the sites of new projects. Unlike FutureGen, EPRI expects the UltraGen projects will be commercially dispatched by electricity grid operators. If the FutureGen concept could accommodate post combustion capture the differential cost of UltraGen CCS could be part of the full portfolio of projects. The differential cost to the host company for demonstrating these improved features are envisioned to be offset by any available tax credits (or other incentives) and by funds raised through an industry-led consortium formed by EPRI.

The UltraGen projects represent the type of "giant step" collaborative efforts that need to be taken to advance integrated PC/CCS technology to the next phase of evolution and assure competitiveness in a carbon-constrained world. Because of the time and expense for each "design and build" iteration for coal power plants (3 to 5 years not counting the permitting process and ~$2 billion), there is no room for hesitation in terms of commitment to advanced technology validation and demonstration projects. EPRI is currently discussing the UltraGen project concept with several firms in the US and internationally, and plans to develop a consortium to support demonstration of the technology.

The UltraGen projects will resolve technical and economic barriers to the deployment of USC PC and CCS technology by providing a shared-risk vehicle for testing and validating high-temperature materials, components, and designs in plants also providing superior environmental performance.

Figure 9 summarizes EPRI's recommended major RD&D activities for improving the efficiency and cost of USC PC technologies with CO_2 capture. Please note that UltraGen III is not included in Figure 9 but the schedule for "Design, construction & operation of NZE USC PC at up to 1400°F w/capture" is expected to commence around 2020.



*for bituminous coal; equally advanced PC plants firing subbituminous coal and lignite will have efficiencies two to four percentage points lower due to higher moisture and ash contents

Figure 9 – Timing of advanced PC and CO_2 capture integration RD&D activities and milestones

Efficiency Improvement and CCS Retrofits for the Existing PC Fleet. It would be economically advantageous to operate the many reliable subcritical PC units in the U.S. fleet well into the future. Premature replacement of these units or mandatory retrofit of these units for CO_2 capture en masse would be economically prohibitive. Their flexibility for load following and provision of support services to ensure grid stability makes them highly valuable. With equipment upgrades, many of these units can realize modest efficiency gains, which, when accumulated across the existing generating fleet could make a sizeable reduction in CO_2 emissions. For some existing plants, retrofit of CCS will make sense, but specific plant design features, space limitations, and economic and regulatory considerations must be carefully analyzed to determine whether retrofit-for-capture is feasible.

These upgrades depend on the equipment configuration and operating parameters of a particular plant and may include:

- turbine blading and steam path upgrades
- turbine control valve upgrades for more efficient regulation of steam
- cooling tower and condenser upgrades to reduce circulating water temperature, steam turbine exhaust backpressure, and auxiliary power consumption
- cooling tower heat transfer media upgrades
- condenser optimization to maximize heat transfer and minimize condenser temperature
- condenser air leakage prevention/detection
- variable speed drive technology for pump and fan motors to reduce power consumption
- air heater upgrades to increase heat recovery and reduce leakage
- advanced control systems incorporating neural nets to optimize temperature, pressure, and flow rates of fuel, air, flue gas, steam, and water
- optimization of water blowdown and blowdown energy recovery
- optimization of attemperator design, control, and operating scenarios
- sootblower optimization via “intelligent” sootblower system use
- coal drying (for plants using lignite and subbituminous coals)

Coal Drying for Increased Generating Efficiency. Boilers designed for high-moisture lignite have traditionally employed higher feed rates (lb/hr) to account for the large latent heat load to evaporate fuel moisture. An innovative concept developed by Great River Energy (GRE) and Lehigh University uses low-grade heat recovered from within the plant to dry incoming fuel to the boiler, thereby boosting plant efficiency and output. [In contrast, traditional thermal drying processes are complex and require high-grade heat to remove moisture from the coal.] Specifically, the GRE approach uses steam condenser and boiler exhaust heat exchangers to heat air and water fed to a fluidized-bed coal dryer upstream of the plant pulverizers. Based on successful tests with a pilot-scale dryer and more than a year of continuous operation with a prototype dryer at its Coal Creek station, GRE (with U.S. Department of Energy support and EPRI technical consultation) is now building a full suite of dryers for Unit 2 (i.e., a commercial-scale demonstration). In addition to the efficiency and CO_2 emission reduction benefits from reducing the lignite feed moisture content by about 25%, the plant's air emissions will be reduced as well.[4] Application of this technology is not limited to PC units firing lignite. EPRI believes it may find application in PC units firing subbituminous coal and in IGCC units with dry-fed gasifiers using low-rank coals.

Improving CO_2 Capture Technologies

CCS entails pre-combustion or post-combustion CO_2 capture technologies, CO_2 drying and compression (and sometimes further removal of impurities), and the transportation of separated CO_2 to locations where it can be stored away from the atmosphere for centuries or longer.

Albeit at considerable cost, CO_2 capture technologies can be integrated into all coal-based power plant technologies. For both new plants and retrofits, there is a tremendous need (and opportunity) to reduce the energy required to remove CO_2 from fuel gas or flue gas. Figure 10 shows a selection of the key technology developments and test programs needed to achieve commercial CO_2 capture technologies for advanced coal combustion- and gasification-based power plants at a progressively shrinking constant-dollar levelized cost-of-electricity premium. Specifically, the target is a premium of about \$6/MWh in 2025 (relative to plants at that time without capture) compared with an estimated 2010 cost premium of perhaps \$40/MWh (not counting the cost of transportation and storage). Such a goal poses substantial engineering challenges and will require major investments in RD&D to roughly halve the currently large energy requirements (operating costs) associated with CO_2 solvent regeneration. Achieving this goal will allow power producers to meet the public demand for stable electricity prices while reducing CO_2 emissions to address climate change concerns.

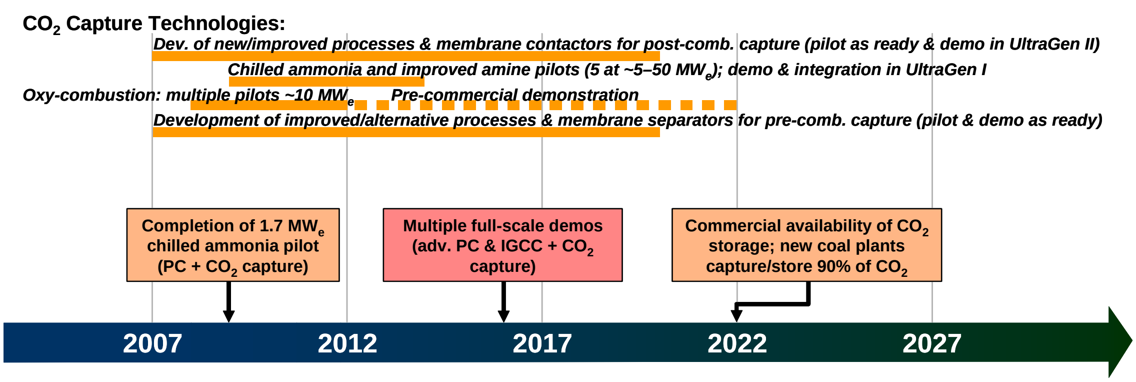


Figure 10 – Timing of CO_2 capture technology development RD&D activities and milestones

[4] C. Bullinger, M. Ness, and N. Sarunac, "One Year of Operating Experience with Prototype Fluidized Bed Coal Dryer at Coal Creek Generating Station," 32nd International Technical Conference on Coal Utilization and Fuel Systems, Clearwater FL, June 10–15, 2007.

Pre-Combustion CO_2 Capture (IGCC)

IGCC technology allows for CO_2 capture to take place via an added fuel gas processing step at elevated pressure, rather than at the atmospheric pressure of post-combustion flue gas, permitting capital savings through smaller equipment sizes as well as lower operating costs.

Currently available technologies for such pre-combustion CO_2 removal use a chemical and/or physical solvent that selectively absorbs CO_2 and other "acid gases," such as hydrogen sulfide. Application of this technology requires that the CO in synthesis gas (the principal component) first be "shifted" to CO_2 and hydrogen via a catalytic reaction with water. The CO_2 in the shifted synthesis gas is then removed via contact with the solvent in an absorber column, leaving a hydrogen-rich synthesis gas for combustion in the gas turbine. The CO_2 is released from the solvent in a regeneration process that typically reduces pressure and/or increases temperature.

Chemical plants currently employ such a process commercially using methyl diethanolamine (MDEA) as a chemical solvent or the Selexol and Rectisol processes, which rely on physical solvents. Physical solvents are generally preferred when extremely high (>99.8%) sulfur species removal is required. Although the required scale-up for IGCC power plant applications is less than that needed for scale-up of post-combustion CO_2 capture processes for PC plants, considerable engineering challenges remain and work on optimal integration with IGCC cycle processes has just begun.

The impact of current pre-combustion CO_2 removal processes on IGCC plant thermal efficiency and capital cost is significant. In particular, the water-gas shift reaction reduces the heating value of synthesis gas fed to the gas turbine. Because the gasifier outlet ratios of CO to methane to H_2 are different for each gasifier technology, the relative impact of the water-gas shift reactor process also varies. In general, however, it can be on the order of a 10% fuel energy reduction. Heat regeneration of solvents further reduces the steam available for power generation. Other solvents, which are depressurized to release captured CO_2, must be re-pressurized for reuse. Cooling water consumption is increased for solvents needing cooling after regeneration and for pre-cooling and interstage cooling during compression of separated CO_2 to a supercritical state for transportation and storage. Heat integration with other IGCC cycle processes to minimize these energy impacts is complex and is currently the subject of considerable RD&D by EPRI and others.

Membrane CO_2 Separation. Technology for separating CO_2 from shifted synthesis gas (or flue gas from PC plants) offers the promise of lower auxiliary power consumption but is currently only at the laboratory stage of development. Several organizations are pursuing different approaches to membrane-based applications. In general, however, CO_2 recovery on the low-pressure side of a selective membrane can take place at a higher pressure than is now possible with solvent processes, reducing the subsequent power demand for compressing CO_2 to a supercritical state. Membrane-based processes can also eliminate steam and power consumption for regenerating and pumping solvent, respectively, but they require power to create the pressure difference between the source gas and CO_2-rich sides. If membrane technology can be developed at scale to meet performance goals, it could enable up to a 50% reduction in capital cost and auxiliary power requirements relative to current CO_2 capture and compression technology.

Post-Combustion CO_2 Capture (PC and Circulating Fluidized-Bed (CFB) Plants)

The post-combustion CO_2 capture processes being discussed for power plant boilers in the near-term draw upon commercial experience with amine solvent separation at much smaller scale in the food, beverage and chemical industries, including three U.S. applications of CO_2 capture from coal-fired boilers.

These processes contact flue gas with an amine solvent in an absorber column (much like a wet SO_2 scrubber) where the CO_2 chemically reacts with the solvent. The CO_2-rich liquid mixture then passes to a stripper column where it is heated to change the chemical equilibrium point, releasing the CO_2. The “regenerated” solvent is then recirculated back to the absorber column, while the released CO_2 may be further processed before compression to a supercritical state for efficient transportation to a storage location.

After drying, the CO_2 released from the regenerator is relatively pure. However, successful CO_2 removal requires very low levels of SO_2 and NO_2 entering the CO_2 absorber, as these species also react with the solvent, requiring removal of the degraded solvent and replacement with fresh feed. Thus, high-efficiency SO_2 and NO_X control systems are essential to minimizing solvent consumption costs for post-combustion CO_2 capture; currently the approach to achieving such ultra-low SO_2 concentrations is to add a polishing scrubber, a costly venture. Extensive RD&D is in progress to improve the solvent and system designs for power boiler applications and to develop better solvents with greater absorption capacity, less energy demand for regeneration, and greater ability to accommodate flue gas contaminants.

At present, monoethanolamine (MEA) is the “default” solvent for post-combustion CO_2 capture studies and small-scale field applications. Processes based on improved amines, such as Fluor’s Econamine FG Plus and Mitsubishi Heavy Industries’ KS-1, await demonstration at power boiler scale and on coal-derived flue gas. The potential for improving amine-based processes appears significant. For example, a recent study based on KS-1 suggests that its impact on net power output for a supercritical PC unit would be 19% and its impact on the levelized cost-of-electricity would be 44%, whereas earlier studies based on suboptimal MEA applications yielded output penalties approaching 30% and cost-of-electricity penalties of up to 65%.

Accordingly, amine-based engineered solvents are the subject of numerous ongoing efforts to improve performance in power boiler post-combustion capture applications. Along with modifications to the chemical properties of the sorbents, these efforts are addressing the physical structure of the absorber and regenerator equipment, examining membrane contactors and other modifications to improve gas-liquid contact and/or heat transfer, and optimizing thermal integration with steam turbine and balance-of-plant systems. Although the challenge is daunting, the payoff is potentially massive, as these solutions may be applicable not only to new plants, but to retrofits where sufficient plot space is available at the back end of the plant.

Finally, as discussed earlier, deploying USC PC technology to increase efficiency and lower uncontrolled CO_2 per MWh can further reduce the cost impact of post-combustion CO_2 capture.

Ammonia-Based Processes. Post-combustion CO_2 capture using ammonia-based solvents offers the promise of significantly lower solvent regeneration requirements relative to MEA. In the "chilled ammonia" process owned by ALSTOM and currently under development and testing by ALSTOM and EPRI, respectively, CO_2 is absorbed in a solution of ammonium carbonate, at low temperature and atmospheric pressure.

Compared with amines, ammonium carbonate has over twice the CO_2 absorption capacity and requires less than half the heat to regenerate. Further, regeneration can be performed under higher pressure than amines, so the released CO_2 is already partially pressurized. Therefore, less energy is subsequently required for compression to a supercritical state for transportation to an injection location. Developers have estimated that the parasitic power loss from a full-scale supercritical PC plant using chilled ammonia CO_2 capture could be as low as 15%, with an associated cost-of-electricity penalty of just 25%. Part of the reduction in power loss comes from the use of low quality heat to regenerate ammonia and reduce the quantity of steam required for regeneration. Following successful experiments at 0.25 MW_e scale, ALSTOM and a consortium of EPRI members built a 1.7 MW_e pilot unit to test the chilled ammonia process on a flue gas slipstream at We Energies' Pleasant Prairie Power Plant. Testing at this site began in late March 2008 and will continue for about one year. The American Electric Power Co. (AEP) has announced plans to test a scaled-up design (100,000 tons CO_2/yr, equivalent to about 20 MWe), incorporating the lessons learned on the 1.7 MWe unit, at its Mountaineer station in West Virginia, with start-up scheduled for late 2009. AEP intends to capture, inject, and monitor for two-to-five years and, thereafter, continue monitoring CO_2 location in the underground reservoir for another several years. EPRI plans to develop a consortium to support this Mountaineer CO_2 Capture testing.

Other "multi-pollutant" control system developers are also exploring ammonia-based processes for CO_2 removal. For example, Powerspan and NRG Energy, Inc. announced plans in November 2007 to demonstrate a 125 MWe design of Powerspan's ECO_2 system at the Parish station in Texas starting up in 2012, and last month Basin Electric announced its selection of Powerspan to provide a similar size ECO_2 system for its Antelope Valley station in North Dakota, also with a 2012 start-up goal.

Other Processes. EPRI has identified over 40 potential CO_2 separation processes that are being developed by various firms or institutes. They include absorption systems (typically solvent-based similar to the amine and ammonia processes discussed above), adsorbed (attachment of the CO_2 to a solid that is then regenerated and re-used), membranes, and biological systems. Funding comes from a variety of sources, primarily DOE or internal funds, but the funding is neither sufficient or well-enough coordinated to advance the most promising technologies at the speed needed to achieve the goals of high CO_2 capture at societally-acceptable cost and energy drain. EPRI is working with the Southern Co. to select and demonstrate one of these processes at the 20+MWe scale, with the collected CO_2 injected into a local underground saline reservoir. The capture portion of this project will be funded mostly by Southern Co., its process supplier, and a collaborative of electricity generation companies assembled by EPRI. The storage portion will be funded largely by DOE under Phase 3 of its Regional Carbon Sequestration Partnership, with cofunding from the private sector. Start-up of the capture unit and compression/transport/injection system is projected for late 2010. Southern Co. and its teammates intend to capture, inject, and monitor for about four years and, thereafter, continue monitoring CO_2 location in the underground reservoir for another several years.

Oxy-Fuel Combustion Boilers

Fuel combustion in a blend of oxygen and recycled flue gas rather than in air (known as oxy-fuel combustion, oxy-coal combustion, or oxy-combustion) is gaining interest as a viable CO_2 capture alternative for PC and CFB plants. The process is applicable to virtually all fossil-fueled boiler types and is a candidate for retrofits as well as new power plants.

Firing coal with high-purity oxygen alone would result in too high of a flame temperature, which would increase slagging, fouling, and corrosion problems, so the oxygen is diluted by mixing it with a slipstream of recycled flue gas. As a result, the flue gas downstream of the recycle slipstream take-off consists primarily of CO_2 and water vapor (although it also contains small amounts of nitrogen, oxygen, and criteria pollutants). After the water is condensed, the CO_2-rich gas is compressed and purified to remove contaminants and prepare the CO_2 for transportation and storage.

Oxy-combustion boilers have been studied in laboratory-scale and small pilot units of up to 3 MW_t. Two larger pilot units, at ~10 MW_e, are now under construction by Babcock & Wilcox (B&W) and Vattenfall. An Australian-Japanese project team is pursuing a 30 MW_e repowering project in Australia. These larger tests will allow verification of mathematical models and provide engineering data useful for designing pre-commercial systems.

CO_2 Transport and Geologic Storage

Application of CO_2 capture technologies implies that there will be secure and economical forms of long-term storage that can assure CO_2 will be kept out of the atmosphere. Natural underground CO_2 reservoirs in Colorado, Utah, and other western states testify to the effectiveness of long-term geologic CO_2 storage. CO_2 is also found in natural gas reservoirs, where it has resided for millions of years. Thus, evidence suggests that similarly sealed geologic formations will be ideal for storing CO_2 for millennia or longer.

The most developed approach for large-scale CO_2 storage is injection into depleted or partially depleted oil and gas reservoirs and similar geologically sealed “saline formations” (porous rocks filled with brine that is impractical for desalination). Partially depleted oil reservoirs provide the potential added benefit of enhanced oil recovery (EOR). [EOR is used in mature fields to recover additional oil after standard extraction methods have been used. When CO_2 is injected for EOR, it causes residual oil to swell and become less viscous, allowing some to flow to production wells, thus extending the field's productive life.] By providing a commercial market for CO_2 captured from industrial sources, EOR may help the economics of CCS projects where it is applicable, and in some cases might reduce regulatory and liability uncertainties. Although less developed than EOR, researchers are exploring the effectiveness of CO_2 injection for enhancing production from depleted natural gas fields (particularly in compartmentalized formations where pressure has dropped) and from deep methane-bearing coal seams. DOE and the International Energy Agency are among the sponsors of such efforts. However, at the scale that CCS needs to be deployed to help achieve atmospheric CO_2 stabilization at an acceptable level, EPRI believes that the primary economic driver for CCS will be the value of carbon that results from a future climate policy.

Geologic sequestration as a CCS strategy is currently being demonstrated in several RD&D projects around the world. The three largest projects (which are non-power)—Statoil's Sleipner Saline Aquifer CO_2 Storage project in the North Sea off of Norway; the Weyburn Project in Saskatchewan, Canada; and the In Salah Project in Algeria—each sequester about 1 million metric tons of CO_2 per year, which matches the output of one baseloaded 150–200 MW coal-fired power plant. With 17 collective operating years of experience, these projects have thus far demonstrated that CO_2 storage in deep geologic formations can be carried out safely and reliably. Statoil estimates that Norwegian greenhouse gas emissions would have risen incrementally by 3% if the CO_2 from the Sleipner project had been vented rather than sequestered.[5]

Table 2 lists a selection of current and planned CO_2 storage projects as of early 2007. Update to table 2: The DF-1 Miller project has been put on hold and may be canceled, so no CO_2 capture is expected by 2010. The DF-Carson project may not start up by 2011 as planned. DOE has indicated that it plans to revise the FutureGen project so CO_2 storage will not take place until after 2012. In October 2007, the DOE awarded the first three large scale carbon sequestration projects in the United States. The Plains Carbon Dioxide Reduction Partnership, Southeast Regional Carbon Sequestration Partnership, and Southwest Regional Partnership for Carbon Sequestration, will conduct large volume tests for the storage of one million or more tons of CO_2 in deep saline reservoirs in the U.S.

[5] http://www.co2captureandstorage.info/project_specific.php?project_id=26

Table 2 – Select Existing and Planned CO_2 Storage Projects as of Early 2007

PROJECT	CO_2 SOURCE	COUNTRY	START	Anticipated amount injected by:		
				2006	2010	2015
Sleipner	Gas. Proc.	Norway	1996	9 MT	13 MT	18 MT
Weyburn	Coal	Canada	2000	5 MT	12 MT	17 MT
In Salah	Gas. Proc.	Algeria	2004	2 MT	7 MT	12 MT
Snohvit	Gas. Proc.	Norway	2007	0	2 MT	5 MT
Gorgon	Gas. Proc.	Australia	2010	0	0	12 MT
DF-1 Miller	Gas	U.K.	2009	0	1 MT	8 MT
DF-2 Carson	Pet Coke	U.S.	2011	0	0	16 MT
Draugen	Gas	Norway	2012	0	0	7 MT
FutureGen	Coal	U.S.	2012	0	0	2 MT
Monash	Coal	Australia	NA	0	0	NA
SaskPower	Coal	Canada	NA	0	0	NA
Ketzin/CO_2 STORE	NA	Germany	2007	0	50 KT	50 KT
Otway	Natural	Australia	2007	0	100 KT	100 KT
TOTALS				**16 MT**	**35 MT**	**99 MT**

Source: Sally M. Benson (Stanford University GCEP), "Can CO_2 Capture and Storage in Deep Geological Formations Make Coal-Fired Electricity Generation Climate Friendly?" Presentation at Emerging Energy Technologies Summit, UC Santa Barbara, California, February 9, 2007. [Note: Statoil has subsequently suspended plans for the Draugen project and announced a study of CO_2 capture at a gas-fired power plant at Tjeldbergodden. BP and Rio Tinto have announced the coal-based "DF-3" project in Australia.]

Enhanced Oil Recovery. Experience relevant to CCS comes from the oil industry, where CO_2 injection technology and modeling of its subsurface behavior have a proven record of accomplishment. EOR has been conducted successfully for 35 years in the Permian Basin fields of west Texas and Oklahoma. Regulatory oversight and community acceptance of injection operations for EOR seem well established.

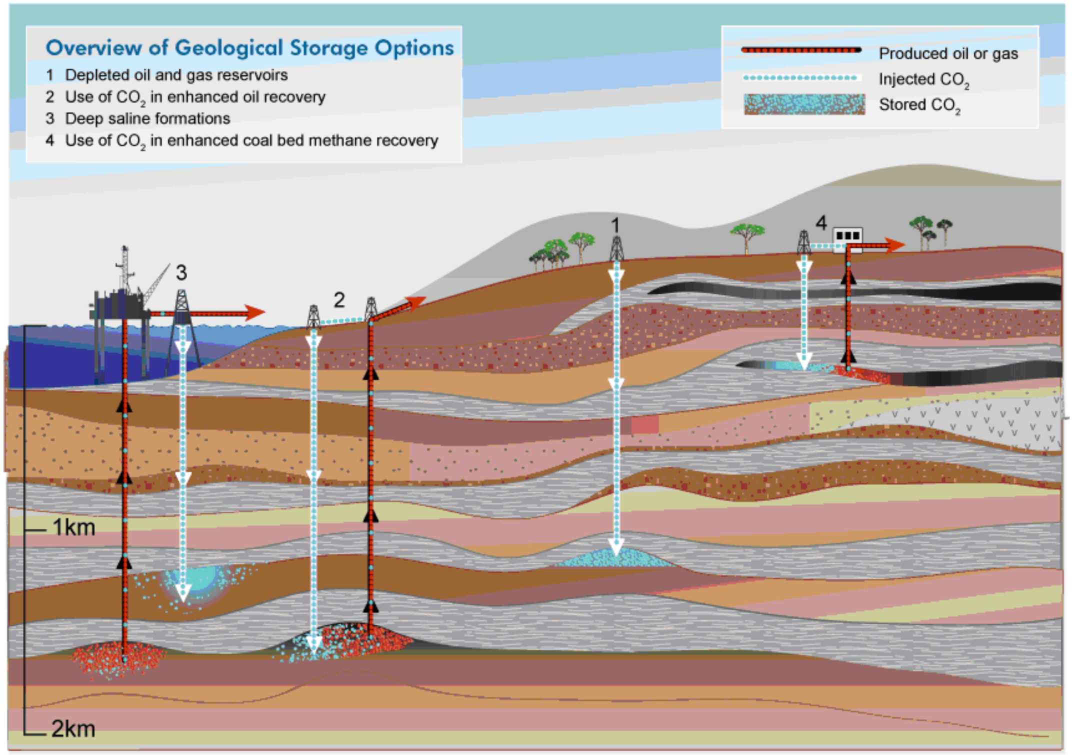
Although the purpose of EOR heretofore has not been to sequester CO_2, the practice can be adapted to include large-volume residual CO_2 storage. This approach is being demonstrated in the Weyburn-Midale CO_2 monitoring projects in Saskatchewan, Canada. The Weyburn project uses captured and dried CO_2 from the Dakota Gasification Company's Great Plains synfuels plant near Beulah, North Dakota. The CO_2 is transported via a 200-mile pipeline constructed of standard carbon steel. Over the life of the project, the net CO_2 storage is estimated at 20 million metric tons, while an additional 130 million barrels of oil will be produced.

Although EOR might help the economics of early CCS projects in oil-patch areas, EOR sites are ultimately too few and too geographically isolated to accommodate much of the CO_2 from widespread industrial CO_2 capture operations. In contrast, saline formations are available in many—but not all—U.S. locations.

CCS in the United States

A DOE-sponsored R&D program, the "Regional Carbon Sequestration Partnerships," is engaged in mapping U.S. geologic formations suitable for CO_2 storage. Evaluations by these Regional Partnerships and others suggest that enough geologic storage capacity exists in the U.S. to hold many centuries' production of CO_2 from coal-based power plants and other large point sources.

The Regional Partnerships are also conducting pilot-scale CO_2 injection validation tests across the country in differing geologic formations, including saline formations, deep unmineable coal seams, and older oil and gas reservoirs. Figure 11 illustrates some of these options. These tests, as well as most commercial applications for long-term storage, will use CO_2 compressed for volumetric efficiency to a liquid-like "supercritical" state; thus, virtually all CO_2 storage will take place in formations at least a half-mile deep, where the risk of leakage to shallower groundwater aquifers or to the surface is usually very low.



Source: Peter Cook, CO_2CRC, in Intergovernmental Panel on Climate Change, Special Report "Carbon Dioxide Capture and Storage," http://www.ipcc.ch/pub/reports.htm

Figure 11 – Illustration of potential geological CO_2 storage site types

After successful completion of pilot-scale CO_2 storage validation tests, the Partnerships will undertake large-volume storage tests, injecting quantities of ~1 million metric tons of CO_2 or more over a several year period, along with post-injection monitoring to track the absorption of the CO_2 in the target formation(s) and to check for potential leakage.

The EPRI-CURC Roadmap identifies the need for several large-scale integrated demonstrations of CO_2 capture and storage. This assessment was echoed by MIT in its recent *Future of Coal* report, which calls for three to five U.S. demonstrations of about 1 million metric tons of CO_2 per year and about 10 worldwide.[6] These demonstrations could be the critical path item in commercialization of CCS technology. In addition, EPRI has identified 10 key topics[5] where further technical and/or policy development is needed before CCS can become fully commercial:

- Caprock integrity
- Injectivity and storage capacity
- CO_2 trapping mechanisms
- CO_2 leakage and permanence
- CO_2 and mineral interactions

[6] http://web.mit.edu/coal/The_Future_of_Coal.pdf
[5] EPRI, Overview of Geological Storage of CO_2, Report ID **1012798**

- Reliable, low-cost monitoring systems
- Quick response and mitigation and remediation procedures
- Protection of potable water
- Mineral rights
- Long-term liability

Figure 12 shows that EPRI's recommended large-scale integrated CO_2 capture and storage demonstrations is temporally consistent with the Regional Partnerships' "Phase III" large-volume CO_2 storage test program. EPRI believes that many of the storage demonstrations should use CO_2 that comes from coal-fired boilers to address any uncertainties that may exist about the impact of coal-derived CO_2 on its behavior in underground formations.

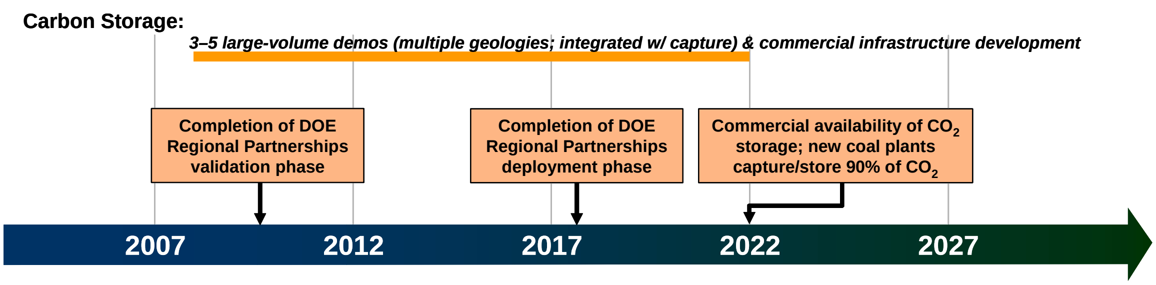


Figure 12 – Timing of CO_2 storage technology RD&D activities and milestones

CO_2 Transportation

Mapping of the distribution of potentially suitable CO_2 storage formations across the country, as part of the research by the Regional Partnerships, shows that some areas have ample storage capacity while others appear to have little or none. Thus, implementing CO_2 capture at some power plants may require pipeline transportation for several hundred miles to suitable injection locations, possibly in other states. Although this adds cost, it should not represent a technical hurdle because long-distance, interstate CO_2 pipelines have been used commercially in oilfield EOR applications. Economic considerations dictate that the purity requirements of coal-derived CO_2 be established so that the least-cost pipeline and compressor materials can be used at each application. From an infrastructure perspective, EPRI expects that early commercial CCS projects will take place at coal-based power plants near sequestration sites or an existing CO_2 pipeline. As the number of projects increases, regional CO_2 pipeline networks connecting multiple industrial sources and storage sites will be needed.

Policy-Related Long-Term CO_2 Storage Issues

Beyond developing the technological aspects of CCS, public policy needs to address issues such as CO_2 storage site permitting, long-term monitoring requirements, and post-closure liability. CCS represents an emerging industry, and the jurisdictional roles among federal and state agencies for regulations and their relationship to private carbon credit markets operating under federal oversight has yet to be determined.

Currently, efforts are under way in some states to establish regulatory frameworks for long-term geologic CO_2 storage. Additionally, stakeholder organizations such as the Interstate Oil and Gas Compact Commission (IOGCC) are developing their own suggested regulatory recommendations for states drafting legislation and regulatory procedures for CO_2 injection and storage operations.[7] Other stakeholders, such as environmental groups, are also offering policy recommendations. EPRI expects this field to become very active soon.

A state-by-state approach to sequestration may not be adequate because some geologic formations, which are ideal for storing CO_2, underlie multiple states. At the federal level, the U.S. EPA published a first-of-its-kind guidance (UICPG # 83) on March 1, 2007, for permitting underground injection of CO_2.[8] This guidance offers flexibility for pilot projects evaluating the practice of CCS, while leaving unresolved the requirements that could apply to future large-scale CCS projects.

Long-Term CO_2 Storage Liability Issues

Long-term liability for injected CO_2 will need to be assigned before CCS can become fully commercial. Because CCS activities will be undertaken to serve the public good, as determined by government policy, and will be implemented in response to anticipated or actual government-imposed limits on CO_2 emissions, a number of policy analysts have suggested that the entities performing these activities should be granted a measure of long-term risk reduction assuming adherence to proper procedures during the storage site injection operations and closure phases.

RD&D Investment for Advanced Coal and CCS Technologies

Developing the suite of technologies needed to achieve competitive advanced coal and CCS technologies will require a sustained major investment in RD&D. As shown in Table 3, EPRI estimates that an expenditure of approximately $8 billion will be required in the 10-year period from 2008–17. The MIT *Future of Coal* report estimates the funding need at up to $800–850 million per year, which approaches the EPRI value. Further, EPRI expects that an RD&D investment of roughly $17 billion will be required over the next 25 years.

[7] http://www.iogcc.state.ok.us/PDFS/CarbonCaptureandStorageReportandSummary.pdf
[8] http://www.epa.gov/safewater/uic/pdfs/guide_uic_carbonsequestration_final-03-07.pdf

Investment in earlier years may be weighted toward IGCC, as this technology is less developed and will require more RD&D investment to reach the desired level of commercial viability. As interim progress and future needs cannot be adequately forecast at this time, the years after 2023 do not distinguish between IGCC and PC.

Table 3 – RD&D Funding Needs for Advanced Coal Power Generation Technologies with CO_2 Capture

<table>
<tr><th></th><th>2008–12</th><th>2013–17</th><th>2018–22</th><th>2023–27</th><th>2028–32</th></tr>
<tr><td>Total Estimated RD&D Funding Needs
(Public + Private Sectors)</td><td>$830M/yr</td><td>$800M/yr</td><td>$800M/yr</td><td>$620M/yr</td><td>$400M/yr</td></tr>
<tr><td>Advanced Combustion, CO_2 Capture</td><td>25%</td><td>25%</td><td>40%</td><td rowspan="2">80%</td><td rowspan="2">80%</td></tr>
<tr><td>Integrated Gasification Combined Cycle (IGCC), CO_2 Capture</td><td>50%</td><td>50%</td><td>40%</td></tr>
<tr><td>CO_2 Storage</td><td>25%</td><td>25%</td><td>20%</td><td>20%</td><td>20%</td></tr>
</table>

By any measure, these estimated RD&D investments are substantial. EPRI and the members of the *CoalFleet for Tomorrow®* program, by promoting collaborative ventures among industry stakeholders and governments, believe that the costs of developing critical-path technologies for advanced coal and CCS can be shouldered by multiple participants. EPRI believes that government policy and incentives will also play a key role in fostering CCS technologies through early RD&D stages to achieve widespread, economically feasible deployment capable of achieving major reductions in U.S. CO_2 emissions.

APPENDIX B

COMMENTS ON REVISED FUTUREGEN

Bryan Hannegan, Vice President, Environment and Generation
The Electric Power Research Institute (EPRI)
3420 Hillview Avenue
Palo Alto , California 94303
650-855-2858

The Electric Power Research Institute, Inc., a tax exempt, non-profit, 501(c)(3) collaborative research and development organization with principal locations in Palo Alto, California, Charlotte, North Carolina, and Knoxville, Tennessee ("EPRI") appreciates the opportunity to provide input and comments on the Department of Energy's plan to restructure FutureGen.

EPRI's comments address the following:

- Clarifying questions on the restructured FutureGen plan.
- Design changes and cost estimates for the addition of CO_2 Capture and Storage (CCS) to a single train of a two-train Integrated Gasification Combined Cycle (IGCC) plant not previously designed for CCS.
- Accelerating Research Development and Demonstration (RD&D) on Advanced Coal Technologies with CO_2 Capture and Storage—Investment and Time Requirements.
- Comments on whether the revised FutureGen approach should allow for advanced coal technology systems, other than IGCC, which also would meet the performance requirements.

Clarifying Questions on the DOE RFI

According to the RFI, DOE will contribute not more than the incremental cost associated with CCS technology for the single power train.

The additional costs for adding CCS to an IGCC plant include:

- Capital costs to cover the process modifications necessary for 90% CO_2 capture
- Operations and maintenance (O&M) costs for the additional units
- Lost revenue from power sales due to the additional auxiliary power use for capture and CO_2 compression
- Capital costs for CO_2 pipeline and CO_2 injection for sequestration
- Possible capital and O&M if pipeline length requires recompression
- O&M costs for pipeline transportation, sequestration and monitoring.

Clarifying Questions:

1. Is it the intent of DOE to cover a) the extra capital costs b) the extra O&M costs c) the lost power cost d) the pipeline, monitoring and sequestration costs (including pipeline compression power costs)?
2. Over what period of operation (how many years) will DOE cover the CCS costs?
3. Some IGCC projects are under consideration for the co-production of other chemicals or fuels (Synthetic Natural Gas, Methanol, Coal to Liquids, etc – often referred to as polygeneration). Will DOE consider the support of CCS at such polygeneration projects under this restructured initiative?

Design Changes for the Addition of CCS to a single train of a two-train IGCC plant not previously designed for CCS.

IGCC Design changes for 90% CO_2 Capture. The main changes in design for capture are the addition of shift reactors and a CO_2 removal process.

The shift reaction $CO + H_2O = CO_2 + H_2$ is exothermic. This results in a reduction in the chemical energy in the syngas so that it now is insufficient to fully load the gas turbine. Additional coal would need to be processed to provide enough syngas to fully load the gas turbine. The percentage increase will depend on the gasification process. Dry coal-fed processes will require a somewhat greater increase than slurry-fed processes because the CO content of the syngas is higher. (The estimated increased coal feed in the referenced papers are in the range 2-9%). The following changes would be required if the plant is to be able to fully load the gas turbine:

- More coal handling and feed system capacity
- A larger Air Separation Unit (ASU) to provide the additional oxygen (perhaps an additional Main Air Compressor (MAC)) See Note 1.
- A larger gasifier to handle more coal and oxygen
- Larger gas cleanup and piping to handle the increased syngas flow

An alternative is to accept the lower output from the originally sized plant. This would mean an additional loss of net power of approximately the same 2-9%, depending on the technology.

The addition of the shift reactor increases the volume of the dry gas flow to the Acid Gas Removal (AGR) H_2S removal system by 40-60%, depending on the gasification process. If the original design used a physical solvent (e.g. Selexol) for H_2S removal, then either a new parallel absorber column will be needed to accommodate the additional flow of syngas from the shift reactors or a completely new absorber designed for the full flow must be added. In all cases a new CO_2 absorber/stripper system must be added.

The addition of 90% capture to a train will require the following changes:

- Replacement of COS/HCN hydrolysis reactor with 2 stages of sour shift reaction
- Additions to syngas cooling train for the shift reactors
- Additions to, or replacements of, the AGR used for H_2S removal to accommodate the increased dry syngas flow
- Addition of a new absorber/stripper system to recover CO_2 as a separate by-product
- Upgrade of the demineralizer water treatment and storage system
- Addition of intermediate pressure steam for water-gas shift reaction (in some cases)
- Modifications to the gas turbine combustion system to accommodate the combustion of hydrogen-rich gas, possibly including more addition of diluent nitrogen or moisture (steam)
- Heat Recovery Steam Generator Low Pressure superheater modifications
- Addition of CO_2 drying and compression to 2000 psig (138 barg).
- Possible adjustments to the CO_2 composition (e.g. H_2S content) depending on the pipeline quality requirements.

Note 1. For many of the designs without capture, ~30-40% of the air supply for the ASU is extracted from the gas turbine compressor. If the turbine supplier indicates no air can be extracted when firing hydrogen in the gas turbine, another air compressor would be needed to fully supply the ASU when capture is added.

Additional Costs for adding CCS to IGCC. The additional costs for adding CCS to an IGCC plant include:

- Capital costs to cover the process modifications listed above necessary for 90% CO_2 capture
- Operations and maintenance (O&M) costs for the additional listed units
- Lost revenue from power sales due to the additional auxiliary power usage for capture and CO_2 compression
- Capital costs for CO_2 pipeline and CO_2 injection for sequestration
- Possible capital and O&M if pipeline length requires recompression
- O&M costs for pipeline transportation, sequestration and monitoring

References: The following publicly available references can be used to obtain more information describing the processes and design changes involved in the addition of CCS to IGCC designs and estimates of the additional costs:

DOE/NETL- 2007/1281 "Cost and Performance Baseline for Fossil Energy Plants" Revision 1, August 2007.

"Preliminary Economics of SCPC & IGCC with CO_2 Capture & Storage." N. Holt (EPRI) presented at the 2nd IGCC & XtL Conference, Freiberg, Saxony, Germany May 9 -10, 2007.

"Phased Construction of IGCC Plants for CO_2 Capture- Effect of Pre-Investment" December 2003. EPRI Report # 1004537. Available from EPRI public domain website and DOE/NETL Fossil Energy website.

"Potential for Improvement in Gasification Combined Cycle Power Generation with CO_2 Capture" by Foster Wheeler for the IEA GHG program April 2003. Available from the IEA GHG website.

<u>Cost estimates for the Addition of CCS to a single train of a two-train IGCC plant</u>

Duke Energy's Edwardsport IGCC Plant will be about 750 MW *gross* or 375 *gross* MW/train. 90% capture on one train yields approximately1.6 million tons per year CO_2 for sequestration and reduces *net* MW output by about 40 MW from 630 to 590 MW.

The extra capital for capture on one train is an estimated $80-100 million but may be more if it is a retrofit.

Extra O&M is estimated at approximately $1.5/MWh or $6.3 million/year. For 10 years the additional O&M would be an estimated $63 million.

Replacing the 40 MW lost power at $65/MWh equals $18.2 million per year. For 10 years the power replacement cost would be $182 million.

Pipeline costs obviously depend on location. If 100 miles of pipeline are required to get the CO_2 to the storage site, at a cost of $1 million/mile the pipeline cost would be $100 million. Actual pipeline costs will vary with terrain, throughput, etc.

Both DOE NETL and EPRI have estimated the incremental cost of adding CCS to an IGCC plant at about 30 $/MWh. These estimates are based on 20- and 30-year plant lives, respectively. If the capital is to be paid off in a shorter time, these estimates will rise. The Department of Energy is interested in funding multiple demonstrations of CCS technology at a commercial scale of at least 300 gross MW per unit plant power train. 300 MW at $30/MWh at 80% CF for 10 years results in a cost of $630 million. If it is the intent to pay for one project for its life of 20 years, the cost would be $1.26 billion and DOE's $1.3 billion would fund only one project. Therefore, the intended funding period for DOE support is a key consideration.

Accelerating RD&D on Advanced Coal Technologies with CO_2 Capture and Storage

Through the development and deployment of advanced coal plants with integrated CO_2 capture and storage (CCS) technologies, coal power can become part of the solution to satisfying both our energy needs and our global climate change concerns. However, a sustained RD&D program at heightened levels of investment and the resolution of legal and regulatory unknowns for long-term geologic CO_2 storage will be required to achieve the promise of advanced coal with CCS technologies. Through research obtained in EPRI's *CoalFleet for Tomorrow®* program—a research collaborative comprising more than 60 organizations from five continents representing U.S. utilities, international power generators, equipment suppliers, government research organizations, coal and oil companies, and a railroad—EPRI sees crucial roles for both industry and governments worldwide in aggressively pursuing collaborative RD&D over the next 20-plus years to create a full portfolio of commercially self-sustaining, competitive advanced coal power generation and CCS technologies.

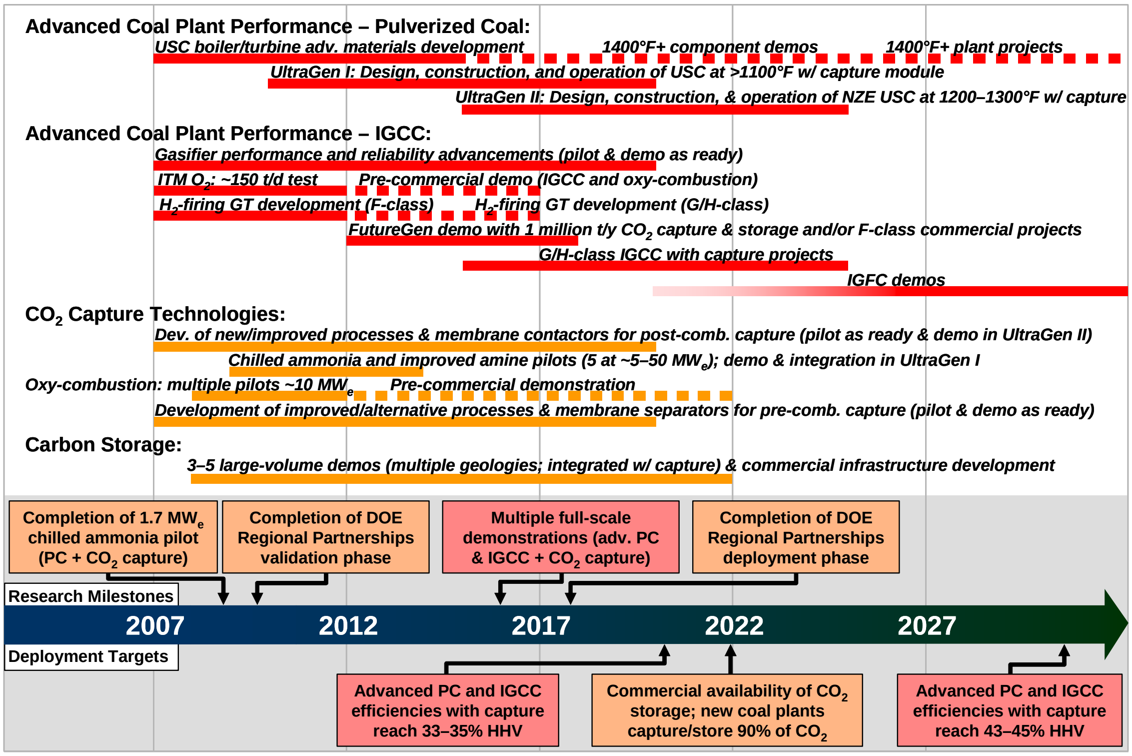
The portfolio aspect of advanced coal with integrated CCS technologies must be emphasized because no single advanced coal technology (or any generating technology) has clear-cut economic advantages across the range of U.S. applications. The best strategy for meeting future electricity needs while addressing climate change concerns and minimizing economic disruption lies in developing a *full portfolio* of technologies from which power producers (and their regulators) can choose the option best suited to local conditions and preferences, and provide power at the lowest cost to the customer. Toward this end, four major technology efforts related to CO_2 emissions reduction from coal-based power systems must be undertaken:

5. Increased efficiency and reliability of integrated gasification combined cycle (IGCC) power plants
6. Increased thermodynamic efficiency of pulverized-coal (PC) power plants
7. Improved technologies for capture of CO_2 from coal combustion- and gasification-based power plants
8. Reliable, acceptable technologies for long-term storage of captured CO_2.

Identification of mechanisms to share RD&D financial and technical risks and to address legal and regulatory uncertainties must take place as well.

In short, a comprehensive recognition of all the factors needed to hasten deployment of competitive, commercial advanced coal and integrated CO_2 capture and storage technologies—and implementation of realistic, pragmatic plans to overcome barriers—is the key to supplying affordable, environmentally responsible energy in a carbon-constrained world.

Figure 1 is an illustration from EPRI's report entitled, "The Power to Reduce CO_2 Emissions – the Full Portfolio"(available at www.epri.com), which depicts the major activities in each of the four technology areas which must take place to achieve a robust set of integral advanced coal/CCS solutions. Important but not shown in the figure are the interactions between RD&D activities. For example, the ion transport membrane (ITM) oxygen supply technology shown under IGCC also can be applied to oxy-combustion PC units. Further, while the individual goals related to efficiency, CO_2 capture, and CO_2 storage present major challenges, significant challenges also arise from complex interactions that occur when CO_2 capture processes are integrated with gasification- and combustion-based power plant processes.



Source: "The Power to Reduce CO2 Emissions – the Full Portfolio," http://epri-reports.org/DiscussionPaper2007.pdf

Figure 1 – Timing of advanced coal power system and CO_2 capture and storage RD&D activities and milestones

<u>RD&D Investment for Advanced Coal and CCS Technologies</u>

Developing the suite of technologies needed to achieve competitive advanced coal and CCS technologies will require a sustained major investment in RD&D. As shown in Table 1, EPRI estimates an expenditure of approximately $8 billion will be required in the 10-year period from 2008–17. The MIT *Future of Coal* report estimates the funding need at up to $800–850 million per year, which approaches the EPRI value. Further, EPRI expects that an RD&D investment of roughly $17 Billion will be required over the next 25 years.

Investment in earlier years may be weighted toward IGCC, as this technology is less developed and will require more RD&D investment to reach the desired level of commercial viability. As interim progress and future needs cannot be adequately forecast at this time, the years after 2023 do not distinguish between IGCC and PC.

Table 1 – RD&D Funding Needs for Advanced Coal Power Generation Technologies with CO_2 Capture

<table>
<tr><th></th><th>2008–12</th><th>2013–17</th><th>2018–22</th><th>2023–27</th><th>2028–32</th></tr>
<tr><td>Total Estimated RD&D Funding Needs
(Public + Private Sectors)</td><td>$830M/yr</td><td>$800M/yr</td><td>$800M/yr</td><td>$620M/yr</td><td>$400M/yr</td></tr>
<tr><td>*Advanced Combustion, CO_2 Capture*</td><td>25%</td><td>25%</td><td>40%</td><td rowspan="2">80%</td><td rowspan="2">80%</td></tr>
<tr><td>*Integrated Gasification Combined Cycle (IGCC), CO_2 Capture*</td><td>50%</td><td>50%</td><td>40%</td></tr>
<tr><td>*CO_2 Storage*</td><td>25%</td><td>25%</td><td>20%</td><td>20%</td><td>20%</td></tr>
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By any measure, these estimated RD&D investments are substantial. EPRI believes that by promoting collaborative ventures among industry stakeholders and governments, the costs of developing critical-path technologies for advanced coal and CCS can be shouldered by multiple participants. EPRI also believes government policy and incentives also will play a key role in fostering CCS technologies through early RD&D stages to achieve widespread, economically feasible deployment capable of achieving major reductions in U.S. CO_2 emissions.

Comments on whether the revised FutureGen approach should allow for advanced coal technology systems, other than IGCC, which also would meet the performance requirements

As stated previously, the portfolio aspect of advanced coal with integrated CCS technologies must be emphasized because no single advanced coal technology (or any generating technology) has clear-cut economic advantages across the range of U.S. applications. EPRI and industry representatives have proposed a program to support commercial projects which demonstrate advanced PC and CCS technologies. The vision entails construction of two (or more) commercially operated USC PC power plants which combine state-of-the-art pollution controls, ultra-supercritical steam power cycles, and innovative CO_2 capture technologies. The projects described below would meet the restructured FutureGen performance requirements:

UltraGen UltraSupercritical (USC) Pulverized Coal (PC) Commercial Projects.
The UltraGen I plant will use the best of today's proven ferritic steels in high-temperature boiler and steam turbine components, while UltraGen II will be the first plant in the United States to feature nickel-based alloys able to withstand the higher temperatures of advanced ultra-supercritical steam conditions.

UltraGen I will demonstrate CO_2 capture modules which separate about 1 million tons CO_2/yr using the best established technology. This system will be about 6 times the size of the largest CO_2 capture system operating today (and that unit does not process flue gas from a coal-fired boiler). UltraGen II will treble the size of the UltraGen I CO_2

capture system, and may demonstrate a new class of chemical solvent if one of the emerging low-regeneration-energy processes has reached a sufficient stage of development. Equally, provided the technology is available, UltraGen II could be an oxy-combustion boiler. Both plants will demonstrate ultra-low emissions and will utilize control technologies identified by the DOE emission control programs. Both UltraGen demonstration plants will dry and compress the captured CO_2 for long-term geologic storage and/or use in enhanced oil or gas recovery operations.

Figure 2 depicts the proposed key features of UltraGen I and II.

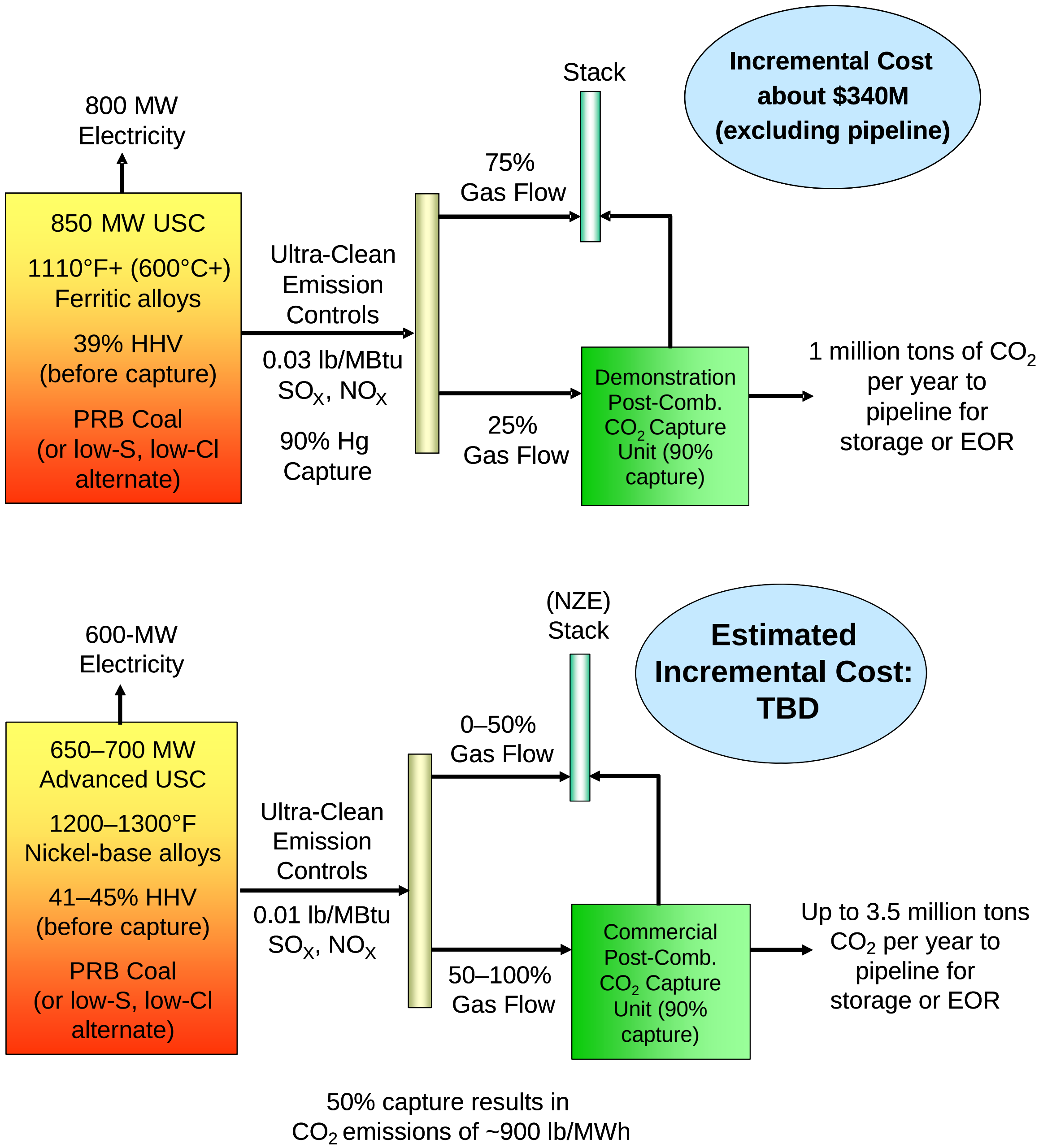

Figure 2 – Key parameters for UltraGen I (upper schematic) and UltraGen II (lower schematic), assuming a subbituminous feed coal such as Powder River Basin

The final project in the series is UltraGen III, which will operate with main steam temperatures up to 1400°F and, with boiler system design improvements, has the potential to achieve generating efficiencies of up to 50 percent. This project will use materials qualified in the DOE's current boiler and steam turbine materials program. The UltraGen Initiative identifies the need for a test facility, ComTes-1400, to test materials and components in support of UltraGen III. Such a test facility is proposed within the DOE materials program and EPRI encourages its implementation.

To provide a platform for testing and developing emerging PC and CCS technologies, the UltraGen program will allow for technology trials at existing sites as well as at the sites of new projects. Like the plan for the restructured FutureGen, EPRI expects the UltraGen projects will be commercially dispatched by electricity grid operators. The differential cost to the host company for demonstrating these improved features are envisioned to be offset by any available DOE demonstration funds, tax credits (or other incentives) and by funds raised through an industry-led consortium formed by EPRI.

The UltraGen projects represent the type of "giant step" collaborative efforts that need to be taken to advance integrated PC/CCS technology to the next phase of evolution and assure competitiveness in a carbon-constrained world. Because of the time and expense for each "design and build" iteration for coal power plants (3 to 5 years, not counting the permitting process, and ~$2 billion), there is no room for hesitation in terms of commitment to advanced technology validation and demonstration projects.

The UltraGen projects will resolve technical and economic barriers to the deployment of USC PC and CCS technology by providing a shared-risk vehicle for testing and validating high-temperature materials, components, and designs in plants also providing superior environmental performance.