Analysis Of Options For Funding Large Pilot Scale Testing Of Advanced Fossil-Based Power Generation Technologies With Carbon Capture And Storage

Pilot and Demonstration-Scale Projects -- Lessons Learned Potential for Public and Private Sector Partnering and Barriers and Opportunities for Multi-National Cooperative Projects

March 21, 2016
Funding and support for this report:

This study comprises four primary sections labeled as Tasks One – Four. Task One is an overview of the study and also provides several conclusions based upon the information provided in the other three Tasks. Task Two was prepared by Howard Herzog, Task Three was authored by L.D. Carter and Task Four by Thomas J. Russial. This study was prepared under contract with the New Energy and Industrial Technology Development Organization (NEDO). Overall supervision of the study was the responsibility of the Coal Utilization Research Council (CURC). The CURC gratefully acknowledges the support and contribution of the staff of NEDO and in particular the leadership of Mr. Hiroyuki Hatada, Chief Representative of NEDO’s Washington D.C. office. The CURC also expresses gratitude for the many contributions made by Howard Herzog, Doug Carter and Tom Russial, the authors of the three reports that are the corpus of this study, for their willingness to share their expertise and overall guidance to the development and execution of this study.

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Table of Contents

1  Task 1 ............................................................................................................................... 1
   1.1 Background and Rationale for the Study ................................................................. 2
   1.2 Primary Findings of the Study ............................................................................... 3
   1.3 Conclusions and a Possible Pathway Forward ...................................................... 4
2  Task 2 ............................................................................................................................... 2-1
   2.1 Overview ............................................................................................................... 2-2
   2.2 Background ........................................................................................................... 2-3
   2.3 Review of CCS Demonstration Programs ............................................................. 2-7
   2.4 Analysis of Selected CCS Projects ...................................................................... 2-22
   2.5 Lessons Learned .................................................................................................... 2-37
   2.6 References ............................................................................................................ 2-43
3  Task 3 ............................................................................................................................... 3-1
   3.1 Introduction ............................................................................................................ 3-3
   3.2 Progressive steps in technology development ...................................................... 3-5
   3.3 Economic and regulatory risks and rewards for new technology ....................... 3-8
   3.4 Perspectives from the private sector .................................................................. 3-11
   3.5 Stakeholder Survey .............................................................................................. 3-19
   3.6 Types of financial incentives .............................................................................. 3-21
   3.7 Conclusions .......................................................................................................... 3-23
   3.8 Attachment 1 – Selected information from IRPs ................................................. 3-25
4  Task 4 ............................................................................................................................... 4-3
   4.1 Task 4 Methodology ............................................................................................. 4-6
   4.2 Options for Multinational Collaboration .............................................................. 4-8
   4.3 Comparative Summary Of Country Information .................................................. 4-10
   4.4 Potential Issues, Lessons Learned, and Knowledge Gaps .................................... 4-28
   4.5 Next Steps ............................................................................................................ 4-31
Overview and Conclusions of the Study

Task 1

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Coal Utilization Research Council (CURC)
1 Overview of the Study

The Coal Utilization Research Council (CURC)\(^1\) wishes to thank the New Energy and Industrial Technology Development Organization (NEDO)\(^2\) for their financial support as well as the guidance and knowledge they provided during the conduct of this study. Our gratitude is given also to the U.S. Department of Energy for support given during the initial organizational planning for the study.

This study is segregated into four tasks which include:

Task One: The Overview of the Study

- briefly describing the purpose of the study and general findings and conclusions

Task Two: Lessons Learned from CCS Demonstration and Large Pilot Projects

- a review and analysis of significant projects undertaken, or abandoned, worldwide in order to generate a set of “lessons learned” which can be considered in the future to better insure successful technology initiatives

Task Three: Factors Impacting Private Sector Investment in Large Pilot CCS Projects

- in addition to the technology risks involved in the development of CCS at the pilot plant stage, the author reviews and analyzes the very significant economic risks associated with CCS technologies and the inadequacy of current economic and regulatory incentives that might encourage development at the pilot scale level

Task Four: Options for Funding Large Pilot Scale Testing of Advanced Fossil-Based Power Generation Technologies with Carbon Capture and Storage

- in order to develop a knowledge base that could be used to evaluate opportunities for multinational collaboration as a means to fund large pilot projects the author examines country-specific information about large pilot plant interest, legal and regulatory conditions, and financial incentives for technology development in Canada, Japan, the

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\(^1\) The Coal Utilization Research Council (CURC) is an organization of coal-using utilities, coal producers, equipment suppliers, universities, and several state government entities interested and involved in the use of coal resources and the development of coal-based technologies (see [www.coal.org](http://www.coal.org)).

\(^2\) About NEDO: Japan’s New Energy and Industrial Development Organization (NEDO) actively undertakes the development of new energy and energy conservation technologies, verification of technical results, and introduction and dissemination of new technologies (e.g., support for introduction). Through these efforts, NEDO promotes greater utilization of new energy and improved energy conservation. With the aim of raising the level of industrial technology, NEDO pursues research and development of advanced new technology. It also supports research related to practical application. Special thanks to Hiroyuki Hatada, Chief Representative, of NEDO’s Office in Washington DC whose interest and support of this study has been key to participation by NEDO.
Republic of Korea, and the United States with the goal of compiling an initial “baseline” of understanding from which a subsequent assessment (that is, a follow-on study) can then be undertaken to consider mechanisms or models that might be used by multiple countries to support common projects.  

1.1 Background and Rationale for the Study

Many national governments have found that development and wide-scale deployment of carbon capture and storage (CCS) technology for fossil-based power generation is necessary to meet world-wide climate objectives. It is also widely believed that the cost of fossil-based power integrated with CCS must be reduced and the technology proven cost-effective at scale to be deployable world-wide. Technology improvements will derive from a combined program of laboratory-scale research and development (R&D), “proof of concept” at a large pilot plant scale (e.g., 10 – 50 MWe), and commercial-scale (200 MWe and larger) demonstration projects. Large pilot-scale projects are a critical step in this technology progression. This is so because commercial-scale versions of these technologies entail prohibitive risk and cost in the absence of successful pilot scale projects.

Despite best intentions, nations collectively have not found a formula to advance beyond R&D activities and to bring the necessary number of large scale CCS pilot and demonstration projects to completion. Accordingly, only a small and insufficient number of large-scale power projects with CCS have advanced. Many projects have stalled or failed for lack of financial support or consistent government policies designed to encourage technology development and demonstration.

On November 18-19, 2014, the Coal Utilization Research Council, (CURC) with support from the United States Department of Energy (DOE) and energy sector companies, convened a workshop to consider industry viewpoints on what is needed to foster advanced coal technologies with CCS at large pilot scale in the U.S. A significant finding from the workshop was that the private sector may be willing to participate in the development of pilot scale projects but that the current uncertain market for CCS does not justify such participation without very significant public support.

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3 Special thanks to New Energy and Industrial Technology Development Organization of Japan (NEDO), Natural Resources Canada (NRCan) and the Korea Institute of Energy Research (KIER) for their participation in the development of information provided in part 4 of this study.

4 The authors of Tasks Two – Four are:

Task Two: Howard Herzog, Senior Research Engineer, Massachusetts Institute of Technology Energy Initiative
Task Three: L.D. Carter, Independent Contractor, formerly Director, Office of Planning and Environmental Analysis, Office of Fossil Energy, U.S. DOE.
Task Four: Tom Russial has been involved with fossil energy and CCS programs for 30 years as a staff attorney and later Chief Counsel at the U.S. Department of Energy’s National Energy Technology Laboratory and more recently in the private sector.

Each of the tasks two – four was drafted by the named author and the information and any conclusions made in the document are solely to be attributed to the author and are not the opinions or conclusions of NEDO, the U.S. DOE or CURC.
Since completion of the November 2014 workshop, it can be argued there is even greater urgency in determining how to initiate the planning, construction, operation and global information sharing needed to undertake large-scale projects equipped with advanced clean coal or other fossil-based power generation technologies that incorporate CO₂ capture and sequestration. This urgency is driven by a number of factors including, but not limited to --

- In December 2015, 195 Nations met in Paris, France at the twenty first session of the Conference of the Parties (COP21) and agreed to non-binding greenhouse gas reductions globally. Notably, Article 2 of the agreement states that the Parties to the agreement will respond to the threat of climate change by: “Holding the increase in the global average temperature to well below 2 °C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5°C....”³ It is widely accepted that broad deployment of CCS is required to meet this climate objective; otherwise the financial costs are exponentially greater to attain the goal and, realistically without CCS the temperature goals are likely not achievable.

- Coal demand continues to increase worldwide growing in production from 3 billion tonnes in 1971 to almost 8 billion tonnes in 2014⁶

1.2 **Primary Findings of the Study**

Readers are encouraged to review the content and conclusions of the three papers following this “overview”. Briefly, the principal conclusions made in these papers are the following:

Task 2: A review of major CO₂-related capture projects worldwide reveals that almost all the successful projects had ties to the oil and gas industry, either as a source of the CO₂ or through the use of the CO₂ for Enhanced Oil Recovery (EOR). To date, there are only three projects operating or under construction at coal-fired power plants. As a result, there has been limited success in driving down the cost of coal with CCS (or other fossil fuel with CCS). Another finding is that diminished international financial support for the development of CCS-related technologies is occurring. This latter conclusion is evidenced most clearly by the abandoned coal-focused CCS initiatives by the European Union and the United Kingdom.

Task 3: Examination of the weak financial position of key U.S. private sector stakeholders (i.e. coal producers) and limited market expectations for U.S. coal use over the next several decades will substantially reduce the chance for promising technologies to advance to large pilot and demonstration testing and commercial deployment. Other issues confronting CCS technology development in the U.S. include:

- The cost and abundance of natural gas supplies largely derived from shale gas, causing power generators to rapidly transition to natural gas fueled electricity generation;


• Clean Air Act regulations, including regulations to control the emissions of CO₂, that have contributed to substantial uncertainty regarding future regulation or government policy related to coal-based emissions; and
• The lack of demand in the U.S. for new coal-fueled power plants and uncertainties associated with CCS have dampened enthusiasm among major technology providers and equipment suppliers for pursuing and developing CCS technology.

Task 4: Legal and regulatory barriers to international collaboration on CCS projects are formidable. Further, it does not appear that sufficient public support will be forthcoming from any one country to meet the need for aggressive and accelerated planning and construction of needed pilot projects. Given current circumstances the combined financial resources of multiple countries are required. Governments have collaborated in the past to support large scale pilots although the history of collaboration on large fossil projects is limited. Successful collaboration is not simple. Technology interests, timelines, and budgetary resources must align; legal, regulatory and contractual constraints must be analyzed and addressed; and complex government and private sector relationships must be reduced to agreement. Opportunities exist for collaborative large fossil pilots but additional analysis and knowledge sharing by public and private sector stakeholders is required to refine the concept and develop effective approaches.

1.3 Conclusions and a Possible Pathway Forward

Without the successful development and widespread use of CCS globally, and given the world’s continued reliance upon coal for affordable energy, the chance for containing global temperature rise is doubtful. Better fossil-based power technologies and CCS technologies at reduced costs will be a key factor in meeting climate change goals. This requires the construction and operation of large scale pilots and follow-on demonstration plants to prove the technologies at near commercial scale prior to widespread commercial deployment. Pursuit of the status quo will not get the world to the commercialization of these technologies in time to realize the goals of COP21.

Much can be learned from efforts around the world during the last two decades to encourage CCS technology development. (See: the “lessons learned” section of H. Herzog’s Task Two paper). In light of the limited success of previous attempts, and the current gravity and urgency of the situation, it seems abundantly clear that much more public sector support is needed. Consideration must be given to bolder, faster and more concerted approaches to ready the technologies for commercial deployment and international collaboration may be a way of accelerating technology development and subsequent deployment.

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7 Even if it is possible to address temperature increases without CCS, as some have argued, the costs would be enormous. For example, the Fifth Assessment Report by the Intergovernmental Panel on Climate Change found that many of the models used in that assessment could not reach a 450ppm CO₂-eq goal without CCS, and for the four that could, mitigation costs increased by an average of 138% compared to model projections that included CCS technology as an emission reduction option. (Source: Working Group III Summary for Policy Makers – 5th Assessment Report, Table SPM.2, United Nations Intergovernmental Panel on Climate Change, 2014.)
Any option that can facilitate and streamline multinational collaboration should be evaluated including, for example, the establishment of an independent, multi-country funded, multinational organization whose primary mission is to accelerate technology development through financial support of large scale pre-commercial plants.
Lessons Learned from CCS Demonstration and Large Pilot Projects

Task 2 Report

Prepared by:
Howard Herzog

Disclaimer: This report contains significant information about dozens of CCS pilot and demonstration projects worldwide. Every effort was made to be as accurate as possible. However, many of these projects are in a state of flux and the references used are quite varied. Therefore, some of the project details may have changed or be in error. However, any such problems will not change the analyses or findings in this report.
2 Executive Summary

This task is part of a project focused upon identifying and understanding the legal, regulatory and financial issues, opportunities and impediments across the globe related to the planning, construction and operation of projects with carbon capture and use/storage of CO$_2$ (CCS). The objective of this task is to identify and assess, primarily from a financing perspective, fossil fuel projects worldwide capable of capturing and using or storing carbon dioxide that have been or are being pursued. To accomplish this goal, programs set up by governments with the objective of promoting CCS demonstration projects were analyzed, as well as selected CCS demonstration and pilot projects. The outcome of this assessment is the following list of lessons learned:

1. There are strong links between the successful CCS demonstration projects and the oil & gas industry.
2. Access to markets has to move beyond EOR.
3. Regulatory drivers are critical to creating markets for CCS.
4. Business drivers play a major role.
5. Over reliance on government subsidies is a risky business.
6. Successful CCS power projects used multiple financing components.
7. Innovative CCS power projects (e.g., poly-generation) are interesting, but may be hard to replicate.
8. Gasification-based power projects have a poor record.
9. Setting arbitrary time limits on projects generally has led to failure.
10. CCS projects that have shorter timelines have greater chances of success.
11. Stronger political support is needed for CCS.
12. All major CCS demonstration projects require a public outreach program.
2.1 Overview

This task is part of a project focused upon identifying and understanding the legal, regulatory and financial issues, opportunities and impediments across the globe related to the planning, construction and operation of projects with carbon capture and use/storage of CO₂ (CCS). The objective of this task is to identify and assess fossil fuel projects worldwide capable of capturing and using or storing carbon dioxide that have been or are being pursued. The focus of this assessment is large scale demonstrations (>1 million tons CO₂/year). However, Section 2.4.3 examines large pilot projects (>10MWe or equivalent). The assessment includes not only projects that have been successful, but also projects that have been abandoned and why (i.e. lessons learned). Note that the task’s objective is not to include every CCS project ever announced, but to include enough projects to generate a set of lessons learned concerning project financing, as well as legal and regulatory issues.

Section 2.2 of this task report presents background material on two key topics: (1) options for financing CCS projects and (2) the current status of CCS demonstration projects. Section 2.3 reviews major CCS demonstration programs worldwide. These are programs set up by governments with the objective of promoting CCS demonstration projects. Section 2.4 analyzes selected CCS projects primarily from a financing perspective. Projects are also presented where other issues (e.g., regulatory, public acceptance) were important. Finally, Section 2.5 synthesizes the information in Sections 2.2-2.4 in order to summarize the lessons learned and to draw conclusions.
2.2 Background

2.2.1 Financing Demonstration Projects
While project financing can be very complex, its purpose is very simple – project financing must pay for the project. In this report, we focus on the income streams that must cover both the capital and operating costs of the project. For commercial technology, markets are generally the sole source of income. With emerging technologies like CCS, markets are usually insufficient, so they must be supplemented with what can be referred to as “technology push” programs. These programs can create revenue streams to partially aid in the financing. Beyond the revenue streams provided by markets and technology push programs, there are other drivers that affect a project’s economic viability. As will be seen in Section 2.4, two important drivers for CCS projects are what we term as business drivers and regulatory drivers. Below is a list that summarizes the main components that have been used to help finance CCS projects.

- Market Pull
  - Carbon markets
  - Electricity markets
  - Enhanced Oil Recovery (EOR)
  - Others (e.g., poly-generation)

- Technology Push
  - Direct subsidies
  - Tax credits (e.g., investment, production)
  - Loan guarantees
  - Mandates (e.g., portfolio standards)
  - Others (e.g., feed-in tariffs, contracts-for-differences)

- Other Drivers
  - Regulatory
  - Business

In this report, the term “access to electricity markets” is used. While projects will have no trouble selling their electricity at market prices, “access to electricity markets” in this report means getting special compensation from these markets. To gain this access usually requires that special permission is obtained from electricity regulators or that a special law or regulation is in effect.

2.2.2 Status of CCS Demonstration Projects
The Global CCS Institute has presented annual lists of CCS projects in various stages of development, going from announced projects (“identify”) all the way to completed projects (“operate”). Note that within the CCS community there are different definitions of what is or is not a “CCS demonstration project”. This report neither endorses nor rejects the GCCSI definitions. We use their lists for two reasons: (1) they represent a consistent time series (used in Table 2-1) and (2) they contain the most inclusive list of projects in operation or under construction (used in Tables 2-2 through 2-4).
One can look at these lists as a project pipeline, as presented in Table 2-1. While the number of completed projects has risen over the past 3 years, the number of projects in the pipeline has significantly decreased. As will be documented later in this report, this is primarily due to the difficulty in financing these projects.

Table 2-1. CCS Project Pipeline as reported by the GCCSI (2013, 2014, 2015)

<table>
<thead>
<tr>
<th>Project Stage</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operate</td>
<td>12</td>
<td>13</td>
<td>15</td>
</tr>
<tr>
<td>Execute</td>
<td>8</td>
<td>9</td>
<td>7</td>
</tr>
<tr>
<td>Define</td>
<td>16</td>
<td>14</td>
<td>11</td>
</tr>
<tr>
<td>Evaluate</td>
<td>21</td>
<td>13</td>
<td>9</td>
</tr>
<tr>
<td>Identify</td>
<td>8</td>
<td>6</td>
<td>3</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>65</strong></td>
<td><strong>55</strong></td>
<td><strong>45</strong></td>
</tr>
</tbody>
</table>

In 2015, there were 22 projects in the operate (i.e., completed projects) and execute (i.e., projects under construction) categories. These are the projects that have successfully obtained project financing and can be classified into three categories: (1) Commercial EOR projects, (2) Pioneer CCS Projects, and (3) CCS RD&D Projects. Each of these categories are discussed below.

2.2.2.1 Commercial EOR Projects.

Nine of the 22 projects can be classified as commercial EOR projects (see Table 2-1). All nine of these projects are currently operating. What sets these EOR projects off from the other hundred or so commercial EOR projects currently active is that they use anthropogenic CO₂ (vs. CO₂ from natural wells). The financing of these projects is relatively straightforward. The CO₂ source produces a high purity stream of CO₂, so the incremental costs associated with using the CO₂ for EOR (vs. just venting the CO₂) are just compression costs and transport costs. The price that the EOR operators are willing to pay for the CO₂ will cover these costs. In summary, the projects in Table 2-2 all relied on EOR markets for their financing.

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8 The project stages have been defined from the GCCSI and are used here. One can roughly translate as follows: Operate (Completed); Execute (Under Construction); Define (Late Project Development); Evaluate (Early Project development); Identify (Announced Project).

9 There is debate whether these commercial EOR projects should be viewed as CCS demonstration projects. The reason is that they are basically commercial projects that use off the shelf technology that lends little to advancing CCS knowledge. There are some exceptions in the list, most notably Weyburn which had an extensive scientific program studying the measurement, monitoring, and verification of CCS in the subsurface.
Table 2-2. Commercial EOR Projects using Anthropogenic CO₂ (GCCSI, 2015; MIT, 2016)

<table>
<thead>
<tr>
<th>Project</th>
<th>Location</th>
<th>Capacity (Mt/yr)</th>
<th>CO₂ Source</th>
<th>Year of Operation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enid</td>
<td>Oklahoma</td>
<td>0.7</td>
<td>Fertilizer</td>
<td>1982</td>
</tr>
<tr>
<td>Shute Creek</td>
<td>Wyoming</td>
<td>7.0</td>
<td>NG Processing</td>
<td>1986</td>
</tr>
<tr>
<td>Val Verde</td>
<td>Texas</td>
<td>1.3</td>
<td>NG Processing</td>
<td>1998</td>
</tr>
<tr>
<td>Weyburn</td>
<td>US/Canada</td>
<td>1.0</td>
<td>Coal Gasification</td>
<td>2000</td>
</tr>
<tr>
<td>Century</td>
<td>Texas</td>
<td>8.4</td>
<td>NG Processing</td>
<td>2010</td>
</tr>
<tr>
<td>Coffeyville</td>
<td>Kansas</td>
<td>0.8</td>
<td>Fertilizer</td>
<td>2013</td>
</tr>
<tr>
<td>Lost Cabin</td>
<td>Wyoming</td>
<td>0.9</td>
<td>NG Processing</td>
<td>2013</td>
</tr>
<tr>
<td>Lula</td>
<td>Brazil</td>
<td>0.7</td>
<td>NG Processing</td>
<td>2013</td>
</tr>
<tr>
<td>Uthmaniyah</td>
<td>Saudi Arabia</td>
<td>0.8</td>
<td>NG Processing</td>
<td>2015</td>
</tr>
</tbody>
</table>

2.2.2.2 Pioneer CCS Projects.

Four of the 22 projects can be classified as Pioneer CCS projects (see Table 2-3). These projects all share two traits: (1) they were built with little or no government support and (2) they all start with a high purity CO₂ source that requires only compression and transport. Two projects are currently operating, one (Gorgon) is under construction, and one has stopped injecting (In Salah). It should be noted that although Gorgon has not started up, planning for the project started in the early 1990s.

One trait the four projects share is that the CCS process was a small part of a larger project. Business drivers played a major role in their justification. Section 2.4 provides more details on understanding the motivation behind these projects.

Table 2-3. Pioneer CCS Projects (GCCSI, 2015; MIT, 2016)

<table>
<thead>
<tr>
<th>Project</th>
<th>Location</th>
<th>Capacity (Mt/yr)</th>
<th>CO₂ Source</th>
<th>CO₂ Sink</th>
<th>Year of Operation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sleipner</td>
<td>Norway</td>
<td>0.9</td>
<td>NG Processing</td>
<td>Saline</td>
<td>1996</td>
</tr>
<tr>
<td>In Salah</td>
<td>Algeria</td>
<td>1.2</td>
<td>NG Processing</td>
<td>Depleted Gas</td>
<td>2004 - 2011</td>
</tr>
<tr>
<td>Snohvit</td>
<td>Norway</td>
<td>0.7</td>
<td>NG Processing</td>
<td>Saline</td>
<td>2008</td>
</tr>
<tr>
<td>Gorgon</td>
<td>Australia</td>
<td>4</td>
<td>NG Processing</td>
<td>Saline</td>
<td>2016</td>
</tr>
</tbody>
</table>
2.2.2.3 *CCS RD&D Projects*

The remaining nine projects all relied on governmental financial support. Seven of these projects resulted from specific government programs designed to promote CCS demonstrations. These programs are discussed in Section 2.3.

Table 2-4 describes these nine projects. The first three are operating, while the last six are under construction (year of operation is their projected start date). Three of the projects capture CO$_2$ from coal-fired power plants, with one being operational -- Boundary Dam (SaskPower) started-up in October 2014.

<table>
<thead>
<tr>
<th>Project</th>
<th>Location</th>
<th>Capacity (Mt/yr)</th>
<th>CO$_2$ Source</th>
<th>CO$_2$ Sink</th>
<th>Year of Operation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Air Products</td>
<td>Texas</td>
<td>1.0</td>
<td>CH$_4$ Reformer</td>
<td>EOR</td>
<td>2013</td>
</tr>
<tr>
<td>Boundary Dam</td>
<td>Canada</td>
<td>1.0 (110 MW)</td>
<td>Coal Power</td>
<td>EOR/Saline</td>
<td>2014</td>
</tr>
<tr>
<td>Quest</td>
<td>Canada</td>
<td>1.1</td>
<td>CH$_4$ Reformer</td>
<td>Saline</td>
<td>2015</td>
</tr>
<tr>
<td>Decatur</td>
<td>Illinois</td>
<td>1.0</td>
<td>Ethanol</td>
<td>Saline</td>
<td>2016</td>
</tr>
<tr>
<td>Kemper</td>
<td>Mississippi</td>
<td>3.0 (582 MW)</td>
<td>Coal Power</td>
<td>EOR</td>
<td>2016</td>
</tr>
<tr>
<td>Petra Nova</td>
<td>Texas</td>
<td>1.6 (240 MW)</td>
<td>Coal Power</td>
<td>EOR</td>
<td>2016</td>
</tr>
<tr>
<td>Abu Dhabi</td>
<td>Abu Dhabi</td>
<td>0.8</td>
<td>Steel</td>
<td>EOR</td>
<td>2016</td>
</tr>
<tr>
<td>Alberta Trunk</td>
<td>Canada</td>
<td>0.3-0.6</td>
<td>Fertilizer</td>
<td>EOR</td>
<td>2016-17</td>
</tr>
<tr>
<td>Alberta Trunk</td>
<td>Canada</td>
<td>1.2-1.4</td>
<td>Refinery</td>
<td>EOR</td>
<td>2017</td>
</tr>
</tbody>
</table>
2.3 Review of CCS Demonstration Programs

2.3.1 United States
The United States officially started an R&D program in CCS in 1997 through the Department of Energy’s (DOE) Office of Fossil Energy’s Clean Coal Program. This program grew significantly over the next decade, but has plateaued in recent years. While this budget did help support pilot projects, it was not meant to support demonstration projects.

The mechanism to support demonstration projects is the Clean Coal Power Initiative (CCPI), which provides direct subsidies to demonstration projects. A minimum 50% cost sharing is required by recipients. The way the CCPI works is that funds get allocated to it through annual budgets. Once enough money is collected in the program, a request for proposals can be issued and awards can be made. Requiring funds through the annual appropriations process can be perilous. So while the funding was steady early on, no funds have been allocated to the CCPI since 2009.

There have been three rounds of funding through the CCPI, as follows (NCC, 2015):

- Round 1 (2003) – focused on “advanced coal-based power generation and efficiency, environmental and economic improvements”
- Round 2 (2004) – focused on “focused on gasification, mercury (Hg) control and carbon dioxide (CO₂) sequestration”
- Round 3 (2009) – focused on “CO₂ capture and sequestration/beneficial reuse (CO₂ EOR)”

In 2009, Congressed passed the American Reinvestment and Recovery Act (ARRA), also known as the stimulus bill. Some of the stimulus funds were targeted specifically for CCS demonstration projects as follows:

- The CCPI received $850 million to help fund their Round 3 call. Awards were made to six projects.
- An Industrial CCS program was allocated $1.52 billion, part of which went to fund three industrial CCS demonstrations in 2010.
- The FutureGen project was “reconfigured” as FutureGen 2.0 and allocated $1 billion.

The combination of CCPI and ARRA formed the basis of the CCS demonstration program in the US. The power projects involved are listed in Table 2-5, while the industrial projects can be found in Table 2-6.
Table 2-5. Power CCS Projects Receiving Support from the Clean Coal Power Initiative and/or Stimulus Funding (MIT, 2016)

<table>
<thead>
<tr>
<th>Company</th>
<th>State</th>
<th>DOE Support (million $)</th>
<th>Size</th>
<th>Capture Technology</th>
<th>Fate</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>FutureGen 2.0</td>
<td>IL</td>
<td>1000 (ARRA)</td>
<td>200 MW 1.1 MtCO₂/yr</td>
<td>Oxy</td>
<td>Saline Formation</td>
<td>Cancelled 2015</td>
</tr>
<tr>
<td>Basin Electric (Antelope Valley)</td>
<td>ND</td>
<td>100 (CCPI 3)</td>
<td>120 MW 1 MtCO₂/yr</td>
<td>PCC</td>
<td>EOR</td>
<td>Cancelled 2010</td>
</tr>
<tr>
<td>Hydrogen Energy (HECA)</td>
<td>CA</td>
<td>408 (CCPI 3)</td>
<td>400 MW 2.6 MtCO₂/yr</td>
<td>IGCC</td>
<td>EOR</td>
<td>Cancelled 2016</td>
</tr>
<tr>
<td>AEP (Mountaineer)</td>
<td>WV</td>
<td>334 (CCPI 3)</td>
<td>235 MW 1.5 MtCO₂/yr</td>
<td>PCC</td>
<td>Saline Formation</td>
<td>Cancelled 2011</td>
</tr>
<tr>
<td>Southern (Plant Barry)</td>
<td>AL</td>
<td>295 (CCPI 3)</td>
<td>160 MW 1 MtCO₂/yr</td>
<td>PCC</td>
<td>EOR</td>
<td>Cancelled 2010</td>
</tr>
<tr>
<td>NRG Energy (Petra Nova)</td>
<td>TX</td>
<td>167 (CCPI 3)</td>
<td>240 MW 1.6 MtCO₂/yr</td>
<td>PCC</td>
<td>EOR</td>
<td>Under Construction</td>
</tr>
<tr>
<td>Summit Power (Texas Clean Energy Project)</td>
<td>TX</td>
<td>450 (CCPI 3)</td>
<td>400 MW 2 MtCO₂/yr</td>
<td>IGCC</td>
<td>EOR</td>
<td>Under Development</td>
</tr>
<tr>
<td>Southern (Kemper)</td>
<td>MS</td>
<td>270 (CCPI 2)</td>
<td>582 MW 3 MtCO₂/yr</td>
<td>IGCC</td>
<td>EOR</td>
<td>Under Construction</td>
</tr>
</tbody>
</table>

The breakdown of the eight projects listed in Table 2-5 are as follows: One (Kemper) received funds through CCPI Round 2, six received funds through CCPI Round 3, and one (FutureGen 2.0) received funds directly from ARRA. Note that all funding from ARRA came with a time limit – all funds had to be spent by the end of September, 2015. This not only affected FutureGen 2.0, but also the CCPI Round 3 projects. As will be seen below, this time limit played a role in decisions to cancel some projects.

The CCPI Round 3 awards were announced in 2009. Two projects were cancelled in 2010. In both cases, the tight timeline was cited as one of the reasons.

- **Plant Barry (Southern).** Southern was awarded $295 million in December, 2009, and cancelled the project in February, 2010. They did proceed with their 150,000...
Because of the needed financial commitment and the tight
timeline for securing funding, it was "not in our best interest to move forward" with
the endeavor at the north Mobile County electric generating plant, said Pat Wylie,
a spokesman for Alabama Power Co., a subsidiary of Atlanta-based Southern’’
(AL.com, 2010).

- **Antelope Valley (Basin Electric).** Basin Electric was awarded $100 million in
  July, 2009, and cancelled the project in December, 2010. It was planned to use the
  existing pipeline to the Weyburn fields to sell its CO$_2$. "The cost and timing of a
  proposed carbon capture project at the coal-fired Antelope Valley Station near
  Beulah have caused the plant’s directors to table the project indefinitely”
  (Bismarck Tribune, 2010).

  Another significant cancellation was AEP’s Mountaineer Project. AEP’s plan was to help
  finance the project through the electricity market, but cancelled the project when this approach
  was not approved by a jurisdictional public utility commission.

- **Mountaineer (AEP).** AEP was awarded $334 million in December, 2009, and
  cancelled the project in July, 2011. A Phase 1 pilot project of about 100,000
  tCO$_2$/yr was already active at the site. This was to be Phase 2 to scale up to 1.5
  tCO$_2$/yr (235 MWe). The financing of the project required AEP to recover costs
  from its ratepayers. This required approval of the Public Utility Commissions
  (PUCs) of both Virginia and West Virginia. "Company officials ... said they were
dropping the larger, $668 million project because they did not believe state
regulators would let the company recover its costs by charging customers, thus
leaving it no compelling regulatory or business reason to continue the program”
(NY Times, 2011). One reason the PUCs did not grant approval was lack of a
national climate policy. "So far, [regulators] have not been willing to support cost
recovery for CCS ahead of a federal mandate to cut carbon emissions from power
plants,” said Melissa McHenry, an AEP spokesperson (Gallucci, 2011).

Of the remaining five projects, two are under construction (Petra Nova and Kemper), two have
been cancelled (FutureGen 2.0 and Hydrogen Energy), and one is still under development
(Summit Power). Summit Power’s Texas Clean Energy Project (TCEP) is nearing a go/no go
decision. Hydrogen Energy was officially cancelled in March, 2016 ( Examiner.com, 2016).
FutureGen 2.0 was effectively cancelled in February 2015 by the US DOE when it became clear
that they could not meet the September 2015 deadline and that Congress would not grant an
extension. The official cancellation announcement was issued in January, 2016 (Marshall,
2016a). More details on these 5 projects are contained in Section 4.
Table 2-6. Industrial CCS Projects Receiving Support from Stimulus Funding

<table>
<thead>
<tr>
<th>Company</th>
<th>Location</th>
<th>DOE Support (million $)</th>
<th>Size (MtCO₂/yr)</th>
<th>Source</th>
<th>Fate</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Leucadia Energy</td>
<td>Lake Charles, LA</td>
<td>261</td>
<td>4.5</td>
<td>New Methanol Plant</td>
<td>EOR</td>
<td>Cancelled</td>
</tr>
<tr>
<td>Air Products &amp; Chemicals</td>
<td>Port Arthur, TX</td>
<td>284</td>
<td>1</td>
<td>Existing Steam Methane Reformers</td>
<td>EOR</td>
<td>Jan, 2013</td>
</tr>
<tr>
<td>Archer Daniels Midland (ADM)</td>
<td>Decatur, IL</td>
<td>141</td>
<td>1</td>
<td>Existing Ethanol Plant</td>
<td>Saline Formation</td>
<td>2016</td>
</tr>
</tbody>
</table>

In 2009, twelve industrial projects received ARRA funding for Phase 1 (R&D). In 2010, the three projects listed in Table 2-6 were granted phase 2 (design, construction, and operation) awards. The Leucadia Energy project was cancelled in September 2014, Air Products is operational, and ADM’s Illinois Industrial CCS Project is under construction. Note that the Illinois Industrial CCS Project follows on from the Decatur pilot project (see Table 2-12) that started in November, 2011.

Not too much public material is available on the Leucadia Energy project. The main process was to gasify coke to produce methanol. The CO₂ would be a by-product of that process, which would be sold for EOR. The reason given for cancellation was that the ultimate cost of the entire project was too large (Business Wire, 2014). While not stated specifically, one can assume that the low natural gas prices in the US made this (and arguably any other gasification project) uneconomic.

In looking at the two successful projects, they share some similar traits. First, they are adding CCS to an existing plant (unlike Leucadia). Secondly, the government money covered about two-thirds the cost of the entire CCS project (Folger, 2014). For Air Products, revenue will be generated by EOR sales. For ADM, the CO₂ will be stored right underneath the site and much of the cost to characterize the subsurface was done as part of DOE’s Regional Carbon Sequestration Partnerships Development Phase III (Decatur project), where DOE paid $66.7 million of the $84.3 million project cost. That work was led by the Illinois State Geologic Survey. Section 2.4 will elaborate a little more on the drivers for the ADM project.
Of all the programs that will be described in this section, one can argue that the US CCS Demonstration Program is the most successful. The program resulted in four successful projects (2 power, 2 industrial) with a potential fifth project (TCEP) still in development.

2.3.2 Alberta, Canada

Besides the US program, the Alberta program is the only other CCS Demonstration Program that has resulted in large-scale CCS demonstration projects being built. The government of Alberta created a C$2 billion Carbon Capture and Storage Fund to support large-scale CCS projects. Four awards were made in 2009 and are summarized in Table 2-7. One is operating, one is under construction, and two have been cancelled.

Table 2-7. Projects Funded from Alberta’s Carbon Capture and Storage Fund (MIT, 2016)

<table>
<thead>
<tr>
<th>Project</th>
<th>Quest</th>
<th>Alberta Carbon Trunk Line</th>
<th>Project Pioneer</th>
<th>Swan Hills</th>
</tr>
</thead>
<tbody>
<tr>
<td>Leader</td>
<td>Shell</td>
<td>Enhance Energy</td>
<td>TransAlta</td>
<td>Swan Hills Synfuels</td>
</tr>
<tr>
<td>Location</td>
<td>Fort Saskatchewan</td>
<td>240 km pipeline</td>
<td>Keephills Power Plant</td>
<td>Swan Hills</td>
</tr>
<tr>
<td>Size (Mt/yr)</td>
<td>1.2</td>
<td>Up to 14.6</td>
<td>1</td>
<td>1.3</td>
</tr>
<tr>
<td>CO₂ Source</td>
<td>Steam Methane Reformers</td>
<td>Refinery Fertilizer</td>
<td>Coal Power Plant</td>
<td>In-situ Coal Gasification</td>
</tr>
<tr>
<td>CO₂ Fate</td>
<td>Saline Formation</td>
<td>EOR</td>
<td>Saline/EOR</td>
<td>EOR</td>
</tr>
<tr>
<td>Project Cost (million C$)</td>
<td>1,350</td>
<td>1,200</td>
<td>1,255</td>
<td>1,500</td>
</tr>
<tr>
<td>Alberta Funding (million C$)</td>
<td>740</td>
<td>495</td>
<td>436</td>
<td>285</td>
</tr>
<tr>
<td>Canada Funding (million C$)</td>
<td>120</td>
<td>63</td>
<td>343</td>
<td>--</td>
</tr>
</tbody>
</table>

Business drivers were a major motivation for the Alberta CCS program. Oil production from oil sands is the dominant industrial activity in Alberta. However, because the production of oil from the sands is energy intensive, it has a larger life-cycle carbon footprint than most (but not all) of the world’s current oil production. As a result, they have become a major target for certain environmental organizations. Two specific examples of how this has played out:
• Low carbon fuel standards – First enacted in 2007 in California, it mandates that the life-cycle greenhouse gas emissions of transport fuels be below a certain limit.

• The Keystone pipeline – The project was to bring oil from Alberta to US Gulf Coast refineries, but was blocked by the Obama administration under great pressure from environmental groups.

One strategy to lower the carbon footprint of the oil sands is through the use of CCS. Alberta took several steps to implement such a strategy, including establishing the Carbon Capture and Storage Fund and enacting a $15/tCO₂ carbon levy on large emitters, with the proceeds going to a technology fund. Additional information on the four projects receiving money from the Carbon Capture and Storage Fund follow:

• **Quest.** Arguably the best CCS Demonstration Project in being on-time and under budget. Reasons for success include: (1) A high amount of direct government funding as a percentage of projected project cost (64%), (2) Receiving two-for-one carbon credits (credits currently $15/tCO₂, rising to $30/tCO₂ by 2017) for a ten year period, (3) “Support from the local community was essential to building Quest. Shell initiated public consultation in 2008, two years before submitting a regulatory application” (Shell.com, 2015), (4) CCS is an important part of Shell’s business strategy to reconcile fossil fuel use and climate change. “Shell proceeded with a final investment decision on the Quest project in the oil sands on a zero net-present-value basis (a decision few other companies could or would be willing to carry on their balance sheet).” (Reiner, 2016).

• **Alberta Carbon Trunk Line.** The government subsidy covered 47% of the projected costs. Other stated reasons for moving the project forward were “the benefits of royalties, taxes, job creation and a lasting CCS infrastructure will significantly outweigh all project costs”.

• **Project pioneer.** Here the government funding covered 62% of the projected costs. Don Wharton, vice-president of policy and sustainability at TransAlta said “Our decision was essentially based on the fact that we could not see a way to make the economics of our CCS project work as we originally intended.” This reinforces the fact that applying CCS at power plants is much more difficult than certain industrial applications.

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Back in 2007 in an effort to get out in front of the issue Alberta passed a law requiring large emitters of greenhouse gases (100,000 tonnes of GHGs a year or more) to scale back the intensity of their emissions by 12 per cent below an agreed upon baseline. The emitters were then required to pay a $15 so-called carbon levy on any emissions over their targets. Since 2009, $380 million has been collected with $212 million of it being invested so far. Of the money that’s been spent $98 million has been invested in renewables, $38.7 million in energy efficiency with the rest going to greening fossil fuel production and carbon capture and storage.
• **Swan Hills.** The government funding covered only 19% of projected costs. The official reason for cancellation was given as low natural gas prices. As was the case with Leucadia Energy in the US, gasification projects appear to be a non-starter with today’s low natural gas prices. Adding to the problem, in-situ (or underground) coal gasification is a commercially unproven technology.

2.3.3 **United Kingdom (UK)**

In November 2007, the UK government announced a £1 billion competition to support the design, construction and operation of commercial scale CCS projects. The competition was limited to coal-fired power plants employing post-combustion CO₂ capture technology. Four potential projects were pre-qualified in June 2008. These projects were led by Peel Energy, BP, E.ON and Scottish Power. In March 2010, two projects, E.ON and Scottish Power, were awarded funding to conduct Front End Engineering and Design (FEED) studies. E.ON decided to withdraw from the competition, leaving only Scottish Power. Despite extended negotiations between the government and Scottish Power, they broke down over who would be responsible for contingency costs (about £100 million). This led Scottish Power to cancel its Longannet project in October 2011.

The UK government decided to keep the £1 billion on the table and re-open the competition in April 2012. For this round, they lifted the restriction of post-combustion capture on coal plants, opening the competition to all capture options and fuels. In November 2012 four projects were selected for the competition. They are listed in Table 2-8.

<table>
<thead>
<tr>
<th>Project</th>
<th>Company</th>
<th>Size MW (MtCO₂/yr)</th>
<th>Capture</th>
<th>CO₂ Fate</th>
</tr>
</thead>
<tbody>
<tr>
<td>White Rose</td>
<td>Alstom</td>
<td>448 (2)</td>
<td>Oxyfuel</td>
<td>Offshore deep saline</td>
</tr>
<tr>
<td>Peterhead</td>
<td>Shell and SSE</td>
<td>385 (1)</td>
<td>Post-combustion Gas</td>
<td>Offshore depleted oil and gas</td>
</tr>
<tr>
<td>Captain Clean Energy</td>
<td>Summit Power</td>
<td>570 (3.8)</td>
<td>Pre-combustion</td>
<td>Offshore EOR</td>
</tr>
<tr>
<td>Teesside</td>
<td>Progressive Energy</td>
<td>400₁₁ (2.5)</td>
<td>Pre-Combustion</td>
<td>Offshore deep saline</td>
</tr>
</tbody>
</table>

On March 20 2013, Peterhead and White Rose projects were announced as the preferred projects and they would receive funding to conduct a FEED study, with a final investment decision to be made by the UK government in 2015 (later moved to 2016). The other two projects were placed on the reserve list in case either of the preferred projects should falter. However, on November 25, 2015, the UK Government unexpectedly withdrew funding for the competition. While the

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₁₁ The total plant size is 850 MW. A 400 MW slipstream would go the capture plant.
FEED studies will be completed, the proposed demonstration projects are not expected to proceed.

The final investment decisions were all awaiting the outcome of the FEED studies. Those studies will eventually be made public, but are currently unavailable. While a £1 billion split between two projects is a healthy start to finance the projects by helping cover the capital costs, the other critical piece of the financing was to come from a “contract-for-difference” to help cover the operating costs. This is a vehicle established by the UK government to help support low carbon technologies. It guarantees a price for the electricity sold by paying any difference between the agreed upon “contract” price and the market price.

Another important aspect of the projects is that they would help build out CCS infrastructure. Both projects would transport the CO\textsubscript{2} offshore to storage locations in the North Sea via pipeline (102 km for Peterhead, 165 km for White Rose). This infrastructure could create CO\textsubscript{2} hubs and trunk lines to help enable future CCS projects.

While no time deadline was originally set for the competition, one can argue that the long timeline in developing CCS projects was also a factor. The competition required continuous political support to keep moving ahead. From original announcement to cancellation of the competition was eight years.

2.3.4 European Union (EU)

In January 2007, the European Commission issued the first EU Energy Action Plan which was endorsed by the European Council in March 2007. In that plan, European leaders agreed that the EU should aim to have up to 12 CCS demonstration projects by 2015. The primary mechanism to achieve this goal was to be a program called the NER300. However, even before the NER300 became established, CCS demonstrations received support from the EU’s stimulus plan (European Energy Programme for Recovery or EEPR) that was established in July 2009.

“The EEPR allocated €4 billion to co-finance projects, aiming to make energy supplies more reliable while simultaneously boosting Europe’s economic recovery and reducing greenhouse emissions. The funds covered 3 broad fields, with financial support to 44 gas and electricity infrastructure projects, 9 offshore wind projects and 6 CCS projects” (Lupion and Herzog, 2013). The six CCS projects were awarded €1 billion in total and are listed in Table 2-9. By itself the EEPR funds are insufficient to support a CCS demonstration, but can be part of the financing package when combined with other programs, like the NER300 or programs in the individual member states.
Table 2-9. The six CCS Demonstration Projects receiving funding from the EEPR (Lupion and Herzog, 2013; MIT, 2016).

<table>
<thead>
<tr>
<th>Company</th>
<th>Location</th>
<th>EU Contribution (million €)</th>
<th>Size</th>
<th>Technology</th>
<th>Fate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vattenfall</td>
<td>Jänschwalde, Germany</td>
<td>180</td>
<td>385 MW 2.7 MtCO₂/yr</td>
<td>Oxy</td>
<td>EGR</td>
</tr>
<tr>
<td>E.ON</td>
<td>Rotterdam, Netherlands</td>
<td>180</td>
<td>250 MW 1.43 MtCO₂/yr</td>
<td>PCC</td>
<td>EGR</td>
</tr>
<tr>
<td>PGE &amp; Alstom</td>
<td>Belchatow, Poland</td>
<td>180</td>
<td>250 MW 0.1 MtCO₂/yr</td>
<td>PCC</td>
<td>Saline Formation</td>
</tr>
<tr>
<td>ENDESA</td>
<td>Compostilla, Spain</td>
<td>180</td>
<td>30-320 MW 1 MtCO₂/yr</td>
<td>Oxy</td>
<td>Saline Formation</td>
</tr>
<tr>
<td>Powerfuel</td>
<td>Hatfield, UK</td>
<td>180</td>
<td>900 MW 4.5 MtCO₂/yr</td>
<td>IGCC</td>
<td>EOR</td>
</tr>
<tr>
<td>Enel</td>
<td>Porto Tolle, Italy</td>
<td>100</td>
<td>250 MW 1 MtCO₂/yr</td>
<td>PCC</td>
<td>Saline Formation</td>
</tr>
</tbody>
</table>

The NER300 was to raise money to support CCS demonstrations by selling 300 million allowances from the New Entrants Reserve (NER) of the EU Emissions Trading System (ETS). Furthermore, the ETS affirmed that stored CO₂ is not emitted and therefore requires no allowances from the ETS. Member States would propose projects for the NER300, those projects would be vetted by the European Investment Bank (EIB) to ensure they met certain financial criteria, and finally the projects would be sent to the European Commission (EC) for funding.

In May 2011, a list of 13 proposals submitted by the Member States was sent to the EIB. Surprisingly, only 4 of the 6 EEPR projects were submitted; the Compostilla and Rotterdam projects were not there. The total amount of funding requested was €11.8 billion. The UK submitted 7 proposals, even though no more than three projects from any Member State could be funded. Breaking down the submitted projects, 11 were power projects (10 coal, 1 gas) and 2 were industrial projects. Of the 11 power projects, 6 proposed post-combustion capture, 3 proposed pre-combustion capture, and 2 proposed oxy-combustion.

In February 2012, the 8 projects that qualified to receive funding were forwarded to the EC. They are listed in Table 2-10. In December 2012, it was announced that none of the proposed projects would receive awards. The primary reason for this is the required financial contributions from the Member States were not forthcoming. It was always assumed by the EU that the bulk of the financing would come from the member states.
Table 2-10. The eight CCS Demonstration Projects qualifying for Round 1 of the NER300 (Lupion and Herzog, 2013; MIT, 2016).

<table>
<thead>
<tr>
<th>Candidates</th>
<th>Developer</th>
<th>Size</th>
<th>Feedstock</th>
<th>Technology</th>
</tr>
</thead>
<tbody>
<tr>
<td>Don Valley UK</td>
<td>2Co Energy</td>
<td>920 MW</td>
<td>Coal</td>
<td>Pre-combustion</td>
</tr>
<tr>
<td>Belchatow Poland</td>
<td>PGE</td>
<td>260 MW</td>
<td>Coal</td>
<td>Post-combustion</td>
</tr>
<tr>
<td>Green Hydrogen Netherlands</td>
<td>Air Liquide</td>
<td>0.55 Mt/Yr</td>
<td>Industrial</td>
<td>H2 Production</td>
</tr>
<tr>
<td>Teesside UK</td>
<td>Progressive Energy</td>
<td>400 MW</td>
<td>Coal</td>
<td>Pre-combustion</td>
</tr>
<tr>
<td>White Rose UK</td>
<td>Alstom</td>
<td>426 MW</td>
<td>Coal</td>
<td>Oxy-combustion</td>
</tr>
<tr>
<td>Killingholme UK</td>
<td>C.GEN NV</td>
<td>430 MW</td>
<td>Coal</td>
<td>Pre-combustion</td>
</tr>
<tr>
<td>Porto Tolle Italy</td>
<td>ENEL</td>
<td>250 MW</td>
<td>Coal</td>
<td>Post-combustion</td>
</tr>
<tr>
<td>ULCOS France</td>
<td>ArcelorMittal</td>
<td>0.7 Mt/ Yr</td>
<td>Industrial</td>
<td>Steel Production</td>
</tr>
</tbody>
</table>

In April 2013, Round 2 of the NER300 opened and only the White Rose project (see table 2-8) qualified. With demise of UK Competition, the White Rose project will not proceed. So the net result of the NER300 and the EEPR is not the twelve projects the Europeans pronounced in 2007, but no projects at all. Given the scope of projected funding and the anticipated participation of so many countries, the failure of the NER300 program can be judged the most disappointing of the CCS demonstration programs.

So what happened? There are a myriad of reasons for failure, as discussed at length in Lupion and Herzog (2013). Some key points are summarized below.

A big issue was financial. Basically, there was not enough money made available to help fund the projects. The biggest component of this was the price of a permit in the ETS. When the program was put in place, it was anticipated permit prices would be at least €20 and probably much higher. However, prices plummeted to less than €5. The lower than anticipated prices had a double impact; not only was significantly less money available to finance projects, but the operating savings from not needing to purchase permits also shrunk dramatically. Add on top of this the dividing of the pie to help finance renewable energy projects under the NER300, one can only conclude that the NER300 was woefully underfunded.

The funding from the NER300 was supposed to be supplemented with additional funds from the member states. However, the member states did not step up. One reason was the weak economies during this time period. Also, many countries in the EU did not prioritize climate action as a budget priority. In the UK, where the government was willing to make a significant financial contribution, there was no alignment between the UK government and the EU on the
criteria for ranking the projects. As a result, the number one ranked project in the NER300, Dom Valley, did not even qualify for the UK competition.

Many member states were ambivalent about CCS. Germany is a good example. Vattenfall spent $100 million of their own money to build the Schwarze Pumpe pilot plant to capture CO\textsubscript{2} via oxy-combustion. They wanted to implement this technology at commercial scale at their Jänschwalde power plant and received EEPR funding. However, they needed the German government to transpose\textsuperscript{12} the European CCS Directive to allow underground storage of CO\textsubscript{2}. The German Bundesrat refused, essentially killing any CCS demonstration projects in Germany (see Section 2.4.2.5).

It should be noted that unlike North America, where a majority of the successful projects tapped into EOR markets, that option is very limited in Europe. Therefore, it is expected that direct government support of CCS demonstration projects has to be a major part of a financial package.

Another problem with the EEPR and the NER300 was the lack of flexibility. Program parameters did not recognize the cost and complexity of CCS projects. The strict timetable is one example. They were fine for the relatively smaller and straightforward renewable energy projects, but unrealistic for the larger and more complex CCS projects. Once in place, these timelines could not be revised. Another example is when a project like Jänschwalde was cancelled, the EEPR funds could not be reallocated to another project, but instead reverted back to the EC.

Finally, the whole EU program brings up the issue of the relationship between CCS and renewables. The NER300 was originally designed for CCS, but renewables were eventually included. This shows the power of the constituencies for renewables and the relative weakness of constituencies for CCS.

2.3.5 Norway
Norway has a long history with CCS demonstration projects. It is home to two of the pioneer CCS demonstration projects, Sleipner and Snohvit. CCS is a natural result for a country that is heavily dependent on the oil and gas industry, but also wants to be a leader in addressing climate change. This later desire can be traced to Gro Harlem Brundtland, who was Prime Minister of Norway for part of 1981, May 1986 to October 1989, and November 1990 to October 1996. 

“In 1983, Brundtland was invited ... to establish and chair the World Commission on Environment and Development, widely referred to as the Brundtland Commission. She developed the broad political concept of sustainable development in the course of extensive public hearings, that were distinguished by their inclusiveness. The commission, which published its report, Our Common Future, in April 1987, provided the momentum for the 1992 Earth Summit” Wikipedia (2016). A major outcome of the Earth Summit was the UN Framework Convention on Climate Change.

A major challenge for CCS in Norway is the scarcity of appropriate CO\textsubscript{2} sources. The power sector is almost carbon-free, due to an abundance of hydroelectric power. When it was proposed to build a natural gas power plant at Kårstø, it turned into a major political battle (Quiviger, 12 Countries transpose directives from the EU by turning them into law at the national level.
2001). Should the plant be required to have CCS? Should the plant be delayed until CCS was more mature? Should the plant be built without CCS, but retrofitted at some future time? After many years of political battles, including the bringing down of a government, the later path was chosen. In 2007, the Kårstø plant went on-line with 420 MWe of gas-fired power. Though the original idea was to eventually retrofit the plant with CCS, today it is not considered a viable candidate for CCS.

In 2006, a gas turbine combined heat and power plant (CHP) was built at the Mongstad refinery. As a condition to obtain the CO₂ emissions permit, Statoil and the government agreed to pursue CCS at Mongstad. The first stage of this agreement was to build a pilot plant called Technology Centre Mongstad (TCM). TCM was to test various capture technologies to eventually be used in a second phase, full-scale CCS at Mongstad. CO₂ would be captured from both the CHP plant’s gas turbines and the refinery’s Cat Cracker. In 2013, it was decided to discontinue work on phase 2 because of doubts related to the future viability of the Mongstad refinery (i.e., there was talk about closing the refinery) (Gassnova, 2015). However pilot plant operations at TCM continue to this day.

The Norwegian government has the goal to “realize at least one full-scale CCS demonstration facility by 2020”. Gassnova, in cooperation with Gassco and the Norwegian Petroleum Directorate (NPD), completed a pre-feasibility study on potential full-scale CCS projects in Norway in May, 2015. “The target segment for potential CO₂ capture sites was mainly existing land-based emissions sources with emissions above 400,000 tons of CO₂ per year”. A summary of the most important findings and recommendations were made public, but the full report was not because it contained sensitive business information (Gassnova, 2015).

The report recommended three possible CCS demonstration options, one at a cement plant, one at an ammonia plant, and one at a waste-to-energy facility. Below are the descriptions quoted from the summary report.

**Norcem Brevik.** In the mapping from 2012, Norcem considered itself relevant for further CO₂ capture studies. Norcem has also provided input to the pre-feasibility study. The CO₂ concentration in the flue gas emissions from cement production is high (16-19 percent), and there is residual heat for CO₂ capture. According to Gassnova, the cement industry needs more information on the potential for CCS. At the pilot facility in Brevik, Norcem has tested several different capture technologies with public support from the research and development programme Climit.

**Yara Porsgrunn.** In connection with the mapping from 2012, Yara considered the ammonia plant in Porsgrunn as relevant for further CO₂ capture studies. Yara has provided input to the pre-feasibility study. Yara has total emissions of approximately 1.1 million tons of CO₂ a year at full production, some of this is sold to the food industry.

**Klemetsrud.** Gassnova has also been in touch with the Waste-to-Energy Agency of Oslo, which is considering CO₂ capture from the waste incineration facility at Klemetsrud. Gassnova indicates that it may be realistic to capture approximately 400,000 tons of CO₂ per year. Klemetsrud may be a relevant facility for CO₂ capture, which could potentially be combined with
other capture projects. Further studies are required before concluding on the viability of the Klemetsrud plant for CCS and Gassnova will continue its dialogue with Oslo municipality on the issue.

While no details on how these projects will be financed, the government of Norway has shown willingness in the past to be very generous with direct subsidies. The government funded pilot project at TCM turned out to be extremely expensive, but the government stayed the course. Whether the current situation of low oil prices will change this outlook is unclear. In any case, a key driver for Norway is their strong beliefs in addressing climate change and accepting CCS as a key component of a climate mitigation strategy. They do not have the ambivalence toward CCS that is shown by most of Europe.

2.3.6 China

There are currently no large-scale (>1Mt CO₂) CCS demonstration projects operating in China. However, there are quite a few pilot projects on the order of 100,000 tCO₂/yr. These projects are summarized in Table 2-11. Five of these projects (all except Shidongkou and HUST) are viewed as potential precursors to larger demonstration projects at the same site.

<table>
<thead>
<tr>
<th>Project</th>
<th>Leader</th>
<th>Size ktCO₂/yr</th>
<th>Source</th>
<th>Fate</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jilin</td>
<td>PetroChina</td>
<td>200</td>
<td>NG Processing</td>
<td>EOR</td>
<td>Operational 2009</td>
</tr>
<tr>
<td>Shidongkou</td>
<td>Huaneng</td>
<td>100</td>
<td>Coal Power</td>
<td>Commercial Markets</td>
<td>Operational 2009</td>
</tr>
<tr>
<td>Ordos</td>
<td>Shenhua Group</td>
<td>100</td>
<td>Coal Liquefaction</td>
<td>Saline Formation</td>
<td>Operational 2011</td>
</tr>
<tr>
<td>Jingbian</td>
<td>Yanchang Oil</td>
<td>40</td>
<td>Coal Gasification</td>
<td>EOR</td>
<td>Operational 2012</td>
</tr>
<tr>
<td>Shengli Oil Field</td>
<td>Sinopec</td>
<td>40</td>
<td>Coal Power</td>
<td>EOR</td>
<td>Operational 2010</td>
</tr>
<tr>
<td>GreenGen</td>
<td>Huaneng</td>
<td>100</td>
<td>Coal IGCC</td>
<td>--</td>
<td>Under Construction</td>
</tr>
<tr>
<td>HUST Oxyfuel</td>
<td>Huazhong University</td>
<td>100</td>
<td>Coal Oxyfuel</td>
<td>--</td>
<td>Under Construction</td>
</tr>
</tbody>
</table>

China does not have any national programs to promote CCS demonstration projects that are comparable to those discussed previously in North America and Europe. However, in a bilateral agreement, the US and China have committed to undertake a major CCS project in China “that supports a long term, detailed assessment of full scale sequestration” (NCC, 2015).

There has been lots of speculation about CCS activities and motives in China over the past few years. When trying to understand CCS and China three points might be considered:
• Poor air quality caused by the emissions of criteria pollutants (e.g., SO$_2$, NO$_x$) is a much bigger issue in China than CO$_2$ emissions. It makes no sense to believe that China will funnel resources to implement CCS at any scale until it implements much less costly controls for the criteria pollutants. China has a long way to go on this later issue.

• Initially, a big motivation for China to develop and implement CCS technology was to become a low cost supplier to the world, similar to what they have become in supplying solar panels. With expectations for the worldwide demand of CCS much diminished compared to a decade ago, one would expect CCS activity in China to be more restrained.

• An area of interest today for CCS in China is a source of CO$_2$ for EOR. Due to cost considerations, the source of the CO$_2$ is more likely to be coal-to-liquids or coal-to-gas plants rather than coal-fired power plants.

In summary, there are two areas where business drivers in China are aligned with CCS, (1) being a supplier to the world and (2) providing CO$_2$ for EOR. Today, the later reason is the primary motivator. The idea of large-scale CCS implementation in China for the primary purpose of reducing CO$_2$ emissions may be decades away.

2.3.7 Australia

In the early 2000s, Australia was an international leader in CCS. However, more recently, Australia has cut back on its activities. This is due in large part to the Abbott government, which came into power in September 2013 and has not been supportive to actions addressing climate change. The most visible example is the repeal of the Australian carbon tax (A$23/tCO$_2$).

The only commercial scale CCS project in Australia is the Gorgon project, a pioneer CCS project that is scheduled to start up in 2016 (see Table 2-3). Another notable project was ZeroGen, which was initiated in 2003 and cancelled in 2010. An analysis of ZeroGen is contained in Section 2.4. Additionally, two major pilot projects were carried out (MIT, 2016):

• Otway started in 2008 and studied injection of CO$_2$. The tests concluded in December 2011 with a total of 65,000 tCO$_2$ injected. The source of CO$_2$ was from natural gas processing. The project is now in phase 2, which is monitoring and studying the CO$_2$ storage.

• Callide Oxyfuel is a 30 MWe capture pilot in Queensland which was conceived in 2003, started operation in 2012 and closed in 2015.

A Low Emissions Technology Demonstration Fund (LETDF) was set up, but only issued one round of funding in 2006 (Zeroco2.no, 2016). Gorgon got A$60 million and Callide got A$50 million. In 2009, The Global Carbon Capture and Storage Institute (GCCSI) was established to help support CCS demonstrations worldwide. It had an A$100 million annual budget. By 2011,
the Australian government began cutting the GCCSI budget and eventually eliminated its government support. The GCCSI has continued as a private organization.

Two projects are active in a planning stage. Both are aimed at developing CO\(_2\) hubs, Carbon Net in Victoria and South West Hub in Western Australia. Neither is near the point where they can make a final investment decision.

2.3.8 **Japan**
Japan was an early leader in CCS R&D. In 1990, it established a research institute, RITE, to focus on CCS technologies. Because Japan has few geologic storage resources, but does have access to deep water, a major focus of the Japanese program was storage of CO\(_2\) in the deep ocean. Deep ocean storage started becoming problematic in the 2000s because it was concluded that the storage was not permanent and because of lack of international acceptance of this storage option.

There are no large-scale CCS demonstration projects in Japan. Two pilot projects are worth mentioning (GCCSI, 2015):

- Tomakomai will capture CO\(_2\) from hydrogen production for injection into two saline formations. Size is 100,000 MtCO\(_2\)/yr and injection is scheduled to start in 2016.

- Osaki CoolGen is planned to capture CO\(_2\) from a 166 MW oxygen-blown IGCC power plant under construction in Osaka.

2.3.9 **South Korea**
“The South Korean Government is currently revising its CCS Master Plan, which includes a large-scale CCS demonstration project operating within certain cost parameters by 2020, and commercial CCS deployment thereafter. The Government’s policy includes support for a number of testing and pilot plants involving a wide variety of agencies and technology providers in the power generation and steel making industry. This includes the Korea Electric Power Corporation (KEPCO) testing of post combustion capture technologies at its Boryeong and Hadong Power Stations. Both projects were increased in scale in 2013 to test the capture of CO\(_2\) from flue gas at 10 MW generation units” (GCCSI, 2015).
2.4 Analysis of Selected CCS Projects

This section will look at some selected CCS demonstration projects in more depth to try and better understand the motivation and financing for a project. A key determination for selection of projects for this section was whether sufficient information was available in the open literature. Also included are projects that contribute important messages for lessons learned, even if specific data is fairly sparse.

In section 2.4.1, projects that received a positive financial decision (i.e., are in operation or under construction) are analyzed. Section 2.4.2 examines projects that did not receive a positive financial decision, most of which have been cancelled, but a couple are still under development. Section 2.4.3 discusses projects at the pilot scale.

2.4.1 Demonstration Projects with a Positive Financial Decision

This section examines:

- The pioneer CCS projects (see Section 2.2.2)
- The three CCS projects at a power plant (Boundary Dam, Kemper, and Petra Nova)
- The Decatur project

2.4.1.1 Pioneer Projects.

Clark (2015) did an analysis of the Gorgon project. This section will start with that analysis, as much of it applies to all the pioneer projects. From Clark (2015):

The changes in climate legislation [in Australia] had seemingly no impact on Gorgon, as preparations for CCS at Gorgon have been in progress for over two decades. Instead of a carbon tax, what drove the use of CCS was the fact that a collaborative decision was made by Chevron and the government of Australia to develop resources at Gorgon using CCS13.

Specific project costs for Gorgon are difficult to locate, but two reasons can be documented that explain how the economics worked out at Gorgon:

1. The cost to add CCS was a relatively small fraction of total costs (compared to power plant projects)
2. There are high market prices for the LNG product14

Costs of CCS for the Gorgon project were less than 10% of the total capital costs (“Discussions with Chevron Representatives,” 2014).

14 In 2012, LNG was selling for almost $17/MMBtu. However, LNG prices in Asia are linked to the world oil price, which has dropped significantly since 2012. Therefore, this statement is no longer accurate for the current markets.
In essence, the inclusion of CCS into the Gorgon project was part of the cost of doing business. While no law or regulation required CCS at Gorgon, there was still a general concern about greenhouse gas emissions, especially a single source that would emit over 3 MtCO$_2$/yr. While adding to the project costs, the determination was made that the costs were relatively small and acceptable. One can assume that a benefit to voluntarily agreeing to limit greenhouse gas emissions is that the project approval and permitting process would proceed much more smoothly.

The Sleipner and Snohvit projects had similar motivations. While there was a carbon tax for offshore operations in Norway (approximately $50/tCO$_2$ when Sleipner was built), the primary decision was as a result of discussions between the government and Statoil$^{15}$. As discussed in section 2.3.5, Norway had a strong commitment to climate change mitigation. These projects would showcase its commitment to the world.

BP’s In-Salah project fit in very well with BP’s overall strategy at the time it was built. BP had a marketing campaign with the theme “Beyond Petroleum”. Basically, BP was trying to market itself as a green company, and CCS was a tactic in that strategy. At about the same time as In-Salah, BP organized and led the CO$_2$ Capture Project$^{16}$, a consortium of petroleum companies. It also followed up In-Salah by announcing a set of three CCS demonstration projects focused on “decarbonized fuel” (see Section 2.4.2.4).

In summary, the four pioneer projects shared the following characteristics, which helped drive the projects:

- The cost of adding CCS was a small percentage (roughly 10%) of overall project costs.
- The project could afford to absorb those costs and still be profitable.
- The companies could justify the costs as a cost of doing business and/or because the project aligned well with a broader business strategy.

### 2.4.1.2 Boundary Dam.

For this project to be successfully completed, it took a combination of business drivers, regulatory drivers, market pull, and technology push. On the one hand, it is a nice roadmap on how to put together a successful project. On the other hand, it shows why it is so hard to develop CCS projects at a power plant and why Boundary Dam is not easy to replicate.

Boundary Dam was a retrofit to boiler unit 3. The net power output after capture is 110 MWe. The original projected cost for the boiler retrofit and CCS was projected to be C$1.1 billion, though that rose to C$1.3 billion. The CO$_2$ was to be sold for EOR, but any unsold CO$_2$ would be injected into a saline formation developed by the Aquistore Project. Fly ash and sulfuric acid would also be sold. Below is an analysis of the project from Clark (2015)$^{17}$:

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$^{15}$ Note that the Norwegian government owns 67% of Statoil, which means the company is generally responsive to government suggestions.

$^{16}$ [http://www.co2captureproject.org/](http://www.co2captureproject.org/)

$^{17}$ For a more detailed description of the Boundary Dam economics, see Clark (2015).
Canada’s 2012 update to the Environmental Protection Act requires new coal plants to be compliant with an emissions limit of 420 tonnes of CO\(_2\) emitted per GWh of electricity produced, as well as existing plants when they turn 40 years old. Lignite coal has a high emission factor (~1050 t CO\(_2\)/GWh for a PC plant\(^{18}\)), and therefore would not be able to meet this requirement without CCS. This policy left SaskPower only two choices: include CCS in their project or allow regulations to strand some of their lignite assets. Saskatchewan has a valuable 300-year supply of coal that SaskPower does not want to be wasted or kept underground.\(^ {19}\)

SaskPower considered two primary options: retrofit the existing unit with CCS or replace it with a base load natural gas combined cycle (NGCC) power plant... Figure 2-1 showcases how Boundary Dam can compete with a base load NGCC plant at current natural gas prices in Canada. Four components played a critical role:

1. There was a substantial federal subsidy from the Canadian government
2. The CO\(_2\) was sold as a by-product for enhanced oil recovery (EOR) for the majority of revenue, along with sulfuric acid and fly ash
3. The fuel cost was significantly lower for lignite than natural gas
4. The project was a retrofit, lowering the capital costs compared to new plant

Figure 2-1: Levelized cost of electricity estimates of the Boundary Dam retrofit by cost category compared to a base load NGCC plant (Clark, 2015)

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\(^{18}\) Calculated using average heat rates from US power plants generating more than 300,000 MWh/yr, totaling 347 PC plants and average emission factors from United States lignite (data from the US Energy Information Administration).

In summary, here are the key components that drove the successful financing of Boundary Dam:

- **Regulatory Driver:** The status quo was not sustainable. Boundary Dam needed to upgrade its boiler on Unit 3 and had only two choices: include CCS in their retrofit or repower with NGCC.

- **Business Driver:** SaskPower did not want to strand their large lignite asset.

- **Technology Push:** A C$240 million direct subsidy was available from the Canadian government. This was 22% of the initial projected project cost of C$1.1 million.

- **Market Pull 1:** They could access CO₂ EOR markets. They also had markets to sell their fly ash and SO₂ (as sulfuric acid).

- **Market Pull 2:** They gained access to the electricity markets by convincing the authorities that retrofitting with CCS is no more costly than repowering with an NGCC. Gaining access to the electricity markets meant that they could pass on the costs to the ratepayers.

**2.4.1.3 Kemper**

The Kemper project is introduced in Section 2.3.1. When Southern Company got the original award from Round 2 of the CCPI in 2004, the plan was to build the plant in Florida. The project was not motivated by CCS, but the desire to commercialize a new gasification technology, Transport Integrated Gasification or TRIG. A key feature of TRIG is that it can work well with low rank coals like lignite. The gasifier had been under development for years by Southern Company under contract from the US DOE. A pilot plant of the gasification system was in operation at Southern’s Wilsonville, AL facility.

When new edicts were issued from the Florida government, the environment for building a new coal plant in that state became problematic. However, Mississippi proved to be a desirable venue where Mississippi lignite and potential for using CO₂ for enhanced oil recovery were valuable attributes to the project. Further, the Mississippi Public Utilities Commission (PUC) was amenable to rate-base this project, thereby giving Kemper access to the electricity markets.

So the project went forward with the following drivers:

- **Business Driver:** Southern wants to develop markets for its TRIG technology, especially in China and other Asian countries. The state of Mississippi wanted to exploit their natural resources, such as their lignite.

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20 Note that SaskPower is owned by the Provence of Saskatchewan, making some critics speculate on the independence of the regulating authorities.
- **Technology Push:** A $295 million award from the CCPI Round 2. In addition, the project originally qualified for $133 million in investment tax credits (but missed the in-service date deadline and had to return them), as well as a loan guarantee (which they decided to decline).

- **Market Pull 1:** They could access CO₂ EOR markets.

- **Market Pull 2:** They gained access to the electricity markets by approval of the Mississippi PUC. However, the cost recovery was originally capped at $2.4 billion.

The story at Kemper is the large increase in project costs, with total costs now estimated at over $6.6 billion (Marshall, 2016b). These cost increases are NOT primarily due to CCS, but to a variety of issues. However, much can be attributed to implementing multiple first-of-a-kind technologies and the complexity of integrating them together, especially in moving from a pilot plant to a scale of nearly 600 MWe.

In summary, Kemper shares some similarities with Boundary Dam in that it accesses both electricity and EOR markets, as well as having a business driver to use local lignite. However, there is a major difference: where Boundary Dam was a retrofit using proven technology, Kemper is a new build using a first-of-a-kind gasification technology. While there were some technical issues at Boundary Dam, they were at a much smaller and manageable scale.

### 2.4.1.4 Petra Nova

Petra Nova was introduced in Section 2.3.1. Unlike the power projects at Boundary Dam and Kemper, this project is taking place in a de-regulated market. Therefore, access to electricity markets will be only through the market price. However, the Petra Nova project does rely heavily on EOR markets as part of its financial package.

There are two features of the Petra Nova project that make it unique:

- This is a retrofit that uses a post-combustion capture process from the exhaust gas of a coal boiler. The capture process requires a significant amount of low pressure steam. The standard design (as done at Boundary Dam) is to integrate the capture process with the power plant’s steam cycle. In Petra Nova’s case, they installed a HRSG on an existing gas turbine to generate steam from the turbine exhaust. This has several advantages, including not losing plant capacity, taking advantage of low natural gas prices, and easier system integration. See Bashadi (2010) for an in-depth analysis of this approach.

- This is a vertically integrated project. Instead of simply selling the CO₂ to an EOR operator, Petra Nova bought their own oil field to operate.

This project was initiated under the watch of David Crane, then CEO of NRG (Petra Nova is a joint venture between NRG Energy and JX Nippon Oil & Gas Exploration). Some insight into
the business driver can be obtained by understanding where David Crane was taking NRG. This is an excerpt from his letter of resignation as head of NRG:

*The new frontier of the energy business that I pushed the company into, [was] then, and [is] still now, in the long-term best interest of the company's employees, its shareholders, its customers and the earth we all inhabit. As a company that aspires to growth, there is no growth in our sector outside of clean energy; only slow but irreversible contraction following the path of fixed-line telephony* (Lacey, 2016).

There is not much additional information on this project in the open literature. So we can summarize what we do know:

- **Business Driver:** A company that wants to be an innovator in clean energy.

- **Technology Push:** A $167 million award from the CCPI Round 3. Probably other incentives, but information not readily available.

- **Market Pull:** Access to CO₂ EOR markets.

- **Innovated Strategy 1:** Use the exhaust from a gas turbine to provide steam to the capture process. This simplifies the capture plant integration, avoids reducing the plant’s electricity generation, and takes advantage of today’s low gas prices.

- **Innovated Strategy 2:** Vertically integrate the project by becoming owner and operator of oil field for EOR.

In a presentation, NRG suggested some other reasons for the success of the project:

- The DOE grant award included a phased approach with some early cash funding during project definition.

- The commercial value proposition (10% unlevered IRR, a typical hurdle) that was based on strong revenue from EOR.

- The choice of “*Well-understood and proven technology with experienced OEM*”.

- The project cost protections were via “*Fixed price under lump-sum turn-key (LSTK) EPC agreement*” and the timing protections were via “*Guaranteed completion with liquidated damages through EPC agreement*”

### 2.4.1.5 Decatur

The Decatur project is really two projects:

- Illinois Basin – Decatur Project. A pilot project to inject a million tons of CO₂ over a three year period. The project was undertaken as part of the US DOE’s Regional Partnership Program (see section 2.4.3).

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21 [http://www.jcoal.or.jp/coaldb/shiryo/material/2_Session%202_speech%20US%20NRG.pdf](http://www.jcoal.or.jp/coaldb/shiryo/material/2_Session%202_speech%20US%20NRG.pdf)
The Illinois Industrial CCS Project. This is the project in Table 2-6 led by Archer Daniels Midland (ADM).

The Decatur project is unique in at least three ways:

- It is the only project worldwide that started as a pilot project and then evolved into a large-scale CCS demonstration project.
- It is the first and only project to inject CO₂ under a Class VI permit from the US EPA’s Underground Injection Control Program. The Class VI permit was developed specifically for long-term storage of CO₂ in geologic formations. Note that FutureGen 2.0 was also awarded a Class VI permit, but it was never used.
- It is the only CCS demonstration project that can claim negative emissions.

While the project is the exception for North America, in that it does not access EOR markets, it does have some significant advantages in the storage situation: (1) The CO₂ will be stored under the site, so no pipelines costs are involved. (2) All the geologic characterization, as well as the MMV (measurement, monitoring, and verification) protocols, was essentially done by the pilot project.

As discussed in section 2.3.1, about two-thirds of the project costs were covered by a grant from the US government. As seen with other demonstration projects, business drivers are also critical. This project was vetted and approved by the top management at ADM and was motivated by climate change concerns. “ADM, as part of its comprehensive strategy for energy sustainability and environmental responsibility, is implementing the Illinois ICCS project to reduce carbon footprint of industrial processes, e.g., by permanently storing the CO₂ generated during ethanol production in deep underground rock formations, rather than releasing it into the atmosphere” (Gollakota and McDonald, 2014).

In summary, Decatur has quite a bit of similarity with the pioneer projects. The capture cost was relatively small because the process produces a pure stream of CO₂. This just leaves costs for compression and any pipelines. The project was aligned with the company’s business strategies and the price tag was affordable once they obtained the government support.

2.4.2 Demonstration Projects without a Positive Financial Decision

2.4.2.1 FutureGen
The FutureGen project has a very long history. First announced in 2003, an alliance of coal companies and coal burning utilities were to build an IGCC power plant with CCS. This initial project was considered an R&D project, as opposed to a demonstration project, with the US government contributing up to a $1 billion. The project would store 1 MtCO₂/yr for 4 years. The project was cancelled in January 2008; just a month after Mattoon, IL was selected as the plant site. Whatever the reasons for withdrawal of support, what is clear is that political support over a long period of time, just as in the UK’s billion pound competition (see section 2.3.3), is a factor in the fate of a project that is high cost and requires substantial government assistance.
Before the project was cancelled, the MIT Future of Coal study (MIT, 2007) suggested another problem, a lack of clarity of purpose. Specifically, they said:

*First, there is continuing lack of clarity about the project objectives. Indeed, the DOE and consortium insist that FutureGen is a research project and not a demonstration project. This distinction appears to be motivated by the fact that higher cost sharing is required for a demonstration project, typically 50% or more from the private sector. However, the main purpose of the project should be to demonstrate commercial viability of coal-based power generation with CCS; it would be difficult to justify a project of this scale as a research project. The ambiguity about objectives leads to confusion and incorporation of features extraneous for commercial demonstration of a power plant with CCS, and to different goals for different players (even within the consortium, let alone between the consortium and the DOE, Congress, regulators, and others).*

*Second, inclusion of international partners can provide some cost-sharing but can further muddle the objectives; for example, is Indian high-ash coal to be used at some point? This effort to satisfy all constituencies runs the risk of undermining the central commercial demonstration objective, at a project scale that will not provide an agile research environment.*

The project was reconfigured in August 2010 as FutureGen 2.0, with funding of a $1 billion from the stimulus bill (see section 2.3.1). Some original alliance members dropped out, while some new members joined. The new plan was to retrofit a recently idled 65 year old coal-fired boiler owned by Ameren in Meredosia, IL. The chosen CCS technology pathway was oxy-combustion capture. The previous site of Mattoon, IL was to be used as the storage site.

While the FutureGen 2.0 project moved ahead and completed many significant milestones, progress was slow. There were several unexpected hurdles that had to be overcome, including (MIT 2016):

- Mattoon was no longer the site of the power plant, so they no longer had interest in being the storage site and withdrew, requiring FutureGen 2.0 to find, characterize, and permit a new storage location.
- Ameren pulled out of the project, requiring the alliance to acquire the power plant.
- The permit process for the storage wells lasted about 2 years, in part because this was the first time a permit for CO₂ storage wells was issued under the new Class VI category.
- The project faces a lawsuit from the Sierra Club over the lack of a Prevention of Significant Deterioration permit (NCC, 2015).

In the end, time ran out on spending the funding from the stimulus bill. As stated in section 2.3.1, FutureGen 2.0 was effectively cancelled in February 2015 by the US DOE when it became clear that they could not meet the September 2015 deadline. The official cancellation announcement was issued in January 2016. "*We are deeply disappointed that an expiration date for federal funding unnecessarily ended one of the most important clean energy projects of this decade,*" said alliance CEO Ken Humphreys. Sean Major, chairman of the alliance board, added, "*If the federal funding continued, the Alliance*
Board of Directors had confidence that construction would have been successfully completed" (Marshall, 2016a).

In summary, some lessons can be drawn from the FutureGen experience:

- Large complex projects require clarity of purpose in order to keep costs in-line.
- Projects that have very large government subsidies can become politicized. In FutureGen 2.0, the political environment made an extension of the spending deadline essentially impossible.
- Large complex projects will almost certainly face challenges as they go forward that require time to resolve. Setting strict time deadlines is generally a recipe for disaster.

2.4.2.2 ZeroGen
The original FutureGen project in the US inspired similar efforts around the globe, including GreenGen (China) and ZeroGen (Australia). The ZeroGen effort was documented with a case history (ZeroGen, 2012), which provided information from the summary below.

In March 2006, ZeroGen Proprietary Limited was incorporated. In 2008, it was decided to conduct a prefeasibility study for a 500 MWe IGCC power plant with CCS in Central Queensland. It would store 60-90 MtCO$_2$ over a 30 year period. The project was cancelled at the end of 2010. Two major reasons were cited:

- High cost, estimated at AUS$6.9 billion.
- Lack of finding a suitable storage site during the prefeasibility study, despite 70% of the prefeasibility funds being spent on this effort.

ZeroGen is yet another example of gasification projects being too expensive for the power sector. It also brings up a new issue – having an acceptable storage site. Most of the proposed CCS demonstration projects discussed in this report were sited with known storage locations available. In the case of ZeroGen, they had some potential sites targeted, but it was not known whether they would be acceptable until field data was collected, which is an expensive task. Only so many sites could be explored in the prefeasibility study, and these sited proved unacceptable.

2.4.2.3 Poly-generation
Two of the projects that received CCPI awards can be classified as poly-generation projects. These are the Texas Clean Energy Project (TCEP) and Hydrogen Energy California (HECA). They are based on coal gasification technology, but produce additional products in addition to electricity and CO$_2$. In general, these products need to be of higher value to obtain revenues to help pay for the project. HECA has been cancelled and though TCEP is still active, it is unclear whether or when it will proceed.

TCEP plans to produce urea in addition to electricity and CO$_2$. The project is led by Summit Energy, who has done a very good job of project development. They have completed most
agreements necessary, including off-take agreements for electricity, CO₂, and urea, as well as engineering, procurement, and construction agreements (MIT, 2016). The missing piece is the equity partners needed to complete the financing of the project.

HECA had planned to produce fertilizer and other products in addition to electricity and CO₂. They had planned to use petroleum coke as a feedstock, which can be significantly less expensive than coal. However, it appears that HECA had very few agreements in place and had lost their DOE funding (MIT, 2016), as well as the potential buyer of their CO₂ (Examiner.com, 2016). In notifying the State of California Energy Resources Conservation and Development Commission, HECA cited “the timeframe for deploying a project such as HECA has been longer than was anticipated” and “the U.S. Supreme Court’s February 9, 2016 decision to stay implementation of the Obama Administration’s Clean Power Plan … have cast additional uncertainty over the timing of such projects.”

While the poly-generation concept has been around for a while, TCEP and HECA show how difficult it is to implement. A major reason is the recurring theme of the high cost of gasification. The current technologies just seem too expensive for the power sector. The poly-generation idea tries to somewhat counter this with high value added products. When these projects started, they may have had a reasonable chance to succeed. But in the six or so years that they have been under development, first gas, then oil prices decreased dramatically. This means their products have become less valuable: CO₂ prices for EOR are linked to the oil prices and natural gas is the primary feedstock for fertilizer, urea, hydrogen, and other potential poly-generated products. Low natural gas prices mean lower prices for these products.

### 2.4.2.4 BP’s Decarbonized Fuel Projects

BP proposed three projects in the mid-2000s around the concept of decarbonized fuels. The idea was to produce “decarbonized” fuels (DF) from hydrocarbon feedstocks. BP created a Hydrogen Energy unit to pursue the projects. This concept of selling clean fuels to the world was very much in-line with BP’s “Beyond Petroleum” marketing strategy. The three proposed projects were:

- **DF1**, located at the Peterhead Power Plant in Scotland. The project would capture CO₂ from natural gas via pre-combustion and use the CO₂ for EOR in the Miller field in the North Sea. By using pre-combustion capture, hydrogen is sold to the power plant to produce electricity (Paxman, 2007). This project is discussed further below.

- **DF2**, located in Carson, CA, was to gasify PetCoke to produce electricity and CO₂. The CO₂ would be used for EOR. The hydrogen produced by the gasifier would be sent to a turbine to produce electricity (MIT, 2016). This project ran into public acceptance issues and is discussed further in the next section.

- **DF3**, located in Kwinana, Western Australia, was to gasify coal to produce electricity. The CO₂ would be stored in an offshore saline formation. The project

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22 See [http://docketpublic.energy.ca.gov/PublicDocuments/08-AFC-08A/TN210603_20160303T162841_Writeral.of_Revised_Application_for_Certification.pdf](http://docketpublic.energy.ca.gov/PublicDocuments/08-AFC-08A/TN210603_20160303T162841_Writeral.of_Revised_Application_for_Certification.pdf)

23 This is the same power plant that later was a finalist in the UK competition, but for a completely different project.
was to be in partnership with Rio Tinto. The project never really got very far, in part because it was determined that the targeted storage site was inadequate (MIT, 2016).

DF1 provides some good insights into how these projects may fit in well with a company’s business strategy. BP was pushing DF1 for at least two major reasons. First, it was to be the flagship project for what would be a set of projects worldwide that produced “decarbonized fuels”, essentially hydrogen. Even though hydrogen was an intermediate product in all three DF projects (the hydrogen would be used to produce electricity), this fit the image BP wanted to convey.

The second reason had a more direct impact on the project’s financing. The project would use existing infrastructure in the Miller’s field (pipelines, platforms, etc.). Not only would revenue be generated by life extension of the field, BP would avoid decommissioning of the field, which would have a major impact on the corporate balance sheets.

For the project to go ahead, BP required some government support to proceed. Further, they needed a relatively quick answer from the UK government because the oilfield was fast approaching its end of life. It was reported that BP requested the same subsidy that was being paid to wind at that time. Since the size of DF1 was about as big as all the wind projects to that time, the UK government was concerned about how such a large lump sum subsidy would be viewed. Instead, the UK announced its billion pound competition and invited BP to apply. This not only delayed the timing, it added uncertainty. As a result, BP cancelled the project in May 2007 (Royal Society of Chemistry, 2007).

Even though DF1 had a good chance of being completed if the UK government provided support, the overall decarbonized fuel concept was probably headed for failure. The idea of selling a clean fuel (i.e., hydrogen) to a utility fit in well with BP’s business strategy. However, for both natural gas and coal, the cost of “decarbonizing” fuel (i.e., pre-combustion capture) is more expensive than simply combusting the fuel and capturing and storing the CO₂ from the flue gases (i.e. post-combustion capture).

### 2.4.2.5 Projects derailed due to public acceptance

As with any technology, public acceptance problems will arise. There has not been enough experience yet to tell whether CCS projects will be exceptional with regard to public acceptance. A nice review of CCS and public acceptance is given by Ashworth et al. (2012). They stress that “the importance of communication and stakeholder engagement.” Examples of successful public outreach efforts include Decatur, Lacq, and Quest. “Community self-selection” is also important as happened with FutureGen and Otway. On the other hand, a few CCS projects have died because of lack of public acceptance, both at the local level and the national level. They are briefly described below.

**Barendrecht.** This project has become the poster child for public opposition to CCS. About 0.4 MtCO₂/yr from the Shell Pernis refinery was to be stored in two depleted gas fields near Barendrecht in the Netherlands. It appears that neither Shell nor the Dutch government had a real public outreach effort until it was too late. The town saw no local benefits, but did see risks,
as CCS demonstrations on this scale were not yet “proven”. This project has brought home the point that public outreach and stakeholder engagement is an essential part of a large-scale CCS project. Shell learned the lesson well, as seen by their excellent outreach program for the Quest project.

Carson. In hindsight, one can criticize BP for selecting the greater Los Angeles area as the site for one of the first CCS demonstration projects in the world. However, BP looked at this as a “green” project and Carson was an industrial area with a good source of PetCoke and opportunities for EOR. It was California’s environmental justice movement that opposed the project because it put an industrial facility in a lower income neighborhood. It is unclear if better stakeholder engagement would have helped. Besides protest from the environmental justice movement, BP could not get Occidental Petroleum to agree to buy their CO$_2$ for EOR. Eventually, the project was moved to Bakersfield, CA and became the HECA project (BP is no longer involved in the project).

At least two lessons can be learned here. First, good site selection is important and should have identified the environmental justice movement as an issue. Early engagement was called for. Second, announcing the project without at least some discussions regarding the sale of CO$_2$ appears to have been detrimental to the project as well.

Jänschwalde. The two projects discussed above are cases of lack of public acceptance at the local level. Jänschwalde is a case of what can happen with lack of public acceptance at the national level.

Vattenfall wanted to build a 250 MWe oxyfuel CCS power plant in Germany. An oxyfuel pilot project at Schwarze Pumpe had started up in 2009 and this was the next logical step. However due to failure of the German government to transpose the EU CCS Directive, Vattenfall had no options for storing the CO$_2$, so the project was cancelled. From Lupion and Herzog (2013):

_Nearly all Member States with planned CCS projects adopted the Directive by January 2012. However, a clear candidate to host CCS demonstration projects like Germany failed to fully transpose the European Directive. The lack of public acceptance was the main reason for the delayed transposition of the CCS directive. In July 2011, Germany’s lower house approved a bill allowing the underground storage of CO$_2$ but it was rejected by the upper house on September 2011. Following the rejection of the bill by the Bundesrat, a mediation committee was formed without result. This caused Vattenfall to abandon its CCS demonstration project in Jänschwalde, Brandenburg, and stop the planned €1.5 billion investment. The project had been awarded with €180 million from EEPR and submitted an application for the NER300 funding programme._

2.4.3 Large Pilot Projects
Table 2-12 lists large CCS pilot projects that are either operating today or have operated in the past. By large, it is meant that the feed stream is at least as big as the flue gas from 10 MWe of a coal-fired power plant. Roughly, this corresponds to 50,000 tCO$_2$/yr or greater. There are 23 pilot projects listed in Table 2-12. The listed pilot projects had information readily available in the open literature, so there may be some pilots missing from the list. For example, major
equipment suppliers like Alstom and Babcock&Wilcox had in-house pilot plants for their R&D efforts. They tended to keep their results as trade secrets and not publish in the open literature.

The first 11 projects listed in Table 2-12 are focused on storage. The last 12 have a capture focus. Note that there were three sets of linkage:

- Plant Barry is sending its CO$_2$ to Citronelle
- Callide-A sent its CO$_2$ to Otway
- Schwarze Pumpe wanted to send its CO$_2$ to Ketzin, but was prevented because Germany did not transpose the EU CCS Directive (see Section 2.4.2.5).

Linking a capture project to a storage project provides good synergy and helps financing. For example, Citronelle was developed under the US DOE’s Regional Partnership Program, where the majority of the funding came from DOE. It gave Plant Barry, funded in large part by Southern Company and jointly constructed with MHI, a ready-made storage option without the development expenses. Meanwhile, Citronelle can take advantage of a “free” (from their vantage point) source of CO$_2$.

Projects where MIT (2016) reports costs are listed in Table 2-13. Comparing the CCS pilot projects with large-scale CCS demonstrations, it can be seen that they had significantly lower project costs and, in most cases, had a higher fraction of government cost-sharing. The costs for most of the pilot projects are $100 million or less and many pilot projects received over 60% in government support.
Table 2-12. Large CCS Pilot Projects Pilot (MIT, 2016).

<table>
<thead>
<tr>
<th>Project</th>
<th>Leader</th>
<th>Location</th>
<th>CO₂ Source</th>
<th>Size</th>
<th>CO₂ Sink</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cranfield</td>
<td>SECARB</td>
<td>MS, USA</td>
<td>Natural Well</td>
<td>5.4 MtCO₂</td>
<td>Saline</td>
<td>Operated 2009-2015</td>
</tr>
<tr>
<td>Citronelle</td>
<td>SECARB</td>
<td>AL, USA</td>
<td>Coal Power</td>
<td>up to 0.15 MtCO₂/yr</td>
<td>Saline</td>
<td>Operating Since 2011</td>
</tr>
<tr>
<td>Decatur</td>
<td>MGSC</td>
<td>IL, USA</td>
<td>Ethanol Production</td>
<td>1 MtCO₂</td>
<td>Saline</td>
<td>Operated 2011-2014</td>
</tr>
<tr>
<td>Northern Reef Trend</td>
<td>MRCSP</td>
<td>MI, USA</td>
<td>NG Processing</td>
<td>.46 MtCO₂ to date</td>
<td>Depleted Oil EOR</td>
<td>Operating Since 2013</td>
</tr>
<tr>
<td>Farnsworth</td>
<td>SWP</td>
<td>TX, USA</td>
<td>Ethanol &amp; Fertilizer</td>
<td>.39 MtCO₂ to date</td>
<td>EOR</td>
<td>Operating Since 2013</td>
</tr>
<tr>
<td>Bell Creek</td>
<td>PCOR</td>
<td>MT, USA</td>
<td>Gas Processing</td>
<td>2.3 MtCO₂ to date</td>
<td>EOR</td>
<td>Operating Since 2013</td>
</tr>
<tr>
<td>K12-B</td>
<td>GDF Suez</td>
<td>Netherlands</td>
<td>Gas Processing</td>
<td>0.2 MtCO₂/yr</td>
<td>Saline</td>
<td>Operated 2004-2006</td>
</tr>
<tr>
<td>Ketzin</td>
<td>GFZ</td>
<td>Germany</td>
<td>H₂ Production</td>
<td>67 ktCO₂</td>
<td>Saline</td>
<td>Operated 2008-2013</td>
</tr>
<tr>
<td>Otway (Stage 1)</td>
<td>CO2CRC</td>
<td>Australia</td>
<td>NG Processing</td>
<td>65 ktCO₂</td>
<td>Depleted Gas</td>
<td>Operated 2008-2012</td>
</tr>
<tr>
<td>Ordos</td>
<td>Shenhua Group</td>
<td>China</td>
<td>Coal Liquefaction</td>
<td>Up to 0.1 MtCO₂/yr</td>
<td>Saline</td>
<td>Operating Since 2011</td>
</tr>
<tr>
<td>Jilin</td>
<td>PetroChina</td>
<td>China</td>
<td>NG Processing</td>
<td>0.2 MtCO₂/yr</td>
<td>EOR</td>
<td>Operating Since 2009</td>
</tr>
<tr>
<td>Schwarze Pumpe</td>
<td>Vattenfall</td>
<td>Germany</td>
<td>Coal Oxy</td>
<td>30 MWₐ</td>
<td>Vented</td>
<td>(To Ketzin)</td>
</tr>
<tr>
<td>AEP Mountaineer</td>
<td>AEP</td>
<td>WV, USA</td>
<td>Coal Post</td>
<td>30 MWₑ</td>
<td>Saline</td>
<td>Operated 2009-2011</td>
</tr>
<tr>
<td>Compostilla</td>
<td>CIUDEN</td>
<td>Spain</td>
<td>Coal Oxy</td>
<td>30 MWₐ</td>
<td>Vented</td>
<td>Operated 2009-2012</td>
</tr>
<tr>
<td>Puertollano</td>
<td>ELCOGAS</td>
<td>Spain</td>
<td>Coal Pre</td>
<td>100 tCO₂/day</td>
<td>Recycled</td>
<td>Operated 2010-2011</td>
</tr>
<tr>
<td>Lacq</td>
<td>Total</td>
<td>France</td>
<td>Oil Oxy</td>
<td>35 MWₐ</td>
<td>Depleted Gas</td>
<td>Operated 2010-2013</td>
</tr>
<tr>
<td>Buggenum</td>
<td>Vattenfall</td>
<td>Netherlands</td>
<td>Coal Pre</td>
<td>20 MWₑ</td>
<td>Vented</td>
<td>Operated 2011-2013</td>
</tr>
<tr>
<td>Shidongkou</td>
<td>Huaneng</td>
<td>China</td>
<td>Coal Post</td>
<td>0.1 MtCO₂/yr</td>
<td>Commercial Markets</td>
<td>Operating Since 2009</td>
</tr>
<tr>
<td>Shand</td>
<td>SaskPower</td>
<td>Canada</td>
<td>Coal Post</td>
<td>0.043 MtCO₂/yr</td>
<td>Vented</td>
<td>Operating Since 2015</td>
</tr>
<tr>
<td>Mongstad</td>
<td>Statoil</td>
<td>Norway</td>
<td>Gas Post</td>
<td>0.1 MtCO₂/yr</td>
<td>Vented</td>
<td>Operating Since 2012</td>
</tr>
<tr>
<td>Plant Barry</td>
<td>Southern Energy</td>
<td>AL, USA</td>
<td>Coal Post</td>
<td>25 MWₑ</td>
<td>To Citronelle</td>
<td>Operating Since 2011</td>
</tr>
<tr>
<td>Callide-A Oxy Fuel</td>
<td>CS Energy</td>
<td>Australia</td>
<td>Coal Oxy</td>
<td>30 MWₐ</td>
<td>To Otway</td>
<td>Operating 2012-2015</td>
</tr>
<tr>
<td>Boryeong Station</td>
<td>KEPCO</td>
<td>South Korea</td>
<td>Coal Post</td>
<td>10 MWₑ</td>
<td>Vented</td>
<td>Operating Since 2013</td>
</tr>
</tbody>
</table>
The first six projects listed in both Tables 2-12 and 2-13 are part of the US DOE’s Regional Partnership Program. As R&D projects, the non-federal cost-share requirement is only 20% for the projects. These projects are made up of a consortium of companies and organizations, so the cost-sharing can be spread over many entities.

Many of these projects were entered into with the hope that they would be a step toward a large-scale CCS demonstration. The only project that has fulfilled that promise to date is the Decatur project. As discussed previously in this report, plans for large-scale CCS Demonstrations at AEP Mountaineer, Plant Barry, Schwarze Pumpe, and Mongstad did not come to fruition. China is hopeful that the Ordos and Jilin pilots will eventually evolve into large-scale demonstrations.

A major outlier in costs of pilot projects is Mongstad. The Norwegian government financed the whole project through Gassnova and, at first, money was not an issue (this started changing when costs increased dramatically). The project included two complete pilot plants, one for amines and one for chilled ammonia. The chilled ammonia plant was a custom design and required mostly field fabrication, adding greatly to the costs. There are many other unique items and features of Mongstad that led to its large price tag, such as an elevated pipeline from the refinery to the test center and a pair of state-of-the-art control rooms.

Table 2-13. Reported Costs of Large CCS Pilot Projects (MIT, 2016).

<table>
<thead>
<tr>
<th>Project</th>
<th>Total Cost ($ million)</th>
<th>Government Support ($ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cranfield</td>
<td>93</td>
<td>65 (70%)</td>
</tr>
<tr>
<td>Citronelle</td>
<td>111</td>
<td>77 (69%)</td>
</tr>
<tr>
<td>Decatur</td>
<td>84</td>
<td>67 (79%)</td>
</tr>
<tr>
<td>Northern Reef Trend</td>
<td>115</td>
<td>89 (77%)</td>
</tr>
<tr>
<td>Farnsworth</td>
<td>79</td>
<td>53 (67%)</td>
</tr>
<tr>
<td>Bell Creek &amp; Fort Nelson</td>
<td>113</td>
<td>79 (70%)</td>
</tr>
<tr>
<td>Schwarze Pumpe</td>
<td>96</td>
<td>0</td>
</tr>
<tr>
<td>AEP Mountaineer</td>
<td>100</td>
<td>16 (16%)</td>
</tr>
<tr>
<td>Puertollano</td>
<td>18</td>
<td>10 (60%)</td>
</tr>
<tr>
<td>Lacq</td>
<td>83</td>
<td>0</td>
</tr>
<tr>
<td>Buggenum</td>
<td>55</td>
<td>41 (75%)</td>
</tr>
<tr>
<td>Jilin</td>
<td>11</td>
<td>?</td>
</tr>
<tr>
<td>Shidongkou</td>
<td>24</td>
<td>0</td>
</tr>
<tr>
<td>Shand</td>
<td>70</td>
<td>0</td>
</tr>
<tr>
<td>Mongstad</td>
<td>~840</td>
<td>~840 (100%)</td>
</tr>
<tr>
<td>Callide-A Oxy Fuel</td>
<td>A$208</td>
<td>A$76 (36%)</td>
</tr>
<tr>
<td>Boryeong Station</td>
<td>42</td>
<td>?</td>
</tr>
</tbody>
</table>
2.5 Lessons Learned

This section discusses some of the lessons learned from this review of the past two decades of CCS demonstration projects.

1. There are strong links between the successful CCS demonstration projects and the oil & gas industry.

Twenty-one of the 22 successful CCS demonstration projects have occurred in a region with a significant oil & gas industry. The only exception is Decatur in Illinois. EOR provided the financial incentive for all nine commercial EOR projects using anthropogenic CO\(_2\) (see Table 2-2). All four pioneer projects (see Table 2-3) were operated by oil companies and with the CO\(_2\) being a by-product of natural gas processing. Finally, seven of the 9 CCS RD&D projects (see Table 2-4) accessed EOR markets to help with project financing, with one of the remaining two projects being located at an oil refinery.

2. Access to markets has to move beyond EOR.

Lesson 1 has shown the importance of EOR markets to date. For CCS projects to grow numerically and geographically, they will need to access other markets. The two markets that offer the most potential are carbon markets and electricity markets. While somewhat limited today, new regulatory drivers (see Lesson 3) can increase their role.

Today, there are limited carbon markets and they generally have low carbon prices, much lower than needed to incentivize a CCS project at a power plant. So while they can be part of a bigger financing package, at current carbon prices they will play a minor role.

Electricity markets have played a larger role to date than carbon markets. Two of the three successful CCS demonstrations on power plants (Boundary Dam and Kemper) did access electricity markets by gaining approval of their utility regulators to put some (Kemper) or all (Boundary Dam) of the costs in the rate base. However, without policy in place to reduce CO\(_2\) emissions (or the likelihood that these policies would be put in place), gaining access to electricity markets will be difficult. AEP tried to gain access for their Mountaineer project and were denied by their regulators, in part because there was no “federal mandate to cut carbon emissions from power plants”.

Policies that qualify CCS for access to electricity markets would be beneficial. Examples of these types of policies include portfolio standards or feed-in tariffs. The example of this type of policy currently in place for CCS is the UK’s “contracts for differences”. This policy allows CCS projects to contract a price for the electricity they produce. They would then be paid the difference between this contract price and the market price. The projects in the UK’s £1 billion competition were qualified to use this program as part of their financial package.
3. Regulatory drivers are critical to creating markets for CCS.

As discussed in Lesson 2, regulatory drivers are needed to grow carbon markets and give CCS better access to electricity markets. In the case of Boundary Dam, their access to electricity markets was dependent on a regulatory driver being in place. This regulatory driver was a performance standard limiting the amount of carbon emissions coming from certain coal-fired power plants. This did not guarantee CCS would be deployed, but it did require a change from business as usual, allowing CCS to compete. On the other side of the coin, AEP Mountaineer was denied access to electricity markets because there was no regulatory driver in place.

Going forward, new carbon policies will be put in place around the world to follow through on the agreement reached at COP21 in Paris. The key question is whether the policies will be strong enough to help move CCS forward. If policies are market oriented, will they create large enough carbon markets that can help finance CCS projects? If the policies are more command and control, will the regulatory drivers be sufficient to allow CCS projects to tap into electricity or other commercial markets? The exact formulation of these policies will be critical to the future of CCS. For example, in the US, it does not appear that the Clean Power Plan by itself will provide much incentive for CCS projects. This is because the targets are relatively modest and will be met primarily with increased use of renewables (which are heavily subsidized and have portfolio standards in many states) and a switch from coal to natural gas (driven in large part by low natural gas prices).

In general, a more stringent regulation in terms of emissions reduction will generally be more beneficial to CCS’s competitive position. Even if regulations are implemented slowly, the message that more stringent regulations will be coming in the future can help incentivize CCS because it will send a strong signal to the private sector (see Lesson 4 below).

4. Business drivers play a major role.

It is crystal clear from the review of CCS projects in this report that business drivers have been critical to the successful CCS projects. Another way to say this is that projects can greatly improve their chances of success if they align with business interests and/or have a persuasive business case. This can take many forms, as shown by these examples discussed in this report:

- Protecting or promoting assets, including the oil sands in Alberta or lignite in Mississippi, Saskatchewan, or Germany
- Going “beyond petroleum” at BP
- The push for clean energy at NRG
- The goal of “energy sustainability and environmental responsibility” at ADM

As mentioned in Lesson 3, when regulatory drivers send a message that carbon emissions must be cut, it can create business drivers to adopt low carbon technologies. As seen by the examples above, CCS will fit well into many business strategies. On the other hand, we presently have the opposite happening because the regulatory drivers are weak and there is great uncertainty about
when they will be strengthened. The result is that many companies have either reduced or eliminated their efforts in developing CCS technologies.

5. Over reliance on government subsidies is a risky business.

Many successful projects have benefited from government support. For many smaller projects (e.g., pilot projects), the government support was well over 50% of the financing. However, the government support for successful larger projects was a smaller fraction. The projects that required very large government payments have not succeeded. They include:

- FutureGen and FutureGen 2.0 (from US)
- Shell Peterhead and White Rose (from UK)
- BP Peterhead (DF1) (from UK)
- Mongstad (from Norway)

These projects take years to develop. During that time, politics change. These large projects can become easy targets. In the case of the cancellation of the UK competition, it has generated mistrust of the government by industry, which may have a chilling effect on industry participation for future government programs to support CCS.

This analysis tends to show that a more secure path forward for CCS is to have government create the regulatory environment to create business drivers. For initial projects, government financial support will probably still be required to overcome first mover costs. However, this support can be more balanced, such as a program like the CCPI in the US.

6. Successful CCS power projects used multiple financing components.

Power sector CCS in the current regulatory regime is expensive. It is one reason while there are only 3 successful CCS demonstration projects at power plants. If there was a carbon price at a sufficiently high level, perhaps that would be sufficient to finance a CCS project. However, that is not the case today and is unlikely to happen in the foreseeable future. As a result, financing these projects will remain complex and require multiple financing components, as seen at Boundary Dam and Kemper. This leads some people to question the current approach to CCS demonstration projects in the power sector and wonder whether there is a better approach to CCS technology development, especially if we want deployable results in a relatively short timeframe (see Lesson 10).

7. Innovative CCS power projects (e.g., poly-generation) are interesting, but may be hard to replicate.

Innovation in the business model has been attempted in several power sector projects. Petra Nova is the only successful example to date. TCEP and HECA have both been innovative in their approach, but TCEP has yet to come to a financial close and HECA has been cancelled.
Questions have been raised about these projects. Petra Nova bought a pipeline and oil field as part of the project, eliciting comments that this is not a commercial model most power generators could replicate. The poly-generation concept of HECA and TCEP can be looked at as an industrial (chemical) CCS project with electricity as a by-product, as opposed to a power sector project. Given current markets and the long-term projections of price and supply for both oil and natural gas in the U.S. there is a question about subsequent broad commercial application or replication of these project models.

8. Gasification-based power projects have a poor record.

Fifteen years ago, the conventional wisdom was that a near zero emission coal-fired power plant would be based on coal gasification (IGCC) plus CCS. This report reviewed many gasification projects proposed for the power sector, but only one was actually implemented, Kemper. While there may still be a role for IGCC in the future, the pendulum today has swung back to pulverized coal (PC) plants with either post-combustion or oxy-combustion capture.

The primary reason gasification is in trouble in the power sector is that it has proven uncompetitive with PC plants. Until costs for IGCC can be brought more in line with PC, its future in the power sector will remain shaky.

The innovative concept of poly-generation is based on gasification. Perhaps in the future that can be a path forward. However, it is not that attractive today in the U.S. because of low natural gas prices. Natural gas is the primary feedstock for the products that would be produced by poly-generation. As long as natural gas prices remain low, there will be low prices for the commodities it produces. As a result, it makes poly-generation less financially attractive.

9. Setting arbitrary time limits on projects generally has led to failure.

There were two government programs that were set up that had strict time limits, ARRA in the US and the NER300 in the EU. These time limits essentially made the NER300 program a non-starter. In the US, FutureGen 2.0 stated they would have succeeded if given more time. Southern (Plant Barry) realized from the start that the timeline was going to be too tight for them, and immediately cancelled their project under the CCPI (funded by ARRA).

A recurring theme is that CCS projects in the power sector are complex and have many moving parts. It takes time to address them in a rational manner. Programs that set arbitrary time limits are generally not helpful. In some cases these time limits can be very detrimental. The best example is FutureGen 2.0. “Ken Humphreys, chief executive of the FutureGen Industrial Alliance Inc., spelled out in testimony to the Illinois Pollution Control Board that major construction spending can’t begin until the alliance secures a remaining $650 million in private capital. And investors won’t commit financing under the cloud of uncertainty presented by the air permit challenge [brought by the Sierra Club]” (Energy Wire, 2014). The Sierra Club did not need to win the challenge to kill the project; all they needed to do was delay the project so it could not spend its ARRA funds by the deadline.

2-40
**10. CCS projects that have shorter timelines have greater chances of success.**

We live in a dynamic world, so projects with long timelines can be subject to changes that adversely affect them. Politics change, as illustrated by the UK competition. Economics change, as illustrated by the dramatic drop in US natural gas prices over the past several years and the world oil price the past two years. The longer the timeline, the more risk and uncertainty a project may face. As a result, it may be wise for future CCS project demonstrations to have shorter timelines for development.

Examples of successful CCS projects with relatively short development timelines include Boundary Dam and Quest. In both of these cases, an established company was in charge (SaskPower and Shell, respectively). The project took place on their existing industrial sites. They did not need to look outside for an equity partner (as in the case of TCEP).

In general, here are some characteristics to help reduce a project's timeline:

- Develop smaller scale projects
- Use brownfield sites
- Minimize the technical risks (e.g., do the technology development at the pilot scale)
- Work with government for a streamlined permitting process
- Avoid complicated business arrangements

**11. Stronger political support is needed for CCS.**

Unlike renewables, CCS does not have a strong constituency that can sway political support. There have been many examples of how this has adversely impacted CCS projects, including:

- Cancellation of the UK’s £1 billion competition
- Forcing the EU’s NER300 to include renewable projects
- The UK not supporting BP’s Peterhead (DF1) project
- Germany not transposing the EU’s CCS Directive

Going forward, as new regulations and laws are put in force to reduce greenhouse gas emissions, politics will play an important role as to their impact on CCS. Therefore, it is important to have stronger political support for CCS going forward than there has been in the past.

To gain political support, it is important to define the role of CCS as complementary to renewables and not in competition. As long as there is the perception among decision-makers that renewables can solve the climate issue by itself (as in Germany), it will be very difficult for CCS to progress. An “all of the above” strategy as stated by the Obama administration is more amenable to CCS.
12. All major CCS demonstration projects require a public outreach program.

One can only speculate on whether or not public acceptance will be an impediment to CCS going forward. There is just not enough past experience to extrapolate. This report highlighted two projects that ran into public acceptance issues. However, those early projects did not do public outreach until it was too late. Projects that have adopted best practices with regard to public outreach have an excellent record. We have learned that a good public outreach program needs to be part of every major CCS project. Only time will tell if that will be sufficient.
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2-44


Task 3: Factors Impacting Private Sector Investment in Large Scale CCS Projects

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Independent Contractor

Disclaimer: This Task 3 Report has been prepared as part of a larger study of options for funding large pilot scale testing of advanced fossil-based power generation technologies with carbon capture and storage.

The author thanks those who contributed material and comments to improve the quality of this report. However the author is solely responsible for the content of this report. Special thanks are extended to NEDO for its financial contribution to this report.

While the author has endeavored to provide accurate and timely information in this report, no warranty is made as to the accuracy or usefulness of the material contained herein. References to specific companies, products or technologies are not to be construed as endorsements by the author or CURC. Information and statements contained in this report are not intended to be legal advice and should not be relied upon as such.
3 Executive Summary

This paper discusses the factors that influence the degree to which the private sector is willing to invest in large pilot scale projects (approximately 10-50 MWe) that apply carbon capture and storage (CCS) technology to power plants. The discussion is based primarily on market conditions in the U.S., although there is a brief discussion reflecting stakeholders based in Canada, Japan, and South Korea.

The role of large pilot projects in technology development is to provide performance data enabling the design of commercial-scale demonstration units, or in some cases enabling the design of fully commercial units. The traditional private sector stakeholders in large pilot projects and commercial-scale demonstration projects have been companies that supply equipment to fossil-fueled power plants, coal companies, and electric utilities that own or may build fossil fueled power plants, especially coal-fueled power plants. In U.S. markets, two of these three sectors are seriously challenged by unfavorable economic conditions. About 25% of U.S. coal production is from companies that are currently in bankruptcy proceedings, and a coal sector financial index has had remarkably poor performance over the past decade. Equipment suppliers to power plants in the U.S. are faced with minimal incremental demand for additional electrical generating capacity over the next decade and U.S. government agencies project minimal demand for new coal-fueled power plants for a much longer period of time. Electric utilities in the U.S. generally have healthy balance sheets, but a sample of electric utility Integrated Resource Plans (IRPs) found none that expects to build a new power plant equipped with CCS within its planning outlook, typically 20 years.

In most electric power markets, discretionary investments tend to flow toward projects that offer an optimal balance between risk and financial reward. An emerging technology like CCS presents a challenging decision process because of uncertainty regarding many of the basic issues to be considered in projecting risks and rewards. Investment attitudes of potential private sector participants in large pilot projects involving CCS technologies have been gleaned from:

- The stakeholders’ economic strength and current profitability, as reflected in stock price trends, market sector indices, and other published financial information
- Published electric utility planning documents (IRPs)
- U.S. Government projections of future electricity supply by fuel and technology class

Both government and private sector projections generally assume currently available technology, or gradually decreasing prices based on “learning curves” for emerging technologies like CCS. They do not reflect disruptive technologies that could dramatically impact electricity demand, or the economics of potentially transformational electricity supply technologies.
A 2014 report documenting an industry-sponsored workshop on potential support for large pilot projects for CCS

A limited survey of stakeholders, performed for this paper

In general, stakeholders consistently held that their willingness to invest in a large pilot project would depend on the existence of a “persuasive business case” for the investment. In other words, the amount that they would invest would need to be supported by a quantitative analysis that the investment would result in greater profits than other attractive uses of the company’s available funds. Additionally, recognizing that a large pilot project could cost hundreds of millions of dollars, stakeholders said that the necessary resources would have to be available for the project. Within this general framework, the amount of “cost-share” that the private sector would support for a large pilot project was determined to be shaped by a range of factors, including:

- Minimal projected growth in electricity demand in the U.S. over the next decade, and projections for minimal deployment of new coal-fueled units through 2040 (Low demand for a new technology reduces the potential profits that flow from its development.)
- Financial weakness of coal producers in the U.S., and perhaps to a lesser degree, major equipment suppliers to coal-fueled power plants
- Risk of technology failure
- Risk that the commercial technology may be more costly than expected
- The time lag between when an investment in a pilot technology is made and the time when commercial deployment of the mature technology will take place
- The potential for competitors to deploy the developed technology without having to invest in its development (free rider concept)
- The risk of changing regulatory requirements, including CO₂ emission limits and long-term liability for stored CO₂
- The risk of improving economics for competing technologies, exacerbated by the time needed to commercialize power/CCS technologies
- The value of a technology that expands choices for the electric power sector, enhancing technology competition and fostering lower prices
- Whether a large pilot of a technology is sufficient to support commercialization of the technology without also building a commercial scale demonstration unit (this is thought to vary by technology)
3.1 Introduction
This paper discusses factors that influence funding levels that the private sector is willing to provide in pursuit of improved carbon capture and storage (CCS) technologies applicable to the electric power sector. This funding level is often referred to as “cost share,” defined as the fraction of project cost borne by private sector participants in the project. The discussion focuses on projects that are considered “large pilot” scale, and compares investments in large pilot projects with investments at both smaller (small pilots) and larger (commercial demonstration) scale.

The paper will not address the need for CCS technologies in global efforts to reduce emissions of CO₂, other than to note that other analyses have concluded that affordable CCS technologies are either essential to meeting climate change mitigation goals, or can dramatically reduce the cost of reaching those goals. For example, the Fifth Assessment Report by the Intergovernmental Panel on Climate Change found that many of the models used in that assessment could not reach a 450ppm CO₂-eq goal without CCS, and for the four that could, mitigation costs increased by an average of 138% compared to model projections that included CCS technology as an emission reduction option.²⁵

Similarly, the principle of government/private sector cost sharing in technology development is not discussed at length, because there is an extensive record of governments collaborating with the private sector to enable or accelerate the development of technologies that provided a public good, such as meeting a broad environmental objective. Such collaboration in Europe, Japan, and the U.S. has included research and development (R&D), commercial-scale demonstration projects, and early deployment incentives for renewable energy technologies and environmental controls for fossil energy-fueled electric power plants.²⁶

This paper will discuss topics relevant to investment in CCS technology, including:

- How the various stages in development of a new technology differ in terms of scale and risk of failure
- Drivers for private sector investment: risk versus reward
- The outlook for new coal-fueled power plants in the U.S., which is relevant to private sector interest in investing in CCS technology

• The current economic health of the U.S. coal industry, which is relevant to its ability to invest in CCS technology
• Views on CCS expressed by traditional power plant equipment suppliers
• Traditional approaches to providing incentives to emerging electric power technologies
3.2 Progressive steps in technology development

Modern fossil fueled power plants, even without CCS controls, are expensive. For example, capital cost estimates by USDOE/EIA range from $912/kW for natural gas combined cycle (NGCC) systems, to $2917/kW for pulverized coal systems.\(^{27}\) For a 500 MWe power plant, these values equate to a capital cost range of $0.5 – 1.5 billion per power plant. The incremental cost of adding currently available CCS technologies can increase these capital costs by 75-100\%.\(^{28}\) The magnitude of these costs necessitates a stepwise approach to taking new concepts from a laboratory or “bench” scale to a commercial-scale system in order to manage risk of technology failure and miscalculation of technology cost.

In the 1980’s the National Aeronautics and Space Administration (NASA) developed a structured approach to defining technology development stages called “Technology Readiness Levels” or TRLs. The initial system has since evolved somewhat, and has been adopted by government agencies around the world, including the U.S. DOD, U.S. DOE, and the European Commission.\(^{29}\) DOE/NETL reports use TRLs to describe technology developments in CCS and related technologies.\(^{30}\) Table 3-1, taken from an NETL report, presents DOE’s definitions and descriptions of each of the nine TRLs in terms relevant to power systems. In a properly managed technology development program, the risk of technology failure is greatest at the low TRLs, and least as the technology approaches commercialization.\(^{31}\)

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28 Ibid.
Table 3-1. DOE-Fossil Energy TRL Definitions and Descriptions.

<table>
<thead>
<tr>
<th>TRL</th>
<th>DOE-FE Definition</th>
<th>DOE-FE Description</th>
</tr>
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<tbody>
<tr>
<td>1</td>
<td>Basic principles observed and reported</td>
<td>Lowest level of technology readiness. Scientific research begins to be translated into applied R&amp;D. Examples include paper studies of a technology's basic properties.</td>
</tr>
<tr>
<td>2</td>
<td>Technology concept and/or application formulated</td>
<td>Invention begins. Once basic principles are observed, practical applications can be invented. Applications are speculative and there may be no proof or detailed analysis to support the assumptions. Examples are still limited to analytic studies.</td>
</tr>
<tr>
<td>3</td>
<td>Analytical and experimental critical function and/or characteristic proof of concept</td>
<td>Active R&amp;D is initiated. This includes analytical and laboratory scale studies to physically validate the analytical predictions of separate elements of the technology (e.g., individual technology components have undergone laboratory-scale testing using bottled gases to simulate major flue gas species at a scale of less than 1 scfm).</td>
</tr>
<tr>
<td>4</td>
<td>Component and/or system validation in a laboratory environment</td>
<td>A bench-scale prototype has been developed and validated in the laboratory environment. Prototype is defined as less than 5 percent final scale (e.g., complete technology process has undergone bench-scale testing using synthetic flue gas composition at a scale of approximately 1–100 scfm).</td>
</tr>
<tr>
<td>5</td>
<td>Laboratory-scale similar system validation in a relevant environment</td>
<td>The basic technological components are integrated so that the system configuration is similar to (matches) the final application in almost all respects. Prototype is defined as less than 5 percent final scale (e.g., complete technology has undergone bench-scale testing using actual flue gas composition at a scale equivalent to approximately 1–100 scfm).</td>
</tr>
<tr>
<td>6</td>
<td>Engineering/pilot-scale prototypical system demonstrated in a relevant environment</td>
<td>Engineering-scale models or prototypes are tested in a relevant environment. Pilot or process-development unit-scale is defined as being between 0 and 5 percent final scale (e.g., complete technology has undergone small pilot-scale testing using actual flue gas composition at a scale equivalent to approximately 1,250–12,500 scfm).</td>
</tr>
<tr>
<td>7</td>
<td>System prototype demonstrated in a plant environment</td>
<td>This represents a major step up from TRL 6, requiring demonstration of an actual system prototype in a relevant environment. Final design is virtually complete. Pilot or process-development unit demonstration of a 5–25 percent final scale or design and development of a 200–600 MW plant (e.g., complete technology has undergone large pilot-scale testing using actual flue gas composition at a scale equivalent to approximately 25,000–62,500 scfm).</td>
</tr>
<tr>
<td>8</td>
<td>Actual system completed and qualified through test and demonstration in a plant environment</td>
<td>The technology has been proven to work in its final form and under expected conditions. In almost all cases, this TRL represents the end of true system development. Examples include startup, testing, and evaluation of the system within a 200–600 MW plant CCS operation (e.g., complete and fully integrated technology has been initiated at full-scale demonstration including startup, testing, and evaluation of the system using actual flue gas composition at a scale equivalent to approximately 200 MW or greater).</td>
</tr>
<tr>
<td>9</td>
<td>Actual system operated over the full range of expected conditions</td>
<td>The technology is in its final form and operated under the full range of operating conditions. The scale of this technology is expected to be 200–600 MW plant CCS operations (e.g., complete and fully integrated technology has undergone full-scale demonstration testing using actual flue gas composition at a scale equivalent to approximately 200 MW or greater).</td>
</tr>
</tbody>
</table>

In general, this paper will treat “laboratory or bench scale” as TRL 1-5; “small pilot” scale as TRL 6 (approximately 1 MWe); “large pilot scale” as TRL 7 (approximately 10-50 MWe); and “commercial demonstration scale” as TRL 8 (over 200 MWe).

Order of magnitude CCS project capital costs by TRL can be estimated from discussions at a 2014 workshop seeking to determine industry interest in participating in large pilot plant CCS projects. The report of that workshop said that participants believed that small pilot plants (TRL 6) would be about 1 MWe in scale, and cost about $20 million. Large pilot projects (a coal-fired power system with CCS, TRL 7), were judged to be about 25-50 MWe and cost about $250-500 million. Commercial scale demonstration projects (TRL 8), at 200 MWe, would cost about $2 billion. These cost estimates are useful only for gaining an appreciation for the relative change in capital cost magnitude as a technology scales up from the laboratory to a commercial-scale facility. Within a TRL category, costs can vary considerably depending on whether the entire facility is constructed (greenfield) versus being retrofit to an existing power plant; whether a new power system is an integral part of the project or the project is essentially a capture system that treats a slipstream from an existing facility or takes flue gas or syngas from a

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multi-use facility like the National Carbon Capture Center. Additionally, small projects sometimes are “catch-and-release” facilities intended only to demonstrate a CO₂ capture technology, whereas other (typically larger) projects integrate CO₂ capture with pressurization, pipeline transport, and geologic storage or enhanced oil recovery (EOR) reuse and storage of CO₂.

The level of past support of CCS projects by the U.S. government has varied by the scale of the projects. The logic was that small projects are earlier in the technology development process, implying greater risk of failure, and therefore merit a greater relative share of funding by the government. A non-government “cost share” of at least 20% of the cost of project is generally required for R&D activities supported by the U.S. DOE, and at least 50% for demonstration-scale projects. However, these minimum cost-share requirements can be waived by the Secretary of Energy. Two recent “Funding Opportunity Announcements” (FOAs) by the U.S. DOE defined “small pilots” to be about 0.5 – 5.0 MWe, and “large pilots” to be either ≥ 10 MWe or 10 to +25 MWe in capacity. Both FOAs required selected projects to provide a minimum cost share of 20%.

33 The National Carbon Capture Center is a collaborative effort between the USDOE, EPRI, and several electric utilities and coal companies. It provides sites where pre-combustion and post-combustion CO₂ capture technologies can be evaluated at a bench scale or small pilot scale.

http://www.nationalcarboncapturecenter.com/pdf/NCCC%20Overview%202014.pdf

34 Section 988 of Public Law 109-58 (EPACT-05). Implementing regulations under 10CFR600.30 and 10CFR600.302 imply that pilot projects are treated as demonstration projects for purposes of setting cost-share requirements, but given the authority of the Secretary of Energy to waive these limits the practical cost-share requirements appear more flexible than the numeric values would suggest.

35 Small and Large Scale Pilots for Reducing the Cost of CO₂ Capture and Compression, FOA #: DE-FOA-0001190, Issued 2/11/2015; Pre-Project Planning for Advanced Combustion Pilot Plants, FOA #: DE-FOA-0001459, Issued 1/21/2016 (Both issued by USDOE).
3.3 Economic and regulatory risks and rewards for new technology

In market driven economies, investment decisions are based on a balancing of potential risks and potential rewards that are expected to result from an investment, and a comparison of the net rewards of a particular investment compared to alternative investments. Fossil energy-based technologies (without CCS) have dominated U.S. power production for the past century because of their ability to produce reliable power at a relatively low cost. However, with recent regulations mandating the use of CCS on new coal-fueled power plants in the U.S., relative costs have shifted. The U.S. Secretary of Energy has testified that such requirements will eventually be applied to natural gas fueled power plants as well. The challenge for fossil energy based power is to reduce the cost of generators equipped with CCS by improving the technology. There are several types of risk that must be successfully addressed by projects seeking to advance fossil energy-based power plant/CCS technology:

- **Technology failure.** Particularly in the early stages of development of a technology, there is a risk that the technology may not work, or may not work as well as existing technologies.
- **Excessive cost.** Higher than expected cost can manifest in several forms. First, a given development project (e.g., small pilot, large pilot, or demonstration project) can cost more than initially believed. Factors that can lead to these cost increases are discussed below. Second, the development project may meet cost expectations, but the commercial version of the technology may be more expensive than originally believed, undercutting the business case for development of the technology. Third, byproduct markets may provide lower than expected revenues, due to unrelated market changes. For example, a drop in the global price of crude oil can reduce revenues from the sale of CO₂ for EOR.
- **Unanticipated competition.** Fossil-fueled power plants with CCS must compete with other sources of electricity. For a technology with a 10-20 year gap between the current technology project and commercial deployment, projected costs for other technologies and fuels can change significantly. For example, in 2008, USDOE/EIA predicted that the ratio of delivered natural gas prices to power plants in the U.S., versus coal prices (both on a dollar per Btu basis) would be 3.5 in 2014. The actual ratio was 2.1, or a 40% lower differential in fuel costs than expected just six years earlier. Natural gas technology dominates new power additions in the U.S., and natural gas-based generation has approached the level of power generation from coal over the past year. This is a

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36 “Looking into the future, CCS technologies will be required for natural gas, as with coal, to be a major player in a low-carbon world. “, Testimony by Secretary of Energy Moniz before the House Committee on Appropriations Subcommittee on Energy and Water Development and Related Agencies, April 2, 2014.
37 These risks were cited by participants in a 2014 Workshop convened to discuss private sector interest in large pilot projects for CCS, and in response to a limited survey conducted in preparation of this paper. Op. cit., Technical Workshop Report.
40 Table 7.2a, Monthly Energy Review, January 2016, USDOE/EIA, January 2016
dramatic departure from coal’s historical role as the primary source of electric power in the U.S. (See Figure 3-1.) Competition also exists within the coal sector: a new coal technology may be less attractive than another new coal-based power generation technology.

- **Regulatory risk.** It is generally recognized that a “regulatory driver” is needed in order to achieve broad deployment of CCS-equipped power plants, and the same is likely true for large pilot projects or commercial-scale demonstration projects. However, the best design for such a driver is less clear.
  
  o Alberta had a $15/tonne CO$_2$ fee requirement in place for coal-fired power plant emissions, but that regulatory driver, along with approximately $880 million in government grants, was insufficient to prevent cancellation of the TransAlta Project Pioneer CCS facility in Alberta.\(^{41}\) The U.S. has CO$_2$ technology requirements for new fossil fueled power plants under the New Source Review Program, and a “partial CCS” requirement for new coal-fueled power plants under the New Source Performance Standards program, but these rules have not led to a dramatic expansion in large pilot or demonstration-scale projects.

  o Changing government regulations can help or hurt an emerging technology. National GHG reduction goals and changing state and federal interpretations of what constitutes statutorily required “Best Available Control Technology” for CO$_2$ emissions from new power plants can influence the price of coal and gas-fueled power plants. CO$_2$ emission reporting rules, including requirements for monitoring, reporting, and verification (MRV) plans, have been cited as a deterrent to the use of captured CO$_2$ for EOR.\(^{42}\)

  o Some regulations, such as renewable portfolio standards, can create a strong regulatory bias away from fossil fueled power systems with CCS. EPA’s analysis of its “Clean Power Plan” rule projected that U.S. coal-fired power generation, which averaged 2,000 TWH/yr between 2005-2008, would decline to 1,217 TWH/yr in 2025, and 1,144 TWH/yr in 2030.\(^{43}\)

  o Coal itself is not without regulatory risk. On January 15, 2016, Department of Interior Secretary Jewell issued an order\(^{44}\) imposing a moratorium on new leases of federal land for coal production. DOI intends to conduct a study on leasing before issuing any new lease, and the implication of DOI’s order is that leases will either be more restricted or carry a higher cost to the leasee. Since 41% of U.S. coal production is pursuant to Federal leases, this action could increase the cost of coal-based power production in the U.S.

\(^{41}\) See discussion in Task 2 of this report.


\(^{43}\) Regulatory Impact Analysis for the Clean Power Plan Final Rule, USEPA, August 2015.

\(^{44}\) Order no. 3338, USDOI, January 15, 2016.
• **Changing government policy.** In the U.S., the President’s Climate Action Plan cited carbon capture and sequestration as one of many low-carbon technologies that the U.S. would promote.\(^{45}\) However, the most recent budget request by the President totals $360 million in new funds for USDOE Fossil Energy R&D in FY2017, compared to $632 million in FY2016.\(^{46}\) Similarly, the UK recently reversed its policy on CCS and announced that a program aimed at providing £1 billion to two CCS projects in the UK would be curtailed.\(^{47}\)

• **General economic growth and electricity demand.** USDOE/EIA projects that essentially no new coal-fueled power plants will be built in the U.S. within the current forecasting horizon (2040), and virtually no new generating capacity of any type would be needed until after 2025.\(^{48}\) Departures from “conventional wisdom” on the need for additional new electricity generating capacity can alter the business case for a new generating technology. For example, reduced economic growth rates usually imply reduced growth in electricity demand and a weaker environment for new technologies. Conversely, greater than expected economic growth, accelerated retirement of existing generating capacity, and unexpected new sources of electricity demand such as electric vehicles or computer “data centers” can lead to a more positive economic environment for new capacity.

• **Commercialization time lag.** A large new coal-fueled power plant can require up to 7 years to complete design, permitting, and construction once a decision is made to proceed with the project. Commercial-scale demonstration units have a similar time frame for construction, but may require additional time to gather financial support and to record the operating data needed to proceed to commercialization. Large pilot plants require somewhat less time for the pilot project itself, but may still require an additional 10-15 years after completion of the pilot plant before commercial projects can provide revenues from commercial sales. Other types of electric power technology such as wind power and solar power have much briefer cycles of development, and may be more attractive to investors wishing to recover their research investment as quickly as possible.

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\(^{45}\) The President’s Climate Action Plan, White House, 2013 .
3.4 Perspectives from the private sector

There are three industries with an obvious interest in fossil fuel power plants with affordable and effective CCS systems: Electric utilities, power plant equipment suppliers, and coal producers. It is useful to examine each of these industries and factors that they might consider relevant to a corporate investment in a CCS project.

3.4.1 Electric Utilities

Electric utilities in states now using significant amounts of coal for power generation are reasonable candidates for a future project involving a power plant with CCS. Table 3-2 shows that in 2014, 80% of coal use for power generation was in 21 of the 50 U.S. states.
<table>
<thead>
<tr>
<th>State</th>
<th>2014</th>
<th>Cumulative</th>
<th>Cum %</th>
<th>Rank</th>
</tr>
</thead>
<tbody>
<tr>
<td>Texas</td>
<td>101,657</td>
<td>101,657</td>
<td>12%</td>
<td>1</td>
</tr>
<tr>
<td>Illinois</td>
<td>51,563</td>
<td>153,220</td>
<td>18%</td>
<td>2</td>
</tr>
<tr>
<td>Indiana</td>
<td>48,583</td>
<td>201,803</td>
<td>24%</td>
<td>3</td>
</tr>
<tr>
<td>Missouri</td>
<td>43,078</td>
<td>244,881</td>
<td>29%</td>
<td>4</td>
</tr>
<tr>
<td>Kentucky</td>
<td>39,124</td>
<td>284,005</td>
<td>33%</td>
<td>5</td>
</tr>
<tr>
<td>Ohio</td>
<td>38,514</td>
<td>322,519</td>
<td>38%</td>
<td>6</td>
</tr>
<tr>
<td>Pennsylvania</td>
<td>37,105</td>
<td>359,624</td>
<td>42%</td>
<td>7</td>
</tr>
<tr>
<td>West Virginia</td>
<td>31,633</td>
<td>391,257</td>
<td>46%</td>
<td>8</td>
</tr>
<tr>
<td>Michigan</td>
<td>29,364</td>
<td>420,621</td>
<td>50%</td>
<td>9</td>
</tr>
<tr>
<td>Wyoming</td>
<td>26,026</td>
<td>446,647</td>
<td>53%</td>
<td>10</td>
</tr>
<tr>
<td>Alabama</td>
<td>23,873</td>
<td>470,520</td>
<td>55%</td>
<td>11</td>
</tr>
<tr>
<td>Arizona</td>
<td>22,911</td>
<td>493,431</td>
<td>58%</td>
<td>12</td>
</tr>
<tr>
<td>Florida</td>
<td>22,813</td>
<td>516,244</td>
<td>61%</td>
<td>13</td>
</tr>
<tr>
<td>Georgia</td>
<td>22,660</td>
<td>538,904</td>
<td>63%</td>
<td>14</td>
</tr>
<tr>
<td>North Dakota</td>
<td>22,137</td>
<td>561,041</td>
<td>66%</td>
<td>15</td>
</tr>
<tr>
<td>Wisconsin</td>
<td>21,293</td>
<td>582,334</td>
<td>69%</td>
<td>16</td>
</tr>
<tr>
<td>Iowa</td>
<td>19,834</td>
<td>602,168</td>
<td>71%</td>
<td>17</td>
</tr>
<tr>
<td>North Carolina</td>
<td>19,704</td>
<td>621,872</td>
<td>73%</td>
<td>18</td>
</tr>
<tr>
<td>Arkansas</td>
<td>19,281</td>
<td>641,153</td>
<td>76%</td>
<td>19</td>
</tr>
<tr>
<td>Oklahoma</td>
<td>18,741</td>
<td>659,894</td>
<td>78%</td>
<td>20</td>
</tr>
<tr>
<td>Kansas</td>
<td>18,199</td>
<td>678,093</td>
<td>80%</td>
<td>21</td>
</tr>
</tbody>
</table>

| - Total for US | 849,161 | 100%       |

Table 3-2.

In the U.S., 28 states require electric utilities in those states periodically to submit “Integrated Resource Plans” (IRPs) to their state regulatory bodies, typically a public utility commission (PUC). In an IRP, the utility considers its existing fleet of power generators and projected retirements, future electricity demand, environmental regulatory requirements, and projected fuel and technology costs to prepare a least cost plan for reliably meeting future electricity needs in the utility’s service area. The projection outlook is typically 20 years, although some PUCs specify shorter time frames. Given the significant uncertainties involved in a 20 year projection, IRPs often examine several scenarios of the future in order to develop a plan that is robust under varying conditions.

IRP’s for seven electric utilities, serving customers in nine of the 21 states in Table 3-2 as well as 10 other states with lesser levels of coal use, were reviewed to identify their expected addition of

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new coal-fired power generating capacity during the outlook period for that utility’s IRP. Relevant provisions in these IRPs were summarized into the data fields in Figure 3-2. The completed forms are included in this paper as Attachment 1. Note that the IRPs were prepared by the identified electric utilities; the summaries included as Attachment 1 were prepared by the author of this white paper.

Figure 3-2. IRP data summary format.

<table>
<thead>
<tr>
<th>State / Electric utility:</th>
<th>Forecast Horizon, years:</th>
<th>Year IRP adopted:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Did new technology options include coal w/o CCS?</td>
<td>Coal w/CCS?</td>
<td></td>
</tr>
<tr>
<td>Was there a quantitative technology screening?</td>
<td>Did coal pass screening?</td>
<td></td>
</tr>
<tr>
<td>Coal w/o CCS fraction of new capacity:</td>
<td>Coal w/CCS:</td>
<td></td>
</tr>
<tr>
<td>Percent of existing coal retired in forecast period:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>General discussion of coal:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Treatment of 111(d) regulations:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Source:</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Of the seven IRPs, one was submitted in 2014, 5 were submitted in 2015, and one was submitted in 2016, so all are relatively current and were cognizant of pending or recently adopted environmental regulations impacting coal use. All but two specifically considered the EPA “Clean Power Plan” rule that is expected to lead to retirement of a significant fraction of current coal capacity. All of the reviewed IRP’s used a model to evaluate the cost of alternative technologies, including coal-based technologies, to meet future demand. Most considered coal systems with CCS, and some considered coal systems without CCS.

The plans were universally pessimistic regarding coal. None of the reviewed IRPs indicated that the utility expected to build new coal capacity (with or without CCS) during the IRP projection period. Four of the IRP’s expected to retire between 25% and 47% of existing coal generating capacity during that period. The other three provided plans to retire a lower percentage of existing capacity, but one noted that it had already retired about 22% of coal generating capacity in the past four years.

All but one of the reviewed IRPs included a “carbon price” or “carbon tax” assumption in evaluating future build and retirement decisions in their planning models. All but two assumed multiple carbon price scenarios. The average prices in the low or base case modeling began at about $17 per tonne CO$_2$ in 2020-2025, and increased to about $41 per tonne CO$_2$ in 2035-2045 (projection periods varied by IRP). Carbon price assumptions for the high carbon price scenarios were approximately double those in the low or base case scenarios. For perspective, a $30/tonne carbon tax would be approximately equivalent to adding $60 to the price of a ton of coal.
Delivered U.S. coal prices averaged $46/ton in 2014. If the power plant applied CCS technology with 90% capture, the tax would be equivalent to a $6/ton “adder” to the price of coal. Of course, for the unit with CCS, the power plant owner would also have to pay for the cost of the CCS system.

Most of the reviewed IRPs provided the cost of technologies included in their screening models. The range of capital cost for a new coal power plant equipped with CCS ranged from $5450 to $8700 per kW of capacity, and averaged about $7000 per kW. This was significantly higher than the assumed cost for nuclear power (which has lower fuel costs than coal), and several times higher than natural gas-fueled power plants (without CCS).

These IRPs suggest that with currently available technology, and the currently applicable environmental regulatory framework, U.S. electric utilities see little future for coal once the current units, which have an average age of over 40 years, retire. Moreover, most of the reviewed IRPs concluded that either the regulation of CO\textsubscript{2} from existing power plants (EPA’s Clean Power Plan) or a future price on carbon would accelerate the retirement of many existing coal units.

### 3.4.2 Coal producers

The U.S. coal production sector is in economic distress. This is indicated by declining coal production data, declining stock market prices for individual coal companies and for sector “index” portfolios, announced bankruptcies, and anecdotal press coverage of the sector.

Figure 3-3 shows the decline in U.S. coal production and consumption over the past fifteen years. Production for 2015 was down 11% compared to 2014. EIA projects an additional 5% decline by 2017. EPA projects that the 2015 Clean Power Plan will reduce coal fired power generation in the U.S., a sector that historically has consumed about 90% of U.S. produced coal, by 31% in 2020, 39% in 2025, and 43% in 2030, relative to coal generation averaged over 2005-2008 (see Figure 3-4).

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50 The estimates assume a coal carbon content of 60%, which is about the average of bituminous and subbituminous coals in the U.S. Note that carbon prices are reported in $/metric tonne, and coal prices are reported in $/short ton. The delivered price of coal for 2014 is reported in Electric Power Monthly, USDOE/EIA, February 2015.

51 Historic stock price data are available online from several sources. Some of these services adjust the reported prices for dividend payments and stock splits. For example, see: finance.yahoo.com.


53 Short Term Energy Outlook, USDOE/EIA, January 2016.

A broad view of the U.S. coal industry can be found in the Dow Jones Sector Index for the coal sector. Of 98 index subsectors reported by Barrons, the coal subsector index had the worst performance on both a one-year basis and three-year basis. Four of the fifteen largest U.S. coal

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producing companies filed for bankruptcy during the past year. Based on EIA-reported data for 2013, those four companies comprise 25% of U.S. coal production.

3.4.3 Equipment suppliers
Approximately 90% of US coal-fired power generation was provided by three companies: Babcock & Wilcox (B&W), Combustion Engineering (CE), and Foster Wheeler (FW). It is difficult to assess the health of coal-fired power equipment suppliers in terms of these companies because of corporate changes over recent years, and because their business activities are much broader than coal-based or fossil-based power generation. For example, CE was acquired by Asea Brown Boveri in 1990; the fossil energy elements of ABB were acquired by Alstom in 2000; and Alstom was recently acquired by General Electric, which has much broader manufacturing scope than power generating equipment. Similarly, after a century of operation in the U.S., FW incorporated in Bermuda in 2000, in Switzerland in 2008, and was acquired by AMEC to form AMEC Foster Wheeler (headquartered in London) in 2014. B&W operated as an entity for over 100 years, before being acquired by McDermott International, Inc., in 1978, which spun-off its power generation and government operations segments into The Babcock & Wilcox Company (TB&WC) in 2010. In 2015, most power-related segments of TB&WC were spun-off into Babcock & Wilcox Enterprises, Inc.

One approach to determine the factors that impact the willingness and ability of equipment suppliers to support large fossil fueled pilot projects employing CCS technology is to consider the views expressed by participants in the previously cited 2014 workshop on large CCS pilot projects. Participants stated on multiple occasions that they were interested in collaborating on large pilot projects for CCS, but only if a “persuasive business case” could be made for such investments. The term “persuasive business case” was not defined, but is presumed to mean that either:

- The pilot project itself would likely be a profitable venture (revenues, including government contributions, would exceed costs), or
- The project would likely lead to a subsequent commercial product which would be profitable.

Pilot projects are by definition smaller than commercial projects, are generally “first-of-a-kind”, and often are dismantled after the project’s design goals are met. Moreover, a large pilot project may be operated more like a research activity than a commercial power plant. For example, operation may be driven by the need for parametric tests requiring frequent startups and shutdowns, rather than meeting customer electricity demand. All of these factors adversely

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57 Arch Coal files for bankruptcy in latest blow to coal industry, St. Louis Post-Dispatch, January 11, 2016.
58 Based on boiler manufacturer and steam capacity, as reported on USDOE/EIA Form 860, 2012.
impact the cost of electricity from such projects and their ability to be economically viable without government support. Hence, it would seem that the public contribution to such a project would be a dominant factor in its feasibility.

Considering the second alternative (profits from the commercialized technology), the USDOE/EIA’s 2015 Annual Energy Outlook, projects coal-based generating capacity to decline from 300 GW in 2012 to 257 GW in 2018, and remain at about that level through the remainder of the projection period. The EIA analysis did not include impacts of the EPA Clean Power Plan, but EPA’s analysis of that rule projected U.S. coal-based power capacity to decline to 193 GW by 2020, and 174 GW by 2030. Neither of these analyses assumed any significant new coal-based capacity would be built during their projection periods. Similarly, neither analysis projected any new natural gas-based power systems with CCS would be built within their respective projection periods. Perhaps even more discouraging for emerging power technologies is the EIA projection that total U.S. electric power sector capacity would change from 1039 GW in 2014, to 1038 GW in 2025, and 1069 GW in 2030 – virtually no increase in overall capacity. A limited amount of new capacity is projected to replace retiring fossil units, but almost all of this new capacity is either natural gas without CCS or renewable energy-based generation.

USDOE/NETL projects that inclusion of currently available CCS technology on a supercritical pulverized coal power plant will increase its cost of electricity by 74%. The resulting cost of electricity from a coal/CCS unit (90% CO₂ capture) was estimated to be about 148% higher than the cost of electricity from a new natural gas combined cycle (NGCC) unit. A USEPA analysis estimated the cost of electricity for a coal unit with “partial” CCS (reducing CO₂ emissions by 16%) was 65% more than that of a new NGCC unit without CCS.

Presumably a large pilot project, in order to receive funding consideration, would need to show that it would lead to more favorable economics than currently available technology, but a relatively large cost improvement would be needed to change projected marketplace decisions.

3.4.4 All sectors
The previously cited 2014 Coal Workshop reached conclusions similar to those expressed above:

- “New coal-fueled systems are unlikely to be built in the U.S. without CCS, but current CCS systems are not cost-competitive with the lowest cost power systems (currently NGCC without CCS).”
- “Panelists believed that pilot projects were a necessary step in the technology development process.”

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64 Regulatory Impact Analysis for the Clean Power Plan Final Rule, USEPA, August 2015.
“Customers and technology developers expressed an inability to provide more than 10-20% of a pilot project’s cost. Panelists indicated that the bulk of the cost for pilot projects would have to come from the federal government, although EOR revenues and polygeneration designs might offset overall costs via revenues that were additional to electricity sales, and international investors or State agencies might contribute part of a project’s cost.”

“Electric utility panelists expressed the greatest interest in pilot projects for “transformational technologies,” defined to include pressurized oxy-combustion, chemical looping systems, and power cycles based on use of supercritical CO$_2$ as a working fluid (instead of water or steam).”

“A deployment-based financial return on a pilot plant investment could require 15-20 years, and depend on highly uncertain factors like changing public policy, future regulations, and possible development of lower cost competing energy sources.”
3.5 Stakeholder Survey

A brief survey form was provided to individuals employed by two major U.S. electric power generators and two electric power equipment suppliers. The intent of the survey was to obtain a sample of industry views on its willingness to support coal-CCS technology development projects at various scales (small pilot, large pilot, commercial demonstration), and related information.

The responses were generally similar with respect to views on the relative sizes, costs, and roles of small pilot projects, large pilot projects, and commercial scale demonstration projects. Responses differed considerably in terms of respondents’ estimates of the share of a project that the respondent (private sector) was willing to assume. Table 3-3 summarizes these views.

<table>
<thead>
<tr>
<th>Question</th>
<th>Size range of project</th>
<th>Capital cost, $million/MW</th>
<th>Key cost assumptions</th>
<th>Primary purposes of project</th>
<th>Cost-share willingness</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Small pilots</td>
<td>Large pilots</td>
<td>Commercial scale demonstrations</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Size range, Mwe</td>
<td>1 - &lt;5</td>
<td>10 - 50</td>
<td>100 - 500</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Capital cost, $million/MW</td>
<td>4 - 25</td>
<td>2 - 3 w/o power system;</td>
<td>1.2 - 10</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>13 - 20 w/integrated power</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>- key cost assumptions</td>
<td>Assumed an existing</td>
<td>Whether the pilot includes</td>
<td>Smaller value reflects</td>
<td>Enable commercial scale</td>
<td>0 - 25%</td>
</tr>
<tr>
<td></td>
<td>power platform or test</td>
<td>a new power generating</td>
<td>retrofit estimate</td>
<td>tests; support guarantees</td>
<td>0 - 30%</td>
</tr>
<tr>
<td></td>
<td>facility</td>
<td>unit</td>
<td></td>
<td>and financing</td>
<td>0 - 5%; 40 - 50%</td>
</tr>
<tr>
<td>Primary purposes of project</td>
<td>Demonstrate process is</td>
<td>Enlarge proof of concept;</td>
<td>Enable commercial scale</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>technically feasible</td>
<td>enable design of next stage</td>
<td>tests; support guarantees and financing</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost-share willingness</td>
<td>0 - 25%</td>
<td>0 - 30%</td>
<td>0 - 5%; 40 - 50%</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

In general, respondents stated that breakthrough technologies were needed to meet market needs, but one respondent said that incremental progress was also needed to meet shorter term needs. Respondents also anticipated significant (e.g., 50%) capital cost reductions for “Nth-of-a-kind” units compared to the initial commercial-scale demonstration units. Respondents expected that the time period between initiation of construction of a large pilot unit and initiation of construction of a commercially deployed unit would be 3-5 years if the pilot unit were large enough to allow a direct jump to commercial deployment. However, if a commercial scale demonstration unit were necessary before commercial deployment could occur, then 8-10 years would be required before commercial units could begin construction. The possible need for a commercial demonstration unit is an important issue in considering both the timing and economics of a technology investment decision. It may be possible for some CCS technologies, such as solvent capture systems and membrane capture systems, to be tested on slipstreams in sizes that could then be commercially deployed without the need for a commercial-scale demonstration unit. Other technologies, including transformational technologies like oxy-combustion and chemical looping systems may require the cost and time needed for a fully
integrated (power and capture) commercial-scale demonstration system after successful testing at the large pilot scale.

Respondents’ views varied regarding the most important barriers to large pilot projects and commercial scale demonstrations. Equipment suppliers were most concerned about financing, including the availability of government support for large pilots and demonstration projects. Electric power suppliers were more concerned about shifting environmental requirements and the cost-competitiveness of CCS systems.

As part of the work conducted under Task 4 of this project, technology stakeholders in Canada, the Republic of Korea and Japan were asked if their governments allowed financial support of large pilot projects evaluating carbon capture technology, and if so, the typical levels of private sector cost-share required by their respective governments. They responded that their governments do have programs to provide financial support for such large pilot projects. CCS projects in Canada, in practice, generally have been supported by at least a 25% private sector contribution. In the Republic of Korea, minimum private sector cost-share ranged from 10-50%, depending on the size of the company participating in the project (small companies were required to contribute less). Japan requires 33-66% cost-share minimums, also based on company size. The stakeholders were not queried on the basis for the cost-share requirements or on factors considered by potential private sector project participants in determining their willingness or ability to support a particular level of cost-share for large pilot projects involving CCS technology.

The Canadian respondent stated that the time required for large pilot projects to be reflected in commercial products was a function of the following factors:

- Government policies, priorities, and the timing of public funding
- The TRL of the specific technology
- RD&D capacity of both the public and private sector
- The economic strength of the technology developer

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66 Task 4 Questionnaire Response – Canadian information, 2016.
68 Personal communication, Dr. Junichi Yoshida, NEDO, to T. Russial, February 10, 2016.
3.6 Types of financial incentives

If one assumes that a relatively small fraction of the cost of a large pilot project will be provided by traditional private sector stakeholders (i.e., electric power generators, equipment suppliers, and coal producers), then it is useful to consider who will provide the bulk of the required capital. A comprehensive discussion of potential funding mechanisms is beyond the scope of this report, but several examples of funding sources used in the past, or sources currently used for other types of power technologies, are provided below.

3.6.1 Grants and direct subsidies

In the U.S., the federal budget appropriations process has provided funds to foster development of a range of advanced energy technologies for several decades. With respect to coal-fired power generation, federal funds have contributed to the development of flue gas desulfurization technology, low-NOx burner and post-combustion NOx reduction technologies, mercury reduction technologies, and advanced power systems such as fluidized bed combustion and integrated gasification combined cycle (IGCC) power systems. USDOE provides a general description of both the CCS R&D program and larger scale demonstration projects. The Massachusetts Institute of Technology maintains a data base of CCS projects, organized by country, and includes publicly available data on grants and direct subsidies for each project. The European Commission established the NER 300 program to foster development of low carbon energy demonstration projects. CCS technologies are eligible for this funding but, as discussed in Task 2 of this project, no CCS project has been funded.

3.6.2 Tax credits

In the U.S., federal investment tax credits and production tax credits have been established for qualifying CCS technologies. The investment tax credit allows a taxpayer to take a credit of a specified percentage, e.g. 30%, of a qualifying investment, and apply that credit against federal taxes otherwise due. The production tax credit is based on a dollar per tonne allowance, e.g., $10 or $20) times the number of tonnes of CO₂ stored in a given year. Current production tax credits are limited to the first 10 years of CO₂ storage by a project, and subject to a maximum number of tonnes eligible under the program.

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Certain renewable energy power generation technologies have been awarded a “per kilowatt-hour” production tax credit for their first ten years of operation. The credit varies by technology and is indexed to inflation. For example, the credit for wind, geothermal, and certain biomass systems is $0.023 per kWh.\(^{77}\)

Accelerated depreciation provisions have also been used in the U.S. to offset a portion of the capital cost of eligible environmental control equipment, but this approach has not been applied to CCS technology.

### 3.6.3 Loan guarantees
Section 1703 of the Energy Policy Act of 2005 authorized the U.S. DOE to provide guarantees for private sector loans that would finance certain eligible technologies, including coal-fueled power plants with CCS. To date, no loan guarantee has been provided to a coal-fueled unit.

### 3.6.4 Feed-in tariffs
Feed-in tariff programs have been used extensively with renewable energy technologies such as solar energy power generation, and typically mandate that utilities enter into long-term contracts with generators at specified rates, usually well above the retail price of electricity. In the U.S., feed-in tariffs have been used by several state and local governments to encourage solar energy. German and Danish programs have also used feed-in tariffs to support wind energy.\(^{78}\)

### 3.6.5 Regulatory incentives
Renewable portfolio standards (RPS) are enforceable rules that mandate a specified percentage of electricity sales by a generating entity be provided by qualifying renewable energy sources, such as wind, solar, or biomass. A majority of states in the U.S. have adopted RPS.\(^{79}\) The RPS concept could be expanded to include fossil-fueled facilities with CCS under a “clean energy standard”, but this approach has not been broadly undertaken.\(^{80}\)

Several climate change mitigation bills introduced into the U.S. Congress between 2007 and 2009 included incentive provisions for initial deployment of CCS technology. For example, HR 2454 would have provided up to $90 per tonne of CO\(_2\) captured and stored from eligible facilities.\(^{81}\) This bill was passed by the U.S. House of Representatives but rejected by the Senate.

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\(^{79}\) Database of State Incentives for Renewables & Efficiency, NC Clean Energy Technology Center, [http://sequestration.mit.edu/tools/projects/index_pilots.html](http://sequestration.mit.edu/tools/projects/index_pilots.html).


\(^{81}\) The funds would have been provided by the sale of allowances required to be purchased from the federal government under the legislation, and the awarded subsidies were characterized as “bonus” allowances. H.R. 2454, American Clean Energy and Security Act of 2009, Section 115, passed by the House of Representatives June 26, 2009.
3.7 Conclusions

In market-based economies, companies invest in activities that allow them to make the most profit; are compatible with applicable laws and regulations; and advance the company’s view of its role in society. For electric power generators employing CCS technology, the latter considerations are generally favorable: these systems enable compliance with regulations and evidence positive corporate environmental behavior. Therefore, for practical purposes the factors most critical to limiting a company’s willingness to participate in development of a fossil fuel power technology with CCS are economic in nature.

In general, different factors impact the willingness of the private sector to invest in a large pilot project, compared to factors influencing decisions to invest in a commercial-scale demonstration project. For example, the commercial-scale project is better defined (because pilot scale work has been completed), and is usually closer in time to a point where deployment revenues can offset the technology development investment. Hence, applying factors relevant to commercial-scale demonstration projects to large pilot projects would not reflect industry practice.

Ultimately, the developer of an emerging power/CCS technology must be able to project that the mature (commercial) version of that technology will be able to compete with alternative sources of electric power generation or developer cannot prepare a “persuasive business case” for the CCS technology development investment. Economic factors relevant to investing in large pilot scale power/CCS technologies can be separated into contextual factors that relate to the general economic environment, and technology-specific factors that relate to the nature of an emerging technology.

The importance of contextual factors may vary by sector of the coal-based power industry (equipment suppliers, electricity generators, coal suppliers), but include:

- The minimal growth in electricity demand projected for the U.S. over the next 25 years, and the fact that virtually no new coal-based generating capacity is expected to be built (based on current economic projections and current technology costs).
- In near term U.S. markets, new coal-fueled power plants are more costly than new natural gas-fueled units and this is reflected in recent market behavior. This marketplace reality resonates with multiple electric utility IRPs that reached the same conclusion, as well as EPA modeling for the New Source Performance Standard rule. Note that the competitiveness of coal systems may vary in markets where natural gas is more costly than in the U.S., or in the U.S. under higher (future) natural gas price scenarios.
- The extraordinary weakness in the U.S. coal production sector. 25% of current U.S. coal production is from companies now in bankruptcy proceedings. Similarly, major

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82 EPA concluded that, the levelized cost of electricity from new coal-fueled power plants with partial (16%) CCS is 65% more than for new natural gas systems. The addition of partial CCS only exacerbated coal’s disadvantage. [Regulatory Impact Analysis for the Final Standards of Performance for GHG Emissions from New, Modified, and Reconstructed Stationary Source: Electric Utility Generating Units, EPA-452/R-15-005, USEPA, August 2015.](#)
equipment suppliers have recently undergone financial consolidation with the result that the companies that built most of the coal-fired power generators in the U.S. have been acquired by other entities. Companies in tenuous economic circumstances may have little or no discretionary investment resources.

Technology-specific factors that can influence a company’s willingness to invest in a large pilot project include:

- Risk of technology failure
- Risk that the commercial technology may be more costly than expected
- The time lag between when an investment in a pilot technology is made and the time when commercial deployment of the mature technology will take place
- The potential for competitors to deploy the developed technology without having to invest in its development (free rider concept)
- The risk of changing regulatory requirements, including CO₂ emission limits and long-term liability for stored CO₂
- The risk of improving economics for competing technologies, exacerbated by the time needed to commercialize power/CCS technologies
- The value of a technology that expands choices for the electric power sector, enhancing technology competition and fostering lower prices
- Whether a large pilot of a technology is sufficient to support commercialization of the technology without also building a commercial scale demonstration unit (this is thought to vary by technology)
### 3.8 Attachment 1 – Selected information from IRPs

<table>
<thead>
<tr>
<th>State / Electric utility:  TX, LA, AR / AEP-SWEPCo</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Forecast Horizon, years:</strong> 20</td>
</tr>
<tr>
<td><strong>Did new technology options include coal w/o CCS?</strong> No</td>
</tr>
<tr>
<td><strong>Was there a quantitative technology screening?</strong> Yes</td>
</tr>
<tr>
<td><strong>Coal w/o CCS fraction of new capacity:</strong> 0</td>
</tr>
<tr>
<td><strong>Percent of existing coal retired in forecast period:</strong> ~ 25% capacity (Dolet &amp; Welsh 2). Or about 40% if you include PPA being dropped.</td>
</tr>
<tr>
<td><strong>General discussion of coal:</strong> Currently operates 5 coal plants totaling 3.1 GW. Generally refer to coal units as “solid-fuel” units to include coal and lignite. “Going in” coal capacity drops from 2015-16, then remains constant. Decrease (~800MW) in power purchase agreement capacity after 2017. Solid-fuel capacity share drops from 46% to 35%; generation drops from 84% to 53%, with replacement generation contributed by NGas, wind, and utility scale solar. “For coal generation resources, the proposed EPA NSPS rulemaking effectively makes the construction of new coal plants environmentally/economically impractical due to the implicit requirement of CCS technology.” (Nuclear was also deemed capital cost prohibitive.) Installed CC in $/kW for Coal/CCS was 8100; Nuclear: 6300; NGCC 1200-1500. LCOE, $/MWH, was 219 / 142 / 94-106.</td>
</tr>
<tr>
<td><strong>Treatment of 111(d) regulations:</strong> Evaluated the final (August 3, 2015) CPP rule and limits for AR, LA, TX. Stated that additional analysis is needed to better understand the final rule’s requirements.</td>
</tr>
<tr>
<td><strong>Other:</strong> SWEPCo summer peak was 5149MW in 2015.</td>
</tr>
<tr>
<td>Growth based in part on Moody’s Analytics regional projections (Constant dollar US GDP growth at 2.0%/yr thru 2035). NGas prices from EIA AEO2015.</td>
</tr>
<tr>
<td>Evaluated a range of fuel, electricity, and implied carbon prices (scenarios).</td>
</tr>
<tr>
<td>Includes an extensive discussion of compliance with a list of environmental rules.</td>
</tr>
<tr>
<td>“Base”, “Low Band”, and “High Band” pricing assumptions include $15/tonne CO₂ for 2022 and beyond. The “High C” scenario assumes $25/t, beginning in 2022. (All appear to escalate w/inflation.) Demand decreases throughout projection period, but new capacity is needed after 2021 due to retirements and deratings.</td>
</tr>
<tr>
<td>Preferred plan retires 528MW coal unit in 2016, 700MW of NG-stm units. Adds 435MW NGCC in 2026, Volt VAR Optimization to reduce demand 92MW, 850MW of utility solar, up to 53MW dist solar, 1200MW wind, 356MW efficiency.</td>
</tr>
</tbody>
</table>
### State / Electric utility: TVA / TN, KY, AL

<table>
<thead>
<tr>
<th>Forecast Horizon, years</th>
<th>Year IRP adopted: 2015</th>
</tr>
</thead>
<tbody>
<tr>
<td>Did new technology options include coal w/o CCS? Yes</td>
<td>Coal w/CCS? Yes</td>
</tr>
<tr>
<td>Was there a quantitative technology screening? Yes</td>
<td>Did coal pass screening? No</td>
</tr>
<tr>
<td>Coal w/o CCS fraction of new capacity: 0</td>
<td>Coal w/CCS: 0</td>
</tr>
<tr>
<td>Percent of existing coal retired in forecast period: 36% Capacity; 41% Generation (ApxE)</td>
<td></td>
</tr>
</tbody>
</table>

**General discussion of coal:** No new coal. Retiring all coal units at Allen, Colbert, Johnsonville, and Widows Creek; 2 of 3 units at Pradise; possibly retire Shawnee; consider other retirements based on cost.

TVA currently operates 41 coal units at 10 plants: 11.9 GW; will decrease to 10.3 GW by 2016. Reduced CO$_2$ by 32% between 2005-13.

Current generation is 40% coal, 33% nuclear, 10% hydro, 13% ngas, 3% renewables.

Generally, new coal was assumed to be configured with CCS (Fig 6-9).

Assumed overnight capital cost, 2013 $/kW: Coal w/o CCS: $2908; coal w/CCS $6518; nuclear $5856; nuclear SMR $8252; NGCC $1097; Utility solar $1080-2059; Resid solar $3529. Presented capital cost w/financing in a graphic comparison to Lazard 2014 report.

**General discussion of coal:** No new coal. Retiring all coal units at Allen, Colbert, Johnsonville, and Widows Creek; 2 of 3 units at Pradise; possibly retire Shawnee; consider other retirements based on cost.

TVA currently operates 41 coal units at 10 plants: 11.9 GW; will decrease to 10.3 GW by 2016. Reduced CO$_2$ by 32% between 2005-13.

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**Treatment of 111(d) regulations:** Sec 7.1.3, p.89: Analysis preceded final EPA rule. TVA’s general plan results in a 30% CO$_2$ reduction (v 2005), similar to proposed CPP.

**Other:** General plan is to retire up to 1000 MW of coal, add (midrange estimates) 4000 MW solar, 1100 MW wind, 6200 MW NGas (CC&CT) by 2033 (Fig 2). Approximately 3400 MW of EE savings. Completing work on two nuclear units will satisfy base load power needs. Continuing Research on SMRs, which are now cost prohibitive.

Sensitivity analysis: More EE reduces NG and RE resources. RE is sensitive to NGas price.

ORNL constitutes 13% of total sales.

Peak demand dropped from 33GW in 2008 to 29GW in 2012 (12%).

Projected capacity gap (needs vs current resources - retirements) is 41GW-31GW = ~ 10 GW (Fig 4-7). Projected demand growth is 1%/yr (p.55).

Demand scenarios included “Current”, “Stagnant Economy”, “Growth Economy”, “DeCarbonized Future”, and “Distributed Marketplace.” Gas prices jump from $5 to 9/mmbtu in 2019-2020 under DeCarbonized scenario, slightly less under Growth scenario; otherwise gradually increase over projection period in nominal dollars.

Base assumption for carbon pricing is ~ $9/T CO$_2$ in 2022 -> $19/t in 2033. DeCarbonization scenario is $48/t in 2020 -> $60/t in 2033. (all nominal, Fig.6-6)
State / Electric utility: MO / Ameren

<table>
<thead>
<tr>
<th>Forecast Horizon, years: 20</th>
<th>Year IRP adopted: 2014</th>
</tr>
</thead>
<tbody>
<tr>
<td>Did new technology options include coal w/o CCS? Yes</td>
<td>Coal w/CCS? Yes</td>
</tr>
<tr>
<td>Was there a quantitative technology screening? Yes</td>
<td>Did coal pass screening? No</td>
</tr>
<tr>
<td>Coal w/o CCS fraction of new capacity: 0</td>
<td>Coal w/CCS: 0</td>
</tr>
<tr>
<td>Percent of existing coal retired in forecast period: 33% (1.8 GW).</td>
<td></td>
</tr>
</tbody>
</table>

General discussion of coal: Assumed any new coal would require CCS, based on EPA proposed rules. TPC capital cost was $5453/kW for coal; $1259/kW for NGCC. LCOE: $16.3/MWh vs $9.45/MWh (Table 6.3). Currently, 5.4 GW of 10.3 GW total capacity is coal.

Treatment of 111(d) regulations: Plan predates final EPA rule, but achieves a 30% reduction in CO₂ emissions from 2005 levels (Ch 10-1).

Other: No new coal. Plan adds 600 MW of NGCC, 400 MW wind, 45 MW solar, 28 MW hydro, 5 MW landfill gas; plus EE savings.

Projects consumption to grow 12% (Peak 8%) over 20 years – about 0.6%/yr and 0.4%/yr.

Ameren did quantitative COE screening analysis, based in part on B&V analysis for 2011 IRP – Assumptions in Chp 6.

Coal USCPC w/Capture Total Project Cost: $5453/kW, LCOE = 16.3 c/kWh.

NGCC: $1259/kW, LCOE = 9.45 c/kWh.

Nuclear overnight capital costs from several sources averaged $4821/kW (2013 $s); used Vogtle cost: $4882/kW, but also assumed a SMR cost of $5000/kW, LCOE = ~ 10.3 c/kWh.

Considered a range of C-taxes (Chp 2). Ranged from 0 to various prices beginning in 2025. The range is expressed as 2025-2035 nominal dollars per ton CO₂: $23-51/t, 34-77/t (mid or most likely case), 53-116/t.
### State / Electric utility: AZ, CA, CO, MT, OR, UT, WA, WY / PacifiCorp

<table>
<thead>
<tr>
<th>Forecast Horizon, years</th>
<th>20</th>
</tr>
</thead>
<tbody>
<tr>
<td>Year IRP adopted</td>
<td>2015</td>
</tr>
<tr>
<td>Did new technology options include coal w/o CCS?</td>
<td>Yes</td>
</tr>
<tr>
<td>Coal w/CCS?</td>
<td>Yes</td>
</tr>
<tr>
<td>Was there a quantitative technology screening?</td>
<td>Yes</td>
</tr>
<tr>
<td>Did coal pass screening?</td>
<td>No</td>
</tr>
<tr>
<td>Coal w/o CCS fraction of new capacity</td>
<td>0</td>
</tr>
<tr>
<td>Coal w/CCS:</td>
<td>0</td>
</tr>
<tr>
<td>Percent of existing coal retired in forecast period</td>
<td>47%</td>
</tr>
</tbody>
</table>

**General discussion of coal:** Coal provides 50% (5.9 GW) of current capacity (Table 5.2); decreases to 24% by 2034 (p.192). Coal plants are in AZ, CO, MT, UT, WY (mostly UT and WY). “New coal-fueled resources received minimal focus during this planning cycle due to ongoing environmental, permitting and sociopolitical obstacles for siting new coal-fueled generation.” (p88). Retire or convert to gas 2.8 GW of existing coal by 2034. (p.189)

**Treatment of 111(d) regulations:** Plan predated final EPA rule but considered 2014 proposed rule.

**Other:** Plan addresses AZ, CA, CO, MT, OR, UT, WA, WY. Average load growth assumed to be 0.85%/year for 2015-2024; used a 13% reserve margin. Capital and operating costs for supply options are in Table 6.1. CC, 2014 $/KW, Coal w/o CCS: 3289, Coal w/CCS 5946, NGCC range ~ 700-900, wind ~ 2200 (31% cf in UT; ID: 43% cf in WY), Solar (50MW) ~ 2700 (cf 25-31%), Advanced nuclear 9042, SMR nuclear 5754. Plus 6 options for energy storage.

Reduced coal generation is “offset primarily by increased energy and capacity from new natural gas and DSM resources.” (p.192). CO₂ emissions decrease from 50 mm tpy (2015) to 40 mm tpy (2034) (p.195).

Fig 7.10 shows assumed C-price is $22/ton CO₂ in 2020, rising to $76/t in 2034 for core analysis, $22-160/t in Hi-CO₂ sensitivity analysis.

**Source:** 2015 IRP, Vol 1, PacifiCorp, March 31, 2015, (copy filed with Wyoming) [https://dms.wyo.gov/ManageDocket.aspx?DocketId=EBN0gwd3mrQJUpChk8vo9YbcGYVYl9SulbFTNiY8Glc%3d](https://dms.wyo.gov/ManageDocket.aspx?DocketId=EBN0gwd3mrQJUpChk8vo9YbcGYVYl9SulbFTNiY8Glc%3d)

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### State / Electric utility: NC, SC / Duke Energy Carolinas

<table>
<thead>
<tr>
<th>Forecast Horizon, years</th>
<th>15</th>
</tr>
</thead>
<tbody>
<tr>
<td>Year IRP adopted</td>
<td>2015</td>
</tr>
<tr>
<td>Did new technology options include coal w/o CCS?</td>
<td>No</td>
</tr>
<tr>
<td>Coal w/CCS?</td>
<td>Yes</td>
</tr>
<tr>
<td>Was there a quantitative technology screening?</td>
<td>Yes</td>
</tr>
<tr>
<td>Did coal pass screening?</td>
<td>No</td>
</tr>
<tr>
<td>Coal w/o CCS fraction of new capacity</td>
<td>0</td>
</tr>
<tr>
<td>Coal w/CCS:</td>
<td>0</td>
</tr>
<tr>
<td>Percent of existing coal retired in forecast period</td>
<td>16% (note recent retirements below)</td>
</tr>
</tbody>
</table>
**General discussion of coal:** Coal capacity share decreases from 31% (2016) to 20% (2030), with NGCC making up most of the change. No Duke coal capacity in SC, but 6.8 GW in NC.

2.0 GW of coal capacity retired between 5/2011 and 5/2015. Another 1.1 GW is projected to retire under the IRP by 6/2028 (Allen 1-4).

**Treatment of 111(d) regulations:** No coal units in SC, but 7GW in NC. NC plan appears based primarily on BB#1 only. (p.14) No additional detailed discussion.

**Other:** 2015 report is an abbreviated update of 2014 IRP. Growth in summer peak is projected at 1.4%/year for 2016-30. Total system capacity in 2005 was 13.1 GW (NC) + 8.3 GW (SC) = 21.4 GW. “Over the next 15 years, the Company projects filling the increasing demand with investments in natural gas, nuclear, renewables and EE and DSM.” (p.85) Detailed cost information redacted in both 2014 & 2015 IRPs.

2014 IRP assumed two CO\(_2\) price scenarios for 2020-2029: 17–36 $/t; 20–50 $/t


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**State / Electric utility: WV / Appalachian Power Company**

<table>
<thead>
<tr>
<th>Forecast Horizon, years:</th>
<th>10 required; 30 conducted</th>
<th>Year IRP adopted:</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Did new technology options include coal w/o CCS?</td>
<td>No</td>
<td>Coal w/CCS?</td>
<td>Yes</td>
</tr>
<tr>
<td>Was there a quantitative technology screening?</td>
<td>Yes</td>
<td>Did coal pass screening?</td>
<td>No</td>
</tr>
<tr>
<td>Coal w/o CCS fraction of new capacity:</td>
<td>0</td>
<td>Coal w/CCS:</td>
<td>0</td>
</tr>
<tr>
<td>Percent of existing coal retired in forecast period:</td>
<td>~ 9%</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**General discussion of coal:** Coal capacity share decreases from 61% (2016) to 53% (2025); generation share decreases from 85% (2016) to 71% (2025). 7 coal units (1245 MW) retired due to MATS, prior to 6/2/2015. Plan converts & retires two Clinch River units (9% of current coal capacity, including partial ownership of OVEC units in OH). Neither coal nor nuclear additions were evaluated due to large size of generating units and small incremental power needs, and both technologies were deemed prohibitively expensive (p.72, 73).

**Treatment of 111(d) regulations:** Still being reviewed (p.31-33).

**Other:** Key actions are converting Clinch River #1 & #2 (474MW) from coal to gas, and then retiring units in 2026; add wind, solar, NGCC; expand EE. Analysis assumed a $15-20/tonne CO\(_2\); tax from 2022 to end of analysis period (2045) (p.ES-3). Average demand is assumed to increase by 0.3%/y through 2025. Notes that PJM only recognizes (counts) 5% of wind nameplate capacity (was 13%), 38% of solar NP capacity, and 0 for run-of-river hydro. Utility-scale solar comprises about 95% of total solar additions. Various scenarios were evaluated in sensitivity analyses. New Generation cost assumptions are in Exh B (p.143). Installed capital costs, $/kW, were: Coal w/CCS: 7200-8700 ; Nuclear: 6500; NGCC: 1200-1300. Fuel cost (levelized for 2016-2055, 2015 $/mmBtu) for Coal/NG/Nuclear were 3.6, 7.3, 1.1 (respectively). LCOE for Coal/NG/Nuclear, 2015 $/MWH, were 211-240,
State / Electric utility: WV / Monongahela PC & Potomac Edison Co.

<table>
<thead>
<tr>
<th>Forecast Horizon, years</th>
<th>Year IRP adopted</th>
</tr>
</thead>
<tbody>
<tr>
<td>15</td>
<td>2015</td>
</tr>
</tbody>
</table>

| Did new technology options include coal w/o CCS? | Yes |
| Did coal w/CCS? | No |
| Was there a quantitative technology screening? | Yes |
| Did coal pass screening? | No |

| Coal w/o CCS fraction of new capacity | 0 |
| Coal w/CCS | 0 |

Percent of existing coal retired in forecast period: Unclear, but plan to cofire w/gas.

General discussion of coal: MPC is predominately coal based (3082 MW), with partial ownership of a pumped storage hydro unit (488 MW share) and three small Purpa units (160 MW). Expect a 4% reduction in CO₂ emissions for every 10% of NGas cofiring (p.38). Co-firing modification expected to cost $85-140/MW.

Treatment of 111(d) regulations: Cited rules but did not analyze compliance measures.

Other: Basic plan is to purchase or acquire 850 MW of additional capacity (based on future analysis, current analysis indicates that least cost source would be NGCC), and to “retrofit some or all of Mon Power’s existing coal-fired units to implement co-firing with up to 30% natural gas burn.” (p.5, 57). Note that Potomac Edison is an electricity transmission and distribution company. Screening analysis calculated LCOE from existing coal units ($57/MWH), new NGCC ($70/MWH), new coal ($120/MWH), new nuclear ($126/MWH), PV solar ($187/MWH), wind ($228/MWH), and others. Coal unit did not include CCS.

Options for Funding Large Pilot Scale Testing of Advanced Fossil-Based Power Generation Technologies with Carbon Capture and Storage

Task 4 Report
Multinational Government Collaboration

Prepared by: Thomas J. Russial
Consultant to the Coal Utilization Research Council

Disclaimer: The information contained in this report is for the purpose of informing an analysis of multinational government collaboration as a means to increase the prospects for success of large pilot scale projects. It does not constitute official policy statements or positions of the countries studied. While the author has endeavored to provide accurate and timely information in this report, no warranty is made as to the accuracy or usefulness of the material contained herein. Information and statements contained in this report are not intended to be legal advice and may not be relied upon as such.

The author extends his thanks to the representatives of the New Energy and Industrial Technology Development Organization, Korea Institute of Energy Research, and Natural Resources Canada for their valuable contributions to the Task 4 effort. The author also extends thanks to L.D. Carter and Ben Yamagata for their very constructive comments during the review of this report.
<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Full Form</th>
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</thead>
<tbody>
<tr>
<td>APEC</td>
<td>Asia Pacific Economic Cooperation</td>
</tr>
<tr>
<td>CCS</td>
<td>Carbon capture ad storage</td>
</tr>
<tr>
<td>CCUS</td>
<td>Carbon capture utilization and storage</td>
</tr>
<tr>
<td>CEAA</td>
<td>Canadian Environmental Assessment Act</td>
</tr>
<tr>
<td>CFR</td>
<td>United States Code of Federal Regulations</td>
</tr>
<tr>
<td>CO₂</td>
<td>Carbon Dioxide</td>
</tr>
<tr>
<td>CSLF</td>
<td>Carbon Sequestration Leadership Forum</td>
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<tr>
<td>CURC</td>
<td>Coal Utilization Research Council</td>
</tr>
<tr>
<td>EPA</td>
<td>United States Environmental Protection Agency</td>
</tr>
<tr>
<td>FOA</td>
<td>Funding Opportunity Announcement (USDOE)</td>
</tr>
<tr>
<td>FY</td>
<td>Fiscal year</td>
</tr>
<tr>
<td>GHG</td>
<td>Greenhouse gas</td>
</tr>
<tr>
<td>IEA</td>
<td>International Energy Agency</td>
</tr>
<tr>
<td>IGCC</td>
<td>Integrated Gasification Combined Cycle</td>
</tr>
<tr>
<td>IP</td>
<td>Intellectual property</td>
</tr>
<tr>
<td>KIER</td>
<td>Korean Institute of Energy Research</td>
</tr>
<tr>
<td>LOI</td>
<td>Letters of Expression of Interest</td>
</tr>
<tr>
<td>NEDO</td>
<td>New Energy and Industrial Technology Development Organization</td>
</tr>
<tr>
<td>NRCan</td>
<td>Natural Resources Canada</td>
</tr>
<tr>
<td>NSPS</td>
<td>New Source Performance Standards</td>
</tr>
<tr>
<td>NSR</td>
<td>New Source Review</td>
</tr>
<tr>
<td>METI</td>
<td>Ministry of Energy, Trade and Industry</td>
</tr>
<tr>
<td>MWe</td>
<td>Megawatt electric</td>
</tr>
<tr>
<td>MWh</td>
<td>Megawatt hour</td>
</tr>
<tr>
<td>PSD</td>
<td>Prevention of Significant Deterioration</td>
</tr>
<tr>
<td>RFI</td>
<td>Request for Information</td>
</tr>
<tr>
<td>R&amp;D</td>
<td>Research and Development</td>
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<tr>
<td>RD&amp;D</td>
<td>Research, Development and Demonstration</td>
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<tr>
<td>TRL</td>
<td>Technology Readiness Level</td>
</tr>
<tr>
<td>USDOE</td>
<td>United States Department of Energy</td>
</tr>
<tr>
<td>US</td>
<td>United States</td>
</tr>
</tbody>
</table>
4 Executive Summary

The purpose of the large pilot plant study is to evaluate options for governments and industry to fund projects that will test advanced fossil-based power generation technologies with carbon capture and storage (CCS). Task 4 of the study is focused on multinational collaboration as a means to mitigate the cost and financial risk associated with large pilot projects. The study defines “multinational collaboration” to mean two or more governments providing financial support to an individual large pilot project or group of projects. “Large pilot project” means a project that tests advanced fossil fueled electric power generation technology, carbon capture technology, or storage technology that has not been tested beyond small scale and is capable of significantly reducing the cost of fossil-based power integrated with CCS. The starting assumption of the study is that large pilot projects are generally within the range of 10-50MWe. As discussed in the Report, participants have been asked if they agree with the assumption.

The study premise - widely accepted by many in the climate community - is that broad deployment of CCS is required to meet global climate objectives but that the cost of fossil-based power with CCS must be reduced for the technology to be affordably deployable world-wide. Cost reduction will come from technology innovation. Before a new power plant technology can be deployed, it typically must be proven at large pilot scale and subsequently demonstrated at commercial scale.

History reveals that the high cost and financial risk associated with first-of-a-kind pre-commercial projects has caused many technically sound projects to fail for lack of adequate resources despite some amount of financial assistance from a government source. Budgetary constraints limit the amount of funds that governments are able to contribute to large scale projects. Consequently, the public contribution to individual projects can be more a function of the available funds rather than the funds that are required to effectively initiate and then take a project through definition, planning and design, construction and operation. Furthermore, optimistic projections on the need, timing and utilization of the new technologies may lead to an unrealistic belief that the private sector can bear a significant portion of project cost and be able

Task 4 Key Findings

1. Multinational collaboration offers the opportunity for governments to leverage resources to mitigate the cost and financial risks associated with large pilot projects and thereby increase the number of successful projects.

2. Government funded fossil energy research programs have similar objectives and development timelines. Further analysis of overlapping interests may lead to a suite of power and CCS technologies that are well suited for multinational collaboration at the large pilot scale.

3. Various issues have the potential to hinder multinational collaboration.
to recover the investment on commercially acceptable terms. Difficulties encountered by pre-commercial projects and cost and financial risk are discussed in the Task 2 and Task 3 Reports.

Government to government collaboration on research and development (R&D) activities has proven effective in various forms. Since insufficient funding often proves fatal to large pre-commercial projects, Task 4 concentrates on financial support rather than on other types of collaboration. Large pilot projects may cost in the 10s to 100s of millions of dollars depending upon the technology and level of CCS integration. By leveraging the common interests and resources of like-minded governments, the odds of project success may significantly improve when compared to the case where individual governments go it alone.

The Task 4 study countries - Japan, the Republic of Korea, Canada and the United States (US) - have a long history of cooperation on fossil energy and/or CCS R&D through various mechanisms including multinational member organizations such as the Carbon Sequestration Leadership Forum (CSLF), the International Energy Agency (IEA), and the Asia Pacific Economic Cooperation (APEC) as well as country to country agreements and understandings. The four provide an excellent opportunity to explore the potential for multinational financial cooperation on large pilot projects.

Study country information was compiled on large pilot project interest; relevant law, regulation and policy; existing or planned government programs that may provide financial support for large pilot projects; and, potential issues. A comparative review was conducted and the data suggests that opportunities exist for collaboration that can contribute to the success of large pilot projects. Additional knowledge, analysis and discussion are needed to further refine the concept. Key points and identified issues are highlighted below and discussed in the report.

Multinational collaboration requires a shared interest in the advancement of fossil power and CCS technologies which clearly is the case for the study countries who have been leaders in fossil energy R&D. However, shared does not necessarily mean identical and for successful collaboration there must be an alignment of technology interests, development timelines, project size, and budgetary priorities and resources. Opportunity areas for large pilot projects may include advanced capture technologies, second generation and transformational power technologies and others. The limitations of Task 4 do not allow for an assessment of specific technologies that are ready for multinational collaboration. Further analysis of intersecting needs and interests by a broad group of government and other stakeholders can lead to a suite of technologies that is well suited for collaboration.

Based on the study country sample, and historical examples, countries have authority to support large scale multinational projects in one fashion or another. Nevertheless, national laws or

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83 Examples include knowledge sharing, researcher exchanges, and collaborative projects.
84 See Task 3 Report.
policies may restrict a country’s ability to financially support extraterritorial projects and/or may limit funding to domestic companies. Individual country laws and policies must be examined in the context of the various collaborative models to determine effective approaches to deal with legal or policy restrictions.

Terms and conditions contained in government funding agreements may conflict with provisions used by other governments or simply may not be familiar to companies that have not previously done business with the government. Intellectual property (IP) rights have been identified as a trouble spot for multinational projects although the potential for conflict and misunderstanding is not isolated to IP. Significant delay may occur while provisions are analyzed and negotiated. A detailed understanding of where issues and conflicts may arise and development of solution pathways can streamline resolution and contribute to successful collaboration.

Collaboration models should be evaluated to determine which would be most effective for large pilot projects taking into consideration stakeholder interests and concerns. The examination may include the advantages and disadvantages of formal and informal government to government relationships, how issues that may impact project success can best be addressed under the various models, timing in light of technology deployment needs, host site location and knowledge sharing obligations.
4.1 Task 4 Methodology

A questionnaire was developed addressing four focus areas:

PART A: INTEREST IN LARGE SCALE FOSSIL BASED PILOT PROJECTS

PART B: LAW, REGULATION AND POLICY

PART C: PROGRAMS THAT MAY SUPPORT LARGE-SCALE PILOT PROJECTS

PART D: ISSUES THAT MAY BE ENCOUNTERED ON MULTINATIONAL COLLABORATIVE PROJECTS

NEDO, KIER and NRCan supplied information related to Japan, Korea and Canada respectively. The author supplied information on the US.85

Part A sought information that would lead to an understanding of whether there is a shared vision of the need for large pilot projects. Participants were asked about their country’s interest in advanced fossil based power technology with CCS and testing at large pilot scale, technologies of interest, timelines for technology development and deployment, if 10-50 MWe is an appropriate range, host-site potential, and, the advantages and disadvantages of integrated or non-integrated testing of advanced power technologies at large pilot scale with CCS.

Part B was designed to gain an understanding of a country’s laws, regulations and policies that may apply to multinational collaborative large pilot projects. A Task 4 objective is to see if there are similarities between legal, regulatory and policy schemes that would facilitate collaboration, conflicts that might impede collaboration and uncertainties that have yet to be addressed. Participants were asked about their country’s authority to financially support projects that are supported by other countries and the country’s authority to financially support extra-territorial projects. For Task 4 purposes, “financial support” was defined to mean governmental assistance to a project that defrays a portion of the project’s developmental, financing, capital and/or operating cost. Information was requested about requirements that may attach to a country’s financial support agreements including domestic preference provisions, intellectual property provisions, and real and personal property rights. Participants were also asked if their country’s environmental laws, regulations or policies apply to extraterritorial projects receiving government support and whether their country’s laws or regulations would require a large pilot project to utilize CCS.

Part C sought information about a country’s existing and planned programs that may be a source of financial support for large pilot projects. Information was also sought about the process the country would use to obtain and select proposals and enter into financial support agreements.

85 The author has been involved with fossil energy and CCS programs for 30 years as an attorney with the U.S. Department of Energy and more recently in private practice. Relevant US information is taken from public sources.
Like Part B, the objective is to see where there are similarities and conflicts between the processes, provisions, and terms and conditions used by the study countries.

In Part D, the study participants were asked to provide their insights into issues and conflicts that may be encountered with multinational collaboration on large pilot projects and their personal experiences dealing with the resolution of such matters.

After receipt of the completed questionnaires, follow-up clarifications were held as needed. Using the responses, a comparative review of the study country policies and programs was conducted by the author. Results of the review are summarized in this Report along with a discussion of potential issues that may be encountered with multinational collaboration, and a discussion of current knowledge gaps.
4.2 Options for Multinational Collaboration

Discussed below are three models for multinational collaboration that could be used to support large pilot projects. Many variants are possible.

4.2.1 Pooled Support

The term “pooled support” is used here to mean the transfer of government funds to a lead government or government affiliated organization for a project or projects. Funds may be transferred via bilateral or multilateral agreements.

The FutureGen project in the US is an example of where a pooled funding approach was employed. The project was supported by the USDOE through a cost-shared financial assistance cooperative agreement with the FutureGen Industrial Alliance. The USDOE invited international participation. In 2006, the Governments of Korea and India entered into agreements with the USDOE whereby the two countries would each contribute $10 million in cash for use by the USDOE on the cooperative agreement. In consideration, Korea and India would be entitled to membership on the FutureGen Government Steering Committee, access to project information, and other benefits set forth in their respective agreements with the USDOE.

The ITER collaboration on fusion energy research is representative of another type of pooling arrangement. By multilateral agreement signed in 2006 and entering into force in 2007 (after Member ratification), the ITER International Fusion Energy Organization was established as a distinct international organization for the joint implementation of the ITER Project. The agreement, supplemental agreements and rules define the purpose, governance, operations, and functions of the Organization as well as Member rights and obligations. The ITER Organization controls the project and separate legal personality provides the Organization with the capacity to enter into agreements with States and/or other international organizations and to conclude contracts, acquire, hold and dispose of property, obtain licenses and initiate legal proceedings in the territories of its members. Members make in-kind contributions of components and other property to the ITER Organization. Operating costs will be shared among Members at established percentages. The ITER relationship differs from the typical

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86 A cooperative agreement is a type of financial assistance agreement used by the US Government to transfer anything of value to a non-federal entity to accomplish a public purpose rather than acquire property or services for the government. Cooperative agreements are used when substantial involvement is anticipated between the government and the recipient in carrying out the activity. Grants are used when substantial government involvement is not anticipated. 2 CFR 200.24.
88 The FutureGen project changed substantially after 2008. It ultimately did not reach construction and operation.
89 The ITER Members are the European Atomic Energy Commission, Japan, Korea, China, India, the Russian Federation, and the United States. Detailed information about ITER can be found at https://www.iter.org/.
government to company relationship seen in fossil energy projects where developers seek to scale-up privately owned technologies. Although the ITER approach may not be directly transferable to large fossil pilots, ITER nevertheless demonstrates that governments can effectively pool resources to collaborate on large research activities.\footnote{90}

Pooled support offers certain advantages when compared to the case where project developers must seek support from separate governments. The larger pool increases the amount of funds that may be committed at one time to individual projects thereby improving project financial viability and certainty. The relationship between the governments and project developers proceeds on one timeline and under one set of rules rather than on multiple timelines with different rules that may contain conflicting requirements.

Pooled support also has potential disadvantages. Governments must agree amongst themselves on their respective rights and obligations including rights derived from the supported projects. Reconciliation of interests and agreement negotiation may take considerable time and delay technology development. Project developers must be willing to accept obligations flowing from the government to government agreement which may or may not be consistent with the developers’ commercial interests. Pooled support may also be perceived as reducing the number of opportunities to receive government financial support when compared to the case where governments would otherwise individually provide assistance.

4.2.2 \textit{Coordinated Support}

The term “coordinated support” is used here to mean the case where governments collaborate on a common activity but where each provide financial support directly to the project lead company or to a member of the project team. Collaboration may be by formal government to government agreement or through other mechanisms.

The Callide Oxyfuel Project in Queensland Australia provides an example of successful coordinated support. In 2004, an Australian-Japanese working group was established to conduct a feasibility study on the conversion of a 30 MWe power plant to demonstrate oxycombustion with CO$_2$ capture.\footnote{91} The study was completed in 2006, project financial closure was in 2008,

\footnote{90} CERN is another example of successful multinational collaboration on large research activities. Information about CERN and the Convention for the Establishment of a European Organization for Nuclear Research is available at the CERN Council website
\footnote{91} “Callide Oxyfuel Project Technical Fact Sheet.” December 2013.
and the demonstration phase completed in 2015. The project was conducted through a joint
venture arrangement among the project industrial participants. Financial support for the project
from Japan’s Ministry of Energy, Trade and Industry (METI) went to the Japanese industry
participants. Financial support from the Australian Commonwealth Government, Queensland
Government and Australian Coal Association Low Emission Technology Ltd. went to other
industry participants. A thorough summary and lessons learned report on the Callide project,
including a discussion of the project participant relationships, was prepared by Oxyfuel
Technologies Pty Ltd for the Global CCS Institute. The report notes that the project structure
was effective but that there were many considerations and issues to be resolved during
negotiation of the various agreements.

Coordinated support can mitigate project risks. As with pooled support, a greater amount of
funds can be committed at one time to individual projects thereby improving project viability and
certainty. Coordinated support also offers the potential for governments to coordinate timelines
and reconcile conflicting requirements in advance thereby eliminating delay that otherwise may
occur while project developers seek to reconcile conflicts with individual governments.

4.2.3 Coincidental Support
The term “coincidental support” is used here to mean the case where governments support a
common activity without
government to government
coordination. Each may provide
financial support directly to the
project lead company or to a
member of the project team.
Coincidental support typically
occurs when governments have an
interest in the same project (or
elements of the project technology)
and project team members are incorporated in or otherwise affiliated with the sponsoring
country.

Coincidental support from governments (or from components of the same government) is often
vital to large scale pre-commercial projects since a single mechanism is often not adequate to
make a project financially viable. However, the independence of the mechanisms means that
project proponents must satisfy multiple government organizations each with its own timeline.
This can create substantial delay and uncertainty which does not favor project development.

4.3 Comparative Summary Of Country Information

92 “Callide Oxyfuel Project – Lessons Learned.” Oxyfuel Technologies Pty Ltd., 2014. Available at:
A comparison by Questionnaire focus area is provided below. Some questions require additional inquiry or could not be readily answered and the responses were understandably deferred or marked as uncertain.

4.3.1 **Part A: Interest in Large Scale Fossil Based Pilot Projects**

The objective of Questionnaire Part A was to gain a general understanding of study country interest in piloting advanced technologies at large scale and to see if a degree of harmony exists on technology type, timing, size, and nature of large pilot projects. All study countries have multi-faceted fossil energy and CCS R&D programs and all expressed continued interest in developing advanced fossil-based power systems with CCS. The Questionnaire did not seek a complete and final statement of each country’s pilot plant activity and it would be impossible for participants to provide such information since future RD&D plans are influenced by various factors including government budgets, markets, smaller scale R&D success, and climate objectives. Table 1 provides an overview of the Part A responses.
### Table 4.1 Part A – Interest in Large Scale Pilot Projects

<table>
<thead>
<tr>
<th>Question</th>
<th>Japan</th>
<th>US</th>
<th>Korea</th>
<th>Canada</th>
</tr>
</thead>
<tbody>
<tr>
<td>Would the electric power sector within the country be a user of advanced fossil power with CCS?</td>
<td>Uncertain</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Do companies within the country develop and market advanced fossil based power and/or CCS technology?</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Technologies of Interest at Large Pilot Scale</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>- Gasification</td>
<td></td>
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<tr>
<td>- Oxygen Separation</td>
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<td></td>
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<tr>
<td>- Turbines</td>
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<tr>
<td>- Capture</td>
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<tr>
<td>- Storage</td>
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<tr>
<td>- Chemical looping cycle</td>
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<tr>
<td>- Fuel cell</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>- A-USC boiler</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>- Combustion Oxycombustion Chemical Looping</td>
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<tr>
<td>- Post Combustion Capture</td>
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<tr>
<td>- Supercritical CO₂ systems</td>
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<tr>
<td>- CO₂ capture from natural gas systems (Recently initiated and planned activities)</td>
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<tr>
<td>- Capture (Currently supporting)</td>
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<td>- Combustion</td>
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<tr>
<td>- Gasification</td>
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<td>- Capture</td>
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<tr>
<td>- Storage</td>
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<td></td>
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<tr>
<td>- CO₂ Utilization</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Technology Timeline</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>(1) Large Scale Pilots</td>
<td>(1) 2020</td>
<td>(1) By 2020</td>
<td>(1) 2017 ~ 2021</td>
<td></td>
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<tr>
<td>(2) 2025</td>
<td>(2) 2020-2025</td>
<td>(2) 2022 ~ 2027</td>
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<td></td>
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<tr>
<td>(3) 2030</td>
<td>(3) Mid-2020s</td>
<td>(3) 2027 ~ 2031</td>
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<td></td>
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<tr>
<td>Transformational</td>
<td></td>
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<td></td>
<td></td>
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<tr>
<td>(1) 2016-2030</td>
<td></td>
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<td>(2) 2025-2035</td>
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<td>(3) 2030s</td>
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<tr>
<td>(1) Second Generation</td>
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<tr>
<td>(2) 2017-2021</td>
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<tr>
<td>(3) Mid-2020s</td>
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<tr>
<td>Factors:</td>
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<td></td>
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<tr>
<td>- Policy &amp; Priorities</td>
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<td></td>
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<tr>
<td>- Tech Readiness Level (TRL)</td>
<td></td>
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<td></td>
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<tr>
<td>- RD&amp;D capacity of public &amp; private Organizations</td>
<td></td>
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<td></td>
<td></td>
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<tr>
<td>- Stakeholder investment ability</td>
<td></td>
<td></td>
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<td></td>
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<tr>
<td>- Public funding timeline in support of stakeholder RD&amp;D</td>
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<tr>
<td>Is 10-50 MWe the appropriate range for large pilot projects?</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>Are there potential host-sites within the country?</td>
<td>Uncertain</td>
<td>Yes</td>
<td>Uncertain</td>
<td>Yes</td>
</tr>
</tbody>
</table>

Part A asked the participants to describe their government’s interest in the development of fossil based power technology with CCS and testing at large pilot scale. While individual RD&D
programs differed, the responses reveal a mutual interest among the countries in advancing fossil based power and/or CCS technologies through large pilot scale testing and ultimately commercial deployment. The Part A responses also indicate that companies within each country develop and market fossil power technology and/or CCS technology, and the electric power sectors in three countries are likely users of the integrated technologies. Use within Japan is reported as uncertain.\textsuperscript{93} Hence, the responses suggest that countries have similar environmental and economic motivations for supporting large scale pilots which should weigh in favor of multinational collaboration. Country interest in commercial markets for domestic technologies may be a factor in the decision making process and collaborative structure.

The list of technologies of interest at large pilot scale reveals overlaps and differences. It is assumed that reported technology areas are based on known interests and activities which may evolve over time. To illustrate, the US technology list is based on recently initiated and planned large pilot activities included in USDOE budgets. Nevertheless, the US has supported and continues to support development of many advanced technologies at laboratory and small scale that ultimately must be piloted and demonstrated at larger scale prior to commercial deployment. The same holds true for other study countries.

Large pilot project interest in capture technology appears on all lists. Furthermore, all countries have capture pilots or demonstration projects underway or planned. Examples include:

1. Japan’s Osaki CoolGen Project which will integrate pre-combustion capture with an oxygen blown IGCC system and later an integrated gasification fuel cell combined cycle system.\textsuperscript{94}

2. Two capture pilots testing dry sorbent and advanced amine technologies on 10 MW slip streams from the Boryeong and Hadong Power Stations in Korea.\textsuperscript{95}

3. SaskPower’s Boundary Dam Integrated Carbon Capture and Storage Project in Canada.\textsuperscript{96}

4. A 2015 USDOE Funding Opportunity Announcement (FOA) seeking development of 10+ MWe post-combustion capture facilities.\textsuperscript{97} Six large scale projects were selected for Phase 1 definitional activities which will be followed by a down-selection for Phase

\textsuperscript{93} In addition to its other R&D efforts, Japan continues to investigate storage including a demonstration project to store CO2 under the seabed off-shore in Tomakomai Area in Hokkaido. See “Demonstration Project.” Japan CCS Company., Ltd.: http://www.japanccs.com/en/business/demonstration/index.php.


\textsuperscript{96} Information about the Boundary Dam Carbon Capture Project is available at http://www.saskpowerccs.com/.

\textsuperscript{97} FOA #: DE-FOA-0001190, Small and Large Scale Pilots for Reducing the Cost of CO2 Capture and Compression. Issued February 11, 2015.
The FOA plans for 2 large pilots. USDOE’s FY 2017 Budget Request seeks funding to support a third pilot.

Accordingly, the continued development of advanced capture technologies appears to be of common interest.

The high cost of fossil power with CCS has been cited as a significant impediment to widespread deployment and this is reflected in reported large pilot interest in second generation and transformational power generation technologies that can significantly improve the cost effectiveness of integrated systems. Examples include chemical looping cycles, advanced oxy-combustion, fuel cell based systems, advanced ultra-supercritical boilers, and supercritical CO₂ power cycles. Recent activities include a USDOE action initiated in 2016 that, subject to future budgets, is expected to lead to up to two 10+ MWe oxycombustion pilot plants and up to two 10+ MWe chemical looping pilot plants. DOE is also planning for a 10 MWe supercritical CO₂ pilot.

Technology development timelines reported for Japan, the US and Korea are in general agreement with large pilots initiated in the 2017 to 2020 timeframe, demonstrations by the mid-20s and commercial deployment by the 2030s. The US is projecting an expanded schedule for certain transformational technologies with development and scale up in the 2016 – 2030 timeframe and demonstrations beginning in 2025. The Canadian response correctly notes that timelines are influenced by multiple factors including policies, priorities, budgets and technical readiness.

Three responses support a 10-50 MWe range as an appropriate scale for large pilot projects. During a 2014 Technology Workshop convened by CURC and attended by industry, government

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100 FOA #: DE-FOA-0001459, Pre-Project Planning for Advanced Combustion Pilot Plants. Issued January 21, 2016. See also FY 2017 Congressional Budget Justification. op.cit.


and financial sector representatives, it was noted that certain advanced technology components may be appropriate for pilot scale testing at a smaller size prior to commercial demonstration.\textsuperscript{103}

Potential host sites for large pilot plants are likely available in the US and Canada. Host site availability in Japan and Korea was reported as uncertain. At 10-50 MWe, pilot projects will be beyond the range of most existing power and CCS test platforms. To illustrate, Technology Centre Mongstad (TCM) in Norway is believed to be the world’s largest post-combustion capture test facility with two units each at approximately 12 MWe in size.\textsuperscript{104} So while TCM can accommodate large post-combustion pilots at the lower end of the range, new build power technology pilots and slip stream capture technology pilots attached to existing power or industrial facilities will be required.

Bench and small scale development of power generation, capture and storage technologies typically proceeds independently with fully integrated projects occurring at the larger scales. Part A sought comments on the advantages and disadvantages of integrated versus non-integrated large pilot testing of power generation systems and CCS. As an example, the question asked if a new combustion system or new gasification system could be effectively and economically tested at large pilot scale without CCS integration. Questionnaire Part B, discussed later, asks if national or subnational laws or regulations would require a large pilot scale fossil fueled power plant to utilize CCS. The Part A responses are summarized below and suggest that the issue may be technology specific, priority specific, site specific, and influenced by project economics.

Using the example, the Japanese response notes that an IGCC system with carbon capture will be effectively and economically tested at large pilot scale.

The Korean response states that advanced technology concepts should be tested in large pilot scales to prove technology performance and reliability and the concepts should be integrated with real coal-fired power plants to see how the capture plant affects operation and controllability of the main coal fired power plant. Based on data from integrated pilot systems, more accurate economic analysis can be obtained.

The Canadian response indicates that integrated pilot scale testing at an existing pilot plant could have consequences for the plant such as shutdown of plant operations for some time and the need for the utility to find alternative power sources to supply its customers. The response noted that testing at plants with more than one generating unit could possibly take place without complete

\textsuperscript{103} "Technical Workshop Report /An Industry View: Advancing the Next Generation of Coal Conversion Technologies." (Convened by the Coal Utilization Research Council, with support from its members and the USDOE), L.D. Carter for U.S. Energy Association under contract to U.S. DOE, 2014

shutdown of the plant but that a detailed techno-economic feasibility study would be required to validate the approach.

Adding his thoughts, the author identifies the following potential advantages of non-integrated testing:

1. Substantially lower total project cost reducing the private investment and government financial support needed for project viability.

2. Substantially faster project development and implementation due to less complex project design, financing, host site requirements, environmental review and permitting, procurement and construction.

3. Elimination of integration and operational risk associated with systems not required to prove the piloted technology.

Potential disadvantages are:

1. Projects not producing saleable products (e.g. electricity, steam, CO₂ for enhanced oil recovery) will be more reliant on balance sheet financing for the private sector share of the project cost and therefore may be less attractive to project developers.

2. Projects that do not have a long-term commercial use may reduce the number of potential host sites.

3. Permitting of large power generation pilot plants without CCS might be difficult in some jurisdictions.

4.3.2 Part B: Law, Regulation and Policy

Questionnaire Part B was designed to gain a general understanding of each country’s legal, regulatory and policy requirements associated with large scale projects that may facilitate or impede multinational collaboration. This is a complex, multi-disciplinary, and often nuanced area. The Part B objective was to obtain background information that could frame a future more detailed examination and discussion. Beyond the scope of the immediate inquiry are requirements and obligations that may be established or modified through formal bilateral or multilateral collaboration agreements. Table 2 provides an overview of the Part B responses.

105 Balance sheet financing is typically debt financing that appears on a company’s cash flow statement and balance sheet, and which impacts debt-equity ratios and perceived corporate strength. An alternative to balance sheet financing for projects generating revenues might be “Project Financing” which can be accounted “off balance sheet.”
### Table 4-2 Part B – Law, Regulation and Policy

<table>
<thead>
<tr>
<th></th>
<th>JAPAN</th>
<th>US</th>
<th>KOREA</th>
<th>CANADA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Does government have authority to provide support to large pilots receiving support from other governments?</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Does government have authority to support extra-territorial large pilot projects?</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Uncertain</td>
</tr>
<tr>
<td>Do domestic preference requirements attach to financial support?</td>
<td>No</td>
<td>Yes</td>
<td>Uncertain</td>
<td>Yes</td>
</tr>
<tr>
<td>Do support agreements restrict developer from exploiting technology?</td>
<td>No</td>
<td>No</td>
<td>Uncertain</td>
<td>No</td>
</tr>
<tr>
<td>Does government reserve interests in intellectual property</td>
<td>No</td>
<td>Yes</td>
<td>Uncertain</td>
<td>No</td>
</tr>
<tr>
<td>Does government reserve interests in real or personal property</td>
<td>No</td>
<td>Yes</td>
<td>Uncertain</td>
<td>Uncertain</td>
</tr>
<tr>
<td>Do government environmental laws, regulations or policy have extra-territorial application?</td>
<td>No</td>
<td>See Discussion</td>
<td>No</td>
<td>See Discussion</td>
</tr>
<tr>
<td>Would national or subnational laws require a large scale fossil-based power pilot to use CCS?</td>
<td>No</td>
<td>See Discussion</td>
<td>No</td>
<td>See Discussion</td>
</tr>
</tbody>
</table>

Part B confirms that the study countries have authority to provide financial support to large pilot projects that are supported by other governments. Examples of successful larger scale projects that received multinational support from other than the host country include the IEAGHG Weyburn-Midale CO₂ Monitoring and Storage Project in Saskatchewan and the previously mentioned Callide Project in Australia.\(^{106}\) Japan, Korea and the US may also provide financial support to large pilot projects conducted outside of their boundaries. The authority to provide extra-territorial financial support is reported as uncertain in Canada noting that Canadian participation in projects performed in other countries usually involved in-kind support. Support for extraterritorial projects may have limitations as illustrated by the USDOE’s recent post-combustion capture FOA which restricts foreign host sites to pre-existing facilities constructed with the intent to pilot CO₂ mitigation technology.\(^{107}\)

Part B asked if domestic preference requirements would attach to government financial support for large scale projects. Restrictions limiting the award of support to domestic entities were

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\(^{107}\) FOA #: DE-FOA-0001190. op.cit.
reported as well as limitations on the percentage of funds that could be spent extraterritorially. These limitations by themselves do not preclude multinational collaboration but do require projects to be structured around the requirements. The ability for an individual large pilot project to satisfy the limitations would be based on project specifics. Preference requirements linked to intellectual property (IP) rights were identified for the US. The responses are summarized below.

The Japanese response reported no applicable requirements. The Korean response reported domestic preference requirements as uncertain but noted that terms are negotiable. The Canadian response indicates that funding programs directed to energy RD&D, usually support projects managed by legal entities validly incorporated or registered in Canada. US preference provisions are summarized below:

1. The USDOE utilizes a provision in its financial assistance agreements requiring a percentage of the direct labor element of project cost to be performed in the US unless the recipient can demonstrate to the satisfaction of the USDOE that the US economic interest will be better served through a greater percentage of the work being performed outside the US. Recent USDOE Fossil Energy Funding Opportunity Announcements (FOAs) have set the percentage at 50% and 75%.109

2. The USDOE utilizes provisions limiting eligibility of prime recipients of financial assistance agreement to entities incorporated in the US, or organized under the laws of the US. Recent Fossil Energy FOAs allow foreign entity participation, but require the prime recipient to be a US subsidiary or affiliate of the foreign entity unless the requirement is waived by the USDOE.110

3. A “Preference for United State Industry” provision is included in agreements requiring the recipient to agree that neither it nor any assignee will grant to any person the right to use or sell any “subject invention” in the US unless such person agrees that any products embodying the subject invention or produced through the use of the subject invention will be manufactured substantially in the US. A subject invention is an invention conceived or first actually reduced to practice in the course of or under any contract, grant, agreement, understanding, or other arrangement with the US.111 The requirement may be waived by the USDOE upon a showing that reasonable but unsuccessful efforts have been made to grant licenses on similar terms to potential licensees that would be

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108 NEDO has also explained that when participating in an international collaboration through a memorandum of understanding with another government, NEDO support is provided to an entrusted company that is a Japanese company or a subsidiary or affiliate of a Japanese company.

109 FOA #: DE-FOA-0001190 and FOA #: DE-FOA-0001459. op.cit

110 Ibid.

111 US law permits domestic small businesses and non-profit entities to elect to retain title to subject inventions. 35 U.S.C. § 202. For USDOE agreements, title to inventions conceived or first reduced to practice by large business and other types of organizations vests in the US and such entities must obtain must obtain a patent waiver from the USDOE to obtain title to the inventions. 42 U.S.C. § 5908.
likely to manufacture substantially in the US or that under the circumstances domestic manufacture is not commercially feasible.\footnote{35 U.S.C. \S 204 (small businesses and non-profit organizations): 2 CFR 910, SUBPART D Appendix A. (For other entities receiving support from the USDOE).}

4. The USDOE has included a “U.S. Competitiveness Provision” in patent waivers requiring the recipient to agree that products embodying any waived invention or produced through the use of any waived invention will be manufactured substantially in the US, unless the waiver recipient can show to the satisfaction of the USDOE that it is not commercially feasible to do so.

5. For costs incurred within the project budget, agreements require that: (i) at least fifty percent of equipment, materials, or commodities procured and transferred by ocean vessel must be transported on privately owned US commercial vessels; and, (ii) air transport of people or property involving a country other than the United States must be performed by a US carrier or under a cost-sharing arrangement with a U.S. flag carrier. Certain exceptions apply.\footnote{Cargo Preference Act (46 U.S.C. \S 55305); International Air Transportation Fair Competitive Practices Act (49 U.S.C. \S 40118).}

Intellectual property rights may be one of the more challenging aspects of government supported project development with the difficulty amplified when multiple team members are involved. In order to develop the issue, Part B asked if a government’s financial support agreements: (1) would in any way restrict a technology developer from commercially exploiting IP used or created during a large pilot scale project; and, (2) reserve any government interest in IP developed or used for a large pilot scale project.

Based on the responses, it appears that all study countries allow developers to own and exploit created IP and/or have a process whereby the developer may obtain ownership and the right to exploit IP. In the US, ownership is qualified to the extent of the government’s US preference and competitiveness provisions (discussed above) and other reserved rights (discussed below). The Korean response notes that financial supporters and participating organizations have priority in use of the technology and intellectual properties and that sometimes terms are negotiable. In Canada, for “Grants and Contributions” funding programs, IP that arises in the course of an RD&D project vests in, or is licensed to, the recipient subject to the government’s reserved license (discussed below). The Canadian response also describes the process when a federal researcher is involved in a project. In that case the parties negotiate background and foreground IP rights, how and by whom IP will be commercialized, what type of licenses will be issued, and the royalty split between collaborators. The countries shared conceptual approach to IP – where developers own and exploit the technology - should benefit multinational collaboration on large pilot projects by encouraging private sector investment. However, the details behind country policies must be further examined to determine if and where conflicts may arise and how their resolution may be streamlined.
With respect to government rights in project IP, the Japanese response indicates that no rights are reserved. Korea’s reservation of rights requires additional inquiry. The Canadian response indicates that under Grants and Contributions programs supporting energy RD&D activities, the recipient grants to the Government of Canada a non-exclusive, irrevocable, world-wide, royalty-free license in perpetuity to use project reports and modify such reports and documents for non-commercial governmental purposes. Rights reserved by the USDOE are summarized below.\textsuperscript{114}

1. \textit{Technical Data and Software}. The US Government obtains “unlimited rights” in data first produced under an agreement. Unlimited rights means the right to use, disclose, reproduce, prepare derivative works, distribute copies to the public, and perform publicly and display publicly, in any manner and for any purpose, and to have or permit others to do so. The USDOE Fossil Energy R&D Program is covered by a special data law that authorizes the USDOE to agree to protect first produced data from public disclosure for up to 5 years from development.\textsuperscript{115}

The Government obtains “limited rights” in data developed at private expense that embody trade secrets or are commercial or financial and confidential or privileged. When an agreement requires delivery of limited rights data, the Government reserves the right to reproduce, and use and disclose the data for specified purposes which include for evaluation purposes under the restriction that the limited rights data be retained in confidence and not be further disclosed.

When an agreement requires delivery of computer software developed at private, the Government reserves the right to reproduce, use and disclose the data for specified purposes including for use in or with the computer or computers for which it was acquired and backup purposes.

FOAs issued by the USDOE’s Office of Fossil Energy have advised recipients that delivery or third party licensing of proprietary software or data developed solely at private expense will not normally be required except as specifically negotiated in a particular agreement.\textsuperscript{116}

2. \textit{Copyrights}. For first produced copyrighted data, including computer software, the Recipient must grant to the Government, and others acting on its behalf, a paid-up nonexclusive, irrevocable, worldwide license to reproduce, prepare derivative works, distribute copies to the public, and perform publicly and display publicly for all such data. For data not first produced in the performance of an agreement, that is delivered under the agreement, the recipient must grant to the Government, or acquire on its behalf,

\textsuperscript{114} USDOE provisions differ based on recipient type. Clause sets are found at: http://energy.gov/gc/standard-intellectual-property-ip-provisions-financial-assistance-awards.

\textsuperscript{115} 42 U.S.C. § 13541

\textsuperscript{116} FOA #: DE-FOA-0001190 and FOA #: DE-FOA-0001459. op.cit
a license of the same scope as set forth for first produced data, or, in the case of software a license of the same scope as required for delivery of restricted computer software.

3. **Patents.** When the Recipient of a USDOE agreement retains or obtains title to subject inventions, the Federal Government retains a non-exclusive, nontransferable, irrevocable, paid-up license to practice, or have practiced for or on behalf of the US, the subject invention throughout the world. The Government’s reserved rights may have limited consequence for developers of large pilot projects in that most projects will be based on previously patented technologies and the US Government would not itself be a significant user of fossil based power and CCS technology. Inventions may nevertheless arise during pilot projects.

The US also retains “March-in-Rights” in subject inventions in which a Recipient has title. These provide the Government the right to require the Recipient, an assignee or exclusive licensee of a subject invention to grant a non-exclusive, partially exclusive, or exclusive license in any field of use to a responsible applicant or applicants, upon terms that are reasonable under the circumstances. If the Government’s request is refused, the Government has the right to grant such a license itself. Specified reasons for exercising March-in-Rights include the case where the Recipient or assignee has not taken or is not expected to take within a reasonable time, effective steps to achieve practical application of the subject invention. March-in-Rights are exercised infrequently.

Part B also asked if a government’s financial support agreements would reserve a government ownership interest in real or personal property acquired for a large scale pilot project. Similar to IP, government rights in project acquired real or personal property could discourage private investment and hinder multinational collaboration. The Japanese response indicated that no property rights were reserved. The Korean response stated that normally developers or participating organizations own properties acquired for the project. For Canada, additional inquiry is necessary. In the US, the recipient obtains conditional title in real and personal property unless federal law authorizes the government to vest unconditional title. When title is not unconditionally vested and the property is no longer needed for federally sponsored projects, the following disposition procedures apply:

1) Personal property with a per unit fair market value less than $5000 may be retained, sold or otherwise disposed of with no further obligation to the Government.

2) The recipient may elect to retain title to personal property valued at $5000 or more, and real property, without further obligation to the Federal Government, by compensating the

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117 35 U.S.C. § 203 (small businesses and non-profit organizations); 2 CFR 910, SUBPART D Appendix A (For other entities receiving support from the USDOE).
Federal Government for that percentage of the current fair market value of the real
property or equipment that is attributable to the Federal participation in the project.

3) If the recipient does not wish to retain title to real or personal property, the Government
may require the recipient to: (i) transfer title to the Federal Government or to a third party
provided that, in such cases, the recipient is entitled to compensation for its attributable
percentage of the current fair market value of the real property or equipment, plus any
reasonable shipping or interim storage costs incurred; or, (ii) sell the real property or
equipment and pay the Federal Government for that percentage of the current fair market
value of the property that is attributable to the Federal participation in the project (after
deducting actual and reasonable selling and fix-up expenses, if any, from the sale
proceeds).118

For the USDOE’s Fossil Energy Program, federal law provides the Secretary of Energy (or
designee) discretion to unconditionally vest fee title or other property interests acquired under
projects in any entity, including the United States.119

Part B asked if a government’s environmental laws, regulations or policies apply to extra-
territorial large pilot projects receiving financial support from the government. The responses
from the Japanese and Korean participants indicate that no laws, regulations or polices would
apply. In the US and Canada, environmental reviews may be required in certain circumstances
as summarized below.

US domestic environmental laws, regulations and policies generally do not apply to projects
conducted outside of the US.120 An exception exists under Presidential Executive Order 12114
which requires Federal Agencies to consider in their decision making the environmental effects
abroad of major federal actions. The Order excludes from its coverage, federal actions that
significantly affect the environment of a foreign nation that is involved in the action.121 Actions
subject to the Executive Order undergo an environmental review process which may involve
environmental impact statements, bilateral or multilateral environmental studies, or concise
reviews of the environmental issues involved.

Under the Canadian Environmental Assessment Act (CEAA) 2012, an environmental assessment
of a designated project may be required when there is the potential for adverse environmental
effects that are within federal jurisdiction including effects on:

118 2 CFR 200.311; 2 CFR 200.313; 2 CFR 910.360
119 42 U.S.C. § 16291a
120 Exceptions may be embodied in specific statutes (e.g. Section 470a–2 of the National Historic Preservation Act,
16 U.S.C. § 470a–2, addressing federal undertakings outside the US which may directly and adversely affect a
property which is on the World Heritage List or on the applicable country's equivalent of the National Register). Litigation
in the US has also tested extraterritorial application of various US environmental laws.
121 Executive Order 12114. Available at: http://www.archives.gov/federal-register/codification/executive-
order/12114.html.
• fish and fish habitat;
• other aquatic species;
• migratory birds;
• federal lands;
• effects that cross provincial or international boundaries;
• effects that impact on Aboriginal peoples, such as their use of lands and resources for traditional purposes; and,
• changes to the environment that are directly linked to or necessarily incidental to any federal decisions about a project.122

Guidance from the Canadian Environmental Assessment Assessment further states that if the Minister of the Environment considers that a project has the potential to cause significant adverse environmental effects across boundaries between non-federal and federal lands, or across provincial or international boundaries, then the Minister has the discretion to anticipate and prevent degradation of environmental quality; and to facilitate public participation in the environmental assessment of projects where the federal government is involved.123

The final Part B question asked if national or subnational laws or regulations would require a large pilot scale fossil fueled power plant (e.g. oxycombustion power plant) to utilize CCS. If CCS is required for power technology pilots, projects will be more complicated, costs will be increased, and implementation timelines expanded when compared to a pilot without CCS. The Japanese and Korean responses indicate that CCS would not be required for a power plant pilot.

In the US, a requirement for CCS will likely depend upon the size and nature of the pilot project. In 2015, the Environmental Protection Agency (EPA) finalized regulations establishing standards of performance for greenhouse gas (GHG) emissions from new, modified and reconstructed electric utility generating units.124 The standard for newly constructed sources is 1,400 lb CO₂/MWh which in the case of coal-fueled units will require “partial” CCS (approximately 16% capture) or co-fueling with natural gas. The standards apply to units that: (1) are capable of combusting more than 250 MMBtu/h (260 GJ/h) heat input of fossil fuel (equivalent to 73 MW heat input) 125; and (2) serve a generator capable of supplying more than

125 An electric power generating unit with 250 MMBtu/h heat input will have a generating capacity between approximately 20-30 MWe, depending on the efficiency of the system, which is in part attributable to the level of CO₂ capture. Therefore, for the size range considered for large pilots in this study (10 – 50 MWe) some US projects would likely be subject to these performance standards and others would not.
25 MW net to a utility distribution system. Hence larger pilots that meet the triggering requirements would require CCS or natural gas co-fueling to comply with the regulations. States may impose more stringent requirements as is the case in California which established a standard for baseload generation owned by, or under long-term contract to publicly owned utilities, of 1,100 lbs CO₂/MWh.¹²⁶

Independent of the applicability of the previously discussed New Source Performance Standards (NSPS), certain new sources may nevertheless be required to employ CCS pursuant to the EPA’s New Source Review (NSR) Program. EPA first issued regulations in 2010 addressing permitting requirements for GHG emissions under the Prevention of Significant Deterioration (PSD) component of the NSR Program. Under PSD permitting, any major stationary source that is either newly constructed or modified and that will cause a significant net increase in emissions is required to utilize best available control technology (BACT) for each regulated air pollutant. A BACT analysis takes into consideration technical feasibility and cost. EPA restricted applicability of PSD regarding GHG emissions under a “Tailoring Rule” issued in 2011, and that rule was reversed in part by the Supreme Court in 2014.¹²⁷ EPA subsequently issued guidance stating that NSR/PSD permits would be required to address GHG emissions only for new sources subject to PSD for conventional pollutants (so-called “anyway” sources, with the potential to emit, considering the reduction by pollution controls, 100 tons per year of a conventional NSR pollutant) and only if the source (after controls) had the potential to emit 75,000 tons per year of GHGs.¹²⁸ Under these applicability criteria it is likely that commercial-scale demonstration units could be subject to NSR-BACT for GHG emissions. It is possible but unlikely that large pilot units would exceed the applicability thresholds.

In Canada, additional examination is required to understand if Canadian regulation would require large pilot scale fossil fueled power plants to employ CCS. Canada’s federal Department of Environment (now Environment and Climate Change Canada or ECCC) finalized regulations in 2012 to reduce GHG emissions from coal-fired electricity generation.¹²⁹ The performance standard took effect on July 1, 2015, and establish a standard of 420 tonnes of CO₂ per gigawatt hour of electricity produced for new coal-fired electricity generation units (those commissioned after July 1, 2015), and units that have reached the end of their life. New and end-of-life units that incorporate technology for CCS can apply to receive a temporary exemption from the performance standard until December 31, 2024. Units will have to provide documented evidence

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¹²⁶ Information about California’s standards is available on the California Energy Commission’s website at http://www.energy.ca.gov/emission_standards/index.html.
¹²⁸ Memorandum from Janet McCabe, Acting Assistant Administrator, Office of Air and Radiation, USEPA, to EPA Regional Administrators, July 24, 2014.
that they are meeting yearly regulated construction milestones including beginning commissioning of the CCS system (including the capture, transport and storage of CO₂) by January 1, 2024. If a generator installs a CCS system on an existing unit prior to its end-of-useful-life then they may be deferred from meeting the performance standard on an end-of-useful-life unit for 2 years.¹³⁰

4.3.3 **Part C: Programs That May Support Large-Scale Pilot Projects**
The objective of Part C was to gain an appreciation of the processes that typically are used by study countries to select and fund pilot projects and to learn if programs exist or are planned that may provide financial support for large fossil-based pilots. Table 3 provides an overview of the Part C responses.

¹³⁰ECCC-Coal-Fired Electricity Generation Regulations – Overview.”
http://ec.gc.ca/cc/default.asp?lang=En&n=C94FABDA-1
### Table 4-3 Part C – Programs for Large Scale Pilot Projects

<table>
<thead>
<tr>
<th>Does country have existing or planned programs that may support large fossil-based pilot scale projects?</th>
<th>JAPAN</th>
<th>US</th>
<th>KOREA</th>
<th>CANADA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Yes • OCG step II project. (Budget not yet open)</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>NRCan funding programs which could support large fossil-based pilot projects are either completed, ending by March 31st, 2016 or fully committed.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Do government support programs require cost sharing for pilot projects?</th>
<th>JAPAN</th>
<th>US</th>
<th>KOREA</th>
<th>CANADA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Yes 66%, 50% or 33% (Based on company size)</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>NRCan, Total Canadian government assistance (federal, provincial/territorial and municipal governments) may be limited (e.g. 75% of total project costs).</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>What mechanisms are used to support pilot projects?</th>
<th>Primarily contracts</th>
<th>Financial Assistance Cooperative Agreements</th>
<th>Grants</th>
</tr>
</thead>
</table>

| What process is used to obtain and select project proposals? | Proposals are selected by Board of Review consisting of outside intellectuals. | Typically, competitive Funding Opportunity Announcements with selection based on evaluations provided by panels of experts. Larger projects may be phased with down-selection of projects that proceed to later phases. | 1. Request for Information (RFI) to select appropriate project titles. 2. RFI Responses. 3. Solicitation of Proposals. 4. Competitions to select projects. 5. Recommended funding approved by Senior Management Committee. 6. Negotiation of contribution agreement. For competitive projects - typically: 1. Call for Letters of Expression of Interest (LOI). 2. LOI review by technical committee. 3. Selected proponents invited to submit full proposals. 4. Proposal review by technical committee. |

All study countries have on-going large pilot projects and/or demonstration projects receiving government support. With respect to recently initiated and planned activities, the USDOE expects that approximately $143,500,000 in USDOE funds will be available to support large pilot projects under its post-combustion capture FOA and $10,000,000 available for selections
under its Pre-Project Planning for Advanced Combustion Pilot FOA. Both FOAs require a minimum 20 percent non-federal cost-share.\textsuperscript{131} Funding has been requested in FY2017 to: (1) support front end engineering design and initial construction of a large pilot facility to capture CO\textsubscript{2} from natural gas power systems; and, (2) continue development of a 10 MWe supercritical CO\textsubscript{2} power cycle pilot facility.\textsuperscript{132}

All countries generally require some level of cost-sharing for government supported projects. For Korea and Japan, cost-sharing percentages are based on company size. For USDOE funded projects, a minimum 20\% non-federal cost-share is required for applied R&D regardless of company type. Pilots in the 10-50 MWe range typically would be subject to the 20\% cost-sharing requirement. The percentage may be reduced or eliminated upon a determination by the Secretary of Energy (or designee) that the reduction is appropriate. The USDOE requires a minimum 50\% non-federal cost share for demonstration projects which may also be reduced if the Secretary (or designee) determines that the reduction is appropriate taking into consideration technical risk.\textsuperscript{133} In Canada, the total of federal and subnational government contributions to a project could be subject to a percentage limitation.

Governments quite naturally use different methods to obtain and evaluate proposals and different forms of agreement to fund projects. Since projects receiving multinational support (other than pooled support) must comply with each country’s proposal requirements and contractual terms and conditions, a more detailed comparative analysis of country policies and terms would be beneficial to determine if, or where, conflicts may arise and how conflicts may be resolved.

\textsuperscript{131} FOA #: DE-FOA-0001190 and FOA #: DE-FOA-0001459. op.cit
\textsuperscript{132} FY 2017 Congressional Budget Justification. op.cit.
\textsuperscript{133} 42 U.S.C. § 16352. Basic and fundamental research is not subject to minimum cost-sharing requirements.
4.4 Potential Issues, Lessons Learned, and Knowledge Gaps

Drawing on information provided by the participants and the author’s experience, the following is a summary of matters for possible consideration by government and private sector stakeholders interested in multinational collaboration.

4.4.1 Intersection of Government Interest in Fossil Based Technology with CCS
It is important to understand where the future interests of governments may intersect that could form the focus of multinational collaboration. The information provided by the study country participants suggests that there are opportunities. Further analysis by stakeholders could lead to the identification of a suite of technologies that may be well suited for multinational collaboration at the large pilot scale. Additional knowledge is required to support the analysis, including:

1. A deeper understanding of the technology development objectives of individual countries.

2. The impact of the Paris Agreement and regional and national climate mitigation strategies on advanced technology needs and the timing of technology development efforts.

3. How and when large pilot projects are considered in a government’s budgeting process.

4.4.2 Restrictions on Multinational Support and Domestic Funding Restrictions
Individual country law, regulation, or policy may limit the ability of governments to financially support extraterritorial projects or to provide support to companies not incorporated in or otherwise affiliated with the country. Instances are seen in the Questionnaire responses and more would be expected as other countries are considered. Such restrictions can present challenges for collaboration on large pilot projects.

The USDOE’s labor cost limitation illustrates the issue. As discussed earlier, USDOE agreements have required a percentage of the direct labor cost to be performed in the US unless the recipient can demonstrate that the US economic interest will be better served through a greater percentage of the work being performed outside the US. Participants in the 2014 Technology Workshop identified the limitation as a barrier to international participation in pilot projects. As noted by a study participant, compliance requires an allocation of funds among participating countries according to the respective level of support which may be possible for the construction of modules but becomes difficult during operations since the majority of labor cost will be assumed in the country where the facility is installed. Structuring project funding around domestic restrictions may not be possible or may be suboptimal in certain cases. Success may depend on government flexibility such as the waiver option embodied in the USDOE provision.

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134 Technology Workshop Report. op.cit.
Various questions should be explored:

1. What are each country’s restrictions and how do they operate?

2. How may the restrictions hinder multinational collaboration?

3. To what extent will restrictions chill the interest of project developers in proposing projects for multinational support?

4. What opportunities exist for flexibility under applicable law, regulation or policy?

5. What effective ways are available to comply with the restrictions without compromising the benefits of multinational collaboration?

4.4.3 **Host Sites**
Suitable (and willing) host sites are required for large scale projects. Multinational collaboration can expand host site opportunities for countries seeking to advance fossil power with CCS. Possible benefits may be a greater number of viable host sites, demonstration of technology where it is needed, market opportunities for companies associated with the funding countries, and potentially lower project cost. This may include the piloting of technologies in countries unable to provide financial support. Questions for further exploration include the limit of national laws and policies on extraterritorial projects and the advantages and disadvantages of various options.

4.4.4 **Intellectual Property Rights**
Intellectual property rights have been identified as a concern for multinational projects. Matters related to negotiation of ownership rights among project company team members are outside the scope of this study. However, issues arising from government requirements are worthy of consideration. During the 2014 CURC Technology Workshop, participants on an international roundtable viewed IP issues to be generally manageable, but they also viewed IP protection as more difficult for a project involving other countries and suggested that IP be addressed in the initial stages of planning a pilot plant project. Preference provisions embodied in IP clauses such as the US requirement for U.S. manufacturing of new inventions were also cited as barriers to international collaboration. Based on his experience, the author agrees that IP requirements are manageable but notes that management takes a thorough understanding of government requirements by all parties involved. When parties are not familiar with the requirements - as can be the case on multinational projects – the time needed to reach agreement can be substantially longer. Further analysis requires an in depth understanding of IP policies and provisions used by individual countries. Stakeholders can identify issues that are likely to arise

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135 Technology Workshop Report. op.cit.
136 Ibid.
and assess whether the issues can be reasonably managed or if they have the potential to impact project success. Lessons learned, approaches for issues resolution, and streamlining suggestions can be developed.

4.4.5 Conflicts between Terms and Conditions of Individual Governments
Multiple financial support agreements create the risk of conflicting terms and conditions. For example, if two or more governments reserve inconsistent ownership rights in property acquired for a large pilot project, the project proponents are put in the difficult position of having to reconcile the provisions with the individual governments or risk being in breach of one or more agreement. Wherever conflicts occur, they can slow project development and ultimately impact project success. A better understanding of where material conflicts exist would be worthwhile along with lessons learned in dealing with conflicting requirements.

4.4.6 Integrated Versus Non-integrated Power Technology Pilots
Government RD&D programs are seeking to reduce cost and improve effectiveness of CCS systems and fossil based power systems to ready the integrated technology (i.e. with both the power system and the CCS system) for commercial deployment at prices that are affordable. A large pilot project testing power generation technology will be more expensive, complex and longer if it must be integrated with CCS. However, the inclusion of CCS can lead to an understanding of integration issues that might be encountered at commercial scale and may improve pilot project economics if markets exist for the CO₂ and other products. Further analysis of advantages and disadvantages of integrated versus non-integrated testing is warranted.

4.4.7 Optimal Models for Multinational Collaboration
The advantages and disadvantages of various multinational collaboration models should be assessed taking into consideration technology development objectives and government and private sector interests and concerns. Issues for consideration may include how funding is committed to best meet pilot project needs, barrier issues that might be addressed in a formal agreement that cannot be addressed in an informal relationship, and timing and approval processes. Knowledge sharing is often an element of multinational agreements. Information sharing from large pilot projects poses a particular problem since such projects are typically based on pre-existing privately owned technology that developers cannot or will not share for risk of diluting their proprietary position. Lessons learned from past multinational collaborations should be evaluated.

4.4.8 Evolving Priorities, Policy Objectives and Approaches
Government budgets, priorities, policy objectives and approaches change over time. As noted by a study participant, changes can put a given project in a constant state of flux. The Task 2 Report prepared by Mr. Herzog provides examples illustrating how changing government priorities and

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137 Reserved property interests on large scale pilots may also impact project financing and private sector investment decisions.
policies can impact large scale projects. Shorter duration pilot projects may be at less risk of policy changes than longer duration demonstration projects. Nevertheless, it is an issue for large pilot projects and the effects may be exacerbated when multiple governments are involved.

4.5 Next Steps

The results of Task 4 suggests that multinational collaboration offers the opportunity for countries to leverage resources to mitigate the cost and financial risks associated with large pilot projects and thereby increase the number of successful projects. Additional study is required to refine the concept. Subject matter experts from government and the private sector can be engaged to further develop issues for consideration by stakeholders. Stakeholders can use the combined work under Tasks 2, 3 and 4 to evaluate options for governments and industry to come together to successfully fund projects.

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