Retrofitting of Coal-Fired Power Plants for CO_2 Emissions Reductions

An MIT Energy Initiative Symposium

Massachusetts Institute of Technology
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About the MITEI Symposium on the Retrofitting of Coal-Fired Power Plants for CO_2 Emissions Mitigation

The MIT Energy Initiative (MITEI) sponsored a symposium on the retrofitting of coal-fired power plants to capture CO_2 emissions. This report summarizes the views of symposium participants and identifies many key issues, opportunities, and possible "next steps" associated with retrofitting coal-fired power plants for carbon capture. The report represents a range of views from those at the symposium and where possible, includes consensus or general recommendations from the presenters and participants; *it is in no way intended to represent the views of all the participants, of specific participants, or of the rapporteur*.

Participants represented the range of stakeholders with expertise, equities, and interests in the topic and included 54 representatives of utilities, academia, government, public interest groups, and industry. This invitation-only event was designed specifically to elicit different perspectives and identify areas in which research, policy development, and analysis are needed to address this critical environmental concern.

The focus of the symposium was the retrofitting of existing pulverized coal plants, either through add-ons to existing plants, the rebuilding and upgrading of existing boilers to facilitate carbon capture, or increasing the thermal efficiency of existing boilers to reduce greenhouse gas emissions per unit of power output. Participants, however, also discussed a range of additional technology options, including the repowering of existing boilers with alternative fuels such as biomass or natural gas, rebuilding existing plants with more efficient coal technologies such as IGCC or oxy-combustion, and co-firing with low-carbon fuels.

To maximize time and to focus the discussion at the symposium, three topical white papers, commissioned from subject matter experts, were circulated to the symposium participants in advance of the event. These papers were designed to be thought-provoking and to provide participants with frameworks, data, points of view, and information on the issues to be discussed at the symposium. They were not intended to be comprehensive or definitive works and were a priori assumed to reflect the points of view and expertise of the individual authors only. Other symposium participants submitted papers for discussion purposes as well.

As several participants noted, this symposium provided the first major opportunity for stakeholders with extensive experience and knowledge to exchange frank points of view on the value and prospects for retrofitting coal-fired power plants in the U.S. The symposium was conducted under Chatham House rule so that participants could candidly discuss topics. Therefore, with the exception of the views of the symposium co-chairs and the authors of the white papers, there are no specific attributions in this report.

This report is intended to provide federal policy makers with insights on the importance and nature of the problem and a range of possible policies and research investments that will help mitigate CO_2 emissions from existing coal-fired power plants. The full texts of the discussion papers and some supporting slides are included in the appendices. As noted, additional papers were also submitted to inform the discussion. The texts of many of these papers are posted on the MIT Energy Initiative website (http://web.mit.edu/mitei).

The MIT Energy Initiative would like to thank all of the Symposium participants for sharing their time and expertise. We extend a special thanks to Entergy and its CEO Wayne Leonard who supplied the motivation for this event and made it possible through financial support. We would also like to thank those who submitted papers and allowed us to use information, slides, and tables in this report. Finally, we thank the Clean Air Task Force for allowing us to include their paper, Advanced Post-Combustion CO_2 Capture, authored by Howard Herzog, Jerry Meldon, and Alan Hatton and supported by the Duke Foundation, in this report.

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FOREWORD

As CEO of Entergy Corporation, I have personally devoted a great deal of attention to the need for society to take effective action on the climate change issue. Entergy is a strong advocate for starting now on the path to significant reductions in greenhouse gas emissions by mid-century.

The impetus for this symposium was our conviction that an effective, sustainable response to climate change must include retrofit technologies to reduce CO_2 emissions from existing coal-fired electric power generating plants.

It is well known that coal-fired generation contributes over 80% of the CO_2 emissions from this country's electric power sector, and that the world's installed base of conventional coal plants is growing steadily as developing countries — China, in particular — increase their generating fleet to bring electricity to people who do not have what we consider a basic necessity.

What is less well understood, I believe, is that these coal plants are going to continue to operate for decades, even as our industry turns to carbon-free electric power generating technologies such as solar, nuclear, biomass, geothermal, and others. Once built, coal plants are, in most cases, the cheapest source of base load power generation and will not be phased out absent very high CO_2 prices. It's basic economics. The great majority of costs for a plant are sunk at the time it starts operation; only the "to go" costs matter in deciding whether to continue running the plant.

Thus, our view is that an effective strategy for achieving significant and cost effective reductions in CO_2 emissions requires the deployment of new technologies to retrofit existing coal plants and reduce their CO_2 emissions. If we are to sustain an effective climate program and grow our economy, we can't kill coal; we have to save it. That may seem strange to hear from a CEO of an electric company with less than 10% of its capacity in coal-fired generation — but it is the inescapable conclusion of our analysis.

We also concluded that not enough is being done to commercialize this technology on a timeframe consistent with the climate change goals. That is why we asked the MIT Energy Initiative (MITEI) to bring together the nation's leading experts in this field to assess the current issues surrounding retrofit technologies and to formulate a concrete action plan to move forward quickly.

In my view, the symposium fills a major void in the climate change policy debate. This report provides the most comprehensive and up-to-date analysis of retrofit technology issues. Now it is up to policy makers to provide the requisite focus and sense of urgency to get this technology developed.

There are no guarantees that the entire world will sign on to CO_2 reduction or stabilization. There is no panacea that will make a solution quick or "cheap." What does appear certain is that carbon capture and sequestration is an absolutely necessary technology — albeit insufficient by itself — to address the greatest challenge our generation may ever face.

I want to express my thanks and appreciation to Ernie Moniz and Melanie Kenderdine of MITEI, Professor John Deutch, and all the symposium participants. We look forward to working with you to implement these excellent recommendations.

Wayne Leonard
CEO, Entergy Corporation
Symposium Co-Chair

SUMMARY FOR POLICY MAKERS

On March 23, 2009, the MIT Energy Initiative (MITEI) sponsored a symposium on *Retrofitting Coal-fired Power Plants for CO_2 Emissions Reductions* to investigate different pathways for CO_2 emissions reductions using current technology, identify promising RD&D for cost reduction, and discuss policy and institutional barriers to CO_2 emissions reductions in the United States. The deliberations were informed by three commissioned white papers and from additional contributions submitted by workshop participants. These documents are available at www.mit.edu/mitei.

We summarize for policy makers the key points from the lively discussions among the diverse group of participants. **We stress that the observations here are those of the authors and are not offered as a consensus view of the participants**.

- ***There is today no credible pathway towards stringent GHG stabilization targets without CO_2 emissions reduction from existing coal power plants, and the United States and China are the largest emitters.***

  The United States and China account for about 40% of global anthropogenic CO_2 emissions and for over half of global coal use. Both countries have immense reserves of relatively low-cost coal. In the United States, almost half of all electricity is supplied by coal power plants that average 35 years of age and produce about a third of U.S. CO_2 emissions. China has brought on line in the last five years a coal electricity production capacity about equal to the total U.S. installed capacity. Coal will continue to be used for power generation from existing plants in both countries, so mitigation of CO_2 emissions from these plants is a high priority for research, development, demonstration, and deployment (RDD&D).

  Workshop discussions focused mainly on options and actions for the United States. However, the dominant contribution of China in coal-based emissions highlighted the importance of developing more economical CO_2 emissions mitigation technologies. *There is a "China Test" about whether CO_2 emissions mitigation can be accomplished at a sufficiently small incremental cost that China and other emerging economies can afford to implement it.* Passing this test is a critical RD&D goal for the next decade.

- ***There are multiple pathways to reduce CO_2 emissions from existing coal plants.***

  For existing coal plants, post-combustion capture followed by long-term, large-scale, sequestration is the most direct pathway to avoiding nearly all CO_2 emissions. The workshop discussion focused in large part on this path, addressing which plants are amenable to capture retrofits.

  Efficiency retrofits of existing coal plants can result in modest reductions of CO_2 emissions per unit of electricity produced. This is especially attractive for older, less-efficient plants. There is a range of approaches from boiler to control system improvements. A rough estimate is that 4–5% emission reduction could be realized relative to business as usual if efficiency improvements were introduced at less efficient coal plants. This action has the highest benefit/cost ratio for CO_2 mitigation.

  Biomass co-firing is another retrofit option for net CO_2 emissions reduction, if the feedstock is available. Indeed, if biomass use is combined with CCS there are negative net CO_2 emissions.

  Major rebuilds of existing coal plants are another option. There is a range of possibilities for such rebuilds, starting from capturing substantial value from use of an existing site and its infrastructure, and perhaps from its existing permits as well. Rebuilds are likely to be expensive, but will include large efficiency gains, for example, rebuilding an old subcritical unit to a high efficiency supercritical (SCPC) or ultra-supercritical (USCPC) unit, with or without CCS. More extensive rebuilds include conversion to oxygen-driven combustion or to an IGCC plant with CCS. Additional options discussed in the background papers include co-generation and, for gasification plants, poly-generation of fuels and electricity.

Finally, repowering (biomass, natural gas) at coal plant sites is an option when CO_2 emissions charges are high and retrofit and rebuild are not attractive. Use of some elements of existing infrastructure (e.g., grid connections) can reduce project costs.

- ***The U.S. government must move expeditiously to large-scale, properly instrumented, sustained demonstration of CO_2 sequestration, with the goal of providing a stable regulatory framework for commercial operation.***

  Obviously, without sequestration, CO_2 capture has no purpose. A substantial sequestration demonstration program should include several sites with storage of one to several megatons per year scale. EOR projects provide some useful information about geological storage, if properly instrumented and monitored, but neither the EOR regulatory framework nor the potential for EOR is adequate for CO_2 mitigation from coal fired generating units at a scale that will be material for climate change risk mitigation. The primary focus of the government program for the long-term sequestration at scale should be deep saline aquifers. Since a major source of CO_2 emissions is the existing coal fleet, *the DOE CCS demonstration program should include projects at existing plants.* The Clean Coal Power Initiative (CCPI) is placing increased emphasis on retrofits, but it has neither sufficient funds nor project management resources to support the large-scale projects called for here, certainly not in sufficient numbers.

  A robust R&D program should include exploration of *advanced sequestration technology options*. Examples are enhanced biological sequestration and beneficial uses of CO_2 in materials.

- ***Relatively large (300MWe or greater), high efficiency coal plants with installed FGD and SCR capability are the best candidates for CCS retrofit.***

  Such plants make up less than half of the existing fleet. With current and evolutionary amine-based capture technology, *estimates of the capture cost were generally in the \$50-70/ton of CO_2 range for the Nth-plant.* This estimate of the cost of CO_2 emissions abatement is significantly higher than is generally recognized in the United States, but is not dramatically higher than the costs experienced in Europe (at current exchange rates).

  China has a significant number of recently built supercritical plants because of its aggressive deployment of coal power plants in this decade. Consequently there may be many opportunities for retrofit of Chinese coal plants when CO_2 emissions are priced, assuming that the incremental cost for CCS for air-driven combustion units is reduced substantially through RD&D.

  By contrast, retrofit is not attractive for old, lower efficiency, smaller, subcritical units. Rebuilding or repowering is an option depending on significant CO_2 prices being in place.

  Extensive modifications require both retrofit and rebuild. An important option is oxy-combustion modification to the existing coal fleet to replace an air fired combustion system with an oxygen fired combustion system. This modification requires both significant retrofit and rebuild, so there are many challenges. For example, infiltration into existing air fired older boilers may be acceptable for current operation, but the retrofit oxy-combustion system is likely to require plugging the leaks, which is an expensive undertaking.

- ***"Real world" retrofit decisions will be taken only after evaluation of numerous site-specific factors. Some of the key screening factors include:***

    - Proximity to geologic sequestration or EOR site and/or CO_2 pipeline
    - Available space: space constraints may make carbon capture retrofit impossible, or limit the amount of capture that is possible
    - Access to increased water supply
    - Existence of FGD and SCR capability
    - Practicalities of heat and power integration
    - Implication of a retrofit for dispatch in the regional system.

    It is unclear at the moment how restrictive these criteria will be for the existing fleet. EPRI is carrying out five site-specific case studies to help inform the discussion. It is quite possible that these site-specific screens will substantially limit that part of the existing coal fleet in the U.S. for which retrofit or rebuild is attractive or result in partial capture solutions tailored to the current plant configuration.

- ***CO_2 capture cost reduction is important.***

    CO_2 capture costs are large because both the capture and release step is expensive and because the capture process conditions influence other steps in the conversion process. Accordingly, CO_2 capture technology deserves significant R&D support as part of a balanced retrofit program.

- ***A robust U.S. post-combustion capture/oxy-combustion/ultra-supercritical plant R&D effort requires about $1B/year for the next decade.***

    A balanced R&D effort includes advanced simulation and analysis, exploratory research, proof of concept, pilot plants, leading to large scale demonstrations. Such an R&D program should be pursued with urgency. There are many important directions for research of intermediate term and "over-the-horizon" technologies. Near term R&D opportunities that are being pursued include a chilled ammonia capture project and exploration of new amine chemical solvents for binding CO_2. Longer-term opportunities included ionic liquids, membrane separations, and perhaps use of algae or other biomaterials to capture and convert the CO_2.

    Exploratory research could lead to a major breakthrough relevant to the "China test." It should be noted that some of the advanced capture approaches are appropriate only for oxygen driven systems. Oxygen separation cost reduction would be a critical enabler for both oxy-combustion retrofit and for various rebuild options, including gasification. Advanced materials research is important for ultra-supercritical plants.

    In addition there are R&D opportunities directed principally at new builds based on advanced gasification or novel approaches such as chemical looping.

- ***The Federal government should dramatically expand the scale and scope for utility-scale commercial viability demonstration of advanced coal conversion plants with CO_2 capture. The program should specifically include demonstration of retrofit and rebuild options for existing coal power plants. New government management approaches with greater flexibility and new government funding approaches with greater certainty are a prerequisite for an effective program.***

    Symposium participants discussed the range of desirable demonstration projects for retrofit of pulverized coal combustion including oxy-combustion, repowering, and poly-generation. The estimated cost range for these projects to be borne by industry and government was $12-15B over the next decade, in addition to the research budget.

Given the urgency of establishing CO_2 emissions reduction options for the existing coal fleet, and the likelihood that there will not be a strong CO_2 emissions price signal for several more years, a Federal utility-scale cost- and risk-shared demonstration program needs a clear near term focus on commercial viability within the electricity market structure reasonably anticipated over the next 10–15 years, rather than technology-forcing requirements. The financial assistance agreements with the private sector should be based on commercial terms and conditions rather than government procurement restrictions. Multiple demonstrations will be needed in parallel, requiring substantial outlays, experienced management, and careful evaluation.

Such a strategy can be begun under the current DOE Clean Coal Power Initiative (CCPI) demonstration program, if it is expanded and has enhanced flexibility for speeding up the government process and for private sector project management and financial accounting.

However, new legislation should be considered in parallel with the CCPI program solicitation and implementation. An expanded commercial viability utility-scale demonstration program should be established through a quasi-government corporation. The authorities of the new corporation should be designed with a broader mandate than that of the CCPI program, encompassing the full range of low-carbon electricity technologies and fuels and financed from a multi-billion dollar annual small electricity line charge (as has been under consideration in the Congress).

Time is of the essence.

The retrofit, rebuild, or repowering of the existing coal fleet, in the U.S. and in China, to reduce CO_2 emissions dramatically is a necessary step towards achieving GHG stabilization targets. Practical options that will justify the vast investments needed over the next decades require validation from demonstration, development and research. Failure to do so will both drive up CO_2 prices (and the cost of electricity) and leave us with a continuing dearth of appropriate technology options.

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Symposium Co-Chair

The MIT Energy Initiative's Symposium on The Retrofitting of Coal-Fired Power Plants for CO_2 Emissions Reductions

FINDINGS IN BRIEF

FROM THE RAPPORTEUR'S REPORT ON THE SYMPOSIUM

The proceedings of the MIT Energy Initiative's (MITEI) Symposium on the Retrofitting of Coal-fired Power Plants for CO_2 Emissions Reductions are summarized in this report which reflects the major points of discussion, and the general findings and recommendations of the participants at the event. It is important to note that this is a report on the proceedings and papers that informed those proceedings; it is not a study. The report represents a range of views from those at the symposium and where possible, includes consensus or general recommendations from the presenters and participants; *it is in no way intended to represent the views of all the participants, of individual participants, or of the rapporteur.*

Symposium Structure and Framing of the Issues

The symposium's 54 participants, all experts in the subject matter, helped to frame the issues, opportunities, and difficulties associated with retrofitting coal-fired power plants and other emissions mitigation options for coal-fired power plants. The findings identify a range of possible "next steps" for the consideration of policy makers and other interested individuals and entities.

Participants engaged in moderated discussions after reading background materials and commissioned white papers provided to them in advance of the event. Symposium Co-Chair Wayne Leonard provided a high-level framing of the issues associated with existing coal-fired power plants. The authors highlighted key points from their white papers, and selected discussants offered brief responses to the points made by the authors. Symposium participants then engaged in wide-ranging discussions framed by the topics of the white papers, which included:

- near-term technologies for the retrofit of existing coal-fired power plants and other near-term options for reducing CO_2 emissions;
- "over the horizon" technologies that will help to affordably mitigate CO_2 emissions from existing plants in the longer term; and
- options for federal coal-fired power plant CO_2 emissions mitigation research management principally through government/industry partnerships.[1]

In addition to the commissioned papers, a number of participants voluntarily supplied various papers and slides to all participants in advance of the March 23rd event to further inform and focus the discussion. Data, points of view, and information from these papers are integrated into the text of this report and are available at the MITEI website. MIT Institute Professor John Deutch provided summary remarks at the symposium and led a concluding discussion. A summary of the issues and findings of the symposium follows.

Framing of the Issues

Issues Summary. Many participants felt that replacing all or even a large fraction of existing coal-fired power plants with new, clean, low-carbon technologies is not an economically viable option in the near term. This, coupled with forecasts of large increases in coal-fired power generation around the world, highlights several overriding and urgent concerns:

- The key driver for business decisions on the future of existing coal plants will be their "going forward" costs per MWh compared to the relatively high "all in" costs of low/no carbon alternatives. High all-in costs and the uncertainty about technology options and future natural gas prices complicate climate policy which has to balance affordability with climate imperatives.

- Current federal research, development, and demonstration (RD&D) programs of sufficient scope and scale for retrofitting coal-fired power plants are not adequate to have an appreciable and timely impact on mitigating climate change. To achieve key public policy goals, significant investments are required in a range of associated carbon mitigation technology options.

- U.S. responses to climate change must keep the developing world in mind, China in particular. Global carbon mitigation goals cannot be met without the active engagement and participation of the Chinese. Effective policies and technology development in the U.S. should pass the *"China Test" which asks the question whether CO_2 emissions mitigation can be accomplished at a sufficiently small incremental cost that China and other emerging economies will be motivated to implement it.* This is a critical RD&D goal over the next decade. It is important to recognize the considerable coal technology development going on elsewhere, especially China.

Findings. Framing the Issue: The Need to Retrofit Existing Coal-Fired Power Plants

Finding: Absent serious and sustained effort to mitigate CO_2 emissions from existing coal-fired power plants, supported by RD&D investments to broaden the range of technology alternatives and reduce their cost, it will be very difficult to affordably and rapidly meet the imperatives of climate change.

Finding: Traditional RD&D approaches have been inadequate to meet the need for affordable and effective retrofits of existing coal plants for CO_2 capture. A new approach to RD&D is required.

Finding: The world cannot achieve significant reductions in CO_2 emissions, avoiding the most disruptive impacts of climate change, without commitments to reduce emissions from existing coal-fired power plants in the U.S. and China. The U.S. and China have a shared interest in developing and deploying a range of technologies to retrofit existing coal-fired power plants. Bilateral approaches on climate change should be encouraged and supported as a matter of U.S. policy. Joint research programs between the U.S. and China should be supported and funded. A mechanism for sharing the results of unilateral projects should be created and *supported*.

Panel One. Near-Term Technologies for CO_2 Mitigation

Issues Summary. Post-combustion capture and efficiency improvements ranging from minor upgrades to major rebuilds are the two near-term options for mitigating CO_2 emissions from existing power plants. The range of plant and site characteristics determines mitigation options.

- CO_2 avoidance costs for *retrofitting* smaller, older subcritical plants with PCC are significantly higher than those for newer, larger supercritical plants. Retrofits of plants for PCC favor the newer supercritical coal plants which are more efficient, will have a long remaining lifespan, and are more likely to have good SO_2 and NO_x controls already in place. Technical papers submitted for the symposium identified up to 184 GW — around 59% of installed capacity — as theoretically suitable for PCC retrofits given current technology forecasts; site and plant characteristics will likely substantially lower this percentage. Ninety percent capture from those units that are theoretically capable of PCC retrofits would result in a 50% reduction of CO_2 emissions from the U.S. coal power sector.

- Parasitic energy losses *associated* with PCC are substantial. Much of the research for post-combustion capture is and should be focused on reducing parasitic energy losses.

- There may be opportunities for *rebuilds* at sites where there are older, subcritical PC units. Rebuilds could be economically viable depending on the site characteristics; the demand for additional power generation resulting from the higher capacity of a rebuild; and the cost of competing sources of supply. CO_2 avoidance costs for rebuilds are generally lower than those for retrofitting existing PC plants for PCC. Also, rebuilds avoid the efficiency and capacity losses associated with PCC for subcritical plants, while reducing all emissions to near zero.

Panel One Findings. Near-Term Technology Options

Finding: A carbon price signal is *essential* for making technology choices to mitigate carbon emissions from existing coal plants. Without such a signal, it will be impossible to make rational decisions about retrofit, rebuild, repowering, or other options.

Finding: Lowering CO_2 avoidance costs is critical to providing consumers with affordable electricity. Policy makers must be cognizant of CO_2 avoidance costs of different types of power plants and accommodate these differences in climate change mitigation policies and technology investments.

Finding: Ninety percent capture of CO_2 from 59% of coal-fired capacity in the U.S. (the absolute upper limit of existing plants that are suitable for PCC) would reduce emissions from the U.S. power sector by 50%.

Finding: One size does not fit all! Understanding these limitations is underappreciated but critical to a successful strategy for mitigating CO_2 emissions from existing coal-fired power plants. Different plants and sites require different technology solutions. Flexibility of approaches is essential for maximizing CO_2 mitigation and minimizing electricity costs to consumers. Research programs should focus on reducing the parasitic electricity losses at SC plants retrofitted with PCC, as well as efficiency improvements at smaller subcritical plants without PCC options. EPRI has launched projects with five utilities with different types and sizes of plants to quantify the costs and operational impacts of adding advanced amine combustion systems.

Finding: An inventory of plants and sites is needed to identify the physical attributes of the fleet, to assess relative plant efficiencies and to determine which plants are suitable for retrofitting, rebuilding, repowering, etc. This inventory should inform policy makers about the range of needs, options, and potential consequences of various climate policy options.

Finding: In general, cost-effective retrofits for carbon capture are most suitable for newer, larger plants. "Nth" plant CO_2 avoidance costs for supercritical plants are significantly lower than those for subcritical plants. RD&D programs should support first-mover demonstration projects for supercritical plants. Policies should support efficiency improvements, rebuilds, or repowering for very old, smaller plants $\leq$ 100 MW.

Finding: In a transitional and immature market that includes both PCC retrofits and plants without CCS, the higher costs of power from PCC plants could make them undesirable and potentially underutilized. This is a critical issue with well-founded arguments on both sides. Congress should carefully consider the issues surrounding the potential dispatch of power from PCC plants to meet both climate change mitigation and affordability objectives.

Finding: There are potential environmental and health issues associated with emissions of PCC solvents such as amines or ammonia. Research should be supported to minimize and understand the issues associated with these emissions for utility-scale plants.

Finding: Site size limitations are an underappreciated issue in the development of policies and technologies to mitigate CO_2 emissions from existing coal-fired power plants. Federal research programs should include a component focused on reducing the size of components or the "stacking" of components to affordably reduce the footprint of retrofits, or possibilities for partial capture, which could also enable a smaller component footprint.

Panel Two. "Over the Horizon" Technologies for CO_2 Mitigation

Issues Summary: "Over the Horizon" technology options are defined as technologies that might be *available for commercial demonstration and deployment in ten years or more.* These technology options generally fall into three categories:

- improvements in post-combustion capture options to include better amines and advanced flue gas capture processes, almost all of which are in the early stages of research (ammonia is a notable exception);
- development and demonstration of advanced combustion and gasification options for generating power from coal, including oxy-combustion, ultra-supercritical, and IGCC plants; and
- poly-generation options utilizing FT and gasifier technologies to generate electricity, produce liquid fuels, and provide a suite of high-value chemical and other products.

"Over the Horizon" research needs include highly exploratory research for novel capture options such as microalgae systems and biomimetic approaches; basic research in high-temperature materials and enhancing; performance of a range of experimental solvents and sorbents; process engineering to better integrate IGCC subsystems; and development and demonstration of PCC, ultra-supercritical, oxy-combustion, and IGCC plants.

Panel Two Findings. "Over the Horizon" Technologies

Finding: Retrofit options are limited to PCC capture for supercritical plants and for a subset of subcritical plants and to oxy-combustion retrofits of supercritical plants (oxy-combustion retrofits may look more like rebuilds than retrofits). Choices need to be informed by additional research that, for post-combustion capture, increases capture concentrations and decreases the costs of power losses from steam extraction and compression; and for oxy-combustion, reduces the costs of air separation and compression. Demonstrations are essential for assessing these options.

Finding: Advanced PCC technologies that show the most promise include amine additives and ammonia solvents. Another promising area of research is in advanced sorbents, including specialized structured materials, liquid phase absorbents, and functional adsorbent surfaces, all of which could lead to significant reductions in parasitic energy requirements.

Finding. Rebuild opportunities include ultra-supercritical plants and IGCC. Both show promise for increased efficiency and reduced cost of CO_2 capture. These rebuild opportunities are expensive and require the development and demonstration of new technologies to provide affordable commercial options. USC plants need research, particularly in high-temperature, high-pressure corrosion resistant materials. IGCC plants require development and demonstration focused largely on the integration aspects of the plant and on reducing O&M costs. In addition, advanced gasifiers may be important, particularly if size reduction has a commensurate impact on capital cost. Demonstrations are essential for assessing these options.

Finding. Ultra-supercritical plants have lower CO_2 emissions even without capture because of their extremely high efficiencies. This may provide an option for rebuilds at locations where capture is not an option because, for example, the site offers no nearby sequestration opportunities or commercial CO_2 pipelines.

Finding. Rebuild options must be weighed against each other as well as against poly-generation and repowering options, particularly natural gas combined cycle and natural gas cogeneration repowering. Analysis is required to understand the legal and regulatory barriers to these options. CTL with biomass co-firing requires additional research for reducing CO_2 emissions from transportation fuels and for plant operations as well as policy analysis to identify and then reduce barriers to this option.

Panel Three. Research Management: Government/Industry Partnerships

Issues Summary. A recurring theme of the symposium was the urgent need for a new or dramatically improved, large, and focused federal research program for carbon mitigation from existing coal-fired power plants. This urgency is complicated by the economics of existing plants and the high cost of replacements, the range of plant and site characteristics, the availability of substitute fuels, and limited near-term technologies for retrofit, including lack of sequestration options.

Evidence suggests that the economic benefits of an accelerated technology program for mitigating CO_2 emissions from coal-fired power generation are substantial. A recent study for the Pew Center stated that "….with the experience gained from 30 demonstrations of CCS, the capital costs of wide-scale implementation of CCS in coal-fueled plants could be $80 to $100 billion lower than otherwise."[2]

Participants generally felt that DOE programs, as currently designed, could not provide timely outcomes, sufficient to meet the urgency of the climate change challenge. There was support for a new program at DOE and some suggested fairly radical departures from the current DOE model, including the establishment of a quasi-government corporation to manage large-scale commercial demonstration projects.

Panel Three Findings. Research Management: Government / Industry Partnerships

Finding: Existing programs at DOE, both in structure and focus, are inadequate to meet the research needs for technology development to mitigate CO_2 emissions from existing coal plants. The GAO has concluded that DOE's research strategy has, until recently, devoted relatively few resources to lowering the cost of CO_2 capture from existing coal-fired power plants, focusing instead on innovative technologies applicable to *new* plants (emphasis added).

Finding: Absent or in advance of the wholesale programmatic changes proposed by some participants, DOE's CCPI Round III should be modified to enhance opportunities for success, to engage industry more effectively, and to expedite research. CCPI Round III should be expanded to fund a broader research portfolio beyond retrofits and should include efficiency upgrades, rebuilds, repowering, and co-firing with biomass. Consideration should be given to including a component for research on CO_2 capture from natural gas power plants.

Finding: A research portfolio should span the research continuum and should support breakthrough research opportunities, continuing evolutionary technology R&D and commercial-scale demonstration programs. A notional 8–10 year program with total funding of around $13.4 B, focused on PCC and oxy-combustion was suggested. Many thought this should be expanded to include efficiency, repowering, co-firing, and PCC on gas plants.

Finding: New research and/or innovation models are essential for demonstrating options to mitigate CO_2 emissions from existing coal plants. Options discussed include an "Enhanced DOE Management" model; a new quasi-government corporation, specifically to manage large-scale commercialization demonstrations; and direct federal payments for CO_2 emissions mitigation, with larger payments for early actors.

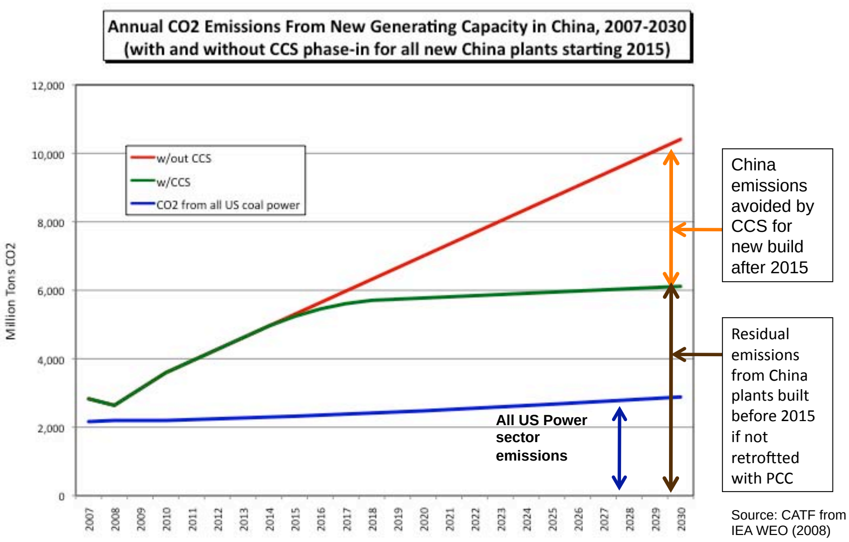
I. Framing The Issue. The Need To Retrofit Existing Coal-Fired Power Plants

Anthropogenic CO_2 emissions are major contributors to climate change, which poses many risks to the health of the planet. These are likely to include sea level rises; loss of habitat and the potential extinction of many species; volatile and extreme weather, including increased drought, related fires, and hurricanes; the loss of significant agricultural output; and enhanced security risks from "climate change [which] acts as a threat multiplier for instability in some of the most volatile regions in the world, according to the Military Advisory Board in recent House testimony."[3]

Existing coal-fired power plants represent 20% of total global CO_2 emissions. Combined, the U.S. and China account for over half the world's total coal plant capacity, which currently stands at 1,333 GW. Worldwide, coal-fired power plants produce 40% of all electricity compared to 50% in the U.S. Collectively coal-fired electricity generation represents 33% of total U.S. CO_2 emissions, second only to *all* transportation sectors.[4]

Electric sector CO_2 emissions are growing, not stabilizing. It is estimated that by 2020, there will be 2232 GW of coal-fired power capacity, a 65% increase over current levels; 80% of this incremental growth will occur in China (see Figure 1) and India. The significant growth of the economies of these two nations, coupled with their large coal reserves and reliance on conventional coal-fired power generation, will substantially increase CO_2 emissions into the atmosphere and further strain the world's capacity to respond to climate change imperatives.

Figure 1



Source: Armond Cohen, Clean Air Task Force, March 23, 2009

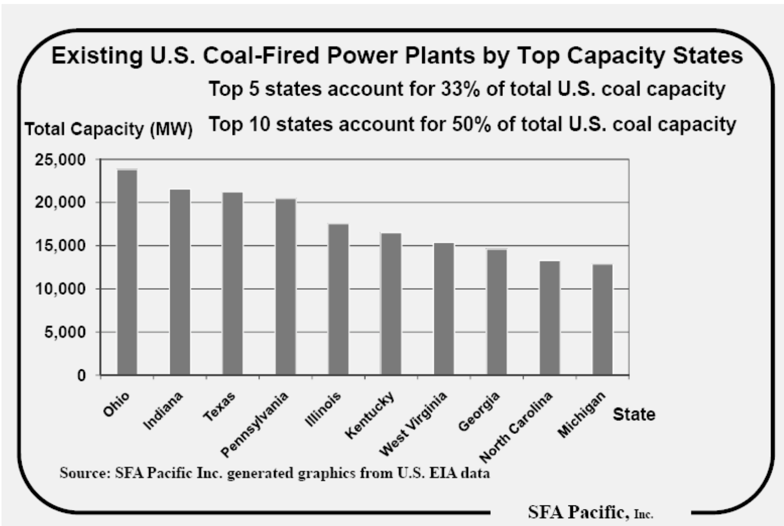
The rapid expansion of China's coal-fired power plant fleet is especially problematic. China's fleet capacity of 417 GW now exceeds that of the U.S. and it has the third largest coal reserves in the world. Before the current economic slowdown, the pace at which China was building power plants — one coal-fired plant per week built at roughly one-third the cost of those built in the U.S. — is indicative of its rapid economic growth. China's plants are, on average, also much newer than those in the U.S.

Over the next 20 years, China's coal consumption is expected to more than double. This is despite plans to build 100 new nuclear plants in that same timeframe. Meeting the "China test"— developing and deploying CO_2 mitigation technologies for coal-fired power plants with low carbon avoidance costs — is essential to an effective climate change policy for existing coal-fired power plants in both the U.S. and the developing world.

Coal-Fired Power Plants in the U.S. The current fleet of U.S. coal plants has a capacity of 332 GW, supplies around 50% of the nation's electricity, and represents over one trillion dollars in investment. Five states are home to about one-third of the entire coal-fired power generation fleet in the U.S.; ten states have around 50%.[5] (see Figure 2)

The typical U.S. coal plant is 500-700 megawatts; units greater than 300 MW in size account for over 71% of total capacity. The U.S. fleet is relatively old; the average age is 35 years. Sixty percent of U.S. installed capacity is over 30 years old. Importantly, *U.S. coal plants 35 years old and older account for 7% of the world's anthropogenic fossil fuel CO_2 emissions.*[6]

Figure 2. U.S. Coal Fleet Capacity by Location



The characteristics of the current fleet of U.S. coal-fired power plants are important to this discussion and to understanding and assessing the available technology and policy options. Most of the U.S. fleet of coal-fired power plants employs pulverized coal combustion boiler technology, either subcritical or supercritical (there is also 8800 MW of circulating fluidized bed plants). *Subcritical power plant boiler and turbine systems operate* in the range of 1025° F and have a typical efficiency of 32% (HHV). *Supercritical* power plants operate at higher temperatures. This enables them to operate at efficiencies [7] as high as 42%, although most operate at significantly lower levels. Higher plant efficiencies translate into lower CO_2 emissions for a fixed amount of electricity.

The amount of supercritical coal-fired capacity in today's U.S. coal fleet is approximately 75 GWe, or about 23% of the total coal capacity, compared to 13% worldwide. Japan has the highest percentage (70%) of supercritical and ultra-supercritical plants, giving it the most efficient fleet in the world.[8]

The initial capital investment for many U.S. coal plants has been paid off, a reflection of the age of the fleet (only 10% is less than 20 years old). Plants subject to cost-of-service regulation provide relatively low-cost electricity to consumers. For plants operating in deregulated markets, low capital charges enhance the profit margins of their owners. There are strong economic incentives for both the generators and consumers of low-cost electricity from existing plants to keep them operating for as long as possible, dispatching as much power as possible. This creates major complications for climate mitigation responses.

Shutting down fully amortized plants and replacing them with higher-cost new plants with low CO_2 emissions could have significant economic impacts and would likely raise substantial political opposition. This is in spite of the low efficiency of and relatively high CO_2 emissions from many existing coal-fired plants.

Forecasts that show few coal-fired plant retirements illustrate the strong economic incentive to keep existing plants running and underscore the importance of retrofitting existing plants as well as moving forward with capture options for new plants. The 2009 EIA Annual Energy Outlook (AEO) projections through 2030 show only 2.3 GW (0.7%) of coal capacity retirements and 24.8 GW of new capacity, an overall net increase of 7%.[9]

Limitations of Low Carbon Fuels/Other Options for Large-scale Capture. When making business decisions about the future of existing coal-fired power plants, an appropriate comparison is the replacement cost of the alternatives. There are currently three conventional low/no carbon emissions baseload power generation options to coal-fired power generation — nuclear power plants, combined cycle natural gas turbines (CCGT), and hydropower (which has significant location limitations). Symposium participants were provided the following data in the framing discussion; a typical existing coal plant *without* CO_2 capture has an average MWh "going forward" cost of around $45/MWh including the cost of controls for SO_x, NO_x, and mercury.[10]

In contrast, the "all in"[11] replacement costs for nuclear power range from around $84/MWh[12] to $155/MWh.[13] For natural gas CCGT, current gas prices put the all-in costs at $45/MWh, although gas prices are relatively low at the moment. A review of natural gas futures contracts, along with additional forecasts, put the all-in 2020 costs for CCGT at over $70/MWh.[14] The all-in costs of the alternatives seriously complicate investment decisions and illustrate the central affordability problem posed by existing coal plants.

Issues Summary: Many participants felt that replacing all or even a large fraction of existing coal-fired power plants with new, clean, low carbon technologies is not an economically viable option in the near term. This, coupled with forecasts of large increases in coal-fired power generation around the world, highlights several overriding and urgent concerns.

- The key driver for business decisions on the future of existing coal plants will be their "going forward" costs per MWh compared to the relatively high "all-in" costs of low/no carbon alternatives. High all-in costs and the uncertainty about technology options and future natural gas prices complicate climate policy which has to balance affordability with climate imperatives.

- There are currently no federal RD&D programs of sufficient scale for retrofitting coal-fired power plants to have an appreciable, positive impact on mitigating climate change. To achieve key public policy goals, significant investments are required in a range of carbon mitigation technology options, including the retrofitting of existing U.S. coal-fired power plants.

- U.S. responses to climate change must keep the developing world in mind, China in particular. Global carbon mitigation goals cannot be met without the active engagement and participation of the Chinese. Effective policies and technology development in the U.S. should pass the *"China Test"* which *asks the question whether CO_2 emissions mitigation can be accomplished at a sufficiently small incremental cost that China and other emerging economies will be motivated to implement it.* This is a critical RD&D goal over the next decade.

Findings. Framing the Issue: The Need to Retrofit Coal-Fired Power Plants

Finding: Absent serious and sustained effort to mitigate CO_2 emissions from existing coal-fired power plants, supported by RD&D investments to broaden the range of technology alternatives and reduce their cost, it will be very difficult to affordably and rapidly meet the imperatives of climate change.

Finding: Traditional RD&D approaches have been inadequate to meet the need for affordable and effective retrofits of existing coal plants for CO_2 capture. A carbon price signal is necessary but insufficient. A new approach to RD&D is required.

Finding: The world cannot achieve significant reductions in CO_2 emissions, avoiding the most disruptive impacts of climate change, without commitments to reduce emissions from existing coal-fired power plants from the U.S. and China. The U.S. and China have a shared interest in developing and deploying a range of technologies to retrofit existing coal-fired power plants. Bilateral approaches on climate change should be encouraged and supported as a matter of U.S. policy. Joint research programs between the U.S. and China should be supported and funded. A mechanism for sharing the results of unilateral projects should be created and *supported*.

II. Near-term Options for Mitigating CO_2 Emissions from Existing Plants

Existing coal-fired power generation capacity — over 1.3 million megawatts – provides consumers with low-cost electricity. The development, demonstration, and deployment of technologies to reduce or capture CO_2 emissions from these existing plants offer a significant near-term opportunity to reduce CO_2 emissions. The next five to ten years represent a critical time for meeting CO_2 mitigation targets by mid-century.

Also, owners and operators of coal-fired power plants possess valuable assets above and beyond affordable power. For example, existing coal plants are strategically located on the electric grid transmission system. They have substantial plant infrastructure, hold difficult-to-obtain site and environmental permits, and have access to existing water and coal transportation infrastructures. The value of these assets should not be underestimated when making policy, technology, and investment decisions on mitigating carbon emissions.

The Range of Technology Options. Climate imperatives demand expeditious and responsible actions and suggest the need for more priority *options for mitigating CO_2 emissions from existing coal plants.* These options fall into broad categories:

- *retrofitting existing plants for CO_2 capture,* in which infrastructure is replaced or enlarged to enable CO_2 capture from an existing plant;
- *increasing the efficiency* of existing coal-fired power generation through a range of minor and major retrofits and operational changes;
- *repowering of existing plants*, which would involve replacing coal as a fuel for power generation with lower carbon fuels, including biomass and, more likely, natural gas;
- *rebuilding a plant for CO_2 capture at an existing site*, which has significant value in permits, land, supply chain infrastructure access, etc; and
- *co-firing* of coal plants with biomass

Symposium participants identified *post-combustion capture retrofits and efficiency improvements* as realistic near-term options for achieving significant emissions reductions from existing plants. While co-firing is also relevant for this timeframe, it was not a specific discussion focus. For discussion purposes, "near-term options" were defined by participants *as incremental technology improvements that are currently available, likely to be available, or possibly available within a five-year time window* (although many options were discussed in the five-ten year time window). Both retrofits and rebuilds for CO_2 capture require significant capital investment.

There are currently three categories of technologies for capturing CO_2 from coal-fired power plants, none of which has been demonstrated at commercial scale and all of which have substantial residual power requirements:

- *Post-combustion capture* is "the process of transforming …low-pressure, low-concentration CO_2 into a relatively pure CO_2 stream"[15] which can then be compressed, transported, and stored. The steam requirements and heat exchanges in this process result in a relative efficiency loss as high as 30%;

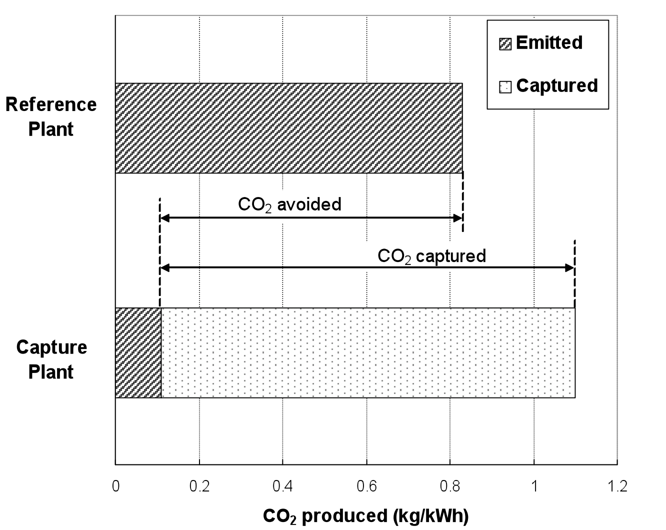
- *Pre-combustion capture* relies on coal gasification to produce synthesis gas that is then water-shifted to produce CO_2 and H_2 streams. Hydrogen streams are fed into a gas turbine to generate electricity. This process enables the separation of highly concentrated CO_2, creating conditions for capture, with the potential for high efficiency. The advantages for capture can offset the higher cost of gasification plants relative to pulverized coal; and

- *Oxy-combustion* is the combustion of coal with pure oxygen in lieu of air. Oxygen production has large power requirements, but oxy-combustion enables the separation of highly concentrated CO_2 and has the potential for relatively high efficiencies.

Economics of Post-Combustion Capture. Several factors challenge CO_2 mitigation opportunities for existing coal plants. Figure 3 is a graphical representation of *avoided* CO_2 which is the difference between actual emissions per kWh between a reference and a capture plant. Due to the parasitic energy requirement (and its associated additional CO_2 production), the amount of emissions avoided is always less than the amount of CO_2 captured.[16]

If, as a matter of policy, the federal government effectively puts a price on carbon through a cap-and-trade program, the impacts of CO_2 *avoidance costs* for many existing coal power plants, largely older, smaller subcritical units, would be significantly higher than those for supercritical coal plants. CO_2 price signals must be high enough to stimulate wholesale fuel switching (an unrealistic outcome), promote dramatic efficiency improvements, or provide incentives for CO_2 CCS.

Figure 3. Avoided CO_2 emissions from a CO_2 capture plant



This poses a significant dilemma for U.S. policy makers. On the one hand, relatively old coal-fired plants are one of the largest sources of CO_2 emissions in the country; on the other hand, they affordably supply U.S. consumers with a significant fraction of their electricity.

On the policy side, a cap-and-trade system for carbon reductions is theoretically superior to a tax, *if the cap is set appropriately and is enforced.* Overall CO_2 emissions reductions sufficient to mitigate climate change, however, are highly dependent on how restrictive the cap is and how the government actually effects the implementation of a carbon price. Off-ramps have the potential to distort the CO_2 marketplace and weaken the effectiveness of and the ability to enforce a meaningful cap. To effectively mitigate CO_2 emissions, Congress and the Administration need to "get the carbon price right" through a meaningful cap, provide for enforcement of the cap, and, at the same time, develop and support research investments and flexible policies to help meet the cap by accommodating the range of plant characteristics, plant locations, and plant economics.

This range of plant and site characteristics establishes a dividing line between those plants that are candidates for retrofit with today's technologies and technologies expected in the near term; those that are more suited for enhanced efficiency improvements; and those that might be candidates for rebuilds, repowering, closure, or other options. One of the key objectives of RD&D on PCC is to move that dividing line by increasing the number of plants that are candidates for affordable post-combustion capture.

For the near term, PCC is the only category of processes that is mature enough for a commercial-scale capture plant (although some companies are looking seriously at oxy-combustion). Chemical absorption of CO_2, which forms the basis for PCC, has been used for 70 years to produce CO_2 from natural gas processing for high value industrial uses. The only commercial post-combustion capture plants (these are much smaller than would be required for PCC at scale) use an amine solution to selectively absorb the CO_2 from flue gases where CO_2 is typically found in low concentration levels of around 12%. Amine concentrations are kept low because they can corrode and degrade equipment. Lower concentrations translate into larger equipment sizes and additional costs for amine regeneration. The CO_2 is then stripped from the amine solution which is recycled to the absorber. The highly concentrated CO_2 must be compressed using energy-intensive compressors and then moved through pipelines to storage sites.[17]

Most of the cost of CCS is in the capture and compression stages. Separating, recovering, or capturing CO_2 represents around 50% of CCS costs. Compressing the CO_2 to liquid-like conditions is 25% of the cost, with the remainder for transportation pipeline and well injection into geologic formations. Costs also include the capital, fuel, labor, and equipment for the actual retrofitting of a plant. Plant output losses from the addition of capture and related compressions systems represent a relative efficiency decrease for the plant of 24%. Roughly 60% of this loss is due to steam extraction from the plant's generating turbines. This steam is used for the processes that break the bonding of CO_2 to the amine solution. Another 35% is lost by the electricity used to drive the compressors. Finally, the electricity used to drive the flue gas through absorbers accounts for around 5% of parasitic losses.[18] The loss in overall plant efficiency due to parasitic energy losses associated with PCC processes substantially increases coal consumption per unit of energy as well as electricity costs for consumers. As such, research on PCC focuses in large part on reducing parasitic energy losses.

Comparison of CO_2 avoidance costs to an existing baseline coal plant identifies the clearing price that will both incentivize the use of CO_2 post-combustion technologies (as opposed to simply paying the CO_2 emissions price) and serve as a target for technology-driven cost reductions. Price volatility in a cap-and-trade system complicates this point. If a cap-and-trade system does not, as a matter of policy, ensure that the permit price will be above avoided costs for many years into the future, it will discourage large-scale capital investments. Table 1 depicts the results of analysis of CO_2 avoidance costs associated with two post-combustion capture retrofits of a *typical subcritical pulverized coal plant compared to a baseline plant without PCC.*[19]

Table 1. Carbon Avoidance Costs for Retrofit of a Subcritical Plant (Simbeck, Roepooritat)

CO_2 Mitigation Options	Net MWe	New capital $ millions (2008)	$/KWe	Net Efficiency % HHV	CO_2 Emissions Mt/MWhe	CO_2 Avoidance $/mt CO_2	Power Cost Mid-2008 $/Mwh
Baseline Paid-off Old Coal Plant no CCS,*sub PC with FGD size set to NGCC MW*	543	Paid off	Paid off	33.6%	0.95	Baseline	$36.8
Old PC & ST with new Post CCS add-on, *new small BT ST + MHI amine CO2 scrubber*	398	$528	$1,325	24.7%	0.13	$74	$97.9
Old PC + upgrade & new Post CCS add-on rebuild *SH/RH + sub SST/gen & JHI amine scrubber*	418	$755	$1,807	25.9%	0.12	$79	$102.4

Relative efficiency loss: 26%

Notable points from Table 1:

- the CO_2 avoidance cost is $74 per ton of CO_2;
- the installation of CO_2 capture equipment for this configuration takes the efficiency of the plant from 33.6% to 24.7%, a *relative* efficiency loss of 26%; and
- capital costs for this retrofit are over one half billion dollars.

As noted earlier, FGD and SCR upgrades are important for the operation of CO_2 capture equipment. Many smaller, older subcritical plants do not have FGD or SCR upgrades. FGD and SCR retrofits also take up space at a plant site. *High CO_2 avoidance costs, the need to remove sulfur via FGD and NO_x via SCR upgrades prior to CO_2 capture, and the additional parasitic efficiency losses associated with FGD limit many subcritical plants as PCC opportunities, especially for smaller subcritical plants.*

Table 2 reflects the results of the analysis of *CO_2 avoidance costs for a new supercritical plant with post-combustion capture, compared to a supercritical plant without PCC.*[20] Data in Table 2 assume costs in 2007 dollars; "Nth" plant costs (meaning it ignores first mover costs); 90% CO_2 capture and an 85% capacity factor; and the use of bituminous coal (Illinois #6). It does not include CO_2 transport and storage costs. It also assumes the use of available technology; the resolution of regulatory issues in ways that do not impose significant new burdens; and operations at scale (i.e., 500 MWe net output before capture).

Table 2. Capture (including compression) Costs for Nth Plant SCPC Generation (Herzog, Meldon, Hatton)

Plant	Total Plant Cost	CO_2 Captured	Cost of CO_2 Avoided	CO_2 Emitted	Heat Rate (HHV)	Thermal Efficiency (HHV)
Baseline	$1910/kWe	0$	Baseline	0.830 kg/kWh	8868 btu/KWh	38.5% including:
						Capital: $ 38.8/MWh
					Relative efficiency loss: 24%	Fuel: $ 15.9 MWh
						O&M $ 8.0/MWh
						Total $ 62.6/MWh
With CO_2 capture	$3080/ kWe	90%	$52.2/ Ton	0.109 kg/kWh	11625btu/ KWh	29.3% including:
						Capital: $ 62.4/MWh
						Fuel: $ 20.9/MWh
						O&M: $ 17.0/MWh
						Total $100.3/MWh

Key points from these data:

- CO_2 avoidance costs for a new build supercritical plant with PCC is $52.2 per ton for capturing 90% of the CO_2 emissions (exclusive of transport and storage costs);
- the relative efficiency loss is 24% for the new PCC plant compared to the baseline unit;
- overall plant efficiency is 29.3%;
- dollar per kilowatt costs increase by 62%; and
- incremental plant cost increase is $1170 per kWe, or 61%.

It should be stressed that these costs are for the "Nth" plant. *Costs do not include first mover costs nor do they include the premium cost for retrofits* (which will vary depending on plant/site characteristics). These additional costs would likely move the retrofit costs for a first of a kind plant over $100 per ton for capture, transport, and storage.[21] Reducing these costs or finding less expensive or more effective alternatives is essential to a successful climate mitigation strategy.

A range of CO_2 avoidance costs was discussed by participants or offered in the submitted technical papers, from around $50 MWh to over $90 per MWh, depending on the assumptions. EPRI analysis concluded that the breakeven cost of electricity for a hypothetical 600 MW plant that is retrofitted with CO_2 capture and compression equipment, and purchases replacement power from a plant with PCC at a levelized cost of $110/MWh (to make up for parasitic losses of 175 MW), to be about $75/MWh, including transport, sequestration, and monitoring of the stored CO_2[22] (price of actual dispatched power would be lower). These costs represent significant investment and higher electricity prices. Without policies that encourage the dispatch of this higher-cost power, however, it will be difficult for this relatively CO_2 free power to compete in a transitional, immature market-place where power from plants without CCS is still being sold.[23]

Cost is Not the Only Limitation on Retrofitting. While the cost of CO_2 avoidance is the fundamental factor when considering PCC retrofits, there are many other characteristics of both the plant and the site that may affect this decision. Space requirements to retrofit a 500 MW plant with a CO_2 capture system and compression equipment, for example, are around six acres. Also, retrofits place additional demands on water for cooling. Plants may not be suitable for retrofitting for PCC for a range of other reasons. Other first-order criteria include:

- NO_X/SO_X controls at the site;
- restrictions caused by existing plant layout; and
- proximity of the facility to a sequestration site.

There is a range of "second order" criteria as well, including:

- options for steam turbine modifications;
- efficient use of condensate flow return;
- capability to increase cooling systems;
- the ability to expand "house power" electrical distribution; and
- capture bypass provisions.[24]

Finally, there are also environmental and public health concerns about amine discharges associated with post-combustion capture, as well as with discharges from newer ammonia absorbers being developed for post-combustion capture. Participants cited the experience with ammonia discharges in production of tar sands in Canada, which shut down operations for several months at significant expense. Research in this area should be included in any portfolio on post-combustion capture of CO_2 emissions. The ultimate resolution of possible environmental issues may further limit site options.

EPRI analysts concluded that cost-effective retrofits for carbon capture are most suitable for boilers that are "300 MW or larger and less than about 35 years old." EPRI identified around 184 GWe — around 59% of installed capacity — as suitable for PCC retrofits (the absolute upper limit of existing plants that are suitable for PCC). Ninety percent capture from these units would result in a 50% reduction of CO_2 emissions from the U.S. coal plant power sector.[25] At a minimum, if CCS retrofits were applied proportionately between subcritical and supercritical plants across the entire coal fleet, then 23% of the 184 GWe suitable for retrofit would be supercritical. At maximum, if every supercritical plant was suitable for retrofit (which is probably unlikely, given space and storage restraints), then 40% of the 184 GWe suitable for retrofit would be supercritical. EPRI therefore estimates that the supercritical component of the U.S. retrofit base to be somewhere in the range of 23%–40% of the 184 GWe. More detailed work is underway to sharpen this estimate.[26]

Decreasing parasitic losses from PCC retrofit equipment is the focus of much of the ongoing research. Small increases in efficiency of supercritical steam plants can be achieved through improving combustion technologies, decreasing the boiler exit temperature, or lowering the condenser pressure, which can produce efficiency gains by as much as 2%.

Coal Plants Without Retrofit Options. As noted, EPRI analysis indicates that 59% of coal-fired power plant capacity would be candidates for PCC retrofitting (although actual candidates will be limited by specific site/plant characteristics). This begs the question: What are the near-term options for mitigating emissions from the remaining 41% of coal-fired capacity?

In the absence of very high CO_2 prices, it may not be economical to shut these plants down, although both rebuilding and repowering are alternatives that warrant serious consideration. These plants, however, because of their age, size, and relatively low efficiencies even *without* the parasitic losses associated with PCC (retrofits of some older plants could result in, as noted by a participant, an "embarrassingly low" 17% efficiency) are responsible for a higher share of CO_2 emissions than their GW share. These units are also less likely to have FGD or SCR retrofits.

Enhanced Plant Efficiency. Increasing the efficiency of existing plants offers a practical way to reduce coal-fired power plant CO_2 emissions for plants that are not suitable for capture retrofits. An incentive for increasing the efficiency of these plants is found in cap-and-trade systems, for which the value of issued allowances will increase over time as caps are lowered. Efficiency improvements at existing sites could help to avoid the cost of buying allowances, or allow the sale of allowances that may be allocated to the plant owner/operator, providing incentives for undertaking any relatively low-cost emissions reductions at older plants where PCC is not an option.

Options for increasing efficiency, however, can be technically complex and costly. Changes to the plant and plant site may invite new regulation by triggering NSR requirements. This could lead to much higher costs and, coincidentally, might actually slightly *increase* CO_2 emissions. Nevertheless, there are several ways to increase the efficiency of existing plants, largely through process optimization and equipment upgrades. Some of these improvements, such as combustion tuning and reduction of steam losses, are relatively inexpensive.

The simplest means for enhancing efficiency at existing plants involves upgrades of the power plant to enable slightly higher steam quality, achieved through higher steam superheat and reheat temperatures. This would require the rebuilding of the steam turbine and the electric generator. This option nets an absolute efficiency increase of around 2% at moderate costs. According to the National Coal Council, "a two percentage point gain in efficiency provides a reduction in fuel use of about 5% and a similar reduction in CO_2 emissions."[27] An overall 5% reduction in fleet CO_2 emissions through efficiency upgrades appears possible.[28]

Repowering: Replacing Coal as a Fuel for Power Generation*. Repowering of existing coal plants is an option for plants where CCS is not an economically or technically feasible option.* Coal can be replaced with lower carbon fuels for power generation, including biomass or, more likely, natural gas repowering with a new combined cycle unit.

Biomass has lower capital costs if used in old coal units, but it also has a number of supply and delivered energy price issues. Widespread replacement of coal with natural gas could significantly raise the price of gas; it is estimated that replacing *all* coal-fired power generation with natural gas would translate into a 60% increase in current gas consumption.[29] Suggestions that we replace all coal generation with natural gas-fired plants are somewhat spurious; less dramatic replacements would have a more limited impact on prices, assuming current or increased levels of supply. While natural gas prices have dropped sharply in the last few years, gas price volatility and concerns about supply availability (in spite of a substantial increase in domestic production last year) raise concerns in some quarters about the use of NGCCs for a higher percentage of U.S. baseload power generation.

There is, however, another natural gas-fired power generation option that deserves serious attention, as it could meet key policy objective for both the U.S. and China. Especially dramatic efficiency increases can be achieved through natural gas repowering with additional cogeneration capability. In fact, *the highest possible generation efficiencies using today's available technologies are achieved through repowering a plant with high-power-to-heat gas turbine-based cogeneration with up to 80% efficiency*.[30] This option involves repowering and is highly complicated from a regulatory perspective. It would require federal policy reforms to encourage high-efficiency electricity regardless of source or location and would likely meet resistance from coal-fired utilities. The European experience with cogeneration, however, is encouraging and there are also significant opportunities for cogeneration in China, where regulatory regimes are less fixed and are, therefore, less discouraging of the cogeneration option.

Rebuilding: Location, Location, Location. A new state-of-the art supercritical boiler, ultra-supercritical PC boiler, oxy-fuel plant, or IGCC (with CCS) could be used to rebuild at an existing site that is host to an old subcritical steam cycle PC plant. This has the key advantage of gaining value from existing site investments, permits, and proximity to infrastructure and water, while minimizing or avoiding the net efficiency or capacity losses otherwise incurred by adding a PCC retrofit.

Depending on the available space, rebuilding on sites where retrofits are not feasible offers many advantages including proximity to water supplies and coal distribution systems. Also, conversion of an existing coal plant site to a new state-of-the-art coal-fired power plant with nearly zero emissions is likely to be easier to permit than a new greenfield coal power plant. Participants expressed specific concerns about water requirements for rebuilt or new facilities which could be twice as high as those of an older retrofitted plant.

Issues Summary: Post-combustion capture and efficiency improvements ranging from minor upgrades to major rebuilds are the two near-term options for mitigating CO_2 emissions from existing power plants. There is a range of plant and site characteristics that determines mitigation options.

- CO_2 avoidance costs for *retrofitting* smaller, older subcritical plants with PCC are significantly higher than those for newer, larger supercritical plants. PCC retrofits of plants favor the newer supercritical plants which are more efficient, will have a long remaining lifespan, and are more likely to already have good SO_2 and NO_x controls in place. Submitted technical papers identified up to 184 GW — around 59% of installed capacity — as suitable for PCC retrofits given current technology forecasts. Ninety percent capture from these units would result in a 50% reduction of CO_2 emissions from the U.S. coal power sector, assuming that all of these units would have the appropriate plant/site characteristics.

- Parasitic energy losses associated with PCC are substantial; much of the research for PCC is and should be focused on reducing parasitic energy losses.

- Efficiency upgrades are the only near-term option for approximately 41% of the fleet. Some participants opposed federal efficiency incentives, believing efficiency upgrades were sound business decisions and, as such, needed no specific federal incentives.

- There may be opportunities for *rebuilds* at sites where there are older, subcritical PC units. Rebuilds could be economically viable depending upon the site characteristics, the need for additional power generation resulting from the higher capacity and efficiency levels of a rebuild, and the cost of competing sources of supply. Though the total cost of rebuilds is higher, the CO_2 avoidance costs for rebuilds are generally lower than those for retrofitting existing PC plants for PCC. Also, rebuilds avoid the efficiency and capacity losses associated with PCC for subcritical plants, while reducing all emissions to near zero.

Panel One Findings. Near-Term Technology Options

Finding: A carbon price signal is *essential* for making technology choices to mitigate carbon emissions from existing coal plants. Without such a signal, it will be impossible to make rational decisions about retrofit, rebuild, repowering, or other options.

Finding: Lowering CO_2 avoidance costs is critical to providing consumers with affordable electricity. Policy makers must be cognizant of CO_2 avoidance costs of different types of power plants and accommodate these differences in climate change mitigation policies and technology investments.

Finding: Ninety percent capture of CO_2 from 59% of coal-fired capacity in the U.S. (the absolute upper limit of existing plants that are suitable for PCC) would reduce emissions from the U.S. power sector by 50%.

Finding: One size does not fit all! Understanding these limitations is underappreciated but critical to a successful strategy for mitigating CO_2 emissions from existing coal-fired power plants. Different plants and sites require different technology solutions. Flexibility of approaches is essential for maximizing CO_2 mitigation and minimizing electricity costs to consumers. Research programs should focus on reducing the parasitic electricity losses at SC plants retrofitted with PCC, as well as efficiency improvements at smaller subcritical plants without PCC options. EPRI has launched projects with five utilities with different types and sizes of plants to quantify the costs and operational impacts of adding advanced amine combustion systems.

Finding: An inventory of plants and sites is needed to identify the physical attributes of the fleet, to assess relative plant efficiencies, and to determine which plants are suitable for retrofitting, rebuilding, repowering, etc. This inventory should inform policy makers about the range of needs, options, and potential consequences of various climate policy options.

Finding: In general, cost-effective retrofits for carbon capture are most suitable for newer, larger plants. "Nth" plant CO_2 avoidance costs for supercritical plants are significantly lower than those for subcritical plants. RD&D programs should support first-mover demonstration projects for supercritical plants. Policies should support efficiency improvements, rebuilds, or repowering for very old, smaller plants $\leq$ 100 MW.

Finding: In a transitional and immature market that includes both PCC retrofits and plants without CCS, the higher costs of power from PCC plants could make them undesirable and potentially underutilized. This is a critical issue with well-founded arguments on both sides. Congress should carefully consider the issues surrounding the potential dispatch of power from PCC plants to meet both climate change mitigation and affordability objectives.

Finding: There are potential environmental and health issues associated with emissions of PCC solvents such as amines or ammonia. Research should be supported to minimize and understand the issues associated with these emissions for utility-scale plants.

Finding: Site size limitations are an underappreciated issue in the development of policies and technologies to mitigate CO_2 emissions from existing coal-fired power plants. Federal research programs should include a component focused on reducing the size of components or the "stacking" of components to affordably reduce the footprint of retrofits, or possibilities for partial capture, which could also enable a smaller component footprint.

III. "Over the Horizon" Technologies for CO_2 Mitigation from Coal Plants

At the symposium, "over the horizon" technologies were assumed to be technologies that, after research and development investments, *might be available for commercial demonstration and deployment in ten years or more*. It was understood that not all of these research pathways will be successful; there is risk and there will be failures. Also, there is not a clear dividing line between near-term and over the horizon technologies. There might be major breakthroughs in a shorter timeframe. Most of these technologies are, however, in the relatively early stage along the research continuum, although some, such as oxy-fuel combustion and IGCC, are at the demonstration phase of development. Demonstrations will take many years to complete.

There are several promising longer-term options for mitigating CO_2 emissions from coal plants that merit research investment, including advanced technologies for PCC; oxy-combustion plants; pre-combustion capture through gasification/IGCC plants; ultra-supercritical plants; and coal liquefaction/poly-generation plants.

Advanced Technologies for Post-Combustion Capture. Post-combustion capture research, both near- and longer-term, focuses in large part on increasing process efficiency by reducing parasitic energy losses associated with CO_2 capture. Generally, near-term efficiencies are achieved through relatively minor upgrades and process improvements. Longer-term research for post-combustion capture focuses largely on the CO_2 separation process in flue gases.

Table 3 depicts a range of research pathways being pursued for enhancing the efficiency of separation/decreasing the parasitic energy load for post combustion capture. These pathways are described in more detail below.[31]

Table 3. Flue Gas & Novel R&D Pathways

Absorption	Reactive Solids	Adsorption	Membrane Separation	Novel Approaches
AMINE	CaO Na_2CO_3 NaOH/CaO LiO/Li_2ZrO_3 Li_4SiO_4	Zeolites 5A, 13X, MCM-41 Carbon Silica Alumina Amine-doped membranes Potassium salt-doped	Gas/liquid contractors	Biological Algae (photosynthesis) Carbonic anhydrase (enzyme-catalyzed CO_2 hydrolysis)
Other alkanolamines Blended alkanolamines AMINE/Piperazine K2 CO_3/Piperazine Less corrosive amines Less degradable amines			Perm-selective & high-temperature polymers	
Chilled ammonia		Exploratory Adsorption Self-assembling organic nano-channels & metal/organic frameworks Poly-ionic liquids		
Nonaqueous solvents				
Polyamines, ionic liquids CO_2 hydrates				

When a capture and compression system is added to a supercritical plant for PCC, the plant's overall thermal efficiency (the fraction of the energy released by combustion of the fuel that is transformed into electricity) drops from 38.5% to 29.3%, a relative decrease in efficiency of 24% (see Table 2). One third of this parasitic loss (8%) is from compression, and the rest (16%) is attributable to separation.[32]

For an SCPC plant without capture, the minimum theoretical energy requirement for separating CO_2 is 3.2%; the actual parasitic load is, however, five times that amount or 16%. This compares to a 4.6% minimum energy requirement for compression which reduces overall efficiency by 8%, or less than two times the difference between the minimum energy requirement and actual parasitic load for compression. *As such, the separation process provides much greater opportunities for efficiency than compression.*[33]

Absorption Processes: A brief description of the current separation process informs a roadmap for development of a range of technologies to reduce parasitic energy losses for PCC. The current method for PCC separation uses a liquid amine absorber, which is selective for CO_2, to "scrub" the flue gas. The *absorption process* takes place in towers known as scrubbers, where CO_2 is selectively absorbed from the flue gas into the liquid solvent. In a stripper, the heated amine is exposed to steam and the CO_2 is desorbed; this leaves high concentrations of CO_2 for compression, transport, and sequestration. The steam (i.e., water) is separated from the CO_2 via condensation during the compression step. The stripped amine liquid is recycled back to the scrubber.

Amines are corrosive, making construction materials more expensive. Also, stripping CO_2 from amines raises the price of generating electrical power by a significant amount. The capital costs of scrubbing decrease as rates of CO_2 absorption increase, largely because such processes require smaller absorbers. Higher absorption rates mean lower costs. In addition, higher loadings of CO_2 require smaller equipment and lower operating costs, another potential cost savings.

Amines work on all gas plants, for which combustion is much cleaner than for coal. However, only a subset of commercial amine processes have been operated at coal plants because coal plant flue gases contain other pollutants, primarily particulate matter and SO_2. These pollutants can degrade the amines and/or cause operational problems such as foaming. To date, the largest amine plants have captured around 1,000 tons of CO_2 per day; a 500 MW coal plant, however, produces around 10,000 tons of CO_2 per day. Therefore, amine technologies for appropriate coal plants need to scale up by an order of magnitude.[34]

A major focus of research has been on developing improved amine solvents. Mixed or hindered amines show promise in reducing parasitic energy losses, but the lower energy requirements of these advanced amines have typically resulted in lower CO_2 absorption rates. Research to address this problem has focused on additives such as piperazine to increase the absorption rates of those amines that require less energy to capture.

Research in alternative solvents, particularly ammonia solvents, is promising. Ammonia-based solutions are less corrosive and more stable than MEA or other advanced amines. A recent study of the economic performance of ammonia suggests that the amount of steam required to regenerate the ammonia solvent is about one third the cost of that of amine, but this has yet to be confirmed in pilot tests; it also concluded that operating costs could be 15% lower and capital costs 20% lower.[35] Ammonia, however, has poor mass transfer properties compared to amines, which translates into larger absorber requirements. Ammonia is also a toxic chemical and participants expressed concern about discharges; greatly limiting or eliminating slippage of ammonia into the atmosphere should be a focus for research.

Advanced processes using new types of sorbents have been proposed, including liquid crystals and ionic liquids. While research is still in its infancy, the hope is that these materials can be "engineered" to improve their characteristics for CO_2 capture, resulting in significantly reduced energy requirements to capture CO_2.

Adsorption Processes: Adsorption processes enable flue gases to accumulate on the surface of a solid or liquid. Non-reactive physical sorbents include carbonaceous materials, crystalline, and naturally occurring zeolites. Activated charcoal, for example, has high porosities with CO_2 capture capacities of 10–15%; CO_2 selectivities are low, limiting its application to those capture systems that require relatively low CO_2 purity. Zeolites, also physical sorbents, have

CO_2 selectivities that are 5-10 times greater than carbonaceous materials, but their CO_2 capacities are 2–3 times lower.[36] In addition, their performance is impaired by water.

Chemical sorbents such as calcium carbonate ($CaCO_3$, limestone) can capture both CO_2 and SO_2. This option is attractive because it has high capture capacity and has been demonstrated over time. It has been the focus of intense research activity because it has shown promise for reducing separation costs, exploiting high temperatures, and improving energy efficiency by generating steam from the heat released in carbonaceous reactions. This capture process loses capacity over time and, therefore, requires frequent replacement.

Advanced solid adsorbents include metal-organic frameworks, porous crystalline solid materials, such as zeolitic imidazolate frameworks or "ZIFs," which appear to have high CO_2 capacities as well as selectivities; functional fibrous matrices designed to address the capacity and responses in adsorbents; and poly-ionic liquids which have shown promise for advanced sorption capacity and rates. Participants with experience in ZIFs were not optimistic about their commercial prospects for at least ten years but noted the possibility of a potential 28% reduction in the incremental cost of electricity through a five-fold decrease in the energy required to regenerate the absorbent.[37]

Membrane-based Solutions. Another area of PCC technology development is membrane-based solutions. Membranes generally consist of thin polymeric films, the permeation rates of which vary inversely with the thickness of the membranes. Membranes must be designed to recover CO_2 selectively in flue gases. The current selectivities of polymer membranes fall well below the selectivities of amines. However, combined amine/polymeric membrane systems show promise in raising CO_2/NO_x selectivities and are the focus of increased research interest.

Microporous membranes can also serve as platforms for CO_2 absorption and stripping. These membranes serve to separate gases and liquids. CO_2 and NO_x easily transfer through nonselective gas-filled membrane pores with selectivity provided by a liquid, typically an aqueous amine solution. Mass transfer rates for microporous membranes are comparable to conventional absorption and stripping and their modularity makes them easy to replace or expand. They are, however, difficult to scale up and to achieve economies of scale.

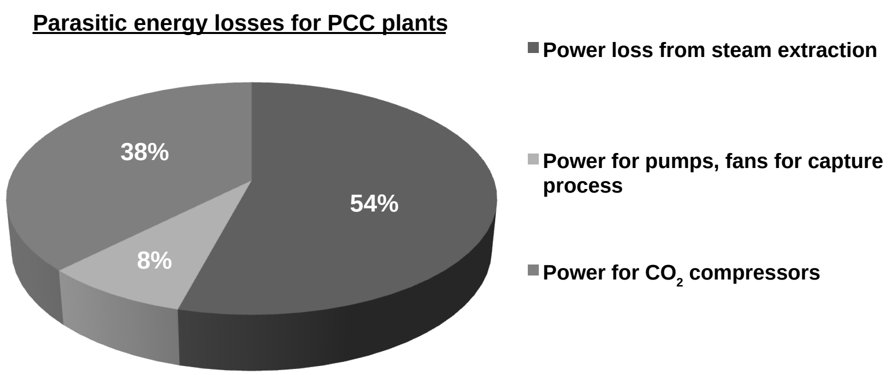
Biomimetic and Other Novel Approaches: Biomimetic approaches mimic or are inspired by living systems for capturing and/or converting CO_2. They include the use of enzyme carbonic anhydrase which can react with water to promote CO_2 scrubbing in flue gases; and microalgae systems which consume CO_2 in photosynthesis, with the potential to eliminate the need for compression and sequestration. There is also interest in cooling flue gases to separate the CO_2 as dry ice. These are all in the highly exploratory phase of research.

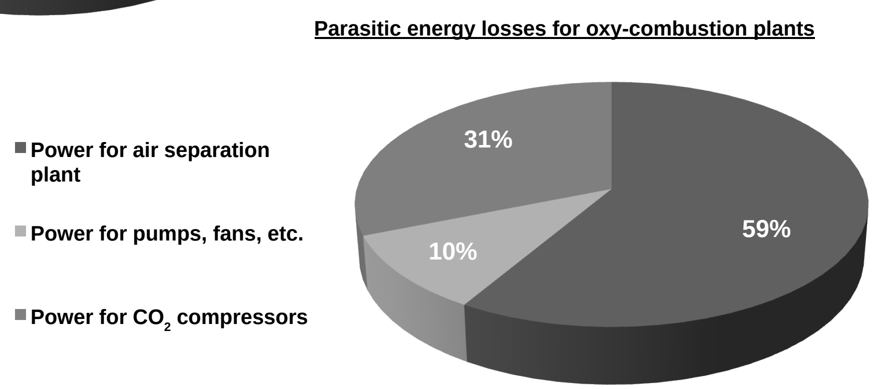
Alternative Combustion/Conversion Pathways. As noted, there are several alternative pathways to PCC and/or dramatically increased power generation efficiency, which are generally in the development and demonstration phase. Not all options are suitable for retrofit but all offer potential rebuild options, depending on the economics and the availability of space at an individual site. Even absent CCS as the key enabling technology for CO_2 reductions from coal-based power generation, deployment of any of these advanced coal combustion/conversion plants could reduce CO_2 emissions through enhanced efficiencies compared to subcritical plants.

Oxy-combustion. As noted, oxy-combustion utilizes high purity oxygen in place of air. Because the nitrogen has been removed, the mass flow rate of combustion products is reduced. Oxy-combustion leads to increased combustion temperatures. High temperatures are addressed by recirculating the flue gas (mainly CO_2) to the combustion chamber which helps maintain furnace temperatures at levels comparable to those of air combustion. The resulting flue gas has CO_2 concentrations above 90% on a moisture-free basis. After the straightforward removal of non-condensibles (N_2, O_2) and criteria pollutants, the CO_2 is ready for compression and sequestration.

Oxy-combustion plants could enable relatively easy capture of CO_2 at high rates (around 97%) as well as drastic reductions in NO_x emissions. Production of oxygen is, however, very expensive and represents the largest cost in the CO_2 capture process. To understand oxy-combustion research thrusts, it is instructive to compare the sources of parasitic energy losses from a typical PCC plant to those from an oxy-combustion plant as seen in Figure 4.[38]

Figure 4. Parasitic Energy Losses for PCC and Oxy-combustion Plants





The typical PCC power plant in Figure 4 operates at 38.5% efficiency (HHV) before capture. As noted earlier, relative parasitic energy losses associated with PCC are about 24%. For the oxy-combustion plant, assuming an 8% efficiency gain from the boiler (which may be difficult to achieve for a retrofit), parasitic relative energy losses are around 21%. Oxy-combustion shows promise for achieving a 10–16% improvement in levelized costs over amine capture, but more research is required to inform choices between PCC and oxy-combustion options.[39]

The breakdown of parasitic energy losses provides research direction for oxy-combustion plants, the future of which — either as retrofits or rebuilds — depends in part on developing improved ASUs and compressors, which combined are responsible for 90% of parasitic energy losses in an oxy-combustion plant. Current cryogenic air separation units can handle around 4,000 tons per day. It is feasible to go to 10,000 tpd, sufficient for a 500 MW plant. Larger plants would require multiple trains. Research on ionic transport membranes for air separation is promising, but requires new sealing technologies, additional development of chemical and mechanical stabilities for envisioned compositions, and reduction of high temperature creep.

Straightforward retrofits for oxy-combustion require no changes to the water and steam systems and minimal modifications to the boiler.[40] These modifications, while limited, are required to maintain safe temperatures and to minimize air leakage, which is a significant concern for retrofitting SC plants with oxy-combustion. Promising research suggests that pressurized oxy-combustion helps avoid leakage and also increases plant efficiency.

The composition of the flue gases could be different for the oxy-combustion plant compared to a PC unit and may complicate transport and storage if plant operators have decided *not* to capture criteria pollutants. If criteria pollutants *are* being captured, modifications to existing equipment for removing criteria pollutants and particulate matter from flue gases may also be required for oxy-combustion retrofits.

Some participants took issue with oxy-combustion plants as a retrofit option. They specifically cited real-world issues with leakage and infiltration of air into the unit, a problem that could increase gas volumes by as much as 15%. Larger gas volumes translate into additional compression and purification requirements. They compared oxy-combustion retrofit performance to that of "purpose-built" designs, with such comparisons greatly favoring the latter. They noted that "purpose-built" designs include numerous improvements and incremental gains that are difficult to achieve through retrofits.

Oxy-combustion plants were described by several participants as being "somewhere between a retrofit and a total rebuild," because of the possibility that the boiler might need to be replaced. Nevertheless, there are several oxy-combustion demonstrations underway, including the Vattenfall Schwarze plant and Babcock and Wilcox's Clean Environmental Development Facility.

Ultra-supercritical PC Plants. Ultra-supercritical PC plants achieve higher efficiencies through the use of super-heated steam (more than 1100° F). Existing designs are capable of achieving efficiencies of 44% (HHV) and even higher rates when bituminous coal is used. This translates into a relative efficiency that is 35% higher than the U.S. fleet average. USC plants could reduce coal consumption by 35% per unit of electricity, as well as lower CO_2 emissions by the same percentage; this is without capture.[41]

The relatively lower coal consumption of a USC plant has compound benefits. Reduced coal use per unit of energy output means a smaller footprint for coal handling and emissions control systems which, in turn, means lower operating costs. It is estimated that if the 45 GW of new coal plant capacity additions needed to meet demand between now and 2020 (when CCS is assumed to become commercially available) was from USC plants, we would realize a reduction of 700 Mt of CO_2 emissions over the lifetime of those plants; again, this is *without* carbon capture.[42] There is already a good deal of experience with USC plants in Europe and Japan. Two operating USC gas plants have achieved efficiencies of 49% and, for example, a USC coal plant at Nordjyiland has achieved 47% efficiency. A USC coal plant will likely be constructed in the U.S. in the next 10 years.[43]

The efficiency of ultra-supercritical plants could be increased to 50% (LHV) with new, high-temperature alloys for boiler walls, new heater and reheater tubes and thick walled headers and steam turbines.[44] Additional research needed to maximize USC plant potential includes the following:

- high-temperature and high-pressure corrosion resistant materials;
- non-destructive materials testing technologies;
- new boiler designs that use high-temperature materials, different welding techniques, various testing regimes, and boiler simulations;
- new turbine designs (incorporating blade cooling) for efficient operation at ultra-supercritical operating conditions; and
- new sealing systems for high pressures, new blades, and new rotor designs.[45]

Because supercritical plants require higher steam temperatures and pressures, retrofits of supercritical plants are not possible. USC plants are more suitable for rebuilds at locations at which subcritical and supercritical plants are not candidates for PCC retrofits, but have site characteristics that could accommodate the USC rebuild option.

Integrated Gasification Combined Cycle Plants. Gasification of solid fuels is a well-known energy conversion process that converts carbonaceous solid fuels into chemical synthesis gas. Integrated gasification combined cycle (IGCC) plants rely on this gasification process to enable relatively efficient power generation, the capacity to separate waste streams, (including CO_2 pre-combustion), reduction of air pollutants from power generation, and the ability to produce hydrogen.

IGCC plants produce synthesis gas, cleaned to remove contaminants, to drive a gas turbine and then utilize exhaust gases to generate superheated steam, which in turn runs a steam turbine. IGCC plants remove CO_2 more efficiently than in PC combustion and mercury emissions can be controlled at much lower costs than a PC plant.[46] IGCC plants are not currently cost competitive with high-efficiency SC plants. Without CCS, efficiencies are similar but O&M costs for IGCC are almost 19% higher; TCR ($/kW) for an IGCC plant is over 7% higher than an SC plant and the COE is 7% higher.[47]

IGCC plants have also had reliability problems, caused in large part by the typical load conditions of electric power generation. IGCC plants work best in steady state. Integration of the responses of the various components of an IGCC system is required and is not operationally trivial. Reliability problems center on the gasification block, where problems range from short-lived slurry feed injector nozzles and refractory lining, to corrosion of syngas coolers, to the operational nature of the system, which shuts down entirely when a single component goes down. Recent experience, however, has shown availability of IGCC plants in the 80% range.[48]

Additional research for IGCC is needed on gasification, gas cleanup, and process integration, as well as carbon capture and sequestration. An IGCC plant is not a retrofit option, but is instead a rebuild technology that could take advantage of existing site characteristics and opportunities. Its sensitivities to certain coal types could, however, limit site options.

Poly-generation of Fuels, Power, and Products. Coal to liquids (CTL) from Fischer Tropsch (FT) technologies, combined with a gasifier, can provide liquid fuels for transportation, synthesis gas for power generation, and high value products and chemicals. This option is known as CTL poly-generation.

The FT fuels from this process have virtually zero sulfur and other contaminant emissions. The synthesis gas from the gasifier can be used in combined cycle turbines to generate electricity with extremely low pollutants. CO_2 is easily captured and analysis indicates that capture costs for this process are far lower than those for any stand-alone coal power plant.[49] Unfortunately, CO_2 emissions from FT CTL plants used as transportation fuels, even *with* capture and storage are roughly equivalent to the emissions from the petroleum fuels they would displace.

A cost-effective way to reduce CO_2 emissions from coal to liquids conversion via FT is to co-process biomass with coal, making it a CTL/BTL FT poly-generation facility. Co-processing coal with 10% biomass:

- decarbonizes power generation;
- produces FTL fuel that has CO_2 emissions no greater than the petroleum it displaces; and
- accomplishes both at carbon avoidance prices much lower than those necessary to incentivize CCS at conventional coal plants.[50]

While research is necessary to reduce costs and improve the carbon balance of coal/biomass poly-generation of fuels, power, and products, institutional issues provide the biggest barriers to widespread development and deployment of this option. FT plants are essentially refineries and power plants. The power industry has no experience with refineries and oil companies have little experience with power generation. Several participants expressed support for this under-appreciated option and suggested policy incentives were in order to overcome the institutional barriers that diminish its opportunities in the marketplace.

Performance of Coal Combustion/Gasification Options. Table 4 compares CO_2 emissions, efficiency, and costs of advanced power generation technologies with and without CCS. The cost data in this table were modified from the original calculations to include the recent effect of a 30% increase in construction costs.[51]

These data are for *new* plants. Costs for retrofits will generally be higher although they are difficult to estimate as site and plant specifics vary so widely; in many instances, however, these price differences can be substantial.[52] Also, while costs for retrofits might be higher in general, relative costs will likely differ substantially by individual technology. A PCC retrofit for a supercritical plant, for example, is likely more straightforward and less costly than an oxy-combustion retrofit.

Table 4. Performance of SC, USC, Oxy-fuel and IGCC Plants (Beér)

CCS →	Supercritical Without	 With	USC Without	 With	PC/Oxy With	IGCC Without	 With
CO_2 emitted g/kWh	830	109	738	94	104	824	101
Efficiency% HHV	38.5	29.3	43.4	34.1	30.6	38.4	31.2
TCR $/kW	1937	3120	1976	3042	2990	2080	2756
COE c/kWh	5.50	8.84	5.39	8.44	7.93	5.90	7.50

All plants in Table 4 are possible *rebuild* options to replace old, inefficient subcritical plants, assuming site characteristics are appropriate for the various options; they are also all new build candidates. Two technology options — PCC for supercritical plants and oxy-combustion plants — are also possible *retrofit* options (again, several participants were skeptical of oxy-combustion as a retrofit option), while IGCC and ultra-supercritical plants are considered *rebuild or new build* options only. These numbers will change over time, depending on technology improvements, deployments beyond first movers, experience with technology options, etc. With this understanding, several important points can be made from the new plant data in Table 4:

- oxy-combustion plants have lower capital cost/lower emissions/higher efficiencies than supercritical plants with capture;
- oxy-combustion plants retrofits have lower COE costs per kWh than supercritical plants with capture;
- ultra-supercritical plants with capture have higher efficiencies and lower emissions than IGCC plants with capture;
- IGCC plants with capture have lower capital costs and COE costs than those of USC with capture; and
- Supercritical plants with capture have the lowest emissions, the highest efficiencies, and the highest capital costs.

Issues Summary. "Over the Horizon" technology options are defined as technologies that might be *available for commercial demonstration and deployment in ten years or more.* These technology options generally fall into three categories:

- improvements in post-combustion capture options to include better amines and advanced flue gas capture processes, almost all of which are in the early stages of research (ammonia is a

notable exception);
- development and demonstration of advanced combustion and gasification options for generating power from coal, including oxy-combustion, ultra-supercritical, and IGCC plants; and
- poly-generation options utilizing FT and gasifier technologies to generate electricity, produce liquid fuels, and provide a suite of high value chemical and other products.

Table 5. "Over the Horizon" Research Pathways

"Over the Horizon" Coal-Fired Power Generation/CO_2 Capture Options

	Attributes	Major Issues	Research Pathways
Post-combustion capture plant	Offers near term retrofit options for approx. 59% of installed coal capacity Potential for efficiency improvements	Parasitic energy losses result in 30% lower relative plant efficiency, higher costs Not an option for at least 41% of installed coal capacity	Advanced amines Other solvents, eg, ammonia Adsorption Membrane separation Novel approaches including biomimetic and microalgae systems
Oxy-combustion plant	Potential for high net efficiencies More concentrated CO_2 capture NOx reductions Retrofit option	90% of parasitic losses from ASU/compressors Air separation very expensive Air seepage	Demonstration of cryogenic separation at scale Boiler modifications Materials/processes to relieve stress on boiler, flues, scrubbers
Gasification/ pre-combustion capture plant	Potential for higher efficiencies Relatively easy CO_2 capture Reduction in other pollutants Hydrogen production	Not cost competitive Availability concerns Integration issues Feed problems for certain coals Not a retrofit option	Subsystems integration Air separation cost reduction Hot gas particle cleanup Gasifier design
Ultra- supercritical plant	Highest efficiencies Significant emissions reductions *w/o* capture Substantial experience base	High temperature s and pressures stress plant materials, boilers Not a retrofit option	New high temperature alloys for boilers, other components New boiler and turbine designs Improved seals

The key options, attributes, issues, and research pathways for over the horizon climate mitigation options for coal-fired power generation are summarized in Table 5. "Over the Horizon" research needs range from highly exploratory research for novel capture options such as microalgae systems and biomimetic approaches; to basic research in high-temperature materials and enhancing the performance of a range of experimental solvents and sorbents; to process engineering to better integrate IGCC subsystems; to development and demonstration of PCC, ultra-supercritical, oxy-combustion, and IGCC plants.

Panel Two Findings: Over the Horizon Technologies

Finding: Retrofit options are limited to PCC capture for supercritical plants and for a subset of subcritical plants and to oxy-combustion retrofits of supercritical plants (oxy-fuel retrofits may look more like rebuilds than retrofits). Choices need to be informed by additional research that, for post-combustion capture, increases capture concentrations and decreases the costs of power losses from steam extraction and compression; and for oxy-combustion, reduces the costs of air separation and compression. Demonstrations are essential for assessing these options.

Finding: Advanced PCC technologies that show the most promise include amine additives and ammonia solvents. Another promising area of research is in advanced sorbents, including specialized structured materials, liquid phase absorbents, and functional adsorbent surfaces, all of which could lead to significant reductions in parasitic energy requirements.

Finding: Rebuild opportunities include ultra-supercritical plants and IGCC. Both show enormous promise for increased efficiency and reduced cost of CO_2 capture. These rebuild opportunities are however expensive and require the development and demonstration of new technologies to provide affordable commercial options. USC plants need research, particularly in high temperature, high pressure corrosion resistant materials. IGCC plants require development and demonstration focused largely on the integration aspects of the plant and on reducing O&M costs. Demonstrations are essential for assessing these options.

Finding: Ultra-supercritical plants have lower CO_2 emissions even without capture because of their extremely high efficiencies; this may provide an option for rebuilds at locations where capture is not an option because, for example, the site offers no appropriate nearby sequestration opportunities or commercial CO_2 pipelines.

Finding: Rebuild options must be weighed against each other as well as against poly-generation and repowering options, particularly natural gas combined cycle and natural gas cogeneration repowering. Analysis is required to understand the legal and regulatory barriers to these options. CTL with biomass co-firing requires additional research for reducing CO_2 emissions from transportation fuels and for plant operations as well as policy analysis to identify and then reduce barriers to this option.

IV. Research Management: Government / Industry Partnerships

A recurring theme of the symposium, from the framing of the issues through the near-term and "over the horizon" panels, was the *urgent need for a new, large, and focused federal research program for carbon mitigation from existing coal-fired power plants.* In the final panel, participants discussed such a program and what its key features might include. The urgency of the situation is complicated by the economics of existing plants and the high cost of replacements, the range of plant and site characteristics, the availability of substitute fuels, and limited near-term technologies for retrofit, including lack of sequestration options.

Participants were provided an "Enhanced DOE Management" strawman proposal to help focus the discussion about possible options for a research program and an innovation model to manage such a program. The discussion was far-ranging but generally fell into these areas:

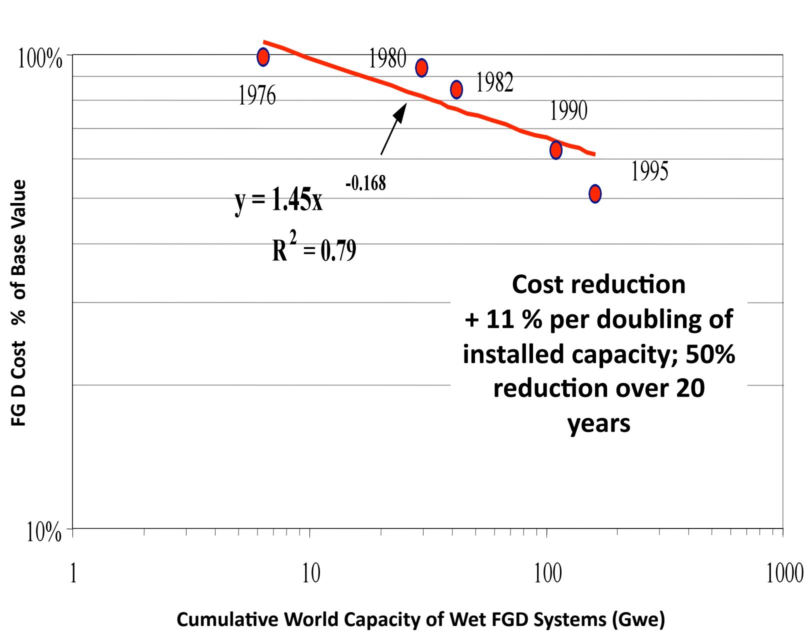
- "lessons learned" from previous experiences;
- the research portfolio or the substantive focus of the program; and
- issues of process and program design that will help enable program success.

Evidence suggests that the economic benefits of an accelerated technology program for mitigating CO_2 emissions from coal-fired power generation are substantial. A recent study for the Pew Center stated that "….with the experience gained from 30 demonstrations of CCS, the capital costs of wide-scale implementation of CCS in coal-fueled plants could be \$80 to \$100 billion lower than otherwise."[53]

While the potential benefits are significant, participants generally felt that current RD&D programs are inadequate for exploiting these opportunities. This view is reinforced by a report from the federal GAO which notes that "DOE's research strategy has, until recently, devoted relatively few resources to lowering the cost of CO_2 capture from existing coal-fired power plants, focusing instead on innovative technologies applicable to new plants."[54]

Lessons Learned. A number of participants pointed to the lessons learned from the development of FGD scrubbers as being instructive for technologies to mitigate CO_2 emissions. In spite of negative industry views and early opposition to the technology — an industry advertisement from the 1980s described the technology as "Scrubbers Described, Examined, and Rejected" — scrubbers were developed, improved, and deployed, after the passage of the Clean Air Act of 1970 and implementation guided by regulations, which required 70–90% reductions in SO_2. It was noted that as these technologies were built and deployed, costs came down. After 20 years, the technologies are reliable, solid waste and sludge problems were resolved and, in some cases, were made into value-added products, and the costs and energy penalties have been cut in half (Figure 5).[55]

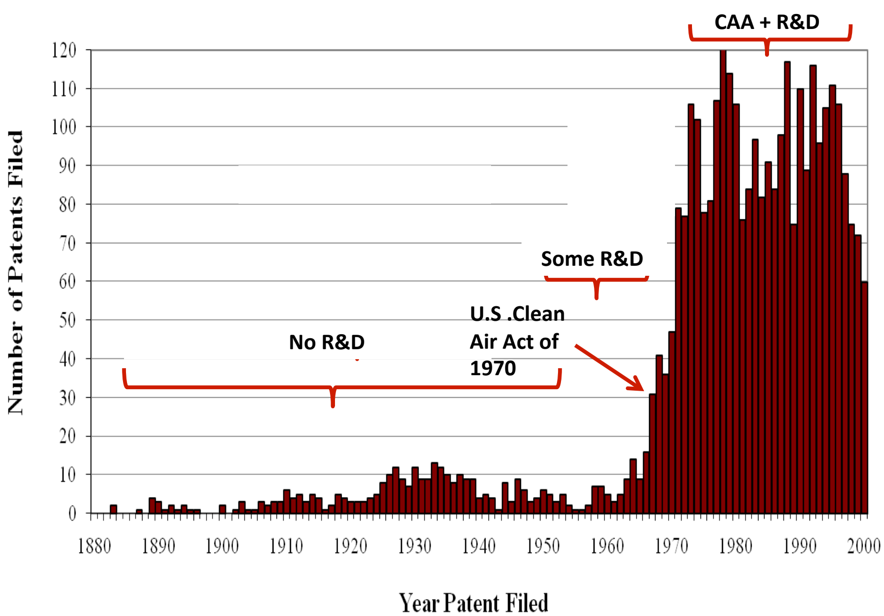
Figure 5. FGD Cost Reductions Over Time



This innovation pathway, driven by the private sector with support from EPRI and DOE, is also illustrated by patent counts. Figure 6 plots patents relevant to SO_2 from 1880 to 2000.[56] While causality is difficult to assert, passage of the Clean Air Act and the debates leading up its passage appear to have inspired a great deal of innovation. Participants generally agreed that, in this instance, regulatory policies stimulated innovations that, in turn, reduced emissions.

Some participants urged caution about drawing too many parallels between FGD development and the Clean Air Act to the mitigation of CO_2 emissions from coal-fired power plants. They noted that CO_2 mitigation is a much more extensive challenge. It will require more expensive capital investments and today's capture technologies have much greater energy requirements. Also, cap-and-trade proposals for CO_2 are much broader in scope and more complicated. Further, it is not clear whether efforts to establish parallel *regulatory* treatment for CO_2 will be undertaken. Nevertheless, the FGD experience is instructive and offers some optimism about the innovation pathway for capture technologies. It also highlights the value of a standards-driven regulatory approach.

Figure 6. SO-Related Patent Counts



The CO_2 Mitigation Research Portfolio. As noted, DOE has focused largely on the development of technologies for new coal-fired power generation options and funding has been allocated primarily to coal gasification-based technologies. While important for meeting long-term climate mitigation goals, gasification/IGGC plants will not likely be developed or widely deployed for some time; DOE's flagship research program in this area has been delayed and restructured and the investment community continues to express skepticism about the viability of IGCC.

Participants generally agreed that DOE programs should be revised to more effectively contribute to reducing CO_2 emissions and there was general support for a program that spanned the full RD&D continuum, including:

- breakthrough research opportunities;
- commercial-scale demonstration programs; and
- continued evolutionary technology R&D.

Participants were provided notional recommendations about the size and components of an eight to ten year, DOE-managed RD&D program for both PCC and oxy-combustion (IGCC research at DOE is supported under the FutureGen program). Table 6 describes the PCC and oxy-combustion components of such a program. Funding totals represent both public and private funding. The program budget is relevant for new builds or for retrofits. Proposed budgets for both PCC and oxy-combustion do not include sequestration or other capture approaches, nor does it include RD&D funding for re-powering, co-firing, or efficiency upgrades.[57]

Table 6. Proposed Research Components for PCC and Oxy-combustion

Component	# of Projects		Cost of Project ($millions)		Total Cost ($ millions)	
	PCC	Oxy	PCC	Oxy	PCC	Oxy
Demonstration	5	3	1000	1200	5000	3600
Pilot Plants	15	10	50 (25-100)	100	750	1000
Proof of Concept	30	20	10	50	300	200
Exploratory Research	50	25	1	2	5	50
Simulation/Analysis					100	100
Contingency					1200	1000
TOTAL					7400	5900

Process Changes will Enhance Research Success. There was widespread agreement that existing programs at DOE, both in structure and focus, were inadequate to meet the research needs for developing technologies to mitigate CO_2 emissions from existing coal plants.

How Current Process Impedes Progress. Of DOE's existing programs, the Clean Coal Power Initiative (CCPI) was deemed the most appropriate vehicle for accommodating the needs of a new program. The focus of the current CCPI Round III solicitation addresses some but not all of the needs for technology development for a broad portfolio of CO_2 mitigation options for existing plants; it does not, for example, support research for efficiency upgrades, rebuilding, or re-powering.

Further, there was concern that the inflexibility of the requirements of the Round III solicitation, coupled with historical DOE practice, would severely inhibit a rapid, comprehensive, and robust response to technology development. Some general concerns with current DOE process were highlighted, including:

- *Program Scope:* The CCPI Round III Program specifically links capture to sequestration. This excludes research on efficiency, co-firing, and ultra-supercritical plants.

- *Excessive time from appropriation to initial award.* For CCPI Round III, the length of time between appropriations and contract awards was expected to be around 31 months, and this was *prior* to the reopening of the solicitation after $800 million in additional funding was appropriated to the program as part of the stimulus package. Participants noted the difficulties of holding large project teams together over this length of time and highlighted the significant drop-off in the number of initial project selections to those projects that actually signed contracts in CCPI Rounds I and II.

- *Inflexible performance objectives.* CCPI sets the "gold" standard level of 90% carbon capture. In a future cap-and-trade regime, there will likely be a market for technologies with a wider range of performance levels.

- *Lack of a liability framework.* The federal government has yet to establish regulations for geologic sequestration. This is problematic for existing DOE programs which have encountered serious impediments due to the lack of a viable strategy for addressing the liability issues. A recent survey of DOE geologic sequestration pilot projects for which data was available found that 60% reported significant legal issues.

- *Selection criteria that do not place priority on commercialization potential.* Commercialization potential appears to be undervalued, where such potential is weighted at only 20% in the technical section of the RFP.

- *Flexible contracting authorities not utilized.* The CCPI program uses a Cooperative Agreement, a vehicle that is widely used by DOE to fund R&D projects with non-governmental entities (private industry, not-for-profit entities, and, in some cases, universities) and well suited for laboratory or small-scale experimental research; it is, however, an extremely cumbersome vehicle for large demonstration projects.

Strawman for RRRC Research Mangement. Participants discussed several possible improvements to DOE process and program design, including an "Enhanced DOE Management Model." This proposed model would build upon the CCPI program model and would specifically address the problems discussed above. The first and most notable difference is the recommendation that CCPI Round III be revised to include research on existing coal plants to cover retrofits including efficiency, rebuilds, repowering and co-firing, for purposes of discussion, the "RRRC Program." The principal elements of the model include:

- *Program Objective.* The objective of the RRRC program would be to develop the technology base to enable business decisions on RRRC technology deployment in 2015–2017 timeframe. Having RRRC technology options ready for a deployment decision by mid-2015 will enable existing plants to make material contributions to achieving 2020 interim reduction targets in the proposed cap-and-trade program.

- *Program Scope and Implementation Strategy.* An RRRC program should support multiple commercial scale (or scalable to commercial scale) demonstration projects, in parallel, on an accelerated basis. The scope of the program would include oxy-combustion and PCC technologies, efficiency improvements, rebuilding, repowering, and co-firing technologies. The technologies could be demonstrated on a variety of coals or on natural gas. Theoretically, this would lower the competitive pressures as a larger set of winners would be supported in efforts to meet the specific needs of individual plants and utility fleets. It would also bring a broader range of research participants into the process.

- *Technical Performance Objectives.* Technologies that achieve significant reductions in or avoidance of carbon dioxide emissions would be eligible. No specific numerical targets would be set. Instead, decisions on the technical performance levels of proposed technologies would be based on an assessment of the size of the technology's market potential under a cap-and-trade program, weighted against availability or expected availability of affordable, higher-performing options. New evaluation criteria would be established that would provide greater weight to commercialization potential.

- *Structure of Federal Financial Incentives.* Federal financial assistance would be awarded as a combination of direct assistance, loan guarantees, and tax credits. A single application process would be established to allow for consideration of the whole federal financial assistance package. The overall level of federal financial assistance would be established on the basis of the need to "buy down" the project costs in order to sell electricity on a competitive basis. For spending assistance (direct awards and loan guarantees), a single federal financial assistance instrument would be developed, using authorities currently available to DOE for Other Transactions Authority and the Title XVII loan guarantee authority.

- *Reduce Risks/Expedite Work.* In order to expedite contract negotiations, reduce risk, and diminish the potential for unrealistic conditions, DOE would enter into "conditional awards" to include provisions to protect the government's interests while outstanding terms and conditions are being finalized. Project awards would allow for contingencies, consistent with normal business practices. In addition, DOE would establish a central reserve fund, not to exceed 20% of the cost of the program, to manage any cost and schedule related issues outside of normal contingencies. Strict cost accountability would be maintained, using commercial practices rather than standard government procurement practices.

- *Expedited Application Evaluation Process.* The current DOE evaluation process would be expedited by separating the technical and financial reviews into two separate processes, and bringing outside experts into both evaluations.

- *More Flexible Demonstration Period.* The length of the demonstration period would reflect market conditions as well as technical considerations. In particular, the length of assistance should allow for a transition where the enactment of a mandatory greenhouse gas reduction program begins to establish a price signal for carbon. Terminating federal assistance for a CCS demonstration project while the market price of carbon is zero or small virtually guarantees that the project will not be able to sell electricity under competitive terms.

In sum, significant changes in CCPI Round III would be essential for accommodating the time drivers, the need for enhanced flexibility, and the expanded as well as more focused scope of an RRRC Program.

Other Research Model Options. There was a lively debate on the nature and structure of an appropriate research management model. Several participants were concerned that the Enhanced DOE Management Model did not go far enough to address the needs and requirements articulated in the discussion and proposed several options, motivated by concerns about DOE's lack of resident commercial expertise and the slow pace of decision-making.

Some advocated eligibility for natural gas-fired power generation capture in addition to coal plants. Participants also proposed radically different means of incentivizing technology development such as "sliding cash payments for CO_2 emissions reductions" with early actors receiving higher prices for their avoided CO_2 emissions. A variation on this theme was a scheme in which the federal government would pay for and take title to the CO_2, establishing both a clear market for CO_2 as well as resolving liability issues. Several participants advocated the creation of a new quasi-government corporation, specifically for the purpose of managing large demonstration projects. Some took exception to funding efficiency research, which was viewed as intrinsic to sound and smart business practices; as such, they felt it should be the purview of the private sector and ineligible for federal support.

There was concern expressed about the ability of the private sector to get financing for large projects, especially in today's economic climate. There were also concerns about the 50% match requirement for industry and its ability to raise funds. This requirement, which has its genesis in a highly regulated power market that no longer exists today, was viewed as extremely discouraging and limiting of the number and range of potential partners in proposals.

The white paper for this session included a comparison of the key features of the existing CCPI Round program and some possible features of two alternatives; an Enhanced DOE Management Program, which could be achieved under existing authorities; and a version of a quasi-government corporation, which would require new statutory language to be established. These are highlighted in Table 7.[58]

Table 7

	Current CCPI Business Model	Enhanced DOE Business Model (Existing Authority)	New Management Entity (New Legislation)
Decision-making Programmatic Project-Specific	Secretary/Assistant Secretary Source Selection Official	Secretary/Assistant Secretary Credit Review Board Model	Board of Directors/CEO Board of Directors/CEO
Application review process	Reviews by DOE personnel with Limited use of consultants; Sequential review by NETL and DOE/FE/HQ	External peer review panels modeled after NSF and NIH (and subject to appropriate non-disclosure and conflict of interest). If necessary, DOE can utilize parallel review teams to ensure consistency	External peer review panels modeled after NSF and NIH (and subject to appropriate non-disclosure and conflict of interest). If necessary, DOE can utilize parallel review teams to ensure consistency
Federal Personnel	All program personnel subject to federal personnel requirements	All program personnel subject to federal personnel requirements	Program management staff can be hired without federal personnel restrictions, and can be limited term appointments (similar to NSF and Sematech)
Funding Mechanism	Cooperative Agreements	Other Transactions Authority (OTA)	Cost-sharing, equity investments, loans, loan guarantees, securitization, insurance
Coordination of financial incentives	Three separate application and decision-making process for cost sharing, loan guarantees and tax credits	Single application and review process within DOE for cost-sharing and loan guarantees; DOE coordination with Treasury to provide seamless interface with the applicant on tax credit	Single application and review process, with seamless interface with Treasury on tax credit issues
Eligible and ineligible costs	FAR cost principles	Generally accepted business practices; FAR ineligible costs would still apply	Generally accepted business practices; FAR ineligible costs would still apply
Cost Controls	Cost cap established at time of award; no cost sharing of cost overruns	Cost cap established when project achieves at least 50% detailed design, but prior to construction; sharing of limited cost increases	Cost cap established when project achieves at least 50% detailed design, but prior to construction; sharing of limited cost increases
Cost Sharing	At least 50% non-federal cost sharing and within budget period	Waivers permitted based upon technology risk; size of sponsoring company and potential benefit of the technology	Waivers permitted based upon technology risk; size of sponsoring company and potential national benefit of the technology
Schedule Controls	Project sponsor is not permitted to request a schedule extension. DOE may in its sole discretion extend schedule by up to four years	Project sponsor is not permitted to request a schedule extension. DOE may in its sole discretion, extend the schedule by up to 4 years.	New entity can establish appropriate incentives or disincentives to encourage timely completion of projects
Audits	DOE Audits (Through DCAA)	3rd Party audits	Audits conducted by new entity or by 3rd parties
Intellectual Property Rights			New entity can negotiate rights commensurate with level of investment
Liability	Applicant indemnifies the government for any project-related liability	DOE provides liability protection for geologic sequestration activities conducted in conformance with EPA VIC permits; DOE establishes reserve fund to cover liability	DOE provides liability protection for geologic sequestration activities conducted in conformance with EPA VIC permits; DOE establishes reserve fund to cover liability

Issues Summary. A recurring theme of the symposium was the urgent need for a new, large, and focused federal research program for carbon mitigation from existing coal-fired power plants. This urgency is complicated by the economics of existing plants and the high cost of replacements, the range of plant and site characteristics, the availability of substitute fuels, and limited near-term technologies for retrofit, including lack of sequestration options.

Evidence suggests that the economic benefits of an accelerated technology program for mitigating CO_2 emissions from coal-fired power generation are substantial. A recent study for the Pew Center stated that "….with the experience gained from 30 demonstrations of CCS, the capital costs of wide-scale implementation of CCS in coal-fueled plants could be $80 to $100 billion lower than otherwise."[59]

Participants generally felt that DOE programs, as currently designed, could not provide timely outcomes, sufficient to meet the urgency of the climate change challenge. There was support for an enhanced program at DOE and some suggested fairly radical departures from current DOE model, including the establishment of a quasi-government corporation to manage large scale commercial demonstration projects.

Panel Three Findings. Research Management: Government/Industry Partnerships

Finding: Existing programs at DOE, both in structure and focus, are inadequate to meet the research needs for technology development to mitigate CO_2 emissions from existing coal plants. The GAO has concluded that DOE's research strategy has, until recently, devoted relatively few resources to lowering the cost of CO_2 capture from existing coal-fired power plants, focusing instead on innovative technologies applicable to *new* plants (emphasis added).

Finding: Absent or in advance of the wholesale programmatic changes proposed by some participants, DOE's CCPI Round III should be modified to enhance opportunities for success, to engage industry more effectively, and to expedite research. CCPI Round III should be expanded to fund a broader research portfolio beyond retrofits and should include efficiency upgrades, rebuilds, repowering, and co-firing with biomass. Consideration should be given to including a component for research on CO_2 capture from natural gas power plants.

Finding: A research portfolio should span the research continuum and should support breakthrough research opportunities, continuing evolutionary technology R&D and commercial-scale demonstration programs. A notional 8–10 year program with total funding of around $13.4 B, focused on PCC and oxy-combustion was suggested. Many thought this should be expanded to include efficiency, repowering, co-firing and PCC on gas plants.

Finding: New research and/or innovation models are essential for demonstrating options to mitigate CO_2 emissions from existing coal plants. Options discussed include an "Enhanced DOE Management" model; a new quasi-government corporation, specifically to manage large-scale commercialization demonstrations; and direct federal payments for CO_2 emissions mitigation, with larger payments for early actors.

Endnotes

1 The full text of commissioned white papers is appended to this document
2 Vello A. Kuuskraa. 2007. *A program to accelerate the deployment of CO_2 capture and storage: rationale, objectives and costs.* Washington, D.C.
3 Wayne Leonard. 2009. Slide presentation.
4 Dale Simbeck and Waranya Roekpooritat. 2009. *Near-term technologies for retrofit CO_2 capture and storage of existing coal-fired power plants in the United States.* MIT Energy Initiative Symposium on Retrofitting Existing Coal Plants for CO_2 Emissions Mitigation. March 23. Cambridge, MA: MIT Energy Initiative.
5 Simbeck and Roepooritat 2009.
6 Simbeck and Roepooritat 2009.
7 Efficiency is defined as the electric energy output as a fraction of the fuel energy input of a thermal power plant
8 Bhattacharya, Sankar. 2008. *Coal-fired power generation: Replacement/retrofitting of older plants.* Presentation in Bangkok Thailand.
9 Simbeck and Roepooritat 2009.
10 Leonard, 2009
11 All-in costs include overnight capital costs + estimated project/site-specific costs, and owner's costs (e.g interest during construction).
12 Massachusetts Institute of Technology. 2007. *The Future of Coal: Options for a Carbon-Constrained World. An Interdisciplinary MIT study.* Cambridge, MA: Massachusetts Institute of Technology
13 Leonard, 2009.
14 Leonard, 2009.
15 Howard Herzog, Jerry Meldon, Alan Hatton. 2009. *Advanced post-combustion CO_2 capture.* Clean Air Task Force, Boston, MA..
16 Herzog et al. 2009.
17 Herzog et al. 2009.
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19 Simbeck and Roepooritat 2009.
20 Herzog et al. 2009.
21 Discussion, 2009. MIT Energy *Initiative Symposium on Retrofitting Existing Coal Plants for CO_2 Emissions Mitigation,* March
22 Steven Specker, Jeffrey Phillips, Desmond Dillon. 2009. *The potential growing role of post-combustion CO_2 capture retrofits in early commercial applications of CCS to coal-fired power plants.* Palo Alto, CA: Electric Power Research Institute, Inc
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28 Edward Levy. 2008. *Carbon Capture and Sequestration: A technological solution for continued coal use in a carbon constrained world.* Washington, D.C.
29 Simbeck and Roepooritat 2009.
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31 Herzog et al. 2009.
32 Herzog et al. 2009.
33 Herzog et al. 2009.
34 Herzog 2009.
35 Herzog et al 2009.
36 Herzog et al 2009.
37 Symposium discussion, March 23, 2009
38 Herzog 2009.
39 Herzog 2009.
40 Herzog 2009.
41 Janos M. Beér, 2009. *Higher efficiency power generation reduces emissions.* National Coal Council Issue Paper, Cambridge, MA: Massachusetts Institute of Technology..
42 Beér, 2009.

43 János M.Beér. 2007. *High efficiency electric power generation: the environmental role.* Progress in Energy and Combustion Science. Vol. 33, No. 2 (April).
44 Beér. 2007.
45 Kenderdine, Melanie. 2005. *Natural gas and alternative technologies: Tools for a new U.S. gas security strategy.* World Petroleum Congress presentation, Johannesburg, South Africa.
46 Beér 2007.
47 Beér 2007.
48 Beér 2007.
49 Thomas G. Kreutz, Eric Larson, Guangjian Liu, Robert H. Williams. 2008. *Fischer-Tropsch Fuels from Coal and Biomass,* Princeton, N.J.
50 Kreutz et al. 2008.
51 Beér 2009.
52 Discussion with Howard Herzog, MIT Senior Researcher.
53 Vello A. Kuuskraa. 2007. A program to accelerate the deployment of CO_2 capture and storage: rationale, objectives and costs. Washington, D.C.
54 US Government Accountability Office. 2008. *Climate Change: Federal Actions Will Greatly Affect the Viability of Carbon Storage as a Key Mitigation Option.* Washington, D.C.
55 Edward S. Rubin. 2009. Presentation slides. *MIT Symposium on Retrofitting Existing Coal Plants for CO_2 Emissions Mitigation.* March 23. Cambridge, MA: MIT Energy Initiative.
56 Rubin 2009.
57 Herzog 2009.
58 Joe Hezir and Melanie Kenderdine. 2009. *Federal research management for carbon mitigation at existing coal plants.* MIT Symposium on Retrofitting Existing Coal Plants, Cambridge, MA.
59 Kuuskraa. 2007.

ABBREVIATIONS / ACRONYMS

AA	aqueous ammonia solution
AEO	Annual Energy Outlook
ARPE-E	Advanced Research Projects Agency-Energy
ASU	air separation unit
BTL	biomass to liquids
CCA	Clean Air Act
CAIR	Clean Air Interstate Rule
CCPI	Clean Coal Power Initiative
CCS	Carbon capture and sequestration
COE	cost of electricity
CTL	coal to liquids
EIA	Energy Information Administration
EOR	enhanced oil recovery
EPRI	Electric Power Research Institute
FGD	flue gas desulfurization
FT	Fischer Tropsch
FTL	Fischer Tropsch liquid
HHV	higher heating value (gross)
IEA	International Energy Agency
IGCC	integrated gasification combined cycle
LCOE	levelized cost of electricity
LHV	lower heating value (net)
LP	low-pressure
MITEI	MIT Energy Initiative
NSR	New Source Review
NGCC	natural gas combined cycle
PC	pulverized coal
RD&D (D)	research, development and demonstration (deployment)
RRRC	retrofit, rebuild, repower, co-firing
PCC	post combustion capture
SCPC	supercritical pulverized coal plant
SC	supercritical
SCR	selective catalytic reduction
TCR	total capital requirement
USC	ultra-supercritical

APPENDICES

A. Wayne Leonard slide presentation, March 23, 2009

B. White Paper, Dale Simbeck and Waranya Roekpooritat, *Near-Term Technologies for Retrofit CO_2 Capture and Storage of Existing Coal-fired Power Plants in the United States,* March 23, 2009

C. White Paper, Howard Herzog, *A Research Program for Promising Retrofit Technologies*, March 23, 2009

D. White Paper, Joe Hezir and Melanie Kenderdine, *Federal Research Management for Carbon Mitigation at Existing Coal Plants*, March 23, 2009

E. Howard Herzog, Jerry Meldon and Alan Hatton, *Advanced Post-Combustion CO_2 Capture*, Prepared for the Clean Air Task Force under a grant from the Doris Duke Foundation, March 1, 2009

F. Symposium Agenda

G. List of Participants

“A Good Story Is a Miracle”

-- Stanley Kubrick

MIT Symposium on CCS Retrofit Technology

J. Wayne Leonard
Chairman and Chief Executive Officer
March 23, 2009

Entergy

Caution Regarding Forward-Looking Statements

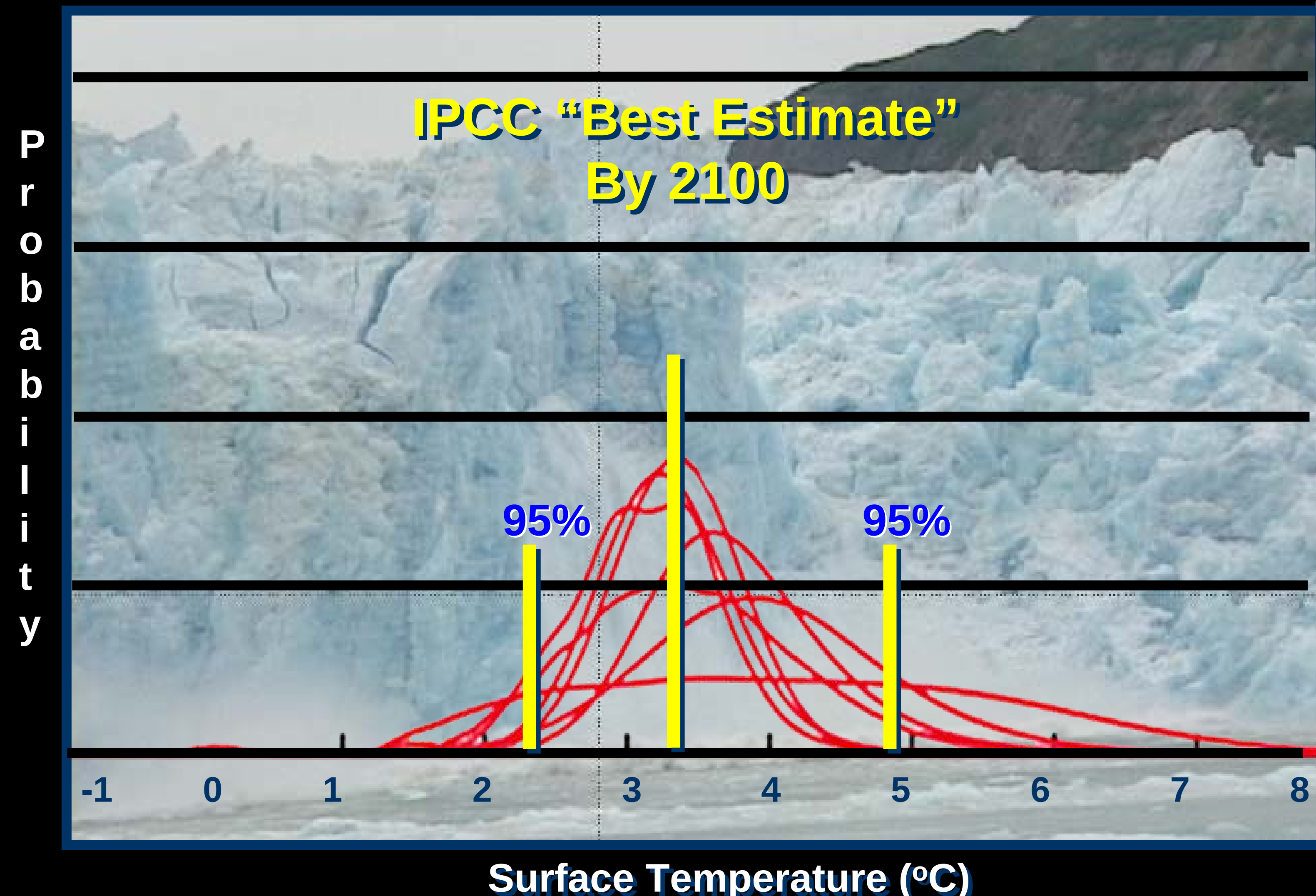
In this presentation, and from time to time, Entergy Corporation makes certain "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Except to the extent required by the federal securities laws, Entergy undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise.

Forward-looking statements involve a number of risks and uncertainties. There are factors that could cause actual results to differ materially from those expressed or implied in the forward-looking statements.

The Princess Bride
As you wish.

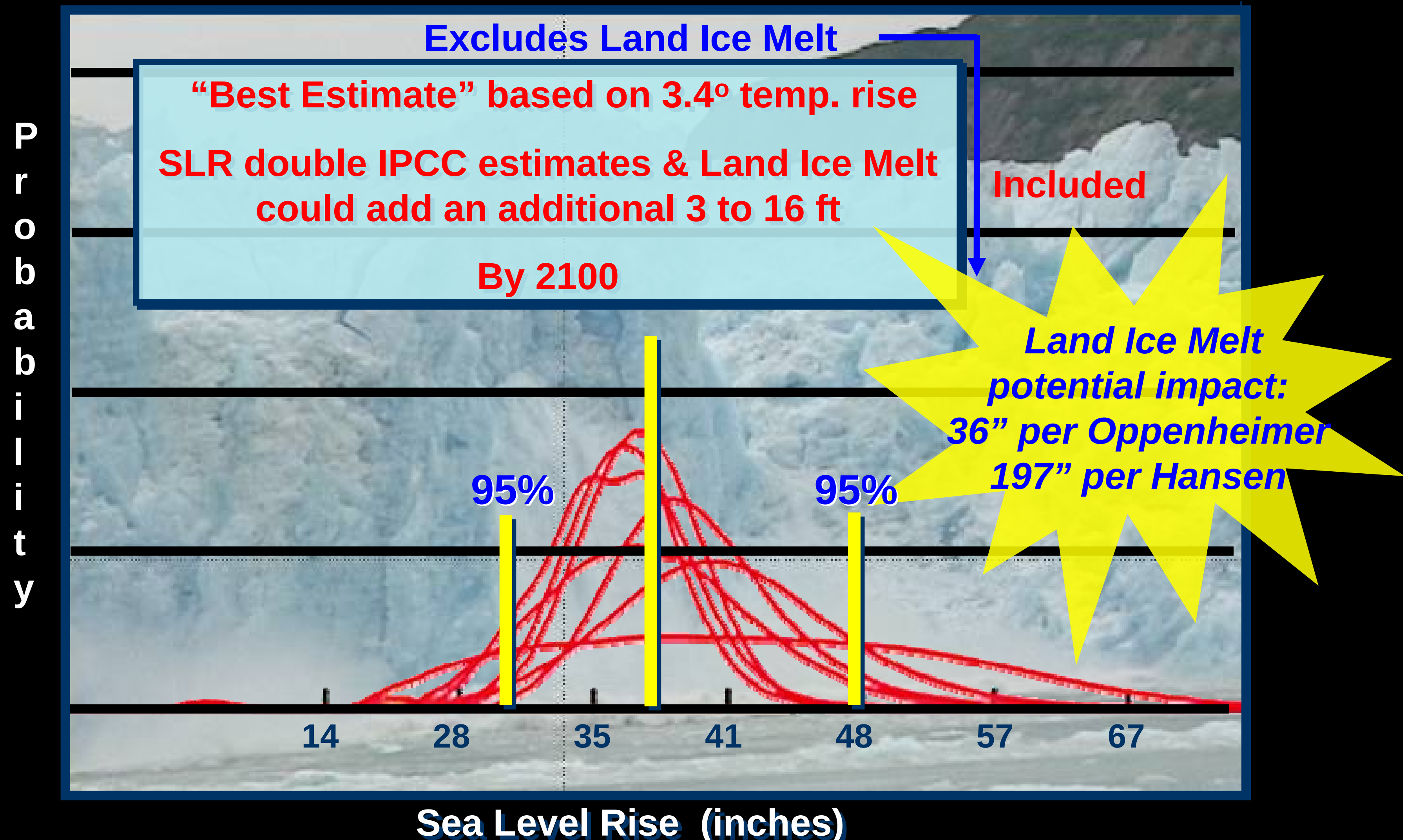
Since the invention of the kiss, there have been five kisses that were rated the most passionate, the most pure. This one left them all behind.

Fat Tails – Surface Temperature



Adapted from Intergovernmental Panel of Climate Change (IPCC) Fourth Assessment Report (AR-4) Fig SPM 5

Fat Tails – Sea Level Rise



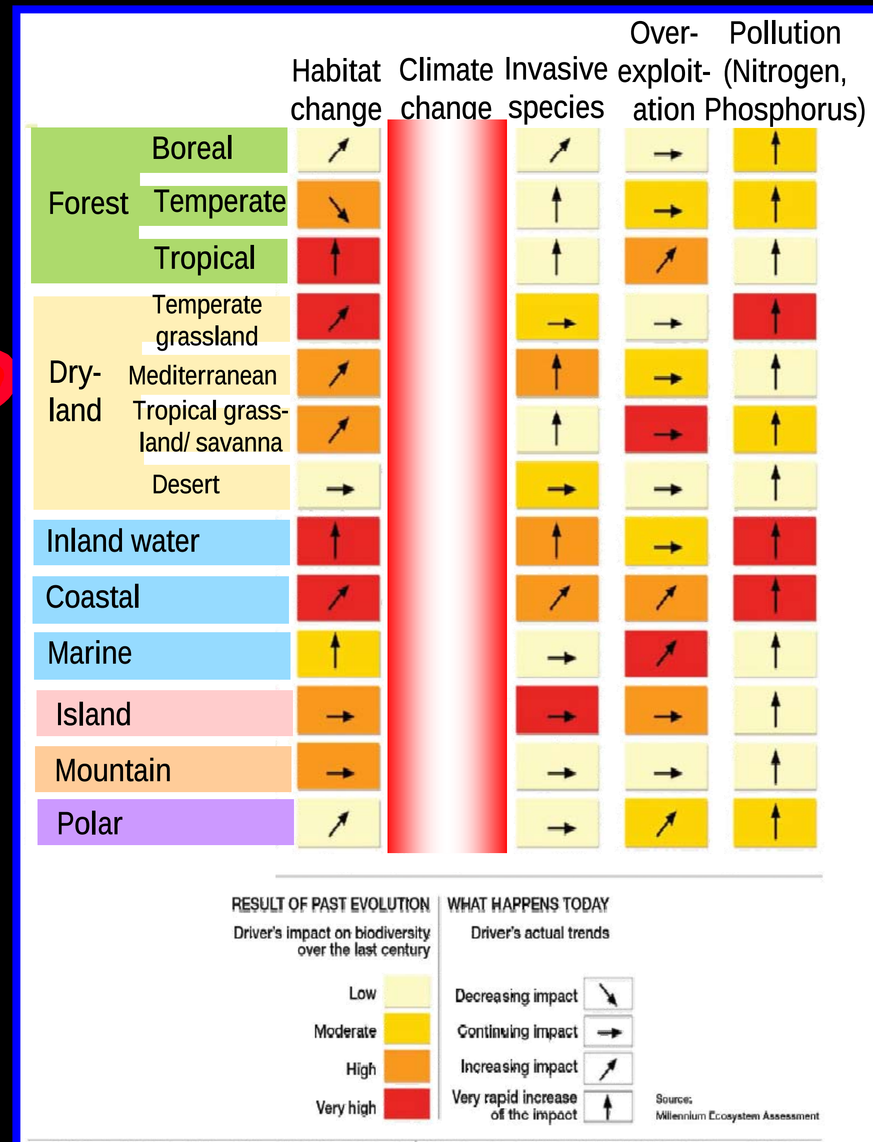
IPCC AR-4 without land ice melting = 7" to 23" (Third Assessment Report (TAR) 4" to 35" from land ice melt)

Adapted from IPCC AR-4 Fig SPM 5 – Using Rahmstorf Empirical Formula (Rahmstorf, et al 2007)

Biodiversity

Every 20 minutes, a species disappears

- At current rates, one-half of all species of life on Earth will be extinct in 100 years
- Two primary and interlinked causes
  - habitat destruction, which already affects 90% of threatened species and
  - climate change which will accelerate future change
- There is a complex, delicate, evolved interrelationship between species and ecosystems
- Temperatures, onset of seasons, food and water availability are impacted by subtle changes in climate



Source: Millenium Ecosystem Assessment; IPCC

Security

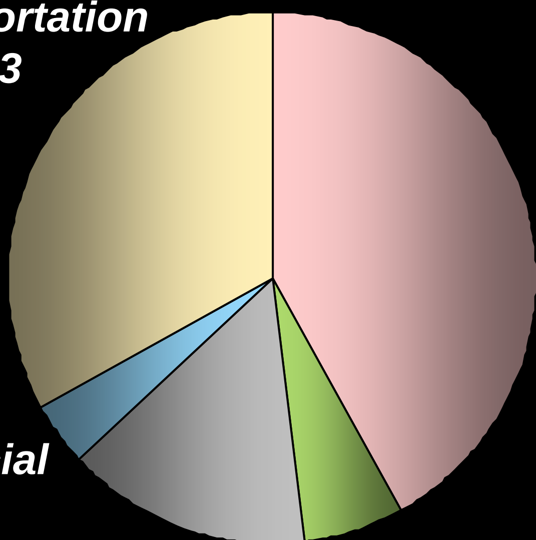
Testimony Before
Committee on Energy & Commerce
June 26, 2008

…Climate change acts as a threat multiplier for instability in some of the most volatile regions in the world.

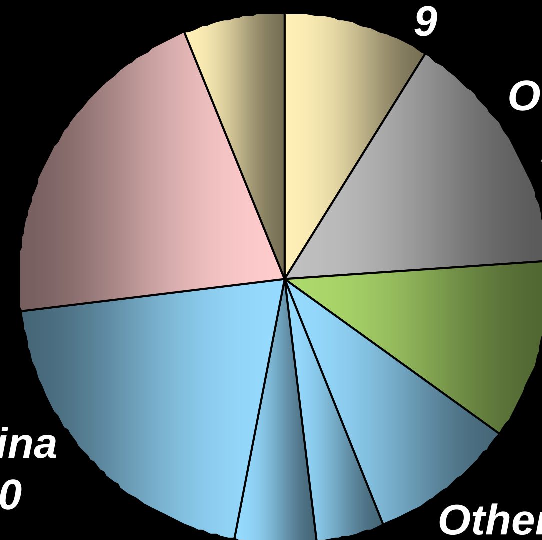
- - Military Advisory Board

Emissions

United States CO_2 Emissions
% of total



World CO_2 Emissions
% of total



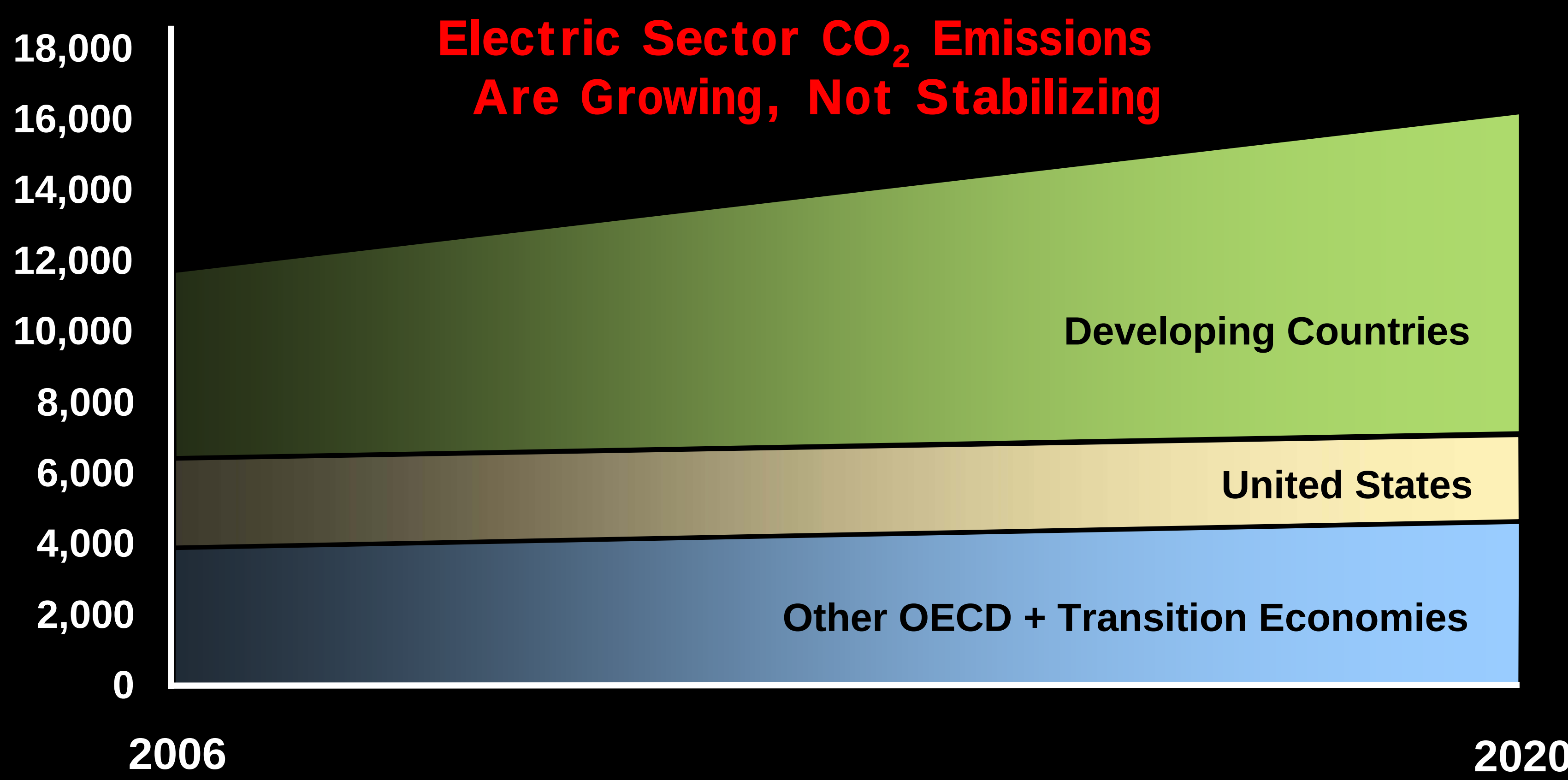
~9% of World's Emissions

Source: EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2007, Table ES-3

Source: Climate Analysis Indicators Tool (CAIT) Version 6.0. (Washington, DC: World Resources Institute, 2009)

A Little Short of Brotherly Love

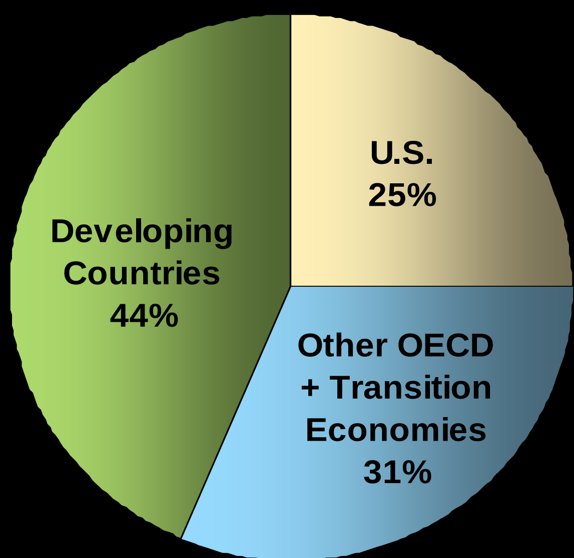
Global Electric Sector
CO_2 Emissions Forecast: BAU – No CO_2 Regulation
Million Metric Tons CO_2



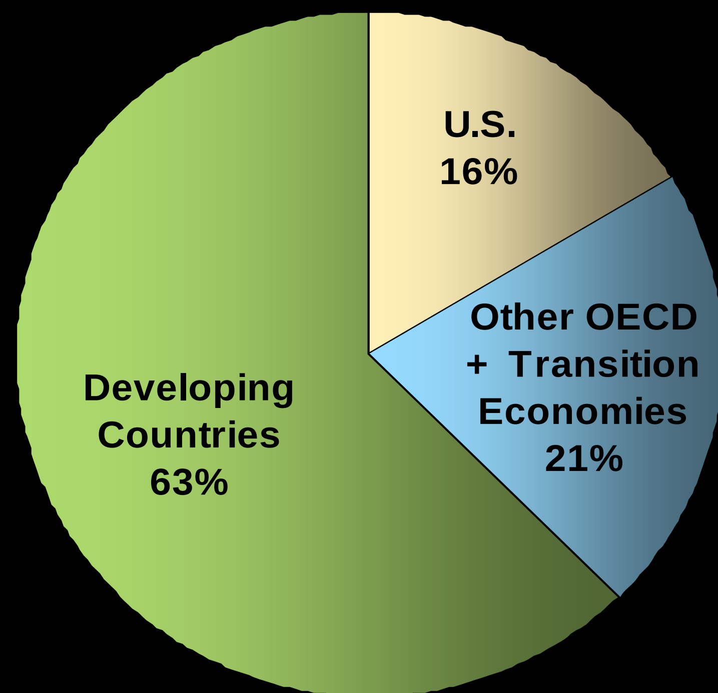
Source: IEA World Energy Outlook 2008 (Reference Case)

Growing Worldwide Coal Capacity Will Exceed 2 Million MW by 2020

New Coal Capacity in the Developing World Is Driving This Growth



2005: 1,333 GW

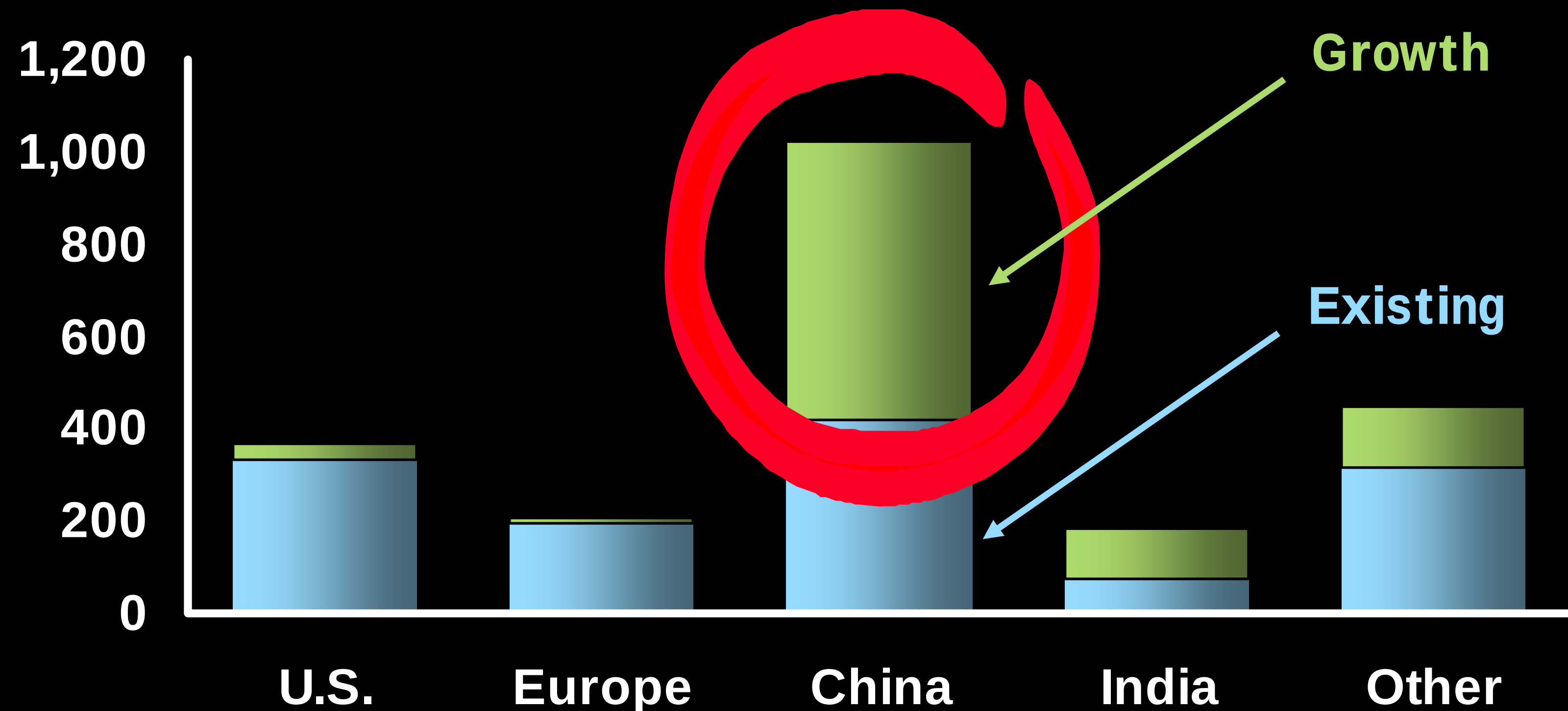


2020: 2,232 GW

Source: IEA World Energy Outlook 2008 (Reference Case)

We Can Fight or Give-up

Installed Coal Capacity
2005 – 2020; GW



The China Test

Source: IEA World Energy Outlook 2008 (Reference Case)

The Challenge

We Don’t Control Our Own Destiny

We Need to Plan Our Response with the Developing World in Mind

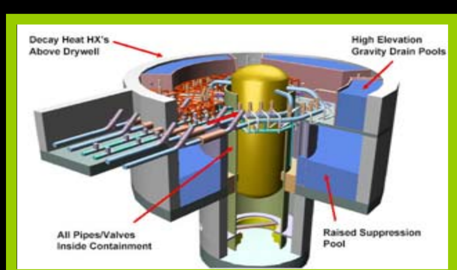
Alternatives

Do Nothing ↔ **Go Slow(er)**

OR

Replace Coal With

Nuclear | **Gas** | **Renewables**



The Secret of Success… Prayer

Cost of Not Dealing With Climate Change Now:

- Creating a 5ºC warmer world by 2100
- Irreversible commitment to sea level rise inundating low lying coastal areas
- Increased coastal flooding impacting up to 30 million people/year
- Increased damage from storms impacting up to 15 million people/year
- Global food shortages as adaptive capacity exceeded in low latitudes and yield decreases in higher latitudes
- Increased burden on health from malnutrition, cardio-respiratory and infectious diseases
- Water scarcity for up to 15 million people
- Catastrophic events

China test? Not a chance

Illustrative

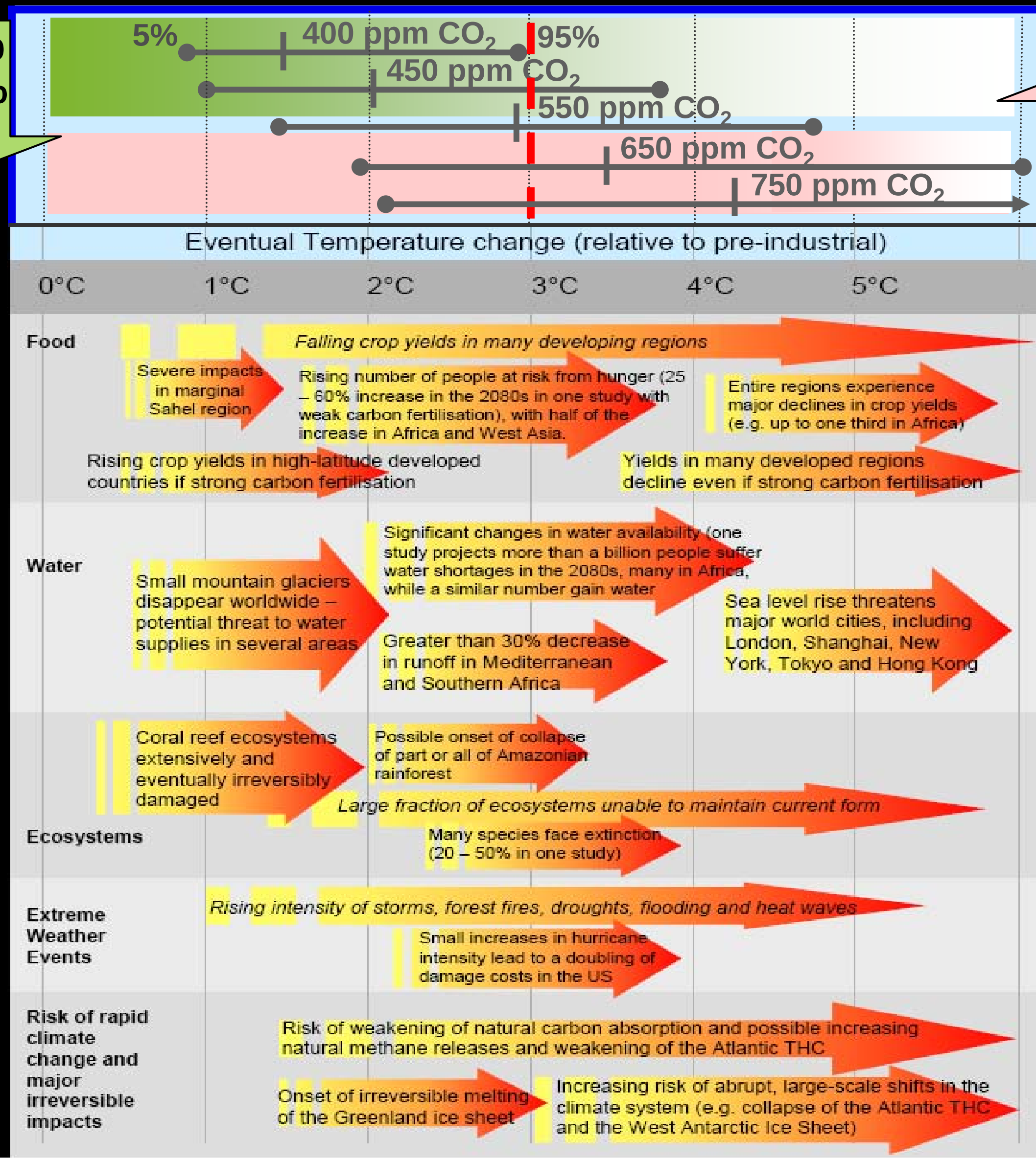
The Challenge – Alternatives

Go Slow(er)

Warner Lieberman 80% <~3º

Illustrative

80% >3º G8 Target

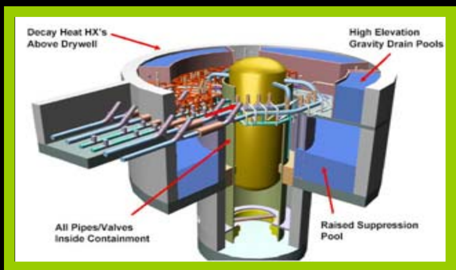


Source: Stern Review – Economics of Climate Change; Various Assumptions and Forecasts

Facing Economic Reality
Two Million MWs of Existing Coal

Replace Coal With

Nuclear



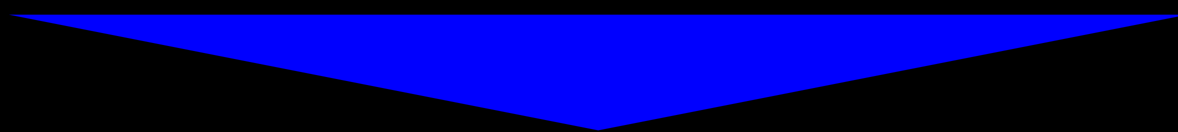
Gas

Renewables

-- everything is harder than it used to be – you got to plan more, you got to prepare, you got to be damn sure what you're doing or you're dead.

It's Bad Business – If Every Job Lost Money

Basic Economics



The Hurdle to Replace Existing Plants –
Only the Marginal Costs Count

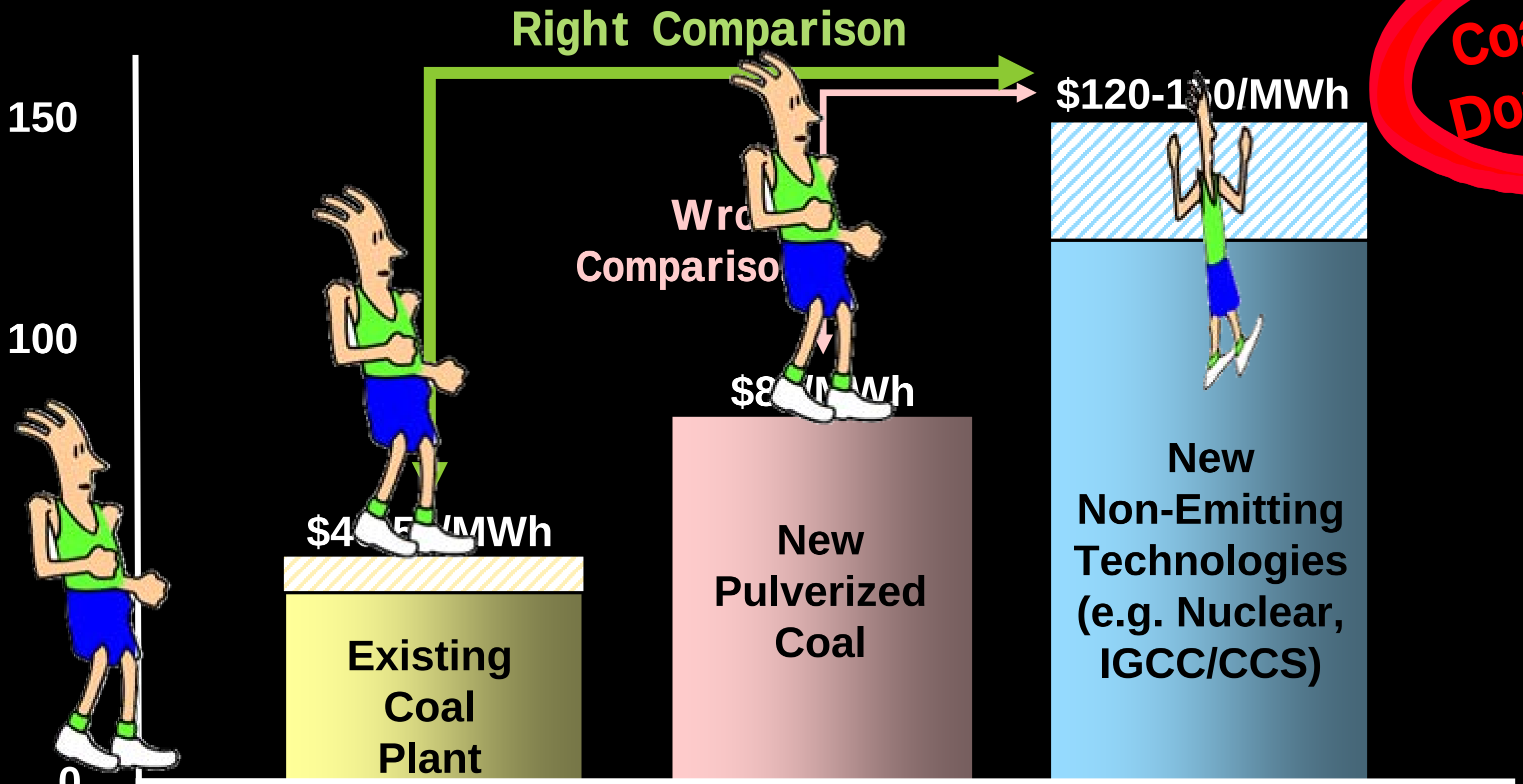
Every Day You Get Older – That's a Law

Comparison of "To Go" Investment to Keep a Coal Plant Operating vs. All-In Cost to Replace It with New Capacity

Lifetime Costs in 2020 $

But…

Coal Plants Don't Retire



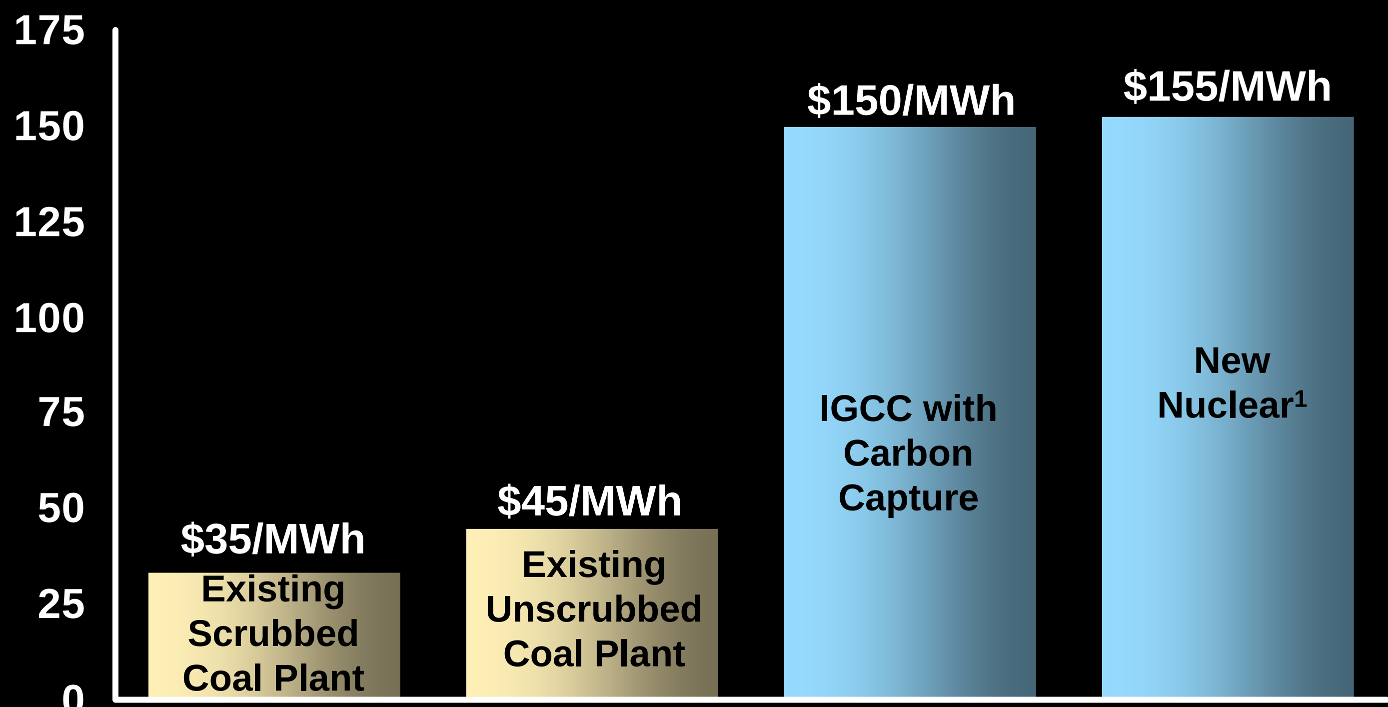
If we don't understand coal economics, we are unlikely to get the policies right

Source: NorthBridge Analysis

Replace Coal with Nuclear

Comparison of "To Go" Investment to Keep a Coal Plant Operating vs. All-In Cost to Replace It with New Capacity

Lifetime Costs in 2020 $



The China Test

- Cost
- Doability – China plans already include 100 new nuclear plants before 2030

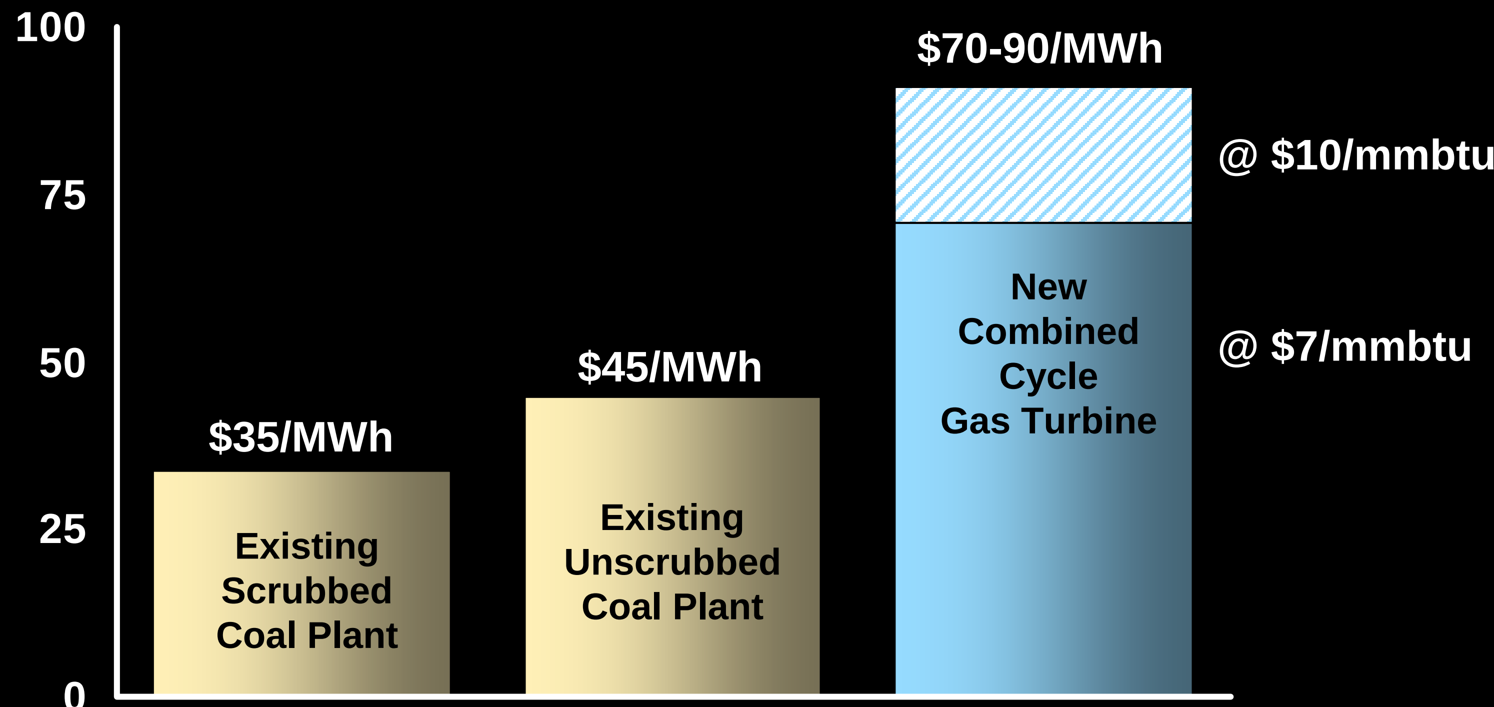
FAIL

Source: NorthBridge Analysis

[1] Assumes $8,000 / kW installed cost in 2020

Replace Coal With New CCGT

Comparison of "To Go" Investment to Keep a Coal Plant Operating vs. All-In Cost to Replace It with New Capacity
Lifetime Costs in 2020 $



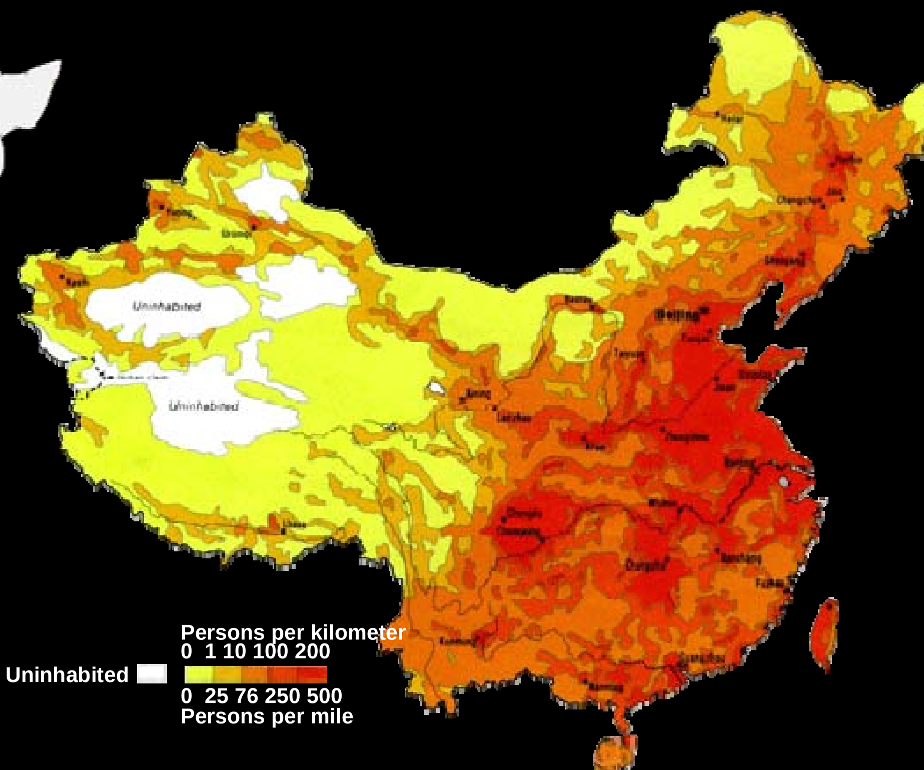
Source: NorthBridge Analysis

The Long (Distance) and Short (Reserves) of It

Gas Reserves

Source: IEA

The Population

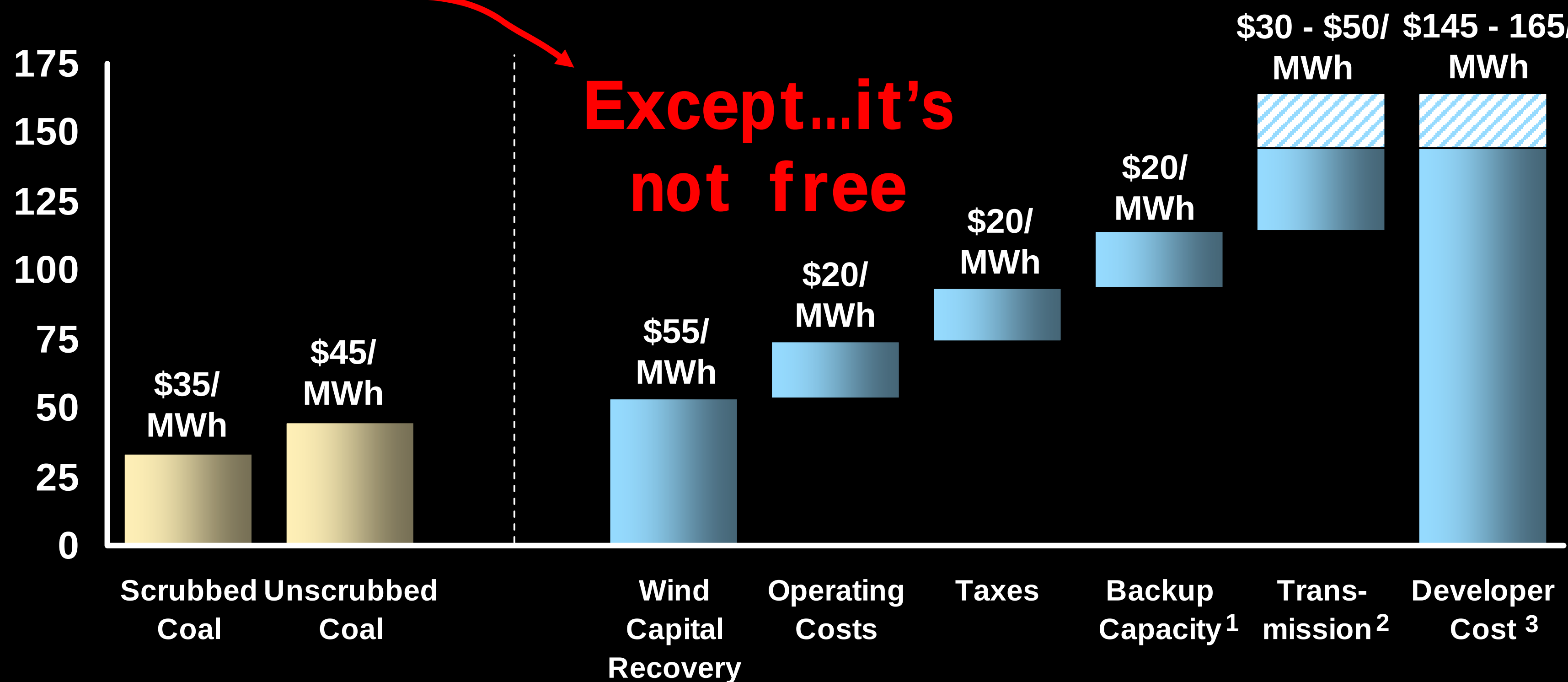


Source: Landing China.com

The China Test FAIL

Replace 'Dirty' Coal with 'Free' Wind

Costs vary significantly; this example is based on Great Plains wind: relatively high quality wind resource, but far from load



Actual capital costs are confidential, but recent reports suggest that installed costs of ~$2,000/kW are typical, with some projects costing more

Source: NorthBridge analysis

[1] Combustion turbine provides capacity and energy sufficient to utilize wind turbines as baseload resource at its average capacity factor

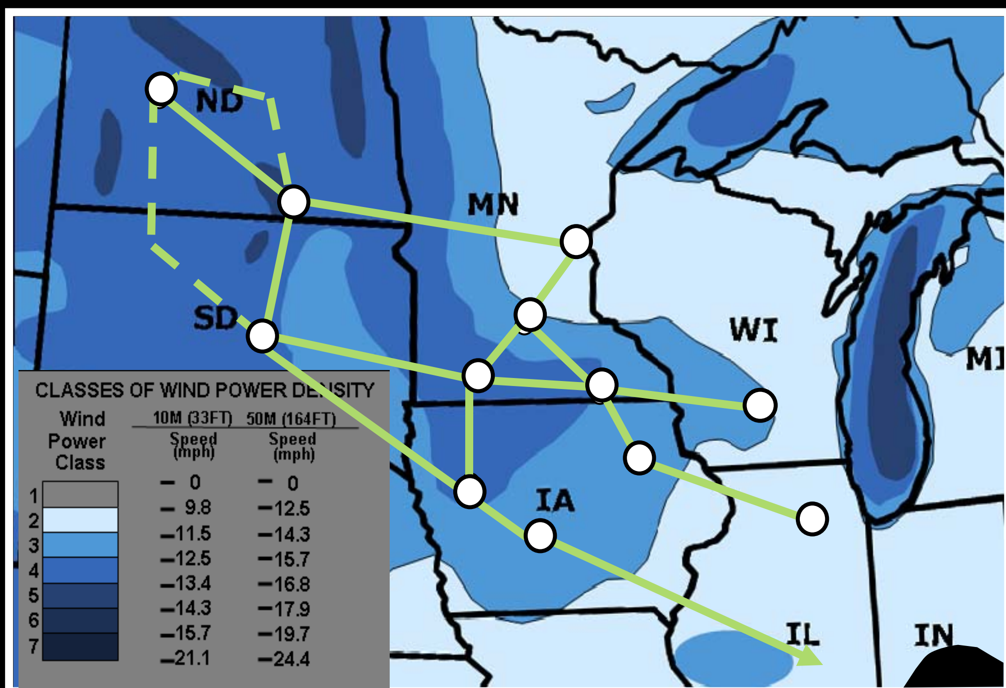
[2] Illustrative transmission expense of transmitting energy produced on the Great Plains to major load center

[3] Does not include benefits of government subsidies or value of renewable energy credits

Replace 'Dirty' Coal with 'Free' Wind

Replace 'Dirty' Coal With 'Free' Wind

Wind – Isn't the Problem The Grid?



- Existing Station Site
- Green Power Express
- Conceptual Extension

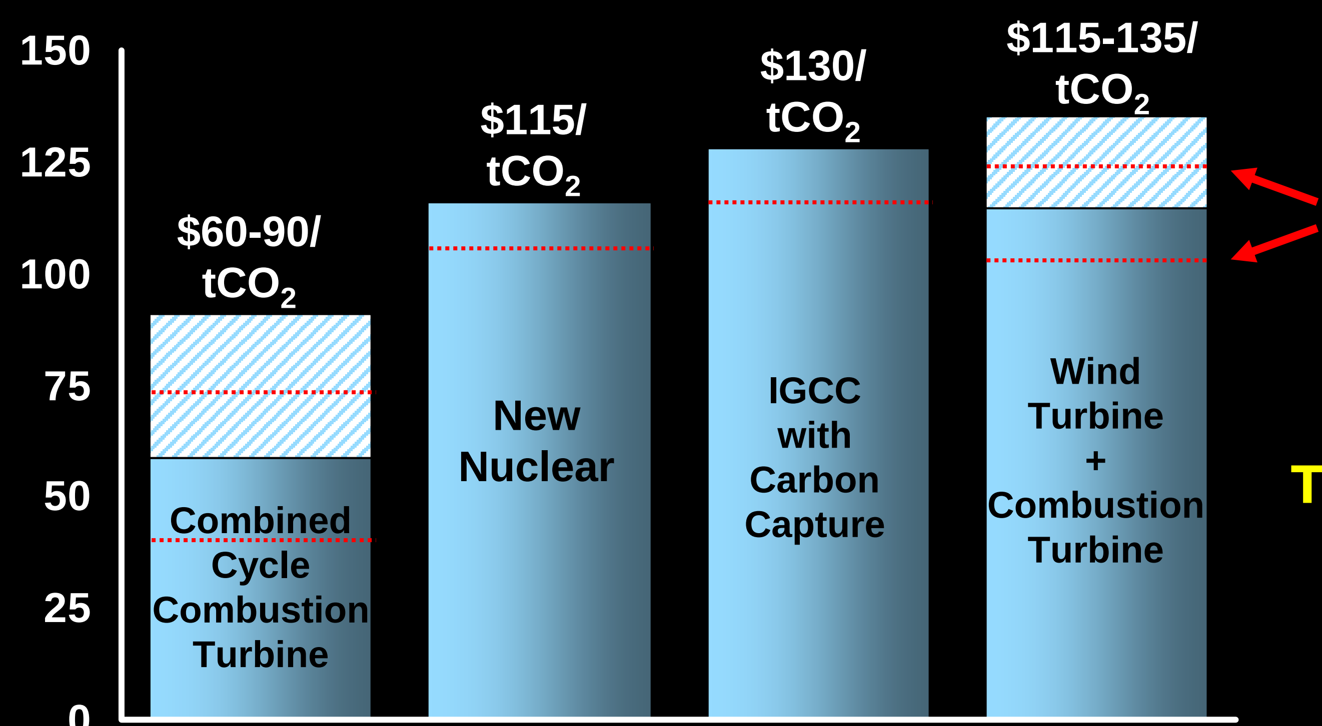
Lack of Cost Transparency

- 2-3 explicit subsidies (50-80 MWh)
- Intermittent resources (back-up needed)
- Long way from population centers
- Best sites gone
- Increasing cost business?
- China test?

Source: FERC testimony; http://www.thegreenpowerexpress.com/concept_map.php

Economic, Political, International (China) Test

Implicit Cost of Replacing Existing Scrubbed Coal



The China Test

Source: NorthBridge Analysis

Summary

Do Nothing → Unacceptable

Go Slow → Too Late

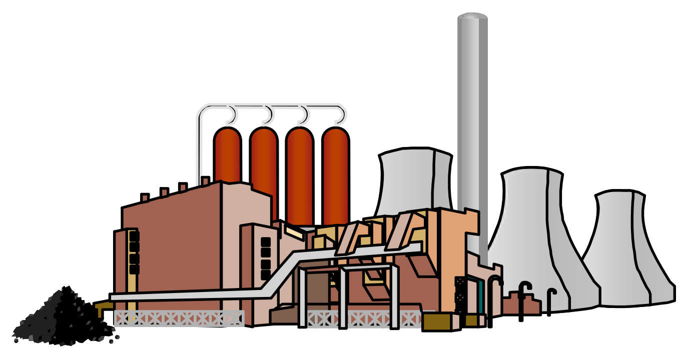
Nuclear Solution → Not Practical

Gas Solution → Not for China

Wind/Solar Solution → Too Expensive for Developing World

Coal Retrofit?

There is a missing link



Commercially viable post-combustion capture and sequestration technology, something that can be retrofitted on existing plants

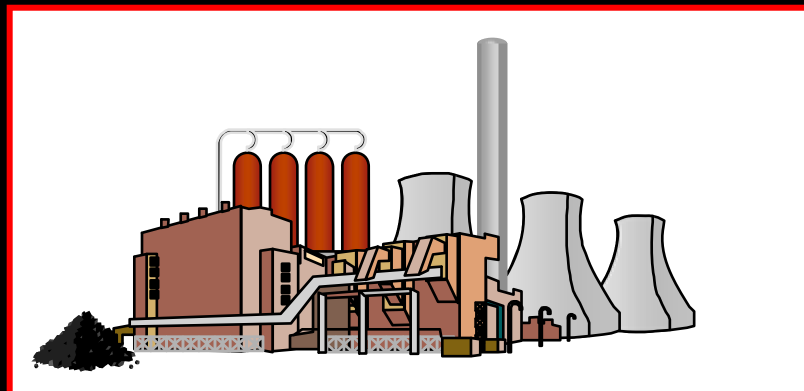
Not Available Today

AND

- ✓ **Huge market potential – enough to attract R&D**
  - **1,300+ GW conventional coal capacity world-wide (growing to ~2,200 GW)**
  - **Credible estimates, i.e., could be commercially available for $50-75/ton**
- ✓ **Government / industry underinvested in R&D**
  - **Pre-stimulus $25M DOE spending on post-combustion capture**

Early Cost Estimates; $/metric ton CO2 Avoided

The Issue Is Cost, Not Doability
It Will Physically Work



EPRI 2008 $50-74	McKinsey 2008 $55-80	IEA 2008 $50-95
Australia National Labs 2008 $58-74		
MIT 2007 $68-84	NETL 2007 $70-101	ICF 2007 $37-43

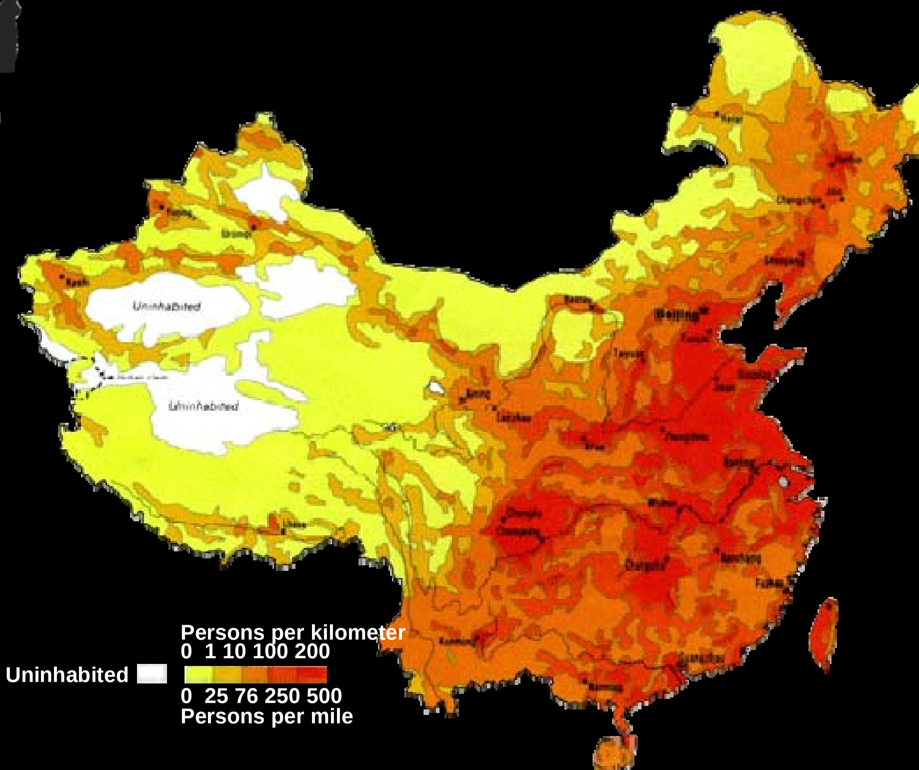
[1] *Includes capture, compression, transport and storage*

The China Test

Coal Reserves

(World's 3rd Largest Reserves) NEAR

The Population



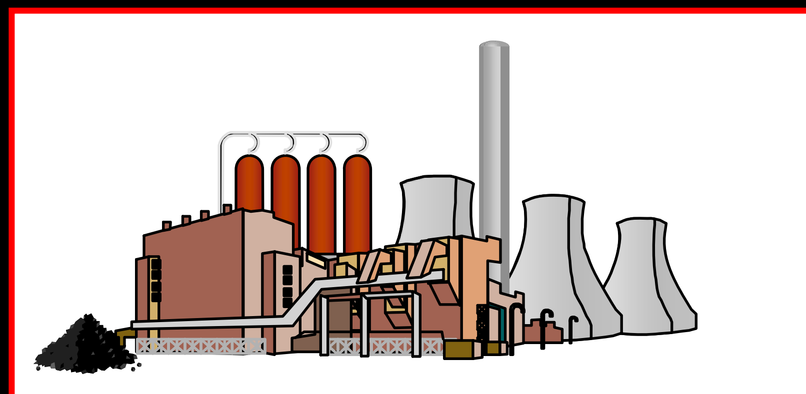
The China Test PASS!

Source: Maps of the World.com

Source: Landing China.com

Carbon Capture Retrofit on Existing Coal

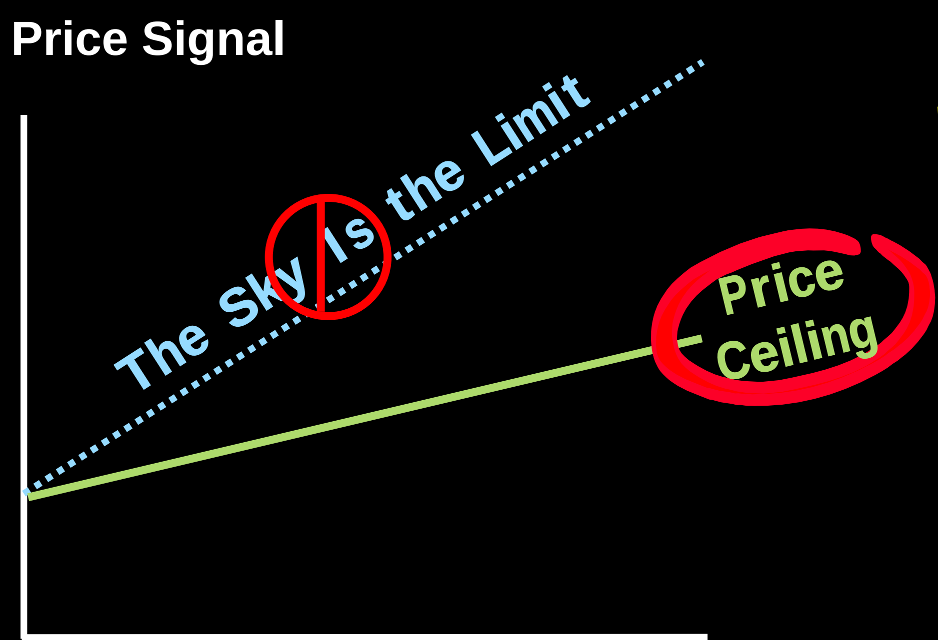
Substantial Value



- U.S. compliance cost savings could be as high as $50-100B/year
- More affordable solution for the rest of the world; savings could be as high as $400-600B/year
- Frees up spending for other purposes
- A way to power PHEVS
- The China Test PASS!

Option Value Is?

Special Circumstances Call for Price Caps



✓ **Provides more political viability**

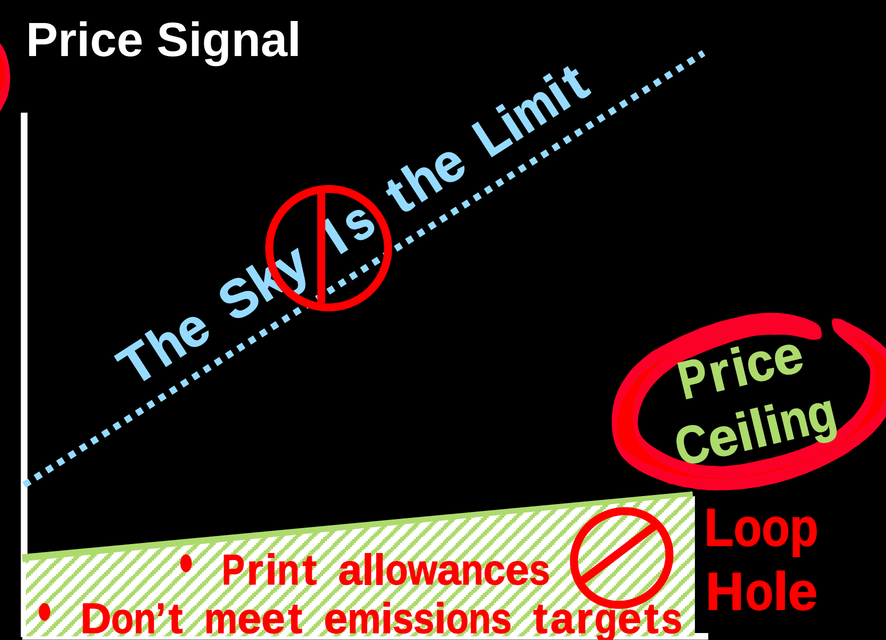
- **Avoids backlash over 'No bottom line'**

✓ **Provides investor certainty**

- **More certain price trajectory versus 'sky is the limit'**

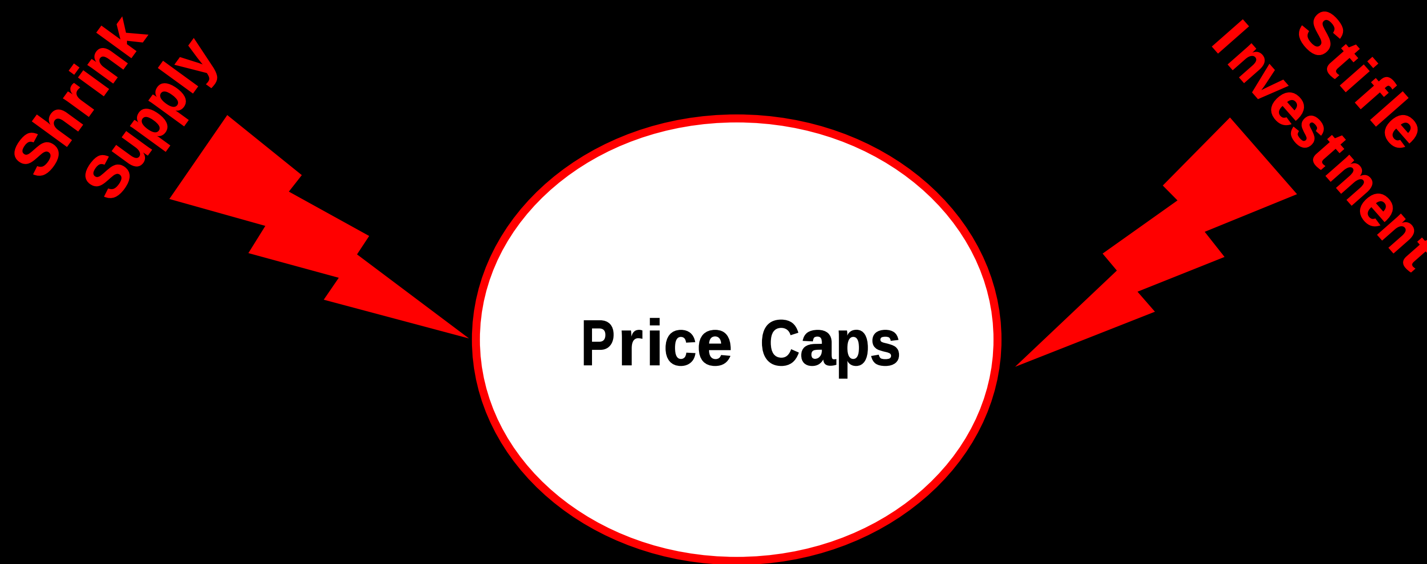
BUT

We can't set ceiling price too low



AND

Price Caps Don Normally Make Good Policy



World-Wide Cap and Trade?

BUT

When benefits / costs are uncertain

AND

World-wide cooperation is critical

Best Approach Is Known, Price Cap Trajectory

Price Signals

Price Signals Alone Will Not Stimulate Needed R&D

The Reason: Uncertainty…

- Stay the course?
- Size of the market – Will China participate?
- Legal and technical issues associated with sequestration, here and abroad

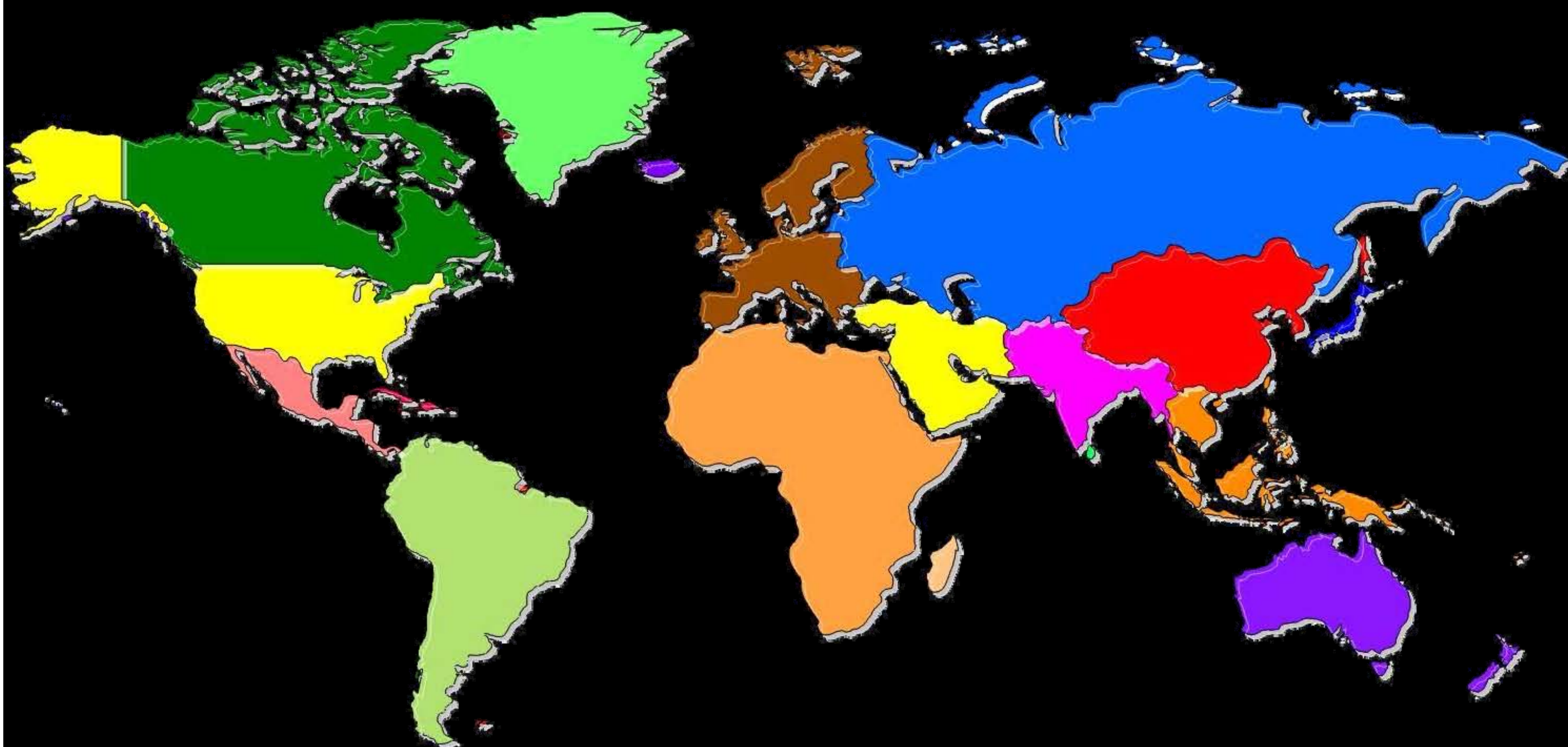
Past Delay Created 'Market Failure' and Now We Are Out of Time

…BUT, It Won't Be Easy

- Traditional R&D is inherently risk averse
  - Incremental scale up
  - Weed out "losers" early on before investing a lot of money
  - Conserve Scarce Funds
- An urgent problem requiring the fastest solution
- Demands a different approach to R&D

'Hard Truths'

The world's people share a <u>common</u> fate



The most significant threat in the electric sector has a common <u>solution</u>

"A Good Story Is a Miracle"

-- Stanley Kubrick

MIT Symposium on CCS Retrofit Technology

J. Wayne Leonard
Chairman and Chief Executive Officer
March 23, 2009

Entergy

Appendix
Views on Climate Change

Entergy Guiding Principles		Other Views
The risk is real; we need to act now to stabilize at 450 ppm: up to 80% reductions by 2050	→	***The science is too uncertain to justify the cost to the economy***
Use an economy-wide, market based approach (preferably cap and trade or tax) to find most efficient solutions	→	***We shouldn't act until the developing world agrees to limits***
We need to build in permanent low-income protection from the start, funded by CO_2 allowance sales or CO_2 tax revenues • **EITC or other rebates**	→	***Income inequality should be dealt with separately, not through environmental legislation***

Appendix
Views on Climate Change

Entergy Guiding Principles

We need a strong but sustainable price signal to stimulate investment in efficiency and new technology

- **Preferably cap and trade, with a high "price ceiling," or a CO_2 tax**
- **Either way, $50/ton by 2020-2025**

U.S. policy must be informed by global reality

- **Part of the solution will need to be a technology fix for existing coal plants**
- **Can't meet the goal through efficiency and/or renewables alone – or through new nuclear alone**

Other Views

Don't set a price signal until we have the control technology

$50 price is too high – it will kill the economy

$50 may be too low – don't set a "price ceiling" at all

"Climate Fed" to set the price

This is a plan for Entergy to get rich with its non-utility nuclear plants

We can solve the problem relatively cheaply by investing in efficiency and renewables

We should build new clean coal (IGCC) and nuclear to replace existing coal

SFA Pacific, Inc.
Technology & Economic Consultants

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Website: www.sfapacific.com

Near-Term Technologies for Retrofit CO_2 Capture and Storage of Existing Coal-fired Power Plants in the United States

White Paper for the MIT Coal Retrofit Symposium

May, 2009

Mr. Dale Simbeck
Ms. Waranya Roekpooritat

Summary

Coal-fired power plants, as large point sources of CO_2, are the logical choice for CO_2 mitigation, via CO_2 capture and storage (CCS) and other options. However, continuing life extension of the relatively old and inefficient fleet of existing United States (U.S.) coal power plants undermines potential CO_2 mitigation efforts.

New coal power plants, with CO_2 capture and geologic storage will slow the rate of growth of CO_2 emissions but the large existing fleet of coal power plants needs to be replaced with lower CO_2 power sources or retrofitted with CCS to significantly lower CO_2 emissions. In the near-term, and perhaps medium-term, there are inadequate non-coal, low- CO_2 emitting alternatives to replace the existing 50% coal-based electricity in the U.S. and 40% worldwide. Therefore to become serious about major CO_2 reductions, consideration should be given to CCS retrofits of existing coal power plants.

Existing coal plants represent approximately 33% of total U.S. CO_2 emissions. As such, the retrofit or rebuild of U.S. existing coal power plants with CCS represents significant opportunities for major CO_2 reductions. Retrofits and rebuilds, however, face many technical, economic and political challenges. The low cost electricity from these mostly paid-off (fully amortized) existing coal plants leads to very high CO_2 avoidance costs.

In addition, the simpler and less capital-intensive retrofit add-on for post-combustion CCS leads to large net efficiency and capacity losses. This type of retrofit will likely favor the newer supercritical steam cycle coal units that already have good SO_2 and NO_x controls. Rebuilds of the older subcritical steam cycle coal units have added advantages and flexibility. Due to the lower efficiency and generally higher SO_2, NO_x, Hg and particulate emissions of the older existing subcritical coal units, rebuilds can avoid most net efficiency and capacity losses while reducing all emissions to near zero. This is an important advantage. Rebuilds can come in the form of a state-of-the-art supercritical coal boiler steam cycle of post- or oxy- combustion CCS or an integrated gasification combined cycle (IGCC) for pre-combustion CCS. Combined cycle repower rebuilds can also be fueled with natural gas (without CCS) or off-site CCS based on coal gasification to synthetic natural gas or H_2. This enables major repowering capacity increases and CO_2 reductions at old coal plant sites considered hopeless for retrofit CCS.

Why Focus on Existing Coal-fired Power Plants?

A key conclusion in the 2001 SFA Pacific private multi-client CO_2 Mitigation Analysis was that coal-based electric power generators, as large single point sources of CO_2, would be forced to meet a disproportionate share of any anthropogenic CO_2 reductions. CO_2 reductions from vehicles are especially problematic and CO_2 emitting industries have, unfortunately, the opportunity to re-locate in countries that do not subscribe to major CO_2 reduction mandates. Various graphics describing the existing U.S. coal-fired power plant fleet are presented in the attached PowerPoint slides. These simple bar-chart graphics include sorts by age, unit sizes, locations (by state), owners, emissions and capital cost of retrofit add-on flue gas desulfurization SO_2 emission control by coal power plant size.

The existing U.S. coal power plant fleet has a summertime capacity of about 314 GWe or about 30% of total capacity yet generates about 50% of the entire U.S. annual electricity. Existing coal-fired power plants are relatively old, and have generally lower efficiency and higher emissions than proposed new state-of-the-art coal-fired power plants. For example, the typical existing coal-fired power in the U.S. as of 2005 EIA data was about 35 years old (on a capacity-weighted average), 33% efficiency (HHV) and only about 40% of this total capacity had SO_2 controls. The average CO_2 emissions are about 0.97 metric tons CO_2 per MW-hour of net electricity or about 20% higher than a new state-of-the-art coal power plant at 39-40% net HHV efficiency.

Most existing U.S. coal-fired power plants are pulverized coal (PC) boilers with subcritical steam cycles. The typical unit size is 500-700 MWe. Due to the age, many of these units were not originally built with SO_2 or NO_x controls. The 1990 Clean Air Act Amendments (CAAA) and the 2005 Clean Air Interstate Rule (CAIR) have led to a number of SO_2 scrubber flue gas desulfurization (FGD), and NO_x controls via selective catalytic reduction (SCR) retrofit additions to these existing coal-fired power plants. This is significant, as many CO_2 capture systems require removal of SO_2 before CO_2 capture or to meet CO_2 pipeline specifications. In addition, some post-combustion CO_2 capture systems favor SCR to reduce NO as it reacts with the CO_2 removal chemical solutions.

CO_2 mitigation poses unique issues and challenges for existing coal-fired power plants. The CO_2 avoidance costs for existing plants can be significantly higher than those for new power plants and, without policy or technology options existing plants will face high CO_2 taxes sufficient to incentivize CO_2 reductions via fuel switching or CO_2 capture and storage (CCS).

Coal-fired power plant locations present additional challenges to existing plants and complicate CCS options, as many plants are not located near good geologic formations for effective CO_2 storage. Costs and successful permitting of long CO_2 pipelines in the higher population density States east of the Mississippi River (where most existing U.S. coal power plants are located) are a major challenge. Furthermore, many of these existing coal-fired power plants have serious space limitations. Space limitations are most severe for existing coal power plants that have already added retrofit or require additional flue gas SO_2 and NO_x control retrofit before adding post-combustion CO_2 capture add-on retrofit.

Status of the Existing U.S. Coal-fired Power Plants
After renewable wind and nuclear power, coal-based power plants generally have the lowest marginal load dispatch power costs. Even older, less efficient existing coal power plants normally have lower power dispatch costs that the most efficient new natural gas combined cycle (NGCC) power plant. This is due to the much lower fuel energy price (dollars per million BTU) of coal compared to natural gas. Less than 10% of U.S. installed coal capacity is under 20 years old; as such the high capital costs associated with original plant construction have been paid off, making the total cost of coal-fired electric power quite low. The coal-based fleet's age and its large power generation share give the U.S. some of the lowest electric power prices in the world.

The current political climate of continuing uncertainty regarding long-term CO_2 mitigation further encourages life extension of existing coal-fired power plants. Existing plant owners face substantial revenue losses and opportunities to accumulate CO_2 reduction credits if they shut down older plants in advance of CO_2 reduction mandates. That is especially true if CO_2 mitigation develops as a "cap and trade" system with large, low-cost, CO_2 allocations to existing coal-fired power generators (as in the past with U.S. SO_2 reduction system).

As such, most existing coal power plant sites, with established locations, cooling water, permits, rights of way, proximity to coal and power delivery infrastructures, are simply too valuable to abandon. In fact, many of the old coal plants are strategically located in the existing electric grid transmission and distribution system. In addition, the time, cost and effort associated with developing new "greenfield" coal power plants sites is likely much greater than to ultimately upgrade or recycle these existing power plant sites. Most existing coal power plant modification, upgrades, retrofits or rebuilds significantly reduce the site emissions, making permitting and pubic acceptance very favorable.

The new U.S. EIA 2009 Annual Energy Outlook projects cumulative retirements of only 2.3 GWe (just 0.7%) of the existing 314 GWe coal power plant capacity in the U.S over the next 20 years assuming business as usual (no CO_2 reduction mandates). This continuing life extension of the old existing coal power plants is politically and economically logical. The key issue is how these old coal power plant sites are best utilized if CO_2 reduction mandates develop.

CO_2 Mitigation Options for Existing Coal-fired Power Plants

In addition to nuclear and renewable hydro/wind/solar replacement of coal-based power, there are three general options for existing coal power plants CO_2 mitigation as follows:

1. Replace coal with a lower carbon fuel like biomass or especially natural gas.
2. Increase the efficiency of the coal-to-electricity generation.
3. CO_2 capture and storage (CCS) from coal utilization

Each option has its own attributes and special issues specific to existing coal-fired power plant applications.

Replacement of coal with biomass is most likely the lowest *capital* cost option. This option, however, has high *fuel* costs and faces potential limits on biomass supplies. Annual supplies of sustainable biomass at reasonable collection, transportation and storage costs are a major challenge, especially for existing coal power plants. This generally limits coal replacement with biomass at existing coal power plants to seasonal co-firing at relatively small amounts (perhaps 5-10% of total annual energy). Biomass based power likely favors new power plants strategically located relative to existing biomass sources and improved new biomass production. Even then, year-round supply limits, high transportation and storage costs plus economy-of-scale generally favor co-processing with coal. More effective biomass utilization also favors fluidized bed combustion (FBC) boilers due to their advantages processing high moisture and hard to feed biofuels plus superior fuel flexibility. Finland has become the world leader in fuel-flexible biomass, peat and coal FBC boiler power generation.

Replacement of coal with natural gas repowering has much greater potential than the biomass option. This generally favors 100% coal replacement and requires more capital to "brownfield" rebuild the old coal plant into a clean, high efficiency natural gas combined cycle (NGCC). NGCC repowering can increase the old coal steam cycle capacity by 300%. However, the long-term natural gas supply and price risks are large. Major coal replacements with NGCC would stress natural gas supplies. *Replacing all the current coal generation in the United States with natural gas would require 17 trillion cubic feet per year of additional natural gas or a 60% supply increase.* That would lead to higher natural gas prices with marginal supplies and prices set by imported LNG. Recent LNG contracts in Korea and Japan are at world oil price energy price parity and reliable estimates of future world oil prices are impossible to predict. More importantly, many believe that if a carbon constrained world develops the big surge in natural gas demand for coal power generation replacement would drive natural gas energy prices to even higher levels than crude oil. That is because the CO_2 generated per unit of energy of natural gas is over 20% lower than of crude oil.

Increasing coal-to-electric efficiency can be achieved in many ways but can be economically, politically and technically complex. The simplest option is a minor upgrade of the old coal-fired power plant to slightly higher steam quality (mainly higher steam superheat and reheat temperatures) plus rebuilding the steam turbine and electric generator for the higher quality steam. This upgrade can increase the net absolute efficiency by about 2% (perhaps from 33% to 35%) at moderate costs. However, the relative efficiency increase and CO_2 reduction per MW is only about 6%. More problematic, a minor upgrade such as this may trigger the New Source Review provisions of the Clean Air Act, necessitating major emissions upgrades. Adding a new higher efficiency wet FGD and SCR would greatly increase costs and CO_2 emission due to increased parasitic power (reducing net efficiency) and increased CO_2 emissions from the limestone reaction in the FGD.

A more expensive but higher efficiency option is a total coal power plant rebuild at the existing old PC site to a clean, high efficiency supercritical PC boiler steam cycle or integrated gasification combined cycle (IGCC). Current capital costs and availability estimates would likely favor the supercritical PC boiler steam cycle along with effective flue gas SO_2 and NO_x controls. A coal power plant rebuild can increase the net absolute efficiency by 6-8% (from perhaps 33% to 40%) for a "relative" efficiency increase of about 20%. Nevertheless, the large capital costs for only a 20% CO_2 reduction usually results in very high costs of CO_2 avoidance, discussed in a later section.

Highest efficiency improvements would be achieved through the replacement of separate direct heat uses and central power plants with effective cogeneration or combined heat and power (CHP). This can increase power generation efficiency from 33% to over 80%. The potential market size and efficiency potential of effective cogeneration can be larger than is generally appreciated. For example consider a 1991 study in Japan by the Japan Gas Association. The study estimated that by just converting existing Japanese industrial steam boiler capacity to heat recovery steam generators (HRSG) behind gas turbine power generation, the cogeneration electric power would represent a 16% national energy saving relative to separate Japanese industrial boilers and central power plants. The CO_2 reduction was estimated at 50 million metric tons per year.

Effective cogeneration is, however, economically, technically and politically complex. To have significant annual benefit cogeneration requires large baseload “heat hosts”. Distributed power generation applications are usually small and just seasonal cycling load cogeneration. The available big baseload heat hosts are limited but do exist at select, large energy intensive industrial applications such as large oil refineries, chemical plants and especially steam stimulation heavy oil production. For example, cogeneration power has increased in just 8 years from only 5% to over 28% of total electric power generation in Alberta, Canada due to deregulations and cogeneration of steam for oil sands steam assisted gravity drain (SAGD) production. Effective cogeneration also favors the use of gas turbines over steam turbines since cogeneration is usually heat host “limited”. For a given heat host, gas turbines can generate 5-10 times more electricity than with a steam turbine in total high efficiency cogeneration (no heat to a condenser or cooling tower). This also greatly reduces the water requirements.

Gas turbine based cogeneration generally means the use of natural gas. “Syngas” generated through coal gasification can also be used in gas turbine based cogeneration. Most commercial gasification plants are utilized for just high value H_2 or H_2/CO based chemicals (like ammonia) or premium fuels (like SNG, gasoline, jet fuel or diesel). Effective polygeneration of large cogen power sales to the grid and syngas chemicals is possible and would improve economics. However this would generally require new coal gasification facilities at the site of the big industrial heat hosts and unprecedented cooperation of coal-based electric generators with oil and chemical companies. Traditional electric utilities prefer to control and own their power generators, especially big revenue baseload capacity.

The final CO_2 mitigation option and focus of this white paper is CO_2 capture and storage (CCS). There are three key steps in CCS:

1. Separating, recovering or capturing the CO_2 into a relatively pure gas stream
2. Compressing this relatively pure CO_2 gas stream to high-pressure supercritical conditions where it is very dense and has physical properties more like liquid than gas.
3. Pipeline transportation and well injection of this supercritical CO_2 into geologic formations much like pipeline transport and well injection storage of natural gas.

The costs of CCS are generally 50% for capture, 25% for compression and 25% for transportation, injection and monitoring. The CO_2 compression and transportation, injection and monitoring steps and costs are very similar for all CO_2 capture options. However, there are three very different process options to CO_2 capture:

1. Post-combustion
2. Pre-combustion
3. Oxy-combustion

Post-combustion is the simplest and generally considered the first choice for CO_2 capture add-on retrofit to existing coal-fired power plants. It is generally viewed as similar to common flue gas desulfurization (FGD) add-on retrofits to existing coal power plants. However, there is 50-500 times more CO_2 than SO_2 in coal combustion flue gas. More importantly, CO_2 capture requires much more energy and parasitic power than FGD. The overall net efficiency and capacity losses of post-combustion CO_2 capture are high, currently in the range of 30%. This means an existing coal power plant at 33% net efficiency and 300 MWe net capacity drops to only about 23% efficiency and 210 MWe by adding post-combustion CCS (including the CO_2 compression parasitic power).

As the name implies, post-combustion CCS is a flue gas CO_2 capture process. After coal combustion with air, the nitrogen-rich flue gas is normally at low atmospheric pressure and still contains several percent of oxygen. The CO_2 is scrubbed out of the flue gas with a liquid chemical solvent. This is usually called the CO_2 absorber and is about the same size as a wet SO_2 FGD absorber. The low CO_2 partial pressure (volume fraction CO_2 in and especially out times total absolute pressure) in the flue gas requires a strong chemical reaction solvent. The chemical is usually a basic amine to react with the acidic CO_2. The presence of oxygen limits the choice to just a select few amines and requires a special additive for high CO_2 loading of the amine. Also most amines will react and degrade with any SO_2 or NO in the flue gas. Thus essentially all the SO_2 and NO_x are removed from the raw flue gas before post-combustion CCS. SO_2 removal is usually via a conventional wet limestone FGD followed by a second special caustic wash to remove the last few percent of SO_2.

The amine leaving the CO_2 absorber, now rich in CO_2, is then heated to regenerate the amine and drive off the captured CO_2 at near atmosphere pressure. This requires a significant amount of low-pressure steam as the heat source and is called the CO_2 stripper. This steam is extracted from the low-pressure section of the big reheat steam turbine to minimize the steam cycle efficiency losses. There is also heat exchange between the CO_2 lean and rich amine going to and from the CO_2 absorber and stripper. Nevertheless, the 1-2 tons of low-pressure steam per ton CO_2 capture leads to a significant loss in the steam turbine output and overall plant efficiency.

Pre-combustion is basically using gasification to convert the coal into first H_2 and CO, and then reacting the CO with H_2O to mostly H_2 and CO_2 ─ called the water-gas CO shift reaction. Coal gasification to H_2 with nearly total CO_2 capture (removal) is commercially well proven, used in over 30 GWt (thermal syngas capacity) of coal-based hydrogen and ammonia plants worldwide.

Similar to natural gas replacement of coal, the conversion of coal into hydrogen for pre-combustion CCS favors the use of this clean (but expensive) fuel gas in a modern gas turbine based combined cycle. Grafting pre-combustion CCS onto an existing coal-fired power plant would require an almost total brownfield site rebuild into an IGCC with an H_2-rich syngas-fired gas turbine. Thus this is a high capital cost, complex and highly integrated option. Also the commercial experience of combusting H_2-rich syngas in modern high temperature (F class) gas turbines is limited to just a few oil refineries and chemical plants. Therefore, pre-combustion

CCS IGCC is viewed as a developmental, chemically complex, and high risk technology by most existing coal power plant owners.

The economics of coal gasification generally favor high pressure operating with oxygen (not air). This is due to capital saving with half as much volume of raw syngas to be processed in expensive gasifiers, syngas coolers and syngas conditioning if oxygen blown. This also means the CO_2 partial pressure (volume fraction CO_2 in and especially out times total absolute pressure) is very high and the CO_2 absorber vessels are quite small. The high pressure CO_2 absorber also enables the use of physical solvent to capture the CO_2. This means little or no stripping steam, dry CO_2 and CO_2 stripping/flashing at slight pressure to slightly reduce the CO_2 compressor power. Thus the CO_2 capture net efficiency and capacity losses are noticeably lower for pre-combustion than post combustion CCS.

Oxy-combustion, as the name implies, is simply combustion of coal with pure oxygen in place of air. However, that requires massive oxygen production, about 2.5 times more pure oxygen than required for pre-combustion CCS. The electric power requirements for large cryogenic air separation units (ASU) to produce oxygen, lead to a large loss in net efficiency and net capacity, about the same as for post-combustion at 30% loss. Oxy-combustion is the least developed of the three CCS options. Nevertheless oxy-combustion is of great interest by many existing coal power plant owners due to its lack of chemical processes and "theoretical" potential of avoiding SO_2, NO_x and Hg controls by geologic storage of a "dirty" CO_2.

The general approach of oxy-combustion CCS for existing coal-fired power plant retrofit is to recycle enough CO_2-rich flue gas to match the mass flow of the original air-fired boiler. This should minimize changes in existing heat-transfer profile and equipment. However, this large flue gas recycle may create issues associated with increased SO_2 and H_2O in the boiler that may require their removal from the recycle flue gas. There are also challenges associated with compressing as well as pipeline standards and storage issues of dirty CO_2. The general view is that the 1-3% O_2 plus H_2O, SO_2, NO_x and Hg will have to be recovered from the dirty raw CO_2 flue gas before compression. In addition, the several percent N_2 in the CO_2 from the negative pressure boiler air leakage and the air separation leads to higher slightly higher CO_2 compression for supercritical CO_2.

Rebuilds versus Retrofits

As briefly mentioned in the previous section, some of the CO_2 mitigation options require major rebuilds, not just add-on retrofits. Specifically, conversion of an existing coal-fired power plant to natural gas (with or without CCS) or continuing coal use via pre-combustion CCS requires major brownfield site rebuilds to NGCC or IGCC. These rebuild conversions from the existing coal steam cycle to a combined cycle are commonly referred to as repowering even when the old steam turbine and generator is replaced.

In addition, post- and oxy- combustion CCS can sometimes favor major rebuilds over simple retrofits. Retrofits require significantly less total capital. However, retrofits also suffer from significant loss of net efficiency and capacity. The costs and source of that lost generation capacity replacement must ultimately be accounted for. Furthermore, retrofitting means that most of the power plant key equipment is still relatively old.

Rebuilding the old subcritical PC units into state-of-the-art supercritical PC boiler or IGCC, both with CCS may have a key advantage. Specifically it minimizes or even avoids any net efficiency or capacity losses of adding CCS. That is because of the higher efficiency and capacity of the new supercritical PC or IGCC (before adding CCS) compared with the relatively low efficiency of the old subcritical PC power plants. That might be a very important advantage to gain public support for CCS. Non Governmental Organizations (NGOs) dislike converting a low efficiency (say 33%) coal power plant into embarrassingly low efficiency (say 22%) retrofit coal plant with CCS. The rebuild option can avoid capacity and efficiency losses relative to the existing coal power plant, while at the same time reducing all emissions. Rebuilds also assure that the entire power plant is new, not just the CCS.

Economics of CO_2 Mitigation for Existing Coal Power Plants

The single most important issue is the cost of CO_2 mitigation. The electricity cost, especially from existing coal-fired power plants, will significantly increase for any meaningful CO_2 reduction. In fact, due to the lower electricity cost from existing paid-off coal power plants, CO_2 avoidance costs are likely higher for these old coal power plants than for proposed new coal power plants.

Attached are two sets of comparative screening analysis spreadsheet outputs calculating costs and performance of various CO_2 reduction options for a baseline existing paid-off subcritical PC boiler power plants. Feedstock options include coal and natural gas both without and with CCS as well as simple retrofit add-on and major rebuilds. All key input assumptions and results are clearly shown to assure maximum objectively via relative transparency. By maintaining the same coal feedrate (even for rebuilds) the absolute performance of retrofit versus rebuild as well as without versus with CCS is directly apparent. The natural gas option was set at the same net capacity as the baseline existing coal plant and its feedrate was also kept constant to show the losses of CCS.

The assumed natural gas price is always a key issue when analyzing the costs of CO_2 mitigation versus coal options. Natural gas prices were varied to "breakeven" prices where the power costs are the same for both coal and natural gas. This means at higher natural gas market prices than these breakeven prices, coal is a cheaper option.

Key inputs and results are shown on the first page summary sheet for each of the two model runs. The following pages are more detailed data for each specific option. The details for each option include a simple process flow diagram (with major energy, mass and volume flows), capital cost build-up from the process units costs and product electric costs (including a simple annual capital charge rate of 15% or a 6.7 year payback of all new capital costs). A key assumption is that the baseline existing coal power plant is paid-off, thus it has relatively low power costs due to the lack of capital charges. The baseline power costs and CO_2 emissions strongly influence CO_2 mitigation costs.

The first run of the comparative screening model assumes no CO_2 emissions tax and is used to calculate the CO_2 avoidance cost of each option. CO_2 avoidance is very useful as it is the CO_2 tax required for each specific CO_2 mitigation option to start becoming economical. This is the easiest way to rank the many options, as the lower CO_2 avoidance costs are the more economical options relative to the baseline. The CO_2 avoidance formula where (b) is the baseline and the other cost and emission units are for each specific option as follows:

$$\$/\text{mt } CO_2 \text{ avoidance} = [\text{mt } CO_2/\text{MWh(b)} - \text{mt } CO_2/\text{MWh}] / [\$/\text{MWh} - \$/\text{MWh(b)}]$$

The CO_2 avoidance results show that all CO_2 options significantly increase power costs due to the low cost power baseline of a paid-off coal unit. Of the CCS cases, the simple retrofit post-combustion add-on was slightly cheaper than the more capital intensive but better performance rebuilds. However, this model does not take into account the lost generation capacity and shorter remaining life of the retrofit versus rebuild. Nevertheless, this lowest CCS CO_2 avoidance cost was still relatively high at $74 per metric ton (mt) CO_2. CO_2 avoidance costs for new coal plant baseline are typically $30-50 per ton CO_2. The lower CO_2 avoidance costs are mainly due to the much higher baseline power costs of a new coal plants with large capital charges. Of the cases without CCS, the NGCC rebuild was competitive with coal adding CCS until the natural gas price is above $8.31 per million Btu (as per cost model run two). Cost model run one of $7.65 per million Btu NG price is just where NGCC and rebuilt PC has the same power cost without a CO_2 tax. The supercritical PC rebuild without CCS was the most expensive CO_2 avoidance cost due to the relatively low CO_2 reduction for a moderately large capital investment.

The second run of the screening model includes an input CO_2 tax based on the lowest coal-based CO_2 avoidance cost from the first cost model run of $74 per metric ton CO_2 emissions. This makes all the power costs high whether doing nothing but paying the CO_2 tax, converting to natural gas or adding CCS. The economic ranking of options is the same as the first run. However this model run makes it clearer why higher CO_2 taxes are required to economically encourage existing coal-fired power plant owners' to reduce CO_2 emissions.

Another important result of this second model run is the "triple point", which is where the power costs are the same (at the input CO_2 tax and natural gas price) for the three key options:

1. Doing nothing - continue using coal as is without CCS but pay the high CO_2 tax. This is low capital, low risk but has high operating costs due to the high CO_2 emissions.
2. Convert to natural gas without CCS but pay about a 60% less CO_2 tax. This is a low capital cost option to a clean, efficient, new power plant but has the risk of future natural gas supplies and prices.
3. Continue using coal but add CCS to avoid most of the CO_2 tax. This is high capital cost option, especially rebuilding to a new more efficient coal power plant. There is also long-term CO_2 storage liability risk but this option provides low operating costs and the largest CO_2 reduction.

The natural gas breakeven price for this triple power was only $8.31 per million Btu. This is quite low as the breakeven natural gas triple point for new coal power plant baseline is usually greater than $12 per million Btu. The low natural gas breakeven price appears mostly due to the high CO_2 tax required to economically encourage existing coal power plants to reduce CO_2.

Again, this second model run does not take into account the lost generation capacity and shorter remaining life of the retrofit versus the rebuilt power plant. This means the lowest cost retrofit add-on of post-combustion CCS to an old coal power plant may not be the best in the longer term. As discussed previously, the higher capital plant rebuilds avoid most of the efficiency and capacity losses.

Outlook for Existing Coal-Fired Power Plant CCS

Existing coal-fired power plants are commonly ignored in the analysis of CO_2 mitigation and CCS. This is because they are so technically and economically challenging plus very site specific. Nevertheless, this simple analysis suggests several important conclusions relative to existing coal power plants:

- The existing U.S. coal power plant fleet is relatively old, inefficient and dirty. However, the current surge of retrofit add-on SO_2 and NO_x controls due to the 2005 CAIR will greatly reduce SO_2 and NO_x emissions. Nevertheless, these retrofits will also reduce the existing coal fleet's over-all efficiency from about 33 to 32% plus there is added CO_2 emission from the limestone used in FGD for an even higher CO_2 per MWh of electricity.
- The new EIA AEO 2009 projects that from now to 2030 with business as usually only 2.3 GW of existing coal power plant retirements and 24.8 GW of new coal power plants will be added for net coal capacity increase of 7%. However, coal based power generation is projected to increase by 18%. This clearly suggests that uncertainty in future CO_2 mandates and the low marginal load dispatch costs of coal units encourage both life extension and increased generation from our aging inefficient existing coal fleet.
- Most existing coal power plant sites are likely too valuable to ever abandon due to location, existing permits and infrastructure. The issue is whether to continue life extending forever with just retrofit add-on flue gas controls as mandated or rebuild to a modern higher efficiency and capacity coal or NGCC power plant.
- The cost of CCS is high due to the large investment plus significant loss of net efficiency and capacity. CCS also has the added challenge for existing coal power plant sites that in many cases are not near good CO_2 storage sites.
- CO_2 avoidance costs appear higher and breakeven natural gas price alternatives (convert from coal to gas) appear lower for existing coal power plants than for proposed new coal power plants. This appears mostly due to the low baseline power costs from paid-off coal power plants.
- Retrofit of existing coal power plants with add-on post combustion CCS has the lowest capital and CO_2 avoidance costs of all the CCS options if the impact of the roughly 30% efficiency and capacity losses and shorter remaining plant life are ignored. Post-combustion CCS has big space requirements, which could be a major limitation.
- Rebuilding (supercritical PC or IGCC) with added CCS on older existing coal power plant sites can avoid most of the net efficiency and capacity losses (relative to the old, less efficiency subcritical PC). It can also solve the space limitation issues of added on retrofit. However these are higher total capital costs options.

Policies and technologies for mitigating CO_2 emissions from existing plants where CCS is not an economically feasible option, should be a high priority. These are the many existing coal power plants situated in locations that are too far from good CO_2 storage sites. In addition many existing coal power plants are located in urban population areas where permitting even short CO_2 pipelines to good CO_2 storage sites make CCS impossible. There are also relatively small coal power plants that are just too small for CCS. For example, there are 22 GW of less than 100 MW size plants and 42 GW of just 100-200 MW size existing coal power plants.

These sites may present the best opportunities for natural gas repowering which can reduce the CO_2 emission per MWh by about 60% while also increasing capacity by a factor of 3. In addition, to control long-term natural gas prices and supply risks synthetic natural gas from coal with CCS could be considered. This would be similar to the commercial Dakota coal gasification SNG plant but with better gasifiers. As these industrial gasification plants have a large pure CO_2 vent regardless of the CO_2 mitigation issue, the incremental costs of CCS are much less than for coal power plants.

Retrofits favor the newer supercritical coal units. Newer coal plants have higher efficiency, longer life spans and most already have good SO_2 and NO_x controls. Options for these plants will be defined by their locations relative to good storage sites and the availability of space to add the post combustion add-on CO_2 absorbers plus the CO_2 stripper and compressor as well as the added cooling towers. The CCS space requirements appear to be similar to add-on FGD. Reviewing several studies suggests a 500 MW gross or 350 MW net (after CCS losses) retrofit post-combustion CCS requires about 4-5 acres. There are ways to minimize space requirements, but they come at higher costs; options include placing the CO_2 absorber in the base of a new wet stack, which is sometimes done for FGD retrofits tight on space.

Rebuilds favor older subcritical coal units. Although the added new capital costs of rebuilds are much higher than retrofits, the CO_2 avoidance costs of rebuilds are closer to those of retrofits. More importantly, the rebuilds with CCS avoid most of the efficiency and capacity losses at the same time they enable the conversion of an existing site to a new coal power plant with almost zero emissions; there is significant cost and value associated with the ease of permitting of such rebuilds relative to those associated with a new greenfield plant with CCS, and with the lower costs of existing coal, water and transmission infrastructures.

Rebuilds can also avoid space limitations and even increase capacity at existing coal plant sites in addition to avoiding most of the efficiency losses of CCS. There are many rebuild options. For post and oxy combustion rebuilds the steam cycle should be converted to state-of-the-art supercritical for the large gain in efficiency over the old subcritical steam cycle. Post combustion CCS can stack SO_2 and CO_2 absorbers in the base of the new stack to save space. Oxy combustion CCS can locate the large air separation unit oxygen plants off-site with a short oxygen pipeline.

Post combustion CCS – H_2-fired IGCC has the added rebuild potential of even off-siting the location of all but the repowered combined cycle. A pipeline of high pressure H_2 (and N_2, if needed) could be transported a moderate distance with the gasification plant located at an optimal site for CO_2 storage or CO_2 pipeline permitting.

Run: 1 - CO2 Avoidance Costs

Summary of Options CO2 Avoidance Costs For Existing Coal Power Plant Baseline

Natural gas price set so the same power costs for replacement NGCC or PC both without CCS & no CO2 tax

Case Number	CO2 Mitigation Options - all built at old PC site	Net MWe	New Capital mid-2008 Millions	constant $ $/kWe	Net Efficiency % HHV	CO2 Emissions mt/MWhe	CO2 Avoidance $/mt CO2	Power Cost mid-2008 $/MWh
O-PC	**Baseline Paid-off Old Coal Plant - no CCS** sub PC with FGD size set to NGCC MW	543	Paid off	Paid off	33.6%	0.95	Baseline	$ 36.8
O-PC-C1	**Old PC & ST with new Post CCS add-on** new small BT ST + MHI amine CO2 scrubber	398	$ 528	$ 1,325	24.7%	0.13	$ 74	$ 97.9
O-PC-C2	**Old PC + upgrade & new Post CCS add-on** rebuild SH/RH + sub ST/gen & MHI amine scrubber	418	$ 755	$ 1,807	25.9%	0.12	$ 79	$ 102.4
NGCC	**Replacement NGCC - no CCS** "F" class NGCC with SCR no CO2 Capture	543	$ 540	$ 993	50.7%	0.36	$ 67	$ 76.2
NGCC-C	**Replacement NGCC with Post CO2 Capture** "F' class GT with MHI amine CO2 scrubber	463	$ 836	$ 1,805	43.3%	0.06	$ 83	$ 110.7
N-PC	**Rebuild SC-PC Power Plant - no CCS** Supercritical PC + FGD & SCR - not CO2 Capture	630	$ 1,354	$ 2,151	39.0%	0.82	$ 302	$ 76.2
N-PC-C	**Rebuild SC-PC with Post CO2 Capture** Supercritical PC with MHI amine CO2 Scrubber	499	$ 1,765	$ 3,537	30.9%	0.10	$ 111	$ 130.8
N-OPC-C	**Rebuild SC-PC with Oxyfuel CO2 Capture** Supercritical PC with oxygen & flue gas recycle	485	$ 1,644	$ 3,389	30.1%	0.07	$ 104	$ 128.0
IGCC-C	**Repower H2-IGCC Pre-comb CO2 Capture** HP GE Gasifier with quench, CO shift & H2/N2-fired GE 7FB GT	517	$ 1,667	$ 3,224	32.0%	0.08	$ 94	$ 119.5

Does not account for power replacement of net drop from the original 543 MWe plus shorter remaining life of the old PC

Input Capital Cost Variables

General Facilities for rebuild/retrofit at existing PC site	25%	of New Installed Process unit capital	**existing site saving???**
Engineering, Startup & Working Cap	15%	of New Installed Process unit capital	
Contingencies	10%	of New Installed Process unit capital	
Inflation adjustment from mid-2004 dollars	650	Ch. Eng. index for mid-2008	**constant $**
Location adjustment	115%	of U.S. Gulf Coast costs to cover extra 10% for CCS risk	

Note: this analysis does not include owner's costs or allowance for funds during construction (AFDC) being capitalized

Input Operating Cost Variables

Average annual capacity factor of all options at	85%	NG can be lower due to its higher marginal dispatch cost		
Capital charges (if capitalize AFDC, lower for same return)	15.0%	/yr of total capital or	**6.67**	yr capital payback
Non-Fuel O&M Costs	4.5%	/yr of total capital less	1.0%	for NGCC
Illinois Bit in Midwest min. shipping	$ 2.00	per million Btu HHV or	$ 48.43	per mt raw coal
Same coal input for <u>all</u> coal cases set at O-PC = NGCC	174.5	mt/hr raw coal design or	1,613	MWt HHV coal input
Breakeven NG price for NGCC= N-PC both wo CCS & no CO2 tax	**$ 7.65**	per million Btu HHV	**NG prices should go up if CO2 tax**	
Breakeven NG price will likely change if high enough CO2 tax to make CO2 capture cost effective				
Natural gas input set to fill 2-7FB GT at	3,654	million Btu/hr HHV	1,071	MWt HHV NG input
CO2 pipeline, injection & monitoring, high due to old PC locations	$ 15.00	/mt ton CO2 or	$ 0.79	per 1,000 scf HP CO2
Limestone minimal shipping	$ 30	/mt		
"what if" minimal gypsum or sulfur byproduct credits	$ (5.00)	/mt gypsum or	$ (26.88)	/mt sulfur equivalent
"what if" NOx emissions requires purchased credits at	$ 2,000	/mt as NO2		
"what if" SO2 emissions requires purchased credits at	$ 1,000	/mt SO2		
"what if" Hg emissions requires purchased credits at	$ 20,000	/lb Hg		
CO2 emissions tax at zero to calculate CO2 Avoidance Cost	**$ -**	**/mt CO2 or**	$ -	per mt carbon equivalent

Must set CO2 emissions tax at zero to calculate CO2 avoidance costs, thus all CCS cases have much high power costs

CO2 avoidance is the lowest CO2 tax where paying the tax or reducing CO2 emissions (with NG or CCS) are the same power costs

A Research Program for Promising Retrofit Technologies

Prepared for the
MIT Symposium on Retro-fitting of
Coal-Fired Power Plants for Carbon Capture

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1. Background and Motivation

The commercialization of Carbon Capture and Storage (CCS) technologies is a significant challenge. It is a difficult enough task on new coal-fired plants, but even a greater challenge for retro-fitting existing plants. This is for several reasons, including:

- Availability of adequate space
- Restrictions caused by the existing plant layout
- Lower efficiency of older plants
- Difficulty in optimizing design, especially concerning the extraction of turbine steam

Today, the only proven CCS capture technology is amine scrubbing. In some ways it works very well – it is highly selective for CO_2 and has recovery rates above 90%. However, it is also very energy intensive. For a new plant, it will reduce the pant output by 25-30%. While this may be acceptable on a new high efficiency power plant, it makes retro-fitting older, less efficient plants very difficult. For example, an existing plant with 35% efficiency when retrofitted with CCS will have its efficiency reduced to 20-25%. This is a very expensive proposition.

If we are going to meet stated emission reduction goals of 50-80% by 2050, the emissions from existing coal plants must be addressed. While the first step may be efficiency improvements[1], this is not sufficient. In the long run, the existing coal plants will either have to be shut down or retrofitted with CCS if we are to meet the emissions targets stated above.

In summary, we cannot ignore emissions from the existing (and growing) coal fleet. If we want to continue to operate these plants, we must retrofit them with CCS. However, current technologies may extract too high a price. Therefore, it is an important research goal to develop new CCS technologies appropriate for retrofits. As discussed below, this is a very challenging goal.

There are two primary approaches to capturing CO_2 from existing plants. The first is post-combustion capture, which includes amine scrubbing. The second option is oxy combustion capture. They are each reviewed in the following two sections. The final section of this paper will address RD&D recommendations.

2. Post-Combustion Capture Technologies

Post-combustion capture technologies are reviewed in a White Paper prepared for the Clean Air Task Force under a grant from the Doris Duke Foundation (Herzog *et al*., 2009). A brief summary follows.

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[1] When doing CCS, efficiency improvements are an important first step. Reducing the amount of CO_2 per kWh reduces the cost of CCS.

At a coal-fired power plant, CO_2 is a component of the flue gas. The total pressure of the flue gas is 1 atm and the CO_2 concentration is typically 10-15%. The process of transforming this low pressure, low concentration CO_2 into a relatively pure CO_2 stream is referred to as post-combustion CO_2 capture. This capture step is typically followed by a compression step, where, for ease of transport (usually by pipeline) and storage, the CO_2 is compressed to 100 atm or more.

The only commercially available technology for post-combustion technologies is the amine chemical absorption process. All commercial amine processes can work with gas-fired power plants, but today only a subset can work on coal-fired power plants. A coal plant flue gas is more difficult to handle because of the pollutants it contains, primarily particulate matter and SO_2. Amine plants have been built to the scale of 1,000 tons of CO_2 per day. An additional order of magnitude scale-up would be required for typical coal-fired power plants, but this should pose no major technical hurdles.

The first amine processes were based on monoethanolamine (MEA) with inhibitors added to prevent degradation and corrosion. Some of the newer processes are based on mixed amines or hindered amines in an attempt to reduce the parasitic energy requirement of the capture process. One challenge is that solvents with lower the energy requirements generally exhibit slower absorption rates. Current research includes investigating the use of the additives like piperazine so one can use an amine mixture that lowers the energy requirement without significantly slowing down the CO_2 absorption rate.

Alternate chemical absorption processes are being investigated. The most prominent efforts are using an ammonia solvent. Compared to amines, ammonia may be able to significantly lower the parasitic energy requirement. However, it presents the challenge of lower absorption kinetics and the need to control the “ammonia slip” (ammonia vapor escaping the process either in the clean flue gas or the captured CO_2).

Membrane and pressure swing adsorption processes have also been suggested. However, in general, they cannot compete with amine scrubbing. The reason is that they rely on a partial pressure driving force. Since CO_2 in the flue gas of a coal-fired power plant has a partial pressure of 0.1-0.15 atm (10-15% concentration, total pressure of 1 atm), membrane and pressure swing adsorption processes are generally impractical. However, membrane technology has successfully been used in combination with chemical absorption processes, but these processes rely on absorption and not membranes to do the separation.

Biomimetic approaches take their cues from living systems that have evolved highly efficient systems for capturing and/or converting CO_2. These include the use of the enzyme carbonic anhydrase, an efficient catalyst of CO_2 reaction with water, as well as microalgae systems because *they consume* CO_2 in photosynthesis. Another approach that has been proposed is to cool the flue gas to low temperatures so that the CO_2 is separated as dry ice.

A relatively new area of investigation involves structured materials, possibly stimuli-responsive, that can have entropic (e.g., shape selective) rather than enthalpic interactions between the sorbate and the separations media. This could lead to a significant reduction of the parasitic energy requirement. These materials could work through the application of stimuli, e.g., an electric field, to modify the separation environment in order to release the captured solute (as opposed to temperature swing). These materials include specialized adsorbents with finely controlled structure (e.g., metal-organic frameworks and ZIFs), the functionalization of adsorbent surfaces (e.g., fibrous matrices, etc.), and liquid phase absorbents such as ionic liquids.

3. Oxy-Combustion Technologies

Because nitrogen is the major component of flue gas in power plants that burn coal in air (as all existing plants do), post-combustion capture is essentially a nitrogen-carbon dioxide separation. If there were no nitrogen, CO_2 capture from flue gas would be greatly simplified. This is the thinking behind oxy-combustion capture: instead of air, the power plant uses an oxygen stream (≥95% purity) for combustion of the coal. The oxygen is produced on-site in an air separation plant, which represents the largest cost component in the capture process.

For retrofit applications, there are three primary concerns:

- The production of oxygen
- The modification of the boiler to use oxygen instead of air. This is necessary to keep temperatures from going too high and to meet the radiative and convective heat transfer characteristics of the boiler. This is accomplished by recycling part of the flue gas to the boiler.
- The clean-up of the flue gas of criteria pollutants (SO_2, NO_x, particulates, mercury) and non-condensibles (O_2, N_2, Ar).

As with post-combustion capture, the resulting CO_2 stream is compressed. It is during compression that the water is removed. The oxy-combustion process is capable of recovery rates of 97% or greater.

It is useful to understand the sources of parasitic energy loss for both the post-combustion and the oxy-combustion processes (MIT, 2007). The percentages below assume a power plant operating at 38.5% HHV[2] efficiency before capture. These numbers are meant to be illustrative, as they may vary from plant to plant.

For post-combustion capture (based on monoethanolamine scrubbing):

- Losses associated with low pressure steam extraction from the turbine (in order to regenerate the amine solution) - 13%
- Power for pumps and fans for capture process - 2%

[2] High Heating Value

- Power for the CO_2 compressors - 9%

This yields a total of 24%

For oxy-combustion capture:

- Power for air separation plant - 17%
- Power for pumps, fans, etc.- 3%
- Power for the CO_2 compressors - 9%
- Efficiency *increase* in boiler – (8%)

This yields a total of 21%, but relies on taking credit for an efficiency increase in the boiler. This has been shown only on paper studies, not in practice. It may also be harder to realize on existing boilers as opposed to new boilers. The above analysis also shows the importance of oxygen production on the economics of oxy-combustion capture.

How does oxy-combustion compare to today's amine scrubbing process? McCauley *et al.* (2008) quote studies that claim oxy-combustion capture shows a 10-16% improvement in levelized costs over MEA. However, there is not enough experience to choose one approach over the other at this point. The largest oxy-combustion boilers are 30 MW_{th}, one at Babcock & Wilcox's Clean Environment Development Facility and one at Vattenfall's Schwarze Pumpe plant. The later pilot plant also includes an oxygen plant and flue gas purification.

Some technologies broadly considered under the oxy-combustion category, such as chemical looping, are not appropriate for retrofits and, therefore, will not be reviewed in this paper. The three critical areas for RD&D reviewed below are oxygen production, boiler modifications, and flue gas purification.

3.1. Oxygen Production

3.1.1 Cryogenic Oxygen Production

The standard technology for large-scale oxygen production is cryogenic fractionation of air. The temperature involves liquefying air and separation via distillation. Energy for refrigeration is provided by compressing the air (and cooling upon expansion). The largest cryogenic air separation units (ASU) today are about 4000 tons per day (tpd). However, it is feasible to go to about 10,000 tpd, which would provide enough oxygen for a 500 MW coal-fired power plant. Above that level, multiple trains would be necessary (Allam, 2008).

Designs of ASUs can vary significantly. Key parameters include what products one is interested in (i.e., oxygen, nitrogen, argon), their purity, their pressure, and the size of the ASU. For the oxy-combustion process, the design specifications include relatively low oxygen purity (95-97%), low pressure (1.3-1.7 bar), low power consumption, and large size (McCauley *et al.*, 2008).

R&D has already started in adapting ASUs to oxy-combustion. Air Liquide (Darde *et al.*, 2008) discuss design studies that show a 20% decrease in energy use over today's ASUs. They also suggest that another 10% savings is possible by integrating the ASU with the power cycle.

3.1.2. Ionic Transport Membranes

While the cryogenic process is today's state-of-the-art, the primary focus of R&D for the next generation of oxygen production is mixed metal oxide ceramic membranes, referred to as both ITM or OTM (Allam, 2008). These work at high temperatures (700 C) and require an oxygen partial pressure driving force. There are at least four major development efforts, Air Products, StatoilHydro, Praxair, and Linde/BOC. The Air Products effort is at a 5 tpd scale, with plans to go to 150 tpd and then 2000 tpd.

To operate ITMs as stand-alone units, one needs high temperature air (a pre-heater will be necessary for oxy-combustion), and recovery of energy from the depleted air (a turbine and heat recovery). This requires much more integration between the oxygen production and the power cycle compared to the current ASUs. One way to improve the process is to sweep the low pressure side of the membrane with flue gas because of its very low partial pressure of oxygen (Pfaff.and Kather, 2008).

Some of the R&D challenges include sealing technology, chemical and mechanical stability of the different compositions envisioned, and reduction of high temperature creep (den Exter *et al.*, 2008). Even if these fundamental issues are resolved, it appears that for ITMs to be significantly better than cryogenic ASUs, they must highly integrate the ITMs into the power cycle.
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3.2. Boiler Modifications

The most straightforward retrofits for oxy-combustion require no changes to the water and steam systems and minimum modifications to boiler. In the boiler, the temperature needs to be kept in a safe operating range and the heat transfer characteristics that the boiler was designed for must be maintained. This involves recycling a significant portion of the flue gas to perform the function of the nitrogen which was removed in the air separation unit. Research questions include at which point in the process to take the recycle stream from (before or after certain flue gas clean-up steps, does it require cooling, etc.) and how to combine it with the oxygen (Tigges *et al.*, 2008).

Another significant issue with the boiler retrofit is air enleakage. Most boilers are designed to run just below atmospheric pressure for safety considerations, which encourages air enleakage. Since the whole idea of oxy-combustion is to not feed air to the boiler, air enleakage needs to be minimized. Proper sealing of the boiler and associated equipment will help minimize air enleakage. Needless to say, this is one area that retrofits pose a much larger challenge than new plants.

The above approach can be termed the “synthetic air” approach. A more sophisticated approach can be termed the “oxy-burner” approach. Instead of mixing the recycled flue gas with the oxygen before entering the boiler, the boiler can be retrofitted with oxy-burners that introduce pure oxygen. This technology is commercially used in certain industries, such as glass, metals, cement, and waste treatment (Cieutat *et al.*, 2008). Some flue gas recycle is still required, but the flue gas is not pre-mixed with the oxygen. This approach will be used to retrofit a 30 MW_{th} boiler for Total’s Lacq CO_2 Project in France.

A more involved approach would be to replace the boiler entirely with a purposely designed oxy-combustion boiler. This would maximize the increase in steam cycle efficiency, decrease boiler size, and could eliminate the need for flue gas recycle. Design of these boilers is a major R&D task. Another approach to boiler design that seems very compatible with oxy-combustion is the use of Circulating Fluidized Bed (CFB) technology (Carbo *et al.*, 2008 and Suraniti *et al.*, 2008). Oxy-combustion can lead to small equipment sizes, control temperatures with circulating solids, and allow use of a wide range of low cost feedstocks.

3.3. Flue Gas Purification

The major impurities that need to be considered for removal from the flue gas are particulate matter (e.g., fly ash), criteria pollutants (e.g., SO_2, NO_x, mercury), non-condensible gases (e.g., Ar, N_2, O_2), and water. For retrofits, the CO_2 concentration in the flue gas exiting the boiler will generally be between 60-70%, with the above impurities making up the difference. The biggest reason for the range is the amount of air enleakage.

There are several strategies being suggested for flue gas purification. All the strategies have a few things in common. First, particulate matter must be removed using the same equipment in use on coal-fired power plants today. Some research may be needed on modifying the equipment for the new flue gas composition. The non-condensible gases and water will be removed during compression (water will be condensed, the non-condensible gases will be flashed).

This leaves the question about what to do with the criteria pollutants. There are at least three approaches:

- Do nothing. Let the SO_2 and NO_x remain with the CO_2 and co-sequester. This is the simplest and least expensive approach. However, it may cause complications for transport and storage (more regulatory and political as opposed to technical). This approach also yields the highest recovery rates for CO_2 (Darde *et al.*, 2008).
- Use the same equipment we do today to remove the NO_x (e.g., SCR - selective catalytic reduction) and SO_2 (FGD - flue gas desulfurization). Research will be needed to modify these approaches for the new flue gas composition.
- Eliminate the use of traditional SO_2 and NO_x control and simply remove them during compression by using a water wash. The SO_2 and NO_x will leave the

system as sulfuric and nitric acids. Air Products has done initial tests of this approach and report that it looks very promising (White *et al.*, 2008).

In general, there is a trade-off between CO_2 purity and CO_2 recovery. This is because as impurities are removed, some CO_2 will leave with them. Another research area is to find ways to maintain high purity with high recovery. This includes using distillation (instead of a simple flash) to remove the non-condensible gases and using membranes to recover CO_2 from the impurity streams.

4. RD&D Recommendations

In Herzog (2009), the RD&D recommendations centered around an RD&D pipeline. In the next section, we reproduce the proposed RD&D program for post-combustion capture. In the following section, we propose an RD&D program for oxy-combustion retrofit capture (additional RD&D funds will be needed for oxy-combustion technologies like chemical looping, which are beyond the scope of this paper).

4.1. Post-Combustion Capture

The cost estimate for an 8-10 year research program in Table 1 below. Note that this is total cost of program, including research funds from both the private and public sector. Also note that it for only post-combustion capture technology – a complete CCS budget would also need to address other capture approaches (i.e., pre-combustion, oxy-combustion), as well as transport and storage.

Table 1. Estimated cost of an 8-10 year US post-combustion research effort.

Component	# of projects	Cost per project (millions of $)	Total Cost (millions of $)
Demonstration	5	1000	5000
Pilot Plants	15	50 (25-100)	750
Proof of Concept	30	10	300
Exploratory Research	50	1	50
Simulation/analysis			100
Contingency			1200
TOTAL			7400

The basis for these estimates is as follows:

- ***Demonstration project.*** This cost per project number is an order of magnitude estimate for a demonstration plant based on estimates from the *The Future of Coal* (MIT, 2007) and experience of FutureGen. Of course, the exact details of what a demonstration looks like can vary widely. We envision power plants in the 200-300 MW range that captures about 60% of the CO_2 (to give the plant parity with emissions from a natural gas power plant).

- ***Pilot plants.*** Pilot plant activity today includes plants sized to process flue gas associated with 1-5 MW of electricity production, as well as plants sized to process flue gas associated with 10's of MW of electricity production. Many technologies have pilot plants built at both scales. Therefore, we anticipate the need for about 15 pilot plant tests. The cost range is attributed to the different size of pilot plants to be built.

- ***Proof of Concept.*** The cost of these projects will be variable – some may be only a few million, while others could be $20 million or more. Our estimate is based on what a reasonable average cost might be.

- ***Exploratory Research.*** We feel it is important to cast a wide net, so we encourage funding many of these projects. After spending about $1 million, enough information should be generated to decide whether it is worthwhile to move to the proof of concept stage.

- ***Simulation/analysis.*** The *Future of Coal Study* suggested $50 million dollars per year on this task to cover all parts of CCS technology. Based on this estimate, we scaled it down to a level for post-combustion capture technologies only.

- ***Contingency.*** Because of the uncertainty in the estimates (and in future prices), we have included a 20% contingency.

4.2. Oxy-Combustion Capture

The cost estimate for an 8-10 year research program in Table 2 below. Note that this is total cost of program, including research funds from both the private and public sector. Also note that it for only oxy-combustion retrofit capture technology – a complete CCS budget would also need to address other capture approaches (i.e., pre-combustion, post-combustion, new oxy-combustion plants), as well as transport and storage.

Table 2. Estimated cost of an 8-10 year US oxy-combustion retrofit research effort.

Component	**# of projects**	**Cost per project (millions of $)**	**Total Cost (millions of $)**
Demonstration	3	1200	3600
Pilot Plants	10	100	1000
Proof of Concept	20	50	200
Exploratory Research	25	2	50
Simulation/analysis			100
Contingency			1000
TOTAL			5950

The basis for these estimates is as follows:

- ***Demonstration project.*** This cost per project number should be similar to post-combustion capture, if the capture efficiency were the same. However, for post-combustion capture, the estimate was based on 60% capture. By its nature, the oxy-combustion process will have capture rates over 90%, so it will be more expensive for similar sized plants (200-300 MW). Since oxy-combustion technology is more homogeneous than post-combustion capture technology, fewer demonstrations are required.

- ***Pilot plants.*** The cost of a pilot plant is based on Vattenfall's experience with their 30 MW_{th} plant ($100 million). Pilot plants can be used to test boiler designs, purification technologies, and/or oxygen production technologies. As with the demonstration projects, fewer pilot plants are recommended for oxy-combustion compared to post-combustion.

- ***Proof of Concept.*** Compared to post-combustion capture, similar price, but fewer projects.

- ***Exploratory Research.*** Compared to post-combustion capture, fewer projects, but more dollars per project. It is harder to isolate a component in a oxy-combustion concept than in post-combustion capture, so the exploratory research will cost more per project.

- ***Simulation/analysis.*** Same as post-combustion capture.

- ***Contingency.*** A 20% contingency, same as post-combustion capture.

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Federal Research Management for Carbon Mitigation for Existing Coal Plants

Discussion Paper
Prepared for
MIT Symposium on Carbon Mitigation for Existing Coal-Fired Power Plants
March 23, 2009

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Federal Research Management for Carbon Mitigation from Existing Coal Plants Discussion Paper

There are currently 645 conventional coal plants in operation in the US, which collectively comprise the single largest source of CO_2 emissions (32%). The current conventional coal plant fleet supplies around 50% of U.S. electricity and represents over one trillion dollars in infrastructure investment.

Also, while there appears to be a de facto moratorium on the construction of new coal fired generation in the U.S. the deployment of coal-fired generation is growing rapidly on a global basis. The significant growth of the economies of China and India, coupled with their large coal reserves and reliance on conventional coal fired-power generation, [1] substantially increases CO_2 emissions into the atmosphere.

The imperatives of climate change and coal consumption in the US, China and other countries suggest a strong public interest in mitigating CO_2 emissions from existing coal plants. The development, demonstration and rapid deployment of cost effective CCS retrofit technologies would return significant benefits under a future cap and trade program. The benefits have been estimated in several different ways, but in all cases they are substantial. For example:

- The National Academy of Sciences conservatively estimated the net present value of economic benefits of $4-7 billion for federal investment in carbon capture technology, and $2-4 billion for investments in carbon sequestration technology.[2]

- A recent study for Pew Center stated that "…with the experience gained from 30 demonstrations of CCS, the capital costs of wide-scale implementation of CCS in coal-fueled plants could be $80 to $100 billion lower than otherwise." [3]

- Achieving the 14% reduction in greenhouse gas emissions in 2020, as proposed in President Obama's FY 2010 budget, could be accomplished at an annual savings of $5-7 billion, beginning in 2020, for every $1 per ton reduction in the marginal price of carbon dioxide allowances resulting from more cost effective control technologies.

While the potential benefits are significant, current RD&D programs are inadequate for exploiting these opportunities. As recently noted by the General Accountability Office, "DOE's research strategy has, until recently, devoted relatively few resources to lowering the cost of CO_2 capture from existing coal-fired power plants, focusing instead on innovative technologies applicable to new plants." [4] At the current program pace, the technologies and infrastructure for

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1 According to the World Coal Institute, "Coal Facts 2008," coal currently accounts for 78% of power generation in China and 69% in India.

2 "Energy Research and Development and America's Energy Future," Statement of Robert M. Fri, Visiting Scholar, Resources for the Future, before the Committee on Energy and Natural Resources, United States Senate, March 5, 2009.

3 "A Program to Accelerate the Deployment of CO_2 Capture and Storage (CCS): Rationale, Objectives, and Costs" Vello A. Kuuskraa, Pew Center on Global Climate Change, October 2007.

4 "Climate Change: Federal Actions Will Greatly Affect the Viability of Carbon Capture and Storage As a Key Mitigation Option", United States Government Accountability Office, September 2008

CO2 emissions capture and sequestration at scale or for low or no-carbon alternative fuels will not likely be deployed widely for at least twenty years, well beyond the decision-making timeframe assumed in virtually all cap and trade proposals.

This profile places significant pressure on the federal government to devise specific policies and programs to capture and sequester CO_2 from existing plants, to dramatically increase plant efficiency, or to employ other technologies and configurations to reduce carbon emissions from existing plants. This paper discusses possible program models to further define and accelerate such support.

Assumptions for Discussion Purposes

For purposes of discussion, we stipulate that:

- a program specifically for retro-fitting [5] conventional coal-fired power plants to capture and sequester carbon, refurbishing existing plants to increase efficiency, re-powering existing plants with advanced CCS technologies such as oxy-firing, or co-firing with low carbon fuels (RRRC) is in the public interest and urgently needed to reduce the cost of compliance with a cap and trade program;
- the program will have a significant and specific focus on development of capture technologies which may or may not be coupled to sequestration activities;
- such a program must span the research continuum from basic research to large-scale demonstration of the commercial viability of key technologies, refurbishments or other improvements, with a significant focus on the latter;
- the program should, at a minimum, be designed to achieve CO_2 emissions levels at a cost per ton that is competitive with estimates of projected market-clearing prices for carbon dioxide allowances;
- to ensure success, the program should have the characteristics of:
    - adequate, sustained funding over time;
    - a program structure that fosters close collaboration among industry, universities and National laboratories to enable rapid research, development and deployment effective program management with significant technical domain expertise including an understanding of the investment/commercial considerations of the industry; and
    - significant inter-agency coordination and committed, capable federal leadership at the highest levels of the agency and within the White House

5 In this paper, retro-fitting is used as shorthand for the suite of technologies that can be applied to existing pulverized coal steam generation power plants, either through add-ons to existing plants, rebuilding and upgrading existing boilers with carbon capture, repowering of existing boilers with gasification or other technologies, modifying the combustion characteristics of boilers through oxy-combustion, increasing the thermal efficiency of existing boilers to reduce greenhouse gas emissions per unit of power output, and co-firing with low-carbon fuels. This suite of technology options is referred to in this paper as Retrofits, Rebuilds, Repowering and Co-firing with low carbon fuels, or RRRC.

Key Questions for Discussion

Designing a robust, high impact and sustained program that is broad in scope and structured and managed to maximize climate mitigation goals, maintain commercial viability and provide affordable power raises both design and process questions for participants to consider as they review this paper:

- Is there an optimal program model to enable rapid development and deployment of technologies necessary to meet program objectives?
- Can such outcomes be accommodated by existing programs at DOE? If so, which one(s)?
- What existing authorities might DOE employ to meet the objectives of such an effort? Are these authorities adequate or being utilized to the maximum extent practicable?
- Is an entirely new program necessary? If so, are new authorities required or are existing organic statutes adequate for addressing the requisite tasks of such a program?
- Are there structural, personnel and/or standard operating procedures at DOE that might impede timely achievement of program objectives?

Review of Current DOE Clean Coal and CCS RD&D Program Activities

To design an RRRC technology program for existing coal plants, it is important to first review current programs at DOE, where the Office of Fossil Energy has several RD&D programs aimed at mitigating the impacts of CO_2 emissions from coal combustion. These include the Clean Coal Power Initiative, the Regional Carbon Sequestration Partnerships Program, several IGCC related programs, and the Innovation for Existing Plants Program (FY 09 budget request is in Figure 1).

Advanced Integrated Gasification Combined Cycle program (IGCC): The IGCC program has been focused on a broad set of technology improvements to current gasification technology to enhance performance, reduce cost and reduce emissions of all pollutants, including CO_2. This program also includes R&D on technology enhancements, such as membrane air separation, to facilitate pre-combustion capture of CO_2. DOE/FE appears to have assigned a high priority to gasification technology as the preferred solution to carbon capture, because the incremental cost for carbon capture from gasification is estimated to be significantly less than the incremental cost for carbon capture from pulverized coal combustion.[6]

The recent GAO report noted that DOE's R&D program has focused on IGCC as the preferred technological option, noting that DOE has invested $2.3 billion in gasification technology.[7] However, the emphasis on this technological solution assumes that many new IGCC plants can be deployed, either as new plants that would replace existing PC plants, or as repowering opportunities at existing PC plants. The DOE analysis is based on a comparison among options for new builds. The DOE analysis did not address the economic trade-offs between constructing new IGCC generation plants with carbon capture and retrofitting or modifying existing PC plants with carbon capture.

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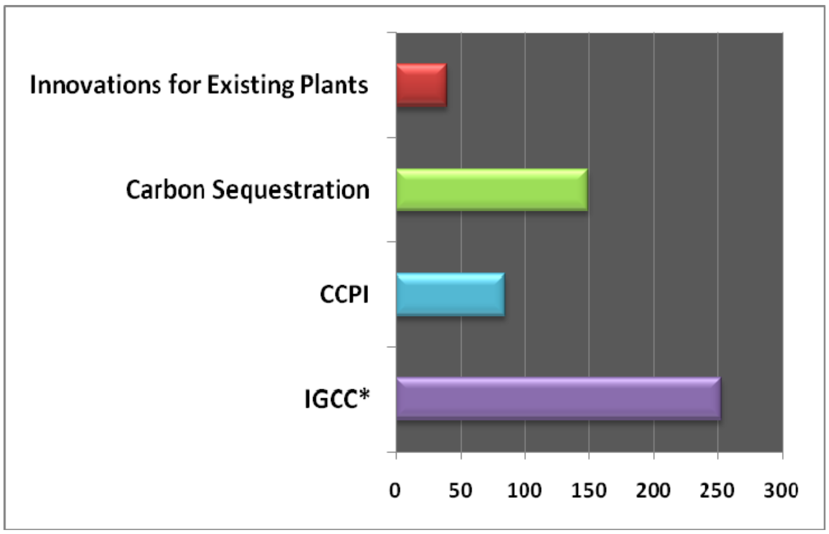
6 The DOE Report "Cost and Performance Baseline for Fossil Energy Power Plants—Volume I: Bituminous Coal and Natural Gas to Electricity," Final Report, 2007 showed that carbon capture would increase the cost of a newly constructed IGCC plant by 35%, while carbon capture would increase the cost of a newly constructed PC power plant by 77%.
7 U.S. GAO, p.34.

Innovations for Existing Plants (IEP): This program historically focused on R&D on technologies for environmental controls at existing pulverized (PC)plants. Since FY 2004, the program has emphasized R&D on the control of mercury emissions. Beginning in FY 2008 2009, DOE shifted the focus to "the development of technology to reduce CO_2 from PC power plants." [8] In February of 2008, DOE released a solicitation for R&D projects "specifically focused on developing technologies for CO_2 capture and separation that can be retrofitted to existing pulverized coal (PC) power plants." [9] In response to this solicitation, DOE awarded a total of $36 million for 15 projects. However, this program is designed to support R&D at the laboratory and pilot-scale, but apparently not demonstration-scale projects.

Figure 1. FY 2009 Budget Request



***includes FutureGen, Advanced Turbines, Advanced IGCC**

FutureGen: The FutureGen program was originally planned for support a single, large scale, green-field demonstration of IGCC coupled with other advanced technologies for carbon capture and geologic sequestration, with the objective of achieving near zero emissions. In 2008, the Bush Administration reorganized the program to broaden its focus from a single plant to several large–scale demonstration facilities. The revised FutureGen solicitation proposed to fund the incremental cost of CCS for an IGCC plant, with the project sponsor funding the full cost of the IGCC portion of the project. DOE issued a draft Funding Opportunity Announcement[10] that specified the following criteria for a demonstration project under the restructured FutureGen:

- Performance levels of 81% carbon capture at a scale of 300 MWe, plus sequestration of at least one million metric tons of CO_2 per year in a saline formation;

8 FY 2009 Congressional Budget Justification, Fossil Energy Research and Development, U.S. Department of Energy, February 2008, p.31.
9 Ibid, p.36.
10 "Restructured FutureGen," Draft Financial Assistance Funding Opportunity Announcement, U.S. Department of Energy, National Energy Technology Laboratory, May 7, 2008.

- DOE cost share of the lesser of the incremental cost of CCS (for a new plant) or 50% of the cost (of a retrofit or repowering project);
- A demonstration period of 2-5 years, after which the project would receive no DOE assistance; and
- A hard cap of $600 million on the federal share, with no allowance for any cost escalation after the time of the award.

DOE received comments on the draft solicitation, but the Bush Administration took no further action. Secretary Chu recently stated that the Obama Administration would review the FutureGen plan. The Secretary stated that “We are taking, certainly, a fresh look at FutureGen, how it would fit into this expanded portfolio.”[11]

Sequestration R&D: This program supports a variety of carbon capture and sequestration activities. About 80% of the sequestration program is allocated to the Regional Carbon Sequestration Partnerships.[12] The Regional Carbon Sequestration Partnerships Program is focused on developing technologies, regulatory policies and infrastructures to enable large scale sequestration of CO_2 from coal-fired power plants for a range of coals and geologies. The Program supports seven regional partnerships. In addition to the regional partnerships, the program supports R&D on several carbon capture technologies, including membrane separation for gasification technology and two oxy-combustion R&D for two pilot scale projects (Babcock and Wilcox and BOC Group).

Clean Coal Power Initiative: The Clean Coal Power Initiative (CCPI) was initiated in FY 2003 to demonstrate a wide range of emerging technologies in coal-based power generation. The program was originally proposed as a 10-year $2 billion program. CCPI Round I and CCPI Round 2 solicitations focused on advanced environmental control and gasification technologies. In August 2008, DOE released a solicitation for demonstration projects as part of the CCPI program (CCPI Round III). Table 1 highlights key features and requirements articulated in the Round III solicitation.

While the CCPI Round III solicitation officially closed on January 20, 2009, it is expected that DOE will re-open the solicitation, make some modifications to the specifications in the solicitation, and extend the deadline for submission of proposals. This will enable DOE to deploy the additional $800 million included in the recent American Recovery and Reinvestment Act, signed into law on February 17, 2009. There also may be a CCPI Round 4 solicitation that would be funded in the upcoming FY 2010 appropriations bill.

11 “DOE taking ‘fresh look’ at FutureGen, energy chief says,” Greenwire, March 5, 2009.
12 U.S. GAO, p.35.

Table1. Key Features of CCPI's Round III Solicitation

Priorities	Funding	Contract Type	Match Requirements	Eligibility	Schedule	Technical Selection Criteria
Deployment of: **--advanced coal based CCS or reuse technologies** **-- 300,000 tons/yr from demonstration plants must be captured & sequestered or put to beneficial use** **--carbon capture process must operate at 90% efficiency**	**--$440M with additional $800M in Stimulus** **--multiple projects will be funded**	**--Cooperative Agreement with flow thru provisions for major subcontractors** **--FAR provisions apply**	**--50% federal cost share,** **--no federal cost share on overruns**	**--Make progress toward 10% COE increase for gasification systems or 35% for combustion and oxy-combustion systems** **--Make progress toward 50 CCS of plant CO2 emissions**	**RFP : 8/11/08** **Submissions: 1/20/09** **Selections: 7/09** **Awards: 6/10**	**<u>Criterion #1 (50%):</u> technology merit, technical plan, site suitability** **<u>Criterion #2 (30%):</u> project organization, project management plan** **<u>Criterion #3 (20%):</u> commercialization potential**

Summary Observations: The GAO Report noted that DOE officials indicated spending about $50 million on carbon capture technology between FY 2002-2007. Beginning in FY 2008, DOE increased the focus of its R&D programs on carbon capture technology. Based on a review of the current recent DOE program plans, budgets and funding solicitations, we can draw several general observations:

1. The DOE R&D programs have had a heavy emphasis on carbon capture technologies related to coal gasification;

2. The R&D programs generally have been more focused on new plant applications rather than retrofits;

3. Carbon capture technology R&D has not been a specific program focus area. In fact, work on carbon capture technology can be found in four different budget line items within the Fossil Energy R&D budget; and

4. All of the carbon capture technology R&D work to date has been at small scale – laboratory experiments and pilot plant testing.

Is CCPI Adequate for Existing Retrofits, Refurbishment, Repowering and Efficiency?

Of all coal technology programs in the DOE Office of Fossil Energy, the CCPI program, as reflected in the Round III solicitation, offers the best starting point for developing a broader RRRC technology initiative. There are however several key issues with the current CCPI program structure that limit its value as a programmatic vehicle for existing coal plant retrofit, refurbishment, re-powering and efficiency RD&D.

Key issues with the current CCPI solicitation can be divided into:

- the structure and focus of the solicitation itself, and;
- generic DOE/federal process issues which manifest in impediments to the timely stand-up and implementation of applied research programs of this type.

➢ **Structure and Focus**

CCPI Round III Solicitation Not Sufficiently Flexible to Meet RRRC Needs: The major features of the CCPI Round III solicitation are highlighted in Table 1. This solicitation, while focused on retrofits, places high priority on sequestering CO_2, stating that "300,000 tons per year from demonstration plants must be captured and sequestered or put to beneficial use."

A specific RRRC program necessarily includes a major focus on the development of capture as opposed to sequestration technologies and may or may not require explicit linkage to sequestration. Indeed, requiring a link at such an early stage of an RRRC program may impede progress in this area of research at a time when a focus on RRRC research is urgently needed.

On the plus side, linking capture and sequestration provides a source of CO_2 for a demonstration program and avoids "catch and release" concerns. Also, this link may reflect the real world system required to manage a CCS business in the future and provide opportunities to develop a business model.

On the other hand, a focus on sequestration implicitly excludes plant efficiency and co-firing research and demonstration. In addition, the specific skills sets on the part of researchers and industry partners for developing capture technologies are very different from those associated with sequestration. Further, broad partnerships sufficient to span the CCS value chain from power plants to reservoir management may be extremely difficult to assemble and retain over the lengthy solicitation period for CCPI Round III. As seen in Table 3, the time period from program authorization and funding to project start-up can take 2-3 years.

Also, as noted DOE programs to date have had much greater focus on sequestration and new plant research issues as opposed to the development of capture technologies for retrofit applications. As a matter of DOE practice and policy, different stages of research development are treated differently in both contract structure and industry match requirements. The one-size-fits all match requirement in the solicitation for CCPI Round III may not be appropriate for the range of research required for a program focused on specific RRRC needs.

Finally, such a structure may or may not reflect the ultimate equities of the parties engaged in the research or the regulatory structures under which the various entities are operating. Liability issues and regulatory requirements will undoubtedly be different across the CCS business chain and should be accommodated in the solicitation.

- **Process Issues and Concerns**

CCPI Solicitation Process Is Extremely Slow, Discourages Participation. Simply stated, from a process perspective, the CCPI program (and its immediate predecessor, the Power Plant Improvement Initiative, PPII) has had a poor performance record. A review of the combined record of the PPII and CCPI Rounds I and II shows that:

- For the combined total of PPII, CCPI Round I and CCPI Round II, summarized in Table 2, DOE received a total of 73 applications, and selected 20 projects for negotiation of awards. However, half of the projects withdrew from the program. As a result, in over nine years only 10 projects were actually implemented**.**

Table 2. PPII/CCPI Solicitation Summary Data

	Power Plant Improvement Initiative	CCPI Round I	CCPI Round II	CCPI Round III
Applications Received (Proposed DOE Share)	24 ($251 M)	36 ($316 M)	13 ($1 B)	TBD
Selections for Negotiation	8	8	4	TBD
--In Negotiations	0	1	0	TBD
--Applications Withdrawn	3	3	1	TBD
Cooperative Agreements Achieved	5	4	3	TBD
--Withdrawn After Reaching a Cooperative Agreement	1	1	0	TBD
Cooperative Agreements in Implementation or Completed (DOE Contribution)	4 ($29 M)	3 ($33.5 M)	3 ($277 M)	TBD

- The process for soliciting applications, conducting reviews and selections and negotiating awards was extremely time-consuming. On average it took 24 months from the time that funds were appropriated until the time of the initial award for the first project. Project schedules are summarized in Table 3.

Table 3. Solicitation Schedules/ DOE Cost-Shared Clean Coal Technology Demonstrations

	PPII	CCPI Round I	CCPI Round II	CCPI Round III
Funds Appropriated	**October 27, 2000 ($95M)**	**November 5, 2001 ($150M)**	**November 10, 2003**	**December 26, 2007**
Solicitation Issued	**+3 Months**	**+4 Months**	**+3 Months**	**8 Months**
Applications Received	**+2 ½ Months (24 applications)**	**+5 Months (36 applications)**	**+4 Months (13 applications)**	**5 Months**
Selections for Negotiations	**+5 Months (8 projects)**	**+5 Months (8 projects)**	**+4 Months (4 projects)**	**+6 Months (projected)**
Initial Award	**+9 Months**	**+13 ½ Months**	**+15 Months**	**+12 Months (projected)**
Total Time from Appropriations to Initial Award	**20 Months**	**27 ½ Months**	**26 Months**	**31 Months (projected)**

There is no evidence to suggest this lengthy process will be shortened to accommodate the urgent requirements for climate mitigation and the need to address past programmatic biases towards new plants through an aggressive CCS program for existing plants.

Based on DOE's announced plans for the CCPI Round III solicitation, it will take 31 months from the time that funds were originally appropriated for FY 2008 until financial assistance awards are expected to be finalized. The likelihood that DOE will re-open the solicitation in response to the enactment of the stimulus funds will extend this timeline even further. This lengthy process is especially problematic as CCPI funds are included in the stimulus package which has a goal of rapid implementation.

CCPI Financial Incentive Structure is Inadequate. The federal financial incentive structure of CCPI is based on 50% direct federal cost sharing of eligible project costs, limited to capital costs plus a short term period of demonstration operations (typically start-up, shakedown and perhaps 12 months of operations). In addition, DOE establishes a hard cost cap, no schedule flexibility and no liability protection for the sponsor related to sequestration operations. The 50% cost sharing was incorporated into the 2005 authorization for CCPI; however, the legislation provided administrative flexibility which has not been exercised.[13]

The level of financial incentive afforded by 50-50 cost sharing appears to be a critical issue. To better understand this issue, it is worth reviewing the genesis of the requirement. The concept of 50-50 cost sharing for coal technology demonstration projects was first established in the Clean Coal Technology Program in the 1985. This program was created to demonstrate technologies for reducing the emissions of acid rain precursors. The program was initiated five

13 Section 988 (c)(2) of the Energy Policy Act of 2005 states that "The Secretary may reduce the non-Federal share required under paragraph (1) if the Secretary determines the reduction to be necessary and appropriate, taking into consideration any technological risk related to the activity."

years prior to the passage of legislation that established a national cap and trade program for reducing acid rain.

At that time, the 50% "buy-down" of project costs by DOE was viewed as a sufficient incentive to encourage demonstration project proposals from the private sector. As further incentive, the federal funds for the future year costs of these multi-year demonstration projects was appropriated in advance, giving private participants a degree of certainty as to the reliability of a sustained and expensive partnership with DOE. [14]

This model has been largely carried over in the CCPI demonstration program, and is embodied in the current CCPI Round III solicitation for CCS retrofit technologies. However, the electricity market into which the Clean Coal Technology Program demonstration projects were deployed has changed greatly over the past two decades. In the 1980s and most of the 1990s, the electricity market was characterized by integrated utilities, with franchise service territories, and cost-based rates subject to state regulation. Host utilities were able to pass through to customers their 50% cost share of a demonstration project. In fact, some state commissions created special cost pass through structures specifically for R&D projects.

The current electricity market is no longer vertically integrated, and the generation segment of the industry consists of both regulated utilities and merchant generators selling into a competitive market. Thus the ability of a power generation company to participate in an RRRC technology demonstration program is dependent upon whether the federal financial incentives are adequate to enable the project to sell its power *competitively*. The experience with the delays and cancellations of recent CCPI demonstration projects may reflect structural issues related to electricity market considerations as much or more than DOE administrative impediments. [15]

In recognition of the market-driven rather than cost-driven nature of the electricity market, it is essential that structuring of the federal financial incentive provide a market-based structure. It is also important that the program solicitation and structure do all it can to encourage industry participation in the face of uncertain funding.

DOE has made some movement to address the rigidities of its cost share practices in its 2008 FutureGen solicitation. The solicitation recognizes that a CCS demonstration project will have incremental costs relative to non-CCS project. Subject to a hard cost cap of $600 million per project, DOE has proposed to fund the lesser of the incremental cost of the CCS component or 50% of project costs. This approach, while more creative and flexible, is still inadequate because it assumes a priori: (1) that an IGCC project (without the CCS features) could be deployed into

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14 Even by the end of the Clean Coal Technology Program (CCTP), it was becoming evident that the business model was not working effectively. The CCTP program awarded funding to a total of 57 projects, of which only 33 or 58% were completed. Of significant note, all 5 projects receiving awards in the fifth and final round of CCTP subsequently withdrew from the program.

15 The DOE FY 2007 Congressional Budget Request proposed a 90% reduction in CCPI funding, from $49.5 million to $4.957 million, justified due to the need to resolve administrative delays identified in the Program Assessment Rating Tool (PART) due to "…legal issues with contract filing, the private sector's difficulty securing adequate financing for their cost-share, extended negotiations over contract terms, and other issues. Furthermore, the PART review identified potential project management concerns." Despite these findings, the only significant change made in the Round III solicitation was dropping the requirement for a repayment plan.

electricity markets on a competitive basis, and; (2) that project sponsors could demonstrate the CCS features within the cost cap established by DOE.

The House Appropriations Committee Report accompanying the FY 2009 Energy and Water Development Appropriations bill proposes a similar approach. The Report recommends that DOE consolidate the existing CCPI Round 3 solicitation and the FutureGen funding into a single new initiative, the proposed "Carbon Capture Demonstration Initiative (CCDI)." The CCDI would be modeled after CCPI Round III, except that the federal share of eligible costs shall "…not exceed the lower of: (1) the incremental cost of implementing a facility with CCS as compared to a state of the art facility without such technology, or (2) 50% of the total allowable costs for each project." [16]

While this language is helpful, it has two limitations: (1) the "lower of" test may limit the federal share to only the 50% level, especially for retrofit projects, and; (2) it is not clear that eligible new build projects would be able to market power at competitive prices even if the level of federal assistance was set on the basis of incremental cost.

Finally the issue of incremental operating costs needs to be addressed. DOE practice is to offer cost sharing only though a specified demonstration period that encompasses start-up, shake down and testing. Typically, the demonstration period covers a period of about two years from the completion of construction, although in a few past cases, the demonstration period has been extended up to about five years. CCS projects will have high incremental operating costs due to the combination of increased plant O&M associated with capture operations, cost for compression, transport and injection of carbon dioxide, and reduced power plant output. These reductions are both significant and continuing. A short demonstration period likely will be inadequate.

***The Performance Objectives in CCPI are not Sufficiently Flexible*.** The CCPI Round III solicitation represents a major advance toward the needs of demonstrating CCS retrofit technologies. However, the performance specifications established in the solicitation are at the same time narrow as well as far reaching. For example:

- The CCPI Round III solicitation incorporates technical performance requirements for reductions in emissions of criteria pollutants and improvements in thermal efficiency guided by 2020 goals set in the Energy Policy Act of 2005.[17] However, the establishment of the carbon capture goal was set administratively at a "gold" standard level of 90**%** carbon capture. Setting an ambitious performance level is appropriate for an R&D program, but a demonstration program that is intended to accelerate commercial deployment should be governed by cost effectiveness considerations. In a future cap and trade regime, there may be a market for technologies with a wider range of performance levels. One of the principal objectives of the proposed cap and trade program is to establish a price for carbon.

16 "Energy and Water Development Appropriations Bill, 2009," H.R. 7324, Committee on Appropriations, U.S. House of Representatives, Report No. 110-921, December 10, 2008.
17 See Section 402(a)(1)(B) and 402(a)(2) (B), and Table 1 in the CCPI Round III solicitation.

The carbon price level may allow for the cost effective deployment of technologies in some applications that do not have to meet the 90% capture level.[18]

- The solicitation is limited to only CCS retrofit technologies at coal-fired power plants. There may be opportunities to demonstrate technologies for CCS from natural gas fired generation more easily and cheaply than for coal.

- The solicitation specifies that all eligible demonstration projects must capture carbon. Alternatives that reduce carbon emissions through increased thermal efficiency or co-firing are not eligible.

CCPI's Selection Criteria Do Not Favor Commercialization Potential. The CCPI Round III solicitation sets out three sets of evaluation criteria: technical, project management and financial. The criteria are as follows:

Technical
50% - Technology Merit, Technical Plan, and Site Suitability
30% - Project Organization and Project Management Plan
20% - Commercialization Potential

Financial
20% - Adequacy of Funding Plan (i.e. non-federal share)
40% - Adequacy of Financial Business Plan (i.e. project economics)

The solicitation further specifies that the technical criteria will be weighted more heavily in the final selection decisions than the financial criteria. Commercialization potential appears to be undervalued, where such potential is weighted at only 20%. In light of the urgent need to address emissions from existing plants, and the imperatives of the stimulus, commercialization potential would seem to be a more important project differentiator than is currently envisioned in the CCPI solicitation under way.[19]

CCPI Does Not Take Advantage of Flexible Contracting Authorities. The CCPI program model contains a number of rigid contracting procedures that, in effect, make cost control an important end in itself.

The CCPI program uses a Cooperative Agreement as the legal instrument for providing federal assistance. A Cooperative Agreement is a financial instrument that is widely used by DOE to fund R&D projects with non-governmental entities (private industry, not-for-profit entities, and in some cases universities). Cooperative agreements are well-suited for laboratory or small-scale experimental research; they are however an extremely cumbersome contract vehicle for funding large projects that are intended to demonstrate the commercial viability of technologies that, while designed to meet public goods, will be used by industry in the private marketplace.

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18 For example the Section 48a and 48b investment tax credits for coal based CCS investments, recently authorized in the Energy Improvement and Extension Act of 2008, require a minimum of 65% carbon capture.
19 The 2005 CCPI authorization legislation would appear to support the adoption of more market-oriented selection criteria. Section 402(d) of the Energy Policy Act of 2005 directs the Secretary to make selections that, in addition to technical performance, "…achieve overall cost reductions…improve the competitiveness of coal…and demonstrate methods and equipment that are applicable to 25 percent of the electricity generating facilities."

Examples of the types of restrictions applicable to cooperative agreements include:

- ***Eligible costs***: The cooperative agreements incorporate the use of cost principles from the Federal Acquisition Regulation (FAR). These principles were established largely to govern federal government acquisition of goods and services and not commercial projects ultimately owned and operated by private entities. Companies that perform government contracting services as their main line of business have developed the necessary capabilities for FAR compliance; FAR requirements however can impose high transaction costs on private firms that only have a single federal financial assistance award.

- ***Cost sharing***: In addition to the problems with cost sharing as a conceptual framework for federal financial assistance, as a matter of practice, DOE's cost sharing requirements are implemented in a very stringent manner. For example, DOE establishes a hard cap on the federal cost share at the time of the financial assistance award when project development costs are partially or largely unknown; there is no way to estimate costs with any degree of precision.

  Also, federal and non-federal cost shares must be maintained throughout each stage of the project, providing no flexibility for the private sector partner to utilize different financing vehicles for planning, design, construction and operation. Finally, although authorized to cost share up to 25% of cost escalation, DOE policy makes cost share on escalation unallowable; this places 100% of the cost risk on the private sector party, creating an unreasonable allocation of risk for first-of-a-kind demonstrations of a new technology.

- ***Reimbursement and Audit Procedures***: DOE funds are provided only on the basis of cost reimbursement and in many cases only after audits by DOE. The solicitation does not permit more business-like practices such as draw schedules or use of third party audits to avoid delays in scheduling government audits.

- ***Schedule Flexibility***: the solicitation allows for no changes in project implementation schedules from those established at the time of the award of the financial assistance. DOE reserves the right to make unilateral changes in schedule, but the project sponsors are prohibited from even requesting modifications to the schedule. This requirement is much more onerous than commercial contracting practices, which allow for mutual renegotiation of project schedules, with appropriate changes in compensation, including liquidated damages, as necessary.

CCPI Has No Sequestration Liability Framework. A significant omission in the CCPI Round III solicitation is the lack of any framework for addressing liability issues associated with geologic sequestration.

The solicitation requires that the project sponsor provide full indemnification of DOE, leaving 100% of sequestration liability risk with the project sponsors**.** Projects that propose to place captured carbon into CO_2 pipelines for use in enhanced oil recovery (EOR) operations may be able to accept full liability risk, since EOR is well established and there is an existing network of pipeline and other facilities to handle the CO_2. However, the CCPI restriction is a serious impediment to CCS projects that may wish to demonstrate storage or sequestration of CO_2 in other geologic media.

The federal government has yet to establish regulations for geologic sequestration, and only a few small scale experiments are currently underway. This is problematic for existing programs; the DOE Regional Carbon Sequestration Program is currently encountering serious impediments due to the lack of a viable strategy for addressing the liability associated with geologic carbon sequestration. A recent survey of 19 of the 25 Phase II geologic sequestration pilot projects for which data was available found that:

- 11 of the 19 projects (60%) reported significant legal issues. Legal issues related to liability have caused one project to be cancelled, and have delayed others;

- The time devoted to non-research functions (legal, permitting, administrative) ranged from 5% to as high as 90% of overall personnel time where significant legal issues were encountered; and

- The prevalence of legal barriers for RD&D projects were encountered for projects with relatively small injection volumes, "…even where risks associated with health and safety, property damage, and CO_2 leakage were widely acknowledged by stakeholders to be negligible." [20]

This study recommended legislation to provide a liability shield for research organizations, along with government indemnification to protect property rights holders, parties granting consent to projects and third parties who may be affected by CCS research.[21] The liability shield and indemnification provision could be limited to non-EOR sequestration, and in particular, geologic sequestration in saline formations which lack the economic incentives associated with EOR applications.

Absent such protection, opportunities to conduct sequestration RD&D activities in geologic formations may be severely restricted. The explicit refusal of DOE to provide any liability protection in the CCPI Round III solicitation may prove to be penny-wise, pound-foolish, since sequestration in geologic formations represents the largest potential source for carbon storage.

The potential for sequestration issues to impede RRRC technology demonstrations cannot be ignored, especially when the CCPI Round III solicitation explicitly ties capture to sequestration. Currently, CCPI Round III and the Regional Carbon Sequestration Partnerships Program are separate endeavors; linkages are clearly needed. The Round III solicitation states that "DOE is interested in allowing demonstration projects under CCPI to integrate with the sequestration field tests…" but the integration is left to the project participants; there is neither any process under the solicitation, nor any special incentives, to facilitate such integration.

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20 "Advancing Carbon Sequestration Research in an Uncertain Legal and Regulatory Environment: A Study of Phase II of the DOE Regional Carbon Sequestration Partnerships Program, "Craig A. Hart, Harvard Kennedy School, Discussion Paper 2009-01, January 2009.
21 Ibid, p21.

Program Drivers for an Expanded and Accelerated RRRC

To date, DOE has focused largely on the development of technologies for new power generation applications and funding has been allocated primarily to coal gasification based technologies. While important for meeting long-term climate mitigation goals, IGGC plants will not likely be developed or widely deployed for some time; DOE's flagship research program in this area has been delayed and restructured and the investment community continues to express skepticism about the viability of IGCC.

This strategy needs to be revised in view of the national priority that has been assigned to achieving national and international reductions of greenhouse gas emissions; there is an urgent need for development and demonstration of technologies that can reduce or sequester carbon emissions from the current fleet of pulverized coal plants.

New, lower cost technology solutions are needed to help reduce the cost of compliance with likely future greenhouse gas emissions targets. The President's FY 2010 budget proposes a national cap and trade program that would reduce emissions by 14% by 2020. The budget assumes that the program would be implemented through auctions that would create a carbon price of about $20 per ton through FY 2019. There is no information currently available as to the possible carbon price path beyond FY 2019.

Current estimates show that retrofitting CCS technologies to existing coal plants have an avoided cost of $67-111 per ton.[22] Absent new technology solutions, two adverse and related outcomes could occur:

- Without sufficient lower cost CCS options, compliance with the caps will not be achieved through retrofit of existing fleets; a large fraction of the current 314 GWe coal fleet will become uneconomic and non-compliant and may have to shut down.

- If there are insufficient compliance options available to meet the reduction targets at the President's budget estimated auction price level, the market clearing price for carbon allowances could driven up to levels of 3-4 times the levels projected in the President's FY 2010 budget.[23]

Time is of the essence. The President's budget projects that the carbon cap, and associated auctions, could begin as early as FY 2012. Capital investments in base load power generation

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22 "Near-Term Technologies for Retrofit CO_2 Capture and Storage of Existing Coal-fired Power Plants in the United States", Dale Simbeck and Ms. Waranya Roekpooritat, Discussion Paper prepared for MIT Symposium on Coal Retrofit Technology, March 2009. A 2007 Report by the Congressional Budget Office, "The Potential for Carbon Sequestration in the United States," estimated the cost of CCS for both new and existing plants in the range of $20-90 per ton, for sequestration in geologic media. A 2008 McKinsey study, "Carbon Capture & Storage: Assessing the Economics", estimated between $38-57 per ton of CO_2 abated for its reference plants, though it put the cost for early demonstration projects at $77-115 per ton.

23 The FY2010 Budget conservatively assumes option prices of about $20 per ton. This results in net revenues, after the proposed set aside for clean energy technologies, of $525.7 billion over the ten year budget horizon through FY2019. This number appears to have been carefully matched to the revenue loss estimate $536.7 billion for the proposed extension of the Making Work Pay Tax Credit, which is the proposed mechanism for recycling climate revenues. The budget appears to anticipate that auction prices could be higher and states "all additional net proceeds will be used to further compensate the public."

have long lead times; 3-4 years for new natural gas combined cycle, five years or more for new coal-fired generation and 8-10 years for new nuclear generation. Further, companies need to start the process of adopting expansion plans; this should be based on the best available information. It is worth recalling that the Clean Coal Technology Program was started five years prior to the passage of related provisions in the Clean Air Act, providing technology options for meeting the requirements of the law.

The current DOE carbon capture R&D program is planned to complete testing at pilot plant scale by 2012 and begin providing performance and cost data at commercial scale by 2020. The schedule for achieving commercial scale projects needs to be substantially accelerated, and the "bandwidth" of data from demonstration facilities needs to be significantly expanded.

The sequestration R&D program should proceed in parallel with the RRRC Demonstration Program to validate the technical feasibility of large scale geologic sequestration. To date, DOE has devoted significantly more resources to sequestration research, and the seven existing regional partnerships are close to initiation of Phase III larger scale field tests. Current estimates suggest that the cost of carbon capture comprise 50% or more of the total cost of CCS, and unlike the regional partnership activity, geology is a secondary driver for a retrofit program; plant type and age, current emissions controls, capacity factors, age, etc., are much more relevant considerations, although proximity to sequestration sites should also drive project selection and development.

In short, cost, time, urgency, the nascent state of the research, historical performance of related DOE programs, and the pending legislative agenda necessitate serious consideration of an alternative management model.

New and Improved Management Models for an RCCC Program

For discussion purposes, we examine two possible enhanced research management models – a DOE model that seeks to take maximum advantage of the current statutory framework and administrative flexibility available to DOE, and a new government corporation as an entity that would assume program responsibility for RRRC technology demonstration and commercialization activities.

Enhanced DOE Management Model: The enhanced DOE management model would build upon the CCPI program model and specifically address the problems discussed in this paper. The principal elements of the model include:

- *Program Objective*: to develop the technology base to enable business decisions on RRRC technology deployment in 2015. Having RRRC technology options ready for deployment decision by mid-2015 will enable existing plants to make material contributions to achieving 2020 interim reduction targets in the proposed cap and trade program.

- *Program Scope and Implementation strategy*: An RRRC program should support multiple commercial scale (or scalable to commercial scale) demonstration projects, in parallel, on an accelerated basis. The scope of the program would include pre-combustion, oxy combustion and post combustion carbon capture technologies, carbon efficiency improvement and renewable co-firing technologies. The technologies would be either for retrofit applications to existing boilers or repowering applications that would include boiler replacement. The technologies could be demonstrated on a variety of coals, or on natural gas. A representative suite of technology options is illustrated in Table 4.

- *Technical Performance Objectives*: Technologies that achieve significant reductions in or avoidance of carbon dioxide emissions would be eligible. No specific numerical targets would be set. Instead, decisions on the technical performance levels of proposed technologies would be based on an assessment of the size of the technology's market potential under a cap and trade program, weighted against the availability or expected availability of affordable, higher performing options.

- *Program cost*: It is estimated that the total cost of the proposed demonstration program for the identified suite of technologies would be up to $15 billion depending upon the number of demonstrations and the level of federal financial incentives.

- *Greater project collaboration and less competition at the demonstration stage*: RRRC technologies for retro-fit, refurbishment, re-powering and co-firing would be demonstrated in parallel. Theoretically, this would lower the competitive pressures as a larger set of winners would be supported in efforts to meet the specific needs of individual plants, and utility fleets. It would also bring a broader range of research participants into the process. DOE should actively promote greater collaboration in project proposals. Robust participation across industry, universities and national laboratories will supply a form of peer review and will help ensure rapid dissemination of results. The competitive stage will occur when successfully demonstrated technologies compete for commercial deployment. More demonstration projects, each with a broader mix of collaborators, will lead to greater market competition and lower compliance costs in the future.

- *Structure of Federal Financial Incentives*: Federal financial assistance would be awarded as a combination of direct assistance, loan guarantees and tax credits. A single application process would be established to allow for consideration of the whole federal financial assistance package. The overall level of federal financial assistance would be established on the basis of the need to "buy-down" the project costs in order to sell electricity on a competitive basis.

- *Project Evaluation Criteria*: New evaluation criteria would be established that would provide greater weight to commercialization potential.

- *Expedited Application Evaluation Process*: The current DOE evaluation process can be expedited by separating the technical and financial reviews into two separate processes, and bringing outside experts into the both evaluations:

    - The technical review would be led by DOE personnel, with the advice and assistance of an outside technical review panel, modeled after NSF and NIH peer review panels, to advise DOE on the relative technical merits of proposals.

- The financial review would be conducted by DOE with the advice and assistance of commercial project finance experts.

- *Corporate Decision-making Model:* The broader objectives of the proposed RRRC demonstration program are more amenable to a Board of Directors decision-making model, rather than the Source Selection Authority model used for R&D solicitations. A DOE Selection Board, modeled after the DOE Credit Review Board, would ensure that the final selections reflected the perspectives of senior Departmental officials with expertise in science, technology, policy, environmental and financial matters.

- *Form of federal financial assistance instrument*: For spending assistance (direct awards and loan guarantees), a single federal financial assistance instrument would be developed, using authorities currently available to DOE for Other Transactions Authority and the Title XVII loan guarantee authority.

- *Conditional and Final Awards*: In order to expedite contract negotiations, reduce risk and diminish the potential for unrealistic conditions, DOE would enter into "conditional awards" to include provisions to protect the government's interests while outstanding terms and conditions are being finalized. Conditional awards could allow for a "draw" of up to 10% of the federal assistance during the period of conditionality, so that project planning and design activities could proceed while remaining issues are resolved. Each award would contain a hard cap on federal assistance, but the cap would be established at the time that detailed design is at least 50% complete.

- *More Flexible Demonstration Period*: The length of the demonstration period should reflect market conditions as well as technical considerations. In particular, the length of assistance should allow for a transition where the enactment of a mandatory greenhouse gas reduction program begins to establish a price signal for carbon. Terminating federal assistance for a CCS demonstration project while the market price of carbon is zero virtually guarantees that the project will not be able to sell electricity under competitive terms.

- *Cost accounting, controls and accountability*: Strict cost accountability would be maintained, using commercial practices rather than standard government procurement practices.[24] The project sponsors could utilize established commercial cost accounting, control and audit procedures, subject to DOE review. DOE payments to the project would be based upon a negotiated draw schedule.

- *Central Reserve Fund*: Project awards would allow for contingencies, consistent with normal business practices. In addition, DOE would establish a central reserve fund, not to exceed 20% of the cost of the program, to manage any cost and schedule related issues outside of normal contingencies. DOE's exercise of the central contingency fund would be subject to special reporting to OMB and Congress.

24 The standard FAR restrictions on unallowable costs specified in 48 CFR 31.205, such as advertising, entertainment, fines and penalties, lobbying, etc. would still apply.

- *Carbon Sequestration Liability*: In order to expedite the demonstration of carbon capture technologies, DOE should consider options that provide greater flexibility to project sponsors.
    - One option is to allow project sponsors to demonstrate initially carbon capture only, deferring a decision on carbon sequestration until such time as the carbon capture technology is successfully demonstrated and a federal regulatory and liability scheme for carbon capture is in place.
    - Another option is for DOE to indemnify demonstration program participants from any liability for geologic carbon sequestration liability so long as the participants can demonstrate compliance with applicable federal and state sequestration regulations and permitting requirements in effect at the time of the project award. DOE indemnification would be transferable to any future national carbon sequestration liability protection regime.

Table 4. Technical Specifications for the RRRC Demonstration Program

PRE-COMBUSTION CCS

Candidate Units	Older, smaller coal units Existing gas turbine units
Demonstration Size	About 200 Mw_e
Coal Type	Varies (depending on gasification technology)
Demonstration	Repower existing generator with IGCC
Candidate Technologies	GE E-Gas Siemens Shell
Number of Demonstrations	3
Alternative Configuration	Industrial polygeneration demonstration

OXY-COMBUSTION

Candidate Units	Moderately old sub-critical PC without SO_2 and NO_x controls
Demonstration Size	300-500 Mw
Coal Type	Low-sulfur
Demonstration	Repowering of unit to supercritical PC with Oxy-combustion
Candidate Technologies	Alstom B&W
Number of Demonstrations	2

POST-COMBUSTION DEMONSTRATION PROGRAM

Candidate Units	Newer supercritical PC units equipped with FGD and SCR
Demonstration Size	200-500 Mw_e
Coal Type	Various
Demonstration	Retrofit CCS to existing facilities
Candidate Technologies	MHI hindered amine Fluor MEA ABB Lummis MEA ConSolve improved amine Alstom chilled ammonia PowerSpan ammonia
Number of Demonstrations	3-6

New Government Corporation Model: The management model described above also could be implemented through the establishment of a new Government Corporation whose mission included the demonstration and commercialization of RRRC technologies.

There have been a number of proposals to establish a new government corporation to accelerate the pace of energy technology commercialization. These proposals are based on a belief that the current Department of Energy is not capable of successfully executing a major technology demonstration and commercialization program.

The MIT Coal Study proposed the establishment of a Clean Coal Demonstration Corporation. Referring to the proposed CCS technology demonstration program, the MIT Report noted that "…DOE has limited capability to carry out such a task: its staff has little experience with commercial practice, it is hampered by federal procurement regulations, and it is constrained by an annual budget cycle." [25]

A 2008 Report by the Center for American Progress recommended an Energy Technology Corporation to manage demonstration projects across all technologies, including carbon sequestration. The Report stated that; "It is particularly important to foster effective government/industry collaboration on demonstration projects because the purpose of such projects is to establish commercial feasibility. Too often, the commercial potential of demonstration projects is obscured by the involvement of federal agencies and their restrictive federal procurement requirements, government-loan repayment procedures, and concerns about intellectual property rights. As a result, the market is not convinced of an effective demonstration of technology and private industry does not get the information it needs from the demonstration to make investment decisions." [26]

These concepts have been embodied in legislation proposed by Senator Bingaman, former Senator Domenici, and Representative Inslee. Table 5 contains a summary of several of these proposals. These proposals have two principal motivations: (1) that the current DOE is not capable of instituting the types of structural and process reforms needed to rapidly respond to the climate challenge, and; (2) a government corporation provides a more flexible structure to manage quasi-business activities.

25 "The Future of Coal: Options for a Carbon-Constrained World," Dr. James Katzer, Executive Director, MIT, 2007, pp 101-102,
26 "A New Strategy to Spur Energy Innovation," Peter Ogden, John Podesta, and John Deutch, Center for American Progress, January 2008.

TABLE 5. SUMMARY OF GOVERNMENT CORPORATION PROPOSALS

<u>MIT</u>

THE FUTURE OF COAL: OPTIONS FOR A CARBON-CONSTRAINED WORLD, MARCH 2007

Scope	3-5 carbon capture demonstration plants (250-500 Mw_e scale) <u>and</u> 3-5 sequestration demonstration projects (1 million MT/year scale)
Method of Support	Purchase of CO_2 through reverse auction under multi-year take or pay contracts
Management	Quasi-public corporation ("Clean Coal Demonstration Corporation")
Budget	$5 billion over 10 years
Financing	Direct Federal appropriation <u>or</u> small charge (less than $0.5 million per kWh) on coal-fired generation

<u>PEW CENTER</u>

A PROGRAM TO ACCELERATE THE DEPLOYMENT OF CO_2 CAPTURE AND STORAGE: RATIONALE, OBJECTIVES AND COSTS, OCTOBER 2007; AND,

A TRUST FUND APPROACH TO ACCELERATING DEPLOYMENT OF CCS: OBJECTIVES AND CONSIDERATIONS, JANUARY 2008

Scope	10-30 commercial-scale demonstrations of CCS over 10- to 15-year period; staggered deployment schedules to gain from "learning by doing" <u>and</u> 5-10 large-scale demonstrations of storage (primarily in saline formations)
Method of Support	Cost reimbursement for CCS capital and operating costs, including reimbursement for reduction in generation output due to CCS operation
Management	CCS Trust Fund, not subject to annual appropriations, managed by a quasi-public or private entity
Budget	$8-30 billion total; $0.8-1 billion per year (2006 $)
Financing	$0.4-0.5 mills per kWh fee on coal-based generation

<u>EPA, CLEAN AIR ACT ADVISORY COMMITTEE (CAAC)</u>

ADVANCED COAL TECHNOLOGY WORK GROUP, JANUARY 2008

Scope	5-10 early commercial CCS facilities over 5- to 10-year period
Method of Support	Payment of incremental costs of CCS through reverse auction
Management	Quasi-Governmental entity managing a quasi-Governmental fund
Budget	$5 billion minimum ($1 billion annually for 5 years), extendable to 10 years
Financing	Three options: 1. Charge on fossil fuel generation 2. Use of proceeds from the auction of allowances 3. Industry contributions

<u>H.R. 6258 –BOUCHER BILL</u>

CARBON CAPTURE AND STORAGE EARLY DEPLOYMENT ACT, JUNE 2008

Scope	Large-scale demonstrations of CCS over 10-year period
Method of Support	Competitive grants and contracts <u>and</u> purchase of CO_2 through reverse auction <u>and</u> recovery of compliance costs
Management	Carbon Storage Research Corporation; private, off-budget entity, established as division or affiliate of Electric Power Research Institute via industry association referendum among fossil fuel-based electricity distribution utilities (those representing 2/3 total fossil fuel-based electricity delivery); corporation dissolves after 15 years
Budget	$1-1.1 billion per year
Financing	Assessment on fossil fuel-based generation: Coal: $0.43 mills per kWh Natural gas: $0.22 mills per kWh Oil: $0.32 mills per kWh

Federal policy on the use of quasi-government corporations is somewhat vague. President Truman was the first President to attempt to establish a federal policy on the formation of government corporations, stating that "Experience indicates that the corporate form of organization is peculiarly adapted to the administration of government programs which are predominantly of a commercial character…" [27] The most recent statement of federal policy was a Clinton Administration OMB Memorandum, "Specifications for Creating Government Corporations" that created a process for OMB review of government corporation proposals. [28] The guidance defined a three part analysis:

- First – is this a businesslike enterprise?
- Second – Why not privatize?
- Third – Should the entity become a government corporation? This requires three findings: (1) the entity is sufficiently businesslike, (2) it cannot privatize immediately, and (3) it would function better as a corporation than under other alternatives.

In view of DOE past performance in managing large capital projects, and in particular, in the implementation of the CCPI program, there is a strong case to be made for vesting the RRRC technology demonstration program activities in a new organization. With respect to the program design specified above, a new government corporation likely would be superior to the current DOE organization in three areas:

- *Management personnel:* the increased flexibility to attract and retain high quality program managers (and out-place poor performing managers) makes the government corporation more attractive that the current DOE.

- *Financial Flexibility*: the program model described above requires a more sophisticated and flexible approach in fashioning a package of federal financial incentives tailored to each project. A government corporation would more likely have a more complete financial "tool box" and the capability to use it to support individual demonstration projects.

- *Carbon sequestration liability management:* An RRRC demonstration program will be a path breaking effort, and will require agility and creativity in addressing liability issues. In fact, it is likely that the experience gained from an accelerated RRRC demonstration program will inform the development of future regulatory and liability management schemes. The types of challenges that could be encountered likely could be better managed through a new government corporation than the existing DOE.

Programmatic features of three alternative research program models – CCPI Round III, an "Enhanced DOE Model" and a "New Management Model" – are seen in Table 6.

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27 U.S. Congress, House Document No. 19, 80th Congress, 1st Session, 1948, pp. M57-61.
28 "Memorandum for Heads of Executive Departments and Agencies on Government Corporations," U.S. Office of Management and Budget, M-96-05, December 8, 1995.

Table 6. Comparison of CCS Technology Program Management Models

	Current CCPI Business Model	Enhanced DOE Business Model (Existing Authority)	New Management Entity (New Legislation)
Decision-making Programmatic Project-Specific	Secretary/Assistant Secretary Source Selection Official	Secretary/Assistant Secretary Credit Review Board Model	Board of Directors/CEO Board of Directors/CEO
Application review process	Reviews by DOE personnel with Limited use of consultants; Sequential review by NETL and DOE/FE/HQ	External peer review panels modeled after NSF and NIH (and subject to appropriate non-disclosure and conflict of interest). If necessary, DOE can utilize parallel review teams to ensure consistency.	External peer review panels modeled after NSF and NIH (and subject to appropriate non-disclosure and conflict of interest). If necessary, DOE can utilize parallel review teams to ensure consistency.
Federal Personnel	All program personnel subject to federal personnel requirements	All program personnel subject to federal personnel requirements	Program management staff can be hired without federal personnel restrictions, and can be limited term appointments (similar to NSF and Sematech)
Funding Mechanism	Cooperative Agreements	Other Transactions Authority (OTA)	Cost-sharing, equity investments, loans, loan guarantees, securitization, insurance
Coordination of financial incentives	Three separate application and decision-making process for cost sharing, loan guarantees and tax credits	Single application and review process within DOE for cost-sharing and loan guarantees; DOE coordination with Treasury to provide seamless interface with the applicant on tax credit	Single application and review process, with seamless interface with Treasury on tax credit issues
Eligible and ineligible costs	FAR cost principles	Generally accepted business practices; FAR ineligible costs would still apply	Generally accepted business practices; FAR ineligible costs would still apply
Cost Controls	Cost cap established at time of award; no cost sharing of cost overruns	Cost cap established when project achieves at least 50% detailed driven, but prior to construction; sharing of limited cost increases	Cost cap established when project achieves at least 50% detailed driven, but prior to construction; sharing of limited cost increases
Cost Sharing	At least 50% non-federal cost sharing and within budget period	Waivers permitted based upon technology risk; size of sponsoring company and potential benefit of the technology	Waivers permitted based upon technology risk; size of sponsoring company and potential national benefit of the technology
Schedule Controls	Project sponsor is not permitted to request a schedule extension. DOE may in its sole discretion extend the schedule by up to four years	Project sponsor is not permitted to request a schedule extension. DOE may in its sole discretion, extend the schedule by up to 4 years.	New entity can establish appropriate incentives or disincentives to encourage timely completion of projects
Audits	DOE Audits (Through DCAA)	3rd Party audits	Audits conducted by new entity or by 3rd parties
Intellectual Property Rights			New entity can negotiate rights commensurate with level of investment
Liability	Applicant indemnifies the government for any project-related liability	DOE provides liability protection From geologic sequestration activities conducted in conformance with EPA VIC permits; DOE establishes reserve fund to cover liability	DOE provides liability protection from geologic sequestration activities conducted in conformance with EPA VIC permits; DOE establishes reserve fund to cover liability

Funding Mechanisms

As stipulated, adequate and sustained funding is essential for the success of the proposed RRRC demonstration program.

The current CCPI program receives annual appropriations, and each of the three CCPI solicitations to date have been fully funded—i.e. DOE had funds on hand from current or past appropriations at the time the cooperative agreements were finalized. Thus recipients did not need to be concerned about the risk if future appropriations were not provided.

The downside of this approach was that the total size of project awards was limited by the level of appropriations that could be provided on a lump sum basis in a single appropriations bill. Both CCPI Round I and CCPI Round II were funded in this manner. CCPI Round III promises to be the largest solicitation to date, with a total federal funding pool of up to $1.5 billion, cobbled together from unspent funds from prior solicitations, FY 2008 appropriations, stimulus funds, and the FY 2009 Omnibus Appropriations Act. However, this result was obtainable only through a unique combination of events that likely will not be replicated. Moreover, the Obama Administration goal to reduce the federal deficit by 50% over the next four years means that there will be increasing pressures on future appropriations levels -- another funding mechanism is needed.

Such a mechanism is found in the clean energy technology funding mechanism proposed in President Obama's FY 2010 budget which would set aside $15 billion per year ($150 billion over ten years) from receipts from the proposed cap and trade program. There is however, a timing problem.

Because the first auctions are not proposed until FY 2012, the new $15 billion funding mechanism would not begin until then. This funding-phase problem could be resolved if DOE were authorized to borrow up to $15 billion from the Treasury, effective the beginning of FY 2010, with revenues from the proposed cap and trade program pledged for repayment as they are received. This amount represents only 10% of the proposed set aside for clean energy technology, but would provide a large and secure funding source to quickly initiate the CCS retrofit demonstration program and enable it to attract a robust set of research partners. Although there are many details to be resolved over the cap and trade legislation, it seems highly likely that some form of mandatory program for carbon dioxide emission reductions will become law in the relatively near future.

A final alternative to provide adequate and sustained funding for the CCS retrofit technology demonstration program is to establish a new dedicated funding source for the program. The most obvious source of funding would be a new fee imposed on coal production with proceeds dedicated to the funding of the RRRC technology program.

The issues surrounding the establishment of a fee were addressed in detail in a two-part study by the Pew Center in 2007.[29] The study recommendation contained three key components:

29 "A Trust Fund Approach to Accelerating Deployment of CCS: Objectives and Considerations," Naomi Pena and Edward S. Rubin, Pew Center on Global Climate Change, January 2008.

- establishment of a Trust Fund, managed by a quasi-public or private entity;
- a dedicated funding source from a new fee of 0.4-0.5 mills per kwh on coal-based generation; and
- independence from annual appropriations.

These concepts were embodied into legislation (H.R. 6258) introduced in by Rep. Rick Boucher in 2008. The details of the Pew recommendations and the Boucher bill are shown in Table 5.

While the fee concept has a sound policy rationale—internalizing the cost of developing CCS controls within the price of coal—the concept has significant political controversy. The utility industry supported the legislation, provided that the fee could be passed through in rates charged to customers. However, this in turn generated opposition from members of Congress concerned about the appearance of imposing a new albeit small tax on consumers, especially in view of the severe economic downturn.

Management Model for the "Over the Horizon" RRRC Program

Separate from the near term demonstration program, there will be a need for continuing basic and applied research to support and accelerate RRRC technology development as well as to conduct analytical work to support the program.

The R&D requirements likely will fall into two areas: further evolutionary process improvements to existing RRRC technologies and R&D on novel and potentially breakthrough opportunities. These structure, participants and requirements of these two R&D activities are very different, both from each other as well as from those for RRRC demonstration projects. As such, they should be managed separately.

The evolutionary R&D activity can be managed through the current DOE Office of Fossil Energy coal technology R&D programs. The Office of Fossil Energy has long experience in managing this type of R&D activity. Moreover, the evolutionary R&D program can be more easily controlled, in terms of scope of work and program schedules, to fit within alternative annual budget profiles.

The potentially breakthrough research requires a different, and separate, management structure. This type of research would be an ideal candidate for inclusion with the DOE Advanced Research Projects Agency—Energy (ARPA-E). ARPA-E, designed to replicate where possible, the successful DARPA program at DOD, is currently being stood up at DOE. Features of the new program focus in large part on process -- relative freedom from the restrictions and requirements under which most federal research programs operate including burdensome contracting, reporting, and oversight orders and regulations, low pay grades, the rigidities of the civil service system, and multi-leveled management hierarchies. Other features will likely include:

- A small, relatively non-hierarchical organization
- Flexible hiring and contracting practices that are atypical of the federal government
- The ability to hire quickly from the academic world and industry at wages substantially higher than those of the federal workforce
- Short tenures, turnover of personnel enabling fresh leadership and ideas on a continuous basis
- A lean, effective, agile – and largely independent – organization that can stop and start targeted programs based on performance and …relevance

- A focus on creative, out of the box transformational research that could lead to new ways of fueling the nation . . . as opposed to incremental research on ideas that have already been developed
- Longer-term research funding in a highly flexible program – risk taking

ARPA-E received an appropriation of $400 million in the stimulus legislation, and likely will receive additional annual appropriations in future years. It is proposed that $40 million, or 10%, of the ARPA-E funds be allocated to R&D focused on breakthrough opportunities in RRRC. This program would be directed by a senior program manager, assisted by a small staff of individual project managers.

In keeping with the general philosophy of the ARPA-E approach, the senior program manager or the individual project managers of both could be scientists or research managers on term appointments or loans to DOE. ARPA-E could develop individual R&D projects drawing from the concepts and ideas presented in the accompanying paper on over-the-horizon research opportunities. In addition, the ARPA-E program, with its greater agility, would be empowered to seek scientific breakthroughs through, for example, the intersection of conventional carbon chemistry with new developments in nanotechnology-based separations, or biochemistry and other cutting-edge technologies. The objective would be to seek out the "home run" opportunities, and cut losses early.

The initial $40 million endowment for a program of breakthrough research in RRRC technology could provide the momentum for the first 1-2 years of research projects. Additional funding likely would be needed beginning in the FY 2011 federal budget cycle.

The drawback to this approach for which there would be three different programs dedicated to meeting the same of similar objectives is governance. DOE has a long history of stove-piped programs and a poor track record for managing cross-cutting issues and programs. There would need to be a coordinating mechanism for RRRC programs; to be effective, it should report to one of the top leaders of the Department, not lower than the appropriate Undersecretary with broad jurisdiction over energy research.

Conclusion

We posed several questions at the beginning of this discussion and would like to re-visit them to summarize this analysis.

- Is there an optimal program model to enable rapid development and deployment of technologies necessary to meet program objectives?
- Can such outcomes be accommodated by existing programs at DOE? If so, which one(s)?
- What existing authorities might DOE employ to meet the objectives of such an effort? Are these authorities adequate or being utilized to the maximum extent practicable?
- Is an entirely new program necessary? If so, are new authorities required or are existing organic statutes adequate for addressing the requisite tasks of such a program?
- Are there structural, personnel and/or standard operating procedures at DOE that might impede timely achievement of program objectives?

Climate imperatives, coupled with the need for affordable electricity supplies and historical program bias, make an RRRC program an urgent necessity. The focus of the current CCPI Round III solicitation would address some but not all of the needs for RRRC technology development. Further, the inflexibility of the requirements of the Round III solicitation, coupled with historical DOE practice, severely inhibit a rapid, comprehensive and robust response to RRRC technology development.

This paper recommends a fundamentally different approach to RRRC demonstration program, as compared to the current CCPI Round III solicitation:

- A commercial, rather than a technical demonstration program
- A program with a broad scope to demonstrate multiple technologies in parallel, and allow the competition at the deployment stage.
- A program that presumes enactment of a mandatory greenhouse gas emissions reduction program, with targets and timetables similar to those proposed in the President's FY 2010 budget, and a planned transition from demonstration into compliance mode of operation.
- A demonstration program based on cost effectiveness considerations rather than technology-forcing requirements
- Federal assistance packages that take into account competitive market pressures rather than stringent but arbitrary cost caps
- Financial assistance agreements based on commercial terms and conditions rather than government procurement restrictions.

The recommended strategy can be implemented using the current CCPI demonstration program as the starting point. However, significant changes in CCPI III would be essential for accommodating the time drivers, the need for enhanced flexibility, and the expanded as well as more focused scope of an RRRC Program. Changes that could be made absent any additional authorities should include:

- an expanded scope which allows for efficiency and co-firing technology demonstrations, as well as demonstration of technologies to mitigate CO_2 emissions from gas-fired power generation;
- change selection criteria to add weight to commercialization possibilities;
- utilization of existing authorities, most specifically "others transaction authority" that could ease contracting impediments associated with cooperative agreements and rigid compliance with the FAR;
- the creation of single financial assistance package for proposal winners;
- additional contract term flexibility including conditional awards, a central reserve fund for unanticipated costs, allowance for use of industry accounting practices and systems, etc.;
- de-coupling of the capture and sequestration requirements of the solicitation, or interim provision of liability protection for geologic sequestration; and
- funding of novel RRRC concepts from the ARPA-E program, recognizing that this would create a need for a high-level coordinating body within DOE to ensure that different RRRC efforts are complementary and not duplicative

Such changes could begin with the anticipated re-opening of the current CCPI Round III solicitation, and could be expanded into a future solicitation in 2010. More fundamental change requires new legislation, most importantly:

- establishing a separate government corporation. While this could ultimately be the best option for successful commercialization of demonstrations, it has a severe timing drawback; it requires new statutory authority and would involve significant startup delays. Consideration of this option in parallel with CCPI Round III is recommended.

Congressional consideration of legislation to authorize the establishment of a new "clean energy" financing authority appears likely in 2009. However, even if such legislation is enacted in 2009, it is likely that the activation of a new quasi-government entity for financing new clean energy technologies may take at least 12, and more likely 18 months. Thus, a new entity may not be operational until sometime in 2011. Timing considerations suggest the need for a parallel strategy of optimizing current DOE processes in tandem with the consideration of a new structure and process outside of DOE.

Advanced Post-Combustion CO_2 Capture

Prepared for the
Clean Air Task Force

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Doris Duke Foundation

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1. Background and Motivation

The total US CO_2 emissions for 2006 were 5934 million metric tons (Mt). Of this, the electricity sector was responsible for 2344 Mt (39.5%). Coal-fired power plants produced 83% of the electricity sector's CO_2 emissions, with most of the remaining emissions from natural gas-fired power plants (EIA, 2007). These emissions were the result of supplying electricity to US homes, businesses, and industry – over 6,000 kWh per person from coal power alone (roughly half the average total US electricity consumption).

In China and India, rapid economic growth and industrialization have resulted in dramatic emissions increases recently and now China, with a population about four times that of the US, is the world's largest CO_2 emitter. More than one coal power plant per week has been built there in recent years. Despite this build, however, Chinese per capita electricity consumption is still much lower than in the US (around 1,500 kWh per year), and India's consumption barely registers on the world scale.

The build of new coal power plants in China and India, and the existing installed base in the U.S. and elsewhere, present a tremendous challenge for reducing global CO_2 emissions over the next several decades. Fortunately, there are opportunities as well as challenges in this situation. Access to the U.S. installed coal base represents an opportunity for data collection, analysis of retrofit potential, and global leadership in CO_2 reductions.

There are essentially three approaches to reducing emissions associated with coal combustion:

- ***Burn less coal.*** In theory, this can be accomplished by both reducing demand for electricity and by substituting other fuels for coal (e.g., nuclear, renewables). In practice, this is very difficult because coal is abundant and relatively inexpensive. Despite concerns about climate change, reliance on coal has been increasing worldwide because there has not been a viable alternative to fill the role coal plays in the world's energy systems. In fact, the recent high oil prices have increased the pressure to expand the use of coal to produce chemicals and transport fuels.

- ***Improve efficiency of coal-fired power plants.*** There is real opportunity for efficiency improvements. However, if these options were aggressively pursued, at best, this effort would only reduce emissions from coal by 10-20% (Beer, 2007). While being a positive step, it is insufficient for developing near-zero emission coal-fired power plant, which may be required by future carbon policy.

- ***Capture and store the CO_2.*** Carbon dioxide capture and storage (CCS) is the only pathway that can allow the world to continue to enjoy the benefits of using coal while drastically reducing the emissions associated with coal combustion. At a minimum, CCS can be a bridging strategy to provide time for alternatives to coal to be developed.

This White Paper will focus on the topic of CCS. In particular, it looks at a set of technologies termed "post-combustion CO_2 capture". We will focus on applications to coal-fired power plants because they constitute, by far, the largest source of CO_2 emissions appropriate for CCS (IPCC, 2005). However, it should be noted that certain industrial processes (natural gas processing, ammonia production, cement manufacture, and more), as well as natural gas-fired power plants are also amenable to CCS.

At a coal-fired power plant, CO_2 is a component of the flue gas. The total pressure of the flue gas is 1 atm and the CO_2 concentration is typically 10-15%. The process of transforming this low pressure, low concentration CO_2 into a relatively pure CO_2 stream is referred to as post-combustion CO_2 capture. This capture step is typically followed by a compression step, where, for ease of transport (usually by pipeline) and storage, the CO_2 is compressed to 100 atm or more.

The idea of separating and capturing CO_2 from the flue gas of power plants did not originate out of concern about climate change. Rather, it gained attention as a possible inexpensive source of CO_2, especially for use in enhanced oil recovery (EOR) operations where CO_2 is injected into oil reservoirs to increase the mobility of the oil and, thereby, the productivity of the reservoir. Several commercial plants that capture CO_2 from a power plant flue gas were constructed in the late 1970s and early 1980s in the US. When the price of oil dropped in the mid-1980s, the recovered CO_2 was too expensive for EOR operations, forcing the closure of these capture facilities. However, the Searles Valley Minerals Plant in Trona, CA, which uses this process to produce CO_2 for carbonation of brine, started operation in 1978 and is still operating today. Several more CO_2 capture plants were subsequently built to produce CO_2 for commercial applications and markets.

All the above plants used post-combustion capture technology. They ranged in size from a few hundred tons of CO_2 a day to just over a thousand tons a day (Herzog, 1999). Deployment of post-combustion capture technologies for climate change purposes will entail very substantial increases in scale, since a 500 MW coal-fired plant produces about 10,000 tons/day of CO_2.

There are two major alternate approaches to post-combustion capture:

- ***Oxy-combustion capture.*** Because nitrogen is the major component of flue gas in power plants that burn coal in air (which nearly all existing plants do) post-combustion capture is essentially a nitrogen-carbon dioxide separation. If there were no nitrogen, CO_2 capture from flue gas would be greatly simplified. This is the thinking behind oxy-combustion capture: instead of air, the power plant uses a high purity (≥95%) oxygen stream for combustion of the coal. The oxygen is produced on-site in an air separation plant, which represents the largest cost component in the capture process.

- ***Pre-combustion capture.*** As the name implies, this refers to the capture of CO_2 prior to combustion. This is *not* an option at the pulverized coal (PC) power plants that comprise most of the existing capacity. However, it *is* an option for integrated coal gasification combined cycle (IGCC) plants. In these plants, coal is first gasified to form synthesis gas (syngas, a mixture whose key components are carbon monoxide and hydrogen). The syngas then undergoes the water-gas shift, in which the CO reacts with steam to form CO_2 and additional H_2. The CO_2 is then removed, and the hydrogen is diluted with nitrogen and fed into a gas turbine combined cycle. The advantage of this approach is that it is much less expensive than the post-combustion capture process. The disadvantages are that there are only a few IGCC plants in the existing coal fleet and IGCC plants are more expensive than PC plants when costs of CO_2 capture are not included.

Post-combustion capture is important because:

- It is compatible with – and can be retrofitted to – the existing coal-fired power plant infrastructure without requiring substantial change in basic combustion technology.
- It is the leading candidate for gas-fired power plants. Neither the oxy-combustion nor the pre-combustion approaches are well suited for gas plants.
- It offers flexibility. If the capture plant shuts down, the power plant can still operate. The other two capture options are highly integrated with the power plant: so if capture fails, the entire plant must shut down. Furthermore, it offers utilities (and regulatory commissions) the option to allow for increased capacity by temporarily curtailing the capture process during periods of peak power demand.
- There has been very slow progress in the commercialization of IGCC for power generation applications. In the US, only two IGCC plants are in operation in the power industry and both were built as demonstration plants. Several utilities are currently considering building IGCC plants; all have considerable obstacles to overcome. The ultimate commercial success of IGCC to provide coal-fired electricity remains uncertain.

Until very recently, it had been widely expected that IGCC power plants with pre-combustion capture would offer the most cost-effective path forward for CCS. In early 2007, for example, there were more than a dozen IGCC project proposals in the US alone. Due in part to dramatic capital cost increases for all technologies, few IGCC proposals survive today. In addition, much of the coal build in the developing world continues to be based on coal combustion – not IGCC – technology. This has stimulated a re-examination of the role of post-combustion capture.

For the reasons discussed above, this paper focuses on near-term as well as advanced post-combustion capture technology that could be applicable to new coal power plants and also to retrofit of existing coal power plants. Specific engineering considerations for retrofits, however, such as steam cycle and steam turbine changes, while generally considered manageable, are outside the scope of this paper. In addition, although this paper focuses on applications to coal power, generally speaking the technologies covered here would also be applicable to natural gas power plants. Section 2 of the paper reviews the current state of post-combustion capture. Current R&D thrusts are presented in section 3, and section 4 focuses on advanced R&D pathways. Finally, section 5 presents RD&D recommendations.

2. Current Status of Post-Combustion Capture

To date, all commercial post-combustion CO_2 capture plants use chemical absorption processes with monoethanolamine (MEA)-based solvents. MEA was developed over 70 years ago as a general, non-selective solvent to remove acid gases, such as CO_2 and hydrogen sulfide, from natural gas streams. The process was modified to incorporate inhibitors that reduce solvent degradation and equipment corrosion when applied to CO_2 capture from flue gas. Concerns about degradation and corrosion also kept the solvent strength relatively low (typically 20-30% amines by weight in water), resulting in relatively large equipment sizes and solvent regeneration costs.

As shown in Figure 1, which depicts a typical process flowsheet, flue gas contacts MEA solution in an absorber. The MEA selectively absorbs the CO_2 and is then sent to a stripper. In the stripper, the CO_2-rich MEA solution is heated to release almost pure CO_2. The CO_2-lean MEA solution is then recycled to the absorber.

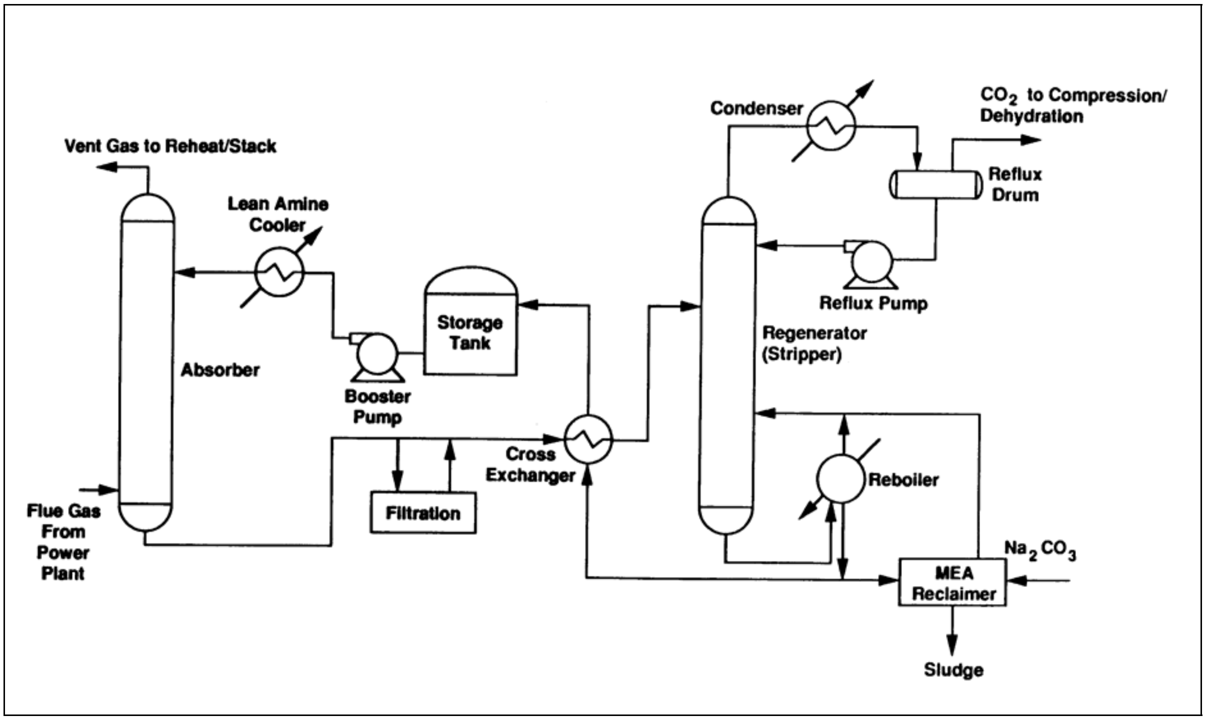

Figure 1. Process flow diagram for the amine separation process.

2.1 Cost of Capture

Table 1 shows representative costs for a supercritical (SC) PC power plant[1] with and without capture based on a modern amine system. Note that the costs include both capture and compression, but exclude transport and storage. These numbers vary over

[1] Current state-of-the-art supercritical plants operate at 24.3 MPa (3530 psi) and 565 C (1050 F) (MIT, 2007).

time and location and do not represent any particular power plant project. Their primary use is to illustrate the relative costs of power with and without CO_2 capture.

The first thing to note is that when a capture and compression system is added, the plant's overall thermal efficiency (the fraction of the energy released by combustion of the fuel that is transformed into electricity) drops from 38.5% to 29.3% (a *relative* decrease of 24%). This is caused by the additional parasitic energy load from the CO_2 capture system. The parasitic load can be broken down into three components:

- Extraction of steam from the plant's electricity-generating turbine to the stripper reboiler accounts for over 60%. The steam provides energy to break the chemical bonds between the CO_2 and the amine; provides heat required to raise the temperature of the amine solution to the operating temperature of the stripper, and sweeps away the released CO_2.
- Electricity to drive the CO_2 compressors accounts for about a third.
- Electricity to drive the blowers to push the flue gas through the absorber accounts for about 5%.

The drop in thermal efficiency with capture has multiple effects on plant cost. First, 30% more coal must be burned to produce the same amount of electricity[2]. More importantly, as indicated in Table 1, the capital cost of the plant in $/kW increases by 61%. This is because capital investment increases by 22% or a factor of 1.22 (to pay for the amine absorption process, compressors, etc.) while electrical output decreases by 24% or a factor of 0.76; thus, the investment cost expressed in $/kW increases by a factor of 1.22/0.76 or 1.61. In other words, parasitic energy drain translates into the consumption of more coal per kWh *and* an increase in plant capital beyond the purchase price of additional equipment. Because of the magnitude of this effect, a *key goal of research in post-combustion capture is to reduce the parasitic energy load*.

[2] This would also increase the variable operating cost of the plant which could reduce the dispatch factor for the plant. This potentially important impact is ignored in this analysis.

Table 1. Updated Capture (including Compression) Costs for Nth Plant SCPC Generation[3] (Hamilton *et al*., 2008)

	Reference Plant	**Units**	**SCPC**
Total Plant Cost		\$/kWe	1910
CO_2 emitted		kg/kWh	0.830
Heat Rate (HHV)		Btu/kWh	8868
Thermal Efficiency (HHV)			38.5%
LCOE	Capital	\$/MWh	38.8
	Fuel	\$/MWh	15.9
	O&M	\$/MWh	8.0
	Total	\$/MWh	62.6
CO_2 Capture Plant			
Total Plant Cost		\$/kWe	3080
CO2 emitted @ 90% Capture		kg/kWh	0.109
Heat Rate (HHV)		Btu/kWh	11652
Thermal Efficiency (HHV)			29.3%
LCOE	Capital	\$/MWh	62.4
	Fuel	\$/MWh	20.9
	O&M	\$/MWh	17.0
	Total	\$/MWh	100.3
\$/tonne CO_2 avoided			
vs. SCPC		\$/tonne	52.2

Table 1 reports the mitigation or avoided cost in \$/tonne CO_2 avoided. Because of the parasitic energy requirement, the number of tonnes avoided is always less than the number captured. As a result, the \$/tonne avoided is always greater than the \$/tonne captured. This is shown graphically in Figure 2. The top bar shows the amount of CO_2 emitted per kWh from a reference plant without capture. The lower bar shows the amounts of CO_2 emitted and captured per kWh from the same power plant with 90% CO_2 capture (includes compression). Because of the parasitic energy requirement, more CO_2 is produced *per kWh* in the capture plant. The amount of CO_2 avoided is simply the difference in emissions between the reference plant and the plant with capture.

[3] This cost assumes: 2007\$, Nth plant (i.e., ignores first mover costs), 90% capture, 85% capacity factor, bituminous coal (Illinois #6), does not include transport and storage costs, assumes today's technology (i.e., no technological breakthroughs required), assumes regulatory issues resolved without imposing significant new burdens, assumes operations at scale (i.e., 500 MW_e net output before capture).

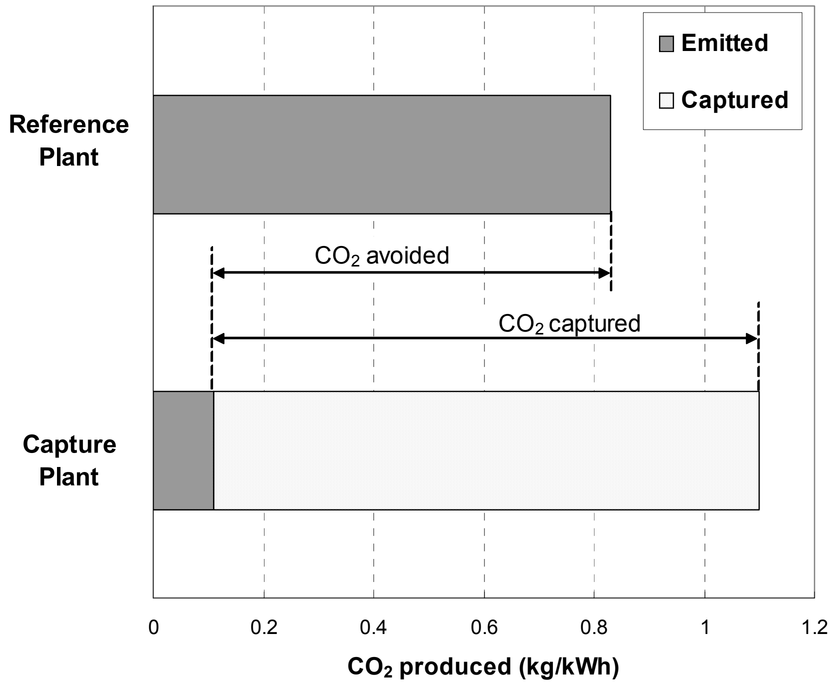

Figure 2. Graphical representation of avoided CO_2. The avoided emissions are simply the difference between the actual emissions per kWh of the two plants. Note that due to the parasitic energy requirement (and its associated additional CO_2 production), the amount of emissions avoided is always less than the amount of CO_2 captured.

The mitigation cost in $/tonne CO_2 avoided is particularly significant because it is the quantity with which the permit price for a cap-and-trade system should be compared. As indicated in Table 1, the mitigation costs for the capture plant come to about $52/tonne of CO_2 avoided. Typically, transport and storage add about $10 more, making the total CCS mitigation cost around $62/tonne of CO_2 avoided. The latter figure suggests the magnitude of the cap-and-trade permit price that is required to make CCS commercially viable, assuming current technology and no other policy incentives.

2.2 Potential for Reducing the Parasitic Energy Loss

As noted above, the parasitic loss due to capture and compression is 24%. About one-third (8%) is due to compression, with the rest (16%) attributable to separation. A key question is how much improvement is possible. To answer this question, a rough "minimum work" calculation is frequently conducted along the lines outlined in Appendix A. There it is shown that:

- The minimum work of separation (for 90% capture) = 43 kWh/t CO_2 captured
- The minimum work of compression = 61 kWh/t CO_2 compressed

By comparison, a typical SCPC power plant without carbon capture produces one tonne of CO_2 for every 1200 kWh of net power generated. It follows that the *minimum* energy requirement for separation (as a percentage of net power production) is [43 kWh/t CO_2 captured] x [9t captured/10t produced] / [1200 kWh/t CO_2 produced] = 3.2%. The estimated *actual* parasitic load (16%) is 5 times that. By comparison, the estimated minimum energy requirement for compression is [61 kWh/t] x [9t/10t] /[1200 kWh/t] = 4.6%. The estimated actual parasitic load (8%) is less than 2 times that. This suggests that there is considerably more room for improving the efficiency of the separation process than for the compression process.

In a typical SCPC power plant without capture, only 38.5% of the energy released by burning the fuel is transformed into electricity – i.e., the "first law efficiency" is 38.5%. The remaining 61.5% can be considered waste heat. Use of some of that waste heat to drive CO_2 capture reduces parasitic power consumption. For example, without the use of waste heat, the separation parasitic load would be about double the 16% stated above. Estimating the maximal extent to which a given plant's waste heat is applicable to CO_2 recovery will require a more complex analysis than the one outlined in Appendix A – i.e., an "exergy" analysis of an integrated power plant/CO_2 capture system.

2.3 Commercial vendors

In the 1970's, when a commercial market was developing for CO_2 captured from power plants (mainly for use in EOR), two processes were developed. One was by Kerr-McGee and the other was by Dow Chemical. The former was based on a 20% MEA solution and used primarily with coal-fired boilers (Barchas and Davis, 1992). The latter was a 30% MEA solution used primarily on natural gas plants (Sander and Mariz, 1992). Today, the Dow technology (ECONAMINE FG) is licensed by Fluor and the Kerr-McGee technology by ABB/Lummus. Several installations worldwide use these technologies.

Three other vendors also offer commercial amine processes:

- **MHI in Japan** developed a process named KM-CDR based on a proprietary solvent termed KS-1 (probably involving a hindered amine) that they offer commercially for gas-fired plants (with an offering for coal-fired plants under development). They claim that their process is the most energy efficient of the commercial offerings. Four commercial units for gas-fired plants have been built with this technology, with four more under construction. Tests are currently being conducted at the pilot scale on coal-fired flue gas (Kishimoto *et al.*, 2008).

- **HTC Purenergy** is offering a process package. It is based on research done at the International Test Centre at the University of Regina that developed a mixed amine solvent. One way they are attempting to lower costs is by offering modular units that can be pre-fabricated. They have a unique marketing strategy, whereby they will finance, construct and manage the process. They also have an option in which they will own and operate the process.

- **Aker Clean Carbon in Norway** also offers a commercial package. The Just Catch process was initiated by Aker Clean Carbon AS with support from a larger industrial consortium (Sanden *et al.*, 2006). Just Catch is aimed at developing and verifying an amine based technology in a cost efficient manner. The preliminary results are based on a set of feasible technological improvements where the further engineering design is performed with the principal goal of facilitating cost-effective solutions, minimizing technical and economic risks, and developing confidence in cost estimation.

- **Cansolv** is offering a CO_2 capture process is based on a recently developed amine system using a proprietary solvent named Absorbent DC101™ (Cansolv, 2008). The solvent is based on tertiary amines, and probably includes a promoter to yield sufficient absorption rates to be used for low pressure flue gas streams (Hakka and Ouimet, 2006). With the use of oxidation inhibitors this process can be applied to oxidizing environments and where limited concentrations of oxidized sulfur exist. It is claimed that this process can also simultaneously remove other acidic contaminants and particulate material, such as SO_x, and NO_x. Two demonstration plants of the Cansolv CO_2 capture system have been built. One in Montreal, Canada, for capture of CO_2 from flue gas of a natural gas fired boiler, and one in Virginia, for CO_2 capture from flue gas of a coal fired boiler. No commercial plants have yet been built.

3. Current R&D Thrusts

Figure 3 outlines the various technology pathways to post-combustion capture. Most of these pathways are discussed in this section; the exploratory technologies are reviewed in section 4.

Flue Gas R&D Pathways

ABSORPTION	Reactive SOLIDS	ADSORPTION	MEMBRANES
MEA, other alkanolamines Blended alkanolamines Piperazine MEA/Piperazine K2CO3/Piperazine Less corrosive amines Less degradable amines Low ΔHrxn amines Chilled Ammonia Nonaqueous solvents	CaO Na_2CO_3 NaOH/CaO Li_2O/Li_2ZrO_3 Li_4SiO_4	ZEOLITES 5A, 13X, MCM-41 CARBON, SILICA, ALUMINA Amine-doped Potassium salt-doped	Gas/Liquid Contactors Permselective and high-temperature Polymers BIOLOGICAL Algae (photosynthesis) Carbonic anhydrase (enzyme-catalyzed CO2 hydrolysis) EXPLORATORY ADSORPTION on self-assembling organic nanochannels, & metal/organic frameworks ABSORPTION by polyamines, ionic liquids

3.1 Absorption

In absorption (or "scrubbing") flue gas is contacted with a liquid "absorbent" (or "solvent") that has been selected because carbon dioxide dissolves in it more readily than nitrogen – i.e., it is *selective* for CO_2. The process takes place in tall columns ("towers") known as scrubbers, in which turbulent flow promotes rapid CO_2 transfer from gas to liquid. Differences in density make it easy to separate the emerging gas and liquid.

To recover the captured CO_2 the loaded solvent is pumped to a "stripper" in which it is exposed to hotter CO_2-free gas, typically steam. Heating of the solvent causes desorption of the CO_2 (and traces of nitrogen). The stripped liquid is pumped back to the scrubber, while the steam/CO_2 mixture is cooled to condense the steam, leaving high-purity CO_2 suitable for compression and, after transportation to an appropriate site, sequestration.

The *capital* costs of scrubbing decrease as the *rates* of CO_2 absorption/stripping ("mass transfer") increase. This is mainly because smaller absorbers and strippers – with correspondingly shorter gas/liquid exposure times - are required when CO_2 transfer rates are higher. *Operating* costs are also lower when the scrubber and the stripper are smaller because correspondingly less electrical energy is consumed as blower and pump *work* that drives the gas and liquid through them. However, the principal operating expense is for the energy consumed as *heat*, primarily to generate steam, but also to warm the loaded solvent.

Water itself is much more soluble to CO_2 than to N_2. However, its *capacity* for CO_2 is still so low that capturing industrial-scale amounts of CO_2 would require the circulation of prohibitively large water flows. *Organic* solvents offer greater CO_2 solubilities and are, therefore, widely deployed to recover it, especially from high-pressure mixtures such as natural gas. However, the near-atmospheric pressures in coal-fired power plants favor use of aqueous solutions of chemicals that *react reversibly* with dissolved CO_2 – i.e., that combine with CO_2 in the scrubber and release it at the higher temperatures in the stripper.

Early systems for recovering CO_2 from industrial gas streams employed hot potassium carbonate solutions that react with dissolved CO_2 to form potassium bicarbonate. However, for many decades now the additives of choice have been *amines* (Kohl and Nielsen, 1997).

3.1.1 Amines

Amines are water-soluble organic chemicals that contain reactive nitrogen atoms. As noted earlier, in CO_2 separation operations the workhorse amine is *monoethanolamine* (MEA). Many other amines and, especially in recent years, amine *blends* such as MEA plus methyldiethanolamine (MDEA), have also been utilized.

Amines react rapidly, selectively and reversibly with CO_2 and are relatively nonvolatile and inexpensive. However, they are corrosive and so require more expensive materials of construction. In addition, they do gradually volatilize (which can be especially problematic in the case of MEA) and they degrade, especially in the presence of oxygen and/or sulfur dioxide, both of which phenomena necessitate the timely injection of fresh solution.

The considerable amounts of thermal energy required to strip CO_2 from loaded MEA solutions are an acceptable expense when the CO_2-purged gas is valuable. However, as emphasized earlier, when MEA is applied to flue gas purification in conventional absorber/stripper systems, the parasitic energy consumption is considerable. As indicated in Table 1, the combined costs of CO_2 capture and compression raise the price of generating electrical power by over 60%. Reducing that percentage is a primary goal of R&D activity, much of which has been exploring the performance of alternative reactants including amines other than MEA (Bonenfant *et al.*, 2003). The results have been encouraging.

Sterically hindered amines have been developed that bind more CO_2 per molecule than MEA (Sartori and Savage, 1983). However, the energy savings relative to MEA are partially offset by capital cost increases for the larger scrubbing equipment that is necessitated by lower absorption *rates*. Alternatively, MEA has been blended either with amines that are less corrosive and require less steam to regenerate (Aroonwilas and Veawab, 2004), or with the additive piperazine (PZ) that is of limited solubility in water and more volatile than MEA but markedly accelerates CO_2 absorption and allows use of lower MEA concentrations (Dang and Rochelle, 2003).

Recent computer simulations indicate that alternative *design configurations*, including operation at multiple pressure levels, can reduce energy requirements for CO_2 capture with PZ+MEA and PZ+MDEA, followed by compression, to 20% of power plant output (Jassim and Rochelle, 2006; Oyenekan and Rochelle, 2007).

3.1.2 Ammonia

Ammonia-based solutions offer possibilities for developing absorption processes based on less corrosive and more stable solvents. At the same time, since ammonia is a toxic gas, prevention of ammonia "slip" to the atmosphere is a necessity. Despite this disadvantage, considerable attention has been drawn to aqueous ammonia (AA) solutions by a decade-old report of superior CO_2 capture performance (Bai and Yeh, 1997). The CO_2 uptake per kg of ammonia is estimated to be 3 times that per kg of MEA (Yeh and Bai, 1999).

Furthermore, a recent economic study (Ciferno *et al.*, 2005) notes that the amount of steam required to regenerate AA (per kg of captured CO_2) is 1/3 that required with MEA (see also Resnik et al., 2004), and estimates that operating and capital costs with AA are, respectively, 15% and 20% less than with MEA. The projected costs of CO_2 capture and compression are only 18-21% of the total cost of electrical power production, which are comparable to the aforementioned calculated cost reductions obtainable via optimization of piperazine-based absorption process configuration.

Ammonia-based systems operate efficiently at lower temperatures than those required for conventional MEA-based scrubbing. The lower temperatures also minimize ammonia volatility and the potential for its slippage. The chemistry is for the most part analogous to that in potassium carbonate solutions, with ammonium ion replacing potassium ion: dissolved ammonium carbonate reacts with CO_2 to form ammonium bicarbonate. However, at the very low absorber temperatures of 0-10^{o}C in the Chilled Ammonia process (CAP), ammonium bicarbonate precipitates as a solid, which requires different handling.

Because the reaction is reversible at lower temperatures than with amine-based solvents, low-quality waste heat available at power plants may be more thoroughly exploited to release captured CO_2 in the strippers of ammonia-based systems.

A further, potentially exploitable advantage is that, unlike MEA, which is degraded by SO_2, ammonium carbonate reacts with SO_2 to form ammonium sulfate and with NO_x to form ammonium nitrate, both of which are marketable as fertilizers. Thus, ammonia-based CO_2 capture may be carried out either separately from or simultaneously with the scrubbing of sulfur and nitrogen oxides.

In a demonstration facility with a startup scheduled for 2011, Powerspan is planning to capture CO_2 from a 120 MW power plant flue gas using an AA system that will be constructed downstream from AA-based SO_X/NO_x control equipment (McLarnon, 2007). Powerspan is currently operating a 20 tons CO_2 per day of pilot facility at FirstEnergy's R. E. Burger plant. Similarly, Alstom Power is testing a 35 tons CO_2 per day CAP-based facility at the We Energies Pleasant Prairie Power Plant.

There will be great interest in the extents to which laboratory and pilot scale successes – including capture and recycle of the toxic ammonia vapor generated in the stripper - are replicated at industrial scale. In the meantime, researchers are actively investigating techniques for further improving AA performance, including the use of additives that reduce evaporative ammonia losses without sacrificing CO_2 capture performance (You *et al.*, 2008).

3.2 Adsorption

3.2.1 Physical sorbents

Carbon dioxide may be recovered from flue gas with a variety of nonreactive sorbents including carbonaceous materials and crystalline materials known as zeolites. High porosities endow activated carbon and charcoal with CO_2 capture capacities of 10-15% by weight. However, their CO_2/N_2 selectivities (*ca.* 10) are relatively low. Because of this disadvantage, the projected capture costs including that of compression are such that carbon-based systems become practical only when the required CO_2 purity is at most 90% (Radosz *et al.*, 2008). Zeolitic materials, on the other hand, offer CO_2/N_2 selectivities 5-10 times greater than those of carbonaceous materials. However, their CO_2 capacities are 2-3 times lower (Konduru *et al.*, 2007; Merel *et al.*, 2008). Moreover, zeolite performance is impaired when water vapor is present.

To be competitive with liquid solvents, solid sorbents must be less sensitive to steam and offer substantially greater capacities and selectivities for CO_2 than currently available physical sorbents (Ho *et al.*, in press).

3.2.2 Chemical sorbents

When heated to 850^{o}C, calcium carbonate ($CaCO_3$, limestone) releases CO_2 (calcines) and thereby transforms to calcium oxide (CaO), which recombines with CO_2 at 650^{o}C. These reactions have a long history of service in industrial processes. Limestone is also widely employed to capture flue gas SO_2. However, it loses capacity over time and, especially if deployed to capture *both* CO_2 and SO_2, requires frequent replacement (Rodriguez *et al.*, 2008).

The $CaO/CaCO_3$ system nonetheless remains attractive because of its high CO_2 capture capacity and long track record. Furthermore, it offers possibilities for power plant configurations that: (a) maximize the benefits of feeding otherwise prohibitively expensive oxygen rather than air (thereby obviating the need for post-combustion CO_2/N_2 separation), (b) exploit the availability of high level heat, and (c) improve energy efficiency by generating steam from heat released in the carbonation reaction (Manovic and Anthony, 2008; Romeo *et al.*, 2008). Consequently, $CaO/CaCO_3$-based CO_2 capture is the focus of continuing intensive research activity.

Alkali metal-based sorbents also capture CO_2, primarily via reactions that transform metal carbonates into bicarbonates, with steam as a co-reactant as when CO_2 reacts with aqueous carbonate solutions. Highly porous sodium-based sorbents operate efficiently in the same temperature range as aqueous amines (25-120^{o}C), but have considerably lower CO_2 capture capacity (Lee et al., 2008). Lithium-based sorbents that function best at 400-500^{o}C offer higher CO_2 capacities (Venegas *et al.*, 2007; Ochoa-Fernandez *et al.*, 2008). The long-term stability and performance of alkali metal-based sorbents under actual flue gas conditions remains to be established.

CO_2 capture by *amines immobilized within porous sorbents* has been an increasingly active area of research; a practical system has been deployed for CO_2 capture in a space mission life support system (Satyapal *et al.*, 2001). A variety of amines, sorbent supports and immobilizing techniques have been tested (Gray *et al.*, 2005; Knowles *et al.*, 2006; Hicks *et al.*, 2008; Yue *et al.*, 2008) and the results have been quite promising. Several amine-derived sorbents exhibit high CO_2 uptake/release capacity and stability in the 50-120^{o}C range. Furthermore, the absence of large quantities of circulating water should make thermal energy requirements for CO_2 release appreciably lower than those of amine based absorption/stripping. As noted above regarding alkali metal-based sorbents, to be commercially viable, these sorbents must be shown to operate stably for extended periods under actual flue gas conditions

3.3 Membrane-based Separations

A third mature technology under consideration for CO_2 capture is membrane-based separation. Membranes, which generally consist of thin polymeric films, owe their selectivities to the relative rates at which chemical species permeate. Differences in permeation rates are generally due (in the case of *porous* membranes) to the relative sizes of the permeating molecules or (in the case of *dense* membranes) their solubilities and/or diffusion coefficients (i.e., mobilities) in the membrane material. Because permeation rates vary inversely with membrane thickness, membranes are made to be as thin as possible without compromising mechanical strength (which is frequently provided by non-selective, porous support layers).

As is true of membrane-based filtration and desalting of water, membrane-based gas separation is a well-established, mature technology. Many large plants are operating worldwide to recover oxygen and/or nitrogen from air, carbon dioxide from natural gas, and hydrogen from a variety of process streams. As is the case with true of absorption and adsorption, economic considerations dictate that membrane systems recover CO_2 from flue gas *selectively*.

Membrane permeation is generally *pressure*-driven – i.e., the feed gas is compressed and/or the permeate channel operates under vacuum and/or a sweep gas is employed. Due to the low partial pressure of CO_2 in the flue gas, this constitutes a major challenge for the membrane-based compared to liquid absorbents or solid adsorbents that are *thermally* regenerated (i.e., heated to strip the captured CO_2).

3.3.1 Polymeric Membranes

Recently, Favre and coworkers (Bounaeur *et al.*, 2006; Favre, 2007) and Wiley and coworkers (Ho *et al.*, 2006, 2008) published the results of extensive calculations that explore the dependence of CO_2 capture costs on membrane selectivity, permeability and unit price. Most significantly, for membranes to be competitive with amine-based absorption for capturing CO_2 from flue gases, their CO_2/N_2 selectivities (i.e., permeability ratios) must be in the 200 range.

With rare exception, the selectivities of available polymers fall well below that. While many have selectivities of 50-60, they tend to be less permeable, i.e. their fluxes are low (Powell and Qiao, 2006). Once again, cost effectiveness may be achievable only when separation is promoted by a CO_2-selective chemical reaction.

Ho and coworkers (Zou and Ho, 2006; Huang *et al.*, 2008) have demonstrated that by virtue of their reversible reactions with CO_2, amines can raise the CO_2/N_2 selectivity of polymeric membranes to 170 while also boosting CO_2 fluxes. If these encouraging results are sustainable for extended periods of operation, such systems will merit serious consideration as candidates for CO_2 capture at coal-fired power plants.

3.4 Membrane Absorption

An alternative approach to CO_2 capture is to use porous membranes as *platforms for absorption and stripping*. In this embodiment, which has attracted considerable interest, membranes serve primarily to separate gas and liquid. Carbon dioxide and nitrogen each transfer easily through nonselective, gas-filled membrane pores. Selectivity is provided by the liquid, which, as usual, is typically an aqueous amine solution (deMontigny *et al.*, 2006; Shimada *et al.*, 2006). One advantage of this approach is that, unlike the case with conventional absorbers, with membrane absorbers there are no inherent restrictions to gas and liquid flowrates.

The performance, when measured in terms of mass transfer rates per unit module volume, can exceed those of absorption and stripping in conventional columns. Furthermore, modularity makes membrane systems easy to replace or expand. However, economies of scale do not apply to modular systems, whereas they do favor traditional, large absorption and stripping columns.

3.5 Biomimetic Approaches

In addition to absorption, adsorption and membrane-based systems, a wide variety of exploratory approaches are under development. Some that have shown promise take their cues from living systems that have evolved highly efficient systems for capturing and/or converting CO_2.

There have been several exploratory studies of the use of the enzyme carbonic anhydrase, which is the most efficient catalyst of CO_2 reaction with water, to promote CO_2 scrubbing from flue gases (Bond *et al.*, 2001). By immobilizing carbonic anhydrase in a bioreactor, Bhattacharya *et al.* (2004) quadrupled the rate of CO_2 absorption in water.

Microalgae systems, which have long been under investigation for CO_2 capture from air (Cheng *et al.*, 2006), are especially attractive because *they consume* CO_2 in photosynthesis. This obviates the need for CO_2 compression and sequestration. Furthermore, the algae biomass can serve as animal feed or an effectively carbon-neutral fuel (Skjanes *et al.*, 2007).

3.6 Other Approaches

Another approach that has been proposed is to cool the flue gas to low temperatures so that the CO_2 is separated as dry ice (Younes *et al.*, 2006). After the initial paper, no further information has been forthcoming.

4. Advanced R&D Pathways

Current technologies for the recovery and separation of CO_2 and other compounds from gas streams (broadly classified into the three categories: absorption, adsorption, and membrane processes, as discussed above) are relatively mature. In almost all absorption and adsorption processes, the separation step entails the formation of molecular complexes, through physical and/or chemical interactions, that must then be reversed through significant increases in temperature. The concomitant need to heat large volumes of sorbents and subsequently to cool these materials to prepare them for the next sorption cycle is wasteful both thermodynamically (unnecessary heating and cooling of inert materials) and dynamically (large thermal mass of inert materials limits heat transfer rates leading to larger required equipment sizes).

While continued improvements in performance of the above technologies can be expected with further research and development, new concepts and materials could provide significant breakthroughs in the performance and costs of capture technologies. Advanced R&D pathways seek to eliminate or at least minimize these large thermal swings, through a greater reliance on structured materials, possibly stimuli-responsive, entropic (e.g., shape selective) rather than enthalpic interactions between the sorbate and the separations media, and through the application of stimuli, e.g., an electric field, to modify the separation environment in order to release the captured solute. Some of these promising new approaches are reviewed in this section.

4.1 Solid Adsorbents

The traditional use of carbonaceous materials for CO_2 adsorption is limited by low CO_2/N_2 selectivities, and while the more structured zeolites have significantly higher selectivities, they have significantly lower capacities, and their performance is impaired when water vapor is present. Advanced research in the development of new adsorbent materials indicates some promising approaches that may overcome many of the limitations of the currently available adsorbents. Some of these approaches are discussed here.

4.1.1 Metal-Organic Frameworks

Metal organic frameworks (MOFs) are porous crystalline solid materials with well-defined cavities that resemble those of zeolites (Millward and Yaghi, 2005; Bourelly *et al.*, 2005; Mueller *et al.*, 2006). They can be tuned to vary the cavity size, accessibility and interactions with molecules contained within the cavity. They are open structures with high capacities for gaseous species and have good diffusional properties. They may not always be sufficiently stable for the conditions under which they would need to be applied in flue gas treatment, however. More recently, nano-systems researchers at UCLA (Banerjee *et al.*, 2008; Wang *et al.*, 2008) have synthesized and screened a large number of zeolitic-type materials known as zeolitic imidazolate frameworks (ZIFs). A few of the ZIFs have been shown to have good chemical and thermal stability in water and in a number of different organic solvents, an advantage over traditional Si-based zeolites, whose performance can be degraded in the presence of steam, for instance. CO_2 capacities of the ZIFs are high, and selectivity against CO and N_2 is good. As there is a great deal of flexibility in the kinds of ZIF structures that can be synthesized, it is likely the new materials with even better adsorption selectivity and capacity can be developed in this way.

4.1.2 Functionalized Fibrous Matrices

The need for both high capacity and fast diffusional response in adsorbents can be addressed by using chemically modified fibrous materials to show adsorptive selectivity and capacity for CO_2. Li *et al.* (2008*a*,*b*) attached polyethylenimine to glass fiber matrices through appropriate coupling chemistry to develop an adsorbent with high CO_2 capacity that worked more effectively in a humid environment, and that could be completely regenerated at high temperature, without loss of performance.

4.1.3 Poly (Ionic Liquids)

A new class of solid adsorbents based on the polymerization of ionic liquids (these are discussed below) has been reported by Tang *et al.* (2005*a,b*). These polymers exhibited enhanced sorption capacity and rates relative to those observed for the room temperature ionic liquids. It was inferred from the results that the mechanism for the CO_2 capture was bulk absorption rather than surface adsorption. Bara *et al.* (2008) showed similar enhanced selectivity in polymerized ionic liquid gas separation membranes.

4.2 Structured Fluid Absorbents

4.2.1 CO_2 Hydrates

Spencer (1999) and others have suggested that CO_2 hydrates be exploited for CCS, in which CO_2 is incorporated in the cages, or clathrates, formed by water molecules under high pressure (7 - 20 bar) and low temperatures (0 - 4°C), as dictated by thermodynamic constraints on the formation of these hydrates. Their concept was not to use the water hydrates as a recyclable absorption medium, although it is conceivable to do so, but rather to sequester directly the hydrate slurry. It has been reported more recently that tetrahydrofuran (THF) reduces the incipient equilibrium hydrate formation conditions, and a process has been described that involves three hydrate stages coupled with a membrane-based gas separation process at an operating pressure that is substantially less than the pressure required in the absence of THF (Linga *et al.*, 2007, 2008). Compression costs were estimated to be reduced from 75 to 53% of the power produced for a typical 500 MW power plant. The importance of this work lies in the use of additives to enhance and expand the range of application of water clathrates, and points to possible new approaches for the design of suitable absorbents under more general conditions.

4.2.2 *Liquid Crystals*

While the concept of relying on the physical hosting of the solute in a structured cavity such as provided by CO_2 hydrates is appealing, the reliance on water as the clathrating agent restricts the accessible range of operating conditions for such processes, although this range can be expanded with the use of additives such as THF. Other structured materials such as liquid crystals, on the other hand, provide potentially more flexible stimuli-responsive sorbents for gas sorption purposes, as their operational temperature ranges can be tuned to be compatible with a given process. Liquid crystals constitute an unusual state of matter in that they can exhibit ordered crystalline-like structures with liquid-like properties over certain temperature ranges, but above a well-defined transition temperature convert to more traditional liquid phases. The restructuring of this phase can be achieved by a slight drop in temperature, or by the application of a suitable electric or magnetic field. As an example, Chen *et al.* (1993, 2000) and Hsuie *et al.* (1994) measured the physical absorption of CO_2 in films of a liquid crystal exposed to pure CO_2 over the temperature range spanning the solid to liquid phase transition. Their experimental results showed that the amount of CO_2 absorbed by the liquid crystalline phase is significantly less than that absorbed in the isotropic liquid. The liquid crystals can be ordered dramatically by very small changes in temperature (1°C) or, in principle, by the application of a strong electric field across the liquid crystal film. Furthermore, their reversibility on physical sorption and desorption of CO_2 with very small external perturbations showed a stimulus-responsive CO_2 separation. The gas solubility in conventional liquid crystals, however, is unacceptably low for CO_2 separation from flue gases, although it is comparable to the capacities exhibited by water clathrates. Note, however, that none of the work done to date on liquid crystals has been focused on using these systems for separations purposes, and thus there is ample scope for enhancing CO_2 capacities through appropriate design of the molecules. Means for the enhancement of CO_2 sorption capacities in liquid crystal systems are required, and advanced materials R&D in this area will require a strongly interdisciplinary approach, drawing on synthetic chemistry, physical characterization, and molecular modeling.

4.2.3 *Ionic Liquids*

Another area that has demonstrated great potential and in which there is currently a great deal of interest is the field of ionic liquids. Ionic liquids are organic salts with melting points usually near room temperature, below 100°C. An unexpectedly large solubility of CO_2 gas in ionic liquids was first reported by Blanchard *et al.* (1999) (see also Anthony *et al.*, 2002). Since then, a growing interest has developed in exploring and understanding the solubility of various gases in ionic liquids (Wu *et al.*, 2004; Anderson *et al.*, 2007). Recently, it has been reported that the CO_2 absorption and desorption rates in poly (ionic liquid)s are much faster than those in ionic liquids and the absorption/desorption is completely reversible (Anderson *et al.*, 2007; Tang *et al.*, 2005*a,b*). The gas absorption capacity of ionic liquids, both in monomeric and polymeric materials, depends on the chemical and molecular structure of the ionic liquids, especially the anions (Tang *et al.*, 2005*a*). In general, ionic liquids are characterized by extremely low vapor pressures, wide liquid ranges, non-flammability, thermal stability, tunable polarity, good electrolytic properties and easy recycling (Cadena *et al.*, 2004). These attributes make them attractive candidate sorbents for CO_2 capture and separation from post-combustion flue gases from coal-fired power plants; however, desorption of CO_2 in ionic liquid media and regeneration of the sorbent require significant thermal energy (Trilla *et al.*, 2008). In addition, the viscosity of ionic liquids is relatively high, about 5-fold higher than that of a traditional aqueous solution of MEA (Meidersma *et al.*, 2007) and increases with CO_2 loading, leading to an additional energy penalty in pumping the sorbent.

4.3 Non-Thermal Regeneration Methods

4.3.1 Electrical Swing Adsorption

Adsorption processes such as with activated carbon, zeolites and other mesoporous adsorbents are generally carried out in thermal swing operations where the adsorption occurs at a given temperature and the desorption and sorbent regeneration is achieved at a significantly higher temperature. Again, the thermal load adds to decreased efficiency of these capture processes. To overcome these issues, an isothermal Electrical Swing Adsorption process has been proposed (Judkins and Burchell, 1999*a,b*; Burchell *et al.*, 2002). Specifically, the adsorption media are selected to be electrically conductive such that when a power supply is applied across the matrix, a current passes through the matrix, with a resulting desorption of the adsorbed component. It has been claimed that the desorption is not through resistive heating of the matrix, but rather through a direct electrical effect on the sorbate-sorbent interactions, but no specific mechanisms have been advanced for such interactions. A similar process has been proposed for an electro-desorption compressor (Pfister *et al.*, 2003), in which the sorbate is adsorbed at a low pressure, and desorbed at a significantly greater pressure; again, it is claimed that the desorption reaction is essentially non-thermal. While much progress has been made in identifying sorbents with the appropriate electrical properties, it is still not clear what the mechanisms for the enhanced desorption processes are. Advanced research should focus on understanding these mechanisms and, once they are understood, on exploiting this understanding in the design of more effective adsorbents, with possibly more controlled stimuli-responsive properties. Molecular modeling could play a large role in such endeavors.

4.3.2 Electrochemical Methods

The electrochemical separation and concentration of CO_2 from a dilute gas mixture has been demonstrated using a benzoquinone as the carrier within a suitable solvent phase (either an organic solvent or an ionic liquid) (Scovazzo *et al.*, 2003). Specifically, CO_2 is able to bind efficiently to the benzoquinone in its reduced or charged state, but is released readily when the carrier is oxidized. This appears to be a promising approach for the post-combustion capture of CO_2 since it does not require significant heating and subsequent cooling of the sorbent phase for regeneration and preparation for the next sorption cycle, and there is ample opportunity for the development of new materials and processes based on such redox approaches. The redox-active carriers must be able to undergo reduction and oxidation in both the presence and absence of the sorbate, must exhibit the desired selectivity and capacity for CO_2 in the reduced state, with a significant reduction in the capacity when the carrier is oxidized. The reaction kinetics should be sufficiently rapid that the reaction does not limit the overall sorption/desorption processes.

4.4 Summary and Conclusions

Advanced R&D on selective CO_2 capture is required to develop new separations aids that have high capacity and selectivity for CO_2 under the typical operating conditions found in flue gas emissions. One avenue of research will be the continued development of specialized adsorbents with finely controlled structure, such as uniform, well-defined cavities and pores, as found with MOFs and ZIFs, that can provide high selectivities and capacities for CO_2 in flue gases, while still being sufficiently robust to the presence of the other components, such as water vapor. The functionalization of adsorbent surfaces (e.g., fibrous matrices, etc.) to provide the desired separations capability and rates is also a target of opportunity for advanced R&D, while liquid phase absorbents such as ionic liquids will continue to be an active area of research, with the continuing goal of optimizing their physical as well as chemical properties. Another research area that deserves attention is the development of non-thermal methods (e.g., electric swing adsorption, electrochemical methods) for regeneration of the sorbents, liquid or solid, which will call for the development of new separation media that are more finely-tuned in their responses to externally-applied stimuli. These requirements pose stimulating challenges for the synthesis of new materials, aided most likely by detailed molecular modeling of sorbate/sorbent interactions, and for new integrative module designs that enable their effective implementation in a process environment.

5. RD&D Recommendations

From the above review of post-combustion capture technologies, one can make a few observations:

- In theory, there are many approaches to post-combustion capture.
- The state of development of these various approaches varies widely.
- If one had to deploy the technology today, the only real option is a chemical absorption process (e.g., scrubbing with amines or ammonia).

In giving RD&D recommendations, it is important to articulate the program goals. For CCS in general (and post-combustion capture in particular) program goals should include both near-term solutions (which can help with development of a commercial technology market in which CCS responds to legislative mandates or carbon costs) and longer-term, improved solutions (which can enable deeper reductions at less pronounced costs). In some discussions, the near-term and longer-term solutions are considered at opposite ends of the RD&D spectra, and both have strong proponents today. However, the reality going forward is that a robust CCS RD&D program will both respond to the shorter-term needs and anticipate the longer-term by creating and maintaining an RD&D pipeline that begins with basic research and ends with commercial demonstrations for worthy technologies.

Since strong rational arguments can be made for each emphasis on either the shorter-term or longer-term scenarios, we recommend that the viewpoints implied by each of them be considered in putting together a research portfolio. This includes activities aimed at "technology readiness" (so the technology can provide a significant amount of emissions reduction) as well as activities aimed at significant cost reductions (through high risk, high reward projects). In other words, ***it is essential to develop a portfolio approach for post-combustion capture RD&D.***

In order to provide a solid basis for this portfolio R&D approach we recommend development of a national statistical database describing features of the existing U.S. coal fleet that are most relevant to assessment of post-combustion capture technology. This database might draw on data currently provided to US EPA, US DOE, FERC, and other organizations, but should include, at a minimum, a statistical representation of the current coal fleet in terms of flue gas temperature, moisture, CO_2, oxygen and sulfur dioxide concentrations, steam cycle and steam turbine parameters, as well as metrics for physical space available at the plant site for retrofit equipment and metrics for local electrical system reserve margin or excess capacity. This information would feed into the portfolio approach, which we envision as a research pipeline.

For convenience, we divide the pipeline into 4 sections:

- ***Exploratory research*** will feed the pipeline. Much of the technologies described in section 4 fall into this category. Since many of these technologies are high risk, high reward, the number of projects in this part of the pipeline should be the greatest, but the cost spent per project should be the lowest. Moving along the pipeline, we would expect the number of projects to drop, but their RD&D costs to rise.

- ***Proof of concept research*** is the next stage of the pipeline. Projects where the exploratory research looks promising will be expected to proceed to this stage. The goal of this phase of the research is to understand whether the technology under consideration is appropriate for the task of post-combustion capture. Activities may include laboratory work to synthesize materials, measurements of basic properties, and analysis of behavior in realistic environments (such as those found at power plants). This is a key stage in the pipeline, in that it becomes much more expensive to move a project to the next stage (pilot plants). The more work done at the proof of concept stage raises the odds that the next stage will be successful if one decides to move forward.

- ***Pilot scale testing*** is the next part of the pipeline. The size of these pilot projects will typically be on the MW or tens of MW scale, so individual project costs can rise significantly. For example, Vattenfall's 30 MW_{th} pilot plant for oxy-combustion capture cost about $100 million.

- ***Demonstration projects*** are the final stage of the pipeline. The scale of a demonstration project is typically 100s of MW and costs could easily exceed a billion dollars per project. At least a few demonstration projects are needed before the technology can claim "commercial readiness". These demonstration projects will need to absorb (and hopefully eliminate) first mover costs and will set a baseline for cost and performance of future commercial plants.

In parallel with the RD&D pipeline, there is a need for competent, objective, and independent analysis of the various technologies in the pipeline. Money for RD&D is always limited, and good analysis tools can help inform what areas look the most promising. This is especially important in the early stages of the pipeline, where one will be limited in the number of technologies to promote to the relatively expensive pilot plant stage.

While having good, independent analytic tools sound like an obvious component, it is usually hard to implement. In many cases, we are asking the analysis to compare apples to oranges to grapefruits. Secondly, most of the data going into these models are from the technology developers, who want to show their technology in the best light. Therefore, we recommend doing this analysis at a very fundamental level – having it be a gatekeeper (rather than ranking the processes). Here are some key components that should be required:

- Energy and mass balances. These are the bases for all processes. Yet, in reading the literature, we are amazed at the claims made about new processes in which no energy and mass balances are provided.

- How does the process match the design criteria? For post-combustion capture, processes need to work well at atmospheric pressures and relatively low CO_2 concentrations (i.e., 5-15% by vol.). We need to understand how the processes deal with the impurities in flue gas, including SO_x, NO_x, oxygen, and water, as well as trace amounts of metals, chlorides, and particulate matter. Estimates need to be made of the recoveries of and selectivities for CO_2 that can be expected.
- In the power industry, processes with high availability are critical. Therefore, it is important to understand the robustness and the operability of a process.
- In this early stage, costs should not be considered major decision criteria. Any cost estimates for a process at an early stage of development are highly uncertain. However, some basis should be provided for assuming that it will be feasible for the process to be cost-effective.
- Preliminary lifecycle impacts analysis. A preliminary 'fatal-flaw' analysis should be performed to assess whether each process has potential for more than niche deployment given critical raw materials or manufacturing constraints, or potential environmental or social impacts.

We can now combine the above framework with the technology assessments supplied earlier to see what the post-combustion capture RD&D pipeline looks like today. We'll start at the demonstration project end and work backwards.

- ***Demonstration projects.*** The G8 has stated a goal of 20 CCS demonstration projects worldwide completed by 2020 (includes post-, pre-, and oxy-combustion, as well as capture from non-power sources). However, in terms of CCS from a power plant, we are still waiting for demonstration project #1. One of the proposed demonstration projects furthest along in its planning, a project in the UK, calls for post-combustion capture. From the project web site[4]: *The Government selected post-combustion capture on coal for the demonstration project as it is most likely to have the biggest impact on global* CO_2 *emissions and because it can be retrofitted once the technology has been successfully demonstrated at a commercial-scale.* The current timeline shows a start date of the demonstration plant as 2014. In the near-term, it seems almost a certainty that any demonstration project involving post-combustion capture will need to be based on chemical absorption technology. In the US, the recently passed stimulus package contains money for CCS demonstration projects, while in Europe, revenues from 300 million permits from the European Trading System have been reserved to fund CCS demonstrations.

- ***Pilot plants.*** At present, pilot activity is focused on testing alternative solvents. At GHGT-9, several groups presented papers reporting pilot activities involving various forms of amines, including CSIRO from Australia (Cottrell *et al.*, 2008), MHI in Japan (Kishimoto *et al.*, 2008), the University of Regina in Canada (Idem *et al.*, 2008), and the EU CASTOR project in Denmark (Knudsen *et al.*, 2008). Alstom and EPRI reported that a 35 tonnes/day of CO_2 chilled ammonia process

[4] http://www.berr.gov.uk/whatwedo/energy/sources/sustainable/ccs/ccs-demo/page40961.html

pilot plant was in operation at the We Energies Pleasant Prairie Power Plant in Wisconsin (Kozak *et al.*, 2008). In addition, Powerspan reported that a 20 tonnes/day of CO_2 pilot plant based on their ammonia process (the ECO_2 process) was nearing completion at FirstEnergy's R.E. Burger Plant in Shadyside, OH (McLarnon and Duncan, 2008). Beyond these chemical absorption technologies, there do not seem to be obvious candidates for new pilot tests in the pipeline at this time.

- ***Proof of Concept.*** There are a large number of technologies being examined at this stage. As described earlier, they include the categories of adsorption, membrane-based separations, biomimetric approaches, as well as advanced approaches looking at new materials (e.g., liquid crystals, ionic liquids or metal organic frameworks) incorporating new designs (e.g., electric swing). However, while a broad range of technologies are being researched, it seems that increased effort (e.g., more funds, more relevant expertise) is needed in this area. This statement is based on the observation that while many technologies are being investigated, at present there are very few candidates ready to advance to the pilot stage.

- ***Exploratory Research.*** This is the research that feeds the pipeline. It is encouraging that a number of new concepts and technologies have recently been considered for post-combustion capture. However, this is just a start and more interest needs to be generated in the basic science community to consider new technologies and approaches for post-combustion capture. Not only is it important to attract new ideas, but it is also important to attract the leading researchers in their field. Having the best researchers lead the effort greatly improves the chance of success. Therefore, it is important to create programs that will attract these world-class researchers.

To reduce program costs, to accelerate technology development, and to ensure that post-combustion capture technology is available globally when and where it is needed, we suggest that some of these RD&D efforts (including demonstrations) might be conducted in cooperation with developing economies such as China and India. In those countries new coal plants are being built at an astonishing rate, and the costs for construction (and RD&D) are significantly lower than in the US. In fact, in some respects, low-carbon energy technology is advancing faster overseas than in the U.S. (witness the GreenGen IGCC under construction with carbon capture in China today, and the large-scale CO_2 geological sequestration effort likely to commence in the near term at a Shenhua coal facility in China). Consideration of a US RD&D program for post-combustion capture as part of a global cooperative endeavor therefore is recommended.

Our conclusions and recommendations on the current status of post-combustion capture technology are:

- A portfolio approach to RD&D, developed in an international context, is required.

- Only chemical absorption technologies are well enough developed to be considered for demonstration.
- Reducing the parasitic energy load is a critical research goal.
- There is a big gap in the RD&D pipeline in the moving of technologies from proof of concept stage to pilot plant stage. Efforts should be focused to close this gap. One strategy to address this gap is to engage experts who have relevant expertise, but that are currently outside the CCS research community.
- Demonstrations are important beyond their immediate goals (i.e., to demonstrate a technology). They give visibility and credibility to the field and can be used to inspire new ideas and new researchers.
- Most technologies currently in the RD&D pipeline will fail. Therefore it is critical to keep feeding the pipeline with new ideas and new researchers to increase the overall chances of success.
- To help make informed decisions along the way, there is a need to develop competent, objective, and independent analysis methodologies for evaluating the various technologies in the pipeline.

The final question is what the cost of this program will be. We estimate the cost of an 8-10 year research program in Table 2 below. Note that this is total cost of program, including research funds from both the private and public sector. Also note that it for only post-combustion capture technology – a complete CCS budget would also need to address other capture approaches (i.e., pre-combustion, oxy-combustion), as well as transport and storage.

Table 2. Estimated cost of an 8-10 year US post-combustion research effort.

Component	**# of projects**	**Cost per project (millions of $)**	**Total Cost (millions of $)**
Demonstration	5	750 (500-1000)	3750
Pilot Plants	15	50 (25-100)	750
Proof of Concept	30	10	300
Exploratory Research	50	1	50
Simulation/analysis			100
Contingency			1000
TOTAL			5950

The basis for these estimates is as follows:

- ***Demonstration project.*** This cost per project number is an order of magnitude estimate for a demonstration plant based on estimates from the *The Future of Coal* (MIT, 2007) the experience of FutureGen, and other estimates. Of course, the exact details of what a demonstration looks like can vary widely, as would costs. We envision both retrofit and, potentially, new power plants in the 200-300 MW range that capture about 60% of the exhaust CO_2 (to give the plant parity with emissions from a natural gas power plant, see Hildebrand and Herzog, 2008).

- ***Pilot plants.*** Pilot plant activity today includes plants sized to process flue gas associated with 1-5 MW of electricity production, as well as plants sized to process flue gas associated with 10's of MW of electricity production. Many technologies have pilot plants built at both scales. Therefore, we anticipate the need for about 15 pilot plant tests. The cost range is attributed to the different size of pilot plants to be built. Many of these would be constructed as slip stream retrofits to existing installations.

- ***Proof of Concept.*** The cost of these projects will be variable – some may be only a few million, while others could be $20 million or more. Our estimate is based on what a reasonable average cost might be.

- ***Exploratory Research.*** We feel it is important to cast a wide net, so we encourage funding many of these projects. After spending about $1 million, enough information should be generated to decide whether it is worthwhile to move to the proof of concept stage.

- ***Simulation/analysis.*** The *Future of Coal Study* suggested $50 million dollars per year on this task to cover all parts of CCS technology. Based on this estimate, we scaled it down to a level for post-combustion capture technologies only.

- ***Contingency.*** Because of the uncertainty in the estimates (and in future prices), we have included a 20% contingency.

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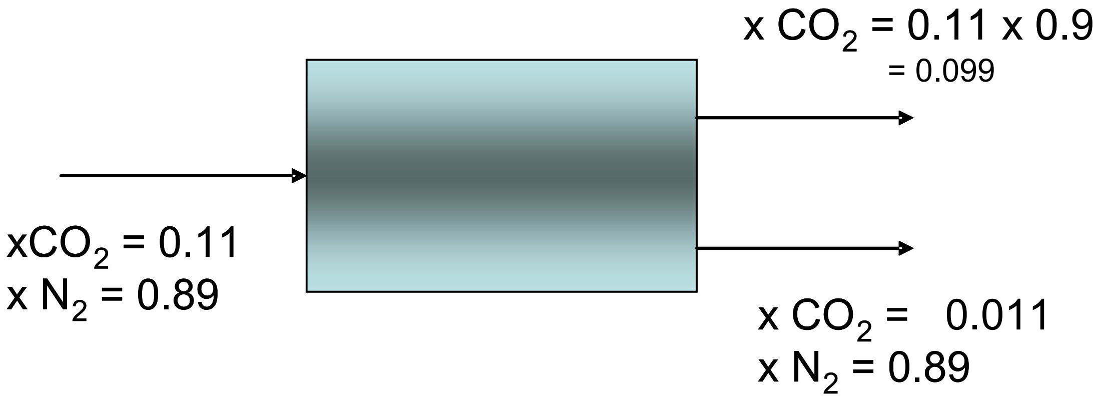
Appendix A. Minimum Work Calculation



Ideal work of separation:

Consider 1 mole of gas containing 11% CO_2 and 89% N2. We will assume separation at 298 K and assume 90% capture of CO_2.

For a steady flow system, we have the minimum thermodynamic work as:

$W_{min} = W_{flue\ gas} - WCO_2 - W_{N2}$

$$W_{min,FG} = -RT\left(\frac{x_{CO_2}}{x_{CO_2}+x_{N_2}}\ln\left(\frac{x_{CO_2}}{x_{CO_2}+x_{N_2}}\right)+\frac{x_{N_2}}{x_{CO_2}+x_{N_2}}\ln\left(\frac{x_{N_2}}{x_{CO_2}+x_{N_2}}\right)\right)$$

$$W_{min,FG} = -8.314x298x(0.11\ln 0.11 + 0.89\ln 0.89)$$

$W_{min,\ FG}$ = 0.859 kJ/gmol flue gas

$W_{min,\ CO2}$ = 0 since it is a pure stream

$$W_{min,N_2} = -RT\left(\frac{x_{CO_2}}{x_{CO_2}+x_{N_2}}\ln\left(\frac{x_{CO_2}}{x_{CO_2}+x_{N_2}}\right)+\frac{x_{N_2}}{x_{CO_2}+x_{N_2}}\ln\left(\frac{x_{N_2}}{x_{CO_2}+x_{N_2}}\right)\right)$$

$$W_{min,N_2} = -8.314x298\left(\frac{0.011}{0.011+0.89}\ln\left(\frac{0.011}{0.011+0.89}\right)+\frac{0.89}{0.011+0.89}\ln\left(\frac{0.89}{0.011+0.89}\right)\right)$$

$W_{min,\ N2}$ = 0.163 kJ/ 0.901 gmol FG
= 0.181 kJ/gmol FG

W_{min} = 0.859 – 0.181
= 0.678kJ/gmol FG

Since 90% CO_2 is captured i.e. 0.9 x 0.11 = 0.099 gmol CO_2/gmol flue gas
W min, normalized = 6.85 kJ/ gmol CO_2 = 0.001904 kWh/ gmol CO_2 = 43 kWh/tonne CO_2 captured

The above result holds for 90% capture.

Ideal work of compression:

Work of compression = Availability at 110 bar – Availability at 1 bar

From NIST webbook

Temperature (K)	Pressure (bar)	H (kJ/mol)	S (J/mol-k)
298	1	22.257	120.54
298	110	11.166	50.979

Availability = H – TS

At 1 bar, availability = -13.664
At 110 bar, availability = -4.0257

Work of compression = 9.638 kJ/mol = 61 kWh/t CO_2 compressed

Power plant work:

From the MIT Coal Study:
SCPC plant
500 MW
415t CO_2/hr
500000kW/415 t/hr = 1200 kWh/t CO_2 produced

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Agenda

Retro-Fitting of Coal-Fired Power Plants for CO_2 Emissions Reductions Symposium

Massachusetts Institute of Technology

March 23, 2009

10:00 - 10:05	**Welcome**	
	Ernest Moniz, MIT, Symposium Co-Chair	
10:05-10:30	**Framing the Issue: Why Retro-fit Technology is Essential**	
	Wayne Leonard, Entergy, Symposium Co-Chair	
10:30-12:00	**Panel**	
	Near-Term Technologies for Retro-fit	
	Chair:	Armond Cohen, Clean Air Task Force
	White Paper Author:	Dale Simbeck, SFA Pacific
	Discussant #1:	Bill Elliott, Bechtel
	Discussant #2:	Paul Allen, Constellation Energy
	Discussant #3	Mark Gray, AEP
12:00-1:00	Lunch	
1:00-2:30	**Panel**	
	"Over the Horizon" Technologies	
	Chair:	Steve Specker, EPRI
	White Paper Author:	Howard Herzog, MIT
	Discussant #1:	Ed Rubin, CMU
	Discussant #2:	Don Langley, Babcock & Wilcox
2:30-2:45	Break	
2:45-4:15	**Panel**	
	Research Management: Government/Industry Partnerships	
	Chair:	Ernie Moniz, MIT
	White Paper Authors:	Joe Hezir, EOP Group
		Melanie Kenderdine, MIT
	Discussant #1:	David Hawkins, NRDC
	Discussant #2:	Bennett Johnston, Johnston & Associates
4:15-5:00	**Discussion/Wrap Up**	
	Leader:	John Deutch, MIT

MITei MIT Energy Initiative

Confirmed Attendees

Symposium on
Retro-Fitting of Coal-Fired Power Plants for CO_2 Emissions Reductions

Ernie Moniz, MIT, Co-chair
Wayne Leonard, Entergy, Co-chair

Paul Allen, Constellation Energy
Kay Arnold, Entergy
Janos Beer, MIT
Don Broeils, Fluor
Steve Caldwell, Pew Center on Climate Change
Joe Chaisson, CATF
Brian Chao, TAQA
Armond Cohen, CATF
Brent Constantz, Calera
Brian Curtis, Calera
Michelle Dallafior, House Committee on Science
John Deutch, MIT
John T. Disharoon, Caterpillar, Inc.
Bill Elliott, Bechtel
Christian Fellner, EPA
Randy Field, MIT
Sarah Forbes, WRI
Julio Friedman, Lawrence Livermore Nat'l Laboratory
Ahmed Ghoniem, MIT
Mark Gray, AEP
Alan Hatton, MIT
David Hawkins, NRDC
Howard Herzog, MIT
Joe Hezir, EOP Group
Rob Hurless, Representing Governor of Wyoming
Kristina Johnson, JHU
Senator Bennett Johnston, Johnston & Assoc.
Melanie Kenderdine, MIT
Haroon Kheshgi, ExxonMobil
Don Langley, Babcock & Wilcox
Terry Leib, GE
Richard Mukhtar, TAQA
Fredrick Palmer, Peabody Energy
Jeff Phillips, EPRI
Len Pollizzotto, Draper Laboratory
Rafe Pomerance, Clean Air-Cool Planet
Pat Profeta, Entergy
Theodore Roosevelt, Barclay's Capital
Ed Rubin, CMU
Mark Savoff, Entergy
Larry Schnadelbach, Entergy
Michael Schnitzer, Northbridge Group
Dale Simbeck, SFA Pacific
Arnie Smith, Fluor
Steve Specker, EPRI
Bill Stevens, EPA
Terry Tyborowski, House E&W Appropriations
Jost Wendt, University of Utah
Bob Williams, Princeton