Clean Air Act Advisory Committee
Advanced Coal Technology Work Group Meeting
Double Tree Hotel Crystal City
March 6, 2007

Welcome

Ben Henneke, Clean Air Action Corporation, introduced himself and commenced the Work Group meeting.

Recap of Information Obtained from February 8th Meeting

Anna Wood, EPA, laid the groundwork for the meeting by reviewing what the Work Group covered in the February 8th meeting. At the last meeting, the Work Group focused on several outputs including: 1) identifying high priority agenda topics; 2) examining barriers impeding the acceleration of Advanced Coal Technology (ACT); and 3) examining opportunities and tools to accelerate the pace of ACT.

Ms. Wood reviewed these outputs in more detail through a PowerPoint presentation. She noted that the barriers and opportunities were listed in the order of the number of votes received during the last meeting. She also noted that the tools discussed last meeting were dropped and folded into the opportunities section of her PowerPoint presentation. This presentation can be viewed on the Work Group's website.

Following her presentation, Ms. Wood said that she and Mr. Henneke took all the identified agenda items and incorporated them into the agendas for the two March meetings. They anticipate having a conference call in April to both discuss additional topics and to lay the foundation for the 6-month interim report.

Ms. Wood reminded the Work Group that they received the draft summary of the meeting minutes from the February 8th meeting and said she welcomed the Work Group's input. Members have two weeks to submit errors and corrections.

Tony DeLucia, East Tennessee State University, commented on the "global nature of the challenge" barrier. He asked if there was there any discussion last meeting about the global nature of the solution. Ms. Wood said that she did not remember specific discussions about the global nature of solutions. Mr. Henneke asked Mr. DeLucia to raise his comment again that afternoon.

New Member Introduction & Overview of Meeting Objectives

Mr. Henneke asked the new members and Work Group member alternates to introduce themselves.

- Todd Johnston, National Mining Association, said he was attending the meeting in place of Greg Schaefer, Arch Coal.
- Dean Metcalf, Xcel Energy, was attending for Marty Smith.
- John Walke, Natural Resources Defense Council (NRDC), was attending in place of Patrice Simms. Mr. Walke is the Clean Air Director for NRDC.

- Ann Weeks, Clean Air Task Force, is an attorney who does legal work related to power plants. She has been working on the ACT issue for several years, and is attending for John Thompson.
- Jim Welsh, Kentucky Public Service Commission, is the Director of Engineering for the Commission, and is a new Work Group member.

Mr. Henneke next reviewed the meeting objectives written on the agenda. Mr. Henneke pointed out that he included tool identification in the last bullet in case a Work Group member identified a tool that is not an opportunity. None of the members had any questions or comments about the objectives.

Advanced Coal Technology for Pulverized Coal Plants

Anna Wood, EPA, introduced the next speaker Carl Bozzuto, who is an executive consultant at ALSTOM.

Mr. Bozzuto began by describing that the vision for new coal power would include a portfolio of clean technologies. He said that there are a lot of different ways to start with coal to make energy, and you do not want to limit your options. Especially with policy, you want to make sure you have a lot of options.

He next explained that with high prices of oil and gas, we have started to see a lot of activity for coal in North America. He talked about the drivers for new coal build. The price of coal is going up, but not that much. However, if you look at the price of coal over any significant time period, the real price of coal is going down. In the interest of generating least cost electricity, people are using coal.

Mr. Bozzuto next talked about the new coal capacity challenges. He said you want to use the low cost domestic coals with the highest reliability and commercial availability. You also want competitive costs. Coal capacity must also involve low emissions and a carbon strategy.

Next Mr. Bozzuto showed operating data for coal combustion for EPA's best in class emissions. He said that the message is that pulverized coal and CFB can be as clean as gasification. There is nothing inherently different that would suggest that one technology is inherently favored in terms of emissions.

He next showed a slide on ultra clean coal combustion emissions control capability. He said that there is a lot of R&D being conducted to try to lessen emissions on today's state of the art facilities. There are constant technological improvements.

Next Mr. Bozzuto showed a slide on multi-pollutant APC systems. A multi-pollutant approach would help with lessening emissions. He gave an overview of targeted emissions level in this multi-pollutant approach. He said that as we learn more, the emissions level will improve. Nonetheless, coal is variable; what works for coal A in location X does not necessarily have the same performance as coal B in location Y.

Mr. Bozzuto next spoke about efficiency, which is the cheapest way to deal with CO_2 and is critical to emissions strategy. He showed a chart that compares the carbon dioxide emissions to the net plant efficiency based on firing Pittsburgh #8 coal. As you go up in net plant efficiency, you end up in the ultra supercritical PC plant range. Over the course of time, you want to be in the range of ultra supercritical, which is advanced coal technology with higher temperatures and pressures of steam. You will get substantial reductions of CO_2 (up to 25% reductions) with high efficiency. Efficiency is less expensive than to try capture and sequestration.

He showed a slide on the progression of plant efficiency via advanced steam conditions and plant designs. Today there are units in the range of 1100 degrees Fahrenheit; Department of Energy (DOE) is looking at programs up to 1400 degrees Fahrenheit with the goal to get to 48-50% efficiency. These efficiency calculations are based on the higher heating value of the fuel. When you burn fuel, you not only get CO_2, you get water vapor. If you can condense the water vapor, you can get energy from it. The higher heating value takes into account getting energy from the water vapor. The idea is to be about in the same range as a combined cycle. The U.S. is heavily centered in the coal industry towards higher heating values, but Europe is oriented otherwise, so you have to be careful when you are reading new literature.

Mr. Bozzuto next showed a slide of the clear trend to advanced supercritical cycles. Since the 1990s, there has been a lot more interest; including 230 supercritical units that have been ordered worldwide. For example, Germany has decided that their approach to reductions in CO_2 is going to come from efficiency by using supercritical plants.

He next spoke about meeting the goals for coal based power efficiency. He said that the future targets for all plants efficiency range up to 50%, and none of today's IGCC or SCPC plants are there yet. He added that there will be a battle in the market to get to the lowest cost with the highest efficiency. He next spoke about increased value for efficiency. With high efficiency, you can save a lot of money on annual fuel savings from the coal prices.

As a CO_2 strategy, you would go after efficiency first as the lowest cost. For example, Scandinavia burns almost no oil. If the cost of carbon is enough, you want to capture and have a place to put it (using enhanced oil recovery or sequestration). This is the logical path to lowest cost of carbon reduction.

He next spoke about the variety of ways to capture CO_2. He showed a table with a number of types of technology that can be used for capture post combustion, including the CO_2 wheel used in Japan and CO_2 frosting used in France. The most common solution however is amine scrubbing.

He next showed a slide on oxygen firing to produce concentrated CO_2 stream. This solution uses an air separation unit. This is not used often because it is expensive to make oxygen. DOE is working on cutting this energy cost, which would start to make this option more attractive, especially as a retrofit. For example, in Vattenfall, Germany there will be a 30 MW oxy fired PC pilot plant. This plant is conscious of its energy use and it fires brown coal with moisture contents that are at 50-60%. They are working to get rid of the moisture to make the process more efficient. By using supercritical, they have improved their efficiency by 30%.

He next shows a slide on amine based scrubbing. It is presently the most commercial technology, primarily used for cleaning natural gas. Amine does not come out too easily, so you have to use steam to help with the process. This need for steam is one reason it became expensive. Amine scrubbing continues to develop as industry focuses on improvements, including designer solvents, alternative solvents, and process integration. In the past few years, estimated costs have decreased from 70 to 40-50 \$/ton CO_2.

ALSTOM is studying ammonia as a solution system. Ammonia reacts with CO_2 and water forms ammonia carbonate and bicarbonates. Moderately raising the temperature reverses the reactions and produces CO_2. It can be regenerated at high pressure. This is helpful because when you put the CO_2 in a holding ground, you have to compress it. Half of the energy cost is compression and half is in the capture for a pulverized coal plant. If you can reconvert the CO_2 at pressure, it takes less work to improve efficiency of capture. The advantages of chilled ammonia include its high efficiency capture of CO_2, low heat of reaction, high capacity for CO_2 per unit of solution, easy and low temperature regeneration, low cost reagent, no degradation during absorption-regeneration, and tolerance to oxygen and contaminations in flue gas.

Mr. Bozzuto next spoke about energy costs and showed a slide of three plants (including one without CO_2 removal, one with MEA, and one with ammonia/NH3). With ammonia, you lose less energy, CO_2 emissions decrease, and the avoided cost of \$/ton CO_2 is about \$20. Scrubbing every power plant in the country would mean you would have too much carbon to sell.

Alvaro Linero, Florida Department of Environmental Protection, said that there is a remarkable difference between MEA and Ammonia. Mr. Bozzuto replied that with IGCC, you have about two for the capture because you have to use steam to reform the gas and you still have to compress it. The gasifier is under pressure, so it is easier to absorb the pressure.

Mr. Bozzuto next showed the experience curve for post combustion CO_2 capture. He said that significant improvements are being achieved and he gave an example of ABB Lumina and designer systems that are using less steam. He said there would be a 5MW demonstration this year at We Energies Pleasant Prairie. He said there are multiple options for innovation combustion, including chemical looping. This involves leapfrog technology with the potential to achieve significantly lower costs than PC/CFB/IGCC. He showed an example of such a chemical loop, including one in which you can make hydrogen.

Next Mr. Bozzuto showed some estimates of costs for different technologies, but gave a notice that the costs are variable and difficult to estimate. He said the costs are relatively similar for the different technologies, so you really do not want to limit your options; you just do not know which is going to come out with the lowest cost. For example, he showed carbon steel and nickel trend prices. He said until these prices settle out, it will be difficult to talk about cost realistically.

He next spoke about technology innovations for CO_2 capture. The injection cost is relatively small. He showed a graph with various values of CO_2 (as you keep increasing the carbon price). There are a lot of innovative options that continue to emerge and develop, including post combustion capture, oxy-fuel firing, and decarbonization.

In conclusion, you want the highest efficiency to minimize CO_2 emissions using lower cost technologies for CO_2 capture. However, no technology is the single answer to all fuels. Industry is best served by a portfolio approach to drive development of competitive coal power with carbon capture technology.

Tony DeLucia, East Tennessee State University, said that he read an article about biofuels being used in transportation and not necessarily in electricity. He asked if there was anything magical about the 10% biomass burning?

Mr. Bozzuto responded that the 10% number is for a coal fueled plant. Up to 5 or 10 percent, you can put almost any biomass. There are plants in Europe looking at burning things like straw up to 40 or 50 percent. With biomass fuel, there is the question about whether you use more energy to make the fuel than what you get out of the fuel itself. If you can use cellulostic alcohol, take cellulose and ferment this and make alcohol, the energy balance is much better, but yeast gets poisoned by products of fermentation, so MIT is looking at genetically modifying yeast. If you can make a liquid fuel, transportation is the place to use it instead of coal plants.

Ann Weeks, Clean Air Task Force, said that on the issue of the London convention, she wanted to clarify that it was not the London Convention that was modified; it was the London Protocol. She added that we need to modify our law in the U.S. to make the change. Mr. Bozzuto responded that we are not at the moment putting any CO_2 under the ocean floor. Norway is doing this however. Ms. Weeks responded that there is a lot of ambiguity in the U.S. law that would need to be corrected.

Eugene Trisko, United Mine Workers, asked about the comparison of the production costs. He asked were those all new plant builds? Mr. Bozzuto responded that the plants were all new. Mr. Trisko followed up and said that with some of the technologies, especially scrubbing, are applicable in retrofit contexts. If you looked at production costs from existing facilities for retrofits, the costs would be lower. Mr. Bozzuto agreed. Mr. Trisko responded that it would be the existing plants providing the infrastructure.

Larry Myer, Lawrence Berkley National Lab, asked what do we do with the existing fleet? Do we do any retrofitting? Mr. Bozzuto replied that if you make the assumption that you have to stabilize at some level, you eventually have to handle the existing fleet. Eventually, some technologies are retrofittable. With IGCC you have to build a new plant. The value of an existing plant with existing turbines is grossly underestimated. Owners would be reluctant to tear down a plant; retrofitting will be done, but it will not happen until the carbon tax price is high enough to make it economical.

<u>Advanced Coal Technology Discussion</u>

Ben Henneke, Clean Air Action Corporation, said that the groups should spend five minutes coming up with a primary and secondary issue that must be in the definition of ACT.

Mark Macleod, Environmental Defense, asked about the overarching consideration. He said the definition may just need to be dynamic, not static. He asked for clarification. Mr. Henneke said that the entire group should agree.

After five minutes, the groups report out on issues that must be included in the definition of ACT. These report outs included the following items (note, see complete list from flip charts below):

- carbon capture and sequestration
- reduces the carbon footprint of power production through efficiency increased beyond where we are now and carbon capture
- results in increased efficiency and reduced overall emissions profile from some baseline
- add storage to carbon capture
- carbon storage
- ability to meet dynamic performance parameters

Mr. Henneke said there is overlap between some of the definitions submitted and that there is a lot of similarity that can be captured in just one piece.

Judi Greenwald, Pew Center on Global Climate Change, said she wanted to see public money driving the technologies.

Steve Jenkins, CH2M Hill, said he agreed with Ms.Greenwald. The CCS piece would be the challenge in determining consensus.

Eugene Trisko, United Mine Workers, said that perhaps we have not sufficiently defined the technology areas we are talking about. For example, there is a whole suite of technologies, such as the ammonia technologies, that may not increase efficiency. On the generation side, enhanced efficiency is a paramount objective with carbon benefits on the side. There should be a definition for retrofit versus new generation technologies.

Al Linero, Florida Department of Environmental Protection, said he thought we should consider related research. For example, some companies may not be able to do storage now but they could do research on it at least.

Mr. Henneke said he wanted to find consensus and similarities on the definition, not the policy or means of getting there. He wanted to find consensus on the definition of ACT. Next the group could talk about the steps (like research and funding) to get there.

Tony DeLucia, East Tennessee State University, said that one of the things he thought should be brought up is the different technologies.

John Campbell, Caterpillar, Inc., said that he thought the difference between prevention and containment is an example of the difference between efficiency and CCS.

Frank Blake, AEP, said that CO_2 capture and sequestration is something we should try to get to eventually. However, improvements in efficiency is representative of what ACT can be. ACT is an improvement based on where we are currently at working towards achieving the promises of other technologies. It does not have to be a giant leap.

Mr. Henneke said that these issues were reasonable. However, where are these steps going?

Mr. Blake responded that the capability to capture and sequester CO_2 would be one goal, along with improving the emissions profile of the plant. If ACT can only include CCS, we are missing the opportunities that exist otherwise to get to ACT.

David Berg, Department of Energy, said maybe the definition should say storage/use?

John Walke, Natural Resources Defense Council, said ACT must address the concept of advanced according to what metric. One metric should be pollution. The next question is what pollution should be covered. In the world we are in, it is reasonable for CO_2 to be included. ACT should be defined by advanced with respect to a carbon constrained future. Just using efficiency as the metric bypasses the pollution question. You can improve efficiency without truly dealing with pollution, or you can improve efficiency without being advanced.

Ann Weeks, Clean Air Task Force, said that ACT must accommodate and include the CCS piece.

Mr. Campbell agreed with Mr. Walke that the critical part is the metric.

David Foerter, Institute of Clean Air Companies, said that carbon footprint is important for the definition, and that storage and capture are the means to achieve the definition of ACT.

Mr. Henneke said each table should spend six minutes coming up with a definition in a manner that would bring about consensus. The groups reported the following items (as noted in the flip charts):

- ACT is the means for significantly reducing or eliminating the release of CO_2 emissions to the atmosphere from coal use
- Technology that reduces the total environmental footprint, including CO_2, while advancing the goal of achieving zero discharges/emissions
- Performance driven technologies and efficiencies for utilizing the energy content of coal
- Technology that reduces carbon through efficiency and/or carbon capture and storage while improving reductions in other emissions
- Technology that minimizes the environmental impact of coal-based production processes (e.g. electricity, fuels) through avoiding emissions of a range of pollutants (i.e. increased efficiency) and/or capturing and disposing of them (e.g. CCS)
- Technology that reduces the carbon footprint through increased efficiency and carbon capture and storage
- CO_2 storage and energy efficiency
- Ability to meet dynamic performance parameters
- Technology forcing efficiency and CO_2 emissions
- More efficient method to capture energy content of coal for the production of electricity and chemicals

Business Case Study and Risks Related to Advanced Coal Technology

Anna Wood, EPA, next introduced David Berg of the Department of Energy (DOE). Mr. Berg, also a Work Group member, is chief policy advisor at the National Energy Policy Office of DOE. He has been working on two business case studies that are a collaborative effort between EPA, DOE, Department of Defense (DOD), and private industry participants. Ms. Wood said Mr. Berg would be sharing information from the case studies and, specifically, risks and ways to mitigate risks associated with accelerating ACT.

Mr. Berg said the first case study looked at the business case for IGCC and the second case study, which is not yet finished, looks at the business case for coal gasification with co-production (of fuel, electricity, and other products). Specifically, the case studies look at the business risks facing co-production plants and at the financial prospects of such plants with and without incentives. He believes the methodology that his group is using is helpful for the Work Group because it offers a different perspective, allowing the Work Group to see how business and government can work together to create more efficient and cost-effective approaches in support of early commercial projects. Mr. Berg said, bottom line, if the Work Group thinks about what it takes to move forward from the perspective of risk, the Work Group can understand why projects are not being built and can begin to identify who is most capable of managing the particular risks that impede the decision to move forward of projects. For example, can the private sector manage a particular risk through an insurance policy or warranty or is this risk something the private sector cannot manage? If the private sector cannot manage as risk, can the government effectively and efficiently accept enough of that risk to allow a project to move ahead?

Mr. Berg next highlighted the findings of the IGCC study, presenting a chart showing the Levelized Cost of Electricity (LCOE) in the Base Case, and the co-production study. The chart shows that LCOE for a plant varies depending on the financial structure of the project and on a range of variables (e.g., cost of coal, cost of construction, plant reliability). Public power is not profit making, investor owned utilities are rate based and have an interest rate that reflects the reduced risk that rate basing provides, and merchant power and Independent Power Producers (IPP) have higher risks because in most cases they do not have assured dispatch. For co-production plants, Mr. Berg showed that a similar range of variables affects the cost of producing fuels, electricity, and other plant products; he also pointed out that CCS adds to the cost of plant products. He said they are in the process of evaluating the cost impacts of adding a sequestration step into a saline aquifer directly below the plant or alternatively piping it and using it for Enhanced Oil Recovery (EOR).

Mr. Henneke asked how the crude-equivalent price for bituminous FT fuels was equivalent to $52 per barrel of oil. Mr. Berg said the assumption is that they built a plant, operated it, and the fuel is at $50.

Judi Greenwald, Pew Center on Global Climate Change, asked about the difference between crude-equivalent price versus the price shown in the parenthesis. Mr. Berg said the ultimate FT fuels price is in the parenthesis and the crude-equivalent price is listed before the parenthesis. In other words, the table shows two prices: crude versus refined.

Mr. Berg continued discussing the highlights of the findings. He said there are a handful of things that stand out in the responses to a risk questionnaire by professionals in the industry. Market risk is high: Any project built today must contend with price volatility in energy markets. At some point in the future, a plant is likely to face losses because sale of its products, which are priced in the range of $50 range on a crude-equivalent basis, will generate a loss or an insufficient revenue stream sufficient to meet the plant's debt payments. The potential for cost overruns also is significant; the engineering/cost index has risen 30 percent over the past few years. Another key concern is a lack of construction and completion certainty related to both potential cost overruns and schedule delays typical of first-of-a-kind projects. DOE's experience with half-scale IGCC projects is that it takes nearly twice as long as expected to reach an adequate level of performance in terms of reliability and operability. Mr. Berg said experts do not expect this issue to surface at the same level for co-production (Co-Pro) plants.

Mr. Berg continued discussing the highlights of findings. Wall Street says that, due to market risk (particularly, price volatility), it is essential for project sponsors to put in place a long-term Purchase Agreement (PA) with a creditworthy off-taker for fuels. For power, it is also essential to have either rate basing or an assured dispatch agreement with an off-taker. Long-term PA's for the federal government, however, are not feasible under current accounting rules.

Mr. Berg next discussed the Co-Pro risk questionnaire results and insights with the financial community and industry. Mr. Berg said it takes many groups to develop an ACT project; his slide on the project participants and their roles highlights this. All the various players and their roles are associated with different risks of the project. Mr. Berg said there is also a time dimension component for risk, and he presented a schematic showing how project risks and participant roles change over time. He also showed a diagram illustrating the study's logic flow and approach to the analysis.

Mr. Berg continued by summarizing questionnaire responses from both the Co-Pro study and the IGCC study. Twenty participants across the transaction chain (which he previously laid out on the project participants slide) responded to the Co-Pro questionnaire. For IGCC, twice as many questionnaire responses were received. For Co-Pro, there were 33 risks and there were slightly more risks for IGCC. Mr. Berg highlighted the top 3 Co-Pro risks: 1) high capital cost, 2) tightness in construction sector (in EPC capacity, warrantees), and 3) price increases in materials & equipment (risk of budget overrun). He mentioned that respondents expressed skepticism that the national policy debate on carbon dioxide will soon be resolved.

James Burns, Shell, said he thought development costs for Co-Pro projects are much higher than what most people on the power side and refinery side are used to. Development risk is much higher than for a normal power plant. Mr. Berg agreed.

Mr. Berg continued his presentation by showing a summary of the highest risk ratings for both Co-Pro projects and IGCC. The right column of the chart shows IGCC results from 2005 based on 50 responses. The risks are plotted in two dimensions: 1) probability that an event will happen, and 2) severity of the impact if the event does happen. The rating is the product of these two numbers. Mr. Berg briefly reviewed the highest risks. He also pointed out that permitting delays and sequestration were not highly rated risks for Co-Pro, but they were highly rated risks for IGCC.

Mr. Berg next showed the 11 technical risk ratings. The highest risks are shown in red, and the next tier of risks is shown in yellow. He next presented a two-dimensional plot showing the overall average for probability, which is a little less than 3, and the overall average for severity, a little over three. The risks fall into the various quadrants depending on their probability of occurrence and severity of impact. The chart is a way of displaying where risks fall on a matrix; it hints at what types of mitigation mechanisms can be brought to bear most effectively.

Mr. Berg said that when his team met with Wall Street, they received information about the following: confirmation of the highest risks, issues for projects moving forward, expectations of capital cost, advocacy of the necessity of a purchase agreement/off-take agreement, concern about the impact of volatility in energy markets, and length of debt. Important information about the industry interviews included confirmation of expectations for internal rate of return (IRR): Early Co-Pro plants are going to need rates of return around 19 percent in order to attract capital. Power utilities are now in the 12 percent range and the returns for public power are even lower.

Mr. Berg followed his discussion on questionnaire results with a discussion on incentives. He reminded the Work Group that the results were based on the assumption that early commercial Co-Pro plants will utilize a project financial structure. Specifically, Mr. Berg's team looked at tax incentives, credit incentives, and grants. Mr. Berg described the impact of this range of government incentives on the prospects of early commercial plants. He pointed out that investment tax credits can reduce output pricing by, effectively, reducing the cost of a plant. Tax incentives, however, have only a limited impact on project creditworthiness because price volatility has been greater in recent years than the impact of tax incentives (which now are about 20 percent of plant cost); plant revenues can easily fall "under water" by more than the 20 percent. Therefore, even with tax incentives, some projects may not get built. Mr. Berg briefly discussed loan guarantees, showing how a properly structured loan guarantee can cost nothing to the government but yield a benefit in lower fuel price equivalent to $800 million of excise tax credits. Grants can be a useful tool, as well, particularly early in the life of a project, but they, like tax incentives, are budgeted on a dollar-for-dollar basis.

Ms. Greenwald asked if the presented results included CCS. Mr. Berg said, no, this was the base case which captures and compresses carbon dioxide; they are currently doing the modeling for the transportation and sequestration part of CCS.

While discussing Co-Pro grants, Mr. Berg stressed that initially having funds is helpful. Mr. Berg finished his discussion on incentives by reviewing the next steps in the project, including analyzing a combination of incentives. Wall Street has indicated that, for large energy projects today, the price of oil in the ground is valued at approximately $33 per barrel; currently, the market value is $60 per barrel. His group wants to define a combination of incentives that can reach this lower level which could potentially obviate the need for a purchase agreement.

Eugene Trisko, United Mine Workers, asked how the in-ground oil cost of $33 per barrel was derived. Mr. Berg said that Wall Street tracks the range of prices for oil over time, and uses the lower end of the range as a proxy price. This factor affects the prospect of a project going into default when Wall Street performs a credit rating for a new major energy project. In doing this, a floor price for oil is looked at as part of the rating process.

John Walke, Natural Resources Defense Council, said the slide entitled "Risk Framework: Probability vs. Impact" had some built-in value and political judgments. He asked if the value judgments were reflections of industry survey results or reflections of Department assessment. Mr. Berg said the ratings were received from those identified on the slide that listed the 20 respondents of the Co-Pro questionnaire. He said "require" is a value judgment only in the sense that the project will not get built without someone addressing risks that prevent a project from moving forward.

Mr. Walke next provided an example that would shift the boxes in the slide around. If there were a mandatory carbon cap in which the allowances were auctioned, the economic dynamic of new plants would change because they would no longer require a government subsidy or industry. Mr. Berg agreed, adding that his team was trying to be policy neutral. They are objectively reporting respondents views of a project's economic and financial prospects. He noted that, sometimes, a government mandate results in a high cost solution, but his group is not making judgments about this. Mr. Berg said he thinks that the market is not going to address some externalities without some type of incentive.

Ann Weeks, Clean Air Task Force, thought that Mr. Berg's group was asking for people's current perceptions in the survey, not for perceptions in a new policy frame. Mr. Berg concurred.

Steve Jenkins, CH2M Hill, asked about Mr. Berg's basis of the Co-Pro plant (i.e., how many barrels per day of fuels and how much power). Mr. Berg said the basis is approximately 30,000 barrels per day of liquid product; there are several hundred megawatts of power, most of which are used internally. The net power export, after carbon capture and compression, is approximately 200 MW.

David Foerter, Institute of Clean Air Companies (ICAC), asked if Mr. Berg had done risk ratings for other advanced coal technologies. Mr. Berg said they had only done risk ratings for IGCC and Co-Pro advanced coal technologies. In 2002, they did risk ratings for nuclear power plants. They have also done risk ratings for DOE's biomass program of DOE and hydrogen program. Mr. Foerter said that the ratings themselves seem to serve as a survey to show reasons for and against building. Mr. Berg agreed, but noted that the work is very project specific. For IGCC, depending on where respondents were in the transaction, the risk ratings were different.

Ben Henneke, Clean Air Action Corporation, asked for an example of a successful loan guarantee program. The government has approximately 80 credit programs, almost all of which use loan guarantees. Home mortgages and student loans are examples of very successful loan guarantee programs. The Overseas Priate Investment Corporation (OPIC) is an example of a program that offers loan guarantees for large capital projects. Mr. Berg said that DOE's past loan guarantee programs (in the 1980s) were not successful.

Ms. Greenwald asked if it was possible to do life cycle CO_2 emissions from these projects in order to assess how a project would fare under different carbon policies. Mr. Berg said if the carbon sequestration cost could be forecasted, this cost could be added to the current numbers.

Ms. Greenwald responded that, even with sequestration, the fuels themselves get burned, so a Co-Pro project is not ideal from a CO_2 life cycle perspective (i.e., not carbon net zero). Mr. Berg agreed, saying that he has been told that if you sequester the carbon from the gasifier and the FT unit, a plant would be roughly carbon neutral compared with other oil-based transportation fuels. If a plant uses some biomass with coal in the gasification step, you can get a decrease, but the current study does not include biomass. Ms. Greenwald said that even staying with oil is not terrific. Mr. Berg said that perhaps we should be thinking about liquid fuels from coal gasification as a niche fuel, but not as fully replacing oil.

Mr. Walke said that with CCS at a production facility, liquid coal is about 10 percent worse than gasoline in terms of CO_2 emissions.

Ms. Wood next introduced Al Linero of the Florida Department of Environmental Protection. Mr. Linero discussed a clean coal technology selection study that is moving forward in Florida. He said Florida has finished the largest gas-fired project in U.S. and FPO has since applied for the largest coal-fired project in U.S. history. FPO submitted their clean coal technology selection study to the public service commission. This is a real life comparison between their different clean coal technology options. FPO is willing to share this comparison. The study, however, assumes that the ALSTOM technology, discussed earlier, will be available to them, so for all cases, they get a large benefit when compared to IGCC. They want to take their plant and install SCR and deep sulfur removal. The University of South Florida is studying the availability of a saline aquifer at about 5,000 feet. Mr. Linero said he would be happy to email the members additional information. He said the FPO project is in the permitting stage. He expects the IGCC application this summer.

Overview of the Clean Air Act

Anna Wood, EPA, next introduced Bob Wayland, leader of the Energy Strategies Group at EPA, who will present an overview of key aspects of the Clean Air Act that relate to power generation. Mr. Wayland’s presentation will be followed by a presentation from Steve Jenkins, CH2M Hill, who will be discussing key provisions of the Clean Air Act related to New Source Performance Standards (NSPS), and how the technologies square against each other.

In his introduction, Mr. Wayland said that his goal was to overview the 3 basic clean air rules and how they relate to existing coal fired generation. He wanted to do this so that as the Work Group studies new technologies and thinks about moving forward, they will know what is required of the current plants. Mr. Wayland said he would be reviewing the National Ambient Air Quality Standards (NAAQS) which has driven the development of the 3 clean air rules: Clean Air Interstate Rule (CAIR), Clean Air Visibility Rule (CAVR), and the Clean Air Mercury Rule (CAMR). Lastly, Mr. Wayland said he would briefly discuss New Source Review (NSR) because NSR will be a key part of how plants using ACT will be permitted. Mr. Wayland provided a brief overview of these major programs.

Mr. Wayland next showed the implementation timeline for CAIR, CAMR, and CAVR. These are staged programs that build off incremental controls. If advanced coal technologies are implemented in 2011, 2012, and 2013, they will be implemented during the same time as other air rules. Mr. Wayland next presented a graph showing past emission levels and projected emission levels with CAIR, CAMR, and CAVR. He pointed out that the goal is to have zero emissions.

Mr. Wayland presented a bar chart from the Integrated Planning Model that is run by the Clean Air Markets Division of EPA. He highlighted the projected growth of coal, and said that a cleaner and more efficient way of using coal is needed. He said the Work Group can help incentivize and force ACT to move forward. Mr. Wayland next reviewed the projected coal capacity with advanced pollutions controls and then continued by presenting pie charts showing the percent of coal-fired generation and controls in 2010, 2015, and 2020. Mr. Wayland noted the shift over time to ACT.

Next, Mr. Wayland presented a map of the U.S. showing projected technology retrofits. These maps show how EPA foresees infrastructure for ACT being implemented over the next 5-15 years to meet the demands set forth in CAIR, CAMR, and CAVR. The map illustrates that because of CAIR, CAMR, and CAVR in east, there are many SCR/Scrubber combinations projected in 2010. These technologies will be implemented to meet the Phase I cap for CAIR and the Phase I cap for CAMR. When burning eastern coals, the mercury is oxidized and the scrubber/SCR combination removes the oxidized mercury efficiently. In the west, in order to achieve the sulfur controls on both powder river basin and lignite coals, there will be more scrubbers and low NOx burners. In 2015, projections show an even greater increase in ACT. By 2020, which is considered full implementation for these programs, there is more activated carbon in the west.

Mr. Wayland presented a graph showing the coal production for the power sections in various parts of the country. Projections show that production of all coal types will increase. This is important because the goal of the CAIR/CAMR/CAVR was not to advantage or disadvantage any one coal type.

Mr. Wayland next reviewed the basics of New Source Review (NSR) and NSR permit requirements. He said that a major source is defined as a source that emits 100 tons per year or more of one of the criteria pollutants.

Mr. Wayland went on to review BACT and LAER. For BACT, he said there is a lot of flexibility. There is the ability to incorporate other energy, environmental, and economic impacts and costs and the ability of determining what technology defines BACT for a particular facility. The flexibility diminishes under LAER, which is very cut and dry. Mr. Wayland finished his presentation by discussing how BACT and LAER are determined.

Barbara Bankoff, Siemens Power, asked Mr. Wayland to explain the non-economic category in the chart showing the projected technology retrofits in 2020. Mr. Wayland said the non-economic category includes existing plants that will go off-line.

Al Linero, Florida Department of Environmental Protection, asked if a delegated state were to ask Mr. Wayland today whether they had to look at IGCC in a BACT review, would he say yes or no. Would he make them analyze IGCC when they are looking at pulverized coal? Mr. Ling responded that the Agency views IGCC as redefining the source.

Ann Weeks, Clean Air Task Force, said it is not true that BACT offers more flexibility than LAER and that LAER is more technology forcing. The purpose of both BACT and LAER is to choose the best possible course. Mr. Wayland confirmed that BACT does not offer more flexibility, but it does offer more alternatives than LAER.

John Campbell, Caterpillar, asked about the typical time frame to get a permit once a company decides to build a plant. Mr. Ling said EPA's experience has been that most permits get issued within a year, but it may take longer. Companies may also go through an appeal process, which may lengthen the time.

Mr. Linero said the slow part of the process is the siting process. Mr. Linero provided an example of a company that was able to receive their permit in 9 months. There are statutory deadlines to act on complete applications; however, he does not know if EPA has similar deadlines.

Judi Greenwald, Pew Center on Global Climate Change, said there is a lot of interest in expedited permitting as a possible incentive for ACT. She asked what expediting permitting entails. Mr. Wayland said none of the steps necessary to get a permit would be skipped; however, the steps would be done quicker. Mr. Wayland said the Work Group could define and recommend expedited permitting as an incentive for ACT.

Mr. Linero pointed out that the background of the Prevention of Significant Deterioration (PSD) of air quality requirement was derived from the Sierra Club v. Ruckelshaus litigation in 1973. That program and EPA's regulations, later codified in the 1977 amendments, were initiated at a time when air quality was expected to worsen throughout the United States. Since 1973, PSD and NSR have been overtaken by the cap and trade initiatives of Title IV for SO_2 control nationwide, SIPs for NOx control, and CAIR. Now that NOx and SO_2 are monetized, these programs are no longer relevant for areas in attainment. EPA has also provided a cap for total allowable emissions from the utilities sector. For areas of the U.S. that are subject to an emission cap and where emissions have been monetized, these programs are irrelevant and should be eliminated.

Steve Jenkins presentation – Implementation of Clean Air Act Requirements for Advanced Coal Technologies

Steve Jenkins, CH2M Hill, said he wanted to focus his presentation on New Source Performance Standards (NSPS). He next discussed the differences in feedstock, fuel, combustion, and emission control for PC and IGCC, and compared how contaminants are removed from PC and IGCC.

Mr. Jenkins explained how IGCC is a different environment than PC. For example, IGCC is a reducing atmosphere, meaning it does not use a lot of oxygen; this differs from PC. Mr. Jenkins further explained specifics of IGCC.

Mr. Jenkins next showed a chart to explain the new NSPS. He pointed out that most of the units of the NSPS are in lbs/MWh. The unit “lb/MMBtu” is most commonly used, so Mr. Jenkins estimated what the numbers would be in these units. For particulate matter, the regulation has both units, so this is not estimated. The reason for some of the differences in IGCC and PC is that when EPA calculates its lb/MWh unit, it is calculated on a gross generation basis. If IGCC and PC have the same gross output because of the internal load in an IGCC unit, the net output of an IGCC until will be less. These numbers are for bituminous coal.

Lisa Stolzenthaler, GE Energy, asked for the basis of the lb/MMBtu unit. Mr. Jenkins said these were pounds of emissions per million Btu’s of heat input to the gasifier.

Ann Weeks, Clean Air Task Force, asked for the translation between input base and output base. What efficiencies did Mr. Jenkins assume for IGCC versus PC? Mr. Jenkins said the efficiencies do not enter because you are only looking at the conversion between MWh units to MBtu units. You can factor in an efficiency level, but for most of the proposed plants, the actual efficiency of proposed PC plants is greater than the efficiency of any of the IGCC plants currently being proposed. Ms. Weeks asked if Mr. Jenkins was proposing that there was no distinction. Mr. Jenkins said that you are only using the gross generation numbers. The net is where some of the efficiency issues may arise. Since the output based numbers are done on a gross generation basis, it is necessary to use gross-based numbers.

Mr. Jenkins said that IGCC units and PC units fall under the same NSPS. There could be problems during initial start-up when plants burn less than 75 percent syngas because the plant may burn more natural gas than syngas. Because of this, NSPS said these plants would not be covered as electric utility steam generating units. These plants would instead be classified as combustion turbines. Meeting the NSPS for NOx may not be possible when burning natural gas in diffusion burners designed for syngas. Industry, therefore, requested modification to the regulations. Mr. Jenkins reviewed EPA’s proposed changes in February 2007. These changes remove any current ambiguity. An IGCC unit that uses coal is covered by the same NSPS as a PC boiler. They are treated equally and an IGCC unit is not regulated in the same way as a gas-fired combined cycle unit.

Mr. Jenkins next reviewed air permitting requirements pertaining to IGCC and PC plants. IGCC and PC plants have similar fugitive dust control requirements and cooling tower requirements; however, Mr. Jenkins noted that IGCC inherently uses less water than PC. This might be beneficial to western states. The same air dispersion modeling would apply to both.

Mr. Jenkins next reviewed what is different when permitting and IGCC plant and permitting a PC plant. The differences include: flare, start-up burner, gasifier pre-heat burner, sulfur recovery unit tail gas incinerator, sulfuric acid plan stack, tank vents, and an air separation unit cooling tower. Mr. Jenkins next reviewed the various aspects of an IGCC air permit application.

Maha Mahasenan, Rio Tinto Energy America, asked a question about proposed plants and gasifiers. Mr. Jenkins said that one proposed plant has 350 percent sized gasifier trains. Most proposed plants have 250 percent.

Mr. Jenkins went on to discuss SCR for IGCC, focusing on technical issues and economic issues. Mr. Jenkins said that no coal-based IGCC system in the world uses SCR. Ms. Greenwald asked if not being able to use SCR, meant that its NOx performance is not as good as PC. Mr. Jenkins said that with SCR, IGCC will likely have lower NOx emission rates, but they do not know this.

Mr. Jenkins next showed a diagram of SCR in a PC Plant. In a PC plant, there are air pre-heater baskets that have large openings due to the fly ash and the exhaust gas. They are designed for removal, easy replacement, and cleaning. The particulates are removed downstream in the electrostatic precipitator of the scrubber system or the bag house. These baskets were made so that they can be replaced or cleaned if there is corrosion. Therefore, you design SCR into a system that is made for cleaning and removal. For SCR in an IGCC plant, however, finned tubing is not designed for removal, replacement or easy cleaning. Interestingly, more IGCC plants are being proposed with SCR than without SCR. Mr. Jenkins listed some of the reasons.

Mr. Jenkins quickly reviewed NOx BACT, and mercury removal for PC and IGCC. Mr. Jenkins answered Ms. Greenwald's question about NOx emission rates for PC and IGCC units; the emission rates are not very different for the two. Mr. Jenkins next showed a graph showing air emission comparisons for NOx and SO_2. The numbers were taken from the air permit applications. The graph shows that NOx emissions are comparable for IGCC and PC; however, IGCC has an edge for SO2 over PC.

Mr. Mahasenan asked for the nominal output of Eastman plant. He asked if it would be several times larger for a commercialized existing plant. Mr. Jenkins said it would be larger.

John Walke, NRDC, pointed out the various drivers and factors not mentioned in EPA's presentation that were mentioned in Mr. Jenkins' presentation. First, he hopes the court will strike down the Clean Air Mercury Rule litigation. This will significantly alter the scenario for EPA's intended installation of scrubbers. Someone said that the cap under CAMR in Phase 2 will take effect in 2018. Mr. Walked pointed out that at the earliest, the Phase 2 cap would be achieved in 2026. This is a two decade delay and if the litigation is successful, this will be changed.

Mr. Walke also said that approximately 20 states have balked at EPA's rule and have developed faster and stronger mercury rules. He said that 2009 and 2010 are the attainment deadlines for ozone and soot under the 1990 standards. EPA left many U.S. citizens in areas that will not reach attainment under CAIR. The states must therefore bring these areas into attainment. The most cost effective solutions in the east remain coal-fired power plants. Therefore, Mr. Walke thinks there will either be additional reduction strategies targeting them or some business that are not in the coal industry will get stuck with the tab for more expensive solutions.

Finally, with regard to BACT and redefining the source, Mr. Walke said that redefining the source is a concept made up by EPA. It is only a product of EPA policy. A relevant decision from 1988 said two things. First, to require a plant that was planning to burn PetCoke to consider, as part of the BACT analysis, burning gas instead. This is not redefining the source. Second, redefining the source, even as understood by EPA, is a matter of requiring a different source category to be built, not a different type of source within a source category. Mr. Walke pointed this out to show that there are very different views of the world than what EPA is representing.

Michael Ling, EPA, said he recognized that there are views that differ from the policy view that he expressed. He asked the Work Group to set aside the legal argument over what the Clean Air Act says about redefining the source and focus on a policy saying IGCC must be considered as BACT. He would like to examine how this would affect permitting and whether it would act as an incentive.

Jeff Logan, World Resources Institute, said BP is proposing to build an IGCC plant in Carson, California that will use PetCoke as a feeding stock, which will then be converted to syngas, which will then be shifted to hydrogen and CO_2 that will be used for Enhanced Oil Recovery (EOR). He asked Mr. Jenkins to explain the regulatory framework for combusting hydrogen in an IGCC plant. Mr. Jenkins said in this gas the NOx emissions would be higher than if using syngas or natural gas. In the end, the NOx emissions will need to be lowered to a level that has not been determined. Mr. Jenkins pointed out that there are dozens of smaller gas turbines that burn nitrogen. Although, no large scale turbines are burning nitrogen, he does not see regulations as greatly impeding the construction of IGCC plants.

Ms. Weeks said it is very valuable for the Work Group to be informed of the legal drivers. Another driver is in the NSR standards; EPA did not consider carbon and this is also being litigated. In the next year there may be some court decisions affecting the Work Group.

Ms. Greenwald said she did not understand Mr. Jenkins' answer to her NOx question. There are 3 situations: IGCC without SCR, IGCC with SCR, and PC with SCR. Where does IGCC with or without SCR fall relative to PC with SCR? In answering her question, Mr. Jenkins showed the bar chart showing air emission comparisons for NOx.   PC and IGCC without SCR have the same level of NOx emissions. IGCC with SCR has the lowest NOx emissions. However, whether or not they will work, is still unknown.

Ms. Wood thanked both Mr. Jenkins and Mr. Wayland for their presentations.

<u>Legal, Liability and Public Perception Concerns Associated with Carbon Capture and Storage Projects</u>

Anna Wood, EPA, introduced the next speaker: Jeff Logan, a Senior Associate at World Resources Institute (WRI).

Mr. Logan explained that he would discuss legal and liability issues, public perception and acceptability, and ongoing international activities.

To start, he said he would talk about WRI's views on CCS. WRI believes that CCS is an essential component of climate strategy; but it is not a silver bullet. Furthermore, the technology for CCS largely exists already, in the sense that we have injected it underground or captured it in small scales at power plants. However, the technology has not led to a thoroughly developed or complete understanding of how all the pieces fit together in a large integrated project. For example, there is not geologic certainty of what happens when we inject below the surface. There is also still uncertainty on the mitigation driver needed for wide-scale deployment. Mr. Logan also explained that there are policy, regulatory, and institutional voids that need to be overcome. Similarly, public acceptability of CCS is largely uncertain. Finally, developing country participation in CCS is crucial. However, before we expect developing countries to do something with CCS, we really have to set the standard in the U.S.

Mr. Logan next said that many scientists now believe that we need to hold degrees of change at temperatures of two degrees or less to deal with climate change. He showed a series of graphs and said that in order to hold at this path, the concentration of CO_2 in the atmosphere must be held at the corresponding blue line (under 500 parts per million). In order to reach that level of concentrations in the atmosphere, the emissions profile that we need shows that in 2020, global emissions will have to peak. Global emissions would include areas like China and India, which are growing rapidly. To accomplish this, CCS is going to have to play a role, which is a huge challenge.

Mr. Logan next explained that there are a lot of different options that can be employed to get large chunks of global reductions in CO_2. Most of the policy options show that about 1200 GW of capture and storage would need to be deployed by 2050. This is an enormous amount of investment that will have to happen. So far most of the projects that have demonstrated CO_2 sequestration are on the order of a 100 MW plant. Comparing what magnitudes we are dealing with now versus the 1200 GW of plants we will need to deal with in the 2050s is fairly mind-boggling.

Mr. Logan next said that there is an interesting timing debate associated with the deployment of CCS. There are people who say that the climate system cannot wait; that we need to begin large scale CCS immediately. On the other hand, there are others that say that the risks of a mistake are so severe that we do not have the luxury of doing it all at once. If we make a mistake early, we will forever have lost the option of CCS.

Judi Greenwald, Pew Center on Global Climate Change, asked what kind of mistake? Mr. Logan said that examples of a mistake would include a large release of CO_2 that affects a neighborhood, or a CO_2 injection that pollutes a large source of drinking water.

Maha Mahasenan, Rio Tinto Energy, added that even mistakes that do not have any adverse environmental health impact could still set progress back.

Ann Weeks, Clean Air Task Force, said she agreed that there was a serious timing debate. Sometimes we take a cautionary approach, but other days we can be stuck in the paradigm of risk assessment. She suggested that we need to get out of these two boxes to make progress.

Mr. Logan next said he would discuss liability and legal issues. He said that when you talk about legal and liability issues, you start fundamentally at the topic of risk. He read a quote from IPCC that said “With appropriate site selection informed by available subsurface information, a monitoring program to detect problems, a regulatory system, and the appropriate use of remediation methods to stop or control CO_2 releases if they arise, the local health, safety and environment risks of geological storage would be comparable to risks of current activities such as natural gas storage, EOR, and deep underground disposal of acid gas.” Mr. Logan said that this shows that experts believe that risks are manageable when CCS is done correctly.

To look more closely at risks, they can be divided into local and global issues. Local risks include risks to the atmosphere or shallow subsurface, which can harm humans, animals, or plants. CO_2 can also become dissolved in the subsurface, which could contaminate underground drinking water or cause interference with deep subsurface ecosystems. There are also quantity-based local risks, including ground heave or induced seismicity. There can be contamination of drinking water by displaced brines, or there can be damage to hydrocarbon reservoirs. A global risk would be the release of CO_2 into the atmosphere, which would increase greenhouse gas emissions.

Next Mr. Logan spoke about selected legal issues. Legal and regulatory analogs exist, but none fit perfectly. There is no national or state regulatory framework to deal with CCS. The one that would fit most closely is the Safe Drinking Water Act that governs CO_2 EOR. It is well developed, but the framework is done to maximize oil recovery, so it is fundamentally different from CCS. There is also natural gas storage, which involves well-understood reservoirs, not saline aquifers. Finally, another potential analog is acid gas injection, which is done a lot in Canada. The relatively small volumes of injection means that this analogy falls short.

CO_2 is currently not regulated, but this will likely change in 2-4 years. If it is labeled a pollutant, the focus on its regulation would change. There is tremendous diversity among states and how they regulate things that are similar to CO_2. This diversity presents an interesting set of challenges for how things can be done on a broad scale.

Mr. Logan next said he would spend time talking about down stream legal issues. One issue related to siting is the need to be able to get large and legal reservoirs to do an injection. For example, there is a reservoir in Illinois that has applied for FutureGen. However, there are 69 different property owners involved who will have to come to some agreement on their rights. The act of getting large and legal reservoirs will be very challenging. The legal issues of eminent domain and unitization according to state interpretation will be critical. In Texas for example, all property owners with a resource have to agree in the same way to use a reservoir.

There are also a lot of legal questions and uncertainties about operation. For example, what kinds of construction materials are required for injection wells? CO_2 is fairly acidic once combined with water. What requirements are there to identify and plug old and abandoned wells? There are tons of these wells all over; even finding where they are is often difficult. If you do not find them, CO_2 will come out to the surface. What kinds of measuring, monitoring, and verification needs to be in place? What kind of accounting measures must be in place? In terms of closure, at what point can you say the project is closed? In Texas, for example, the state said it would take on long-term liability in order to make FutureGen more attractive.

Mr. Logan next explained that CCS liability is not just a long-term post-closure issue. There are specific phases of CCS liability. He showed a table that outlined the significant liability issues along the way. In general, companies are able to deal with the liability issues during most phases. Some public indemnification would need to be in place to make companies confident about liability.

He next showed a conceptual risk profile and said that it changes rapidly over time. The risk profile shows that the need for monitoring slows down as you build up knowledge of what is happening underground. The risk of something bad happening over time declines fairly significantly. He showed a chart that outlined the different kinds of trapping that happen underground. As time goes on, residual phase trapping means that CO_2 becomes mineralized and there is increasing storage security after thousands of years.

Mr. Logan said that with long-term liability, private entities are not likely to develop CCS projects if held responsible forever. Private entities also have limited lifetimes since companies do not stay around forever. There is a need to pass on monitoring and potential remediation responsibility to a public entity at some point after closure. The question remains though about under what conditions this should happen and how long before it should happen. There is also a question about relative requirements of financial responsibility framework. The Price Anderson Act for example is an indemnification created by the government to make sure that nuclear power would be able to handle a catastrophic accident. Finally, there are jurisdictional differences between states that are significant.

Next Mr. Logan talks about public perception. When forming public views on CCS, who is the public? Is it NGOs, university professors, the media, etc? A lot of people use NGOs and the media as the forerunners of what public attitude will eventually be. People now have a low awareness of climate change and energy issues/options. There is also a question about perceived risk and actual risk. The success of initial projects are of utmost importance for public perception. There also must be trust in the messenger; the public does not trust the government or the industry, compared with scientists or NGOs. The discussion of trade-offs and costs become important in a discussion with the public. After people learn more, they realize alternatives are not going to get us as far as we need to go. Finally, there is the question about local stakeholders and those people who live near an injection site. These are all important issues to consider when thinking about the public perception of CCS.

Mr. Logan next showed a chart that demonstrated the public support for different climate change mitigation strategies. The study was conducted by MIT in 2003 and 2006. Mr. Logan noted that a group of people that you interview in 2003 and 2006 may not be directly comparable, so this is an issue. However, you can see that there is a dramatic increase in support for CCS when the public has information and there is a dramatic decline in belief that renewables work if there is more information.

Next Mr. Logan said that when you are doing a CCS project, you must have something for everyone; in other words, you must meet CCS thresholds. He showed a figure that noted the relationship between project developer benefits, climate benefits, and local benefits. Local benefits would come in the form of more jobs or cleaner air, for example.

He next showed a matrix that showed how public participation can be used to help meet goals and usher in change. This matrix was developed by International Association for Public Participation. It emphasizes the following actions to increase the level of public impact: inform, consult, involve, collaborate, and empower. The most activity happens in the inform and consult columns, but there is not enough activity in the involve, collaborate, and empower activities. Mr. Logan said that once people take ownership in how decisions are made, they will feel confident that what is being done is right. He said that building public acceptance for CCS can only happen with robust, transparent, and inclusive regulations.

Finally, Mr. Logan spoke about international activities. He said that CCS is a growing mitigation option. Currently, there is the Weyburn project, the In Salah project, and the Sleipner project that are happening in commercial settings. There are a lot of proposed projects in the U.S, including BP's proposals in California.

In conclusion, Mr. Logan said that site selection is critical; done poorly, the need for clumsy downstream action expands dramatically. It is best to focus on siting a project appropriately from the beginning. He added that heavy MMV is required for early projects to satisfy public acceptability and accounting requirements. Government must also take long-term liability. Finally, a public dialogue on CCS must expand to build trust; transparent and robust regulatory framework is needed for long-term public support.

With this conclusion, questions were taken from the audience. Tony DeLucia, East Tennessee State University, asked if he had thought about Canada's approach to climate change and their targeted education and social marketing? Mr. Logan responded that the Canadian involvement in international negotiations is changing. Five years ago they were very interested in Kyoto, but not it does not look like they will be complying. He said he had not thought about social marketing.

John Campbell, Caterpillar, Inc., said that he was surprised that the analysis did not have any consideration of the individual impact, such as utility bills. Mr. Logan responded that he tried to emphasize that cost is very important in how individuals see this issue. The community citizen perspective is important.

Maha Mahasenan, Rio Tinto Energy, said that if you show the public how much cost increases with the whole suite of options, then you can show that CCS may be the most economical option. He added that he agreed that siting is very important, especially with liability. He mentioned that there is a comprehensive report on www.FutureGenAlliance.org that has a lot of info on siting.

Judi Greenwald, Pew Center on Global Climate Change, asked a question on regulatory analogs. She said that Mr. Logan had mentioned something about underground injection, but she said that she thought states regulated EOR. Mr. Logan responded that the Safe Drinking Water Act has requirements in it that govern how things are injected underground. Under that well classification, state EPAs have authority to give licenses, but class 5 is for demonstration projects.

Ms. Wood said she was curious about international demonstration projects for underground storage and liability issues. Mr. Logan said that IEA is leading some interesting comparative work. Australia and Norway are both countries that have lined up their interests to support CCS and offer interesting examples in how they push these technologies forward.

Discussion of Barriers, Opportunities and Tools

The Work Group split into 6 groups and voted on their top 3 barriers/opportunities from the 29 barriers/opportunities listed from Ms. Wood's earlier PowerPoint presentation. The barriers/opportunities numbering began on slide 5 of her presentation and ended on slide 10. The details of the voting and suggested actions are included in Attachment A.

Closing

Ben Henneke, Clean Air Action Corporation, said that there was some concern that not all of the big issues were being covered. To address this, Mark Macleod has volunteered to do a matrix. The matrix will be a checklist to make sure we are thinking clearly about a lot of these issues and that they are being incorporated into our agenda. He added that there will probably be a lot of overlap on issues. He asked for everyone to contact him or Anna to make sure there are not any other issues that ought to be included in future meetings. He noted that the agenda for the next meeting was already full.

Barbara Bankoff, Siemens Power, said that she was wondering if the group would be expanding more on certain issues. For example, the group had first spoken about some other technologies, such as ocean seeding, which is something that had not yet been addressed in recent meeting. She wanted to know if it was counterproductive to talk about these things at this stage.

Mr. Henneke responded that ocean seeding was a climate change specific technology. Ms. Bankoff agreed, but said it is a mitigation technique, and that this Work Group is focusing mostly on CO_2 mitigation.

Mr. Henneke asked if there were other people who would like to talk about some alternatives? Ms. Bankoff responded that she did not want to make things more complicated, but it seemed that if the group was moving in that direction, there are some other low cost alternatives for mitigation that should be considered.

Mr. Henneke asked if it would be useful if the group ended up stipulating if they thought there was a large number of technologies out there less than a certain cost that could absorb carbon. Would that be enough to go back to how to remove barriers to increase technologies? Ms. Bankoff responded that it may be the approach, and she knows that everything cannot be covered. She said though that if the group does move into CO_2 mitigation and efficiency, she did not want to neglect things that could be helpful. Mr. Henneke responded that it becomes a policy issue as well. Ms. Bankoff said that clear market signals are going to drive a lot of this.

John Walke, National Resources Defense Council, said that it seemed that the list developed last time was impressively broad, but still covered the mandate to drive development of ACT, which is the charge of the group. Going down the road toward mitigation strategies like ocean seeding is probably two or three steps away from the mandate.

Christa Clapp, EPA, responded that she thought that was why the matrix would be really helpful. She said you would see overlap and this will lead to a more informed discussion.

Ms. Wood said that the next meeting is March 29. Everyone would get the meeting summary minutes in advance of the meeting. Everything from the past two meetings is up on the website. They are still updating the member lists, including alternates and are looking to get a financial representative on the committee.

Ms. Wood added that at the next meeting, they would be talking about having conference calls for April. The May 8 meeting is also in DC at the Double Tree to coincide with the full CAAAC meeting. She added that Bill Wehrum testified before the House Subcommittee on Energy and Air Quality today and that the efforts of the Work Group is mentioned in his testimony.

Mr. Henneke thanked everyone for their participation and the meeting ended.

Advanced Coal Technology Work Group Meeting
Double Tree Hotel (Crystal City)
300 Army Navy Drive, Arlington, VA 22202
March 6, 2007

List of Attendees

Name	**Affiliation**
Ann Weeks	Clean Air Task Force
Dan Chartier	EPA
Jim Welch	KY PSC
Robert Hilton	ALSTOM
Gene Trisko	United Mine Workers
Maha Mahasenan	Rio Tinto
Larry Myer	Lawrence Berkley National Lab
Anna Marie Wood	EPA
David Foerter	Institute of Clean Air Companies (ICAC)
Christa Clapp	EPA
Todd Johnston	National Mining Association
Frank Blake	American Electric Power (AEP)
Steve Jenkins	CH2M Hill
Chris Romaine	Illinois EPA
Bob Wayland	EPA/OAQPS
Bob Gruenig	National Tribal Environmental Council

Name	Affiliation
Michael Ling	EPA/OAQPS
Mark MacLeod	Environmental Defense
Barbara Bankoff	Siemens Power Generation
Daniel Cunningham	PSEG
David Berg	Department of Energy (DOE)
Ben Henneke	Clean Air Action Corporation
Judi Greenwald	Pew Center on Global Climate Change
John Campbell	Caterpillar
Alvaro Linero	Florida Department of Environmental Protection
Greg Schaefer	Arch Coal
James Burns	Shell
Lisa Stolzenthaler	General Electric (GE)
John Walke	Natural Resources Defense Council (NRDC)
Bill Auberle	Northern Arizona University
Tony DeLucia	East Tennessee State University
Bob Wayland	EPA
Dean Metcalf	Xcel Energy