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

Written Statement of Scott Miller
General Manager of City Utilities of Springfield
On Behalf of the American Public Power Association
March 12, 2014

Dear Chairmen Schweikert and Lummis and Ranking Members Bonamici and Swalwell, thank you for the opportunity to speak at today's hearing to explore the technological requirements for meeting the newly proposed New Source Performance Standards (NSPS) for emissions of carbon dioxide (CO_2) for electric generating units (EGUs). My name is Scott Miller and I am the General Manager and Chief Executive Officer of City Utilities of Springfield (City Utilities). I am also a member of the Board of Directors of the American Public Power Association (APPA). I am testifying on behalf of my utility and APPA.

City Utilities is a municipal utility that provides electric, natural gas, water, broadband, and transit services to the Springfield area. We serve a population of over 222,000 and have generation capability over 1,100 MW, which includes a mix of fossil and renewable sources. In addition, CU is developing Missouri's largest solar farm.

City Utilities is a member of APPA, the national service organization representing the interests of over 2,000 community-owned, not-for-profit electric utilities. These utilities include state public power agencies, municipal electric utilities, and special utility districts that provide electricity and other services to over 47 million Americans, serving some of the nation's largest cities. However, the vast majority of APPA's members serve communities with populations of 10,000 people or less.

Overall, public power utilities' primary purpose is to provide reliable, efficient service to local customers at the lowest possible cost, consistent with good environmental stewardship. Public power utilities are locally created governmental institutions that address a basic community need: they operate on a not-for-profit basis to provide an essential public service, reliably and efficiently, at a reasonable price.

APPA commends you for holding a hearing exploring the technological requirements for CCS for new fossil fuel-fired power plants. Public power utilities are concerned about the potential or likely impacts of the Environmental Protection Agency (EPA) regulating CO_2 emissions from new power plants by establishing NSPS under the Clean Air Act. The agency's September 20, 2013, re-proposed rule concludes that CCS is the best system of emissions reduction (BSER) adequately demonstrated to reduce CO_2 emissions.[1] APPA strongly disagrees

[1] For the re-proposed NSPS, EPA applied a four-part test to determine BSER. First, is the system of emissions reduction technically feasible? Second, are the costs of the system reasonable? Third, what amount of emissions reductions will the system generate? Fourth, does the system promote the implementation and further development of technology? See p. 25 of Proposed Rule: Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 1430 (Jan. 8, 2014), Docket - EPA-HQ-OAR-2013-0495.

with EPA's conclusions about the commercial demonstration of the technology and believes the agency has failed to look at a variety of issues related to the long-term sequestration of CO_2. Until these issues are addressed, it is premature to require the use of CCS by new coal-fired power plants.

I. EPA's Conclusion That CCS Is Adequately Demonstrated Is Premature.

The re-proposed NSPS would require new coal-fired power plants to achieve an emissions limit of 1,100 pounds of CO_2 per megawatt/hour (lbs CO_2/MWh) (gross) based on a 12-month rolling average compliance period. In the alternative, coal-fired power plants could achieve an emissions limit between 1,000-1050 lbs CO_2/MWh (gross) based on an 84-month rolling average compliance period. Use of CCS technology would be required to meet either standard. Natural gas units with a heat rate greater than 850 MMBtu/h would be subject an emissions limit of 1,000 lbs CO_2/MWh (gross) and need no additional control technology to reduce emissions.

In justifying the use of CCS, EPA modified its definition of the BSER in a manner that promotes newly emerging technologies, such as CCS. The agency asserts that BSER can be technology forcing and consider "the impact a standard will have on further technology development." While the re-proposal acknowledges that there are no commercially operating coal-fired power plants using CCS, the re-proposal asserts that four demonstration projects under development in the U.S. and Canada adequately demonstrate CCS at commercial scale. EPA never addresses the fact that there is no commercial demonstration of sequestration in non-oil and gas recovery locations. Nor does the agency address the myriad of regulatory hurdles impeding the sequestration of CO_2 in the U.S.

A. EPA's Assertion That It Only Needs to Find Carbon Capture, but Not Sequestration Adequately Demonstrated and Achievable Is Erroneous.

EPA looked at three technologies to reduce CO_2 emissions from fossil fuel-fired power plants: (1) super critical pulverized coal (SCPC); (2) total CCS (defined as capturing more than 90 percent of emissions); (3) "practical" CCS (not defined, but implicitly less than 90 percent capture). Comparing the emissions reductions from the three technologies, the agency concluded that partial CCS was BSER because the emissions reductions "that would result from an emissions standard based on SCPC or Ultra Super Critical Pulverized Coal (USCPC), or even IGCC, "would not be consistent with the purpose of CAA Section 111 to achieve 'as much [emission reduction] as practicable.'"[2]

Notably, the proposed NSPS is called partial CCS, but the standard itself is defined solely for purposes of compliance as carbon capture. Nonetheless, throughout the NSPS proposal, there are disjointed discussions of the availability and achievability of both carbon capture and sequestration. Recently, agency officials have emphasized, however, that the agency need only demonstrate the adequacy and achievability of carbon capture. For example, during EPA's Science Advisory Board (SAB) review of the proposed standard in December 2013 and January 2014, the Administrator and other EPA officials underscored that since compliance with the proposed NSPS was limited to carbon capture, the SAB's review of the proposed BSER was

[2] *Id*.

likewise limited to the scientific and peer review issues regarding "carbon capture" (1,100 lb. CO_2/MWh), not sequestration of the CO_2 captured. These assertions, which are repeated in various places in the Notice of Proposed Rulemaking (NPRM),[3] appear to be intended to justify the technical and legal basis for claiming that carbon sequestration has been adequately demonstrated and achievable.

B. None of the Projects or Historical Enhanced Oil Recovery (EOR) Experience EPA Relies Upon Provide a Sufficient Basis to Conclude CCS Is BSER.

EPA asserts that partial CCS is "adequately demonstrated" based on the operation, construction, and/or development of pilot CCS projects at four base load and intermediate load fossil fired EGUs. The pilot projects are Southern Company's Mississippi Kemper Station, SaskPower's Boundary Dam operation, the Texas Clean Energy Project, and the Hydrogen Energy California project. In addition, EPA relies on historic enhanced oil recovery (EOR) operations and terminated international CCS projects as proof that CO_2 sequestration is adequately demonstrated. These characterizations are simply misleading because CCS is not operational, development of the projects is reliant on huge government subsidies, and at least one has been suspended for various technical and financial reasons.

While CO_2 has been recycled in the oil and gas sector for almost forty years, the idea of permanently sequestering it is novel. CO_2 gas functions like a solvent to move oil and gas more effectively than water flooding. The CO_2 currently used in the oil and gas sector in the U.S., Norway, Australia, and Canada is recycled, not permanently stored. Recycling of the gas is far different than permanently storing it underground for thousands of years. The oil and gas sector typically stores the gas for days, weeks, and sometimes months, and usually removes and transports it by specialty pipeline for use at the next oil and gas recovery location.

C. To Date, No CO_2 Has Been Injected and Sequestered at Any of the Cited Demonstration Projects.

None of the four pilot projects described in the NPRM actively capture CO_2 from plant exhausts or sequester CO_2 in the ground. Of the four, two are in the process of being constructed and two are in development. Of the two being constructed, the Kemper plant faces development costs in excess of $1 billion,[4] and is dependent on a technology development for a lignite coal that is not available any other place in the country. The second plant under construction, in Canada, is a post combustion CCS operation at a small research facility boiler that is not scalable.

Of the two projects still in development, there is no firm timeline for construction of either. The California polygeneration project is not expected to get its construction permit for another nine months and then the construction itself will take almost four years. Thus, CO_2 will not be injected in the California project for at least four years, at the earliest. The Texas project, which is not operational, has been unable to secure a purchase power contract from an electric utility and thus the project has been suspended.

[3] *Id*. at 1483/column 3.

[4] Southern Co.: Kemper Plant Construction Cost Could Grow by $40M, Mississippi Business Journal, January 29, 2014, available at http://msbusiness.com/blog/2014/01/29/southern-co-kemper-plant-construction-cost-grow-40m/.

Since CCS is not operational at these pilots, there is no data about their continuous operations, whether the technology can be scaled to commercial operations, or the cost of that technology. Therefore, these pilots cannot form the basis for a finding that the technology is available. EPA is violating the law by making assumptions about a future, theoretically possible technology.

There also is no mention in the NPRM of the inability to complete three CCS pilot projects by public power utilities in Jamestown, New York, Holland, Michigan, and southern Missouri that were discontinued when captured carbon was not feasible for a variety of reasons. City Utilities was actively involved in the Missouri Carbon Sequestration Project. Our experience highlights just some of the issues that need to be addressed before CCS technology can be declared adequately demonstrated.

II. CU's Experience with the Missouri Carbon Sequestration Project.

In 2005, a group of Missouri generating utilities gathered to discuss how CO_2 emissions could be managed if future regulations were imposed. At the time, over 70 percent of electricity provided in the state came from coal-fired generation. It was also becoming apparent that much of the carbon storage research was not addressing geologic conditions found in Missouri. To address this gap in research, City Utilities, Kansas City Power & Light, The Empire District Electric Company, Ameren Missouri, and Associated Electric Cooperative entered into a cooperative agreement with the Department of Energy's National Energy Technology Laboratory (NETL) to research the sequestration of CO_2 in several formations in Missouri.

The project, entitled the Missouri Shallow Carbon Sequestration Demonstration Project, was funded by Congress in two appropriations in fiscal years 2008 and 2010 totaling $4.7 million. Missouri's generating utilities provided a matching share of approximately $1.2 million. CU recently concluded its research activities related to the project.

The purpose of the project was to evaluate the feasibility of on-site carbon sequestration at power plants in Missouri. The project is called shallow carbon sequestration because the target sandstone formation was believed to be at approximately 2,000 to 3,500 feet below the surface. Most sequestration research is directed toward geologic basins at a depth on the order of 10,000 feet. At the shallower depth, CO_2 injection and storage would be in the gas phase, as opposed to liquid, also referred to as supercritical phase, which occurs at greater depths.

The original plan was to drill injection and monitoring wells and inject small quantities of food grade CO_2 to test the ability of the target formation to receive that CO_2. A later monitoring phase was planned to determine the ability of the formation to hold the CO_2 in place for a period of ten or more years. The research was conducted by project partners Missouri State University, Missouri University of Science and Technology, and the Missouri Department of Natural Resources. The project included laboratory analysis of core and water samples, development of hydrogeologic models, bench scale testing of permeability, porosity, and chemical interactions, and downhole testing of geophysical properties.

Some of the project's original objectives were achieved, but ultimately we were not able to substantiate our ability to sequester CO_2 within the state. The site identified for exploration was at City Utilities John Twitty Energy Center, the location of our two largest coal-fired power units with a combined capacity of approximately 500 MW. Drilling and coring proceeded to a depth of 2,186 feet to the Precambrian basement rock. However, the planned injection of CO_2 was not possible. Water quality analysis in the target formation found the Total Dissolved Solids well below the Safe Drinking Water Act standard of 10,000 mg/L, thus precluding injection under federal regulations.

Laboratory testing of core samples did allow an estimate of carbon sequestration potential. Based on a presumed 800 m x 800 m reservoir, a total CO_2 storage capacity of 2.55×10^5 metric tons over 15.8 years was calculated. This would represent about 1 percent of the CO_2 production at John Twitty Energy Center during normal operations during that time frame. In other words, should sequestration have been possible, it would require over 100 wells or well fields, at a conservative cost estimate of $1 million per well, to attain this level of storage capacity, if actual injection corresponded to laboratory test results.

The project was then modified to redirect funds to perform drilling and testing, to the degree funds would allow, at the other partner locations around the state. A second borehole was located at Associated Electric's Thomas Hill Energy Center in North Central Missouri. Basement was encountered at 2,540 feet. Water quality at the target formation was sufficiently saline to permit injection. As at Springfield, the confining layer was found to be effective. Laboratory testing demonstrated reservoir capacity approximately five times greater than Springfield.

The third site was located at Kansas City Power & Light's Iatan Generating Station. Drilling was completed to a depth of 2,090 feet, but due to time and material limitations, the basement rock level was not achieved, nor was core collected.

The fourth site was near an Ameren Missouri plant location south and west of St. Louis. Depth of the target formation was significantly greater than anticipated. Drilling was terminated at 3,625 feet due to physical limitations of the drilling equipment, before reaching Precambrian basement rock. Again, the confining layer and water quality were found to be acceptable for injection. Additionally, the depth of the target formation suggested that super-critical injection might be possible. Gas phase storage was calculated at approximately twice that of Springfield.

In summary, approximately $5.8 million of testing revealed one site where water quality would not permit injection, and we identified two other sites where further testing might be considered. The confining layer analysis was one of the major successes of the project. The project partners were able to identify that the confining layer in three of the locations appear to be adequate to contain CO_2 on the aquifer. Originally planned pressure testing and aquifer permeability had to be abandoned due to cost limitations, so no CO_2 test injections were performed. While some target formation storage capacity was calculated based on laboratory testing, we were not able to demonstrate the long-term storage capability.

Based on the results of the project, it is not clear to City Utilities that CCS technology is a realistic option for utilities seeking to reduce their CO2 emissions from fossil fuel-fired power plants in the near term. As the CEO of a municipal utility, I have an obligation to the city and our customers to spend their money wisely. I cannot tell customers that I would have a degree of confidence that CCS would work.

Looking at all CCS research conducted to date, there appears to be no factual basis on which EPA may assert that carbon sequestration technology has met the Clean Air Act's three-part test for BSER. Sequestration technology has been not adequately demonstrated. It is not widely available and has not been shown to be technically and economically feasible.

III. EPA Failed to Assess the Non-Air Public Health Environmental Impacts in Determining that Partial CCS Is BSER.

Clean Air Act Section 111(a) requires EPA to select a standard of performance that:

> [R]eflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

EPA's preferred NSPS option for coal-fired EGUs—partial CCS—fails to assess or discuss the "non-air public health and environmental impacts" of the technology. The proposed regulation does so by defining CCS as "carbon capture" (i.e., the "s" is silent). Agency protestations that the "non-air environmental effects" of sequestration either do not need to be examined or were examined in a recently issued Class 6 Underground Injection Control (UIC) permit rulemaking[5] are unavailing. The failure to examine non-air environmental consequences of CCS is a blatant violation of the letter and the spirit of the Clean Air Act and the public's trust. EPA's proposed NSPS for fossil fuel-fired EGUs could create an imminent harm of transferring air pollution to other environmental media, not dissimilar to man's disposal of wastes in much of the 19th and 20th Centuries without consideration of the potentially profound human health and environmental damages that would result.

Below are some of the issues the agency failed to address in its BSER determination. These include issues outside the scope of the Clean Air Act.

Hazardous Substance and Superfund Implications for Environmental Releases. EPA has not affirmed whether injection and sequestration of CO_2, an acid gas, is safe in non-oil and non-gas recovery locations. The agency needs to consider whether an acid gas would have the potential to change the pH of soil or, if released into the environment, whether it poses a potential threat to health or the environment. If acid gas injections have the potential to trigger remediation under the Community Emergency Response, Compensation, and Liability Act (CERCLA) (also known as the Superfund Act), then clearly the technology cannot be demonstrated.

[5] 79 Fed. Reg. 350 (Jan. 3, 2014).

Surface Water Contamination. There are increasingly significant questions regarding surface water quantity and quality raised by partial CCS. These involve the substantial quantities of water used in the injection process and the effect of large amounts of compressed gases on groundwater and surface water movement. Also, it is well understood within the agency's water office that seasonal surface water flow is very much affected by hydraulic heads in various groundwater aquifers. Altering these pressure gradients can cause numerous human health and environmental impacts, none of which have been studied by EPA in the context of permanently disposing vast quantities of compressed gases. They are, however, dramatically demonstrated by unprecedented water shortages currently being experienced in western and plains states. APPA believes that these "quantity" issues, ironically, could be exacerbated by the proposed BSER solution, particularly in western states experiencing drought conditions.

Moreover, there is tremendous potential for CCS to interfere with access to water in western states. For example, EPA has not taken into consideration the fact that subsurface western water rights are often depth restricted. Other physical consequences for drinking water, such as changes in hydraulic heads pushing water toward or away from groundwater wells and surface waters, must be closely analyzed and peer-reviewed.

Navigable Waters and Surface Water Flow. Given that EPA is considering policies affecting waters of the United States in another proceeding, it should also examine the consequences of subsurface CO_2 sequestration on "navigable waters" that support a variety of commercial and ecological interests. The agency needs to examine whether there is any chance that subsurface locations where CO_2 is sequestered could later be declared navigable waters.

Endangered Species Act (ESA): There is nothing in the record indicating that EPA has consulted with the U.S. Fish and Wildlife Service (FWS) under Section 7 of the ESA to determine whether sequestration of CO_2 into deep saline aquifers is permitted. Many deep saline aquifers run either through or under ESA's Habitat Conservation Plans, Conservation Banks, and Safe Harbor Agreement sites. While EPA may not be *required* by the CAA to consult with FWS in this specific rulemaking, permit applicants for federal CAA construction permits have to do so.

As U.S. Court of Appeals for the D.C. Circuit Judge Leventhal reminded EPA in *Portland Cement v. Ruckelshaus*[6] – shouldn't the agency be held similarly accountable? If not, how might these ESA-protected areas limit locations for sequestration? Has EPA or NETL attempted to reflect these limitations in its assessment or NETL's Carbon Sequestration Atlas,[7] which gives its prediction of potential geologic sequestration sites? The DOE Carbon Sequestration Atlas does not indicate areas with other environmental restrictions, such as National Parks, Wilderness Areas, etc., where sequestration of CO_2 might not be allowed. Very little mapping has been done of deep saline aquifers on the granular level required to actually predict CO_2 storage on a gigaton basis.

Land Planning: Little, if any, consideration has been given to the amount of land that is required for a commercial-sized operational partial CCS system. Such operations require at least

---

[6] 486 F.2d 375

[7] http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlas/

six square acres of surface space, almost inconceivable for most plants owned by public power utilities and many plants owned by investor owned utilities that were constructed between 1950-1970 near population centers and close to rivers and other water ways for cooling water and coal delivery.

Seismic Activity. Although EPA maintains that it has consulted the U.S. Geological Service (USGS) about seismic activity in the vicinity of EOR, agency officials have not sufficiently consulted with USGS regarding injection of CO_2 in non-oil and gas formations. Nor has the agency addressed specific concerns researchers have that are related to how quickly the CO_2 may be injected to maintain pressure in the rock. In addition, there is nothing in the record that shows that has EPA consulted with state departments of geology about their concerns with the vulnerabilities posed by injection of huge volumes of CO_2 under pressure, including potential earthquakes from hydraulic fracturing (HF). The agency is looking at these issues in its recent inquiry into seismic events for water injects in Oklahoma and Texas for natural gas production disposal wells. Why does it not also inquire and answer these questions in the context of geologic sequestration of CO_2?

In addition, EPA apparently assumes injection research efforts would be free based upon its assessment that the NSPS would have no research and development costs associated with each sequestration project. There are no projections on the cost of detailed acoustic and seismic readings in geologic locations where there is no extractive industry. The agency also appears to assume that there is no cost involved with the multimillion dollar subsurface studies needed in order to conduct permit applications under UIC Class V, Class VI, or Class II for injection of CO_2 by power plants. It is highly improbable that this data exists in the public domain or that it would be free. EPA needs to account for these costs and factor them into its analysis of CCS.

While the separation of CO_2 might be demonstrated, the sequestration of CO_2 is inherently location specific. This means that in each underground location, detailed acoustic readings and seismic assessments must take place by bonded, licensed, and experienced companies to determine the carrying capacity and injection rate into that rock formation for 30 to 50 years. These companies must also rule out any risks of inadvertent seismic events. The NETL Carbon Sequestration Atlas is informative, but offers no indicators of the carrying capacity or storage retention capacity of the listed geologic formations. That information is rock and location specific.

Natural Resource Depletion. EPA's proposed rule fails to identify the consequence of CCS on fossil fuel resources. What makes this glaring omission so troubling is that the record indicates that the agency consulted with the Department of Energy (DOE) and Energy Information Agency (EIA). Yet EPA and DOE apparently missed the very important concept that because CCS separation and injection technologies actually use more fuel with a parasitic power loss of about 30 percent at the plant, that coal-fired power plants (and natural gas-fired power plants with CCS, should that one day be required) will actually cause a hastening of the use of U.S. coal and natural gas. The depletion of fuel resources is equally a requirement of NEPA-like assessments.

Resolution of Underground Access and Trespass Issue. A question EPA has failed to address is how can a technology be demonstrated if it is not legal in all 50 states for a party to inject into and under the property owned by others? Many states do not have separate surface and subsurface land ownership. In most states, a property owner owns what is his land from the surface to "the heavens" and to the middle core of the earth. Only in extractive industry states are there separate ownership options to enable oil, gas, and hard/soft rock mining. Where there are no options for "mineral rights" ownership, the geologic sequestration of CO_2 that might migrate under another person's property is a legal trespass. This is a critical legal issue that has to be resolved before declaring that CCS is commercially demonstrated. Interestingly, all three of the U.S. CCS pilot projects are in oil and gas recovery operations and those states have mineral right ownership of the subsurface.

APPA has several papers and presentations that elaborate in more detail on the issues with CCS. A list of the documents and the links where they can be accessed is included at the end of this statement.

IV. EPA's Science Advisory Board (SAB) Questioned Whether the Agency Addressed Cross-Media Issues in Peer Review Regarding Geologic Sequestration.

On December 4 and 5, 2013, EPA's SAB raised concerns about the scientific and technological bases EPA relied upon when proposing to mandate CCS for NSPS for new coal-fired power plants. Specifically, the SAB expressed concern with the peer review process of the DOE studies that were relied upon in the proposed rule, how the agency came up with its emissions limits for new coal- and natural gas-fired power plants, and the fact that the proposed rule does not address the sequestration side of CCS. EPA responded to those concerns by asserting that regulatory mechanisms for addressing sequestration were outside the scope of Clean Air Act and thus do not need to be addressed in the NSPS for new fossil fuel-fired power plants. Agency staff stated that only the capture side of CCS needs to be addressed.

The SAB, in a letter to EPA Administrator Gina McCarthy, dated January 29, 2014, stated it "defers to EPA's legal view…that the portion of the rulemaking addressing coal-fired power plants focuses on carbon capture" because that is all that is within the scope of the Act. The letter notes, however, that "carbon capture is a complex process, particularly at the scale required under this rulemaking, which may have multi-media consequences." The board expressed its strong view that "a regulatory framework for commercial-scale carbon sequestration that ensures the protection of human health and the environment is linked in important systematic ways to this rulemaking." It encouraged EPA to have the National Research Council review the research and information on sequestration conducted by it, DOE, and other sources.

While SAB deferred to EPA's legal interpretation of its authority to look at cross-media issues rising from sequestration of CO_2, it is significant that the SAB raised these concerns. It is clear that several members of the SAB agree with APPA that these issues need to be resolved before CCS is declared BSER.[8]

V. Conclusion

APPA believes it is premature to conclude that CCS is the BSER adequately demonstrated. While CCS may one day be a viable, economic, and commercially demonstrated technology utilities can use to reduce CO_2 emissions from power plants, it is not one they can use today or in the near future. There are a host of issues EPA has failed to look at related to the long-term sequestration of CO_2, including "non-air public health and environmental impacts" of CCS technology. The agency essentially equates sequestration with EOR. They are not the same. EOR is only available in parts of the country with oil and gas reserves and involves the recycling of CO_2 with no long-term storage. CO_2 captured from power plants in non-EOR areas will need to be stored for thousands of years. The results from the Missouri Shallow Carbon Sequestration Project show that further research is required before utilities can sequester CO_2 in the ground. And based on all CCS research conducted to date, there appears to be no factual basis on which EPA may assert that carbon sequestration technology has met the Clean Air Act's three criteria. Sequestration technology has been not adequately demonstrated. It is not widely available. Nor has it been shown to be technically and economically feasible. Until it has, EPA should reverse its determination that CCS is BSER.

[8] Per the request of the SAB, APPA sent a letter to it on December 9, 2014, outlining our concerns with the many obstacles to commercial demonstration of sequestration. The letter can be viewed at http://www.publicpower.org/files/PDFs/APPA%20Letter%20to%20EPA%20on%20SAB%20--%20FINAL%20--%2012-9-2013.pdf.

Carbon Capture and Storage Papers & Presentations Commissioned by APPA

L.D. Carter, White Paper, "Retrofitting Carbon Capture Systems on Existing Coal-fired Power Plants," November 2007 http://www.publicpower.org/files/PDFs/DougCarterpapernov07.pdf

L.D. Carter, White Paper, "Carbon Capture and Storage From Coal-based Power Plants: A White Paper on Technology for the American Public Power Association (APPA)," May 2007 http://www.publicpower.org/files/PDFs/Doug%20Carter%20-%20Carbon%20Capture%20and%20Storage%20From%20Coal.pdf

Doug Carter, Presentation, "Parasitic Power for Carbon Capture" http://www.publicpower.org/files/PDFs/CarterParasiticower.pdf

Timothy Gablehouse, White Paper, "Geologic CO_2 Issue Spotting and Analysis" July 2009 http://www.publicpower.org/files/PDFs/GablehouseSequestrationWhitePaper72209.pdf

Marianne Horinko, White Paper, "Carbon Capture and Sequestration Legal and Environmental Challenges Ahead," August 2007 http://www.publicpower.org/files/PDFs/Horinko%20CCS%20White%20Paper%20August%2007.pdf

Jonathan Gledhill, Policy Navigation Group; James Rollins, Policy Navigation Group; Theresa Pugh, APPA, White Paper, "Will Water Issues/Regulatory Capacity Allow or Prevent Geologic Sequestration for New Power Plants? A Review of the Underground Injection Control Program and Carbon Capture and Storage," November 2007 http://www.publicpower.org/files/PDFs/UICCCSpaper.pdf

Theresa Pugh Presentation, "Sober Thoughts About CCS for Retrofit or New Fossil Plants as a CO_2 Mitigation Measure from 2009-2029," Presented Nov. 3, 2009 http://www.publicpower.org/files/PDFs/PughCCSpresentation110309.pdf

Theresa Pugh Presentation, "Infrastructure Costs, Permitting Issues and Parasitic Energy Loss for Power Plants with CCS," Presented Jan 29, 2008 in Tucson, AZ http://www.publicpower.org/files/PowerPoint/TPEUECPresentation2008.ppt

Carbon Capture and Storage: Analysis of Potential Liabilities Associated with Groundwater Contamination Due to Geological Sequestration Operations, September 10, 2008
Prepared by Fredric P. Andes and Kari A. Evans, members of the Barnes & Thornburg LLP Water Team, for the American Public Power Association (APPA)
http://www.publicpower.org/files/PDFs/APPA%20CCS%20white%20paper%20Waters%20of%20the%20US.pdf